HUNTON ANDREWS KURTH

HUNTON ANDREWS KURTH LLP
2200 PENNSYLVANIA AVENUE, NW
WASHINGTON, D.C. 20037-1701

TEL 202 • 955 • 1500
FAX 202 • 778 • 2201

BRIAN R. LEVEY
DIRECT DIAL: 202 • 955 • 1629
EMAIL: blevey@HuntonAK.com

May 30, 2023

FILE NO: 029142.0070344

Via www.regulations.gov

Mr. Richard Benware
Engineering and Analysis Division
Office of Water, (4303T)
U.S. Environmental Protection Agency
1200 Pennsylvania Ave. N.W.
Washington, DC 20460

Re: Comments on EPA's Proposed Rule; Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 88 Fed. Reg. 18,824 (Mar. 29, 2023), EPA-HQ-OW-2009-0819

Dear Mr. Benware:

Attached are the Comments of the Utility Water Act Group (UWAG) on EPA's Proposed Rule for the Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-HQ-OW-2009-0819.

We appreciate the opportunity to comment. Please contact me at (202) 955-1629 if you have any questions.

Sincerely,

Brian R. Levey

Brian R. Levey

Attachment

Comments of the Utility Water Act Group on Environmental Protection Agency Proposed Rule; Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category

88 Fed. Reg. 18,824 (Mar. 29, 2023)
Docket ID No. EPA–HQ–OW–2009–0819

May 30, 2023

www.utilitywateractgroup.org

Executive Summary

EPA's new proposed effluent limitations guidelines (ELG) rule represents a staggering change of course on wastewater treatment requirements that were just imposed in EPA's 2020 ELG rule. The electric power industry is transitioning to low- and zero-carbon power as fast as possible consistent with providing affordable and reliable energy. This rulemaking threatens to disrupt those efforts by diverting time and money to a mid-course change unlikely to yield benefits commensurate with its costs. The Utility Water Act Group (UWAG)[1] urges EPA to preserve key aspects of—and tremendous industry and public investments made in reliance upon—EPA's 2020 ELG rule.

A. EPA Should Preserve Key Aspects of the 2020 ELG Rule.

EPA's final 2020 ELG Rule required covered facilities to either commit millions of dollars and years of time to installing new wastewater treatment equipment, or retire. Numerous plants announced plans to retire, and the remainder are now incurring substantial costs to comply with the 2020 Rule's still-binding requirements. Naturally, the costs to comply with the 2020 Rule will be borne by the public in the form of higher electricity rates.

Now EPA is proposing another new ELG rule that would require facilities to abandon ongoing installation and startup of new equipment required by the 2020 Rule, and replace it with different, highly expensive and unproven technology EPA specifically rejected in the 2020 Rule. The result will be a loss of hundreds of millions of dollars on equipment the rule renders obsolete

[1] UWAG is a voluntary, non-profit, unincorporated group of 129 energy companies, which own and operate over fifty percent of the nation's total generating capacity, and three national trade associations of energy companies. The individual energy companies operate power plants and other facilities that generate, transmit, and distribute electricity to residential, commercial, industrial, and institutional customers. UWAG's purpose is to participate on behalf of its members in federal agency rulemakings under the Clean Water Act and related statutes, such as NEPA, and in related proceedings.

just as it is being installed and started up, compounded by substantial additional costs for new equipment required by the proposed rule, further increasing the total cost of electricity to the public and prompting more retirements of reliable baseload sources of electricity. The proposed rule's reversal in course is not supported by the facts and lacks a proper basis under the law.

EPA should preserve the key aspects of, and industry's investments to comply with, the 2020 Rule. Specifically, UWAG urges EPA to preserve its 2020 determinations as to membrane technology by either:

- continuing to recognize that membrane filtration is not nationally available or economically achievable, and poses unacceptable environmental risks; or
- allowing facilities that have made irreversible commitments of resources to comply with the 2020 Rule to continue under the limits established by that rule until 2032, at which point those facilities must either meet new proposed zero discharge requirements or retire or repower by 2035.

These recommendations will allow EPA to ensure that electric utilities and the public are not compelled to incur significant costs in reliance on the 2020 Rule, then suddenly deprived of the benefits of those expenditures and compelled to incur another layer of substantial costs that renders continued operation of reliable baseload facilities uneconomic. As the Supreme Court explained nearly thirty years ago:

> Elementary considerations of fairness dictate that individuals should have an opportunity to know what the law is and to conform their conduct accordingly; settled expectations should not be lightly disrupted. … In a free, dynamic society, creativity in both commercial and artistic endeavors is fostered by a rule of law that gives people confidence about the legal consequences of their actions."

Landgraf v. USI Film Prods., 511 U.S. 244, 265–66 (1994).

B. EPA Must Explain and Support Its Reversal In Course.

UWAG urges EPA not to proceed toward final ELG limits based on unsupported membrane technology that it rejected in 2020. If EPA nonetheless proceeds with a membrane-based ELG rule, it must explain its reversal in course. In particular, EPA should specifically address substantial reliance interests by utilities and the public who irretrievably incurred hundreds of millions of dollars in costs due to the still-binding 2020 Rule.

EPA should further confirm that it has not, as suggested by various media reports, reversed course and proposed costly new ELG requirements on top of ongoing costs to comply with the 2020 Rule in furtherance of an "all in" goal to close coal plants. EPA also should explain and, as appropriate, adjust the retirement provisions of the Proposed Rule so that facilities that have made irretrievable investments in compliance with the 2020 Rule are not unduly excluded from the opportunity to either continue to operate under the 2020 Rule or retire.

C. Any New ELG Rule Must Be Reproposed and Make Important Changes.

EPA should make fundamental changes to the proposed rule and republish it for an adequate public comment period. The current record in support of the proposed rule does not demonstrate that membrane technology is nationally available or economically achievable, or that its environmental risks are acceptable. To the contrary, the few examples of uses of membrane technology referenced in the proposed rule lack detail, are technically flawed, and do not account for full-scale operations. And EPA's analysis of wastewater treatment technology for leachate excludes nearly half of the potentially regulated facilities. Equally problematic, the 60-day comment period was not only shorter than prior, less complex ELG proposals but was far less than necessary for regulated entities to analyze the 80-page, single-space proposal with over 1,300 attachments, and address EPA's request for comments on over 125 topics.

EPA should issue a new proposal that addresses and corrects these flaws and allow a sufficient time for public comment if it intends to proceed with this rulemaking. If EPA declines to do so, it should (at a minimum) make the following key adjustments:

- **Tailor the Rule to Preserve Investments Made in Reliance on EPA's 2020 ELG Rule.**
  - Modify the proposed Early Adopter subcategory to:
    - establish a qualification deadline based on meeting the 2020 Rule discharge limits by the applicability date in a facility's permit;
    - allow facilities that have installed biological treatment based on the 2020 Rule to either: (i) cease coal combustion at a later date than December 31, 2032 (no earlier than December 31, 2035) or (ii) continue to operate subject to zero liquid discharge (ZLD) limits by a permit writer's "as soon as possible" (ASAP) date between December 31, 2032, and December 31, 2040.
  - Establish a new subcategory, if EPA does not incorporate UWAG's recommendations into the proposed Early Adopter subcategory, that would:
    - allow facilities the option to either comply with the zero discharge limits no later than December 31, 2032, or avoid new ELG requirements by committing to repower or retire by December 31, 2035.

- **Maintain the 2020 Rule's Sound Determinations on Flue Gas Desulfurization (FGD) Wastewater Treatment.**
  - Maintain EPA's position that membrane filtration is not nationally available, economically achievable, or environmentally sound for covered units.
  - Maintain EPA's position that chemical precipitation plus biological treatment is best available technology economically achievable (BAT), not membranes, thermal evaporation, or other technologies.

- **Reevaluate, Revise, and Repropose Combustion Residual Leachate (CRL) Limits.**
  - Repropose leachate requirements after EPA evaluates BAT for the complete population of potentially impacted landfills and impoundments.
  - Provide flexibility for landfills and impoundments nearing closure or recently closed or retired, especially if EPA proceeds based on chemical precipitation.
  - Recognize that other stringent technologies are not BAT for leachate because the record lacks sufficient information to support such a determination.

- **Recognize that BAT Determinations Apply only to Direct Surface Water Discharges.**
  - ELG rules are inherently designed to address effluent discharges via outfalls into surface waters; releases into groundwater are subject to separate requirements.
  - BAT determinations do not logically apply to indirect discharges via groundwater to waters of the United States and should not be part of this rule.
    - If EPA proceeds with addressing groundwater issues in the ELG rule, it must address fundamental problems with applying the National Pollutant Discharge Elimination System (NPDES) permit program to these types of releases.

- **Maintain the 2020 Rule's Sound Determinations on Bottom Ash Transport Water (BATW).**
  - Maintain EPA's 2020 determination that a high recycle rate BATW system with a limited purge is the appropriate model technology for BAT limits for BATW.

- **Do Not Apply New ELG's Retroactively to Legacy Wastewater.**
  - EPA should not apply new ELGs retroactively to discharges associated with wastewater that was generated prior to the new ELGs' effective date.
  - EPA should not specify a nationwide technology basis for legacy wastewater if EPA's new ELG applies to wastewater generated before the applicability date.

Table of Contents

Acronyms

ACRONYM	DEFINITION
2030 Baseline	IPM 2030 Pre-Inflation Reduction Act 2022 Reference Case
AMWA	Association of Metropolitan Water Agencies
APA	Administrative Procedure Act
ASAP	as soon as possible
AWWA	American Water Works Association
BA	bottom ash
BAT	best available technology economically achievable
BATW	bottom ash transport water
BCT	best conventional technology
BOD5	biochemical oxygen demand
BPJ	best professional judgment
BPT	best practicable control technology
CAA	Clean Air Act
CBI	confidential business information
CCR	coal combustion residual
CP+LRTR	chemical precipitation followed by a low hydraulic residence time biological reduction treatment
CPCN	Certificate of Public Convenience and Necessity
CRL	combustion residual leachate
CWA	Clean Water Act
DESC	Dominion Energy South Carolina
EDR	electrodialysis reversal
EGU	electric generating unit

ACRONYM	DEFINITION
ELGs	effluent limitations guidelines
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERG	Eastern Research Group, Inc.
ESA	Endangered Species Act
FATW	fly ash transport water
FERC	Federal Energy Regulatory Commission
FGD	flue gas desulfurization
FGDW	flue gas desulfurization wastewater
FIP	Federal Implementation Plan
FOIA	Freedom of Information Act
GHG	greenhouse gas
gpd	gallons per day
gpm	gallons per minute
Gw	gigawatts
IPL	Indianapolis Power & Light
IPM	Integrated Planning Model
LRTR	low hydrologic residence time biological reduction
LWW	legacy wastewater
MATS Rule	Mercury and Air Toxics Standard regulations
MCL	maximum contaminant level
MDL	method detection limit
MDS	mechanical drag system
MISO	Midcontinent Independent System Operator

ACRONYM	DEFINITION
MWh	megawatt hour
NARUC	National Association of Regulatory Utility Commissioners
NEEDS	National Electric Energy Data System
NERC	North American Electric Reliability Corporation
NLT	no later than
NOPP	Notices of Planned Participation
NPDES	National Pollutant Discharge Elimination System
NSPS	new source performance standards
O&M	operating and maintenance
OMB	Office of Management and Budget
ORSANCO	Ohio River Valley Water Sanitation Commission
PFAS	per- and polyfluoroalkyl substances
PP15	Preliminary Effluent Guidelines Program Plan 15
ppm	parts per million
PRA	Paperwork Reduction Act
PSC	public service commission
PUC	public utility commissions
RCRA	Resource Conservation and Recovery Act
RML	reference margin level
RO	reverse osmosis
RPA	reasonable potential analyses
RTO/ISO	transmission organization/independent system operator
SCC	state corporation commission
SDE	spray dryer evaporator

ACRONYM	DEFINITION
SGC	submerged grind conveyer
TBELs	technology-based effluent limitations
TDS	total dissolved solids
TSS	total suspended solids
TTHM	total trihalomethanes
TWF	toxic weighting factor
TWPE	toxic-weighted pounds-equivalent
UWAG	Utility Water Act Group
VIP	Voluntary Incentives Program
VSEP	vibratory shear enhanced process
WV PSC	West Virginia Public Service Commission
WQBELs	water quality-based effluent limits
ZLD	zero liquid discharge

**Comments of the Utility Water Act Group on
Environmental Protection Agency Proposed Rule;
Supplemental Effluent Limitations Guidelines and Standards for the
Steam Electric Power Generating Point Source Category**

I. Overarching Comments

A. Any New ELG Rule Must Be Based on Available, Economically Achievable Wastewater Treatment Technology.

The proposed ELG rule (Proposed Rule or Proposal)[2] must conform to governing Clean Water Act (CWA) requirements. The CWA requires EPA to set ELG limits based on a determination of the BAT for each category. CWA § 301(b)(2)(A), 33 U.S.C. § 1311(b)(2)(A). Specifically, the technology on which ELG limits are based must be available, economically achievable, and reflect the best performance in the point source category. When developing ELGs, the CWA requires EPA to consider "the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate." CWA § 304(b)(2)(B), 33 U.S.C. § 1314(b)(2)(B). Rulemakings to establish ELG limits also must comply with the Administrative Procedure Act (APA) and applicable case law.

The economic achievability requirement is particularly relevant where EPA proposes to require new technology at an especially high cost that immediately renders obsolete new technology EPA just required three years earlier, which has not even become fully operational and which will continue to influence electricity costs for years to come. EPA may not simply assume that the costs of yet another layer of new ELG requirements can be absorbed by utilities

[2] 88 Fed. Reg. 18,824 (Mar. 29, 2023), EPA-HQ-OW-2009-0819-9025.

or the rate-paying public. EPA instead must demonstrate that the costs are economically achievable.[3]

EPA also must account for the fact that, as it has previously recognized, ELG requirements can impact "[r]esidential [e]lectricity [p]rices," 85 Fed. Reg. 64,650, 64,685 (Oct. 13, 2020), EPA-HQ-OW-2009-0819-8491 (2020 Rule). Indeed, the Department of Energy notes "[l]ow-income households face a disproportionately higher energy burden" that is "three times higher than for non-low-income households."[4] EPA should consider and address whether its Proposed Rule will have disproportionate cost impacts on low-income electricity consumers.

Furthermore, recent evidence indicates that public service commissions (PSCs) / public utility commissions (PUCs) often are unwilling to pass along costs, particularly where there is no certainty that the capital investment will have a sufficient period of return (*i.e.*, ensure compliance over a reasonable amortization period of ten years or more).[5] The Virginia State Corporation Commission (SCC), for example, recently found that a company had failed to "establish[] that the ELG investment is reasonable and prudent from an economic or a resource adequacy perspective" and denied the company's request for rate recovery.[6] That EPA is already

---

[3] *Texas Oil & Gas Ass'n v. EPA*, 161 F.3d 923, 928 (5th Cir. 1998) ("EPA must set discharge limits that reflect the amount of pollutant that would be discharged by a point source employing the best available technology that the EPA determines to be economically feasible across the category or subcategory as a whole.").

[4] U.S. Dep't of Energy, Office of State and Community Energy Programs, *Low-Income Community Energy Solutions: Why Institute a Low-Income Lens for Energy?*, www.energy.gov/eere/slsc/low-income-community-energy-solutions (last visited May 25, 2023).

[5] *See*, *e.g.*, Order at 18-19, *In re Electronic Application of Kentucky Power Company for Approval of a Certificate of Public Convenience and Necessity for Environmental Project Construction at the Mitchell Generating Station, An Amended Environmental Compliance Plan, and Revised Environmental Surcharge Tariff Sheets*, No. 2021-00004 (Ky. PSC July 15, 2021) (Kentucky PSC Order July 15, 2021) (denying recovery for ELG compliance costs).

[6] Order Granting Rate Adjustment Clause at 12, *In re Appalachian Power Co.*, No. PUR-2020-00258 (Va. SCC Aug. 23, 2021). Note the Virginia SCC later approved cost recovery for

proposing to change the ELG requirements promulgated less than three years ago gives PSCs/PUCs good reason to question whether investing in yet another round of new technology is reasonable. Indeed, where PSCs/PUCs have approved significant investments to comply with the 2020 Rule, companies and their regulators may be reluctant or unable to retire those facilities.

In the case of rural electric cooperatives, which are private not-for-profit entities owned by the consumers they serve, there is no rate recovery. All costs are passed through directly to the cooperatives' end-of-the-line consumer-members that already spend more of their limited incomes on electricity. For many capital projects, cooperatives rely on debt investors, such as the United States Department of Agriculture's Rural Utilities Service, and those borrowing costs also must be passed on to cooperatives' consumer-members. Public power utilities, as consumer-owned not-for-profit entities of state and local government, obtain 20-40 year bonds to finance large capital projects. Thus, the financing for new technologies would be directly passed on to public power utility customers.

B. The 2020 Rule Made Well-Grounded Determinations Under CWA Standards.

The 2020 Rule reflected years of ELG rulemakings and EPA's review of thousands of pages of studies, reports, and comments on the availability and economic achievability of various wastestream treatment technologies. For example, EPA "carefully consider[ed]" and "reject[ed] membrane filtration" as BAT because (1) "significant information gaps and uncertainties in EPA's record" precluded a finding that membrane filtration is technologically available nationwide; (2) "membrane filtration entails unacceptable non-water quality environmental

---

these facilities. *See* Final Order, *Petition of Appalachian Power Co.*, No. PUR-2022-00001 (Va. SCC Nov. 21, 2022) (Appalachian Power Order (Va. SCC Nov. 21, 2022)).

impacts associated with management of the membranes' byproduct, brine;" and (3) "membrane filtration would result in higher costs to industry." 85 Fed. Reg. at 64,663. EPA also determined in 2020, based on facilities' experience and data it collected regarding the challenges of implementing truly closed-loop BATW systems, that BAT for BATW is high recycle rate systems with a site-specific purge.

C. Companies and Regulators Made Substantial Time and Cost Commitments Based on the 2020 Rule.

The 2020 Rule compelled momentous company decisions—invest millions in new wastewater treatment to comply or retire or repower existing units. Power producers spent the next twelve months planning potential upgrades and financing and seeking approval from state authorities where necessary to either make those upgrades and recover costs from rate-payers or retire or repower. For utilities and state regulators, the choice was often difficult because removing a reliable, cost-effective source of electricity from the grid entails long-term costs and requirements to manage the retired facility and to replace the lost generation source.

Replacement with natural gas units can provide reliable baseload power with lower greenhouse gas (GHG) emissions but is not always an immediate option. Replacement with renewable generation can eliminate GHG emissions, but those facilities often do not provide reliable baseload electricity due to a current lack of large-scale energy storage, leading to potentially higher energy costs and lower reliability in the near term.[7] Some regulators refused to allow facilities to install equipment required by the 2020 Rule, while others refused to let facilities retire.

[7] All generation sources are also subject to the transmission infrastructure constraints in the region to support conveying new sources of low- and zero-carbon power to the electricity user.

By the October 2021 decision deadline set by the 2020 Rule for facilities to choose to retire rather than meet the new technology requirements, at least 74 units at 33 plants notified regulators they planned to retire rather than incur the costs of the 2020 Rule.

D. Facilities and Regulators Faced a Catch-22: Keep Spending Millions on a Rule EPA Planned to Change or Retire a Reliable Facility.

Just eight months after the 2020 Rule took effect, EPA announced in July 2021 that it planned to initiate a new rulemaking to revise the 2020 Rule, including by evaluating membrane technology as the basis for new ELG limits. At the same time, EPA announced that the 2020 Rule would stay in place and that it expected permitting authorities to continue to implement the 2020 Rule. The result was that electric utilities and their regulators faced a profound dilemma about how to proceed—a problem compounded by the challenges utilities and state regulators already faced in planning and funding a rapid transition to lower carbon sources while maintaining the reliability, affordability, and safety of the electric grid.

UWAG immediately raised these concerns to EPA, filing comments on October 14, 2021, on EPA's Preliminary Effluent Guidelines Program Plan 15 (PP15) docket.[8] UWAG explained that a new ELG rulemaking at the same time utility companies are making substantial investments of time and money to comply with technology-driven requirements of the 2020 ELG Rule would cause a substantial loss of time and money for utility companies and state regulators, impose higher costs on consumers, and contradict the technology choice just made by EPA in the 2020 Rule. EPA's new ELG rulemaking moved ahead, unhindered by these concerns.

[8] UWAG, Comments in Response to EPA's Preliminary Effluent Guidelines Program Plan 15 (Oct. 14, 2021), EPA-HQ-OW-2021-0547-0465 (UWAG Plan 15 Comments).

E. EPA's Reversal of Course on Membrane Technology Is Flawed.

EPA's July 2021 announcement that it was planning a new ELG rulemaking based on a re-evaluation of membranes stood in contrast to EPA's rejection of membrane filtration less than one year earlier, and showed no concern for reliance interests of facilities incurring millions of dollars in costs to comply with the 2020 Rule. Similarly, EPA's speed to reverse course on its technology determination was contrary to its practice of waiting at least seven years before revising ELGs due to the time required to incorporate ELGs into NPDES permits and associated costs for facilities.[9]

EPA said it was reversing course because membrane technology was continuing to rapidly advance, but provided no basis for that assertion publicly or in response to Freedom of Information Act (FOIA) requests from UWAG. Nor did EPA explain how abandoning multi-million dollar upgrades that take years to amortize, and instead require entirely separate membrane technology, would be economically achievable. And EPA did not explain how the membrane problems it identified in 2020 (availability, environmental impacts of brine, and cost impacts) disappeared just eight months later. But EPA did note that a new ELG rule fit within its power sector priorities for energy transition—*not* a statutory basis for an ELG rule.

In fact, despite a lengthy proposal and voluminous record, EPA has not demonstrated advances in membrane technology that justify reversing its rejection of membranes in the 2020 Rule. The application of membrane treatment to wastewater by other industries, or in small scale

[9] The CWA requires EPA to review effluent limitations "at least every five years and, if appropriate, revise[]" those limitations. CWA § 301(d), 33 U.S.C. § 1311(d). "In general, the EPA removes an industrial point source category from further consideration during a review cycle if the EPA established or revised the category's ELGs within seven years of the annual reviews. This seven-year period allows time for the ELGs to be incorporated into NPDES permits." EPA, Final 2016 Effluent Guidelines Program Plan, at 3-2 (Apr. 2018), EPA-HQ-OLEM-2017-0286-2232.

pilot studies, is substantially different than use at facilities that generate wastewater at a rate of millions of gallons per day (gpd). The reason membranes are not widely used by the electric utility industry is not lack of technological advancement, but rather that membranes are generally inefficient and uneconomical, and there are few proven, cost-effective methods for disposing of the concentrated wastestreams produced by such treatment systems.[10] Thus, it is unsurprising that EPA does not provide examples of full commercial-scale use of membrane technology to treat wastewater in the steam electric industry, much less demonstrate such technology is generally available.

EPA's reversal in course on membranes is not only technically flawed but also insufficiently supported in the Proposed Rule. Contrary to governing caselaw, EPA fails to acknowledge its abrupt and costly change in course, adequately explain the basis for that change, assess reliance interests on the 2020 Rule, determine whether those interests were significant, weigh such interests against its identified basis for the rule, or take public comment on such information and determinations. *See Dep't of Homeland Sec. v. Regents of the Univ. of Cal.*, 140 S. Ct. 1891, 1913–15 (2020).

[10] Combustion power plants use high volumes of water, the chemistry of which after use in plant processes presents specific treatment needs. Treating such high volumes of wastewater and their unique chemical composition with membrane technology requires not only a scale of membrane equipment commensurate with the volume of wastewater at steam electric plants, but also specialized equipment and processes specific to the various chemical compositions of steam electric wastewater. For example, use of membranes to treat FGD wastewater (FGDW) at steam electric plants generally requires ancillary treatment processes or equipment, such as pretreatment of wastewater prior to passing through the membrane, in order to prevent rapid fouling of the membranes. Use of membranes also requires equipment and methods for addressing the concentrated brine produced by membranes (the pollutants removed from the wastewater). The combination of these requirements generally renders membrane treatment cost-prohibitive and, due to impacts associated with the concentrated brine by-product, environmentally detrimental.

F. EPA Should Confirm GHG Reductions Are Not a Purpose of the Proposal.

Media reports have described EPA's announcement of the new ELG rulemaking as based on a desire to accelerate closure of coal-fired plants. For example, after the Supreme Court decision in *West Virginia v. EPA*, 142 S. Ct. 2587 (2022), that Clean Air Act (CAA) § 111(d) does not authorize EPA to require a shift of electricity generation away from coal-fired plants to reduce GHG emissions, a July 2022 *New York Times* article[11] described how EPA planned to rely on other rules, including water rules (such as the ELG proposal), to make coal-fired plants too expensive to operate.

To understand the basis for EPA's reversal in course on membranes and its decision to conduct a new rulemaking, UWAG asked EPA in a FOIA request for any new information EPA received since the 2020 Rule to support a new ELG rulemaking. EPA provided no new technical information to support the rulemaking in response to that request, including on membranes. But EPA did provide redacted documents from 2021 indicating the ELG reconsideration was part of a "cross-office power sector strategy" and that EPA's Office of Water was "excited to have robust discussions … about how the ELG might contribute [redacted]."[12]

UWAG supports EPA's broader purpose to reduce GHG emissions, but would not support an ELG rule designed to achieve those goals by making coal-fired steam electric plants too expensive to operate. An agency may not rely "on factors which Congress has not intended

[11] Lisa Friedman, *EPA Describes How It Will Regulate Power Plants After Supreme Court Setback*, N.Y. TIMES, July 7, 2022 (N.Y. TIMES July 7, 2022).

[12] Memorandum from Radhika Fox, OW, EPA, Briefing Memo, Memorandum for the Administrator, Steam Electric Reconsideration Option Selection at 1, (June 29, 2021), FOIA EPA-2022-003242, Response Documents 2, ED_006652_00039279-00001; Agenda for June 14, 2021 1pm Meeting w/ Melissa & Benita on Steam Electric, Steam Electric 2020 Rule Discussion at 2 (June 14, 2021), FOIA EPA-2022-003242, Response Documents 2, ED_006652_00039277-00001 (together EPA FOIA Response).

it to consider." *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (*State Farm*).[13] Given the Supreme Court's decision in *West Virginia v. EPA* that a rule designed to shift generation away from coal in order to reduce GHG emissions exceeded EPA's authority under CAA § 111(d), EPA likewise does not have authority to do so indirectly via CWA ELG rulemaking.

G. The Proposal Would Likely Divert Resources From the Transition to Cleaner Generation Sources.

UWAG members have strong incentives to transition away from coal combustion toward lower- and zero-carbon generation (especially renewable energy) as quickly as possible, consistent with their obligations to ensure a safe, reliable, and affordable supply of electricity. These incentives include corporate commitments to reduce GHG emissions, consumer and market demand for such reductions, billions of dollars in funding (including important tax incentives) under recent federal legislation, financial institutions shifting financing away from fossil fuels, and a regulatory climate that favors transition.

But hasty plant closures and costs to comply with new ELG requirements could cause broad disruptions with unintended impacts, such as reduced grid reliability, diversion of resources away from transition to new generation, and increased electricity costs to consumers. As recently noted in the *Wall Street Journal*, there are numerous variables beyond the control of utility companies and EPA that could delay efforts to transition to new generation, such as supply chain problems, labor shortages, and delay permitting new infrastructure:

---

[13] The Supreme Court has emphasized that such major policy questions may not be decided by agencies absent plain direction from Congress, which CWA §§ 301(b) and 304(b) do not provide. *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 160 (2000) ("[W]e are confident that Congress could not have intended to delegate a decision of such economic and political significance to an agency in so cryptic a fashion.").

> Whether or not we can actually permit and build projects at [the modelled] pace is the big unknown …. [T]here are many challenging variables, including grass-roots opposition to large-scale energy projects, yearslong approval processes to connect projects to the grid, delays in importing solar panels and a shortage of construction workers …. Storage developers have in the past year faced supply-chain constraints and an increase in the cost of raw materials, including copper and lithium, critical components of most grid-scale batteries. … Some of the biggest hurdles to the renewable deployment envisioned in the climate bill are bottle-necks in the permitting and siting of transmission lines.

Katherine Blunt & Phred Dvorak, *Climate Bill's Success Hinges on Timely Renewable-Projects Build-Out*, WALL ST. J., Aug. 13, 2022 (internal quotation marks omitted).

The most recent North American Electric Reliability Corporation (NERC) Long-Term Reliability Assessment states that over 88 gigawatts (GW) of generating capacity is confirmed for retirement over the next ten years while electricity peak demand is expected to grow and that policymakers need to "[m]anage the pace of generator retirements until solutions are in place that can continue to meet energy needs and provide essential reliability services." NERC, 2022 Long-Term Reliability Assessment at 7 (Dec. 2022) (2022 LTRA); *see*, Peter Behr, *U.S. risks power outages as coal, gas plants retire—NERC*, ENERGYWIRE, Dec. 19, 2022.

If companies have no choice but to continue operating existing facilities to meet grid reliability requirements and consumer demand, companies and their customers may be forced by the proposed ELG rule to absorb significantly higher costs of switching to new membrane-based systems, new leachate treatment, BATW retrofits, and timing changes among other requirements. For companies that choose to retire rather than install new systems, they nonetheless may be ordered by their governing PSC/PUC to continue operating for grid reliability or other emergency reasons, which would cause disruption in resource and transition planning for those facilities and the affected grid. For facilities that do install new technology under the new rule, companies and their regulators will be financially motivated to keep those facilities operating longer in order to recover those investments over a period of time that keeps rates as affordable as possible.

The result could be that the new ELG rule will divert financial and labor resources that would be better spent on an efficient transition to renewable and other zero- or low-carbon generation sources, thereby delaying new generation sources and causing higher electricity costs (which could have disproportionate economic impacts on lower income communities).

Grid system operators have recently expressed concerns with other EPA rulemakings (such as EPA's proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, 87 Fed. Reg. 20,036 (Apr. 6, 2022)) that may force hasty closures of existing facilities.[14] Those concerns include the time required to obtain regulatory approvals for new generation, the need for current generation sources to provide an interim back-up to renewable resources (which generally provide only intermittent power), and the risk that accelerated retirement of existing generation will exacerbate an already decreasing power capacity margin on the grid (which impacts reliability at a time when increased reserve margins are needed to address generation retirements and severe weather conditions).

H. EPA Should Provide an Additional Public Comment Period Because of the Flaws in the Proposal and the Insufficient Period Provided.

A comment period for a proposed rule must be sufficient to enable parties to evaluate the large amount of data and record materials EPA has accumulated and uploaded to the docket.

[14] *See* Electric Reliability Council of Texas, Inc. et al., Comments on EPA's Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard (June 21, 2022), EPA-HQ-OAR-2021-0668-0413; *see also* PJM, *Energy Transition in PJM: Resource Retirements, Replacements & Risks* at 7 (Feb. 24, 2023) (PJM Report Feb. 2023) ("the combined requirements of [EPA's] regulations [including, specifically, the ELG rule] and their coincident compliance periods have the potential to result in a significant amount of generation retirements within a condensed time frame").

Executive Order 12866 calls for at least 60 days to comment. "[E]ach agency should afford the public a meaningful opportunity to comment on any proposed regulation, which in most cases should include a comment period of not less than 60 days." Exec. Order No. 12866 § 6(a)(1) (Sept. 30, 1993), *reprinted in* 58 Fed. Reg. 51,735, 51,740 (Oct. 4, 1993). If the standard comment period is "not less than 60 days" in "most cases," then there must be cases that deserve more than 60 days. And if this rulemaking, with its enormous record and complex issues, is not such a case, it is difficult to imagine what could possibly qualify.

On March 29, 2023, UWAG submitted a request to EPA to extend the deadline for public comments on the proposed ELG rule to 120 days. *See* EPA-HQ-OW-2009-0819-9981. UWAG made the request based on a number of concerns, including the complexity of the issues, the significant consequences for the industry and the public, and the scope of the record. Unfortunately, on May 11, 2023, EPA denied this request outright and stated there would not be an extension of the comment period. Within the limited 60-day timeframe, UWAG has sought to comprehensively review the Proposed Rule, the underlying data, and the technical support documents. But, with more than 1,300+ supporting documents in the record – some of which did not appear in the docket for weeks and others that had to be obtained from EPA's reading room – this was an impossible task.[15] EPA also solicited comments and requested feedback on over 125 topics. Addressing this range of materials and topics was a substantial undertaking. UWAG's comments attempt to provide meaningful comment on the proposal, but 60 days is simply not enough time to digest, analyze, and address the issues raised in the proposal, especially in light

[15] Not only was it infeasible to review the more than 18 databases and 260 spreadsheets EPA created to support the proposal, it was also infeasible to make comparisons of those databases and spreadsheets to tens of thousands of existing documents from the 2015 and 2020 portions of the record and understand how EPA's new work is consistent with, or differs from, its earlier work.

of the size of the record and its lack of transparency. EPA's issuance of proposed rules addressing GHG emissions under CAA section 111 and legacy coal combustion residual (CCR) surface impoundments during the comment period also hindered the commenting effort and UWAG's ability to provide comprehensive input on potential impacts to the steam electric industry.

II. Comments on Proposed Subcategories

A. EPA Compelled Facilities To Continue To Make Major Investments Under the 2020 Rule at the Same Time it Was Proceeding with this Rulemaking.

On November 3, 2015, EPA published the final 2015 ELG Rule, which provided limitations and standards on various wastestreams, including FGDW, BATW, fly ash transport water (FATW), flue gas mercury control wastewater, gasification wastewater, and CRL. In 2017, EPA received several petitions for review of the 2015 Rule, including a petition from UWAG, dated March 24, 2017, requesting that EPA reconsider the 2015 Rule and requesting that EPA suspend that Rule's approaching deadlines.[16] When EPA decided to reconsider the 2015 Rule, EPA postponed the compliance dates for the FGDW and BATW limits to preserve the status quo. *See* EPA, Postponement of Certain Compliance Dates for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Final Rule, 82 Fed. Reg. 43,494 (Sept. 18, 2017), EPA-HQ-OW-2009-0819-7080 (2017 Postponement Rule). EPA explained that the postponement would "prevent the unnecessary expenditure of resources until EPA finalizes any rulemaking as a result of its reconsideration of the 2015 Rule." 82 Fed. Reg. at 43,495. In particular, EPA pointed to

[16] UWAG, Petition for Rulemaking to Reconsider and Administratively Stay the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Final Rule, 80 Fed. Reg. 67,838–903 (Nov. 3, 2015) (Mar. 24, 2017), EPA-HQ-OW-2009-0819-6478.

estimated costs of compliance with the 2015 Rule and noted that, "in the event that EPA revises these requirements in a future rulemaking, these are costs that would be incurred for activities that ultimately might not be necessary. In that case, this would reflect costs incurred by facilities and potentially passed on to utility rate payers that ultimately did not need to be spent." 82 Fed. Reg. at 43,497.

EPA could (and should) have taken the same approach here. However, when EPA announced it was planning a new ELG rulemaking in 2021, it simultaneously said facilities must continue to comply with 2020 Rule requirements—despite years of time and high costs per facility to meet those requirements. In other words, EPA decided in 2021 to *both* conduct a new ELG rulemaking *and* require facilities to continue with major investments and facility changes under the 2020 Rule. UWAG raised concerns to EPA about the waste of resources and costs that companies and the rate-paying public would face.[17] EPA could have paused compliance and expenditures then, or accounted for these concerns in the proposed rule, but did neither.

As a result of EPA's position, companies have incurred and continue to incur significant costs to raise capital for, plan, design, procure, and construct systems to meet the 2020 Rule's compliance deadlines "as soon as possible."[18] These costs will be lost if, as EPA recognizes,

---

[17] *See* UWAG Plan 15 Comments at 1–3 ("If EPA's new rulemaking seeks to establish new limits based on the installation and operation of different technologies at substantial additional costs, EPA should consider ways to avoid the potential for significant waste of investment in and construction of treatment systems that may soon be superseded.") (footnotes omitted).

[18] *See*, *e.g.*, Petition for Approval of an ELG Project and Related Surcharge at Exhibit DVS-D, pages 4-5 of 12 and 9 of 12, *In re Monongahela Power Company & The Potomac Edison Company*, No. 21-0857-E-CN (W. Va. PSC Dec. 17, 2021) (Testimony providing descriptions of six ELG compliance projects at two facilities with estimated compliance costs of over $142 million) (Monongahela Power Petition for Approval).

facilities are forced to "replace [them] with membrane systems."[19] The costs incurred also will not be fully depreciated, will continue to impact customer affordability with no corresponding benefit to the environment, and will be compounded with the costs of installing different technologies to comply with the new rule unless EPA accounts for such facilities in the final rule.

B. Utilities Have Invested Hundreds of Millions of Dollars To Comply with the 2020 Rule as Mandated by EPA.

Electric utilities, state regulators, and grid operators incurred hundreds of millions of dollars in costs (and countless hours of industry and regulatory effort) to comply with the 2020 Rule. For example, based on public filings with the PSC of Kentucky, estimated capital costs for installing biological treatment at Trimble County, Mill Creek, and Ghent Plants are over $60 million at each facility and over $180 million in aggregate.[20] These costs do not include internal company labor and resources to plan, design, approve, and procure these major new retrofits, which are substantial. Neither do they include the costs of operating and maintaining these systems.

A key aspect of planning for and acquiring new technology required by an ELG rule is the depreciation and amortization of assets, which allow use of electric grid assets across their useful lives and help avoid wasteful expenditures, high costs to consumers, and service

---

[19] EPA, Technical Development Document for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category at 38 (Feb. 2023), EPA-HQ-OW-2009-0819-9950 (DCN SE10372) (2023 TDD).

[20] *See In re Electronic Application of Louisville Gas and Electric and Kentucky Utilities Companies for Approval of Their 2020 Compliance Plan for Recovery by Environmental Surcharge, Public Service Commission of Kentucky*, Nos. 2020-00060 and 2020-00061, Direct Testimony of Robert M. Conroy, Vice President, State Regulation & Rates, Kentucky Utilities Co., Louisville Gas & Elec. Co., Exhibit RSS-2 at 15 and 27, 36 and 48, 57 and 70 (Ky. PSC Mar. 31, 2020) (Conroy Ky. PSC Testimony).

disruptions. Many electric utility companies recover the costs of providing electricity to the public through a combination of rate components that together comprise a customer's monthly electric bill.

In regulated markets, rates are often closely scrutinized and approved by state PSCs/PUCs to generally incorporate many of the costs incurred by utilities to comply with environmental regulations.[21] For example, in December 2021, FirstEnergy submitted to the West Virginia Public Service Commission (WV PSC) a request for rate recovery to allow FirstEnergy to acquire, install, and operate equipment necessary to comply with the 2020 Rule. The submission reflected significant analysis and investigation of the technologies and compliance options for two coal-fired power plants in West Virginia. At the Fort Martin Plant, FirstEnergy is installing a biological treatment system for FGDW that will combine with an existing chemical precipitation treatment system. Based on detailed reviews of the cost of this treatment system, FirstEnergy requested recovery of just over $45 million for the biological treatment system. The WV PSC approved rate recovery for this system around September 2022. Accordingly, FirstEnergy already has invested millions of capital into detailed design engineering and contracts with original equipment manufacturers. If EPA issues a new final ELG rule in 2024, FirstEnergy will already have an operating or near-operational biological treatment system that (once finally paid for over a period of years) will have cost people who pay electric bills in West Virginia over $45 million. FirstEnergy's rate recovery request proposed a

[21] Independent power producers often bear the direct initial costs of these investments, then seek to recover these costs from the sale of the electricity. In the case of not-for-profit public power utilities and electric cooperatives, which have no stockholders, these costs are directly borne by consumers. In many cases, these consumers include rural, minority, and low-income communities. For example, 92% of the nation's persistent poverty counties are served by electric cooperatives. National Rural Electric Cooperative Association, Fact Sheet: America's Electric Cooperatives at 1 (Apr. 2023).

20-year depreciation and amortization period, but the WV PSC approval requires a depreciation study that will take into account multiple factors. For context, previous depreciation periods for equipment were as long as 50 or 60 years.

EPA has indicated in meetings with UWAG members that the Agency expects facilities to be flexible when spending money and designing systems to comply with the 2020 Rule while the Agency revises the regulations. The rate recovery process, however, does not allow companies to design for multiple scenarios. To approve electricity rates, PSCs/PUCs often require certainty. Therefore, projects are at risk of losing funding or have lost funding given the circumstances created by EPA's changes to the ELG Rules.[22]

Whether a new ELG rule forces a facility to either incur additional costs or retire while costs of compliance with the 2020 Rule are still being paid, the result is likely to be higher electricity costs for consumers because additional investments will be needed to either comply with new requirements or fund development of alternative generation to replace the retired facility. This increase in the cost of electricity could have disproportionate economic impacts on lower income communities who already face higher electricity prices and run counter to other efforts by this Administration to reduce energy costs for lower income communities.[23]

Finally, the availability of resources to transition to renewables can be impacted by costs to comply with a new ELG rule. Utilities are often financed by a combination of equity and debt.[24] When utilities perform capital projects, such as to comply with the 2020 Rule, either debt

---

[22] *See* the list of examples in Section II.C.3.c.i, *infra.*

[23] *Electricity prices surged 14.3% in 2022, double overall inflation: US report*, UTILITY DIVE, Jan. 19, 2023, https://www.utilitydive.com/news/electricity-prices-inflation-consumer-price-index/640656/ (last visited May 17, 2023).

[24] Electric cooperatives are private not-for-profit entities and have no investor equity shareholders who can bear the costs of stranded generation assets or investment in new or

or equity (or both) are used to finance the projects. Compounding the costs to acquire treatment technologies to comply with the 2020 Rule with the costs to acquire different replacement technologies to comply with the new ELG rule could divert available debt and equity away from investments that could otherwise be made in lower carbon or renewable energy technologies, such as wind and solar.

Thus, the final rule should include flexibilities that ensure that facilities that have invested money and time to comply with the 2020 Rule may continue to rely on those investments for a period commensurate with their investments.

C. If EPA Maintains the "Early Adopter" Subcategory, It Must Make Critical Adjustments To Account for Ongoing ELG Investments.

EPA proposes a subcategory[25] for plants that have achieved compliance either with the 2015 or 2020 Rule limitations on FGDW and BATW by March 24, 2023, and elect to retire no later than December 31, 2032. Specifically, under EPA's proposed definition for this subcategory, an "Early Adopter" means the owner or operator certifies under § 423.19(e) that the unit has installed by March 24, 2023, treatment technology to meet the 2020 Rule's FGDW limits **AND** the BATW limits **AND** the installed equipment does meet such applicable limits as

---

alternative generation resources. As a result, electric cooperatives ultimately must pass along capital costs directly to their consumer-members through increased electric rates.

[25] EPA establishes technology-based ELGs that reflect pollutant reductions achievable by facilities in certain industrial point source categories. In some cases, EPA will establish different limitations for point source "subcategories," *i.e.*, a subset of the industry with different or unique characteristics. In the 2020 Rule, EPA established a number of subcategories within the ELGs for the steam electric power generating point source category. For example, EPA established a subcategory for facilities that intend to permanently cease coal combustion no later than December 31, 2028. Units that qualify for this subcategory do not have to retrofit treatment to meet the 2020 Rule's BAT limits for BATW or FGDW.

of March 24, 2023, **AND** the unit will cease coal combustion no later than December 31, 2032.[26] EPA solicits comments on various aspects of the proposed Early Adopter subcategory.

1. The Proposed Rule's "early adopter" subcategory recognizes massive ongoing ELG investments, but only for a tiny fraction of facilities.

EPA proposes to address costs already incurred by facilities as a result of the 2020 Rule by including the Early Adopter subcategory. But the proposed subcategory is so narrow that it is available to only a few facilities, leaving most facilities and their customers to absorb millions in lost costs to comply with EPA's 2020 Rule.

The proposed Early Adopter subcategory is available to only the tiny fraction of regulated facilities that have already obtained approvals for, contracted, installed, and started operation of waste treatment equipment required to meet the 2020 Rule's discharge limits—a process that takes years and millions of dollars per unit for most facilities to complete. EPA presents a list of electric generating units (EGUs) that would likely qualify in Table VII-1 of the preamble. 88 Fed. Reg. at 18,859. The table includes only 15 EGUs at five plants that have already adopted technologies to comply with the 2015 or 2020 Rules that may incur costs under the proposal without a subcategory for early adopters. And even this small list exaggerates the actual number of EGUs that would qualify for the subcategory. EPA states that "[m]any of these EGUs have already announced retirement by 2032 or soon thereafter." 88 Fed. Reg. at 18,859. But the Gallatin and Belews Creek EGUs anticipate retiring in 2035, Mountaineer anticipates retiring in 2040, and Miller has no plans for retirement. Thus, under the proposed 2032 cessation

[26] *See* 88 Fed. Reg. at 18,896.

date, only four EGUs—all located at a single facility—would qualify for EPA's proposed Early Adopter subcategory.[27]

2. The Early Adopter subcategory is arbitrary, unduly narrow, and an unjust surprise.

Limiting the subcategory to the few facilities that happen to have already reached the operational stage ignores the 2020 Rule's requirement that *all* facilities reach that stage "as soon as possible:" units that needed more time (and potentially more costs) to do so are arbitrarily punished, including facilities that worked diligently to get their permits revised to include a compliance deadline consistent with the 2020 Rule.

The Proposed Rule's narrow approach is arbitrary and unreasonable in light of existing requirements that govern a broad range of facilities. Under the 2020 Rule, dischargers must meet the FGDW and BATW limits by ASAP beginning October 13, 2021, but no later than (NLT) December 31, 2025. 40 C.F.R. §§ 423.13(g)(1)(i), (k)(1)(i). Under 40 C.F.R. § 423.11(t), this ASAP date must reflect consideration of: (1) time to plan, design, procure, and install compliance equipment; (2) changes being made or planned at the facility in response to specific environmental regulations (*e.g.*, emission guidelines for GHGs under the CAA and regulations that address the disposal of CCRs as solid waste under the Resource Conservation and Recovery Act (RCRA)); (3) time to optimize installed FGDW equipment; and (4) other factors, as appropriate. Permitting authorities established site-specific compliance deadlines ASAP based on a reasonable assessment of these factors for each facility. Excluding most facilities that

[27] Assuming the other eleven EGUs do not qualify for the proposed Early Adopter subcategory, EPA must update the estimated compliance costs for these EGUs and the overall regulatory impact analysis.

worked as quickly as possible to comply with the 2020 Rule from the Early Adopter subcategory is unreasonable.

Moreover, setting an Early Adopter cutoff based on full operation by the date of the Proposed Rule, without any advance warning, results in an unjust surprise to facilities and state regulators who are in the midst of working toward full compliance with the 2020 Rule "as soon as possible." Forcing companies and the public to continue incurring costs to comply with one rule is arbitrary when, at the same time, EPA is developing and proposing a rule that would squander those costs and leave facilities and the public obligated to pay for such expenditures with no commensurate benefit. *See Landgraf,* 511 U.S. at 265–66 ("Elementary considerations of fairness dictate that individuals should have an opportunity to know what the law is and to conform their conduct accordingly; settled expectations should not be lightly disrupted."). EPA claims that it "has taken [such] reliance interests into account in this rulemaking" by creating the Early Adopter subcategory, 88 Fed. Reg. at 18,839 n.23, but, as noted above, the proposed subcategory is so narrow that it is available to only a few facilities.

EPA asserts that "no NPDES permittee has certainty of its limitations beyond its 5-year NPDES permit term, as reissued permits must incorporate any newly promulgated technology-based effluent limitations [TBELs] as well as potentially more stringent limitations necessary to achieve water quality standards." 88 Fed. Reg. at 18,839 n.23. But the situation for the steam electric ELGs is different from other ELGs on many levels, including that many companies are deciding to close units. Surprise and uncertainty are much more significant when companies are required by law to provide reliable electricity in the face of long lead times for developing replacement generation.

Finally, inserting a retirement requirement undercuts the justification for the subcategory. The justification for EPA's proposed Early Adopter subcategory includes "disparate costs" and ability to recover investments and facilities' detrimental reliance on the 2015 and 2020 Rules. *See* 88 Fed. Reg. at 18,859. But, as proposed, if a facility is not prepared to retire/repower under EPA's new timeline, they would receive no relief from EPA on complying with any new promulgated standard.

The potential for misdirected costs and time created by the new proposal and its narrow Early Adopter subcategory will: (i) continue to increase because the 2020 Rule will remain in effect while this rulemaking proceeds; (ii) take years of higher electricity bills to repay; (iii) be compounded by millions in potential additional costs required to install and operate new waste treatment equipment (such as membranes); and (iv) render the biological treatment system unnecessary to comply with the Proposed Rule.

3. The CWA's statutory factors support a broader and more flexible Early Adopter subcategory.

When developing ELGs, the CWA requires EPA to consider "the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, the cost of achieving such effluent reduction, non-water quality environmental impact (including energy requirements), and such other factors as the Administrator deems appropriate." CWA § 304(b)(2)(B), 33 U.S.C. § 1314(b)(2)(B); *see also Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027, 1048, 1052, 1054 (3d Cir. 1975), *amended*, 560 F.2d 589 (3d Cir. 1977), *appeal after remand*, 568 F.2d 284 (3d Cir. 1977) (EPA required to "consider age as it had a bearing on the cost or feasibility of retrofitting plants" and "industry's capability of meeting these costs," including "evidence that many plants cannot raise the necessary capital to finance the installation of anti-pollution devices and would be forced to close").

In the 2020 Rule, EPA determined that the permanent cessation of coal combustion subcategory was necessary due, in part, to the statutory factors of (i) cost, (ii) non-water quality environmental impacts (including energy requirements), and (iii) the age of equipment and facilities involved. The statutory factors that supported the 2020 cessation subcategory still exist and are even more compelling today, as detailed below. Such factors support necessary changes to the Early Adopter subcategory to allow more facilities to benefit from their efforts and expenditures to comply with the 2020 Rule and transition away from coal at a reasonable pace.

a. Costs Support a Broader Subcategory

Based on company announcements and other public statements, in 2020, EPA developed a list of EGUs that it expected to cease coal combustion between 2024 and 2028. *See* 85 Fed. Reg. at 64,680. Without the cessation subcategory, EPA calculated that 23 EGUs would have combined estimated capital costs of $209 million and estimated operating and maintenance (O&M) costs of $21 million per year, leading to combined annualized costs as high as $63 million per year, assuming costs are all incurred between 2021 and the announced year of closure or conversion to a different fuel source. *Id.* EPA found that the shorter amortization periods for these units would lead to much higher costs per megawatt hour (MWh), *see* 85 Fed. Reg. at 64,680, even while EPA significantly underestimated the costs of compliance. *See* UWAG, Cost Comparison for Installing membrane Filtration Treatment, (submitted to U.S. Office of Management and Budget (OMB) Feb. 7, 2023). "For example, while Winyah Unit 2 and Will County Unit 4 have approximate costs of $6/MWh under a normal 20-year amortization period, over the shortened amortization period these costs jump to over $10/MWh. These costs would both be among the highest, if not the highest, costs absent a subcategory for units ceasing coal combustion by 2028." 85 Fed. Reg. at 64,680. "[C]ompressing cost recovery into these smaller amortization periods [would] result in disproportionate costs." *Id.* For EGUs that would continue burning coal until 2033 and 2035, "they will be able to amortize their costs over a time frame closer to the estimated 20-year amortization period used for the industry as a whole." *Id.* at 64,680–81

As noted above, if EGUs that have installed biological treatment to comply with the 2020 Rule are then forced to invest in membrane technology by 2029, shortly before they intend to retire, they will not have a sufficient time period to amortize their costs. As EPA recognized in 2020, compressing cost recovery into these smaller amortization periods will result in disproportionate costs for such facilities. For example, some facilities currently are installing biological wastewater treatment systems to comply with the 2020 Rule and thus would not qualify for the Early Adopter subcategory, as proposed. If those same facilities have plans to retire by 2035 but are required to install a membrane treatment system by 2029, the annualized costs would be exorbitant. Absent a subcategory that appropriately accounts for such circumstances, facilities would be incentivized to continue to operate beyond 2035 to recover such costs.

b. Non-water quality environmental impacts (including energy requirements)

To address this factor, EPA has estimated the incremental change in energy use to operate treatment equipment to satisfy the Proposed Rule. *See* 2023 TDD at 65. This analysis, however, is insufficient because, unlike EPA's approach in the past, the analysis does not consider reliability of the electric grid.[28]

[28] *See*, *e.g.*, Memorandum from Richard Benware, U.S. EPA, to Steam Electric Rulemaking Record, Steam Electric Effluent Guidelines Reconsideration – Evaluation of Final

In the 2019 proposed rule, EPA identified 107 plants that had announced, commenced, or completed retirements and fuel conversions since the issuance of the 2015 Rule. In public statements, 31% of the facilities indicated that environmental regulations, including ELGs, affected their decision-making. *See* 85 Fed. Reg. at 64,680 n.112. Given these statements, EPA concluded that additional flexibility "may help to avoid premature closures of some plants." *Id.* at 64,680. EPA pointed to NERC's 2019 summer reliability assessment (SRA), which "showed one region [Electric Reliability Council of Texas (ERCOT)] that was not anticipated to meet its reference margin, and another [Midcontinent Independent System Operator (MISO)] which was anticipated to be very close to its reference margin (19 percent vs.17 percent)." *Id.* at 64,680.[29] EPA concluded that premature closure of some EGUs was an unacceptable non-water quality environmental impact because it could impact reliability and, thus, the avoidance of these premature closures weighed in favor of subcategorization. *See id.*

Reliability concerns are even more pronounced today. On May 4, 2023, the Senate Energy and Natural Resources Committee held an oversight hearing on the Federal Energy Regulatory Commission (FERC) with all four FERC Commissioners. The Commissioners raised concerns about the "looming resource adequacy crisis":

> Our market operators have been explicitly telling us as much for years. Both MISO and ISO-NE have warned about upcoming scarcity and PJM, the nation's largest wholesale market, and the one that serves Washington, D.C., has recently raised the alarm about impending shortfalls. Were any more proof required of our markets' failure, in the midst of PJM's dire warnings, somehow the prices in its procurement auction, at a time of impending scarcity, went down.

Rule Subcategories, at 3–4 and 7–8 (Aug. 31, 2020), EPA-HQ-OW-2009-0819-8964 (DCN SE09071 (considering reliability as a factor within non-water quality environmental impacts).

[29] Resources below the reference margin level (RML) indicate that the area lacks adequate resources to limit load loss events to less than 1-day-in-10 years, an established resource planning criterion.

> As an engineering matter, there is no substitute for reliable, dispatchable generation. Intermittent renewable resources like wind and solar are simply incapable, by themselves, of ensuring the stability of the bulk electric system. As the wholesale markets' prices are distorted by subsidies, the generation assets with the attributes required for system stability will retire and system stability will be imperiled. Given these market failures, there will be, in time, a catastrophic reliability event.

Full Committee Hearing to Conduct Oversight of FERC, Hearing Before the S. Comm. on Energy & Nat. Res. (May 4, 2023) (written testimony of James P. Danly, Comm'r, FERC, at 2), (emphasis omitted). Commissioner Christie relayed similar concerns: "Dispatchable generating resources are retiring far too quickly and in quantities that threaten our ability to keep the lights on. The problem generally is not the *addition* of intermittent resources, primarily wind and solar, but the far too rapid *subtraction* of dispatchable resources, especially coal and gas." *Id.* (opening statement of Mark C. Christie, Comm'r, FERC, at 1) (emphasis in original).

Furthermore, NERC's May 2023 SRA[30] and 2022 LTRA are more dire than the 2019 SRA referenced in the preamble to the 2020 Rule. The May 2023 SRA finds that "while resources are adequate for normal summer peak demand, if summer temperatures spike … two-thirds of North America is at risk of energy shortfalls."[31] For example MISO, which is responsible for operating the power grid across 15 states in the central part of the country and the Canadian province of Manitoba and serves approximately 42 million customers, has an elevated risk of meeting reserve requirements this summer. "Demand forecasts and preliminary resource data indicate that MISO is at risk of operating reserve shortfalls during periods of high demand or low resource output[, and] MISO's resources are projected to be lower than in the summer of

[30] NERC, 2023 Summer Reliability Assessment (May 2023) (2023 SRA).

[31] NERC, Press Release, Two-thirds of North America Faces Reliability Challenges in the Event of Widespread Heatwaves at 1 (May 17, 2023).

2022." 2023 SRA at 14. "[T]he previously-reported reserve margin shortfall has advanced by one year, resulting in a 1,300 MW capacity deficit for the summer of 2023. The projected shortfall continues an accelerating trend since both the *2020 LTRA* and the *2021 LTRA* as older coal, nuclear, and natural gas generation exit the system faster than replacement resources are connecting." 2022 LTRA at 5. Given that coal generation comprises approximately one-third of MISO's "On-Peak Fuel Mix," *see* 2023 SRA at 14 (Pie Chart), any additional closures caused by the Proposed Rule within MISO would have substantial impacts on reliability.

These concerns, of course, extend beyond MISO. *See*, *e.g.*, PJM Report Feb. 2023 at 7, 16 ("The EPA updated [the ELGs] in 2020, which triggered the announcement by Keystone and Conemaugh facilities (about 3,400 MW) to retire their coal units by the end of 2028. … By the 2028/2029 Delivery Year and beyond … projected reserve margins would be 8%, as projected demand response may be insufficient to cover peak demand expectations."); 2022 LTRA at 7 ("Within the 10-year horizon, over 88 GW of generating capacity is confirmed for retirement through regional transmission planning and integrated processes. Effective regional transmission and integrated resource planning processes are the key to managing the retirement of older nuclear, coal-fired, and natural gas generators in a manner that prevents energy risks or the loss of necessary sources of system inertia and frequency stabilization that are essential for a reliable grid."). These expert assessments further support the notion that EPA must avoid causing premature closures of coal-fired facilities due to new ELG requirements and should modify the Early Adopter subcategory to allow facilities to transition away from coal at a reasonable pace.

But the Proposed Rule seems to ignore the "non-water quality environmental impacts (including energy requirements)" factor in the development of the Proposal. In the face of additional costs of compliance with the 2020 Rule, at least 74 EGUs (at 33 plants) requested participation in the 2020 Rule cessation subcategory. Yet the preamble does not consider potential reliability impacts or discuss or reference NERC's assessments. At a minimum, EPA should have an adequate record basis for finding that its rule would not cause unacceptable non-water quality impacts on reliability due to premature closures despite expressing that very concern in the 2020 Rule.[32]

c. Age of equipment and facilities involved

First, the age of *equipment* factor weighs against requiring ZLD, given the recent installation of new biological treatment at many facilities. Congress certainly did not intend for EPA to turn over its ELG requirements in a way that forced young, expensive treatment technology into obsolescence.

EPA raises other concerns related to the age of the *facilities* in the 2020 Rule: "the possibility that [PUCs] would not allow cost recovery for equipment purchased near the end of a plant's useful life, resulting in stranded assets"[33] and "the need for sufficient time to plan, construct, and obtain necessary permits and approvals for replacement generating capacity." 85 Fed. Reg. at 64,681.

---

[32] As discussed below in Section IX, EPA's baseline analysis and determination that the Proposed Rule would cause only one premature closure of an EGU is flawed. EPA needs to account for facilities that, given the high costs of installing a membrane system on top of recent substantial costs to comply with the 2020 Rule, may have no choice but to retire. Indeed, "the combined requirements of [multiple environmental] regulations and their coincident compliance periods have the potential to result in a significant amount of generation retirements within a condensed time frame." PJM Report Feb. 2023 at 7.

[33] The concept of stranded assets or costs generally refers to "[c]osts incurred by a utility which may not be recoverable under market-based retail competition. Examples include undepreciated generating facilities, deferred costs, and long-term contract costs." U.S. Energy Information Administration (EIA), Glossary, https://www.eia.gov/tools/glossary/index.php?id=S (last visited May 17, 2023).

i. Stranded assets

EPA must explain why this concern about stranded assets does not apply at least equally—if not with greater force—to a new rule that adds a new layer of requirements on top of the 2020 Rule, especially given the possibility that PSCs/PUCs will not allow cost recovery. In a traditional regulated market, investments are approved through a regulatory process and recovered through a regulated rate of return, provided the investments are deemed prudent by the regulator.[34] In a deregulated merchant market, investments bear a greater degree of market risk because the price at which electricity is sold depends on what markets will bear (which is influenced by the overall economy, commodity prices, capital investment cycles, and other price-related regulation (*e.g.*, FERC price caps)).

The proposal does not account for the risk that, in regulated markets, PSCs/PUCs may not approve rate recovery for additional investments in light of capital expenses already imposed on rate payers based on inconsistent technology requirements in the 2020 Rule, as presaged by recent PSC decisions:

- In July 2021, the Kentucky PSC denied a request for approval of over $100 million dollars in new project costs to comply with 2020 Rule requirements at a power plant based on lack of evidence that the projects would be reasonable and cost-effective

[34] The National Association of Regulatory Utility Commissioners (NARUC) explained in a 2020 report: "Societal pressure to move to zero-emissions energy sources, combined with renewable energy mandates, tax incentives for renewable development, and significant cost reductions for wind and solar technologies, have resulted in the continued addition of new wind and solar generating facilities across the country. With intermittent resources accounting for over one-third of total generation in some states, traditional baseload generators have been forced to be more flexible in their operating profile and complement fluctuations in generation from intermittent renewable sources. These conditions have resulted in new challenges for commissions. As economic regulators, they are charged with overseeing the reliable, safe, and affordable operation of the electricity generation and delivery system. The asset life for electric generation can span decades, making today's decisions impactful for customers well into the future." NARUC, *Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices* at 3 (Jan. 2020).

and because of "potential future environmental compliance costs that could add to costs to keep Mitchell in operation beyond 2028."[35]

- In August 2021, the West Virginia PSC approved investments to address ELG requirements at certain facilities;[36] however, the Virginia SCC denied the same investments.[37] The facilities' service territory covered parts of both Virginia and West Virginia. The West Virginia PSC ordered the company to make the investments even if the Virginia SCC continued to deny cost recovery.[38] The Virginia SCC later approved cost recovery.[39]

- In December 2021, the Wisconsin PSC approved a $90 million investment in new wastewater treatment equipment to comply with the 2020 Rule at a coal-fired generating station but faced objections over the company undertaking expenditures at the same time the company was transitioning away from coal, and because the investments would likely become "prematurely obsolete."[40]

- One UWAG member requested a rate recovery period of 6 years for wastewater treatment costs, and the PSC decided to spread it across 12 years to reduce the cost to customers.

Similarly, the Proposal does not account for the risk that, in deregulated markets, lenders may not be willing to finance additional capital investments without assurances that the facilities

[35] Kentucky PSC News Release, PSC Issues Order in Kentucky Power's Request for Mitchell Generating Station Environmental Compliance Projects at 2 (July 16, 2021); *see also* Kentucky PSC Order July 15, 2021.

[36] *See* Commission Order, *In re Appalachian Power Co. et al.*, No. 20-1040-E-CN (W. Va. PSC Aug. 4, 2021) (granting the requested Certificates of Convenience and Necessity for CCR control projects and ELG control projects for all three plants and authorizing a phase-in cost recovery mechanism and initial rate).

[37] *See* Va. SCC Aug. 23, 2021 Order at 12 ("[W]e find that the Company has not met its burden of proving the reasonableness and prudence of the proposed ELG investment costs, including those previously incurred.").

[38] *See* Commission Order at 15, *In re Appalachian Power Co. et al.*, No. 20-1040-E-CN (W. Va. PSC Oct. 12, 2021) (ordering "the Companies proceed with the ELG projects at all three Plants," and ordering "the Companies proceed with construction and take all necessary steps to operate the Plants beyond 2028 and extend their operations to at least 2040.").

[39] *See* Appalachian Power Order (Va. SCC Nov. 21, 2022).

[40] *See* Danielle Kaeding, *$90M in new pollution controls approved for coal plant in southeastern Wisconsin: Groups critical of costly investment in plant as it transitions to natural gas,* WISCONSIN PUBLIC RADIO (Jan. 17, 2022), www.wpr.org/90m-new-pollution-controls-approved-coal-plant-southeastern-wisconsin (last visited May 17, 2023).

and their customers will be willing to absorb the added costs and make economic use of those investments over their useful lifespan.

ii. Timing for replacement generation

A recent Brattle report notes the interrelationship of the timing of retirement of coal-fired power plants and the transition to other generation sources:

> Early retirement [of coal plants] can be an appealing proposition for both utilities and customers, but recovery of major underappreciated investments remains a significant obstacle. Across the country, utilities' unrecovered coal plant investments amount to over $100 billion. … However, recovery of recent investments in major emissions control equipment to comply with various environmental laws pose a major obstacle to early retirements. … Between 2010–2019, 77 GW of regulated coals plants were equipped with capital-intensive environmental control technologies to comply with various environmental laws.[41]

An orderly transition in generation sources would allow economic use of existing resources during the period those resources are being replaced by new generation sources, and optimally the new generation sources themselves would be economical as a result of market forces, tax credits or other funding sources, technological innovation, and upgrades in infrastructure. Such a transition thereby would keep costs to industry and ratepayers manageable, while supporting a transition to cleaner energy that is as fast as possible consistent with keeping electricity affordable, reliable, and safe.

In 2019, it was estimated that a complete transition to renewable energy in the U.S. by 2030 would cost $4.5 trillion, including $700 billion for necessary transmission buildout. Iulia Gheorghiu, *Transitioning US to 100% renewables by 2030 will cost $4.5 trillion: Wood Mackenzie*, UTILITY DIVE, June 28, 2019, https://www.utilitydive.com/news/transitioning-us-to-100-renewables-by-2030-will-cost-rate-payers-45t-wo/557832/ (last visited May 18, 2023). By

---

[41] *See* Brattle, Managing Coal Plant Retirements for an Orderly Transition to Decarbonization, https://www.brattle.com/insights-events/publications/managing-coal-plant-costs-for-an-orderly-transition-to-decarbonization/ (last visited May 17, 2023).

contrast, a disorderly transition could result in broad economic disruption. In 2021, under a pilot project led by 39 global banking institutions, the United Nations' Environment Programme Finance Initiative issued a report[42] that described the financial and economic "risks of a disorderly transition:"

> A disorderly transition, in which the transition to a low-carbon economy occurs in unexpected and chaotic ways, would present significant economic challenges. …
>
> A hasty departure from fossil fuel power generation could mean the destabilization of power resources within such states as a result of the massive short-term costs and technological challenges of modernizing the power grid. … [A]n orderly transition would give governments, investors, and companies an opportunity to seek out alternative investments and begin updating their power generation infrastructure.
>
> A poorly planned disruptive transition would significantly destabilize global power resources if renewable and low-carbon power grids are not ready for widespread deployment.

UNEP-FI Report at 3, 18. Also, As McKinsey notes, "the central role of energy in all economic activity and the profound consequences that disruptions to energy markets can entail highlight the criticality of an orderly transition—one where the ramp-down of high-emitting assets is carefully coordinated with the ramp-up of low-emitting ones and which is supported by the appropriate redundancy and resiliency measures. … Even small disturbances to these systems could affect daily lives, from raising producer and consumer costs to impairing energy access, and could lead to delays and public backlash."[43]

---

[42] United Nations Environment Programme Finance Initiative, *Decarbonisation and Disruption: Understanding the financial risks of a disorderly transition using climate scenarios* (2021) (UNEP-FI Report).

[43] *See* McKinsey & Co, "Solving the net-zero equation: Nine requirements for a more orderly transition" (Oct. 27, 2021), www.mckinsey.com/business-functions/sustainability/our-insights/solving-the-net-zero-equation-nine-requirements-for-a-more-orderly-transition (last visited May 17, 2023).

The confluence of these statutory factors (cost, non-water quality environmental impacts (including energy requirements), and age of equipment and facilities involved) supports critical adjustments to the Early Adopter subcategory.

4. EPA must make critical adjustments to the Early Adopter subcategory.

UWAG supports the concept of a subcategory that addresses costs already incurred by facilities as a result of the 2020 Rule; however, as proposed, the current Early Adopter subcategory contains flaws that prevent it from being utilized to its fullest extent.

a. EPA should revise the qualification deadline to coincide with the 2020 applicability date.

EPA should revise the "Early Adopter" subcategory to include simply "Adopters" of the 2020 Rule. *The Agency should establish a qualification deadline based not on the surprise March 24, 2023 date of the Proposed Rule but instead on meeting 2020 Rule discharge limits by the applicability date in a facility's permit.*

i. Virtually determinative effective date

Setting a deadline based on the date of the Proposed Rule has immediate and substantial compliance implications for facilities that did not meet those requirements by that date. The qualification date must be tied to the date of the final rule, not established by the date of the Proposed Rule. 5 U.S.C. § 553(d) (publication of final rule "shall be made not less than 30 days before its effective date"). Setting a deadline in a proposed rule that will become retroactively binding via the final rule effectively results in an immediate alteration of the legal regime with "virtually determinative" effects on the regulated industry. *See Bennett v. Spear,* 520 U.S. 154, 170 (1997) ("The Service itself is, to put it mildly, keenly aware of the virtually determinative effect of its biological opinions.").

By not satisfying the March 24, 2023 date, the Proposed Rule shows facilities how costly and burdensome compliance with the rule would be if they continue to operate. The Proposed Rule thereby has a powerful, coercive, and immediate impact on regulated facilities. The reason is that facilities face tremendous future costs and time burdens unless they retire, as well as the ever-present risks of CWA enforcement and citizen suits for failure to comply on time. While the Proposal is nominally or theoretically only a proposed rule, in reality, it has immediate and powerful effects well-understood by EPA to likely lead to its objective of hastening plant closures. *See Bennett,* 520 U.S. at 169 ("while the Service's Biological Opinion theoretically serves an 'advisory function' [prior to an agency's action] … in reality it has a powerful coercive effect on the action agency.").

ii. Fair notice

EPA's proposal also runs afoul of the fair notice doctrine. Fair notice encapsulates "the principle that agencies should provide regulated parties 'fair warning of the conduct a regulation prohibits or requires.'" *Christopher v. SmithKline Beecham Corp*., 567 U.S. 142, 156 (2012) (brackets omitted). Many facilities are currently in the process of contracting for and constructing a biological treatment system to comply with the 2020 Rule. EPA's sudden reversal and the changes proposed in this rule do not provide regulated entities fair warning of such requirements. EPA's approach goes against common principles of fairness, which dictate that such facilities should have an adequate opportunity to comply with the law without, at the same time, being forced to waste substantial resources.

For example, the deadline for qualifying for the Early Adopter subcategory is especially cruel for WEC Energy Group's Elm Road facility, which is installing a new $89.5 million biological wastewater treatment system to treat FGDW and is in the final stages of construction and will begin commissioning activities soon. Its NPDES permit requires the new wastewater treatment equipment to be in service to meet the 2020 Rule limits by December 14, 2023.[44] As proposed, this facility would not qualify as an Early Adopter even though it has made substantial progress toward implementing the 2020 Rule consistent with the ASAP date established by its permit writer.

To address these concerns, if EPA maintains the Early Adopter subcategory, the only fair and just approach would be to include units that meet the 2020 Rule limits by the applicability date in the facility's permit.

In the alternative, UWAG would support a subcategory that includes units that have already contracted for but not yet installed biological treatment to comply with the 2020 Rule, *i.e.*, entered into a binding contract by the signature date of the final rule. *See*, *e.g.*, 40 C.F.R. § 122.29(b)(4)(ii).

b. EPA should revise the proposed Early Adopter subcategory's cessation date.

UWAG also has concerns about the back end of EPA's proposed Early Adopter subcategory: the date established by EPA when covered facilities must permanently cease coal combustion. *The Early Adopter subcategory should allow facilities that have installed biological treatment to satisfy the 2020 Rule to either: (i) cease coal combustion at a later date than December 31, 2032 (no earlier than December 31, 2035); or (ii) continue to operate subject to ZLD limits by an ASAP date between December 31, 2032, and December 31, 2040.*

A cessation date later than the date included in the proposed Early Adopter subcategory (December 31, 2032) is necessary to allow for the use of wastewater treatment equipment across

[44] *See* Final Decision at 13–14, *In re Joint Application of Wisconsin Electric Power et al.*, No. 5-CE-152 (Wis. PSC Dec. 14, 2021), ("Construction of the proposed project as authorized is estimated to cost $89.5 million. … Construction is expected to begin in March 2022 with completion by June 2023.").

their useful lives and avoid needless expenditures, high costs to consumers, and service disruptions. The proposed 2032 closure date also could not have been anticipated by utilities or PSCs/PUCs when they approved the projects to install technologies to comply with the 2020 Rule.[45]

Based on the CWA's "goal of eliminating the discharge of all pollutants," *see*, *e.g.,* CWA § 301(b)(2)(A), 33 U.S.C. § 1311(b)(2)(A), installing treatment technology to meet ZLD requirements would achieve a similar outcome as ceasing coal combustion within the context of the CWA. Thus, given EPA's authority to promulgate this rule stems from the CWA, EPA should not require cessation of coal combustion to satisfy the "Early Adopter" criteria. Instead, if EPA includes ZLD as the generally applicable requirement for FGDW in the final rule, a facility should be able to satisfy the Early Adopter subcategory criteria by complying with ZLD by a separate ASAP date (*e.g.*, from December 31, 2032, to December 31, 2040). Under this approach, permittees would demonstrate to the permitting authority why they require until a certain date to comply with ZLD, based on, for example, the cost recovery time period established by their PSC/PUC for the biological treatment system. In other words, permitting authorities under this subcategory would be required to take into account the likely payback period for the biological treatment system in establishing an ASAP date for compliance with ZLD no later than December 31, 2040.

EPA acknowledges that the assumed life of the equipment is 20 years and "amortization periods shorter than eight years may lead to disparate costs." 88 Fed. Reg. at 18,859. Therefore,

[45] This approach also would be consistent with CWA section 316(c), 33 U.S.C. § 1326(c), which protects thermal discharges that have been modified to meet thermal effluent limitations from the need to comply with more stringent limitations for ten years after the date of completing such modification or during the period of depreciation or amortization of such facility.

EPA should ensure that facilities that have made investments of money and time to comply with the 2020 Rule may continue to rely on those investments throughout the life of the equipment and the rate recovery period established by the relevant PSC/PUC. Allowing facilities to continue to operate after their payback period subject to ZLD requirements would be consistent with the goals of the CWA.

D. If EPA Does Not Incorporate UWAG's Recommendations into the "Early Adopter" Subcategory, it Should Establish a New Subcategory that Reflects the 2020 Rule's Cessation Subcategory.

If EPA proceeds with establishing an Early Adopter subcategory that does not reflect UWAG's recommendations, it should establish a new subcategory, similar to the 2020 Rule and its cessation subcategory, allowing regulated facilities that have made irretrievable investments to comply with the 2020 Rule to meet ELG compliance through application of 2020 Rule requirements for a period sufficient to allow facilities and the public to receive a reasonable benefit of investments and obligations incurred as a result of the 2020 Rule, and then either meet any new ELG limits or repower or retire.

Specifically, *UWAG would support a new subcategory that would allow facilities the option to either comply with the zero discharge limits no later than December 31, 2032, or avoid new ELG requirements by committing to repower or retire by December 31, 2035.* This approach has a number of advantages and would address many of the concerns described above. First, it would maximize the useful life of treatment equipment and facility improvements to comply with the 2020 Rule and avoid precipitous abandonment of such treatment equipment and upgrades for replacement with new, unproven technology. It also would place less cost burden on rate-paying customers prior to the end of the useful life of the generating asset while ensuring grid reliability and resiliency and customer affordability. Lastly, a subcategory with these parameters would likely secure more early commitments to retire coal generation by 2035 than under the Proposed Rule, which would instead incentivize indefinite operation of coal facilities to recover significant investments in new treatment technology.[46]

Under the retire/repower option of this new subcategory, EPA should find that membrane technologies are not BAT for FGDW due to the unacceptable disproportionate costs they would impose; the potential of such costs to accelerate retirements of EGUs at this age of their useful life; and the resulting increase in the risk of electricity reliability problems due to those accelerated retirements. CP+LRTR (chemical precipitation followed by a low hydraulic residence time biological reduction treatment) is the only technology basis for FGDW under the subcategory's retire/repower option that would not impose such disproportionate costs. Establishing CP+LRTR as BAT for FGDW under this option would alleviate the choice for these plants to either pass on disparately high capital costs over a shorter useful life, continue to pass on costs for an already retired unit, or risk the possibility that post-retirement rate recovery would be denied.

This subcategory also would allow electric utilities to continue the organized phasing out of EGUs that are no longer economical, in favor of more efficient, newly constructed generating stations. A new subcategory along the lines described above would reduce concerns about over-reliance on natural gas or renewables during the industry's transition period because coal-fired units would be able to contribute electricity for a few additional years to help stabilize the grid. Furthermore, UWAG's recommended subcategory also would promote investment in non-coal-fired units by providing some relief from potential unrecovered costs related to ELG retrofits.

[46] UWAG notes that accelerating retirement of coal generation or reducing GHG emissions is not a proper statutory purpose for an ELG rulemaking under the CWA.

E. If EPA Does Not Incorporate UWAG's Recommendations into the "Early Adopter" Subcategory and Does Not Establish a New Subcategory that Reflects the 2020 Rule's Cessation Subcategory, Then EPA Should Extend the No-Later-Than Date for Compliance with the Proposed FGDW Limits to December 31, 2032.

Given the statutory factors and concerns described in this section, EPA should incorporate UWAG's recommended revisions into the Early Adopter subcategory or establish a new subcategory that reflects the 2020 Rule's cessation subcategory. If EPA does not adopt UWAG's recommendations, then it should at least extend the no-later-than compliance deadline for FGDW limits to December 31, 2032.

F. Units Converting to Other Fuels Should Qualify for Any Final Early Adopter or New Cessation Subcategory.

EPA solicits comment on whether EPA should allow participation in the Early Adopter subcategory if the plant is not retiring but is instead converting to other fuels (*e.g.*, natural gas), as was done in the 2020 Rule for the EGUs permanently ceasing coal combustion by 2028. 88 Fed. Reg. at 18,860. UWAG strongly believes that any new subcategory that includes separate requirements for facilities planning to cease coal combustion should include units converting to other fuels. Such units should be subject to the same BAT basis as units certified to be retired for the reasons discussed below.

1. Like retiring units, repowering eliminates all pollutants related to coal-firing.

Whether a permittee decommissions a coal-fired unit or repowers it, the result will be the complete elimination of BATW and FGDW discharges. The environmental benefits gained from the Proposed Rule's BATW and FGDW requirements are the same regardless of whether a unit is retired or repowered. In terms of BATW and FGDW discharges, there is no environmental basis for distinguishing between the two for the purpose of this rulemaking.

2. Excluding repowered units would discourage repowering at existing coal-fired facilities.

Repowering units on the same site as a former coal-fired unit is a common practice because existing infrastructure and permits can continue to be used and the property is already an established industrial site. According to the EIA, there are four main phases of a coal-fired unit decommissioning—retirement, decommissioning, remediation, and redevelopment. Redevelopment "may involve repurposing the site for another generation technology or some other commercial, industrial, or municipal application. Coal-fired power plants typically occupy land in or near downtown areas or along rivers, and they usually have access to railways, roadways, water, sewers, and other infrastructure."[47] Repowering an entire power plant with natural gas, for example, is "a viable option for power providers because much of the critical infrastructure is already in place, including transmission lines, substations, and water."[48] Also, repowering at the same facility ensures that the site is already approved and permitted for generation activities and discourages unwarranted development of "greenfield" sites for new generation.

By excluding repowered units from any final subcategory, EPA would discourage permittees from repowering units to compensate for retiring units. It also would discourage permittees from using ideal sites (former coal-fired units/facilities) for their repowering projects. UWAG thus urges EPA to include repowered units in the final subcategory to encourage reuse of

---

[47] EIA, *More U.S. coal-fired power plants are decommissioning as retirements continue*, TODAY IN ENERGY (July 26, 2019) (EIA 2019).

[48] EIA 2019; *see also* Don Hopey, *New Castle power plant switching to natural gas,* PITTSBURGH POST-GAZETTE, June 25, 2013 (for units repowered using the existing boilers, all existing infrastructure is reused).

existing power generation facilities, which is both economically efficient and environmentally appropriate.

3. Including repowered units is consistent with EPA's economic impact analysis.

As noted above, in the 2020 Rule, EPA examined cost implications of the Proposal under hypothetical unit retirement scenarios and concluded the costs per MWh would be far higher, in real terms, than the costs for units that were more likely to operate for the full 20-year amortization period. *See* 85 Fed. Reg. at 64,680. This analysis applies equally to repowering units that, for cost purposes, are no different than retiring units. Requiring repowered facilities to incur the substantial costs of retrofitting technologies that will be used for far less than the standard 20-year depreciation period would enlarge the economic impact of the rule. If EPA elects not to include repowered facilities in the final subcategory, it must account for and explain why the economic impacts are justifiable.

III. Comments on Proposed FGDW Provisions

A. EPA Should Maintain its Position that Membrane Filtration Is Not Nationally Available, Economically Achievable, or Environmentally Sound for Covered Units.

In the 2020 Rule, issued less than three years ago, EPA determined membrane filtration was not BAT for FGDW. Now, without adequate support, the Agency proposes to reverse that decision and find that membrane filtration *is* BAT for FGDW. The membrane filtration option, as EPA envisions it, would consist of chemical precipitation followed by membrane filtration with 100 percent recycle of the permeate, to achieve zero discharge of FGDW. 88 Fed. Reg. at

18,837.[49] In contrast, in 2020, EPA specified CP+LRTR as the model technology for FGDW. The CP+LRTR option is not zero discharge.

Moving from a non-zero discharge treatment to zero discharge is a very significant change, one that increases engineering complexity[50] and necessitates extra testing and planning time, and extra system redundancies, due to the severity of the zero discharge limitation. In the 2020 rule, EPA made a careful assessment of membrane filtration for use in treating FGDW and determined that membranes were not technologically available nationwide and would cause unacceptable non-water quality impacts to the environment. EPA also determined that the costs weighed against selecting membranes as BAT. EPA's proposed reversal of its 2020 determination is not supported by the record for the multiple reasons set forth in the following sections.

1. EPA's Proposal does not satisfy the "detailed justification" standard for reversing course on EPA's 2020 determination on membrane technology.

The 2020 Rule came into effect on December 14, 2020. A little over a month later, the new administration designated it as one of a set of rules to be reviewed for possible suspension,

[49] *See also* 88 Fed. Reg. at 18,838 ("[S]pecifically, the technology basis for BAT would include chemical precipitation to remove suspended solids and scaling compounds prior to treatment with one or more stages of nanofiltration, electrodialysis reversal (EDR), RO, and/or forward osmosis. The permeate from the final stage of treatment would then be recycled back into the plant either as FGD makeup water or boiler makeup water.")

[50] The process of incorporating a ZLD system involves many engineering and operational challenges, as compared to a system that allows some discharge. A ZLD process requires running boilers, turbines, absorbers, SCRs, and heat exchangers precisely in concert with the ZLD system. Having to return the permeate from a ZLD system back into the system while keeping the other systems in balance will be a significant challenge at every site.

recission, or amendment in accordance with Executive Order 13990.[51] And on July 26, 2021, EPA announced that it would be evaluating whether changes to the rule were merited, pointing in particular to supposed new advancements in membrane technology just eight months after the effective date of the 2020 Rule.[52]

Changes of position in light of new administrations are to be expected and reflect the proper workings of a democratic republic. But where an agency proposes to change course on an action that has engendered significant reliance interests, the agency must acknowledge and provide a reasoned explanation for its reversal in course. *State Farm*, 463 U.S. at 57 ("'an agency changing its course must supply a reasoned analysis'") (quoting *Greater Boston Television Corp. v. FCC*, 444 F.2d 841, 852 (1970)); *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009) ("[T]he requirement that an agency provide reasoned explanation for its action would ordinarily demand that it display awareness that it *is* changing position. … [T]he agency must show that there are good reasons for the new policy.").[53]

Under the Supreme Court's *Fox Television* decision, EPA may not simply decide to reverse course but must provide a "more detailed justification" for a rule that reflects a reversal

---

[51] Biden–Harris Transition, Fact Sheet: List of Agency Actions for Review; Actions Address the COVID-19 Pandemic, Provide Economic Relief, Tackle Climate Change, and Advance Racial Equity, at 5 (Jan. 20, 2021).

[52] Press Release, EPA, EPA Announces Intent to Bolster Limits on Water Pollution from Power Plants (July 26, 2021).

[53] "Reasoned decision-making requires that when departing from precedents or practices, an agency must 'offer a reason to distinguish them or explain its apparent rejection of their approach.'" *Physicians for Soc. Responsibility v. Wheeler*, 956 F.3d 634, 644 (D.C. Cir. 2020). "[H]owever the agency justifies its new position, what it may not do is 'gloss[] over or swerve[] from prior precedents without discussion.'" *Sw. Airlines Co. v. FERC*, 926 F.3d 851, 856 (D.C. Cir. 2019) (quoting *Greater Boston Television*, 444 F.2d at 852). Rather, an agency must acknowledge and explain its new position, "assess whether there [are] reliance interests, determine whether they [are] significant, and weigh any such interests against competing policy concerns." *Regents of the Univ. of Cal.*, 140 S. Ct. at 1915.

in position if (1) the new rule rests upon contradictory factual findings or (2) the prior rule "has engendered serious reliance interests." *Fox Television*, 566 U.S. at 515. Both factors are present here, underscoring the relevance of the costs associated with reliance on the 2020 Rule and the inappropriateness of EPA ignoring those costs.

In this case, EPA has failed to present an adequate, detailed justification for its change of position on membrane technologies and the resulting proposed imposition of zero discharge standards for FGDW. Based on very limited new information, EPA proposes to overturn its 2020 decision, even though the 2020 Rule set off a frenzy of changes within the industry that are costing billions and will have long-term, very consequential impacts to the industry.

a. The 2020 Rule engendered very significant reliance interests within the industry.

The 2020 Rule is no ordinary effluent guidelines rule. It bats far out of its league. Rather than just apply new water discharge limitations, it encourages the transition to clean energy throughout the nation. Under the cessation of coal burning subcategory (cessation subcategory), a facility certifying to cease coal burning for one or more units by December 31, 2028, may continue to operate the unit or units without meeting the 2020 Rule's BAT limitations, which otherwise would apply no later than December 31, 2025. To qualify for the cessation subcategory, the facility may either retire units or repower them using another fuel without incurring tens to hundreds of millions to retrofit the units to comply with the 2020 Rule's BAT limitations.

The cessation subcategory has been wildly successful in prompting power plant closures and other major changes. By EPA's account, 74 coal-fired units at 33 facilities have filed "notices of planned participation" (NOPPs) in the cessation subcategory. 88 Fed. Reg. at 18,837. Another 12 units opted to be included in the "Voluntary Incentives Program" (VIP) subcategory—which required a higher level of treatment for FGDW—and four units sought to be categorized as "low utilization" units. *Id.* The NOPPs had to be submitted by October 13, 2021. Within a year after the 2020 Rule's publication, then, each company with coal-fired units weighed these options, typically through complex planning models that attempted to account for economic outlooks, predictions of power needs and capacities, and the ability to obtain replacement power or other sources of fuel. After this intense period of analysis, a total of 90 units opted into the three subcategories. *Id.* For the 2020 Rule, EPA estimated that 427 units would be subject to the Rule. 2023 TDD at 14, Figure 1. Using EPA's figure as a baseline, 21 percent of the subject units opted for a subcategory, and the great majority of those units opted for the cessation subcategory.[54]

Ceasing operation of an electric generating unit requires more than a focus on the unit itself. And they are not decisions made in a vacuum. Regulated power producers have an obligation to supply reliable sources of power; a determination to cease operating a coal unit requires an integrated assessment of the capacities of other units to supply replacement power, or planning and funding to build new replacement units. Independent power producers are in a similar situation, as they typically have long-term contracts for provision of power to the grid.

The 2020 Rule also included a subcategory for high FGD flow plants. But under the Proposed Rule, both the high FGD flow subcategory and the low utilization subcategory would be eliminated. 88 Fed. Reg. at 18,826. These facilities, after clearly relying on the subcategories, will have to either retire, repower, or incur significant expenses to meet the Proposal's BAT limitations.

[54] EPA estimates that the number of affected units has decreased since the 2020 Rule by 29 percent, to 304 units. 2023 TDD at 13.

While facilities that have opted, under the inducements of the 2020 Rule, to close or repower are free to continue those actions under the Proposed Rule, their reliance interest is still very great because those closures/repowerings will have major ramifications for years into the future. Facilities that have announced closure of coal units are now engaged in the years-long process of funding, procuring, installing, permitting, and testing replacement units, or the sometimes just-as-long-process of building a connection to a gas line or constructing a new transmission line. In the meantime, they are making many internal adjustments to staffing, equipment, and existing facilities (such as landfills) to account for these changes.

The most obvious reliance impact, of course, is to those facilities that are hastening to meet the 2020 FGD limitations by applying new technologies such as CP+LRTR. Those facilities have had to continue planning and implementation of retrofits despite EPA's reconsideration of the rule. EPA was clear on this point: "While the Agency undertakes this new rulemaking, facilities will continue to be subject to the requirements of the 2015 Rule, *as amended by the 2020 Rule,* which are currently effective. … EPA expects permitting authorities to continue to implement the current regulations while the Agency undertakes a new rulemaking." 86 Fed. Reg. 41,801, 41,802 (Aug. 3, 2021) (emphasis added).

Building new FGDW treatment cannot be accomplished in a short timeframe. For the 2020 Rule, EPA estimated that planning, procuring, installing, and testing a low hydrologic residence time biological reduction (LRTR) system alone—not including chemical precipitation which is required prior to the LRTR—would average 22 months.[55] This is an underestimate of

[55] Memorandum from Elizabeth Gentile, Eastern Research Group, Inc. (ERG), to Steam Electric Rulemaking Record, FGD and Bottom Ash Implementation Timing at 2 (Oct. 17, 2019), EPA-HQ-OW-2009-0819-8191 (DCN SE08480). Note that EPA documents two LRTR systems estimated to take 28 months to complete and one system estimated to take 31 months to complete. *Id.* at 2–3.

the time to complete this transition, according to information UWAG presented in its 2020 Rule comments.[56] But even using EPA's estimate and accounting for contingencies such as supply chain issues, labor shortages, and other unexpected hurdles, all plants subject to the generally applicable FGD limitations of the 2020 Rule must already have incurred significant expenses to ensure compliance with the "no later than" deadline of December 31, 2025.[57]

EPA's record is replete with examples of companies that have long since incurred significant expenses to meet the requirements of the 2020 Rule. For example, American Electric Power (AEP) has been working over the course of several years to obtain state regulatory approvals necessary to recoup costs of implementing the 2020 Rule technologies. Southern Company has been engaged in a long-term FGDW pilot for its Scherer Station since 2020.[58] As of November 2021, the electric utility for the City of Springfield, Illinois, had evaluated FGDW treatment technologies "in considering how to comply with the 2022 ELGs."[59] And EPA has documented that the industry continues to fund pilot studies of FGDW technologies since the 2020 Rule.[60]

---

[56] UWAG, Comments on EPA's Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 84 Fed. Reg. 64,620 (Nov. 22, 2019) at 191–94 (Jan. 21, 2020), EPA-HQ-OW-2009-0819-8456 (UWAG 2020 Comments).

[57] Indeed, EPA concedes that the latest a plant would start incurring costs to comply with the 2020 Rule would be May 2023, and this is based on EPA's flawed estimates of time required to complete the retrofit. 88 Fed. Reg. at 18,858 n.115.

[58] Letter from Scott Hendricks, Mgr., Water & Nat. Res. Permitting Program, Georgia Power, to Richard Benware, EPA, Georgia Power's VSEP Pilot at Plant Scherer and Status of Membrane/Paste Encapsulation Preliminary Research (Apr. 30, 2020), EPA-HQ-OW-2009-0819-8888 ATT 1 (DCN SE08619A1).

[59] Memorandum from U.S. EPA, to Steam Electric Record – EPA-HQ-OW-2009-0819, Notes from Call with City Water, Light, and Power on November 15, 2021 at 2 (Dec. 22, 2022), EPA-HQ-OW-2009-0819-9377 (DCN SE10256).

[60] 88 Fed. Reg. at 18,840.

Looking beyond EPA's record, many facilities have already incurred costs of complying with the 2020 Rule. In January 2021, AEP filed permit modifications for all affected facilities that must install additional technologies to meet the ELG limits.[61] Dominion Energy South Carolina (DESC) recently reported that it "has begun definitive engineering and procurement activities to support construction of the facilities necessary for Williams [Power Station] to comply with the current ELG rule standards by December 31, 2025."[62] As the company explains:

> Williams is the only large generator on the DESC system in the Charleston area and is critical to providing reliable service to customers there. Electric transmission resources and natural gas supplies are limited in the Charleston area, and the 2022 Coal Plants Retirement Study found it was impracticable to retire and replace Williams before December 31, 2030, at the earliest. The modeling presented here shows that early retirement of Williams remains a lower cost option than continuing to operate it until the end of its useful life. While the December 31, 2030 retirement date is ambitious, the timetable is not driven by ELG compliance as is the case with Wateree since DESC must proceed with an ELG compliance project for Williams even under this ambitious timetable.[63]

Many other companies are also in the process of planning, designing, and procuring new FGDW treatment as a result of the 2020 Rule. All of these movements within the industry are affected by the limitations for FGDW that EPA set in the 2020 Rule. Collectively and individually, these multi-million dollar actions are a substantial reliance on EPA's decisions regarding FGDW in the 2020 Rule.

---

[61] American Electric Power Company, Inc. Form 10-Q for the Quarterly Period Ended March 31, 2023 at 18 (May 4, 2023).

[62] Dominion Energy South Carolina, Inc., 2023 Integrated Resource Plan at 40 (filed Jan. 30, 2023) (IRP). According to the IRP, Williams Station needs new FGDW treatment to comply with the rule.

[63] *Id.* at 7.

EPA claims to have assessed these reliance interests. But it points only to the Proposal's "new subcategory for early adopters who relied on certain of EPA's past determinations." 88 Fed. Reg. at 18,839 n.23. This is wholly inadequate as an assessment of reliance interests. The "Early Adopter" subcategory will apply to an extremely small fraction of the affected facilities. As explained in section II.C.1, only four units—all at a single facility—are likely to be eligible for the new subcategory. In short, EPA has in no way satisfied the Supreme Court's requirement that it assess reliance interests by throwing an "early adopter" bone to a single facility.

EPA goes on to note that "no NPDES permittee has certainty of its limitations beyond its 5-year NPDES permit term, as reissued permits must incorporate any newly promulgated technology-based limitations as well as potentially more stringent limitations necessary to achieve water quality standards." 88 Fed. Reg. at 18,839 n.23. This is true, but it is irrelevant to EPA's obligation to assess reliance interests in the case of this rule, where EPA was quick to reject its earlier decision and has not provided an adequate, detailed justification for doing so, as discussed below.

b. The record contains little new information on membranes.

Over more than three years (approximately April 2017 to the final rule in October 2020), EPA gathered substantial data for the 2020 Rule, including reports of membrane pilot studies and information about foreign installations using membranes for various purposes.[64] In contrast, the new information on membranes that EPA has assembled in support of its proposal is meager. In the preamble, EPA cites notes of calls it held in 2021 with DuPont, a membrane manufacturer.

[64] *See, e.g.,* Memorandum from ERG, to Steam Electric Rulemaking Record, Technologies for the Treatment of Flue Gas Desulfurization Wastewater (Aug. 20, 2020), Appendices B and K (membrane pilot study summaries); *Id.* at Appendix S (information on foreign installations of membranes), EPA-HQ-OW-2009-0819-8890 (DCN SE 09213).

88 Fed. Reg. at 18,840 n.28. It also cites to an internal memo that compiles information from vendors about FGDW treatment technologies. *Id.* at 18,839 n.25. And, in addition to the pilot studies identified in the 2020 Rule, EPA claims it has new information about three domestic membrane pilot studies. *See* 88 Fed. Reg. at 18,840. This appears to be the primary new information available to support EPA's choice of membranes as BAT for FGDW. It does not meet the criteria for a "detailed justification."

The notes of EPA's two phone calls with DuPont by and large contain anecdotal information and amount to two pages of text.[65] While DuPont has sold membranes to some Chinese facilities for use in treating FGDW, it appears that DuPont's knowledge of these facilities is limited. The notes contain few site specifications, no performance data,[66] and little to no information on operations and maintenance of these installations. The internal memo[67] compiling information from vendors contains three pages on DuPont's installations. EPA claims DuPont provides "detailed information" on two China installations, but that "detailed information" amounts to one paragraph for each facility. EPA Feb. 15, 2023 Memo at S-1 to S-

---

[65] Memorandum from U.S. EPA, to Steam Electric Record – EPA-HQ-OW-2009-0819, Notes from Vendor Call with DuPont October 29 and December 8, 2021 (Nov. 14, 2022), EPA-HQ-OW-2009-0819-9378 (DCN SE10245) (2021 DuPont Meeting Notes).

[66] While the record contains a small amount of performance data for a Chinese facility (the Changxing Power Plant), that data was gathered prior to issuance of the 2020 Rule. *See* Memorandum from Sara Bossenbroek & Tara Stout, ERG, to Steam Electric Rulemaking Record, Notes from Meeting with DuPont (June 24, 2020), EPA-HQ-OW-2009-0819-8887 (DCN SE08618) (2020 DuPont Meeting Notes), Attachment 3, Derek Stevens, Ph.D. et al., Dow Water & Process Solutions, Case Studies & Analysis of Reverse Osmosis to Treat Flue Gas Desulfurization Wastewater (undated), EPA-HQ-OW-2009-0819-8887 ATT 3 (DCN SE08618A3) (Stevens et al.).

[67] Memorandum from U.S. EPA, to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819, Technologies for the Treatment of Flue Gas Desulfurization Wastewater, Coal Combustion Residual Leachate, and Pond Dewatering (Feb. 15, 2023), EPA-HQ-OW-2009-0819-9656 (DCN SE10281) (EPA Feb. 15, 2023 Memo).

2. Again, no performance data is given, and no operations and maintenance information. The descriptions do not include some key basic facts, such as the size of the units being serviced. This is hardly "detailed information" sufficient for imposing new standards on an entire industry. Importantly, all references listed for the DuPont portion of the memo pre-date the 2020 Rule, with the exception of the notes of EPA's two 2021 phone calls with DuPont. Therefore, any new information from DuPont appears to be limited to the two-page notes document discussed above.

In the preamble, EPA points to specific information it has become aware of since the 2020 Rule that it claims supports its decision on membrane filtration. First, EPA says it "has learned that certain Chinese facilities with membrane installations have successfully achieved zero discharge of FGD wastewater, in part by adjusting the ratios and dosages of the specific chemicals used in their chemical precipitation pretreatment systems." 88 Fed. Reg. at 18,839. However, the cite provided for this statement is to a February 2018 memo of a call with Oasys, a membrane technology company.[68] EPA would have been well aware of this information at the time of the 2020 Rule. Second, EPA claims it "has learned that certain Chinese plants with later installations did not need to pilot membrane filtration systems before successfully installing and operating them at full scale. The operating information from the previous installations was sufficient to successfully install a full-scale membrane system without the need for an intermediate pilot." 88 Fed. Reg. at 18,839. Curiously, though, this statement is cited in a document from the 2020 rulemaking that reports on a call EPA had with DuPont in April 2020, before issuance of the 2020 Rule.[69] Clearly, information learned from Oasys, DuPont, or any

[68] 88 Fed. Reg. at 18,839 n.26 (citing Memorandum from Sara Bossenbroek & Danielle Lewis, ERG, to Steam Electric Rulemaking Record, Notes from Meeting with Oasys Water™ (Feb. 16, 2018), EPA-HQ-OW-2009-0819-7334 (DCN SE06915)).

[69] 88 Fed. Reg. at 18,839 n.27 (citing 2020 DuPont Meeting Notes).

other source before issuance of the 2020 Rule cannot be considered "new information" and cannot serve as a basis for EPA's change of position on membranes as BAT.

EPA acknowledges that, in 2020, the Agency determined it could not rely on information from foreign installations of membranes to demonstrate the availability of the technology because of "too many unknowns … including not knowing enough about their configurations, operations, performance, or long-term maintenance." 88 Fed. Reg. at 18,839. But EPA points to the installations' continued operation since 2020 as an indication that the Agency's concerns in 2020 "may have been overstated." *Id.* at 18,840. EPA is apparently dependent on statements by DuPont for verification of continued operations of these facilities, as it cites no new information except the notes of its 2021 phone calls with DuPont. There is nothing in the record to suggest that EPA has visited any of the Chinese installations or has conversed with the owners, operators, or regulators of these installations.

But nonetheless, EPA claims to have "[a]dditional data on foreign system configurations" since the 2020 Rule, noting:

> EPA was able to learn more about the issues with pretreatment identified at the pilot stage for one of the first Chinese installations. These issues were a result of the FGD wastewater's high suspended solids and high hardness. While these issues were identified at the outset of pilot testing, they were sufficiently resolved through adjustment of the chemical precipitation pretreatment process, leading the facility to install the system at full scale. For later installations at different sites, this Chinese utility ceased conducting pilot tests since appropriate pretreatment steps had already been identified.

88 Fed. Reg. at 18,840.

The cite supposedly supporting this "new information" is EPA's two-page memo of its 2021 conversations with DuPont.[70] However, the cite appears to be erroneous, because that

[70] 88 Fed. Reg. at 18,840 n.28 (referencing 2021 DuPont Meeting Notes, EPA-HQ-OW-2009-0819-9378 (DCN SE10245)).

memo does not include any discussion of a specific site in China although it does discuss some limited aspects of pretreatment. This calls into question when and where EPA gained its supposed "new information" about one of the first Chinese installations and its experience with pilots and pretreatment. In fact, the information about the ceasing of pilot tests by a Chinese utility is included in an earlier portion of the record that pre-dates the 2020 Rule,[71] and information about the use of pretreatment to address suspended solids and hardness for Chinese facilities is also well documented in the pre-2020 Rule record.[72]

Finally, EPA acknowledges that, in 2020, the Agency found "there was not enough information to know if the foreign installations could continually operate as zero discharge systems or whether there would be some periods during which discharges occur." 88 Fed. Reg. at 18,840. EPA asserts that two additional years of operation of these facilities "support[] a finding that continuous zero discharge operations are achievable." *Id.* But again, the only basis EPA apparently has for finding that these facilities continue to operate in zero discharge mode are two phone calls with DuPont. DuPont is not the owner or operator of these facilities. It is not clear that DuPont has any continuing relationship with any of the facilities. Indeed, the lack of information presented in the two-page memo documenting EPA's recent conversations with DuPont suggests that DuPont's current knowledge of these facilities is very limited. The 2021 phone calls with DuPont arguably provide nothing new at all about membranes at the Chinese facilities that was not already contained in the 2020 Rule's record. DuPont recites that it has

[71] 2020 DuPont Meeting Notes at 4, EPA HQ-OW-2009-0819-8887 (DCN SE08618).

[72] 2020 DuPont Meeting Notes, Attachment 3, Stevens et al., EPA-HQ-OW-2009-0819-8887 ATT 3 (DCN SE08618A3) (note particularly the description of softening processes and other pretreatment at the Hanchuan Power Plant) and Water Solutions, Possibility flows with us; MLD-ZLD Flue-gas Desulfurization Wastewater Treatment (2019), EPA-HQ-OW-2009-0819-8887, and Attachment 1, EPA-HQ-OW-2009-0819-8887 ATT 1 (DCN SE08618A1) (two case studies of Chinese installations, including the Hanchuan Power Plant).

"been involved" in treatment of FGD wastewater.[73] DuPont notes that FGD systems in China are often lower capacity and have smaller wastewater flows than U.S. systems. DuPont repeats its recommendation of pretreatment and softening for FGD wastewater. DuPont states that it has collaborated with original equipment manufacturers to help design and demonstrate membrane-based FGD wastewater treatment systems for power plants in China and that these facilities use well-established precipitation methods as pretreatment, with attention toward water softening in order to achieve high recoveries using reverse osmosis membranes. All of this was known by EPA, and was documented, in the 2020 Rule's record.[74] Notably, the memo does not state that the Chinese systems installed by DuPont continue to operate in zero discharge mode, although it notes that Chinese regulations are becoming more stringent, resulting in more plants opting for a ZLD approach.

In sum, EPA has come up short on "new information" to support its change of position on membranes. Its primary basis of "new information" is a rather generic two-page account of its 2021 phone calls with DuPont. While it had discussions with other membrane vendors, the primary information cited by EPA is based on its DuPont contacts. However, much of that information pre-dates the 2020 Rule and so cannot be a basis for its change of position.

The supposed new information about three domestic pilot studies[75] is also insufficient to justify EPA's change of position. See section III.A.2.b, *infra*. For the 2020 Rule, EPA identified the same number of domestic pilots for FGDW treatment and new information about three pilot

---

[73] 2021 DuPont Meeting Notes at 2, EPA-HQ-OW-2009-0819-9378 (DCN SE10245).

[74] *See* 2020 DuPont Meeting Notes, EPA-HQ-OW-2009-0819-8887 (DCN SE08618) and its attachments.

[75] *See* 88 Fed. Reg. at 18,840.

studies merely shows that membrane FGDW treatment is still under study, not that it is ready for commercial deployment.

For all the reasons listed above, EPA has failed to provide a detailed justification for its change of position on the availability of membrane FGDW treatment. For the final rule, EPA may point to information gleaned from its January 2022[76] information request to seven companies, which asked for data on FGDW treatment installations, including those using membrane filtration technology. 88 Fed. Reg. at 18,836. But EPA collected all of that information after it had already selected its regulatory options for the rule. EPA's own documents say that the proposed rule's options were completed in January 2022.[77]

In sum, EPA's reconsideration of the 2020 Rule was largely completed in six short months between July 26, 2021 (when EPA announced its reconsideration) and January 2022 (when the rule options were selected). In this period, the only apparent source of new information on membranes were phone calls with DuPont, which resulted in a rehash of information already on the record, and new information about a few pilot studies. None of this is a strong basis for a radical change of position on the availability of membrane filtration technology for FGDW treatment. It appears that EPA was in a rush to complete this rule, so much so that it could not delay option selection until it had in hand the information on membranes and other technologies that it was requesting from the regulated industry. Under the

[76] The preamble appears to use an erroneous date. Letters to the companies requesting this information are dated December 21, 2021. *See, e.g.,* Letter from Robert K. Wood, Dir., Eng'g & Analysis Div., U.S. EPA, to Jeffrey Hanson, Dir., Envt. Servs. & Corp. Sustainability, Alliant Energy Corp. Services, Inc. (Dec. 21, 2021), EPA-HQ-OW-2009-0819-9697 (DCN SE09689). But since the letters requested a response from the companies by February 23, 2022, it is impossible that any information gleaned from these requests figured into EPA's selection of the proposed rule options that EPA says it completed in January 2022.

[77] *See* EPA, Legacy Surface Impoundment Leachate Sensitivity Analysis (Feb. 14, 2023), EPA-HQ-OW-2009-0819-9645 (DCN SE10415) (*see* sheet named "ReadMe").

APA, EPA may not predetermine the outcome prior to evaluating relevant data. Here, EPA cannot substantiate a "detailed justification" for its reversal of course on this record.

c. EPA has not addressed statements in the media that the new rulemaking is based on a desire to accelerate the closure of coal-fired plants.

EPA has not addressed or accounted for statements in the media that the new ELG rulemaking, and its reversal in course on membranes, is based on a desire to accelerate the closure of coal-fired plants. A January 2022 article in *Climatewire* described an EPA objective to decarbonize the power grid by issuing new rules, including ELG rules, that make coal-fired power plants "less economic":

> EPA is … relying on the knock-on effect of stricter air, waste and water rules. It's a "comprehensive approach" to decarbonize the power grid that's been in the works since the beginning of the Biden administration (Climatewire, Oct. 27, 2021). … The strategy could push the ball forward on Biden's climate commitments by making it less economic to run coal-fired power plants in this country. … EPA began floating the idea of a power sector "initiative" or "strategy" in private discussions last year before international climate talks began in Glasgow, Scotland. … [The approach was] previewed … in the EPA chapter of the influential Climate 21 Project transition-period memo[:] … "Where regulation is justified to address critical environmental damage caused by coal production and combustion, regulation can create climate co-benefits by rectifying the economics of fossil-based generation and competition with clean energy sources" ….
>
> EPA Administrator Michael Regan had asked the agency to "think broadly across the different pollutants in the different media that are affected by the power sector" when charting a course on power plant carbon. … The possible components of the EPA comprehensive strategy all have the potential to change the economics of running and operating coal-fired power plants in such a way as to encourage early retirements. These could include actions related to EPA's rules for power plant mercury and air toxics and pollution that crosses state lines or contributes to regional haze. EPA's existing effluent guidelines and coal waste rules could also play a role.

Jean Chemnick et al., *How Biden Could Close Coal Plants Without CO2 Regulations*, CLIMATEWIRE, Jan. 24, 2022. After the Supreme Court decision in *West Virginia v. EPA* that CAA § 111(d) does not authorize EPA to reduce GHG emissions by shifting generation of electricity away from coal-fired plants, a July 2022 *New York Times* article described how EPA planned to rely on other rules, including water rules, to make coal-fired plants "too expensive to continue to operate:"

> [EPA] is enacting tougher restrictions on coal plants to reduce pollutants like soot and nitrous oxides, and to force the cleanup of water contamination from coal plants. Michael S. Regan, the E.P.A. administrator, has said those and other rules *will have a side-benefit of also reducing greenhouse gas emissions*. He also has indicated rule changes such as these might make some coal plants too expensive to continue to operate, resulting in more of them being closed down. … "If some of these facilities decide that it's not worth investing in, and you get an expedited retirement, that's the best tool for reducing greenhouse gas emissions," he said.

N.Y. TIMES July 7, 2022 (emphasis added). On November 4, President Biden stated "'No one is building new coal plants because they can't rely on it, even if they have all the coal guaranteed for the rest of their existence of the plant. … We're going to be shutting these plants down all across America and having wind and solar.'" Trevor Hunnicutt, *Biden comments on coal-fired plants slammed by Manchin ahead of U.S. midterms*, REUTERS, Nov 5, 2022. The White House later clarified that "the comment was intended to highlight the country's energy transition." *Id*.

Indeed, when UWAG asked EPA in a FOIA request for any new information EPA received since the 2020 rule to support a new ELG rulemaking, EPA provided no new information—including on membranes. Instead, EPA provided heavily redacted documents from 2021 indicating the steam electric ELG reconsideration was part of a "cross-office power sector strategy;" that the Office of Water was "excited to have robust discussions with OLEM, OAR, OP, and OGC about how the ELG might contribute [redacted]," and that EPA met with environmental groups on ELG reconsideration and asked them to "send any new information and data they have as soon as possible." EPA FOIA Response at ED_006652_00039277-00001, ED_006652_00039279-00001; Consolidated notes from March 11, 2021, meeting with

Environmental Petitioners in *Appalachian Voices v. EPA*, No. 20-2187 (4th Cir.), FOIA EPA-2022-003242, Response Documents 1, ED_006652_00039079-00001.

2. Membrane filtration is not technologically "available."

Contrary to EPA's assertions, membrane filtration is not technologically available for the treatment of FGDW. Membrane filtration is an emerging technology. There are no commercial installations of membranes for FGDW treatment in the United States. New Logic, one of the membrane vendors EPA has contacted, claims that it has one full-scale installation in the United States.[78] This is misleading. While New Logic provided a full-scale membrane system for the Colstrip Power Plant in Montana, that system has been decommissioned[79] and treated groundwater only, not FGDW.[80] In treating groundwater, a wastestream with less salts and pollutants than FGDW, Colstrip ran into significant challenges with New Logic's VSEP system, including the inability to control scaling of the membranes and high maintenance costs. And while EPA points to GenOn's plans to use membrane technology for FGDW treatment at two of its facilities,[81] as the Agency knows, GenOn decided to close the coal-fired units at Morgantown and Chalk Point and never deployed any membranes there.[82]

---

[78] Memorandum from U.S. EPA, to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819, Notes from Vendor Call with New Logic on October 1, 2021 (Sept. 26, 2022), EPA-HQ-OW-2009-0819-9380 (DCN SE10290).

[79] Hydrometrics, Inc., *Performance Evaluation Report Plant Site Remedy – 2021 Colstrip Steam Electric Station, Colstrip, Montana,* at 2-1 (Oct. 2021) (noting equipment to be housed in the former building used to house the New Logic vibratory shear enhanced process (VSEP) system).

[80] EPA Feb. 15, 2023 Memo at K-10, EPA-HQ-OW-2009-0819-9656 (DCN SE10281) (Table 6 on page K-10 suggests the VSEP system also treated cooling tower blowdown but, according to the operator, the system only treated groundwater).

[81] 88 Fed. Reg. at 18,842.

[82] *See* GenOn, Press Release, GenOn Holdings, Inc. Announces Retirement of Chalk Point Coal Units at 1 (Aug. 10, 2020), EPA-HQ-OW-2009-0819-9101 (DCN SE09604); Memorandum from U.S. EPA, to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-

a. **Information on international installations is very limited and should not be used to demonstrate "availability" within the United States.**

Lacking any full-scale installations in the United States, for the 2020 Rule, EPA did a thorough search for international installations, and it identified installations in China, South Korea, and Finland. EPA, Response to Public Comments for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category at 2-108 (Aug. 2020) EPA-HQ-OW-2009-0819-9015 (DCN SE08615) (2020 Response to Comments). Despite identifying these facilities, "EPA was unable to obtain operation, maintenance, or performance information from these foreign plants, either directly from the facility, from the vendors, or from site visits." *Id.* Further, the Agency acknowledged that it did not have the following critical information:

- "how these systems are configured or operated,"
- "what levels of reductions they achieve,"
- "whether there are any particular performance difficulties that result from continuous operation," or
- "importantly, how applicable these operations would be to plants across the United States."

Id.

EPA previously concluded that membrane filtration is not available industry-wide and also found it "cannot predict with certainty that the technology will be nationally available in 2028." 2020 Response to Comments at 2-109. To reverse this conclusion, as discussed at length above, EPA needs more than a few conversations with a self-interested vendor or two.

0819, Update to Industry Profile for the 2023 Steam Electric Power Generating Effluent Guidelines Proposed Rule at 8 (Feb. 7, 2023), EPA-HQ-OW-2009-0819-9622 (DCN SE10241) (Industry Profile Update).

Additionally, EPA has not demonstrated that its new information on membranes is applicable to plants in the United States. A great deal of uncertainty regarding the foreign installations, including a lack of information on the types, qualities, and quantities of coal being burned, remains to this day.[83] There is no information on whether the Chinese plants operate as peaker plants or as baseload plants; variations in operations can affect the sufficiency of wastewater treatment or the design of the treatment system in the first place. Without more information, it is impossible to tell if the international facilities are processing wastewater with similar characteristics to that found in U.S. plants.[84] It is impossible to know whether the systems have similar components and similar operating procedures as the systems that EPA is proposing. And it is impossible to know whether these facilities are meeting similar environmental standards (for all media) as those imposed in the United States.

Indeed, the record contains evidence indicating that the international installations are very different from those in the United States. First, DuPont notes that FGD systems in China are

[83] For the 2020 Rule, EPA gathered extensive coal quality data through Section 308 requests to several industry members. *See, e.g.*, Letter from Robert K. Wood, Dir., Eng'r & Analysis Div., EPA, to Mark McCullough, Executive Vice President – Generation, American Electric Power (Jan. 3, 2018), EPA-HQ-OW-2009-0819-7296 (DCN SE06675) (308 Request Letter) (requesting daily identification of type of coal used during FGD pilot- or laboratory-scale testing, including sulfur, chlorine, bromine, and iodine content). In contrast, there appears to be a lack of any data regarding the quality of coal being burned in the Chinese facilities.

[84] This is in contrast to EPA's assessment of Italian facilities for the 2015 Rule. There, EPA conducted a 3-day sampling event, collecting untreated scrubber purge and treated FGD wastewater, at the Federico II Power Plant in Brindisi. EPA also requested and received 1-day grab samples from a second Italian plant. EPA, Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-15-007, at 3-12 to 3-13 (Sept. 2015), EPA-HQ-OW-2009-0819-6432 (DCN SE05904) (2015 TDD). The 2015 record contains detailed sampling event and site visit reports from these facilities. But for the international installations EPA points to in the Proposed Rule, EPA has not conducted any sampling, nor does the record contain much wastewater characterization data.

often lower capacity and have smaller waste flows than U.S. systems.[85] The volume of wastewater flows to be treated is a critical factor in determining the costs of a wastewater treatment system. The larger the flow, the more expensive it will be to treat. EPA should have compared the flows of the Chinese facilities to the range of flows it has documented for United States facilities producing FGD wastewater. But there does not appear to be any analysis of this type in the record.

Second, according to DuPont, some facilities in China are producing industrial-grade salt as a byproduct from FGD wastewater treatment. 2021 DuPont Meeting Notes at 2, EPA-HQ-OW-2009-0819-9378 (DCN SE10245). There is no such market in the United States, which means that, in the United States, the byproduct brine must be disposed of, presenting a significant engineering challenge and adding to the costs of disposal.

Third, DuPont recommends softening prior to wastewater entering the membrane system, and EPA's notes of its meeting with DuPont say that "softening … is a key component." *Id.* But EPA's proposed treatment system does not account for softening. In contrast, chemical precipitation as required in EPA's Proposal does not remove all hardness and produces a much smaller volume of solids than would occur with softening. If EPA were to add softening to its model technology, then it would add both capital and O&M costs.

Fourth, it is not clear that EPA has investigated the disposal or other management of the byproducts from the foreign treatment systems. DuPont appears to have limited information about disposal practices. For the Hanchuan Power Plant, DuPont states that "[f]inal disposal of the salt product is unknown." [86] EPA cannot assess the availability of a technology without

[85] 2021 DuPont Meeting Notes at 2, EPA-HQ-OW-2009-0819-9378 (DCN SE10245).

[86] EPA Feb. 15, 2023 Memo at S-2, EPA-HQ-OW-2009-0819-9656 (DCN SE10281).

studying how its byproducts are handled or disposed. This is a major gap in its understanding of the foreign installations.

Fifth, the record appears to contain very little wastewater characterization and performance data for the Chinese facilities. One International Water Conference paper offers a summary chart showing the recovery of the first pass reverse osmosis unit for the Changxing Power Plant over 100 days.[87] This is insufficient to support a finding that the Chinese plants have demonstrated the effective use of membranes for FGDW treatment.

For all these reasons, EPA's reliance on the international installations is clearly inappropriate. While EPA often cites *American Frozen Food Institute v. Train,* 539 F.2d 107 (D.C. Cir. 1976) (*AFFI*), for the proposition that it may use technology data from foreign facilities, that case is distinguishable here. In *AFFI*, EPA contacted two Canadian potato processors and used their effluent reduction data—along with data from one American plant—to set biochemical oxygen demand (BOD5) and total suspended solids (TSS) limits based on biological treatment systems. *Id.* at 148–49. EPA also followed up with the Canadian government to ensure that the Canadian processors operated within "similar tax guidelines, receive no direct pollution control subsidies, and compete in similar markets." *Id.* at 159, *reprinting* 39 Fed. Reg. 10,862, 10,862 (Mar. 21, 1974).

Thus, *AFFI* differs from the current proposal in two important ways. First, EPA had performance data from an American facility that it used—in conjunction with data from the two Canadian facilities—to develop limits. In the proposal, EPA has presented no FGDW treatment performance data from the United States because there is no full-scale installation. Having data from at least one full-scale domestic installation—and correlating that data with reliable

[87] Stevens et al., EPA-HQ-OW-2009-0819-8887 ATT 3 (DCN SE08618A3).

performance data from a foreign installation—is helpful for ensuring appropriate, attainable limits. This reasonable approach is what the Court in *AFFI* approved. This is far different from taking limited data from a foreign installation, failing to sample or even visit that installation, and then using full-scale foreign installations only to determine that the BAT technology is "available" within the United States.

Second, in *AFFI*, EPA was careful, when dealing with the foreign installations, to obtain information beyond technological aspects when determining whether the operations and constraints on Canadian processors were fairly comparable to American processors. The Agency contacted the Canadian government to discuss whether the Canadian facilities operated in a similar market, with similar incentives and regulations. But for this Proposal, there is no indication that EPA made attempts to determine whether the Chinese facilities operate under similar environmental laws across media, whether their disposal of byproducts from the FGDW treatment is appropriate and subject to similar restrictions as in the United States, or whether the technologies applied are heavily subsidized by the government or subject to other types of favorable treatment. Therefore, EPA's reliance on *AFFI* as precedent for its use of the limited data from Chinese installations is not warranted.

b. EPA's reliance on new information about three pilot studies is not warranted.

EPA also relies on new information about pilot studies to justify selection of membrane filtration as BAT for FGDW treatment. All pilot studies have their limitations, and all pilots must be understood in a proper context. Many pilot studies are designed to determine the outer bounds of treatability using the technology, and thus "push" the system to its limits, in ways that are unrealistic for routine operation. It is not clear that EPA has fully assessed the pilot studies dealing with membranes and taken into consideration their limitations and their objectives.

Since the 2020 Rule, EPA has supposedly identified new information about three pilot studies. 88 Fed. Reg. at 18,840. In particular, EPA points to an Electric Power Research Institute (EPRI) study of the Saltworks Electrodialysis Reversal (EDR) Selective Technology[88] and claims it supports the proposed conclusion that membrane filtration is BAT for FGDW. However, EPA fails to put this pilot into proper context. First, it was a small-scale pilot, operating at 264 to 793 gallons gpd. EPA's estimated FGD purge flow rates for the 22 plants that it predicts would need to comply with FGDW zero discharge requirements range from 7,000 to 1,810,080 gpd. EPRI, EPRI Comments on Proposed Effluent Limitations Guidelines Rule at 11–12, Tbl. 1-2 (May 26, 2023) (EPRI Comments). This EDR pilot is no indication that the technology will properly scale up to handle these much larger flows. Second, as EPRI notes, only 15 grab samples were taken during the entire pilot study. *Id*. at 25. Third, as EPRI describes in more detail, the EDR system has significant limitations in the quality of treated water entering the treatment system and also in the extent of concentration possible. *Id*. at 25–26. According to EPRI, because of these limitations, most sites would need additional treatment, such as through a thermal evaporator and/or crystallizer, to minimize the volume of brine for encapsulation*.* *Id.* at 26–29. Fourth, EPRI explains that the system requires a high-pH physical/chemical treatment step (pH of 11) to remove low solubility metals, fluoride, and silica. EPRI believes most existing physical/chemical treatment systems cannot achieve this pH without significant equipment modifications, which will require significant increased costs. *Id.* at 25. After the high pH stage, the system would need acidification to a pH of 3 with sulfuric acid, so there would be additional equipment modifications, with their attendant costs, to allow for the acidification stage. *Id.* Therefore, this pilot does not demonstrate that membrane filtration is

[88] 88 Fed. Reg. at 18,840.

BAT. It does not even demonstrate that the EDR technology is suitable for FGDW treatment. Much more research would be needed before reaching any determinative answer. This is particularly true given the many adjustments that would be needed to the physical/chemical treatment processes.

EPA also claims in the preamble to have new information on two additional domestic pilot applications of membrane treatment for FGDW, but EPA has not identified what it is claiming as "new information" and has not identified which two additional pilots it is referring to.

Also, EPA's information regarding some of the pilots is very limited. For instance, in the 2023 TDD, EPA states that it has identified 17 pilot-scale studies of nanofiltration and reverse osmosis used for FGD wastewater treatment world-wide. However, EPA explains in a footnote that "EPA has limited data on the performance and configuration of these full-scale membrane systems. … Some references include only plant name or location. For this reason, some references may be describing the same installation, and EPA does not have enough information to determine where this may be the case." 2023 TDD at 24 n.14, 25 n.15. Where EPA only has a name and location of an installation—and no further details—it is critically important *not to use that information as support for a nationwide regulation.* In fact, it appears that EPA has not done its homework when it cannot, by its own admission, determine whether all the references are to separate facilities or if there might be some overlap that is causing an overestimate of the actual number of installations.

c. Use of membrane filtration for other purposes or in other industries is irrelevant for determining whether it is BAT for FGDW.

EPA also claims that use of membrane filtration in other applications for other wastestreams supports its selection as BAT for FGDW. 88 Fed. Reg. at 18,840–41. That members of the power industry use membranes for very different water treatment issues, such as to treat side-streams of intake water to purify boiler makeup water or for treatment of ash transport water or cooling tower blowdown, is not relevant to whether membrane filtration is an appropriate model technology for FGDW. The flow volumes and characteristics of each of these waters are unique and must be evaluated separately. Also, operation and maintenance of membranes in these circumstances (*e.g.*, number and timing of membrane cleaning backwashes; appropriate length of membrane use prior to replacement, etc.) would be very different from operation and maintenance for treating FGDW. For example, the source of boiler makeup water is usually a local waterbody or potable water. For either source, the total dissolved solids (TDS) are generally less than 600 parts per million (ppm),[89] where EPA has estimated the average concentration of TDS in FGDW as 32,500,000 ug/L, or 32,500 ppm.[90] Additionally, the few gallons-per-minute flow for boiler makeup water is very much lower than the typical flow rate of FGDW.

Additionally, EPA enumerates the other industries that are using membrane filtration in some form or fashion, including use of membranes for agricultural uses, such as manure management and oil processing as part of oil and gas extraction. 88 Fed. Reg. at 18,841. But again FGDW is quite variable, depending on other system components and the type of coal being burned, and has unique fouling and scaling characteristics. Therefore, referencing these other, far-afield uses of membranes is not at all useful to demonstrating that membrane filtration is BAT for FGDW.

[89] World Health Organization, Total dissolved solids in Drinking-water; Background document for development of WHO *Guidelines for Drinking-water Quality* at 1, WHO/SDE/WSH/03.04/16 (2003).

[90] 2015 TDD at 10-10, Tbl. 10-3 (average effluent pollutant concentrations for FGD surface impoundments).

d. The management of brine produced by membrane filtration raises substantial technological and environmental concerns.

Membrane filtration produces two streams: a clean stream, often known as "permeate," which sometimes can be recycled into other processes; and a concentrated brine, which must be disposed of in an appropriate manner. As it evaluates membrane filtration, EPA also should make a thorough investigation of the means of disposing of the brine it produces.

i. Brine treatment and disposal processes and impacts to landfills

In some circumstances, facilities heat the brine until all of the water evaporates and only crystallized solids remain (*i.e.*, thermal evaporation). The solids then are placed in a landfill. This is an expensive process due to the thermal energy required to evaporate off the excess liquid and the cost of removing and disposing of the solids. Also, there are growing concerns with the placement of this material in landfills, due to the high salt content of the solids and the natural solubility of salts. In one case, a landfill in Orlando, Florida, experienced landfill liner degradation once FGD solids were added.[91] The strong leachate was incompatible with the landfill's geo-composite liner. Aside from the risk of compromising the liner of the receiving landfill, the long-term stability of the crystallized brine in a landfill is questionable, due to its hygroscopic nature. To our knowledge, there are no long-term tests of the stability of crystallized FGDW brine in landfills.

A recent paper on brine management issues states:

> Disposal of concentrates, brines, physical chemical treatment residuals, and crystallizer salts (collectively described as salt-laden wastes) should aim for environmentally and economically responsible disposal today without creating future environmental challenges. The haphazard combination of salt-laden wastes and coal combustion products (CCPs) in existing CCP landfills may not achieve

[91] *See* Tetra Tech et al., "Orlando Coal Ash Landfill: A Case History for Designing and Building New Coal Ash Landfills" presented by Mohamad Alhawaree (June 10-11, 2013).

> this goal, and could lead to serious challenges….The chemistry of both the salt-laden [waste] and CCP materials will dictate whether they can react compatibly to achieve solidification or stabilization of the mixture so that all pollutants are properly sequestered over the long-term.[92]

The paper goes on to describe the many factors that affect the stabilization of materials, including the properties and compatibility of the concentrates/brines, the "mix design" of the ingredients, the introduction of additives such as lime, and landfill operations. *Id.* In addition, the use of softening agents upstream can impact the chemical composition of the liquid waste and change how it will interact with CCP materials. *Id.* Moreover, site-specific factors, such as topography of the disposal site, distance between the power plant and the disposal site, and local and state landfill regulations are important to consider when deciding upon a mix design and identifying proper disposal practices. *Id.* at 5.

For this Proposal, EPA has not chosen thermal evaporation as the model means of treating and disposing of brine. Instead, EPA has selected paste encapsulation as its technology of choice. 2023 TDD at 36. For paste encapsulation, the brine is mixed with fly ash and some additives, such as quicklime, so as to convert the brine to a material that can be pumped at high velocity to an on-site disposal landfill. Without an on-site landfill, it would be impossible to use a pumping system to deliver the material to the landfill. Alternatively, the brine can be mixed with additional fly ash and additives, so that it has a much drier consistency, and then trucked to a landfill. According to EPRI, a pumpable mixture of brine contains a greater weight percentage of brine than a trucked mixture. EPRI Comments at 6. EPRI provides the following general percentages for pumpable and truckable mixtures. *Id.*

---

[92] EPRI, Considerations for Concentrate Management from Wastewater Volume Reduction Technologies*,* No. 3002024773, at 3 (2023).

Type of Mixture	Weight Percentage of Brine	Weight Percentage of Fly Ash	Weight Percentage of Quicklime
Pumpable	35	60	5
Truckable	18	77	5

As EPRI explains, the moisture content suitable for a pumpable mixture is not suitable for a truckable mixture, due to the potential for liquefaction of the material during transit. *Id.* Therefore, much more fly ash needs to be mixed in with the brine if the method of disposal is by trucking to an on-site or off-site landfill. Of course, this difference in fly ash content is very significant for forecasting the costs of transportation and disposal of brine. The more fly ash needed to create the correct moisture content for transportation, the greater the amount of mixture that will need to be hauled or pumped away for disposal. *See* Section III.A.2.d.iv.(a) below for further discussion of this issue.

ii. Further research is needed on paste encapsulation.

As EPRI explained in its 2019 report,[93] research to support paste encapsulation of FGDW brine is far from complete. EPRI noted the following gaps in existing research.

First, most wastewater encapsulation relies on cement hydration chemistry, in that typical hydration reactions observed in concrete also typically occur in encapsulation systems. However, in a paste system, a higher moisture content might be favorable to optimize permeability. In practice, the specific liquid-to-solid ratios and the types and amounts of additives will depend on site-specific conditions and could change over time due to fluctuations in temperature or brine content.[94] Therefore, EPRI recommends that expanded research be

[93] EPRI, Considerations for Treating Flue Gas Desulfurization Wastewater Using Membrane and Paste Encapsulation Technologies, No. 3002017134 (Nov. 2019), EPA-HQ-OW-2009-0819-9672 (DCN SE10396) (EPRI Membrane Report).

[94] EPA agrees that "[e]lectric utilities may have to conduct research and complete pilot testing to determine the most effective encapsulation blend, considering plant-specific details such as coal-type and FGD wastewater characterization." Memorandum from U.S. EPA, to

conducted to include more chemistries and time-based results and to evaluate long-term encapsulation properties.[95]

Second, systems needing chemical softening prior to introduction into the membranes create sodium-based compounds. In such cases, isolation of the salts is based solely on physical solidification, rather than chemical stabilization. Therefore, the implications of chemical softening and its downstream effects on safe disposal should be further researched.[96] This is particularly critical research since DuPont, a leading vendor of membranes, stresses the importance of softening prior to introduction of the wastewater to the membranes. According to EPA, DuPont stated that "[p]retreatment and softening for FGD wastewater is a key component of membrane filtration treatment systems to reduce suspended solids and hardness."[97]

Another critical research concern is the long-term stability of encapsulated materials.[98] While research has been conducted at the laboratory scale, most of the current physical and environmental property data is for material cured for 90 days or less, and there is limited field testing of encapsulated brine. Without long-term data, it is impossible to be sure whether or not the material will be subject to leaching or other degradation in the future or will threaten the integrity of landfill liners.

Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819, 2023 Steam Electric Supplemental Proposed Rule: Fly Ash Availability at 1 (Feb. 27, 2023), EPA-HQ-OW-2009-0819-9685 (DCN SE10242) (EPA Feb. 27, 2023 Fly Ash Memo). EPA also agrees that "the exact encapsulation blend may vary from plant to plant." *Id*.

[95] EPRI Membrane Report at 15.

[96] *Id.*

[97] 2021 DuPont Meeting Notes at 2, EPA-HQ-OW-2009-0819-9378 (DCN SE10245).

[98] Kirk Ellison, *Landfill Sequestration of Brine: Research Updates*, 2019 World of Coal Ash Conference, May 13-16, 2019, EPA-HQ-OW-2009-0819-8721, ATT 23 (DCN SE 08655A023).

iii. There are obstacles to obtaining permits for disposal of brine encapsulation wastes.

Even if the substantial, unanswered technical questions about brine encapsulation were not a concern, there would still be regulatory hurdles to its disposal in some locations. State regulations for solid waste disposal vary considerably, but nearly all of them attempt to regulate important factors such as compaction and liquid content. As EPRI points out, compaction performance is important to long-term landfill stability. EPRI Comments at 7. Further, EPRI notes that compaction requirements may limit the allowable moisture added to fly ash destined for landfills because the optimum moisture content for compaction is often lower than the moisture limit needed for transport to the landfill. *Id.* If power plants were to attempt to solve this problem by putting the mixture on a stack-out pad to promote drying and lower the moisture content, then the Proposal would need to consider the costs of this additional step, including construction and maintenance of the pads and equipment used to move the waste material to the pads and then to trucks. *Id.*

There are other good reasons why solid waste landfills are cautious about receiving paste encapsulation materials. As noted in UWAG's comments on the 2020 Rule, once it is disposed of in a landfill, paste encapsulation materials would have a very low infiltration rate and, when commingled with CCRs that have a higher infiltration rate, would create layers of impenetrable barriers. These layers could prevent drainage from reaching the leachate collection system and cause or contribute to a "blow out," such as what occurred at the King George County Landfill in Virginia. *See* 84 Fed. Reg. 64,620, 64,633 (Nov. 22, 2019), EPA-HQ-OW-2009-0819-7106.

In any event, it is not clear that disposal of brine encapsulation waste materials in state-regulated landfills would be possible nationwide. This could be a major obstacle to use of EPA's choice of model technology. States generally are concerned with liquid wastes entering landfills, and many require that all wastes pass the "paint filter test" (and certify no free liquids in the waste) prior to placement in a landfill.[99]

iv. EPA has greatly underestimated the amount of fly ash needed to encapsulate brine.

Research by EPRI indicates that EPA has greatly underestimated the amount of fly ash needed for the encapsulation of FGDW brine. EPA has not provided its individual facility fly ash estimates, apparently due to confidential business information concerns. And it is not clear on the record whether EPA assumes that the mixture for encapsulation is pumpable or truckable or perhaps assumes that some plants will pump the mixture and others will truck it. Despite the ambiguity of the record, EPRI's detailed analysis has identified several problems. *See* EPRI Comments, Sec. 1.

(a) EPA used erroneous values to estimate brine and fly ash.

The amount of brine produced by a membrane filtration system depends on its percent recovery rate. With a higher percent recovery rate, the system will produce higher amounts of permeate and lower amounts of brine. With a lower percent recovery rate, the system will produce less permeate and more brine. EPRI believes that EPA's method of estimating fly ash based on a ratio of fly ash to FGD purge flow is a flawed approach. EPRI Comments at 1. EPRI points out that EPA used a value from EPRI's 2020 comments (160,000 tons per year for fly ash

---

[99] *See, e.g.*, Tenn. Dep't of Env't & Conservation solid waste management regulations, TENN. COMP. R. & REGS. 0400-11-01-.01, defining "industrial by-product" to mean "materials generated by manufacturing or industrial processes that are non-toxic, non-hazardous, contain no domestic wastewater, and pass the paint filter test (Method 9095B)." *See also* 9 VA. ADMIN. CODE § 20-81-140.B.4.a, prohibiting sanitary landfills from accepting, unless specifically authorized, "free liquids," defined as "liquids that readily separate from the solid portion of a waste under ambient temperature and pressure as determined by the Paint Filter Liquids Test, Method 9095." 9 VA. ADMIN. CODE § 20-81-10.

to encapsulate 432,000 gpd flow of brine) incorrectly. In EPRI's example, it was estimating fly ash for the encapsulation of ***brine generated from a thermal evaporator,*** which can achieve a higher recovery rate than membrane systems. *Id*. at 2. Therefore, the values given in EPRI's example are not applicable to brine generated from a membrane system.[100]

Instead of EPA's flawed system for estimating brine and fly ash, EPRI recommends using the FGD purge flow for each plant and the overall recovery rate that can be consistently achieved, calculating the volume and mass of brine generated, and using those results to calculate the mass of fly ash and other additives required to encapsulate the brine mass. *Id.* For example, for a plant with 100 gallons per minute (gpm) of FGD purge flow and a 70 percent overall membrane recovery rate, EPRI estimates that 298,151 tons per year of fly ash will be needed. But for the same flow, EPA estimated only 26,640 tons per year of fly ash. *Id.* at 4, Fig. 1-2. This is a very significant difference, as EPRI's estimate is more than 10 times EPA's estimate, and the mass of fly ash used to encapsulate the brine, of course, will affect the costs of transportation and disposal.

A key component here is percent recovery. What percent recovery did EPA assume when it estimated brine generation and then estimated fly ash needed to encapsulate that brine? EPRI took EPA's fly ash estimates and EPA's assumed ratio of 0.185 tons of fly ash per year per gpd of FGDW and evaluated the overall membrane recovery that would be needed to meet EPA's fly ash estimate of 26,640 tons per year. EPRI discovered that the applicable membrane recovery rates were 99.0 percent (assuming all plants use a truckable mixture) and 94.7 percent (assuming all plants use a pumpable mixture). *Id.* at 7, Tbl. 1-1. As EPA knows, these percent

[100] EPRI noted that it provided in its 2020 comments a different value for fly ash tons per year for encapsulation of brine from a membrane system. *See* EPRI Comments at 2.

recovery rates are not realistic on a routine basis for membrane filtration of FGDW.[101] In the 2023 TDD, EPA states that it "calculated brine flow rate based on the average recovery from the membrane treatment vendors used for FGD wastewater." 2023 TDD at 47. EPA then sets forth a formula showing that 30 percent of the FGDW volume would end up, after treatment, as brine. *Id.* Therefore, EPA acknowledges that a 70 percent average recovery rate is appropriate; EPRI agrees with a 70 percent average recovery rate for membrane filtration, assuming the FGD purge is the industry average of 24,100 mg/L TDS and that 100 percent of the permeate is reused. EPRI Comments at 21. Given this, EPA must correct its calculations of fly ash to accurately reflect this recovery rate, rather than the inordinate recovery rates EPRI has shown are applicable to EPA's fly ash analysis. *See Id.* at 7, Tbl. 1-1.

The magnitude of error here is too great, and it directly impacts the estimated costs of selecting membrane filtration as BAT. Therefore, UWAG requests that EPA recalculate its brine and fly ash estimates, in consultation with EPRI's experts.

(b) EPA overestimates the numbers of plants with sufficient fly ash.

According to EPA, 20 of the 22 plants it expects to install membrane filtration will have sufficient fly ash to encapsulate their brine if they do not sell any of the available fly ash.[102] EPRI disputes these findings. It finds that only 3 of 22 plants will have sufficient fly ash to encapsulate their brine assuming no fly ash is sold. *See* EPRI Comments at 8 and 9, Fig. 1-5. EPRI's estimate is based on a 70 percent overall recovery rate and use of a truckable mixture.

[101] While EPA notes that EPRI's pilot of the Flex EDR Selective system averaged a 93 percent recovery rate, 88 Fed. Reg. at 18,840, that is not indicative of what can be expected during normal operations. The pilot was a short-term pilot and was very small-scale.

[102] EPA Feb. 27, 2023 Fly Ash Memo at 5, EPA-HQ-OW-2009-0819-9685 (DCN SE10242).

EPRI goes on to show that EPA's total fly ash estimate for the 22 plants during the years 2017–2020 are greater than the plant-specific values reported on EIA Form 923 for the same years. EPA's calculations estimated about 20 percent more fly ash was produced than what the plants actually reported to EIA. *Id.* at 13. Since the EIA data is readily available, it would make sense to use actual fly ash tons reported, rather than attempt to estimate them.[103] This is the best data available, and the data should not be ignored.

Again, EPRI's estimates of the number of plants with insufficient fly ash and its demonstration, using EIA data, that EPA is overestimating fly ash produced are very significant issues. EPA needs to make a very careful reexamination of its methods and conclusions. UWAG urges EPA to undertake such a reexamination in consultation with EPRI prior to issuing a final new rule.

(c) Contrary to EPA's conclusion, brine encapsulation using fly ash will impact fly ash sales and beneficial reuse.

EPA also claims that 16 of the 22 plants expected to install membrane filtration will "have enough fly ash remaining to encapsulate brine generated from membrane filtration with no impact on the revenue generated from selling fly ash."[104] This is inaccurate, according to EPRI. Using reported EIA data and EPRI's estimates of fly ash needed to encapsulate brine, EPRI determined that only five of the 22 plants did not sell ash between 2018–2020. EPRI Comments at 17. The remaining 17 plants would have to divert fly ash from beneficial reuse to encapsulate

[103] EPA's apparent reason for not using EIA-923 data is that the form "requires only thermoelectric power plants with a total steam turbine capacity of 100 megawatts or greater that produce combustion byproducts to report such information." EPA Feb. 27, 2023 Fly Ash Memo at 4 n.2, EPA-HQ-OW-2009-0819-9685 (DCN SE10242). But all of the 22 plants that EPA expects to install membrane filtration are above the specified capacity threshold.

[104] EPA Feb. 27, 2023 Fly Ash Memo at 5, EPA-HQ-OW-2009-0819-9685 (DCN SE10242).

their membrane filtration brine and would suffer a loss of revenue because of the diversion. In fact, EPRI found that 15 of the 17 plants would have to use all of their fly ash for brine encapsulation, thereby forfeiting 100 percent of fly ash sales. *Id.*

EPRI estimates—again based on EIA data—that 1.5 million tons of fly ash that is currently being beneficially reused by the 22 plants at issue will be diverted to encapsulation, while an average of 13 million tons of fly ash was used in concrete and waste stabilization applications for the years 2018–2020. *Id*. The removal of 1.5 million tons from this market is a significant percentage and belies EPA's conclusion that it "does not anticipate that the fly ash needed for brine encapsulation [will] significantly impact the fly ash market."[105]

Not to worry, claims EPA, because, based on EIA reports, it has "identified more than 100 coal-fired power plants generating over 9.6 million tons of unsold [fly ash (FA)] that could be redirected from disposal towards either encapsulation or beneficial reuse." 88 Fed. Reg. at 18,842. But many of the plants generating unsold fly ash may be located in areas where transportation costs would make it prohibitive to sell the ash, or they may be using it for their own waste stabilization needs. A lack of sales does not equate to having fly ash available for sale. The impact on beneficial reuse and overall fly ash sales is another area where UWAG urges EPA to reassess its analysis, taking into account all of EPRI's research and conclusions.

EPA's second proposed "solution" to the problem of fly ash shortfalls is to harvest previously disposed ash for use in encapsulation. 88 Fed. Reg. at 18,842. Again, EPA overlooks the hurdles involved in this process. The harvesting of previously disposed ash is largely

[105] EPA Feb. 27, 2023 Fly Ash Memo at 4, EPA-HQ-OW-2009-0819-9685 (DCN SE10242).

unworkable due to the additional costs of digging up and transporting the fly ash. These costs would add enormously to the costs of disposal.

3. EPA's analysis of whether membrane filtration/paste encapsulation is economically achievable is deeply flawed.

The many flaws in estimations of fly ash needed for brine encapsulation, fly ash sales forfeited, and the potential impacts on beneficial reuse of fly ash are reason enough to call into question EPA's conclusion that membrane filtration and paste encapsulation is BAT and is economically achievable. But these issues are just part of the story of EPA's failure to properly consider costs.

a. EPA's cost estimates fail to include some units that will continue to operate.

In reviewing EPA's estimates of individual generating unit costs, UWAG noted some apparent discrepancies. By all accounts, EPA expects units at Plants Bowen, Cardinal, and Ghent to continue operating; therefore, under the Proposal's preferred option, they will need to install membrane filtration. EPA lists these plants as "discharging FGD wastewater after 2028."[106] It also calculates fly ash availability for purposes of brine encapsulation for each of these plants.[107] But in its compilation of generating unit level costs by option, EPA assigns zero costs to Bowen, Cardinal, and Ghent for Regulatory Option 3, which would require membrane filtration for FGDW.[108] The table below consists of all units that EPA has identified as having

---

[106] Memorandum from U.S. EPA, to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819, Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings at 1 & 3, Tbl. 1, (Sept. 12, 2022), EPA-HQ-OW-2009-0819-9379 (DCN SE10287).

[107] EPA Feb. 27, 2023 Fly Ash Memo at 6, Tbl. 3 & 7, Tbl. 4, EPA-HQ-OW-2009-0819-9685 (DCN SE10242).

[108] Memorandum from U.S. EPA, to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the

pollutant loadings for FGDW over 10 million pounds under the baseline and needing ZLD under Regulatory Option 3.[109] These units also would have 0 pounds of pollutants for FGDW under Regulatory Option 3. For some of these units, EPA estimates substantial capital costs under Regulatory Option 3 (ZLD), while for others (highlighted in yellow), EPA estimates $0 capital costs.[110]

Unit	Capital Cost Under FGDW Regulatory Option 1 (Table 2 – CP+LRTR)	Pollutant Loadings Under Baseline for FGDW (lbs) (Table 11)	Capital Cost Under FGDW Regulatory Option 3 (Table 4 - ZLD)	Pollutant Loadings Under Regulatory Option 3 (Table 11)
Bowen3	$0	13,100,000	$0	0
Bowen4	$0	12,700,000	$0	0
Amos1	$0	48,800,000	$11,920,216	0
Amos2	$0	15,800,000	$51,115,293	0
Amos3	$0	11,400,000	$16,582,736	0
Elm RoadA	$0	11,000,000	$7,342,403	0
Elm RoadB	$0	11,000,000	$7,342,403	0
Seminole1	$0	14,900,000	$14,818,965	0
Big Bend4	$0	70,200,000	$63,519,045	0
Cardinal2	$0	11,500,000	$0	0
Cardinal3	$0	34,600,000	$0	0
Ghent1	$0	10,900,000	$0	0
Ghent2	$0	12,200,000	$0	0
Ghent3	$0	7,070,000	$0	0
Ghent4	$0	11,200,000	$0	0
Trimble1	$0	15,000,000	$9,036,763	0
TrimbleA	$0	106,000,000	$63,482,397	0
Mitchell1	$0	11,300,000	$10,388,325	0
Mitchell2	$0	11,300,000	$10,388,325	0

2023 Proposed Rule at 10, Tbl. 4 (Feb. 28, 2023), EPA-HQ-OW-2009-0819-9686 (DCN SE10381) (EPA Feb. 28, 2023 Costs & Loadings Estimates Memo).

[109] EPA Feb. 28, 2023 Costs & Loadings Estimates Memo at 10–13, Tbl. 4 & 50–53, Tbl. 11, EPA-HQ-OW-2009-0819-9686 (DCN SE10381).

[110] *Id.* at 10, Tbl. 4.

It is not clear why EPA estimates $0 capital costs for the facilities highlighted in yellow (Bowen, Cardinal, and Ghent). How does EPA expect these facilities to erase their pollutant loadings without any capital expenditures? Plant Bowen Units 3 and 4 are not retiring. EPA appears to have misinterpreted information about the potential retirement of Bowen Units 1 and 2 as indicating plans to retire Bowen Units 3 and 4, according to the document cited in its memo updating the industry profile.[111] For Cardinal, EPA appears to have concluded that an AEP announcement of reductions in its coal fleet meant it was retiring Cardinal Units 1, 2, and 3.[112] Buckeye Power has always owned Cardinal Units 2 and 3, while AEP owned Cardinal Unit 1. However, in August 2022, AEP sold Unit 1 to Buckeye Power. While Buckeye has filed a cessation NOPP for Unit 3, it plans to keep operating Units 1 and 2. As to Ghent, there is nothing in EPA's updated Industry Profile to suggest that the status of this plant has changed. LG&E/KU intends to continue operating Ghent Units 1, 3, and 4, and the Unit 2 decision will be based on Certificate of Public Convenience and Necessity (CPCN) approval. In sum, it appears EPA has miscategorized at least 7-8 units (two at Bowen, two at Cardinal, and three to four at Ghent). Since the Proposal finds that 22 plants would be subject to FGDW retrofits under the preferred regulatory option, adding three more plants to that list is a significant increase.

[111] *See* Southern Company, Third Quarter 2021 Earnings Conference Call at slide 15 (Nov. 4, 2021), EPA-HQ-OW-2009-0819-9231 (DCN SE09636) (noting "potential" coal retirements by 2028).

[112] Sonal Patel, *AEP Will Shutter Nearly Half its Giant Coal Power Fleet—5.6 GW—by 2030*, POWER MAGAZINE (Nov. 10, 2020), EPA-HQ-OW-2009-0819-9099 (DCN SE09602) (claiming AEP planned to retire "Cardinal" in 2030. In fact, AEP sold Cardinal Unit 1 to Buckeye Power in August 2022.).

Additionally, EPA appears to have concluded that DESC's Williams Station is retiring prior to needing an FGD retrofit.[113] As already noted, the latest company IRP indicates otherwise. *See* note 62, *supra*. The IRP suggests that the retirement data of December 2030 is aspirational, as the text refers to the date as "the earliest" possible retirement date. IRP at 28. Therefore, EPA should assume that Williams will operate beyond 2032 and thus will need additional technologies to meet the Proposed Rule's requirements. Also, LG&E/KU plans to continue operating Mill Creek Units 3 and 4, but EPA has assigned zero costs for FGD retrofits to these units.[114]

At a minimum, EPA should explain its apparent oversight and recalculate the Proposal's estimated costs. Bowen Units 3 and 4 total 1,400 MWs, while Ghent is 2,225 MWs, and Cardinal Units 1 and 2 total 1,180 MWs. The costs of retrofitting these units for FGDW compliance under Option 3 will be substantial. EPA needs to add these units into its calculations and rerun all of its models to account for these additions and any other similar mistakes.

b. The record is not transparent, but it is clear that EPA has underestimated FGDW retrofit costs.

It appears EPA has based its costs for membrane filtration/paste encapsulation largely on aggregated vendor costs. The record is far from transparent in this area. EPA only provides generic cost curves and formulas for its calculations, without providing any data on the individual vendor estimates and with scant additional data used to develop the cost curves and formulas. For example, EPA lists the following components of its BAT technology (membrane filtration and paste encapsulation) in the 2023 TDD:

---

113 *See* Industry Profile Update at 6, Tbl. A-1, EPA-HQ-OW-2009-0819-9622 (DCN SE010241).

114 EPA Feb. 28, 2023 Costs & Loadings Estimates Memo at 11, Tbl. 4, EPA-HQ-OW-2009-0819-9686 (DCN SE010381).

- chemical precipitation treatment equipment (equalization and storage tanks, pumps, reaction tanks, solids-contact clarifier, and gravity sand filter);
- chemical precipitation chemical feed systems (lime, organosulfide, ferric chloride, and polymers);
- chemical precipitation solids-contact clarifier to remove suspended solids;
- membrane filtration treatment equipment (membrane filtration, reverse osmosis, and storage tanks;
- brine encapsulation; and
- transportation and disposal of solids in a landfill.[115]

One might consider this a fairly detailed list of the components EPA is costing out to arrive at its estimates for membrane filtration and brine encapsulation. But this list and the rest of the 2023 TDD—including the section titled "Cost Methodology for Membrane Filtration"—do not clarify EPA's assumptions about, and estimates of, underlying costs. For example, what costs are included in "brine encapsulation?" If EPA is using a pumpable mixture, what size pipes and pumps are being costed out for the system? What length of pipe is EPA costing out, keeping in mind that power plants often have a fair amount of acreage and the nearest landfill may be located across the property from the FGDW treatment system? What amount of quicklime or other additives is EPA costing out for purposes of creating either a pumpable mixture or a truckable mixture? What size pugmill or other mixing equipment is EPA including in its estimate? How much redundancy is EPA planning for within these systems?[116]

[115] 2023 TDD at 36.

[116] EPA's 2020 cost methodology document for membrane filtration with paste encapsulation is of little help. Memorandum from Sara Bossenbroek & Danielle Stewart, ERG, to Steam Electric Rulemaking Record, Flue Gas Desulfurization Membrane Filtration with Encapsulation Cost Methodology (Aug. 7, 2020), EPA-HQ-OW-2009-0819-8695 (DCN SE08625). It lists certain components, such as "[p]umps" or "[p]iping (installed)," as included in the estimates, *id.* at 2, without providing any details of the number, size, or materials of construction. And EPA's 2020 "vendor-specific" cost methodology for membrane filtration with

Additionally, EPA's costs appear to be largely dependent on aggregated vendor-generated cost estimates that are used to generate cost curves for capital costs and O&M costs. The individual estimates provided by each vendor are not available for review, as they are deemed CBI, and so it is not clear how EPA aggregated those estimates to arrive at its cost curves. It is also not clear if the vendor estimates were actually comparable and included all ranges of costs. However, from recent experience with EPA's similar estimates in the 2020 Rule, we believe EPA is greatly underestimating the costs of membrane filtration and paste encapsulation.

As an illustration of how this process results in underestimates of costs, we can review EPA's estimated costs for CP+LRTR in the 2020 Rule and compare it to actual estimated costs for biological treatment alone (*i.e.*, not including any adjustment for chemical precipitation) that UWAG members have incurred or reported to their regulators.

---

encapsulation is confidential business information (CBI) and therefore not available to the public. ERG, Flue Gas Desulfurization Membrane Filtration with Encapsulation Vendor-Specific Cost Methodology (posted Aug. 31, 2020), EPA-HQ-OW-2009-0819-8918 (DCN SE08596).

Cost Comparison for Installing Treatment Technology
To Satisfy the FGD Wastewater Limits in the 2020 Rule

Plant Name (Units)	EPA Estimated Costs for Biological Treatment + Adjustment for Chemical Precipitation (Pre-tax 2018 dollars)[117]		UWAG Member Estimated Costs for Biological Treatment ($)	
	Capital	O&M	Capital	O&M
Fort Martin (Units 1 and 2)[118]	10,997,849	576,766	45,597,126	553,000
Trimble County (Units 1 and 2)[119]	12,785,392	1,535,726	64,800,000	3,085,416
Mill Creek (Units 1-4)[120]	5,560,844	442,871	68,000,000	3,069,562
Ghent (Units 1-4)[121]	9,068,391	741,951	70,200,000	4,215,581
Mitchell (Units 1 and 2)[122]	13,463,922	--	48,811,000	--

In the 2023 Proposal, EPA continues to understate the estimates for chemical

[117] Memorandum from Eastern Research Group, Inc., to Steam Electric Rulemaking Record, Generating Unit-Level Costs and Loadings Estimates by Regulatory Option at 30–37, Tbl. 5 (Generating Unit-Level Costs for FGD Wastewater Treatment under Regulatory Option B) (Aug. 31, 2020), EPA-HQ-OW-2009-0819-8934 (DCN SE08638) (ERG Costs and Loadings Memo). EPA calculated a treatment-in-place adjustment to estimate the capital and O&M costs that would be incurred by plants that already operate some components of the model chemical precipitation treatment system. *See* EPA, Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-20-001, at 5-25 to 5-26 (Aug. 2020), EPA-HQ-OW-2009-0819-8935 (DCN SE08650) (2020 TDD).

[118] Monongahela Power Petition for Approval at Exhibit DVS-1, page 2 of 2.

[119] Conroy Ky. PSC Testimony, Exhibit RSS-2 at 15, 27. Estimated capital costs for Trimble County have changed since the March 31, 2020 filing. Capital costs in this chart have been revised accordingly to reflect more accurate internal company estimates.

[120] *Id.*, Exhibit RSS-2 at 36, 48. Estimated capital costs for Mill Creek have changed since the March 31, 2020 filing. Capital costs in this chart have been revised accordingly to reflect more accurate internal company estimates.

[121] *Id.* at Exhibit RSS-2 at 57, 70. Estimated capital costs for Ghent have changed since the March 31, 2020 filing. Capital costs in this chart have been revised accordingly to reflect more accurate internal company estimates.

[122] Direct Testimony of Brian D. Sherrick on behalf of Appalachian Power Company and Wheeling Power Company, Company Exhibit BDS-D3 (W. Va. PSC undated).

precipitation and biological treatment. As an example, in the table below are EPA's plant-level calculations of costs for Ft. Martin to comply with the 2020 Rule by installing partial pretreatment and a SeHawk bioreactor. Despite EPA's adjustment to 2021 dollars, Ft. Martin's actual capital costs are still more than ***three times higher than EPA's estimate***, while EPA's O&M costs are higher than Ft. Martin's estimated O&M.

Treatment System[123]	EPA Cost Estimates Capital (2021$)	EPA Cost Estimates O&M (2021$)
Partial pretreatment	4,791,710	110,039
SeHawk bioreactor	7,272,181	619,201
Total	**12,063,891**	**729,240**

For membrane filtration/paste encapsulation costs, the differences between EPA's estimates and industry estimates are also very significant. For example, Alabama Power obtained a site-specific estimate for retrofititting membranes plus pretreatment at Miller Units 1–4. The estimate is $279 million in capital costs, with annual O&M costs of $10.3 million. In contrast, EPA estimated only $18.7 million in capital costs for Miller to retrofit membranes, with estimated O&M costs of less than one million.[124]

EPRI has provided very detailed, well-documented capital and O&M cost estimates for membrane filtration and paste encapsulation at each of the 22 plants that EPA has identified as needing FGD retrofits under the proposal.[125] EPRI Comments at 32–35 and Tbl. 2-2. EPRI went to lengths to makes its costs comparable to EPA's. For instance, like EPA, it made the following assumptions:

- The three plants opting into the 2020 Rule's VIP received zero costs.
- The remaining 22 plants are assumed to have chemical precipitation and biological treatment in place.
- The assumed capital costs are those required to convert each plant from chemical precipitation and biological treatment to chemical precipitation, membrane filtration, and brine encapsulation.

---

[123] EPA, FGD Wastewater Proposed Rule Cost Database, EPA-HQ-OW-2009-0819-9955 (DCN SE10416).

[124] EPA Feb. 28, 2023 Costs & Loadings Estimates Memo at 14–15, Tbl. 5., EPA-OW-2009-0819-9686 (DCN SE10381).

[125] EPRI's objective was to describe its cost methodologies in detail, and it does so through extensive appendices attached to its comments. These appendices deserve careful review and comparison to EPA's methodologies.

Despite these similar baseline assumptions, EPRI's capital cost estimates are eight times higher than EPA's for the industry as a whole, and its O&M cost estimates ***are a staggering 41 times higher than EPA's.*** In evaluating total annualized costs, EPRI's estimate of industry costs is 25 times higher than EPA's estimate. *See* id. at 32–35, 39.

In analyzing these very significant differences in estimates, EPRI points to several key parameters.

First, EPRI believes that EPA should have used FGD peak flow, instead of a lesser, "optimized" flow, to estimate capital costs. EPRI's choice of peak flow rate makes sense because "treatment systems must be able to treat to compliance levels at all operating flow conditions." EPRI Comments at 39.

Second, EPRI's estimates include a redundant equipment train for the membrane filtration system, which is necessary because membranes must be taken out of service for frequent cleanings. *Id.*

Third, EPRI believes EPA should be using the FGD purge flow rate instead of an optimized flow to estimate O&M costs. *Id.* at 41. Apparently, EPA used an optimized flow as the basis for developing O&M costs for brine management. But as EPRI points out, using an optimized flow assumes that the flow will be cycled up, leading to higher chloride and TDS concentrations. However, cycling up is not feasible, in EPRI's judgement, for membrane systems because the higher TDS concentrations "leads to a greater tendency for membrane scaling and lower membrane system percent recovery." *Id.* For this reason, EPRI believes EPA should use the FGD purge flow rate for all O&M estimates.

Fourth, it is critical to the cost estimates to assume a membrane recovery rate that can be consistently achieved across the industry. *Id.* at 42. EPRI used a 70 percent membrane recovery in its estimates. But as shown in the EPRI Comments, some of EPA's assumptions regarding the amount of fly ash needed to encapsulate brine indicate much higher percent recovery rates, ranging from 94.7 percent to 99.0 percent. EPRI Comments at 7.

EPA's lack of transparency on costs is detrimental to the public's interest in understanding EPA's approach to costs of the rule. Members of the public deserve to understand not just what the final numbers are, but also how those numbers relate to important underlying factors and to the realities of their own sites. This lack of transparency has hindered UWAG's ability to compare industry-generated costs to EPA's costs. As these comments have pointed out, there are several significant issues with the way EPA has estimated certain factors that contribute to costs of membrane filtration and paste encapsulation, such as:

- EPA's very significant underestimation of fly ash necessary to encapsulate brine from membrane filtration;
- EPA's use of a value related to brine generated from a thermal evaporator system to estimate brine generated from a membrane filtration system;
- EPA's severe underestimation of the number of plants that will have sufficient fly ash to use in encapsulating brine;
- EPA's erroneous conclusion that there will be a minimal impact to the fly ash beneficial reuse market from the necessary diversion of fly ash for use in brine encapsulation;
- EPA's failure to account for costs attributable to some units that will continue to operate; and
- the very significant underestimations of capital and O&M costs for retrofitting membrane filtration for all units.

These problems with EPA's proposal, taken collectively, are enough to warrant EPA's reconsideration of the regulatory models used in the Proposal. UWAG urges EPA to take the necessary steps for a proper analysis of each listed issue and to work with industry to understand the real costs of the Proposal.

c. EPA has failed to account for stranded costs from 2020 Rule compliance.

In addition to underestimating technology costs, EPA appears to ignore the financial issues created for industry members when new pollution control equipment, such as biological reactors, must be scrapped and replaced within a few years of their deployment. Typically, EPA does not revisit an industry with a recent revision of its effluent guidelines. The Agency tends to wait about seven years before considering whether the industry is again ripe for a revision of its ELGs. But when the Agency returns to the same industry for another round of ELG revisions within a three-year period, the result will be stranded assets and stranded costs. In early 2021, rather than stay the 2020 Rule while reconsidering it, EPA explicitly stated that facilities remained subject to the 2020 Rule and instructed permitting authorities to continue to implement the 2020 Rule. 86 Fed. Reg. at 41,802. As a result, many companies have continued to plan, design, engineer, and install technologies, including complex systems such as CP+LRTR and technologies to minimize BATW purge, to ensure compliance with the 2020 Rule.

If facilities now must replace those technologies with new technology to meet the Proposed Rule's ZLD requirements for BATW and FGDW, they will not be able to fully amortize their investments in 2020 Rule technologies. For example, to employ membrane filtration/paste encapsulation (EPA's preferred option), a facility would have to abandon use of its LRTR well before the end of the system's useful life and well before the end of its amortization period. EPA should take into account these stranded costs when evaluating the overall economic impact of its Proposal.

B. Chemical Precipitation Plus Biological Treatment—Not Membranes, Thermal Evaporation, or Other Technologies—Is BAT for FGDW.

In addition to membranes, EPA asks the public to assess the applicability of many other technologies to FGDW. None of the other "zero discharge" technologies EPA lists (thermal evaporation, spray dryer evaporators (SDEs), evaporation ponds, recycling) should be selected as BAT for FGDW. Like membrane filtration, thermal evaporation presents a range of technical difficulties when used for FGDW treatment. Also, it does not solve the issues surrounding brine disposal. EPA did not select other zero discharge technologies as BAT "because they achieve the same pollutant reductions as the proposed BAT technology basis (membrane filtration) but at a higher cost." 88 Fed. Reg. at 18,843. Nonetheless, EPA asks for comment on whether it should determine in the final rule "that any one or more of these technologies constitutes an additional BAT technology basis for controlling pollutants discharged in FGD wastewater in addition to membrane technology, or alternatively, in place of membrane technology." *Id.*

The correct BAT technology for FGDW is chemical precipitation plus biological treatment, as set forth in the 2020 Rule. As discussed earlier, EPA has not established a detailed justification for reversing its position on BAT for FGDW, and it cannot do so merely by waving off adverse comments in the final rule. No amount of sensitivity analyses and corrections to the industry profile will cure a rushed and flawed Proposed Rule.

1. Thermal evaporation is prone to operational difficulties.

UWAG agrees with EPA that thermal evaporation technologies are not BAT for FGDW, but for reasons beyond costs. The full-scale thermal evaporators that have been used for FGDW are prone to operational difficulties. UWAG urges EPA not to overlook this aspect of the technology, as part of the proper consideration of the BAT factor "engineering aspects of the application of various types of control techniques." CWA § 304(b)(2)(B), 33 USC § 1314(b)(2)(B). Significant operational difficulties should not routinely occur for a "best available" technology, and yet the industry's experience with thermal evaporators reveals routine difficulties.

At the Petersburg Station, Indianapolis Power & Light (IPL) installed a thermal evaporator in 2018. Since that time, the system's performance has been less than ideal. When EPA held a conference call with IPL after 2.5 years of system operation, IPL reported "it is important to consider the water balance and changes in the hydraulic load, including rainfall and evaporation, so that the thermal FGD system is not overwhelmed."[126] The thermal system has not lived up to its intended purpose:

> The thermal system can only handle a portion of the FGD wastewater at the station. IPL previously assumed that if the FGD wastewater treatment system can handle the full load, then It can also handle reduced loads; this assumption did not hold due to evaporative losses. In hindsight, plant staff recommend testing a system at all levels throughout the operating range prior to selecting a treatment technology. … Since installation, IPL has added many flow meters to try to identify when the flow balance is upset.

IPL Call Notes at 3–4, EPA-HQ-OW-2009-0819-8891 (DCN SE09218).

EPA also reports that IPL stated that its "pretreatment process for the evaporation system should be two to three times more robust than it was designed for." *Id.* at 4. Clearly, this is not a thermal evaporator that has operated without difficulties.

Other operators of thermal evaporators also have had significant problems. The Iatan Power Plant's thermal evaporator was taken out of service in 2017. EPRI reports that its evaluation of five ZLD thermal wastewater treatment systems "demonstrate that crystallizer systems are complex and very challenging to operate." EPRI Comments at 29. EPRI found common challenges among the systems, including scaling and line plugging, system foaming, flow obstructions, and overall equipment performance not meeting design criteria. *Id.* With this type of operating record, EPA should not select this technology as BAT.

---

[126] Memorandum from Danielle Stewart, ERG et al., to Steam Electric Rulemaking Record, Notes from Call with Indianapolis Power & Light – Petersburg Generating Station at 3 (Aug. 14, 2020), EPA-HQ-OW-2009-0819-8891 (DCN SE 09218) (IPL Call Notes).

2. Thermal evaporators present other types of challenges.

Aside from a poor operational record within the industry when it comes to treating FGDW, thermal evaporators present challenges that go to their overall costs and efficiency. These challenges are summarized below.

- An evaporator/crystallizer uses a large amount of energy to create a concentrated brine. EPA has estimated, based on data obtained from vendors, that the energy requirements for an evaporation system are approximately 110kW/100 gallons treated.[127]

- Thermal evaporators use large amounts of chemicals for chemical precipitation and conditioning of the wastewater prior to concentration of the blowdown stream. The process to soften the FGDW consumes a large amount of lime and soda ash.[128] In the 2015 Response to Comments, EPA agreed that an evaporation system capable of treating 410 gpm FGDW with 40,000 ppm chlorine in the water would require ***as much as 40 tons of lime and 80 tons of soda ash per day.***[129]

- The large amounts of lime and soda ash added to the system means that a large amount of byproduct sludge is created, which must be dewatered and sent for disposal.

- Because FGDW is so corrosive, many metal components must be made from exotic, corrosion-resistant metals, at additional expense. As Duke told EPA, "[s]ome replacement parts have long lead times and high costs due to metallurgies."[130]

See also EPRI Comments at 29 (noting that achieving ZLD for FGDW will require more than half of industry plants to install crystallizers).

---

[127] H.A. Nebrig et al., "Preliminary Assessment of a Thermal Zero Liquid Discharge Strategy for Coal-Fired Power Plants," Paper 11-36, at 3, presented at the International Water Conference (Nov. 13–17, 2011).

[128] *Id.* at 5.

[129] EPA, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Response to Public Comments at 6-98 (Sept. 2015), EPA-HQ-OW-2009-0819-6469 (DCN SE05958).

[130] Memorandum from Deb Bartram & Danielle Stewart, ERG, to Steam Electric Rulemaking Record, Notes from Site Call with Duke Energy's Mayo Steam Station at 4 (June 15, 2020), EPA-HQ-OW-2009-0819-8558 (DCN SE 08964).

3. SDEs also present challenges and are not BAT.

As with other thermal systems, SDEs are not suitable as BAT because their application is limited and because SDEs do not solve the problem of handling the solids byproducts. As one vendor told EPA, SDEs are a potential technology for plants with a single power block and a small wastewater flow rate.[131] For plants with multiple power blocks that are not in close proximity, the flue gas ducting systems would not be easy to combine.[132]

Further, SDEs produce solids byproducts that contain a high level of salts and are very hygroscopic. The handling of the solids in a landfill (and the proper long-term sequestration of pollutants in the solids) remains just as much an issue for plants with SDEs as it is for plants with thermal evaporators and crystallizers.

C. If EPA Imposes New FGDW Requirements, EPA's "No Later Than" Date Is the Minimum Necessary for Membrane Filtration or Thermal Evaporator Retrofits.

If EPA imposes any new ELGs in the final rule, EPA's proposal to set a "no later than" date of December 31, 2029, would provide companies with the minimum time necessary to plan, design, test, procure, and install new equipment, such as membrane filtration and paste encapsulation for FGDW, assuming the final rule is issued by mid-2024. In light of a number of concerns facing the industry, EPA should provide facilities until at least December 2030 to implement the new requirements.

1. Supply chain problems persist, along with worker shortages.

Procurement and installation of new systems at power plants have been hampered recently by supply chain problems, despite the official end of the pandemic. PJM is concerned

[131] EPA Feb. 15, 2023 Memo at P-1 to P-2, EPA-HQ-OW-2009-0819-9656 (DCN SE10281).

[132] *Id.*

that semiconductor supply chain disruptions pose a risk to construction of replacement power,[133] and that would be a risk for construction of retrofits as well. Recently, TVA's President cited supply chain issues for delays in constructing new solar power, which will be needed to replace coal-fired generating units that are slated for retirement.[134] And late last year, PG&E's independent safety monitor found that the company was low on critical spare parts, "running below minimum safe levels for some 150 types of parts."[135] The monitor cited a PG&E report that supply shortfalls potentially could lead to "prolonged outages." *Id.*

Additionally, there is a growing shortage of skilled workers, such as welders and ironworkers. The American Welding Society estimates that, by 2024, there will be a national shortage of 400,000 welders.[136] Planned construction of advanced nuclear reactors will require many skilled workers, including welders,[137] who are in short supply as older workers retire. These same workers will be needed for major retrofits, such as membrane filtration systems.

2. Appropriate flexibility in timing of retrofits helps to avoid reliability issues.

Because of the many coal-fired closures occurring throughout the industry, flexibility in timing of retrofits is warranted to help avoid reliability issues. As PJM recently explained:

---

[133] PJM Report Feb. 2023 at 16.

[134] Dave Flessner, *TVA turns to the sun for more power but supply chain woes undermine some projects*, CHATTANOOGA TIMES FREE PRESS, May 2, 2023 (CHATTANOOGA TIMES FREE PRESS May 2023).

[135] NBC Bay Area, *PG&E Supply Chain Challenges Could Mean Longer Outages: Report*, Oct. 11, 2022, https://www.nbcbayarea.com/investigations/pge-warns-supply-chain-shortages-could-trigger-prolonged-outages/3027640/ (video, last viewed May 18, 2023).

[136] Manufacturing Tomorrow, *How will Labor Shortages Impact Metal Fabrication in 2022?* Mar. 7, 2022.

[137] Matthew Dalton, *Nuclear Power is Poised for a Comeback. The Problem is Building the Reactors*, WALL ST. J., June 23, 2022.

> For the first time in recent history, PJM could face decreasing reserve margins … should these trends – high load growth, increasing rates of generator retirements, and slower entry of new resources – continue. The amount of generation retirements appears to be more certain than the timely arrival of replacement generation resources, given that the quantity of retirements is codified in various policy objectives, while the impacts to the pace of new entry of the Inflation Reduction Act, post-pandemic supply chain issues, and other externalities are still not fully understood.[138]

PJM cited the planned retirements of Conemaugh and Keystone Stations (collectively 3,400 MWs) due to the 2020 Rule as major factors in declining capacity.[139]

Other signs of the risk of reliability concerns also abound. In June 2022, PJM stepped in to ask that Indian River Station, which was slated to retire, continue to operate for at least four more years due to delays in making necessary grid connections.[140] Indian River is now operating under a "Must Run" agreement. *Id.* Also, Power Engineering reported that at least six coal-fired plants pushed back their closure dates in 2022, often due to the timing of necessary interconnections.[141] These amendments to closure dates seem likely to continue, given the many reported delays in building replacement power.[142]

---

[138] PJM Report Feb. 2023 at 17.

[139] *Id.* at 7.

[140] Molly McVety, *Indian River Power Plant shutdown delayed for 4 years. Why your electric bill will rise?*, DELAWARE ONLINE, Aug. 3, 2022, https://www.delawareonline.com/story/news/local/2022/08/03/coal-powered-indian-river-power-plant-shutdown-delayed/65384383007/ (last visited May 18, 2023).

[141] Kevin Clark, *Explaining the Delays of U.S. Coal Plant Retirements*, POWER ENGINEERING, Aug. 23, 2022, https://www.power-eng.com/coal/explaining-the-delays-of-u-s-coal-plant-retirements/#:~:text=In%20June%2C%20Wisconsin%20utilities%20WEC%20Energy%20Group%20and,challenges%20have%20surfaced%20in%20Missouri%20and%20New%20Mexico. (last visited May 18, 2023).

[142] *See, e.g.,* CHATTANOOGA TIMES FREE PRESS May 2023 (reporting that 3,000 MWs of solar power ordered by TVA from independent power producers "'is in jeopardy'" due to supply chain problems).

With major transitions come some unavoidable hurdles, and EPA's timeframe of "no later than" December 31, 2029, is the minimum time necessary to ensure the transition away from coal does not further endanger reliability.

3. The record justifies a "no later than" date no earlier than December 31, 2029.

Putting aside potential causes of delays and reliability concerns, the "no later than" date should be no earlier than December 31, 2029, solely on the basis of the time it takes to plan, design, procure, and install major new systems, such as membrane filtration or thermal evaporators. For example, IPL's retrofit of a thermal evaporator system for FGDW took about 6 years (2012-2018), and IPL told EPA that "a seven-year timeframe may have been more appropriate for allowing the effective evaluation of the complex water balance system and technologies, including more time to pilot test other technologies."[143]

As UWAG stated in its 2020 Comments, constructing FGDW retrofits can take at least five years, not including time required to study wastewater characteristics, create new water balance diagrams, conduct FGD pilot studies, and obtain screening-level bids from vendors. Further, industry members likely will need to schedule construction outages around routine maintenance outages to avoid grid impacts. Timeframes for specific FGD retrofit projects outlined in UWAG's 2020 Comments range from 52 months to 82 months, including commissioning and start-up.[144] Even more time will be needed for membrane filtration retrofits because of the need for detailed pilot studies over a sufficient period of time and over varying operating conditions.

[143] IPL Call Notes at 4, EPA-HQ-OW-2009-0819-8891 (DCN SE09218).

[144] UWAG 2020 Comments at 191–94.

Additionally, contrary to what EPA has stated,[145] there is a shortage of appropriate contractors for membrane filtration systems. There are only a few manufacturers of membranes that would be suitable for FGDW treatment, and this will create a backlog of orders. BKT/Tomorrow Water has indicated that it is not pursuing the U.S. steam electric market.[146] Also, Oasys has gone out of business, leaving a limited number of vendors. Further complicating the potential retrofits is that no one contractor can offer installation of the complete membrane filtration system. There will need to be multiple contracts or subcontracts to procure the right equipment, and that will add time and expense to the process.

In short, with the current transition going on in the industry, the near certainty of supply chain issues for any major project, possible worker shortages, a contractor backlog, and the potential impacts to reliability, it makes good sense for EPA to set a date no earlier than December 31, 2029,[147] for compliance with the proposal. Nothing in the CWA precludes EPA from setting an availability date that comports with the realities the industry is facing. *See Clean Water Action v. EPA,* 936 F.3d 308, 316–17 (5th Cir. 2019).

D. Alternatively, if EPA Selects Membrane Filtration as BAT, Then it Should, at a Minimum, Include Membrane Filtration-Based BAT Limits That Allow Regular or Intermittent Discharges.

As already stated, the proper BAT technology for FGDW clearly is chemical precipitation plus biological treatment, with the limits set in the 2020 Rule. But EPA has

[145] 88 Fed. Reg. at 18,862.

[146] Memorandum from U.S. EPA, to ELG Planning Record: EPA-HQ-OW-2009-0819, Notes from Meeting with BKT – April 9, 2021 at 3 (Feb. 21, 2023), EPA-HQ-OW-2009-0819-9560 (DCN SE10253).

[147] As stated above, if the final rule is not issued by mid-2024, then this applicability date should be moved back to ensure no less than a five-year period from the effective date of the rule to the "no later than" date.

requested comment on potential alternative membrane-filtration based effluent limitations if comments demonstrate that regular or intermittent discharges of FGDW are a necessity for some facilities. 88 Fed. Reg. at 18,840. Allowing regular discharges from membrane filtration systems is appropriate to help ensure the longevity and integrity of the membranes. For example, secondary backwash rinses of the membranes could be discharged with little environmental impact. These regular discharges during maintenance would lessen the stringency of a zero discharge requirement, while incentivizing proper maintenance of the system. If EPA were to allow such discharges, they should be subject to TSS and oil and grease limits equal to current best practicable control technology (BPT) and to arsenic and mercury limits consistent with the use of chemical precipitation.

E. Leasing Equipment To Treat FGDW Is Not Feasible.

EPA solicits comments on whether costs are disparate in light of the ability of utilities to lease additional treatment stages to meet any new limitations, including the proposed ZLD for FGDW. 88 Fed. Reg. at 18,860. Companies generally disfavor leasing equipment long-term when it is essential to proper operations. To add, for instance, additional thermal treatment stages or extra membrane stages to meet ZLD requirements would be problematic. First, there is normally a significant lead time prior to being able to lease such equipment. Second, if the type of equipment being leased is new to the facility operators, they will need training time and experience with the equipment prior to its deployment. Third, specialized equipment of this sort may not be compatible with the facility's treatment without special adjustments. Therefore, leasing equipment for treatment of FGDW is not easily done and is not an automatic fix.

IV. Comments on Proposed Combustion Residual Leachate (CRL) Provisions

A. EPA Should Re-Propose the CRL Requirements After it Evaluates BAT for the Complete Population of Potentially Impacted Landfills and Impoundments.

EPA's rush to issue the Proposed Rule led to critical missteps in its development. In particular, when EPA developed the population of landfills and impoundments that would be subject to the proposal, it failed to include nearly half of the potentially regulated facilities. This is a particularly egregious error that undermines EPA's estimated benefits, costs, and regulatory impacts.

Before implementing a proposed rule under the APA, federal agencies are required to publish the proposed rule to "give interested persons an opportunity to participate in the rule making through submission of written data, views, or arguments." 5 U.S.C. § 553(c). The Second Circuit has held that "[w]hen the basis for a proposed rule is a scientific decision, the scientific material … [supporting] the rule should be exposed to the view of interested parties for their comment. ... To suppress meaningful comment by failure to disclose the basic data relied upon is akin to rejecting comment altogether." *United States v. Nova Scotia Food Prods. Corp.*, 568 F.2d 240, 252 (2d Cir. 1977). The Ninth Circuit more specifically held that "Congress clearly intended to give those members of the public interested or affected by … [potential] regulations a meaningful voice in shaping those plans and regulations," which occurs "only if the public is able to make intelligent, informed, meaningful comments." *Washington Trollers Ass'n v. Kreps*, 645 F.2d 684, 686 (9th Cir. 1981). By limiting the information made available to the public, such as the quantity of landfills and impoundments potentially regulated by the proposal, the public is unable to meaningfully comment on the proposal's potential impacts and benefits. Thus, EPA should re-propose the requirements for CRL after it has had the opportunity to evaluate BAT for the complete population of potentially impacted landfills and surface impoundments.

In July 2021, EPA announced its plans to initiate a new rulemaking to revise the 2020 Rule. According to the notice, EPA announced it would evaluate whether membrane technologies should be BAT for FGDW, in addition to considering whether the 2020 Rule's requirements for BATW should be revised. 86 Fed. Reg. at 41,802. Not until February 2, 2022, did EPA publicly announce it was in the process of evaluating potential regulatory changes to the existing ELGs for CRL and legacy wastewater (LWW) and requested public input "on options for the proposed regulatory revisions." Memorandum from Richard Benware, Steam Electric ELG Team Leader, Eng'r & Analysis Div., Office of Sci. & Tech., U.S. EPA Office of Water, thru Robert Wood, Dir., Eng'r & Analysis Div., Office of Sci. & Tech., U.S. EPA Office of Water, Posting EPA-HQ-OW-2009-0819 to Regulations.gov for Public Access at 1 (Feb. 1, 2022), EPA-HQ-OW-2009-0819-9017. Critically, however, it appears the CRL Proposed Rule population was completed in January 2022 (EPA, CCR Lined Landfill Sensitivity Analysis, EPA-HQ-OW-2009-0819-9646 (DCN SE10411)), and the regulatory options for the Proposed Rule had been issued by January 2022. EPA, Legacy Surface Impoundment Leachate Sensitivity Analysis (Feb. 14, 2023), EPA-HQ-OW-2009-0819-9645 (DCN SE10415).

EPA's rush to complete the CRL population and proposed regulatory options—contrary to its February 2, 2022 request for public input on these matters—created critical flaws in its CRL analysis. In particular, instead of relying on publicly available information about the universe of landfills (*e.g.*, company websites for CCR Rule[148] compliance documentation), "EPA

[148] EPA, Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities, Final Rule, 80 Fed. Reg. 21,302 (Apr. 17, 2015) (CCR Rule).

used data from the 2009 Steam Electric Survey to identify the population of landfills containing combustion residuals that collect and discharge [CRL].” 2023 TDD at 18. For the Proposed Rule, EPA updated this data set to remove plants intending to retire coal-fired units by December 31, 2023, and add plants that have constructed new landfills. EPA concluded that 68 plants or 168 EGUs met this criteria. *Id.* at Tbl. 6. But, anecdotal evidence, industry experts, and the record itself all indicate that EPA's estimated population is incorrect.

In EPA's Feb. 28, 2023 Costs & Loadings Estimates Memo, EPA-HQ-OW-2009-0819-9686 (DCN SE10381), Table 10 provides costs for chemical precipitation treatment of CRL for EPA's estimated 69 plants. *Id.* at 43–49, Tbl. 10. One UWAG member has four composite-lined landfills with leachate collections systems—one is an active landfill, and three are closed landfills. In Table 10 of EPA's unit-level costs memo, only one landfill is listed, and it is a closed landfill. The other three landfills are not included in EPA's unit-level cost table. EPA's *Evaluation of Potential CRL in Groundwater*, EPA-HQ-OW-2009-0819-9678 (DCN SE10250), explains how EPA estimates the number of plants that may have discharges of CRL via groundwater, *i.e.*, the converse of which plants have leachate collection. Therefore, the bullets in Section 4.1 of this memo (*id.* at 8–9) are helpful in clarifying which landfills would have to apply end-of-pipe CRL treatment to meet the proposed BAT limits. As expected and consistent with the 2023 TDD, EPA notes in this memo, *id.* at 8, that 69 landfills[149] were categorized as composite-lined with leachate collection. But the second bullet indicates that 65 landfills were categorized as composite-lined “because the documents made available online … [identified]

[149] Here, the record refers to 69 *landfills* as the population of entities potentially subject to the proposed CRL requirements, whereas in other locations in the record, such as the 2023 TDD, EPA refers to 69 *plants*. EPA should clarify throughout its analyses whether it is referring to plants or landfills.

composite liner[s].” *Id.* It appears that these 65 landfills with composite liners should also be included in the total population. EPRI, in reliance on this information, found that 134 plants (not 69) would likely incur costs to comply with EPA’s proposed BAT limits for CRL. *See* EPRI Comments at 65, Tbl. 4-1.

Finally, EPA itself acknowledges this error. In EPA’s Legacy Surface Impoundment Leachate Sensitivity Analysis, EPA-HQ-OW-2009-0819-9645 (DCN SE10415), EPA acknowledges that it “identified several surface impoundments that may collect and discharge leachate” after the Proposed Rule options had been completed. Moreover, EPA’s CCR Lined Landfill Sensitivity Analysis, EPA-HQ-OW-2009-0819-9646 (DCN SE10411), indicates that EPA “identified additional lined landfills through a review of company websites for CCR rule compliance documentation.”[150] Surprisingly, EPA states it “*may* include some or all of these additional landfills in the CRL population for the final rulemaking.” *Id.* (emphasis added). By not including the complete population of landfills and impoundments in its analysis for developing the proposed CRL requirements, EPA’s approach was arbitrary, capricious, and a senseless oversight, especially given the extent to which much of this information was available through EPA-mandated CCR websites.

The population of potentially impacted landfills underlies a substantial portion of the Proposal’s analysis, including the data for evaluating CRL treatment technologies, *see* 2023 TDD at 29–30, and EPA’s estimated costs for plants to install and operate chemical precipitation treatment of CRL, *see id.* at 48–49; EPA Feb. 28, 2023 Costs & Loadings Estimates Memo at 43–49, Tbl. 10, EPA-HQ-OW-2009-0819-9686 (DCN SE10381) (pollutant loadings under

[150] The list of plants identified after the regulatory options and population had been completed appear in Worksheet Title “CCR Lined Landfill Costs.” Approximately 65 plants appear on that list.

baseline and post-compliance conditions); 2023 TDD at 60–62 and 63, Tbl. 20. Given that all of these analyses and EPA's proposed regulatory options are based on a landfill/impoundment population that is nearly half the size of the complete regulated universe, EPA should reassess its proposed CRL requirements and provide a new proposal that includes an accurate analysis of the potential impacts on the entities subject to such requirements.

B. If EPA Issues Final CRL Requirements Based on Chemical Precipitation, it Should Provide Flexibility for Landfills and Impoundments Nearing Closure or Recently Closed.

If EPA proceeds to issue final CRL requirements based on chemical precipitation and the flawed analyses discussed above, EPA should provide different CRL limitations for landfills and impoundments nearing closure or recently closed. Given the substantial reduction in leachate flows and pollutant loadings after closure, there should be flexibility for landfills and surface impoundments nearing closure or recently closed such that limitations could be postponed until a few years after closure to avoid construction of a larger, more expensive treatment system that would operate for a relatively short period of time.

1. Reduction in leachate flow post-closure

Upon closure of a landfill or impoundment, the quantity of flow and the pollutant loadings substantially decrease.[151] Research shows that closed landfills and impoundments have reduced leachate flow rates due to less rainfall that percolates through or drains from the materials placed in a landfill or that pass through the impoundment structure:

[151] When a surface impoundment is closed, the facility generally drains the wastewater and fills in the impoundment. The CCRs beneath the wastewater may or may not be removed before filling. If the CCRs are left in place, then the surface impoundment essentially becomes a landfill, and the rate of leachate production would substantially decrease after closure. Where a facility removes the CCRs prior to filling in the impoundment, the closed impoundment would unlikely produce CRLs.

> Post-closure care involves the monitoring and maintenance of the landfill to ensure that it remains stable. For lined landfills with leachate collection, during post-closure care, there are two remaining sources of water – the existing water in the pore spaces around the [coal combustion product] and the final cover system infiltration. Drainage of existing water from pore spaces often occurs over a decade or more following final cover completion. As pore water depletes, drainage ultimately reaches a steady-state flow rate associated with infiltration through the final cover system. EPRI modeling showed that closure eventually reduced leachate flow for landfills in the central Atlantic Coast area by 95% or more.

EPRI, *Potential Challenges in Landfill Water Management, Technical Brief – Coal Combustion Products Management*, 3002024772, at 3 (July 2022) (citing EPRI, *Coal Combustion Residuals Leachate Management: Characterization of Leachate Quantity and Evaluation of Leachate Minimization and Management Methods*, 3002006283 (Dec. 2015)[152]). Likewise, Table 6-8 in EPA's TDD for the proposed 2015 Rule indicates that the average leachate generation from active landfills is 65,500 gpd/plant, whereas average leachate generation at retired landfills is 5,950 gpd/plant, less than 10 percent of active landfills.[153] Indeed, closing a landfill terminates the addition of coal combustion products and moisture conditioning water and significantly diminishes the contribution of precipitation. *See* EPRI Comments at 75. As a result, closure alters leachate flow in at least two ways: (i) the precipitation-related peak flows, approximately 2-4 times greater than average flows, are nearly eliminated upon closure; and (ii) the average flow rate declines and eventually reaches an equilibrium much smaller than flows immediately prior to closure. *See id.* 75–76. Therefore, the post-closure changes in leachate flows can be characterized by a rapid initial depletion phase and a slow secondary phase approaching equilibrium. *See id.* at 76. Specifically, EPRI's modeling demonstrates that leachate flows

[152] EPA-HQ-OW-2009-0819-9639 (DCN SE10386).

[153] EPA, TDD for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-13-002, at 6-13, Tbl. 6-8 (Apr. 2013), EPA-HQ-OW-2009-0819-2257 (DCN SE01964).

decrease significantly in the initial years after the landfill has been closed and covered, but the time it takes to reach equilibrium depends on the thickness of the landfill. *See id.* at 77–79. Given the reduction in flows from closed landfills and EPRI's modeling, it would be unreasonable for EPA or state permitting authorities to apply the proposed CRL limits to facilities within the initial depletion phase. A more sensible approach would be to allow facilities to design a treatment system to address flow after it has reached equilibrium.

2. Reduction in pollutant loadings post-closure

In reliance on this data, UWAG has calculated an estimate of pollutant loadings in leachate at closed landfills compared to active landfills, using the untreated CRL water quality data in Table 17 of the 2023 TDD. 2023 TDD at 61, Tbl. 17. As you can see from the table below, each closed landfill would have approximately 60,000 lbs/year of pollutant and using toxicity weighting factors, the load per plant would be approximately 38 toxic-weighted pounds-equivalent (TWPE) per year. These numbers substantially contrast with EPA's estimate of approximately 980,000 lbs/year at each plant. *See* 2023 TDD at 63, Tbl. 20 (baseline 67,700,000 lbs/year divided by 69 plants).

Retired CRL Pollutant Loading Calculation

Pollutant	Toxic Weighted Factor	Untreated CRL[154]	Pollutant Loading[155]	
		Average Conc. (µg/L)	lb/year	TWPE/yr
Total Suspended Solids		35,800	649	
Total Dissolved Solids		3,500,000	63,435	
Priority Pollutants				
Antimony	0.01225	3.75	0.1	0.0
Arsenic	4.04133	38.40	0.7	2.8

[154] Untreated CRL water quality obtained from Table 17 of the 2023 TDD.

[155] Annual pollutant loading calculated using pollutant concentration and retired CRL daily flow obtained from Table 6-8 of the 2013 TDD multiplied by 365 days.

Cadmium	23.11680	10.10	0.2	4.2
Chromium	0.07570	2,120.00	38.0	3.0
Copper	0.63482	7.58	0.1	0.1
Mercury	117.11802	1.06	0.0	2.3
Nickel	0.10891	46.50	0.8	0.1
Selenium	1.12134	111.00	2.0	2.0
Thallium	1.02706	1.16	0.0	0.0
Zinc	0.04689	211.00	4.0	0
Non-conventional Pollutants				0
Aluminum	0.06469	2,990.00	54.0	4.0
Barium	0.00199	53.20	1.0	0.0
Boron	0.00834	22,400.00	406.0	3.0
Calcium	0.00003	408,000.00	7,395.0	0
Chloride	0.00002	413,000.00	7,485.0	0
Cobalt	0.11429	38.60	0.7	0.1
Iron	0.00560	37,100.00	672.0	4.0
Magnesium	0.00087	118,000.00	2,139.0	2.0
Manganese	0.07043	2,720.00	49.0	3.0
Molybdenum	0.20144	1,380.00	25.0	5.0
Sodium	0.00001	308,000.00	5,582.0	0
Sulfate	0.00001	1,790,000.00	32,442.0	0
Vanadium	0.03500	1,910.00	35.0	1.0
TOTAL (TSS and TDS Only)			**64,084.0**	**N/A**
TOTAL (all except TSS and TDS)			**56,333.0**	**38.0**

Therefore, if we assume the same water quality for leachate from active and retired landfills, then retired landfills have approximately 1/10 of an active landfill's load.

Although not required by the CWA, an analysis of cost-effectiveness offers a useful metric to compare the efficiency of regulatory options in removing pollutants. In the effluent guidelines context, EPA has often considered the BAT factor for "cost" using a cost-effectiveness method that is expressed as $/TWPE (where TWPE is a toxic weighting factor that represents the toxic-weighted pound equivalent of a particular pollutant discharge).[156] "Cost

[156] *See* EPA, Toxic Weighting Factors Methodology, EPA-820-R-12-005, at 1-1 (Mar. 2012) ("EPA began developing [Toxic Weighting Factors (TWFs)] in the early 1980s to

effectiveness is defined as the incremental annual cost, expressed in 1981 constant dollars, per incremental toxic weighted pound of pollutant removed by a treatment technology."[157] In EPA's own review of recent BAT determinations, cost-effectiveness ranged from $1/lb-eq (inorganic chemicals) to $404/lb-eq (electrical and electronic components), in 1981 dollars. *See* 78 Fed. Reg. 34,432, 34,504 (June 7, 2013).[158] Typically, the cost has been less than $200. *See id.*; *see also* 68 Fed. Reg. 25,686, 25,701 (May 13, 2003). Given EPA's estimate that the total industry annualized costs for 69 plants is $99 million/year or $1.4 million/plant[159] and UWAG's estimates of 38 TWPE/year at a closed landfill, the cost-effectiveness of applying the proposed regulatory option to such facilities would be drastically higher than past ELG requirements.

In sum, the lower flows and smaller quantity of pollutant loadings in leachate at closed landfills does not justify substantial capital cost investments just prior to or recently after closure.

3. Expensive treatment system

When developing a treatment system, a facility will size the equipment based on peak or maximum flow rate to ensure the infrastructure can adequately manage the wastewater flow. Given the lower flows and substantially smaller quantity of pollutants in leachate from a closed landfill, EPA should postpone the applicability of the proposed CRL limits until a number of years after closure to avoid investments in larger, more expensive treatment systems that would only operate for a limited period of time.

---

compare the relative cost effectiveness of treatment technology options for … effluent guidelines.").

[157] *Id.* at 6-1 (internal citation omitted).

[158] *See also id.* at 6-2, Tbl. 6-1 ("Examples of Effluent Guidelines Cost-Effectiveness Analysis Ranked by Dollars Per TWPE Removed").

[159] EPA, Regulatory Impact Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-23-002, at 3-7, Tbl. 3-2 (Feb. 28, 2023) (RIA).

EPA estimates that the annualized costs for compliance with proposed CRL requirements would be $99 million or approximately $1.4 million per plant. But EPA's annualized costs substantially underestimate the costs of treating CRL with chemical precipitation and ignore other cost constraints at closed landfills and impoundments. EPA's *Evaluation of Potential CRL in Groundwater*, EPA-HQ-OW-2009-0819-9678 (DCN SE10250), helps clarify which landfills would have to apply end-of-pipe CRL treatment to meet the proposed BAT limits. Consistent with the 2023 TDD, this document notes that 69 landfills were categorized as composite-lined with leachate collection. *Id.* at 8. But the second bullet indicates that "65 landfills were categorized as composite-lined because the documents made available online … identified … composite liner[s]." *Id.* It appears that these 65 landfills with composite liners also should be included in costs to industry as presented in the 2023 TDD, which would nearly double EPA's estimated costs. Indeed, EPRI's annualized cost estimate for EPA's proposed CRL limits is approximately 170 percent higher than EPA's estimate, given differences in the estimated number of plants that will have costs to comply with the limits, the use of peak flow rate as the basis for designing a treatment system instead of a plant's average daily leachate flow rate, and other O&M cost considerations. *See* EPRI Comments at 65–69.

It also would be more difficult than EPA anticipates to treat CRL with chemical precipitation to meet the proposed BAT limits, which would further increase treatment costs. EPA set the numeric standard for arsenic in CRL based on FGDW data, which does not adequately represent the achievability for chemical precipitation in CRL application. The assumption that chemical precipitation treatment of FGDW and CRL can achieve similar effluent characteristics oversimplifies the underlying factors that dictate effective arsenic removal. Arsenic may appear in both particulate and dissolved forms in the wastestream, and, although total arsenic is higher for FGDW, the dissolved arsenic concentration is higher for CRL. In 2013, EPA presented FGDW data for three plants to demonstrate the technical feasibility of achieving arsenic limits with CP+LRTR. This data, however, showed little to no dissolved arsenic removal. *See id.* at 73. Given that the average dissolved arsenic concentration in CRL is higher than the proposed BAT limit, many plants may have difficulty achieving dissolved arsenic removals. *See id.* at 74. This would likely require additional investments in treatment technology and/or equipment to satisfy the proposed BAT limits.

Thus, it would be unreasonable for EPA to require facilities to incur these significant costs to satisfy the proposed CRL limits just prior to closure.[160]

C. If EPA Intends To Regulate Closed Landfills/Impoundments and Retired Plants, It Should Issue a New Proposal That Adequately Assesses Such Facilities.

If EPA had analyzed data from closed landfills and impoundments, then it may have reached the conclusions in the previous section. Instead, EPA disregarded data for closed landfills and impoundments when it developed the Proposed Rule and did not assess or include potential regulatory impacts to retired facilities in its analysis. Thus, if EPA intends to regulate such facilities, it should issue a new proposal with adequate analyses of closed landfills and

[160] EPA also appears to provide little support for its estimate that chemical precipitation systems can achieve mercury and arsenic limitations within 22 months. *See* 88 Fed. Reg. at 18,862 (citing “SE10289”). EPA cites a 2015 presentation to support its 22-month timeline, but this presentation provides a single slide about physical/chemical treatment. The slide provides a 19-month timeline for *after* the treatment system has been authorized and for installing a system to treat FGDW, not CRL. *See* Sargent & Lundy Webinar - Steam Electric Effluent Limitations Guidelines, at 25 (Oct. 29, 2015), EPA-HQ-OW-2009-0819-9659 (DCN SE10289). Based on UWAG member experience, utilities will need to perform pilot/bench studies (2-4 months), design the system (4-8 months), obtain approvals/permitting (5-18 months), contract with vendors (1-2 months), procure and install the system (6-12 months), and start-up (1-3 months). Thus, on average, it would generally take a company much longer than 22 months to design and install a chemical precipitation treatment system that would meet the proposed BAT limits for CRL.

impoundments and retired facilities, or such facilities should be exempt from additional regulation and remain subject to the limits that apply under current law.[161]

1. Closed landfills and impoundments

The data EPA relied on to develop the proposed CRL limits appears to exclude data from closed landfills and impoundments. The preamble indicates that EPA is basing the proposed effluent limitations on the chemical precipitation system for treating FGDW, as described in the 2015 Rule because the record indicates that CRL is similar to FGDW. 88 Fed. Reg. at 18,848/3.

> In promulgating the 2015 rule, EPA determined that [CRL] from landfills and impoundments includes similar types of constituents as FGD wastewater, albeit at potentially lower concentrations and smaller volumes. Based on this characterization of the wastewater and knowledge of treatment technologies, EPA determined that certain treatment technologies identified for FGD wastewater could also be used to treat leachate from landfills and impoundments containing combustion residuals.

88 Fed. Reg. at 18,848. Setting aside the issue of whether CRL is sufficiently similar to FGDW to function as the basis for CRL limits, the 2015 data set appears to exclude a substantial portion of the industry: closed landfills and impoundments.

As noted above, EPA conducted a detailed study of the steam electric power generating industry between 2005 and 2009 (the Steam Electric Survey). 2015 TDD at 3-1. As part of the Steam Electric Survey, EPA required a subset of plants to sample their leachate from impoundments and landfills containing combustion residuals. *Id.* at 6-20. EPA referred to the landfills and impoundments as "management *units*" in the 2015 TDD and described CRL as including seepage and/or leakage "from a combustion residual landfill or impoundment *unit.*" *Id.* at 6-11 (emphases added). EPA used the CRL data collected from the survey responses to

---

[161] Under current law, EPA's BAT determinations in the 1982 Rule control, not best professional judgment (BPJ). See Section X.A, *infra*.

identify pollutants of concern for the wastestream. *See id.* at 6-20. Notably, "*EPA excluded data from retired or closed units for use in this analysis* because combustion residual leachate from retired units is not regulated in the final rule." *Id.* at 6-20 (emphasis added). Regardless of whether it was appropriate for EPA to exclude such data at the time, EPA cannot reasonably rely on the 2015 analysis now to promulgate requirements that apply to retired or closed landfills or impoundments. If EPA intends to regulate such facilities, then it should issue a new proposal with data and analyses of pollutant loadings, costs, and treatment technologies associated with treating CRL at retired or closed landfills or impoundments. Otherwise, it should exempt such facilities from the proposed CRL limits.[162]

2. Retired plants

Likewise, the proposal does not adequately consider impacts to retired plants. According to the proposal's TDD, "EPA used data from the 2009 Steam Electric Survey to identify the population of landfills containing combustion residuals that collect and discharge leachate to surface waters …." 2023 TDD at 18. "For the 2023 proposal, EPA updated this data set to remove plants that intend to *retire all coal-fired EGUs as of December 31, 2023* and add plants that have constructed new landfills since 2015." *Id.* (emphasis added, footnote omitted). Table 6 summarizes CRL discharges by the steam electric power plants included in EPA's costs and loadings analyses. *Id.* at 18, Tbl. 6. Table 6 includes 68 plants and Table 12 in the 2023 TDD, *Estimated Cost of Implementation for Combustion Residual Leachate by Regulatory Option*, *id.* at 52, includes 69 plants (EPA does not explain the one plant discrepancy). Likewise, EPA's

[162] For similar reasons, EPA should consider excluding or re-analyzing *impoundment* leachate. The 2015 data on which EPA relies for its analysis does not distinguish between *landfill* leachate and *impoundment* leachate. It is not clear whether the concentration of pollutants in impoundment leachate would be the same as leachate from a landfill, but impoundment leachate likely contains fewer pollutants.

Feb. 28, 2023 Costs & Loadings Estimates Memo, EPA-HQ-OW-2009-0819-9686 (DCN SE10381), at Table 10 provides costs for chemical precipitation treatment of CRL for 69 plants. *Id.* at 43–49, Tbl. 10. Thus, it appears the population of plants included in EPA's costs and loadings analyses does not include plants that intend to retire all EGUs as of December 31, 2023. The regulatory text, however, indicates CRL limits apply to all facilities, regardless of their retirement status. If EPA intends to regulate all facilities, then it should issue a new proposed rule with reasonable loadings and cost estimates for retired facilities. If the Agency does not plan to issue a new proposed rule to allow the public to comment on the compliance costs and loadings estimates for retired facilities, then EPA should exclude retired facilities from the final rule.

Moreover, when developing ELGs, the CWA requires EPA to consider the age of facilities involved and the cost of achieving effluent reduction. CWA § 304(b)(2)(B), 33 U.S.C. § 1314(b)(2)(B). The costs of achieving effluent reduction at retired plants would also be much higher than compliance costs at operating facilities. For example, the cost to power the treatment system is expected to be higher at a retired facility due to the additional cost needed to bring power to the facility when no power is being generated onsite. Also, unlike at operating plants where staff at the facility could also operate the chemical precipitation system, an operator at a retired facility would likely work exclusively on the wastewater treatment system. Finally, assuming the landfills are no longer accepting coal combustion products at a retired facility, residuals from a chemical precipitation system would likely need to be hauled and disposed of in a different location, which would result in higher costs. But EPA has not considered these costs. Indeed, EPA has not considered any costs for implementing the proposed CRL limits at retired plants. Therefore, EPA should exclude such facilities from the new limits or develop a new proposal that adequately assesses the potential regulatory impact on retired facilities.

D. The Record Lacks Sufficient Information for EPA To Determine That More Stringent Technologies are BAT for CRL.

1. EPA's Proposal Does Not Evaluate More Stringent Alternatives.

The Proposed Rule evaluates four regulatory alternatives, but each alternative includes the same technology basis for CRL, chemical precipitation. None of the alternatives for the Proposed Rule consider a technology basis for CRL based on more stringent technologies. If EPA intends to establish limits for CRL based on more stringent technologies, then it would need to issue a new proposal that provides data and analyses evaluating such technologies as regulatory alternatives so the public may have a meaningful opportunity to provide informed public comment.

Given the APA's requirement that an agency "examine the relevant data and articulate a satisfactory explanation for its action," *see State Farm*, 463 U.S. at 43, "it is especially important for the agency to identify and make available technical studies and data that it has employed" prior to the comment period. *Connecticut Light & Power Co. v. Nuclear Regulatory Comm'n*, 673 F.2d 525, 530 (D.C. Cir. 1982). "[A]n agency cannot rest a rule on data that, in critical degree, is known only to the agency." *Time Warner Entm't Co., L.P. v. FCC,* 240 F.3d 1126, 1140 (D.C.Cir. 2001) (internal quotation marks, citation, and alterations omitted). Rather, "'[t]he most critical factual material that is used to support the agency's position on review must have been made public *in the proceeding* and exposed to refutation.'" *Owner–Operator Indep. Drivers Ass'n v. Fed. Motor Carrier Safety Admin.,* 494 F.3d 188, 199 (D.C. Cir. 2007) (quoting *Ass'n of Data Processing Serv. Orgs. v. Bd. of Governors of the Fed. Reserve Sys.,* 745 F.2d 677, 684 (D.C. Cir.1984)) (emphasis in original).

The critical factual material necessary to support a determination that more stringent technologies are BAT for CRL, such as the estimated costs and benefits, pollutant loadings, and regulatory impacts, has not been provided to the public. EPA's estimated compliance costs do not address the costs of installing more stringent technologies to treat CRL. The estimated total annualized compliance costs for CRL is $99 million under all four regulatory options. RIA at 3-7, Tbl. 3-2.[163] A final rule that includes CRL limits based on more stringent technologies would be contrary to Executive Order 12866, which requires agencies to assess the "costs and benefits of potentially effective and reasonably feasible alternatives to the planned regulation," Exec. Order No. 12866 § 6(a)(3)(C)(iii), *reprinted in*, 58 Fed. Reg. at 51,741, and OMB Circular A-4 which states that "[a] good regulatory analysis is designed to inform the public and other parts of the Government (as well as the agency conducting the analysis) of the effects of alternative actions."[164] The same is true for potential benefits of alternative treatment technologies for CRL, which have not been calculated by EPA or provided to the public for comment.[165] Thus, if EPA sought to establish CRL limits based on biological, membrane, or thermal treatment, it would need to issue a new proposal that analyzes the potential costs and benefits of such alternatives to allow for fully-informed public comment.

[163] The RIA does not appear to have been posted to docket EPA-HQ-OW-2009-0819 as of the time of this filing; however, it is available at https://www.epa.gov/system/files/documents/2023-03/steam-electric-regulatory-impact-analysis_proposed_feb-2023.pdf (last visited May 19, 2023).

[164] OMB, Circular A-4, Regulatory Analysis (Sept. 17, 2003), https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/.

[165] While EPA appears to have calculated estimated costs associated with applying more stringent technologies to CRL in a Microsoft Access database, *see* Combustion Residual Leachate (CRL) Proposed Rule Cost Database, EPA-HQ-OW-2009-0819-9958 (DCN SE10420), the Agency has not presented this information to the public in a format that would allow for meaningful comment.

2. The Record Contains Insufficient Data to Support a Conclusion that CRL Is Similar to FGDW.

EPA's 2023 TDD also does not describe or evaluate biological, membrane, or thermal treatment for CRL. Instead, EPA references and defers to analyses of how these technologies perform when treating FGDW. *See* 2023 TDD at 30. EPA states that leachate "from landfills and impoundments includes similar types of constituents as FGD wastewater," although the concentrations of the constituents in leachate are generally lower than in FGD wastewater. *Id.* at 29. "Based on this characterization of the wastewater and knowledge of treatment technologies, EPA determined that certain treatment technologies identified for FGD wastewater could also be used to treat leachate from landfills.…" *Id.* *See* EPA Feb. 15, 2023 Memo, EPA-HQ-OW-2009-0819-9656 (DCN SE10281). But EPA has not provided sufficient information in the record to demonstrate that CRL is adequately similar to FGDW to establish limits based on more stringent technologies. Therefore, EPA could not rely on such data to determine that more stringent technologies are BAT for CRL.

EPA states in the preamble that it "received supplemental CRL sampling data covering 25 landfills. EPA analyzed these data in the *CRL Analytical Data Evaluation* (SE10249) and found that CRL has a similar wastewater characterization to FGD wastewater." 88 Fed. Reg. at 18,849. Importantly, however, the document referenced by EPA (EPA Memorandum, [CRL] Analytical Data Evaluation (Dec. 13, 2022), EPA-HQ-OW-2009-0819-9637 (DCN SE10249)) does not compare CRL to FGDW; it compares earlier untreated CRL data to the newer untreated CRL data. There does not appear to be anything in this memorandum that supports EPA's preamble statement. If EPA is relying on this memo alone to make the case that CRL is similar to FGDW, then it has failed to prove its case.

In the 2015 rule, EPA calculated an average pollutant load for untreated CRL using data from 26 landfills and 15 impoundments collected in the Steam Electric Survey. 2015 TDD at 10-24. But, as stated in the 2015 TDD, EPA "did not identify any plants … operating a chemical precipitation system to treat landfill leachate," so it simply transferred over the FGD chemical precipitation effluent removal concentrations to leachate. 2015 TDD at 10-24. EPA did the same thing for biological treatment, using average FGD biological treatment removal concentrations for leachate. *Id.* In this way, EPA sought to estimate pollutant removals for treatment of CRL by chemical precipitation and biological treatment. *See id.* at 20-24 to 10-25, Tbl. 10-8; 10-26, Tbl. 10-9. Based on UWAG's review of the record for the 2023 proposal, EPA apparently has not estimated pollutant removals for biological, membrane, or thermal treatment of CRL.

EPA's CRL Analytical Data Evaluation (DCN SE10249) compares the untreated CRL concentrations per analyte from the 2015 Rule with the new voluntary data EPA received during preparation for this proposal. EPA then finds that the new voluntary data is "similar to the concentration data set used to estimate CRL pollutant loadings and removals, as described in Section 6.4 of the TDD and shown in Table 1." *Id.* at 3, EPA-HQ-OW-2009-0819-9637 (DCN SE10249). Notably, this memo does not describe the types of wastes contained in the landfills, which would likely make a substantial difference in pollutant concentrations. For example, the memo does not indicate whether the landfill contains FGD solids, fly ash, bottom ash (BA), or some combination of these wastes. The type of waste in the landfill could be important, given the potential variation in leachability. *See*, *e.g.*, Constance L. Senior et al., *Fate of mercury collected from air pollution control devices*, EM: AIR & WASTE MGMT. ASS'N'S MAGAZINE FOR ENVTL. MANAGERS 15-21 (July 2009) ("The results show that mercury is strongly retained by the fly ash and unlikely to be leached at levels of environmental concern.”). Thus, it appears EPA (i) did not use the new data in computing pollutant concentrations in untreated leachate, (ii) did not distinguish between the types of wastes each landfill received, and (iii) continues to apply FGD chemical precipitation removals for computing removals from leachate using those technologies.

Moreover, while FGDW and CRL may contain similar pollutants, the quantity of each pollutant varies significantly. The table below compares untreated FGDW and CRL water quality information from EPA’s 2015 TDD, EPA’s 2020 voluntary request for data, and data from an inactive landfill at the Rivesville Power Plant. As the table demonstrates, there are substantial differences between the two wastestreams. In particular, the particulate concentrations for arsenic and mercury are much lower in CRL.

Pollutant	**Average concentration (micrograms per liter (µg/L)**		
	FGD (EPA, 2015)[166]	**CRL – Voluntary request (EPA, 2020)[167]**	**Untreated CRL at Rivesville Power Plant**
Arsenic	507	7.6	64
Mercury	289	0.04	<MDL[168] (MDL: 0.002)
Chloride	7,180,000	707,000	9,300
Sulfate		2,870,000	1,003,000
Total Dissolved Solids	33,300,000	5,570,000	2,149,000

[166] 2015 TDD, Tbl. 6-3.

[167] CRL Analytical Data Evaluation, EPA-HQ-OW-2009-0819-9637 (DCN SE10249), at 4, Tbl. 1.

[168] The method detection limit (MDL) is defined as the minimum measured concentration of a substance that can be reported with 99 percent confidence that the measured concentration is distinguishable from method blank results. *See* EPA, *Definition and Procedure for the Determination of the Method Detection Limit, Revision 2*, EPA 821-R-16-006, at 1 (Dec. 2016).

Although EPA collected new leachate data for this rulemaking, instead of using it to analyze leachate characteristics, determine pollutants of concern, and then evaluate potential pollutant removals, the Agency apparently is still relying on borrowed FGDW data from the 2015 record and ignores the leachate data it collected for this rulemaking.[169] EPA's approach to CRL appears to essentially rubber stamp the approach the Agency took in 2015 without appropriate updating—updating that would be required to support a determination that more stringent technologies are BAT for CRL.

3. The Costs of Installing More Stringent Technologies to Treat CRL Would Be Unreasonable.

The limited cost analysis performed by EPA indicates that the costs of treating CRL with more stringent technologies are unreasonable. As noted above, EPA's estimated costs for CRL treatment with chemical precipitation are inaccurate, and the overall cost to industry would be substantially higher, given EPA's estimate of only 69 impacted facilities. Such costs would be even higher if EPA determined a more stringent technology is BAT. For example, in EPA's Spray Dryer Evaporator Cost Methodology, EPA-HQ-OW-2009-0819-9684 (DCN SE10247), EPA applies spray evaporation costs to the underestimated population of plants discharging CRL. EPA's calculations show that the capital costs of treating CRL with spray evaporation would be nearly \$1.3 billion and annual O&M costs would be \$64 million. *Id.* at 15, Tbl. 7. Furthermore, EPRI's calculations indicate that the annualized cost per plant of treating CRL with

[169] EPA also appears to substantially overestimate the quantity of chromium in leachate. Table 17 in the 2023 TDD shows average chromium concentrations in untreated CRL to be 2,120 ug/L, but CRL data from UWAG members and other sources indicates that chromium concentrations are generally substantially lower. For example, publicly available information from EPA's NetDMR website indicates that, at one UWAG member facility, monthly chromium concentrations in CRL over the course of a 21-month period never exceeded 10 ug/L and averaged approximately 2.5 ug/L during this time period.

chemical precipitation + membrane filtration would be approximately $8 million/year. *See* EPRI Comments at 82, Tbl. 6-1. Thus, if EPA applied such cost estimates to the full population of impacted landfills and impoundments, the costs would be extreme.

The incremental reduction in pollutant loadings are not justified by these substantial costs. *See id.* at 84 ("there would only be a minor increase in pollutant reduction if membrane treatment was the BAT for CRL instead of CP alone."). Based on EPRI's estimates, the minor incremental increase in pollutant reduction achieved from installing an advanced membrane system for CRL would cost approximately $761 million more for the industry. *Id.* at 81, 83.

E. EPA Should Exempt Untreated Overflow From Large Storm Events Where Facilities Co-Treat CRL and Stormwater.

Many facilities' leachate collection systems also collect low volume waste, stormwater, or other on-site streams, making it very difficult to separate or extract leachate from the system. Indeed, based on how some landfills are constructed, it is technically infeasible to collect only leachate. For many plants, CRL and stormwater are comingled prior to treatment and discharge, and it would be extremely costly to separate out CRL from stormwater. Therefore, the combined wastestream rule would apply in most circumstances to such comingled wastestreams. *See* 2015 TDD at 14-12 (citing 40 C.F.R. § 403.6(e)).

Where CRL is comingled or co-treated with stormwater, large storm events should be exempt from the any final CRL limits, given the substantial and sudden variation in wastewater flow rate. This approach would be consistent with section 423.12(b)(10), which establishes BPT limitations for coal pile runoff, and section 423.15, which establishes new source performance standards (NSPS) limitations for coal pile runoff. Both of those provisions exempt any untreated overflow from facilities designed, constructed, and operated to treat coal pile runoff that results from a 10-year, 24-hour rainfall event. Where facilities are designed, constructed, and operated to similar standards, any overflow combined wastestream of CRL and stormwater should be exempt from any final CRL limits.

V. Comments on Proposed BAT Limits for Functionally Equivalent Discharges

County of Maui v. Hawaii Wildlife Fund, 140 S. Ct. 1462 (2020), holds that the CWA "requires a permit when there is a direct discharge from a point source into navigable waters or when there is the *functional equivalent of a direct discharge* … when a point source directly deposits pollutants into navigable waters, or when the discharge reaches the same result through roughly similar means." *Id*. at 1476 (emphasis in original). In the ELG proposal, EPA briefly discusses *County of Maui* and proposes that for those limited situations where *County of Maui* would apply—*e.g.*, for any potential releases of pollutants from surface impoundments or landfills used to treat or manage CCR through groundwater to WOTUS that are the functional equivalent of a direct discharge—NPDES permits would be required. 88 Fed. Reg. at 18,828, 18,850.

Specifically, EPA asserts that "unlined landfills and surface impoundments potentially discharge CRL through groundwater before entering surface water" and proposes "that any discharge through groundwater that is the functional equivalent of a direct discharge under the *Maui* decision would be subject to the same BAT limitations as discharges that occur at the end of [the] pipe." *Id.* at 18,850. EPA solicits comments on the appropriateness of the Agency's proposed BAT findings and their application to any releases of CRL via groundwater that permitting authorities ultimately determine are subject to NPDES permitting. *Id.*

UWAG expects that, in the great majority of cases, releases of CRL from landfills and impoundments into groundwater (which are regulated under RCRA) to surface waters do not amount to "discharges of pollutants" from point sources through groundwater to WOTUS that would qualify as the functional equivalent of a direct discharge under *County of Maui.* UWAG does not believe it would be appropriate, or warranted, for EPA to address these issues in this rulemaking for the reasons discussed below, not the least of which is that there are already extensive state and federal regulatory schemes in place that govern releases of CRL in groundwater.

A. *County of Maui* Establishes a Detailed, Fact-Specific Set of Factors Permitting Agencies Will Need To Evaluate To Determine Whether Releases of CRL from Landfills and Surface Impoundments Through Groundwater That Reach Surface Waters Qualify as the Functional Equivalent of a Direct Discharge.

County of Maui involved a citizen suit alleging that releases of sewage from the County's wastewater reclamation facility through groundwater to the ocean constituted discharges of pollutants to navigable waters that required an NPDES permit. 140 S. Ct. at 1469. The County's facility pumped treated sewage into four wells that released the "effluent" into an aquifer connected to ocean waters. *Id.* The wells were about a half mile from the coast, and the Supreme Court characterized the affected groundwater as flowing half a mile or so from the facility to the ocean. *Id*. All parties agreed that the wells at issue in *County of Maui* fell within the definition of "point source," and the only question on which the Court ruled was whether a "discharge of pollutants" occurs when pollutants leave a point source and are conveyed to navigable waters by groundwater.

The Supreme Court majority concluded that federal jurisdiction under the CWA applies "when a point source directly deposits pollutants into navigable waters, or when the discharge reaches the same result through roughly similar means" that make the discharge "the *functional equivalent of a direct discharge*." *Id.* at 1476 (emphasis in original). To arrive at this new "functional equivalent" test, the Court first looked at the statutory purpose and definitions. It cited the broad language Congress used in describing which discharges are covered by the permit requirement and, in particular, the statute's use of the word "any" in the definitions of "pollutant," "point source," and "discharge of pollutants." *Id.* at 1469. The Court then turned to the central linguistic question: "Is pollution that reaches navigable waters only through groundwater pollution that is 'from' a point source, as the statute uses the word?" *Id.* at 1470. The Court acknowledged that "[t]he word 'from' is broad in scope, but context often imposes limitations." *Id.*

The Court characterized its "functional equivalent of a direct discharge" test as designed to fulfill "Congress' basic aim to provide federal regulation of identifiable sources of pollutants entering navigable waters without undermining the States' longstanding regulatory authority over land and groundwater." *Id.* at 1476. Thus "[w]hether pollutants that arrive at navigable waters after traveling through groundwater are 'from' a point source depends upon how similar to (or different from) the particular discharge is to a direct discharge." *Id.*

A determination whether the indirect entry of pollution into navigable waters is the functional equivalent of a direct discharge from a point source into those waters must be based on evidence of the characteristics of the pollution that enters navigable waters (*e.g.*, quantity, dilution, and chemical composition) relative to the wastewater when it left the point source. *See id*. at 1476–77 (relevant factors include the "extent to which the pollutant is diluted or chemically changed as it travels, … the amount of pollutant entering the navigable waters *relative to* the amount of the pollutant that leaves the point source, … [and] the degree to which the pollution (*at that point*) has maintained its specific identity") (emphases added). Under this test, discharges from a pipe that ends "a few feet from navigable waters" and emits pollutants that travel "through groundwater (or over the beach)" to navigable waters "clearly" would require a permit. *Id*. The pipe located many miles away and emitting pollutants that take many years to arrive via groundwater would not. *Id.*

Although the Court provided a non-exclusive list of seven potentially relevant factors that could be considered in assessing what is functionally equivalent to a direct discharge, because those factors include no quantitative measures, their application will vary. The Court says that "[t]ime and distance will be the most important factors in most cases, but not necessarily every case." *Id.* at 1477. Beyond these specific factors, the Court tells those seeking to understand what qualifies as the functional equivalent of a direct discharge to look to the "underlying statutory objectives." *Id.* "Decisions should not create serious risks either of undermining state regulation of groundwater or of creating loopholes that undermine the statute's basic federal regulatory objectives." *Id.* Thus, following *County of Maui,* permitting authorities should not assume that releases of pollutants from point sources into groundwater in the vicinity of a jurisdictional water are the "functional equivalent" of direct discharges to that water.

UWAG expects that, in the majority of cases, releases of CRL from landfills and surface impoundments to groundwater (which are regulated under RCRA) do not amount to "discharges of pollutants" from a point source through groundwater to WOTUS that would qualify as the functional equivalent of a direct discharge under *County of Maui.* Even where evidence shows that such pollutants "ultimately reach" a jurisdictional water, permitting agencies will still need to make a determination that entry of such pollutants into a jurisdictional water is the "functional equivalent" of a direct discharge into that water, which will require consideration of the relevant factors, including time and distance between the point source and entry of the pollution into jurisdictional waters and the quantity, dilution, and chemical composition of the pollutants that enter those waters.

B. The ELG Rule Is Not the Appropriate Regulatory Avenue To Address Releases of CRL to Groundwater.

Many local, state, and other federal programs already regulate landfills and surface impoundments, including addressing releases of pollutants to groundwater. EPA should not infringe upon those programs or introduce uncertainty by adopting potentially conflicting or contradictory requirements.

The Supreme Court recognized in *County of Maui* that the structure of the CWA "indicates that, as to groundwater pollution and nonpoint source pollution, Congress intended to leave substantial responsibility and autonomy to the States," as evidenced by the limited role Congress authorized EPA to play in both respects. 140 S. Ct. at 1471. Consistent with Congress' intent, states have long enforced comprehensive regulatory schemes that cover releases in groundwater. *Id.*

In addition, RCRA regulations provide important federal protections for groundwater in proximity to coal ash landfills and surface impoundments. *See* CCR Rule, 80 Fed. Reg. 21,302. In 2015, EPA promulgated comprehensive and protective new federal standards governing the disposal of coal ash in surface impoundments and landfills. *See id*. The CCR Rule, issued pursuant to RCRA's non-hazardous waste "Subtitle D" provisions, is designed to ensure "'no reasonable probability of adverse effects on health or the environment'" from the disposal of coal ash. *See id.* at 21,311; 42 U.S.C. § 6944(a). EPA put this comprehensive groundwater protection scheme in place to "ensure that groundwater contamination at new and existing CCR units will be detected and cleaned up as necessary to protect human health and the environment." 80 Fed. Reg. at 21,396. Indeed, EPA acknowledges in the ELG Proposal that the 2015 CCR Rule provides comprehensive requirements for the safe disposal of CCR, based on "the culmination of extensive study on the effects of coal ash on the environment and public health." 88 Fed. Reg. at 18,831.

Among other things, the CCR Rule establishes requirements for the management and disposal of coal ash, "including requirements designed to prevent leaking of contaminants into groundwater." *Id.* The rule also includes provisions addressing monitoring for and remediation of any releases of CCR constituents into groundwater. 40 C.F.R. § 257.90(b)(1) & (b)(2), § 257.98(a). The CCR Rule's extensive groundwater monitoring and corrective action requirements were designed specifically to address the attendant risks from coal ash disposal, including potential impacts to downgradient surface water. *See, e.g.*, 80 Fed. Reg. at 21,322 (noting that EPA's risk assessment developed for the CCR Rule included consideration of the "potential impact from the interception of contaminated groundwater plumes by surface water bodies").

Many UWAG member facilities are already addressing groundwater issues under these CCR requirements.

EPA should not disturb these existing regulatory frameworks. For policy reasons and to avoid imposing additional—and potentially contradictory—requirements, EPA should not address releases of CRL into WOTUS via groundwater in this rulemaking. Rather, EPA needs to revise its NPDES rules, found at 40 C.F.R. Part 122, to deal holistically with the complex topic of indirect releases of pollutants into WOTUS via groundwater. EPA should establish, through notice-and-comment rulemaking, appropriate substantive and procedural requirements for application of *County of Maui*. In such a rulemaking, EPA would be better positioned to address NPDES permitting of releases of pollutants into WOTUS via groundwater, including where releases to groundwater have been regulated or are subject to regulation by state groundwater programs or other federal regulations.

C. EPA Has Ignored Several Fundamental Issues That Are Critical to Understanding Whether and How the NPDES Program Would Apply to Potential Releases of CRL Through Groundwater to WOTUS.

In the proposal, EPA declines to address the definition of any term in the CWA, such as point source or the discharge of a pollutant because "[t]hose issues are outside the scope of this rulemaking." 88 Fed. Reg. at 18,850. But these threshold issues, such as whether a CCR impoundment or landfill constitutes a "point source" as that term is defined by the CWA, are integral to understanding how permitting authorities would apply the NPDES program to potential releases of CRL from a CCR landfill or impoundment through groundwater to WOTUS. EPA's failure to address these fundamental issues will cause great uncertainty for permitting authorities and permittees, should the Agency proceed with addressing these issues in any final rule.

Unlike *County of Maui*, where all parties agreed that the wells at issue fell within the definition of "point source," there is a question here regarding what constitutes the "point source." The CWA defines a "point source" as "any discernible, confined and discrete *conveyance*, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, rolling stack … *from which pollutants are or may be discharged*." CWA § 502(14), 33 U.S.C. § 1362(14) (emphases added). This definition expressly requires a "discernible, confined and discrete conveyance," something that carries an object to a particular place from another. *Id.* The point source "conveyance" must be the means by which pollutants are transported to and deposited into navigable waters, and the discharge of pollutants occurs only at the outfall where that conveyance adds pollutants to navigable waters.

In *Sierra Club v. Virginia Electric & Power Co.*, 903 F.3d 403, 410–11 (4th Cir. 2018) (*VEPCO*), the Fourth Circuit held that diffuse seepage of pollutants through the bottom of the company's ash pond and landfill did not qualify as the sort of "confined and discrete conveyance" required by the CWA's definition of point source. Sierra Club argued that the settling ponds were "point sources," because they were "'containers[]' one of the facilities included as examples in the definition of point source." *Id.* at 412. But the court rejected this position, noting that:

> in so arguing, Sierra Club would have us read the critical, limited word 'conveyance' out of the definition. Regardless of whether a source is a pond or some other type of container, the source must still be functioning *as a conveyance* of the pollutant into navigable waters to qualify as a point source. In this case, the diffuse seepage of water through the ponds into the soil and groundwater does not make the pond a conveyance any more than it makes the landfill or soil generally a conveyance.

Id. (emphasis in original).

Although *VEPCO* predates *County of Maui,* the Supreme Court's decision in *County of Maui* does not overturn this aspect of *VEPCO* because the parties in *County of Maui* agreed that the wells at issue were within the definition of "point source" and that groundwater was a nonpoint source. Nothing in the *County of Maui* decision, therefore, affects the Fourth Circuit's determination that diffuse seepage from an ash pond or landfill is not itself a point source.

In addition, EPA does not address *when* a pollutant released from a point source that reaches WOTUS through groundwater is a functional equivalent of a direct discharge and therefore subject to NPDES permitting requirements. A release of CRL into groundwater is not regulated under the CWA *unless* it is released from a point source and travels through groundwater to WOTUS in a manner that is the functional equivalent of a direct discharge to WOTUS under *County of Maui*. But, by not providing any interpretation or guidance on when the passage of a pollutant from a "point source" through groundwater to WOTUS is the functional equivalent of a direct discharge, EPA is, as Justice Alito warned, leaving permittees to "'feel their way on a case-by-case basis,'" where the costs of uncertainty are so great. 140 S. Ct. at 1491–92 (Alito, J., dissenting) (citing *Rapanos v. United States*, 547 U.S. 715, 758 (2006) (Roberts, C.J., concurring)). EPA dodges the many practical questions that are likely to be raised—such as what distance is close enough; how much time is fast enough; what volume is enough—as the regulated community and permitting authorities grapple with how to apply *County of Maui* to evaluate whether any potential releases of CRL from landfills or surface impoundments through groundwater reach surface waters.

1. EPA's attempt to address potential CRL releases through the NPDES program is unworkable.

More fundamentally, the NPDES program is not well-designed to regulate releases of pollutants via groundwater to WOTUS. Rather, the NPDES program focuses on treating end-of-pipe discharges directly into surface waters. *See* 40 C.F.R. § 122.45(a) (requiring that effluent limitations, standards, and prohibitions be established "for each outfall or discharge point of the permitted facility").

Establishing effluent limitations requires identifiable discharge points where the pollutant being added "into" a navigable water can be measured. This can occur only if pollutants are added into navigable waters by a "discernible, confined and discrete conveyance." CWA § 502(14), 33 U.S.C. § 1362(14). But there is typically no identifiable outfall or discharge point that can be used to develop permit conditions where there is an addition via groundwater rather than an addition from a point source. It may not be possible to determine with specificity where the groundwater connects with a navigable water, as the NPDES rules anticipate. The velocity and volume of groundwater flow also can vary based on numerous factors such as the amount of precipitation and discharges by others into the water table. There even can be reverse exchange of flows, where surface water flows into groundwater. "End of pipe" treatment technologies fail to account for unique aquifer conditions that may preclude groundwater extraction followed by treatment. That complex hydrology can confound the application and enforcement of NPDES effluent limits and monitoring requirements.

How can a permittee comply with effluent limits if it does not know where precisely the pollutant enters the groundwater or subsequently enters surface water? How can the permittee monitor the amount and concentration of pollutants entering a jurisdictional water if it cannot identify or access where the groundwater enters? What happens if the interface's location changes? Compounding these concerns are pollutants from other sources in the groundwater, whether entering the groundwater from other sources on the surface or naturally occurring as water seeps through rocks. The amount of those constituents, and the relative contributions, will vary over time based on a host of factors outside the permittee's control.

BAT determinations do not logically apply to indirect discharges via groundwater to WOTUS and should not be part of any final ELG rule. Applying BAT requirements to releases of CRL via groundwater would mean pumping and treating contaminated groundwater to BAT standards and then discharging that effluent to WOTUS in a manner that is the functional equivalent of a direct discharge. The effluent would have to be collected, treated, monitored, and reported to the same BAT and permitting standards as other similar wastewater discharged via an NPDES permitted outfall. But EPA has not included any sampling and analytical results, engineering studies, fate and transport modeling, or other data for CRL discharges through groundwater to WOTUS that purportedly are the functional equivalents of a direct discharge.

And EPA has not evaluated what changes may occur to CRL, and its constituents, as it migrates through groundwater to WOTUS.[170]

Groundwater quality is affected by numerous geochemical processes during groundwater flow through geological materials. The distinct difference between the chemical characteristics of pore water within CCR material and the characteristics of groundwater quality downgradient of CCR management units requires consideration of geochemistry. It is well documented in the literature that certain CCR constituents that are detected in pore water (typically at higher concentrations than in groundwater) can be affected by geochemical processes that occur between constituents dissolved in groundwater and geological materials through which it flows. The effects of these geochemical processes, which often result in the attenuation of CCR constituents, can explain observed differences between the characteristics of pore water and groundwater. The extent of the interactions between dissolved constituents in groundwater and geological materials ranges from limited interaction for constituents such as boron, chloride and sulfate, to strong interactions for constituents such as arsenic and cobalt.

Geochemical reactions or processes that can affect CCR constituents include: adsorption/desorption on the surfaces of metal hydroxides—an interaction whereby constituents adsorb to metal hydroxide soil minerals; cation exchange with clay minerals—a process where

[170] EPA requests comment on whether releases of CRL through groundwater are different than other wastewaters potentially subject to the final rule and whether these releases should be defined as a separate wastestream or subcategorized and how, including whether these discharges should be subject to BAT limitations on a case-by-case, BPJ basis. 88 Fed. Reg. at 18,850. As described in these comments, releases of CRL through groundwater are different from other wastewaters. Appropriate treatment of any releases of CRL through groundwater to surface waters should be evaluated on a site-specific basis to account for specific geochemistry conditions, including, but not limited to, the state of mercury, pH conditions, and other metals present. Certain treatment types, such as chemical precipitation, could create unintended consequences with non-regulated metals, if the individual CRL release is not evaluated properly.

positively charged constituents (cations) absorb to negatively charged clay minerals, subject to competition and concentrations relative to other constituents; and mineral precipitation or dissolution—a process where dissolved constituents in groundwater combine to form a soil mineral. Groundwater quality measured at a given groundwater monitoring location is a result not only of the interactions between its constituents and the geological materials through which it flows, but also of flow from upgradient sources (including background). Thus, the area upgradient of a groundwater monitoring well can be thought of as an interacting geochemical and hydrogeologic system, including: materials that contribute chemical mass to groundwater; the physical properties of the geological materials that govern direction and rate of groundwater flow; minerals in the geologic materials that can interact with constituents that are transported by groundwater; and the pH and redox conditions of groundwater. This geochemical and hydrogeological system, which includes natural and anthropogenic sources and interactions with natural geologic materials, is referred to as the upgradient system. Understanding and accounting for the geochemistry of geological materials is critical to interpret the processes influencing current conditions of groundwater chemistry, and to evaluate the effects of activities, such as capping or groundwater remediation, on the evolution of groundwater quality.

Without analytical data and an understanding of the chemical, physical, and biological characteristics of the discharged wastewater and groundwater, EPA has provided no support for its proposal that releases of CRL through groundwater to surface waters are equivalent to CRL collected in leachate collection systems, or that the proposed effluent limitations for CRL are appropriate for CRL releases from a point source through groundwater to WOTUS. Moreover, the technology-based treatment standards proposed for CRL ignore the practical benefits of in-situ treatment processes, which can be used effectively to achieve groundwater protection standards.

For the reasons explained above, EPA's proposed approach to permitting CRL releases via groundwater to surface waters would not be workable or realistic in most circumstances and would raise implications far broader than establishment of ELGs, which are not properly within the scope of this rulemaking.

2. EPA should not require or recommend submission of supplemental information to permitting authorities.

EPA recommends that "all facilities with CCR landfills or surface impoundments evaluate whether there are any … discharges that are subject to the NPDES permit program" under *County of Maui*. 88 Fed. Reg. at 18,888. If, after such evaluation, the facility determines there may be releases of CRL through groundwater to surface waters that would be a functional equivalent of a direct discharge, EPA "strongly recommends that the permittee expeditiously seek permit coverage." *Id.* To help permitting authorities "decide" whether to issue a permit authorizing such discharges, EPA "recommends" permittees submit a permit application with "sufficient information to inform that decision." *See id.* If the state permit application forms are not specific to discharges through groundwater (which most, if not all, are not), EPA "recommends that permit applicants with potential CRL discharges through groundwater ... submit a permit application using the existing form" and provide a slew of "supplemental information that would assist the permitting authority." *See id.* EPA provides a list of over 20 categories of information it recommends permittees provide to aid regulators in determining whether to issue a permit authorizing such discharges. *Id.* at 18,889.

As an initial matter, UWAG expects that few permittees have facilities with CCR landfills or subject impoundments that have potential CRL releases via groundwater to surface waters that would amount to a functional equivalent of a discharge under *County of Maui*, and UWAG expects that EPA would have the same understanding. However, UWAG disagrees with EPA's recommendations to solicit this information because such requirements could be misconstrued or misinterpreted and place significant (and unnecessary) burdens on permittees and regulators.

As such, and given the regulatory protections already in place for discharges of CRL to groundwater under the CCR Rule and/or state programs, EPA should not recommend or require facilities with CCR landfills or surface impoundments to submit these 20 categories of information regarding the potential presence of leachate in groundwater. EPA appears to believe that "much of the supplemental data and information described below … is already required and made publicly available under the CCR rule[, and therefore] … the incremental burden to facilities … [is] minimal." *Id.* at 18,889. Rather than minimizing the burden to facilities, this simply raises the question why EPA would recommend submission of duplicative information and burden both permittees and permitting authorities if this information is already being evaluated under a separate (and more appropriate) regulatory scheme.

EPA concedes that this process can be "time consuming and intensive," *id.* at 18,889, for both permittees and permitting agencies. Indeed, it would be difficult and time-consuming for UWAG members to collect and provide this detailed information and to determine equivalency to an end-of-pipe discharge. Some of the "recommended" information may already be required for facilities under the CCR Rule, but other categories of suggested technical information are not.[171] And even where the information already exists for CCR regulated units, submitting the

[171] For example, creation and reporting of isoconcentration plots is not required under the CCR Rule. And the approach of using a minimum, maximum and average for several of the recommended categories of data over a large and undefined period of time is inconsistent with

full list of data and compiling a functional equivalent discharge evaluation as outlined in the proposal would require concerted effort. Evaluating sorbents and constituent mass flux alone could take several months of review.

EPA also solicits comment on whether it should alternatively obtain the "recommended" information through a series of CWA Section 308 information request letters. *Id.* at 18,890. As explained above, UWAG does not agree that EPA should require submission of this information at all, nor does UWAG agree that EPA should do so through Section 308 information requests. Moreover, it is inconsistent for EPA to state that "much of the supplemental data and information … is already required and made publicly available under the CCR rule," *id.* at 18,889, and, at the same time, request comment on whether the Agency should expend time and resources to obtain through Section 308 information requests information that it contends is already available.

3. The costs and regulatory burdens associated with requiring NPDES permits for potential releases of CRL via groundwater to WOTUS would be exorbitant.

EPA's Proposal fails to accurately account for the substantial costs and regulatory burdens imposed on permitting authorities and permittees. Requiring submission of this data (and potentially, NPDES permits) for such diffuse sources would result in a substantial administrative burden to permitting agencies. Evaluating those applications and issuing permits would impose a previously unforeseen and crushing workload on states that are (with a few exceptions) responsible for issuing the majority of NPDES permits.

---

common subsurface data analysis and evaluation procedures. If a final rule incorporates a list of recommended general and technical information of this nature, EPA should re-evaluate the list, consider whether each item provides appropriate information and provide guidance on acceptable approaches for the data requested, and assess the costs of creating and compiling the information.

Before *County of Maui* was decided, state environmental protection agencies spent "nearly 1.6 million hours and nearly 70 million dollars each year processing NPDES permits."[172] The states warned that "[t]he load of NPDES permits that may need to be issued and enforced by state agencies is likely to increase astronomically" if the Supreme Court required permits for discharges of pollutants via groundwater to surface waters and noted that "[t]hese increased burdens threaten to divert scarce resources away from state-specific programs that already protect the Nation's waters…." West Virginia et al. *Amici* Br. at 6.

The states also highlighted the practical implementation problems they would face in trying to implement a permitting program given "the diffuse nature of groundwater dispersal," explaining that states "likely would not be able to complete this torrent of new NPDES permitting tasks with any clarity, and certainly not without considerable, unjustifiable cost." *Id.* at 32. Indeed, the proposal raises numerous questions as to how permitting authorities would develop draft permits, solicit and address comments, and issue final permits. To name just a few, even if NPDES permit writers could identify a discharge point, where would the owner or operator conduct necessary sampling or monitoring? The locations could be beyond the owner or operator's control. And how would the permit writer distinguish between pollutants released from the "point source" and pollutants from sources further up the groundwater gradient?

As the states explained in their *amici* brief in *County of Maui,* "the direction and speed of groundwater flow [which] depend on geography and gravity, not design" would "make it extremely challenging to draft a permit with precise discharge parameters," much less "monitor

---

[172] *See* Brief of *Amici Curiae* State of West Virginia et al. in Support of Petitioner, *County of Maui v. Hawai'I Wildlife Fund*, No. 18-260, at 29 & n.8 (May 16, 2019) (citing EPA ICR No. 0229.21 Supporting Statement, Information Collection Request for National Pollutant Discharge Elimination System (NPDES) Program (Renewal), EPA ICR at *17, tbl. 12.1 (Dec. 2015), https://www.reginfo.gov/public/do/ DownloadDocument?objectID=60917402)).

compliance." *Id.* at 32–33. While state permitting authorities are readily able to "measure outflow from a pipe into navigable waters to ensure discharge levels are compliant with an NPDES permit … track[ing] the volume of pollutants that reach navigable waters after seeping into the ground and joining the complex subsurface network of groundwater flows" is another issue entirely. *Id.* at 33. Thus, "[a]t a minimum, States overseeing an NPDES regime that … [applies to] groundwater would likely need to procure exp[e]nsive and time-consuming environmental impact studies in order to obtain a quantum of data that could (at least conceivably) provide them with the sort of precision, coherence, and scientific integrity necessary.…" *Id.*

If EPA issues a final ELG rule that recommends or requires that permitting authorities review and potentially "process and issue a swell of technologically challenging and complex NPDES permits to sources that have never been subject to that process," *id.* at 33, the permitting process would become even more burdensome and expensive than it already is. And regulated entities would be placed in an untenable position. Even if the permitting authorities agree that a functionally equivalent discharge is not present and an NPDES permit is unnecessary, that determination could be second-guessed in a citizen suit.

These regulatory and permitting costs are separate from, and in addition to, EPA's evaluation of costs associated with treating releases of CRL from CCR landfills and surface impoundments that are discharged through groundwater. EPA, Evaluation of Potential CRL in Groundwater, EPA-HQ-OW-2009-0819-9678 (DCN SE10250). EPA developed a "methodology … [to] estimate[e] the maximum amount of groundwater potentially impacted by CRL and an estimate of the rate at which groundwater could be pumped to capture leachate from CCR landfills and surface impoundments … that may seep into groundwater and ultimately reach surface water." *Id.* at 1. EPA's analysis recognizes that "there may be limited ability to treat leachate in groundwater in-situ for some contaminants," and, as a result, it would likely be necessary to pump leachate-laden groundwater from the ground prior to treatment. *Id.* at 2. Regardless of which technology option for direct discharge of CRL is applied, pursuant to EPA's analysis, the costs would be exorbitant. *Id.* at 12–13, 32–57.

4. EPA should not create nationwide requirements for CRL annual monitoring reports and recordkeeping.

EPA proposes that a "facility treating combustion residual leachate in groundwater … shall file an annual combustion residual leachate monitoring report each calendar year to the permitting authority or control authority for indirect discharges of the treated CRL." *See* 88 Fed. Reg. at 18,902 (proposed 40 C.F.R. § 423.19(k)(1), *Annual Combustion Residual Leachate Monitoring Report*). This annual reporting requirement would be implemented via NPDES permits that authorize releases of CRL through groundwater. *Id.* at 18,891.

Specifically, in the proposed regulatory text, EPA would require monitoring data for each pollutant identified in "Table 1 to Paragraph (k)(2)(iv)," and "[g]roundwater monitoring data as the [CRL] leaves each of the landfills and surface impoundments discharging through groundwater" and "[g]roundwater monitoring at the point the [CRL] enters each surface waterbody," with a description of the location of monitoring wells, screening depth, and frequency of sampling. *See* proposed 40 C.F.R. § 423.19(k)(2), 88 Fed. Reg. at 18,903. But there is a significant lack of detail regarding these requirements and how they would be implemented.

And, as EPA correctly notes, the 2015 CCR Rule "set recordkeeping and reporting requirements, as well as requirements for each plant to establish and post specific information to a publicly accessible website." 88 Fed. Reg. at 18,831. Therefore, given the potential burden associated with collecting and submitting unnecessary information and the duplication of these proposed monitoring requirements with those under the CCR Rule,[173] EPA should not include any specific monitoring report requirements in a final rule. Instead, EPA should defer to permitting authorities to determine the scope, types of monitoring information to be included in any permits, and the appropriate timeframes for submitting these reports, depending on the site-specific circumstances.[174]

VI. Comments on Proposed BATW Provisions

A. EPA Should Maintain its 2020 Determination That a High Recycle Rate BATW System With a Limited Purge Is the Appropriate Model Technology for BATW BAT Limits.

EPA's 2020 determination that a high recycle rate BATW system with a limited purge is the appropriate model technology for BATW BAT limits remains accurate. The factors EPA is to consider in setting BAT weigh in favor of maintaining the 2020 BATW determination, including "the process employed," "the engineering aspects of the application of various types of control techniques," "process changes," "the cost of achieving such effluent reduction," and "such other factors as the Administrator deems appropriate." CWA § 304(b)(2)(B), 33 U.S.C.

---

[173] There may be duplicative monitoring requirements between the Proposed ELG Rule and the CCR Rule. For example, both arsenic and mercury are listed as Appendix IV constituents under the CCR Rule; however, the sampling methods for arsenic and mercury under RCRA differ from the CWA sampling methods. *Compare* 40 C.F.R. pt. 257 *with* 40 C.F.R. pt. 136.

[174] As explained herein, EPA should not include any specific monitoring report requirements in a final rule. However, if EPA does so, it should provide in the preamble additional information to explain the specific requirements in proposed § 423.19 (k)(1), *Annual Combustion Residual Leachate Monitoring Report.* For example, the approach of using a minimum, maximum, and average for several of the data requests over a large and undefined period of time is inconsistent with common subsurface data analysis and evaluation procedures. This proposed monitoring requirement should be reevaluated because it is not informative of true subsurface conditions and would incur unnecessary expenditure of resources to monitor, compile, and report.

§ 1314(b)(2)(B). As EPA recognized in the 2020 Rule, while some facilities with wet BA systems can operate as ZLD systems, most systems require some discharges to manage maintenance issues, precipitation events, water imbalances, and water chemistry imbalances.

EPA has not provided new information that justifies its change in position. At the core of the 2020 Rule was EPA's understanding that it has been difficult for wet systems to operate a true closed-loop system or achieve complete recycle. 85 Fed. Reg. at 64,669. EPA suggests that "most facilities" have installed dry handling or closed-loop systems but does not address whether (and if so, how many of) the facilities with "closed-loop systems" have achieved complete recycle versus those that are discharging a small percentage consistent with the 2020 Rule's standards.[175] Throughout its discussion of BATW, instead of putting forth new data showing that ZLD is now more achievable, the proposal relies on puzzling double negative statements about how nothing in the record proves that the challenges of closed-loop systems cannot be addressed. *See, e.g.,* 88 Fed. Reg. at 18,845 ("There is no record evidence that infrequent maintenance events cannot be overcome with reasonable steps and, therefore, this concern does not provide a basis for rejecting closed-loop systems at BAT."). These vague assertions are insufficient to support EPA's proposed BAT determination and fail to meet EPA's obligation to provide a reasoned explanation for its change in position from the 2020 Rule. *See State Farm*, 463 U.S. at 43; *Fox Television*, 556 U.S. at 516.

---

[175] 88 Fed. Reg. at 18,844. EPA notes that "[a]t the time of the 2020 rule, EPA estimated that more than 75 percent of plants already employed dry handling systems or wet sluicing systems in a closed-loop manner, or had announced plans to switch to such systems in the near future." *Id.* EPA states, without any citation or reference to any document in the record that "[o]ne vendor estimates that only seven ash conversions remain in the entire industry." *Id.* n.65. This unsupported estimate for remaining ash conversions tells us nothing about the amount of facilities that are operating high-recycle rate systems versus facilities that are operating truly closed-loop systems. EPA does not appear to have provided any statistics on this point.

The system challenges EPA identified in the 2020 Rule remain. Allowing a blowdown purge for BATW provides operational flexibility, improves the longevity of recirculating systems (and thus their overall feasibility), avoids significant costs, and has a minimal environmental impact. EPA should maintain its 2020 BAT determination requiring a high recycle rate system with a limited purge.

If EPA does not maintain its 2020 determination, it should make other critical adjustments to the BATW provisions, including broadening the exclusion for maintenance events and explicitly allowing for one-time purges for large storm events.

1. For many facilities, a limited purge is needed to operate the BATW system reliably and efficiently.

The ability to blow down a small sidestream from BATW recirculating systems under certain limited conditions is critical to allow facilities to operate their BATW systems in ways that increase system reliability and energy efficiency and avoid excessive corrosion, scaling, and premature failure of equipment. Largely ignoring the record developed for the 2020 Rule and even more recent information in the record,[176] EPA dismisses the challenges identified in the 2020 Rule with maintaining closed-loop systems and, without support, asserts that these issues can be managed with the expenditure of additional costs. *See* 88 Fed. Reg. at 18,845. Even where these challenges can be managed, EPA acknowledges that the additional expenditures

[176] *See, e.g.,* Memorandum from U.S. EPA, to Steam Electric Record – EPA-HQ-OW-2009-0819, Notes from Meetings with UCC Environmental (UCC) June 10 and October 13, 2022, and Other UCC Correspondence at 2–3 (Feb. 15, 2023), EPA-HQ-OW-2009-0819-9963 (DCN SE10457) (EPA UCC Envtl. Notes) ("UCC did state that allowing for flexibility and maintenance is 'the right thing to do' for maintaining closed loop bottom ash handling systems. UCC also stated that the ten percent purge provision is helpful to maintain closed loop operations at those plants with difficult water chemistry....").

would be substantial. UWAG addresses each of the challenges of maintaining closed-loop BATW systems identified in the 2020 Rule in turn.

a. Blowdown is needed for managing non-BATW flows.

A small amount of blowdown is often needed to manage non-BATW flows, such as cooling water, seal trough water, wastewater from equipment cleaning, and/or boiler tube leaks.[177] Although the 2020 Rule found that non-BATW inflows have the potential to result in water imbalances within a closed-loop system, in this proposal, EPA asserts, without support, that closed-loop systems can be sized to handle these additional wastestreams. 88 Fed. Reg. at 18,845. In some cases, these wastestreams may be difficult to segregate, and some amount of purge is required. Sizing up the system to accommodate such non-BATW inflows could be challenging for facilities that are already in the process of complying with the 2020 Rule and could result in significant costs. *See* UWAG 2020 Comments at 17.

b. Discharge allowance is needed to manage precipitation-related inflows.

Some amount of discharge allowance may be needed in some cases to manage precipitation-related inflows. *See, e.g.,* EPRI Comments at 88. Although the 2020 Rule found

[177] *See, e.g.,* EPRI Comments at 85–86 (highlighting plants with high recycle rate systems that have inflows that exceed the ability of BA systems to reuse the plant's wastewater); Memorandum from U.S. EPA, to Steam Electric Record – EPA-HQ-OW-2009-0819, Notes from Meeting with EPA, UCC, and ERG on August 26, 2021 at 6 (Jan. 14, 2022), EPA-HQ-OW-2009-0819-9696 (DCN SE10368) (blowdown is necessary in some instances when outage wash water displaces transport water); EPRI, *Guidance Document for Management of Closed-Loop Bottom Ash Handling Water in Compliance with the 2015 Effluent Limitations Guidelines (ELGs)*, 3002008345, at 4-2 (Dec. 2016), EPA-HQ-OW-2009-0819-7362 (DCN SE06963) (EPRI 2016) (In discussing the challenges of inclusion of non-transport waters in the closed-loop system, EPRI provides the following examples: "[A]t Plants A and F, 'new' water is used for the pump seals of pumps in the loop, and the seal water flows into the loop mixing with the ash transport water because it cannot be segregated from discharging to the closed-loop system. Recirculated water supply is not used because the seal water quality requirements cannot tolerate the solids in the recirculated water supply.").

that managing precipitation-related inflows has the potential to result in water imbalances in the BA handling systems, in this Proposal, EPA asserts that precipitation-related inflows can be adequately managed with design improvements, including the use of roofing. 88 Fed. Reg. at 18,845. While systems are often engineered with extra capacity to handle rainfall and runoff from a certain size precipitation event, these events may occur back-to-back, or plants may receive events with higher rates of accumulation beyond what the plant was designed to handle. *See* 85 Fed. Reg. at 64,670 n.76; UWAG 2020 Comments at 16–18. Even where facilities have installed large tanks for system volume management, there are concerns with precipitation during high intensity events (such as tropical storms) or during extended periods of reduced or no generation.[178] As UWAG has previously explained, enclosing a remote mechanical drag system (MDS) to eliminate precipitation inflows is impractical and adds significant costs. *See* UWAG 2020 Comments at 16 n.14. EPA does not attempt to quantify all of the costs that would be involved in enclosing remote MDSs.[179]

If EPA does not maintain the 2020 Rule's allowance of up to 10 percent of volumetric purge, EPA at least should allow for unlimited one-time purges due to large precipitation events "where drains or other precipitation-collection components may not be amenable to roofs or other covers." *See* 88 Fed. Reg. at 18,845. EPA seeks input on the appropriate storm event for

[178] *See, e.g.,* Duke Energy, Duke Energy Response to Voluntary Information Request (Feb. 28, 2022), EPA-HQ-OW-2009-0819-9087 (DCN SE09680).

[179] In estimating the costs of the high recycle rate system under Proposal Options 1 and 2, EPA added a plant-level capital cost of $1,146,630 (2021$) to build a roof over the remote MDS to mitigate stormwater contributions to the system. 2023 TDD at 44. EPA assumed that O&M costs for the roof were zero "as the structure is only intended to protect from stormwater and does not have heating, ventilation, or air conditioning." *Id.* However, remote MDSs contain heated water and, as a result, an enclosed remote MDS likely would require an enhanced ventilation system to reduce condensation on walls and other surfaces, which could cause excess corrosion and potential safety issues with limited visibility. The actual costs are likely more than what is represented by EPA's cost estimates.

such an allowance. *Id.* As it did in the 2020 Rule, EPA should base its allowance of precipitation-related purge on a 10-year, 24-hour storm event, which is a well-defined metric and already in use for the management of coal pile runoff within the steam electric industry. *See* UWAG 2020 Comments at 18–19.

c. Purge allowance is needed for maintenance events.

Some amount of discharge is needed in certain scenarios for maintenance events that are not covered by the exemption for "minor maintenance events." The 2020 Rule allowed for some discharge related to maintenance events that fall outside the 2015 Rule's exemption for "minor maintenance" or "leaks" from the BATW definition. Maintenance events, such as draining the remote MDS to repair the drag chain or draining for scheduled inspections or other maintenance, require a large amount of transport water to be transferred out of the equipment. Maintenance-related activities can require emptying certain equipment that may involve draining water in the range of hundreds or thousands of gallons. EPRI, *Closed-Loop Bottom Ash Transport Water: Costs and Benefits to Managing Purges,* 3002013706, at 1-1 (Sept. 2018), EPA-HQ-OW-2009-0819-7346 (DCN SE06920) (EPRI 2018). As EPA's proposal acknowledges, EPRI (2018) documented several major maintenance events at facilities using remote BA settling devices that required some amount of purge. EPA suggests in this proposal that, when maintenance wastewater volumes are too large to be managed in existing maintenance tanks, "utilities can, at additional cost, lease storage tanks for short-term maintenance." 88 Fed. Reg. at 18,845. While temporary storage tanks may be an option in some scenarios, facilities require lead time to rent large tanks, and requiring them to do so would limit operational flexibility. As EPRI points out, in many cases, it would require dozens of tanks (if they are available and if the facility has sufficient flat land available to store them) to manage purge volumes associated with draining remote MDSs for maintenance activities. *See* EPRI Comments at 87. In addition, some plants have observed solids buildup in storage tanks due to closed-loop systems' solids carry-over, which leads to reduced residence time of the storage tanks. *See id.*

If EPA does not adopt high-rate recycle systems as BAT, it should, at a minimum, revise the definition of BATW in section 423.11(p) to exempt maintenance events. The current definition of BATW exempts "minor maintenance events." *See* 40 C.F.R. § 423.11(p) ("Transport water does not include low volume, short duration discharges of wastewater from minor leaks (e.g., leaks from valve packing, pipe flanges, or piping), minor maintenance events (e.g., replacement of valves or pipe sections), FGD paste equipment cleaning water, or bottom ash purge water[.]"). The proposal solicits comment on whether EPA should expand the exemption for minor maintenance events. 88 Fed. Reg. at 18,845. Such non-minor maintenance events could include maintenance-related activities that require emptying equipment within the BATW system. Although these may occur infrequently, discharge may be required for such events.[180] If the final rule does not allow for some amount of purge for high recycle rate systems to address maintenance events, it should revise the definition of BATW to remove the limitation to "minor" maintenance and exempt "maintenance events." Although it would be appropriate for EPA to require information regarding such a maintenance event (*e.g.*, permittee could be required to note in the discharge log the type of maintenance being performed), any requirement for a "demonstration that the maintenance water could not be managed within the system," *see*

---

[180] Examples of maintenance events that are not included in EPA's definition of "minor maintenance events" include (but are not limited to): BA hopper refractory or steel hopper plate replacement; BA hopper enclosure replacement or sluice door maintenance; remote MDS wear plate or steel hopper plate replacement; closed-loop system surge tank plate steel replacement or maintenance; or MDS mechanical failure (*e.g.*, chain derailment), wear plate replacement, or steel hopper plate replacement or maintenance. *See* EPRI 2016 at 4–3 to 4–4; 2015 TDD at 2-7.

88 Fed. Reg. at 18,845, would impose a vague restriction and create unnecessary hurdles for operators that would limit the utility of the exemption.

d. Discharge is needed to manage water chemistry.

Finally, for some high recycle rate BATW systems, some amount of discharge is needed to manage water chemistry.[181] Approximately half of the plants surveyed by EPRI in 2019 observed acidity in the recirculation system originating from the seal water or cooling water in the hopper overflow that comingles with BATW and can be difficult to segregate. *See* EPRI Comments at 85. To address the resulting increases in acidity, which coincide with increases in sulfates, a combination of chemical treatment and purging is often required to avoid corrosive or scaling conditions. *Id.* For some plants, the transition from operating as a high recycle rate system to closed-loop results in scaling and corrosion issues requiring full system outages and component replacements.[182]

Although the 2020 Rule allowed for limited discharges to allow facilities to maintain water system chemistry, in this proposal, EPA suggests that: corrosivity can be managed through pH adjustment; high scaling potential can be managed with acid and/or antiscalants; fine particulates could be further settled out with polymers and other coagulants; and "where all else fails, the same slipstream of purge … could be treated with RO and recycled back in as clean makeup water." 88 Fed. Reg. at 18,846. These measures do not always solve the problem. For

[181] *See, e.g.,* UCC Envtl. Notes at 2–3, EPA-HQ-OW-2009-0819-9963 (DCN SE10457) (noting that the purge allowed by the 2020 Rule is very helpful for "plants with challenging water chemistry"); Duke Energy Response to Voluntary Information Request at 2, EPA-HQ-OW-2009-0819-9087 (DCN SE09680) (stating "[l]ower than predicted pH in the recirculating water has resulted in the replacement of some piping and installation of pH (caustic) adjustment" and "higher purges are needed to maintain scaling indices within acceptable ranges.").

[182] *See, e.g.,* Memorandum from U.S. EPA to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819, Notes from Meeting with Burns & McDonnell on September 10, 2021 at 2 (Jan. 14, 2022), EPA-HQ-OW-2009-0819-9653 (DCN SE10248).

example, although scaling can sometimes be managed with antiscalants or pH control, if the sulfuric acid demand is high enough or is concentrated in the closed-loop system via evaporation, then calcium sulfate (another scalant) could theoretically form, in which case the plant would need to use an alternative acid (which could contribute to corrosivity issues) or purge water from the system to reduce the concentration of scaling ions. EPRI 2018 at 1–2. Moreover, as EPRI points out, using reverse osmosis (RO) treatment to concentrate contaminants in purge water to a brine would require brine encapsulation and disposal, requiring fly ash supply that is already challenged by the proposal's requirement for FGD membrane treatment. EPRI Comments at 86.

2. The environmental impact of a 10 percent-by-volume discharge allowance is minimal.

As UWAG noted in its 2020 comments, the 2020 Rule's allowance of 10 percent purge would remove approximately 93.4 percent of the TWPEs attributable to BATW compared to pre-2015 levels. *See* UWAG 2020 Comments at 51; *see also* EPRI Comments at 88 (high recycle rate system with purge "eliminates the significant majority of pollutants discharged"). EPA estimated in the 2020 Rule that actual purge rates necessary on a day-to-day basis may be less than one percent of the system's volume, with higher purges necessary at less frequent intervals due to precipitation and maintenance. *See* 2020 Response to Comments at 2-128. Even assuming the proposed maximum purge allowed by the 2020 Rule, however, "the average gallons per day released by high recycle rate systems will be two percent of the average gallons per day released by surface impoundments, and therefore will also be 1.5 percent of the pollutant releases expected from surface impoundments." *Id.* Therefore, industry-wide, EPA estimated "this combination of reduced volume and increased recycling reduces discharges by 366 million pounds of pollutants per year, and thus makes reasonable further progress toward the CWA goal to eliminate the discharge of pollutants." *Id.* (citing CWA §§ 101(a), 301(b)(2)(A), 33 U.S.C. §§ 1251(a), 1311(b)(2)(A)). It is still the case that allowing a purge provides the majority of pollutant reduction that would be achieved by requiring ZLD, with the remaining pollutants being very low toxicity. *See* EPRI Comments at 88.

EPA's prior conclusion remains sound based on the minimal environmental impact of a site-specific purge allowance not to exceed 10 percent. The amount of BATW discharge in a high recycle rate system would be a small fraction of the amount of BA water previously discharged at plants not recycling their BATW and would result in only a minimal environmental improvement over closed-loop systems. Based on the 2023 TDD estimates of pollutant loadings and removal, under Option 2, which would establish the 2020 Rule's volumetric purge limitation for BATW based on high recycle rate systems, the estimated total industry-level pollutant removals is approximately 575 million lb/year. *See* 2023 TDD at 64, Tbl. 21. Under Option 3, which would establish a BATW ZLD requirement, the estimated total industry pollutant removals is approximately 584 million lb/year. *See id.* That is just a 1.6 percent increase in total industry pollutant removals that would be gained by requiring ZLD for BATW. Further, EPRI notes that EPA has overestimated the pollutant reduction that would be achieved by requiring ZLD for BATW by approximately 65 percent. *See* EPRI Comments at 84–85. Based on EPRI's calculations, the industrywide pollutant reduction achieved from ZLD for BATW would be approximately 9 million lb/year (or lower), not 26 million lb/yr as EPA estimates. *Id.* at 85.[183]

[183] Consideration of pollutant concentrations in establishing BAT for BATW is appropriate here. In the *SWEPCo* case, the court found fault with EPA setting BAT for leachate equal to existing BPT, finding that there was no reasonable further progress toward the Act's goal of eliminating pollutants. *See Sw. Elec. Power Co. v. EPA*, 920 F.3d 999, 1027 (5th Cir. 2019) (*SWEPCo*). The court also rejected comparison of leachate pollutant load to pollutant load from all steam electric facilities. *Id.* In contrast, EPA's 2020 BAT determination for BATW did not set BAT equal to BPT, but required high recycle rate model technology, with stringent flow

As EPRI previously noted, "[a]llowing a purge that is a fraction of the current bottom ash transport water discharge would achieve nearly all of the environmental benefits of a complete ban on transport water discharge." EPRI 2018 at vii.[184]

EPA should conclude that high recycle rate systems with a limited site-specific purge, which provides the majority of pollutant reduction that would be achieved by requiring ZLD for BATW, would be consistent with EPA's obligation to select a technology that "will result in reasonable further progress" toward pollutant discharge elimination. CWA § 301(b)(2)(A), 33 U.S.C. § 1311(b)(2)(A).

3. The costs associated with complete recycle BATW systems are not justified.

The costs associated with complete recycle BATW systems are not justified under CWA § 304(b)(2)(B), 33 U.S.C. § 1314(b)(2)(B) (one of the factors for EPA to consider in setting BAT is "the cost of achieving such effluent reduction"). EPA asserts that dry handling and closed-loop systems are economically achievable without explaining what has changed since the 2020 Rule that now supports that determination. Instead, EPA merely asserts that it "never found that the additional costs to achieve zero discharge were not economically achievable" and points to its flawed Integrated Planning Model (IPM) analysis. 88 Fed. Reg. at 18,846.[185]

---

limitations on the purge. In addition, the relevant comparison here for considering pollutant concentrations is a comparison of BATW pollutant loads. Even with EPA's apparently inflated data, the evaluation of BATW pollutant concentrations continues to demonstrate that high recycle systems with limited site-specific purge is BAT.

[184] Based on data collected at seven sites, EPRI calculated the TWPE of estimated purges from partially closed-loop BA dewatering systems. EPRI found that the average of TWPE per year of purge water (accounting for background water quality where known) was only 2.5 percent of EPA's 2015 calculated TWPE per year per plant. *See* EPRI 2018 at 3-3.

[185] See the discussion in Section X regarding the flaws in EPA's economic assessment of the rule's industry-wide costs and impacts.

As a threshold matter, EPA improperly used the 2020 Rule as a baseline in evaluating the costs of the proposal even though some facilities are still in the process of installing the technologies required by the 2020 Rule. EPA therefore found that BA dischargers will have installed MDSs or remote MDS and therefore would incur no costs to install high recycle rate systems. 2023 TDD at 41, 44. To evaluate the costs of achieving the proposed ZLD BATW, EPA started with the assumption that facilities already have installed dry handling or high recycle rate systems. *Id.* at 41. EPA found that the incremental compliance costs would be limited to the capital and O&M costs for RO. *Id.* at 41, 48. As EPRI points out, EPA underestimates significantly the total cost to the industry to implement an RO system for BA purge. *See* EPRI Comments at 86. Moreover, as discussed in more detail in section III.C, many facilities are still in the process of complying with the 2020 Rule's BATW requirements consistent with their permits' "as soon as possible" dates before December 31, 2025. EPA's calculations do not account for that reality.

EPA estimates that implementation costs for the industry (a total of 42 plants) for going from a high recycle rate system to ZLD for BATW are as follows (in millions of pre-tax 2021 dollars):

Regulatory Options	Capital Cost	Annual O&M Cost
1 or 2 (HRR systems)	$21.90	$1.97
3 (ZLD)	$257.00	$27.30

See 2023 TDD at 51, Tbl. 11. Based on these estimates, as compared to the high recycle rate systems as authorized under the 2020 Rule, implementation of ZLD for BATW would result in additional implementation costs of approximately $235.1 million in capital costs and approximately $25.33 million in annual O&M. *See id.* EPA estimates that the total annualized compliance costs for BATW ZLD would be $45 million per year (pre-tax) as compared to $3 million per year (pre-tax) for high recycle rate systems. *See* RIA at 3-7, Tbl. 3-2.[186] Therefore, even using EPA's flawed baseline, a comparison of EPA's industry-wide costs for high recycle rate systems to ZLD demonstrates a significant cost differential between these options without commensurate environmental benefit.[187]

Based on these analyses and consistent with the well-supported findings of the 2020 Rule, EPA should conclude that high recycle rate BATW systems are economically achievable and reasonable, while closed-loop systems are not. EPA has not provided sufficient information in this proposal to support a departure from its 2020 determination that a high recycle rate system with limited volumetric purge allowance is BAT for BATW. Maintaining the 2020 BAT determination for BATW provides operational flexibility, improves the feasibility for BATW recirculating systems, avoids significant costs, and results in substantial progress toward pollutant discharge elimination.

B. UWAG Supports EPA Maintaining its Position That Quench Water Is Not "Bottom Ash Transport Water" or "Bottom Ash Purge Water."

As EPA's proposal notes, many EGUs with dry handling (through under-boiler MDS or compact submerged conveyor systems) rely on wet hoppers that catch and cool hot BA in quench water (also referred to as contact water). 88 Fed. Reg. at 18,848. UWAG supports EPA's acknowledgement in the proposal that BA quench water is considered to be low volume

---

[186] Whereas, EPA estimated for the 2020 Rule that it would cost the industry approximately $63 million per year in after-tax costs to go from a high recycle rate BATW system with a volumetric purge to a ZLD, in this proposal, EPA has "update[ed] these conservative cost estimates to $45 million per year pre-tax." 88 Fed. Reg. at 18,846. EPA proposes to find that these costs are economically achievable. *Id.* These updated cost estimates appear to significantly underestimate the total costs to industry to implement RO for bottom ash purge. *See* EPRI Comments at 86.

[187] *See, e.g.,* EPRI 2018 at vii ("Meeting the elimination of discharge requirement would be costly to plants and could restrict operational flexibility without a concomitant improvement in impacts to the environment.")

waste and not "transport water" because "the water is not used to transport the BA." *Id.* UWAG urges EPA to maintain that position, which facilities have relied on since the 2015 and 2020 Rules.

The proposal solicits comment on "whether [EPA] should continue to allow (or alternatively not allow, through a zero-discharge requirement) a purge for both contact water and transport water." *Id.* at 18,848. It also seeks comment on whether the purge of contact water, which is not covered by the definition of transport water in 40 C.F.R. § 423.11(p), should be included as "bottom ash purge water" under section 423.11(cc) and thus subject to a BPJ analysis. *Id.* at 18,848. EPA asserts in the proposal, without data, that "there may be little difference in [pollutant] concentration[s] between transport water and contact water." *See id.* (noting an "absence of data from actual under-boiler purges").

UWAG strongly urges EPA to maintain its current position on quench water. Quench water is not BA transport water—it is not used to transport BA, as EPA acknowledges. *Id*. at 18,848. Nor is it BA purge water—it is not a purge—and therefore it would be inappropriate to take a different position in this proposal, without support, to include quench water as "bottom ash purge water" under section 423.11(cc) that is subject to a BPJ analysis by the permitting authority.

EPA presents no basis for a change in approach on quench water. As EPA noted when it determined that this quench water and overflow should not be included in the "transport water" definition, the water is not used to transport the BA, resulting in decreased contact times and thus decreased pollutant concentrations from the BA. *Id.* EPA does not actually evaluate pollutant concentrations from contact water in this Proposal. *See, e.g.,* 2023 TDD at 58–59 (evaluating pollutant concentrations for transport water only). Quench water is generally a minor amount of flow with low pollutant concentrations. At the Longview Power Plant, for example, the contact water blowdown from the BATW system's under boiler conveyor is a miniscule flow, just 15 gpm less moisture in the ash.[188]

Reversing EPA's previous determinations that quench water overflow from MDSs and submerged grind conveyors (SGCs) is not "transport water" would disadvantage those companies who proactively installed technologies that use smaller volumes of water than conventional BATW systems. A number of facilities already have installed dry ash handling systems with an MDS. Based on the 2015 and 2020 Rules, these facilities reasonably understood that they would not have BATW discharge. If EPA were to change course and treat quench water and overflow as "transport water," these facilities could be required to implement treatment they did not anticipate. Reversing course on quench water also would disincentivize the future installation of such systems.

Given the lower pollutant concentrations and that the additional cost to regulatory agencies and the industry to regulate and treat such a wastestream is disproportional to the environmental benefit, the definition of "transport water" (40 C.F.R. § 423.11(p)) should continue to exclude quench water and overflow from MDSs and SGCs. And even if EPA retains the 2020 Rule's BATW purge allowance under 40 C.F.R. § 423.13(k)(2)(i), it should not seek to add quench water and overflow to the "bottom ash purge water" definition under section 423.11(cc).

---

[188] *See* Longview Water Balance Diagram (Dec. 20, 2019), https://apps.dep.wv.gov/webapp/_dep/securearea/public_query/ePermittingApplicationSearchPage.cfm, (enter "Longview" in the "Identify Applicant" field, click "Reissue NPDES Industrial" for Permit ID WV0116238, click "Attachments," click File Name "Water Balance Diagram.pdf").

VII. Comments on Proposed Legacy Wastewater Provisions

A. New ELGs Properly Apply Only to Wastewater Generated After Their Applicability Date.

LWW discharges should be governed by ELGs in effect at the time the wastestream is generated. To ensure regulated facilities can reasonably know, plan for, and treat wastewaters in accordance with governing ELGs, new ELGs should not apply retroactively to discharges of LWW generated prior to the ELG's effective date.

1. EPA proposes to newly apply Part 423 to decant and dewatering wastewaters at inactive or retired power plants.

EPA proposes to apply Part 423 to discharges of decant and dewatering wastewaters at inactive or retired power plants because the discharge of these wastewaters "'result[s] from the operation of a generating unit.'" 88 Fed. Reg. at 18,854. EPA solicits comment on whether any wastewaters at retired plants, such as LWW, should be explicitly included or excluded. UWAG submits that ELGs should not apply retroactively to wastewaters generated (and typically already treated under prior ELGs) before new ELGs are promulgated.

2. The applicability date for ELGs should be consistent for all types of discharges from existing sources regulated under Part 423.

EPA should apply new ELGs to LWW in the same manner it applies them to its component wastestreams, namely, to wastewater generated "on and after" the date on which the new ELGs become applicable. As EPA explains, "Legacy wastewater can be comprised of FGD wastewater, BA transport water, FA transport water, CRL, gasification wastewater and/or FGMC wastewater generated before the 'as soon as possible' date that more stringent effluent limitations from the 2015 or 2020 rules would apply." *Id.* at 18,836. In the proposed rule, EPA proposes to apply new ELGs for BATW, FGDW, and CRL to wastewater that is generated "on and after" the date on which the new ELGs become applicable. *See id.* at 18,897–98 (proposed

40 C.F.R. § 423.13(k)(1)(i), BATW; 40 C.F.R. § 423.13(g)(1)(i), FGDW; and 40 C.F.R. § 423.13(l), CRL).

Thus, EPA proposes to base the applicability date of new ELG limits for BATW, FGDW and CRL on the date on which those wastewaters are generated, thereby allowing facilities to ensure that, when they generate wastewater, they have the appropriate systems in place to treat that wastewater to meet applicable ELG limits. EPA has taken this same approach in the past with new ELGs for other wastestreams from EGUs under the rule. For example, the 2015 ELGs for FATW, flue gas mercury control wastewater, and gasification wastewater all apply to wastewater generated "on and after" the date on which the ELGs have, or will, become applicable. *See* 40 C.F.R. § 423.13(h)(1)(i) (ELG for FATW); 40 C.F.R. § 423.13(i)(1)(i) (ELG for flue gas mercury control wastewater); and 40 C.F.R. § 423.13(j)(1)(i) (ELG for gasification wastewater). In fact, the 2015 Rule for these wastestreams—which were not challenged and are not subject to revision in the current proposal—apply the 1982 ELGs to wastewater that was generated *prior to* the date on which the new 2015 ELGs were, or are, to become effective. For example, in the 2015 ELG for FATW, the rule provides, "[f]or discharges of [FATW] generated *before* the date determined by the permitting authority, ... the quantity of pollutants discharged in [FATW] shall not exceed the quantity determined by multiplying the flow of [FATW] times the concentration listed for TSS in § 423.12(b) [*i.e.*, the BPT standard of the 1982 ELG]." 40 C.F.R. § 423.13(h)(1)(ii) (emphasis added). The rule contains similar provisions for flue gas mercury control wastewater, 40 C.F.R. § 423.13(i)(1)(ii), and gasification wastewater, 40 C.F.R. § 423.13(j)(1)(ii), that were generated prior to the applicability date of the new 2015 ELGs.[189]

[189] While *SWEPCo* vacated the LWW portions of the 2015 rule, the Fifth Circuit did so on other grounds and without addressing potential application of an ELG to wastewater generated prior to its effective date.

EPA should take the same approach to ELGs for LWW and similarly provide appropriate regulatory assurance to facilities to ensure that, when they generate LWW, they are able to know, install, and operate the proper waste treatment systems to treat that wastewater under applicable ELG limits. Doing so is consistent with both past and proposed ELGs for other wastestreams, avoids unexpected and unplanned burdens on facilities for wastestreams generated prior to a new ELG, and recognizes that, in most cases, LWWs have already been treated in a manner that is consistent with ELGs in effect at the time the LWW was generated (thereby avoiding duplicative or inconsistent ELG requirements).

3. The CWA does not authorize EPA to apply new ELGs retroactively to previously-generated wastestreams.

In UWAG's comments on EPA's 2019 proposed ELG rulemaking for BATW and FGDW, 84 Fed. Reg. 64,620, UWAG explained that, based on the language of the statute and its legislative history, the CWA does not authorize EPA to apply new ELGs retroactively to LWW generated prior to their effective date. *See* UWAG 2020 Comments at 209–11. UWAG noted that it is far from clear that EPA possesses authority to retroactively apply new ELGs to wastewater generated and managed pursuant to prior ELGs. Such an approach undermines the clarity and advance notice the CWA's technology-based provisions were intended to provide to dischargers. The treatment technologies on which EPA based prior ELGs—such as surface impoundments, which are highly effective at removing suspended solids but which typically require large areas and long retention times to achieve optimal results—made it functionally impossible to discharge within a short amount of time after wastewater generation and prior to the time EPA might impose new and different ELGs requiring the use new technologies.

As EPA and various courts have recognized, Congress understood that technology-based limits might, in some cases, force existing dischargers to cease operating rather than bear the substantial costs of retrofitting the necessary technologies.[190] But imposing more stringent ELGs on wastewater already generated by the source affords no such choice. Wastewater retained in the treatment system designed to meet prior ELGs cannot be held indefinitely in most cases, including where a facility has shut down and has no further revenue to fund expensive additional technology. In other words, facilities that continued operations after adoption of the 1982 ELGs did so subject to the requirements of the 1982 ELGs for any wastewater they generated and retained using the technologies they built to meet those ELGs, even after they ceased operations. But they did not know and could not reasonably plan for different, more stringent additional ELGs to subsequently apply to that wastewater.

EPA did not dispute UWAG's position on retroactivity, acknowledging:

> "[S]ome commenters raised legal arguments asserting that applying a new BAT requirement to wastewater that is generated prior to the effective date of that new BAT requirement (legacy wastewater) is retroactively overriding the prior legally enforceable BAT requirement. While this legal argument may have merit, it is beyond the scope of this rulemaking."

[190] *See* Conference Report and Debates at 231 (Oct. 4, 1972), *reprinted in* Legislative History of the Federal Water Pollution Control Act Amendments of 1972: P.L. 92-500: 86 Stat. 816: Oct. 18, 1972 (1972) ("If the owner or operator of a given point source determines that he would rather go out of business than meet the 1977 requirements, the managers clearly expect that any discharge issued in the interim would reflect the fact that all discharges not in compliance with such 'best practicable control technology currently available' would cease by June 30, 1977."); H.R. 11896 Together with Debate and Report at 450, *reprinted in* Legislative History of the Federal Water Pollution Control Act Amendments of 1972: P.L. 92-500: 86 Stat. 816: Oct. 18, 1972 (1972) ("No one in Congress wishes to legislate so irresponsibly that we drive out of business those who sincerely wish to abide by the new pollution laws but who, because of a bad state of the economy, will be forced to close."); Hearings before the Subcommittee on Environmental Pollution of the Committee on Environment and Public Works, U.S. Senate, Ninety-Fifth Congress, First Sess., at 505–06 (June 28-30 and July 1, 1977), *reprinted in* Covington & Burling. Clean Water Act of 1977 (1977) ("We have contended that currently available control technologies are not practicable. … By applying enough resources, to be sure, there is at least the theoretical possibility of obtaining the result demanded by EPA. But the cost increase resulting therefrom would surely reduce demand for our product and could possibly put the entire line and thus the manufacturing plant out of business.").

2020 Response to Comments at 2-2.[191]

4. Applying a new ELG to LWW in a manner that is duplicative or inconsistent with past ELGs would be arbitrary and capricious.

Moreover, applying a new ELG to LWW in a manner that is duplicative or inconsistent with past or other ELGs could be arbitrary and capricious under the Administrative Procedure Act, 5 U.S.C. §§ 551 *et seq*. (1970) (APA).

The CWA explicitly requires EPA to consider a number of specific factors when selecting BAT technologies for a given industrial category or class of point sources, including the age of equipment and facilities involved, the process employed, the engineering aspects of the application of various types of control techniques, process changes, and the cost of achieving such effluent reduction. CWA § 304(b)(2)(B), 33 U.S.C. § 1314(b)(2)(B). It also expressly authorizes EPA to consider "such other factors as the Administrator deems appropriate." *Id.* Taken together, all of these factors weigh in favor of applying those ELGs to LWWs that were in place at the time the wastewaters were generated.

LWW has been managed consistent with prior ELGs through treatment technologies (such as surface impoundments) employed at the time the wastewater was generated. For these wastestreams (as with others), the "age of equipment and facilities involved," the "process

---

[191] In addition, UWAG is not aware of any court that has addressed the issue of retroactive application of new ELGs to previously generated wastewater, including wastewater already treated in compliance with prior ELGs. In the challenge to EPA's 2015 final ELG Rule for legacy wastewater and combustion residual leachate, 80 Fed. Reg. 67,838, the United States Court of Appeals for the Fifth Circuit was faced with this issue but left the question unresolved. *See SWEPCo*, 920 F.3d 999. In that decision, the Court found it unnecessary to reach Petitioners' claim that the CWA does not grant the Administrator authority to base BAT limits on when wastewater is generated, but instead requires setting BAT limits for categories and classes of point sources, regardless of when wastewater is generated. *Id.* at 1015. As we have discussed above, however, EPA has found it appropriate in more than one rulemaking to impose ELGs based on when a wastewater was generated, before or after the applicability date of the ELG, and no court has found that approach to be contrary to the statute.

employed," and the "engineering aspects" of control measures all must be taken into consideration when deciding whether to require additional treatment for discharges of wastewater already treated under the current governing standard. *Id.*

Consideration of the ELGs under which the wastewater was held and treated also is an important factor that the CWA authorizes EPA to consider, pursuant to its authority under "other factors that the Administrator deems appropriate." The CWA's technology-based provisions were designed to provide clear, consistent, nationally applicable effluent limitations for wastewater discharges from a given category or class of industrial sources based on the technology EPA determined was the "best available" for wastewater produced by those sources.[192] The language and structure of the technology-based provisions make it clear that

---

[192] *See, e.g.,* Senate Report 92-414, to Accompany S. 2770, at 8 (Oct. 28, 1971), *reprinted in* Legislative History of the Federal Water Pollution Control Act Amendments of 1972: P.L. 92-500: 86 Stat. 816: October 18, 1972 (1972) ("In order to carry out the objective of this legislation, a two-phase program for applying effluent limits is created … the second based on best available technology…. In Phase II … communities and industries will be required to apply, ... the best available technology."); Remarks of the Hon. John D. Dingell on Administration Efforts to Amend S. 2770 in Conference, at E 4883 (May 9, 1972), *reprinted in* Legislative History of the Federal Water Pollution Control Act Amendments of 1972: P.L. 92-500: 86 Stat. 816: October 18, 1972 (1972) ("My colleague, HENRY S. REUSS, and I, joined by more than 40 other Members of the House, a few weeks ago sought to have the House adopt the 20th century concept of the Senate bill (S. 2770)" to address pollution through the use of best available technology); Submission of the Conference Report (S. Rept. 92-1236) on S. 2770 to the Senate - Senate Consideration of, and Agreement to the Conference Report, at S. 16873–74 (Oct. 4, 1972), *reprinted in* Legislative History of the Federal Water Pollution Control Act Amendments of 1972: P.L. 92-500: 86 Stat. 816: Oct. 18, 1972 (1972) ("In determining the 'best available technology' for a particular category or class of point sources, the Administrator is directed to consider the cost of achieving effluent reduction. The Conferees intend that the factors described in section 304(b) be considered only within classes or categories of point sources and that such factors not be considered at the time of the application of an effluent limitation to an individual point source within such a category or class."); Hearings before the House Public Works Committee, on H.R. 11895 and H.R. 11896, at 290 (Dec. 7-10, 1971), *reprinted in* Legislative History of the Federal Water Pollution Control Act Amendments of 1972: P.L. 92-500: 86 Stat. 816: Oct. 18, 1972 (1972) ("S. 2770 eliminates over a period of time the concept of water quality standards and instead depends completely on effluent limitations based on the best available technology or better.).

EPA must consider the attributes of the industrial source of discharges. In this case, the source of the discharges comprises one or more treatment systems that were built and managed in order to achieve the 1982 ELGs. In determining whether and how to further regulate wastewater from those sources, assuming *arguendo* further regulation is lawful, it is entirely appropriate—indeed, essential—to consider the extent of reduction already achieved, the age of the equipment employed, process issues, engineering aspects, and, of course, cost.

If new and different treatment standards are imposed on LWW discharges that already have been treated through an existing ELG, a facility potentially faces duplicative ELG treatment standards for the same LWW by virtue of having first treated the wastewater on site through surface impoundments required by the ELG in effect at the time of wastewater generation, then later treating the same wastewater through other technology required by a new rule (*e.g.,* chemical precipitation or biological treatment). While it may be technically possible to impose multiple successive treatment standards on the same wastestream, it would be arbitrary and capricious and contrary to the statute for EPA to impose the additional treatment standards on wastewater previously treated, if EPA fails or refuses to consider whether the standards are warranted based on the extent of reduction already achieved through the surface impoundments, the age of the equipment employed, process issues, engineering aspects, and additional cost. Under CWA § 304(b)(2)(B), EPA "shall" take into account the enumerated factors in making a BAT determination; the Agency "is not free to ignore any individual factor entirely." *Tex. Oil & Gas Ass'n,* 161 F.3d at 934 (EPA's failure "under the plain meaning" of § 304(b)(2)(B) to consider the age of equipment and facilities is "an abuse of discretion"); *see also, Am. Iron & Steel Inst. v. EPA*, 526 F.2d 1027, 1048 (3d Cir.1975), *cert. denied*, 435 U.S. 914 (1978) (remanding agency rule to EPA where EPA failed to consider a statutory age factor as it bore on the cost or feasibility of retrofitting certain older steel mills).

B. If EPA's New ELG Nonetheless Applies to Wastewater Generated Before the Applicability Date, EPA Should Not Specify a Nationwide Technology Basis for Such Wastewater.

If EPA insists on issuing a final rule that retroactively applies to wastewaters generated (and typically already treated under prior ELGs) before the applicability date of the new ELGs, then such requirements should not be based on any particular technology. EPA should not specify a nationwide technology basis for BAT applicable to "legacy wastewater."

By the time the new rule becomes effective, many UWAG members will have completed dewatering impoundments or will have significantly reduced their total volume of LWW. Therefore, the technology that represents BAT for LWW is likely to vary at any given site depending on the types of wastes and wastewaters present, the characteristics of the LWW, the quantity of LWW, treatment costs, and the extent to which satisfying ELG requirements would interfere with closure timeframes required under the CCR Rule. Indeed, the vast majority of plants also combine some of their LWW in surface impoundments with other wastestreams, including cooling water, coal pile runoff, metal cleaning wastes, and low volume waste sources. For example, in the 2015 Rule, EPA estimated FGDW compliance costs for 65 plants that use an impoundment as part of their treatment system. For 54 of the 65 plants (83 percent), the FGDW is comingled with, at least, fly and/or BATW. For another eight of the 65 plants (12 percent), the FGDW is commingled with non-ash wastewater, such as cooling tower blowdown or low volume waste sources. *See* 2015 TDD at 8-19. Because surface impoundments are typically open, with no cover, they also receive direct precipitation. As a result of these factors, the characteristics of LWW contained in surface impoundments (*e.g.*, flow rate and pollutant concentrations) vary at any given plant, as well as across plants nationwide. Therefore, establishing a nationwide technology basis is not justified.

C. UWAG Opposes Legacy Wastewater-Specific Factors for States To Consider When Establishing BPJ Limits.

The factors the permitting authority must consider when establishing BPJ-based BAT effluent limitations are specified in CWA § 304(b), 33 U.S.C. § 1314(b) and 40 C.F.R. § 125.3(d). EPA, however, solicits comments on whether EPA should explicitly promulgate specific elements related to these factors for LWW BPJ determinations. *See* 88 Fed. Reg. at 18,852 (listing potential elements). Given their lack of resources, state permitting authorities already struggle to perform timely BPJ analyses. Further complicating the process by mandating that states consider additional factors and/or conduct additional analyses benefits neither the permittee nor the permit writer. Naturally, when making a BPJ determination, state permitting authorities are likely to consider some, if not all of, the factors listed in the preamble. *See id.* However, mandating in regulatory text that permitting authorities nationwide must consider certain factors would be unnecessarily burdensome. Finally, the factors EPA promulgated at 40 C.F.R. § 125.3(d) are identical to those listed in CWA § 304(b), 33 U.S.C. § 1314(b). Promulgating additional factors that go beyond those listed in the statute may be considered by a court to go beyond EPA's authority under the CWA and thus be *ultra vires*.

D. Dividing Legacy Wastewater into Various Subcomponents Is Unnecessary and Would Cause Further Confusion.

The preamble describes two categories of LWW that are distinguished by their generation date and, per EPA's suggestion, would each be subject to separate BPJ analyses: (i) wastewater that is continuously or intermittently generated and discharged to a pond after the issuance of the first permit implementing the 2015 or 2020 Rule but before the compliance date specified in the permit (the ASAP date required by the rule) and (ii) wastewater accumulated over years in a surface impoundment that is later drained during the closure of that surface impoundment. *See* 88 Fed. Reg. at 18,851. According to EPA, by segregating wastewaters continuously or intermittently generated and discharged after permit issuance from those already accumulated in surface impoundments, states could justify more stringent BAT requirements on a BPJ basis. EPA notes that the first category may be able to be more easily transmitted to other treatment systems at the facility, whereas the second category would be typically treated with modular, leased systems for a shorter period, making treatment more affordable.

These categories are unnecessary and create greater ambiguity. Would LWW generated after the issuance of the first permit implementing the 2015 or 2020 Rule still be considered within the first category if the facility has ceased coal combustion or will soon cease coal combustion? More stringent BAT requirements would not be justified given that the treatment systems at the facility may soon be shutdown or dismantled. Furthermore, if a permitting authority applied a BPJ analysis to LWW at a site, there would be more important factors to the agency's determination than the date the wastewater was generated, such as the category of wastewater (*e.g.*, BATW, FGDW, or FATW), the quantity of flow, and whether the wastewater comingles with low volume wastes or stormwater. Thus, consistent with EPA's rationale for not specifying a nationwide technology basis for this wastestream, EPA should not attempt to divide LWW into two categories. Such an approach would only raise further questions and confuse regulators and permittees alike, without any commensurate environmental benefit.

EPA also is proposing, and soliciting comment on, the following set of definitions and proposing to require a separate BAT/BPJ analysis for each category of LWW: the layers of a closing surface impoundment's wastewater that is located … (i) "from the water surface down to the level sufficiently above any [CCRs] that, when drained, does not resuspend the [CCRs]," (Decant Wastewater) and (ii) "below surface impoundment decant water due to its contact with either stationary or resuspended [CCRs]" (Dewatering Wastewater). Proposed 40 C.F.R. § 423.11(dd) and (ee), 88 Fed. Reg. at 18,896-97. The proposed definitions are far too subjective. What does it mean to be "sufficiently above" CCRs? How does one determine whether draining the impoundment resuspended the CCRs? Also, ash is typically not stored in a level fashion across the entire pond. If the elevation of the surficial water in the pond is at a point where only a small portion would be considered dewatering wastewater, would all of the wastewater drained at the time be considered dewatering wastewater? These definitions would be difficult to apply and are unnecessary.

Furthermore, these discharges can be effectively regulated via existing water quality-based limits. For example, one UWAG member's surface impoundment dewatering plans require monitoring throughout the dewatering process (from beginning to the end). Current BPT limits are required, and reasonable potential analyses (RPAs) are performed to assure water quality standards are being met. States currently are applying water quality-based effluent limits (WQBELs) when necessary. Data from another UWAG member indicates that solids control is all that is necessary to maintain compliance with state water quality standards as ponds are closed. EPA should not separate or distinguish these wastestreams and should allow states to regulate such waters in accordance with state water quality standards because these discharges are small, of short duration, and soon to be terminated. Thus, there is no need to treat decant and dewatering wastewaters any differently.

Regardless of EPA's approach to decant and dewatering wastewater, the Agency should ensure that any discussion of these wastewaters and "pore water" is consistent with the CCR

Rule and its treatment of "free liquids." *See* 40 C.F.R. § 257.53. It is important that all definitions and descriptions of these waters are synchronized across EPA programs.

Finally, EPA has identified 22 surface impoundments at 17 facilities that the record indicates are composite lined and are in compliance with CCR Rule Part A requirements. EPA solicits comment on whether the Agency should establish a subcategory or different limitations applicable to discharges of these LWWs. Because there is no evidence to suggest the composition of the wastewater at these facilities would be any different, EPA should refrain from establishing a separate subcategory.

VIII. Comments on the 2020 Rule's Subcategories

A. UWAG Agrees That EPA Should Maintain the 2020 Rule's Voluntary Incentive Program and the Permanent Cessation of Coal Combustion Subcategory.

At least 12 EGUs (at four plants) have requested participation in the 2020 Rule VIP. 88 Fed. Reg. at 18,837. According to EPA, the proposal "would not impact dischargers choosing to meet the 2020 VIP effluent limitations for FGD wastewater." *Id.* at 18,887. UWAG agrees that this is the right approach. EPA should maintain the 2020 Rule's VIP option for compliance with FGDW limits.

UWAG also agrees that EPA should maintain the 2020 Rule's permanent cessation of coal combustion subcategory for FGDW and BATW requirements. Electric utility companies are transitioning to cleaner energy sources as quickly as feasible, consistent with ensuring affordable electricity rates and grid reliability. In reliance on the 2020 Rule's cessation subcategory, many companies committed to retiring or repowering a substantial number of coal-fired units that supply electricity across the country. Indeed, 74 EGUs (at 33 plants) have requested participation in the permanent cessation of coal combustion subcategory. 88 Fed. Reg. at 18,837. For companies regulated by the 2020 Rule, the 2020 cessation subcategory provides a mechanism for companies to transition away from coal-fired generation with adequate time and resources to find, develop, or connect sufficient alternative power sources. EPA correctly recognized in the 2020 Rule that technologies other than surface impoundments were not BAT for this subcategory "due to the unacceptable disproportionate costs they would impose; the potential of such costs to accelerate retirements of EGUs at this age of their useful life; the resulting increase in the risk of electricity reliability problems due to those accelerated retirements; and the harmonization with the CCR rule." 85 Fed. Reg. at 64,682.

IX. EPA's Estimated Costs and Benefits Are Flawed.

A. EPA's Model for Calculating Estimated Impacts Is Flawed.

UWAG collected operating status and retirement information from its members and publicly available resources. Based on this data, EPA's estimated impacts of the Proposed Rule on generating capacity, electricity costs, retirements/premature closures, etc., appear to be flawed because the facts on the ground are inconsistent with EPA's assumptions. For example, EPA's IPM incorrectly modeled retirement dates for a significant number of facilities. The IPM 2030 Pre-Inflation Reduction Act 2022 Reference Case ("2030 Baseline") incorrectly modeled the retirement of 23 units (25 boilers) by 2030, representing almost 10.7 GW of coal capacity. *See* Incorrectly Modeled Retirements Table, below. Two of these retirements, LaCyne Unit 1 and Madison Unit 3, were not even in the 2030 Baseline because the National Electric Energy Data System (NEEDS) erroneously listed them as retired in 2025 and 2027, respectively.

In addition, IPM modeled as operating in 2030 23 units (27 boilers) that have announced/planned retirement dates between 2019 and 2030. *See* Incorrectly Modeled as Operating Table below. The capacity of these retired units, which should be removed as operating units in the 2030 Baseline, is 12.2 GW.

In sum, IPM's 2030 Baseline lists 417 coal units (generators/boilers). Once you remove units less than 25 MW and industrial/institutional facilities and account for units with multiple boilers, the list is reduced to 359 units. Based upon the following modeling errors and mischaracterizations, it was determined that 70 of the 359 units were erroneously modeled in 2030, which represents approximately 20 percent of the IPM coal units modeled in 2030. These modeling errors, described in greater detail in the tables below, are categorized as the following: Retirement Errors (46 units); Gas Conversion Errors (12 units); Idling Errors (Coal Units Only) (12 units).

In light of these significant errors, EPA should correct its baseline to adequately assess potential impacts of the proposed rule on the electric utility industry, rerun the model to account for these corrections, and provide an opportunity for public comment on the updated results. *See*, *e.g.*, *Am. Radio Relay League, Inc. v. FCC*, 524 F.3d 227, 237 (D.C. Cir. 2008) ("'It is not consonant with the purpose of a rule-making proceeding to promulgate rules on the basis of inadequate data….'") (quoting *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 393 (D.C. Cir. 1973)).

Incorrectly Modeled Retirements

No.	Unique ID	ORIS Code	Plant Name	Summer Net (MW)	Retirement/ Conversion	Note
1	1040_B_1	1040	Whitewater Valley 1	34.774	2034	Use during peak load periods during the hot summer months and cold winter months. 2020 IRP Base Case indicates retirement May 31, 2034.
2	10784_B_BLR1	10784	Colstrip Energy LP	38.0		No announced retirement.
3	1384_B_1	1384	Cooper 1	116.0		No announced retirement.
4	1384_B_2	1384	Cooper 2	225.0		No announced retirement.
5	165_B_2	165	GREC 2	492.0		No announced retirement.
6	2240_B_8	2240	Lon Wright 8	82.0		No announced retirement.
7	2712_B_3A	2712	Roxboro 3*	347.0	2028-2034	2022 Carbon Reduction Plan accepted by PSC retirement Jan. 1, 2028-34 (12/30/22).
8	2712_B_3B	2712	Roxboro 3*	347.0	2028-2034	2022 Carbon Reduction Plan accepted by PSC retirement Jan. 1, 2028-34 (12/30/22).
9	2712_B_4A	2712	Roxboro 4*	349.0	2028-2034	2022 Carbon Reduction Plan accepted by PSC retirement Jan. 1, 2028-34 (12/30/22).
10	2712_B_4B	2712	Roxboro 4*	349.0	2028-2034	2022 Carbon Reduction Plan accepted by PSC retirement Jan. 1, 2028-34 (12/30/22).
11	2817_B_1	2817	Leland Olds 1	221.0		No announced retirement.
12	2828_B_1	2828	Cardinal 1	585.0		Unit purchased by Buckeye and will not be retired in 2028 (8/2/22).
13	2828_B_2	2828	Cardinal 2	585.0		No announced retirement.
14	6064_B_N1	6064	Nearman Creek 1	243.0		No announced retirement.
15	6068_B_2	6068	Jeffrey Energy Center 2	671.7	2039	To be retired at the end of 2039 (2021 IRP).
16	6095_B_1	6095	Sooner 1	516.0	2044	Probable retirement date from PSC Testimony (12/31/17) and 2021 IRP.
17	6095_B_2	6095	Sooner 2	515.0	2045	Probable retirement date from PSC Testimony (12/31/17) and 2021 IRP.
18	6138_B_1	6138	Flint Creek 1	494.0	2039	Retire January 1, 2039, SWEPCO 2023 IRP (March 28, 2023).
19	6177_B_U1B	6177	Coronado 1	380.0	2032	To be retired by 2032 and continued seasonal curtailments.
20	6195_B_2	6195	John Twitty Energy Center 2	275.0		No announced retirement.
21	6768_B_1	6768	Sikeston Power Station 1	240.0		No announced retirement.
22	8042_B_1	8042	Belews Creek 1	1,110.0	2036	2022 Carbon Reduction Plan accepted by PUC retirement date January 1, 2036, found full gas conversion do not indicate favorable economics (12/30/22).
23	8042_B_2	8042	Belews Creek 2	1,110.0	2036	2022 Carbon Reduction Plan accepted by PUC retirement date January 1, 2036, found full gas conversion do not indicate favorable economics (12/30/22).
24	1241_B_1	1240	La Cygne 1	757.8	2032	2022 IRP Update to be retired in 2032.
25		6190	Madison 3	624.8		Plan to install CCS by 2028 (4/12/22).
			Total	**10,708.1**		

* Multiple boiler unit

Incorrectly Modeled as Operating

No.	Unique ID	ORIS Code	Unit ID	Plant Name	Summer Net (MW)	Retirement/ Conversion	Note
1	10743_B_CFB1	10743	CFB1	Morgantown Energy Facility*	25.0	2019	Has not sold electricity to the grid since 2019. Deactivation January 2020. Continue to sell steam to WVU.
2	10743_B_CFB2	10743	CFB2	Morgantown Energy Facility*	25.0	2019	Has not sold electricity to the grid since 2019. Deactivation January 2020. Continue to sell steam to WVU.
3	1167_B_9	1167	9	Muscatine Plant #1	160.8	2028	MPW Board selected ELG compliance options for FGDW and BATW but retain 2028 retirement as secondary option in NOPP (8/31/21)
4	1356_B_2	1356	2	Ghent	495.0	2028	CPCN (2022-00402) to be retired in 2028 due to the Transport Rule (12/15/22)
5	1393_B_6	1393	6	R S Nelson	524.0	2030	Deactivate 2028 - 2023 Entergy LL 2023 IRP (10/21/22).
6	1733_B_3	1733	3	Monroe (MI)	773.0	2028	2022 IRP retires in 2028 (11/3/22).
7	1733_B_4	1733	4	Monroe (MI)	762.0	2028	2022 IRP retires in 2028 (11/3/22).
8	2721_B_5	2721	5	James E. Rogers Energy Complex	544.0	2026	2022 Carbon Reduction Plan accepted by PSC retirement date Jan. 1, 2026 (12/30/22)
9	2828_B_3	2828	3	Cardinal	620.0	2028	Unit to be retired in 2028
10	3122_B_3	3122	3	Homer City Generating Station	648.9	2023	To be deactivated July 1, 2023 (3/31/23).
11	470_B_3	470	3	Comanche (CO)	750.0	2030	To be retired at the end of 2030 (10/31/22).
12	50835_B_1	50835	1	TES Filer City Station*	30.0	2025	Estimated retirement date of 2025. Plant to keep using coal until its PPA end in 2025. Will not be operating in 2030
13	50835_B_2	50835	2	TES Filer City Station*	30.0	2025	Estimated retirement date of 2025. Plant to keep using coal until its PPA end in 2025. Will not be operating in 2031
14	55479_B_3	55479	3	Wygen 1	85.0	2030	EEI Financial Conference -To be converted or replaced at the end of engineering lives - 2030 (November 7-9, 2021)
15	594_B_4	594	4	Indian River Generating Station	410.0	2026	Unit shutdown extended to 2026 due PJM concern over reliability(8/2/22).
16	6113_B_3	6113	3	Gibson	630.0	2029	2021 IRP retirement date 2029 (12/15/21).
17	6113_B_4	6113	4	Gibson	622.0	2029	2021 IRP retirement date 2029 (12/15/21).
18	6194_B_171B	6194	171B	Tolk	532.0	2028	To be retired in 2028 (10/31/22).
19	6194_B_172B	6194	172B	Tolk	535.0	2028	To be retired in 2028 (10/31/22).
20	6641_B_1	6641	1	Independence Steam Electric Station	821.7	2030	Reached agreement with Sierra Club and NPCA to cease burning coal by Dec. 31, 2030; approved by Federal judge on Mar. 11, 2021.
21	6641_B_2	6641	2	Independence Steam Electric Station	842.0	2030	Reached agreement with Sierra Club and NPCA to cease burning coal by Dec. 31, 2030; approved by Federal judge on Mar. 11, 2021.
22	7097_B_BLR1	7097	BLR1	J K Spruce	560.0	2028	Board voted to retire the unit by 2028 (1/23/23).
23	879_B_51	879	51	Powerton*	384.5	2028	To be retired in 2028 due to ELG.
24	879_B_52	879	52	Powerton*	384.5	2028	To be retired in 2028 due to ELG.
25	879_B_61	879	61	Powerton*	384.5	2028	To be retired in 2028 due to ELG.
26	879_B_62	879	62	Powerton*	384.5	2028	To be retired in 2028 due to ELG.
27	10678_B_BLR1	10678	BLR1	AES Warrior Run Cogeneration Facility	180.0	2024	AES terminated PSA and will repurpose site for low carbon solutions (4/18/23)
				Total	**12,201.8**		

* Multiple boiler unit

Gas Conversion Errors

No.	Unique ID	ORIS Code	Unit ID	Plant Name	Capacity (MW)	Retirement/ Conversion	Note
1	7097_B_BLR2	7097	BLR2	J K Spruce	785	2027	Board voted to convert to natural gas by 2027 (1/23/23).
2	8066_B_BW73	8066	BW73	Jim Bridger	523	2030	Retire as a coal unit convert to natural gas in 2030 - 2023 IRP (3/31/23)
3	8066_B_BW74	8066	BW74	Jim Bridger	530	2030	Retire as a coal unit convert to natural gas in 2030 - 2023 IRP (3/31/23)
4	994_B_3	994	3	AES Petersburg	528	2025	To be converted to natural gas in 2025 (11/4/22)
5	994_B_4	994	4	AES Petersburg	530	2025	To be converted to natural gas in 2025 (11/4/22)
6		4162	1	Naughton	156	2026	Retire as a coal unit and convert to natural gas in 2026 - 2023 IRP (3/31/23)
7		4162	2	Naughton	201	2026	Retire as a coal unit and convert to natural gas in 2026 - 2023 IRP (3/31/23)
8	6034_B_1	6034	1	Belle River	635	2025	2022 IRP converts to natural gas in 2025 (11/3/22).
9	6034_B_2	6034	2	Belle River	635	2026	2023 IRP converts to natural gas in 2025 (11/3/22).
10	1012_B_3	1012	3	F B Culley	270	2027	2022-23 IRP converting unit to natural gas in 2027 (4/19/23)
11	6041_B_2	6041	2	H L Spurlock	510	N/A	No coal to gas conversion
12	56786_B_1	56786	1	Spiritwood Station	92	2023	Converted to natural gas in 2020
				Total	**5,395**		

Idling Errors

No.	Unique ID	ORIS Code	Unit ID	Plant Name	Capacity (MW)	Retirement/ Conversion	Note
1	2291_B_4	2291	4	North Omaha	120	2026	Converted to natural gas
2	2291_B_5	2291	5	North Omaha	216	2026	Converted to natural gas
3	3_B_4	3	4	Barry	362	2028	Converted to natural gas
4	564_B_2	564	2	Stanton Energy Center	466	2027	Converted to natural gas
5	594_B_4	594	4	Indian River Generating Station	410	2026	Unit shutdown extended to 2026 due PJM concern over reliability(8/2/22).
6	6139_B_1	6139	1	Welsh	528	2028	Cease burning coal in 2028, 2023 IRP modeling had NG conversion 2028 to 2038
7	6139_B_3	6139	3	Welsh	528	2028	Cease burning coal in 2028, 2023 IRP modeling had NG conversion 2028 to 2038
8	6193_B_061B	6193	061B	Harrington	339	2024	Converted to natural gas
9	6193_B_062B	6193	062B	Harrington	339	2024	Converted to natural gas
10	6193_B_063B	6193	063B	Harrington	340	2024	Converted to natural gas
11	8066_B_BW71	8066	BW71	Jim Bridger	531	2023	Converted to natural gas
12	8066_B_BW72	8066	BW72	Jim Bridger	527	2023	Converted to natural gas
				Total	**4,706**		

B. EPA Cannot Attribute Benefits to an Action Without Attributing Impacts at a Commensurate Scale.

EPA's benefits analysis relies on broader parameters than its analysis of regulatory impacts, exaggerating the estimated air quality benefits of the proposed rule as compared to the projected closures and reduction in coal generating capacity. This approach is arbitrary and capricious. *See*, *e.g.*, *Sierra Club v. Sigler*, 695 F.2d 957, 979 (5th Cir. 1983) ("The [agency] cannot tip the scales of [its analysis] by promoting possible benefits while ignoring their costs. Simple logic, fairness, and the premises of cost-benefit analysis … demand that a cost-benefit analysis be carried out objectively.").

Under the baseline, EPA's market model analysis predicts a decline in total coal generation capacity during model years 2028–2055 of 68 percent from 131.7 GW in 2028 to 41.7 GW in 2055. RIA at 5-5. When looking at the incremental impact of the Proposed Rule relative to the baseline, EPA concluded that "coal capacity is estimated to decrease for all years from 2028 to 2055, adding to the already significant reductions projected in the baseline," and "[c]oal retirements are estimated for all years, ranging between 0.1 to 1.8 GW." *Id.* at 5-8. "[G]eneration from coal is estimated to decrease for all years from 2028 to 2055 by 1.2 to 11.5 thousand GWh." *Id.* at 5-8. This is evident from Table 5-3, *id.* at 5–7, reproduced below (highlighting added).

Table 5-3: Incremental National Impact of Proposed Option 3 Relative to Baseline, 2028-2055							
Economic Measures	Option 3 Changes Relative to Baseline						
	2028	2030	2035	2040	2045	2050	2055
Total Costs							
Total Costs (million 2021$)	$364	$168	$249	$86	$87	$22	$28
Prices							
National Wholesale Electricity Price (mills/kWh)	0.03	0.02	0.08	0.00	0.02	0.00	0.00
Total Capacity (Cumulative GW)							
Renewables[a]	-0.1	-0.1	1.0	0.5	1.6	0.1	-0.1
Coal	-0.1	-0.3	-1.7	-1.2	-1.8	-0.7	-0.7
Nuclear	0.0	0.2	0.6	0.6	0.6	0.2	0.2
Natural Gas	0.3	0.0	0.5	0.2	0.5	0.3	0.4
Oil/Gas Steam	0.0	0.0	0.4	0.4	0.4	0.1	0.0
Other[c]	0.0	0.0	0.1	0.0	0.1	0.0	0.0
Grand Total	**0.0**	**-0.1**	**0.9**	**0.5**	**1.5**	**0.0**	**-0.1**
New Capacity (Cumulative GW)[b]							
Renewables[a]	-0.1	-0.1	1.0	0.5	1.6	0.1	-0.1
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	0.3	0.0	0.5	0.2	0.5	0.3	0.4
Other[c]	0.0	0.0	0.1	0.0	0.1	0.0	0.0
Grand Total	**0.1**	**-0.1**	**1.6**	**0.7**	**2.2**	**0.4**	**0.4**
Retirements (GW)							
Combined Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	0.1	0.3	1.7	1.2	1.8	0.7	0.7
Combustion Turbine	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	-0.2	-0.6	-0.6	-0.6	-0.2	-0.2
Oil/Gas	0.0	0.0	-0.4	-0.4	-0.4	-0.1	0.0
Other[c]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Grand Total	**0.1**	**0.0**	**0.7**	**0.2**	**0.8**	**0.3**	**0.5**
Generation Mix (thousand GWh)							
Renewables[a]	-0.1	0.1	4.4	1.8	5.8	0.4	-0.2
Coal	-1.2	-6.3	-9.7	-6.6	-11.5	-3.1	-2.9
Nuclear	0.0	1.7	4.6	4.6	4.7	2.1	2.1
Natural Gas	1.4	4.7	1.2	0.4	1.4	0.2	1.2
Oil/Gas Steam	-0.1	-0.1	-0.1	-0.1	-0.3	0.1	-0.2
Other[c]	0.0	0.7	0.8	1.1	1.2	1.2	1.2
Grand Total	**0.1**	**0.3**	**0.5**	**0.0**	**0.2**	**-0.4**	**0.0**

a. Renewables include hydropower and non-hydropower renewables.

EPA-821-R-23-002 5-7

These potential impacts are significant, especially given concerns about regional transmission organization/independent system operator (RTO/ISO) reserve margins and reliability described above in Section II.C.3.b. However, when EPA analyzed the impact on national and regional electricity markets, including premature closures, it only looked at model year 2030. This approach is inconsistent with EPA's air quality benefits analysis and underestimates regulatory impacts.

EPA claims that the proposed rule "would affect the operating status of very few steam electric plants, with only one additional plant closure." 88 Fed. Reg. at 18,866. EPA estimated that the Proposed Rule requirements would result in a net reduction of 249 MW in steam electric generating capacity *as of the model year 2030*, reflecting full compliance by all plants. *See id.* at 18,866, Tbl. VIII-3. This capacity reduction corresponds to the 0.3 GW retirements in the 2030 column in RIA, Table 5-3, and a net effect of approximately one EGU early retirement or closure. But EPA's conclusion excludes the other retirements that were projected by EPA to occur in later years as a result of the Proposed Rule.

Furthermore, the scope of this analysis is inconsistent with how EPA assessed potential benefits of the rule—in particular air quality benefits. EPA evaluated potential effects resulting from net changes in air emissions of four pollutants: carbon dioxide (CO_2), nitrogen oxide (NOx), sulfur dioxide (SO_2), and primary particulate matter ($PM_{2.5}$). EPA, Benefit and Cost Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-23-003, at 8-1 to 8-5, (Feb. 28, 2023) (BCA).[193] Like the RIA, EPA notes that "IPM projects generation from coal to decrease in all model years as a result of the proposed rule. Over the period of analysis, the reductions are smallest in 2028 (1.2 thousand GWh) and highest in 2045 (11.5 thousand GWh). … The net effects of these changes in the generation mix are reductions in air emissions …."

[193] The BCA does not appear to have been posted to docket EPA-HQ-OW-2009-0819 as of the time of this filing; however, it is available at https://www.epa.gov/system/files/documents/2023-03/steam-electric-benefit-cost-analysis_proposed_feb-2023.pdf (last visited May 22, 2023).

BCA at 8-1 (citing RIA, Chapter 5). To estimate the climate benefits associated with the changes in CO_2 emissions, EPA used estimates of the social cost of carbon (SC-CO_2) to value changes in CO_2 emissions. BCA at 8-5 to 8-15. Table 8-8 shows the annualized climate benefits associated with changes in CO2 emissions *over the 2025-2049 period* under each discount rate for the Proposed Rule by category of emissions. *See* BCA at 8-15, Tbl. 8-8. In other words, this calculation appears to aggregate the climate benefits from the entire period of analysis (2025–2049), and not just model year 2030, as was done for the regulatory impacts. The numbers in Table 8-8 were carried over and used by EPA in Table XII-6 in the preamble to the Proposed Rule, which estimates hundreds of millions of dollars in annualized climate change benefits from the rule and over $1 billion dollars in annualized air pollutant benefits. *See* 88 Fed. Reg. at 18,876.

It appears EPA applied a different measuring stick for air quality benefits than projected retirements. EPA's analysis is arbitrary and capricious, unless it uses a commensurate scale to compare the potential benefits and impacts of the Proposed Rule.

X. Comments on Implementation Issues Associated with the 2020 Rule and the Proposed Rule

A. EPA's 1982 BAT Determination for CRL and LWW Control Until the Agency Takes Further Action.

EPA contends that permitting authorities must continue to conduct BPJ analyses and establish limits pursuant to 40 C.F.R. § 125.3(c)(2) and (3) for BA purge water, CRL, and LWW until EPA issues a final rule. 88 Fed. Reg. at 18,886. UWAG disagrees with this position. While EPA is engaged in rulemaking on LWW and CRL, EPA's 1982 BAT determinations control.

When the Fifth Circuit vacated the 2015 ELGs for LWW and CRL, the relevant provisions of the 1982 Rule were reinstated by operation of law. EPA's Environmental Appeals

Board squarely addressed this issue in a 2020 decision regarding legacy wastewater requirements for the Arizona Public Service Company's Four Corners Power Plant:

> The general rule is that a court's judgment vacating a regulation has "the effect of reinstating the rules previously in force." *Action on Smoking & Health v. Civil Aeronautics Bd.*, 713 F.2d 795, 797 (D.C. Cir. 1983); *see Prometheus Radio Project v. FCC*, 652 F.3d 431, 454 n.25 (3d Cir. 2011). On occasion, courts upon vacating a regulation specify what law should govern. For example, in *Paulsen v. Daniels*, the Ninth Circuit invalidated an interim 1997 regulation but held that a subsequent amendment to the regulation in 2000 should apply rather than the prior 1995 regulation because a court had held that the prior regulation misinterpreted the relevant statutory language. 413 F.3d 999, 1008 (9th Cir. 2005). But in *Southwestern Electric,* the Fifth Circuit did not specify that in light of vacatur of parts of the 2015 ELGs, permit writers should be governed by some other requirement than the prior regulation in force—the 1982 ELGs. Moreover, the Fifth Circuit vacated only the 2015 ELG's provisions on legacy bottom ash transport water. The 1982 steam electric ELGs were not before the Fifth Circuit on review, and the court took no action to vacate that regulation. *See Sw. Elec. Power,* 920 F.3d at 1003-04 (explaining that the court was hearing a challenge to the 2015 steam electric ELGs concerning "two discrete parts of the rule").

In re Arizona Pub. Service Co., 18 E.A.D. 245, 293 (EAB 2020) (order denying review).

For LWW, the 1982 Rule reflects EPA's determinations as to effluent limitations consistent with BPT and BAT. For CRL, the 1982 Rule reflects EPA's determination as to BAT. Both FGDW[194] and CRL were classified as "low volume waste"[195] for purposes of all limits and

---

[194] EPA's 1982 ELG left open the possibility that the Agency would develop additional BAT ELGs for FGDW and, in the preamble, referred to that wastestream as reserved. 45 Fed. Reg. 68,328, 68,333 (Oct. 14, 1980) (proposed rule); EPA, Steam Electric Power Generating Point Source Category; Effluent Limitations Guidelines, Pretreatment Standards and New Source Performance Standards, Final Rule, 47 Fed. Reg. 52,290, 52,291 (Nov. 19, 1982) (1982 Rule). Instead of actually reserving judgment on that wastestream, however, EPA included it in the definition of low volume wastes, which applies for purposes of the BPT and NSPS limits and its BAT determination.

[195] The 1982 ELG definition of "low volume waste sources," § 423.11(b), provides:

> (b) The term "low volume waste sources" means, taken collectively as if from one source, wastewater from all sources except those for which specific limitations are otherwise established in this part. Low volume wastes sources include, but are not limited to: wastewaters from wet scrubber air pollution control systems, ion exchange water treatment system, water treatment evaporator blowdown, laboratory and sampling streams, boiler blowdown, floor drains, cooling tower

standards imposed by the 1982 rules, while BATW and FATW were subject to wastestream-specific limitations and standards. The BPT ELGs and NSPS were identical for BATW and low volume wastes, requiring compliance with limitations on TSS, oil & grease, and pH; the NSPS imposed more stringent limits for FATW. Thus, with the exception of FATW, existing facilities were subject to effluent limitations just as stringent as those EPA determined were justified under the more rigorous statutory test applied to new sources.

The 1982 Rule did not include additional, separate BAT effluent limitations for FATW, BATW, and low volume wastes. As the record supporting EPA's 1982 Rule demonstrates, EPA made a detailed analysis of additional technologies that might be available to reduce toxic pollutants and determined, based on its evaluation of the relevant statutory factors, that no further technology could be justified.[196] Thus, the 1982 Rule reflects EPA's implementing action for those wastestreams under CWA §§ 301(b)(1)(A) and (b)(2)(A) (the BPT and BAT provisions respectively).

---

basin cleaning wastes, and recirculating house service water systems. Sanitary and air conditioning wastes are not included. 47 Fed. Reg. at 52,305.

[196] *See, e.g.,* EPA, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, Proposed Rule, 39 Fed. Reg. 8294–95, 8297, 8303, 8305, 8306 (Mar. 4, 1974); EPA*, Development Document for Proposed Effluent Limitations Guidelines and New Sources Performance Standards for the Steam Electric Power Generating Point Source Category*, EPA 440/1-73/029, at 1, 122–26, 148, 177 (Mar. 1974), EPA-HQ-OW-2009-0819-5450 ATT 18; EPA, Steam Electric Power Generating Point Source Category, Effluent Guidelines and Standards, Final Rule, 39 Fed. Reg. 36,186, 36,195, 36,197, 36,199 (Oct. 8, 1974); EPA, Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category, EPA 440/1-74 029-a, at 1 (Oct. 1974), EPA-HQ-OW-2009-0819-8721 ATT 34; 45 Fed. Reg. at 68,333, 68,337–39, 68,341, 68,342, 68,351–52; 47 Fed. Reg. at 52,291, 52,293, 52,296–97; EPA, Development Document for Final Effluent Limitations Guidelines, New Source Performance Standards, and Pretreatment Standards for the Steam Electric Point Source Category, EPA-440/1-82/029, EPA-HQ-OW-2009-0819-2186 at 337, 376-98, 438–41, 464–65, 467, 472, 473, 475, 475–83, 476, 496, 498–99 (Nov. 1982).

In 2020, EPA established BPT limits for CRL, *see* 85 Fed. Reg. at 64,716, but took no action to reverse or change its BAT determination from 1982. *See id.* at 64,674 n.91 ("EPA is not establishing BAT for leachate in the current rulemaking.").

EPA's BPT and BAT determinations from 1982 control for LWW and EPA's BAT determination from 1982 controls for CRL until EPA completes its rulemaking. Thus, there is no statutory basis for case-by-case, BPJ decision-making by states, as courts have recognized.[197] *See Louisville Gas & Elec. Co. v. Ky. Waterways All.*, 517 S.W.3d 479 (Ky. 2017); *Nat. Res. Def. Council v. Pollution Control Bd.*, 37 N.E.3d 407 (Ill. App. Ct. 2015); *Tenn. Clean Water Network v. Tenn. Dep't of Env't & Conservation*, Case No. WPC10-0116, Doc. No. 04.30-110315A (Tn. Water Quality, Oil & Gas Bd. Dec. 17, 2013).

UWAG acknowledges that the Fifth Circuit assumed in *SWEPCo*, 920 F.3d at 1021, that, but for the BAT limits it vacated and remanded, states would have authority to set BPJ limits. But the Court's analysis was not informed by any briefing on the underlying question of the applicability of the 1982 Rule. EPA contended that the issue, having never been properly raised and addressed during the public comment period, was not properly before the Court. And because the environmental petitioners never raised the issue—and, indeed, actively opposed any BPJ approach—EPA never examined the issue or took any position on it. Thus, although the Court vacated the CRL and LWW limits in part because it assumed states otherwise would be

[197] CWA § 402(a)(1)(B) authorizes the Administrator and, by extension, States to administer the NPDES program, to impose "prior to the taking of necessary implementing actions relating to [§ 301, *inter alia*] all such requirements, such conditions as the Administrator determines are necessary to carry out the provisions of this chapter." 33 U.S.C. § 1342(a)(1)(B). This provision notably does not require that specific limits be set but instead anticipates that EPA will have made a nationally applicable decision for the industry discharges in question.

able to set BPJ limits, it neither considered nor opined on whether the scope of the 1982 Rule would prevent that outcome.

Even if there were some question about the applicability of the 1982 Rule, EPA's Environmental Appeals Board has recognized that the statute and its own rules do not compel BPJ determinations for every wastestream or pollutant potentially subject to technology-based limits. *See In re Arizona Pub. Serv. Co*., 18 E.A.D. at 293 ("[EPA Region 9] did not clearly err in concluding that relevant parts of the 1982 ELGs are now currently in effect given the Fifth Circuit's vacatur of the corresponding parts of the 2015 ELGs."). Rather, EPA and the States have some discretion to decide whether and when such action is necessary, taking into account factors such as pending rulemakings.

In sum, when the Fifth Circuit vacated the 2015 ELGs for LWW and CRL, the relevant provisions of the 1982 Rule were reinstated by operation of law. As a matter of law, when a regulatory determination is vacated and remanded, the previous regulatory determination controls and is automatically reinstated. *See, e.g.*, *Paulsen v. Daniels*, 413 F.3d 999, 1008 (9th Cir. 2005) ("The effect of invalidating an agency rule is to reinstate the rule previously in force."). Thus, besides EPA's 2020 BPT limits for CRL, EPA's determinations in the 1982 Rule control until EPA completes its current rulemaking.

B. UWAG Supports a Two-Year Temporary Reporting Requirement.

EPA solicits comment on the potential creation of a temporary reporting requirement, which would be in place prior to the facility meeting a ZLD limit. 88 Fed. Reg. at 18,891. Under such an approach, a plant would not include an optimization period in the calculation of its ASAP date. Rather, the plant would monitor and report any necessary discharges over the first year of attempted zero discharge while the system was being optimized, and these discharges would not be a violation of the zero discharge requirements.

Commercially proven technology designs generally take a full year to optimize. Treatment of FGDW using membrane filtration is an unproven technology and thus would likely require additional time beyond one year of operational experience and optimization to meet the ZLD limit. Also, additional equipment may be required during optimization to reliably meet ZLD, and a discharge would be needed until the additional equipment is installed and optimized. For example, in order to meet the specifications of a chemical precipitation treatment system, a proven technology, one UWAG member needed at least 18 months to optimize the equipment. This process generally includes a two-six month startup and tuning period, at least two months of initial performance testing, and twelve months of performance optimization and verification. Accordingly, UWAG believes the temporary reporting requirement should be two years.

C. The Scientific Literature That Describes the Threat of Bromides from Power Plants Contains Critical Flaws.

In consultations conducted with state and local government entities, EPA received comments from drinking water utilities describing the threat of bromide to drinking water treatment systems. The journal articles on which the drinking water utilities have predominantly relied to describe the threat of bromides from power plants contain significant errors. Due to recent retirements of coal-fired power plants, changes in industry practices, the use of conservative estimates in the articles' calculations, and an explicit error in an equation that likely permeates throughout the research, the articles overestimate the quantity and potential impact of bromide discharges. Nevertheless, UWAG supports EPA's proposed approach to regulate bromide on a site-specific basis, rather than via a national ELG.

1. The articles overestimate the number of power plants discharging FGD wastewater.

The scope of this issue is more limited than some would suggest. In comments and a letter to EPA regarding discharges of bromide, the American Water Works Association

(AWWA) and the Association of Metropolitan Water Agencies (AMWA) claimed there are "407 coal-fired power plants with the potential to impact at least 573 drinking water treatment facilities downstream from them."[198] In addition, the scientific articles cited in the administrative record for the proposal also significantly overstate the number of coal-fired power plants that discharge FGDW to surface waters. For example, the 2018 Good and VanBriesen study[199] cited in the 2019 VanBriesen Report[200] identified and evaluated bromide mass loadings to surface water from 140 coal-fired power plants.[201] According to the EIA and other industry information current as of December 31, 2018, however, there are only 87 electric generating units with at least one operable wet FGD system discharging to surface water. Further, of the seven facilities on the Ohio River modeled by Cornwell (2018),[202] two are no longer in operation, and one does not discharge to surface water. Therefore, the number of power plants that could potentially discharge bromide to water treatment facilities is approximately 38 percent less than that used in the Good and VanBriesen (2018) analysis and over 75 percent less than the 407 power plants cited in research papers and comments submitted to EPA. As a result, the

---

[198] Letter from AWWA & AMWA, to the Hon. Scott Pruitt, Adm'r, EPA, Steam Electric Power Plant Effluent Limitations Guidelines Rulemaking and Safe Drinking Water at 1 (June 8, 2018), EPA-HQ-OW-2009-0819-7598 (DCN SE06903).

[199] K.D. Good & J.M. VanBriesen, *Coal-Fired Power Plant Wet Flue Gas Desulfurization Bromide Discharges to U.S. Watersheds and Their Contributions to Drinking Water Sources*. 53 ENVTL. SCI. & TECH. 213–23 (2019) (Good and VanBriesen (2019)). https://doi.org/10.1021/acs.est.8b03036.

[200] Jeanne M. VanBriesen, *Methods to Assess Anthropogenic Bromide Loads from Coal-Fired Power Plants and Their Potential Effect on Downstream Drinking Water Utilities* (Dec. 2019) (2019 VanBriesen Report).

[201] *See* 2019 VanBriesen Report at 4.

[202] David A. Cornwell et al., *Modeling Bromide River Transport and Bromide Impacts on Disinfection Byproducts*, J. OF THE AM. WATER WORKS ASS'N, Volume 110, Issue 11 (Nov. 2018), EPA-HQ-OW-2009-0819-7856 (DCN SE07937) (Cornwell (2018)).

potential impact to downstream water treatment plants is also considerably less, and the overall scope of this issue is much smaller than some have claimed.

2. The articles overestimate the quantity of bromide within coal.

Similarly, the quantity of bromide in FGD wastewater also has been overestimated. To estimate bromide loadings in FGD wastewater, the research does not rely on data from direct monitoring of the wastewater discharges; rather, the calculation is based on the facility's estimated coal consumption, the potential chloride in coal, and an assumed 0.02 bromide-to-chloride ratio in all coals. This approach has a number of flaws. Chiefly, bromide content varies considerably among the various types of coal burned by power plants. For example, the estimated bromide content used by Good and VanBriesen (2019)[203] was higher than the content of the vast majority of coal normally used at power plants. Due to a metric based on data availability rather than actual coal usage, the data used in Good and VanBriesen (2019)'s bromide mass load calculations overestimated nationwide concentrations by 58 percent for bituminous coal, 5 percent for subbituminous coal, and 50 percent for lignite.[204] Cornwell (2018) also calculated the bromide content using a maximum bituminous coal concentration, resulting in an extreme outlier.[205]

Most importantly, Good and VanBriesen, in multiple articles, rely on an equation that contains two significant errors associated with how they calculated bromide mass loadings from each facility.[206] To calculate dry coal tonnage, Good and VanBriesen attempted to convert as-

[203] Good and VanBriesen (2019).

[204] EPRI, *Impacts of Bromide from Power Plants on Downstream Disinfection Byproduct Formation: A Literature Review*, No. 3002017477, at 2–7 (Nov. 2019) ("EPRI Bromide Report").

[205] *Id.*

[206] *Id.* at 6-2.

received (wet) coal weight to dry coal weight, so that the coal amount could be combined with the bromide concentration in ppm, dry. However, the equation incorrectly includes the "(1 - moisture content)" variable in the denominator, when it should be in the numerator.[207] Second, the equation as written should use a moisture content fraction, not a percent. When the erroneous formula is applied, it overestimates the mass of bromide by 14 percent for bituminous coal, 88 percent for subbituminous coal, 130 percent for lignite coal, and 42 percent for refined coal.[208] Thus, when one combines the inflated bromide concentrations, discussed above, with this flawed equation, the results in the scientific literature overestimate bromide mass loadings to water by 80 percent for bituminous coal, 98 percent for subbituminous coal, and 245 percent for lignite coal.[209] Because of the significant overestimate of mass loadings, the potential quantity of bromide in FGD wastewater is considerably less than what the research indicates.

3. The scientific literature relies on outdated bromide usage surveys.

Conducted prior to 2013, the surveys cited in the recent literature also overstate the amount of bromide added to refined coal or for mercury control. Based on these outdated surveys, Cornwell (2018) assumes a worst-case scenario of bromide added per kilogram of dry coal of 300 mg (or 300 ppm), and Good and VanBriesen (2019) at 216 assumed a baseline bromide addition of 100 ppm and a maximum of 460 ppm.[210]

Surveys conducted from 2014–2017, however, show that bromide addition rates declined dramatically as power plant operators gained more experience with mercury control and due to

---

[207] The authors have acknowledged this error, and they have submitted a correction to the journal. *See* 2019 VanBriesen Report at 41 n.6.

[208] EPRI Bromide Report at 6-2.

[209] *Id.* at 6-3.

[210] Good and VanBriesen (2019).

concerns with cost and corrosion effects.[211] For example, by reducing bromide levels, plant operators learned they can sufficiently control mercury emissions for compliance with the Mercury and Air Toxics Standards regulations (MATS Rule). Based on the data from the more recent surveys, approximately 83 percent of the electric generating units with wet FGDs had bromide addition rates of 120 ppm or less, and the median usage was 60 ppm.[212] Moreover, of the remaining 17 percent of facilities that added bromide at rates above 120 ppm, all are ZLD plants. In other words, Cornwell's 300 ppm estimate *is nearly three times the highest rate reported in the updated survey data,* and Good and VanBriesen's baseline of 100 ppm *is nearly double the median usage in the most recent data*.

4. Discharges of bromide are likely to decrease over time.

Claims in the drinking water utilities' June 2018 letter that bromide discharges will increase absent CWA controls are also incorrect. There are many coal-fired power plants retiring and less frequent dispatch of the remaining coal-fired power plants. According to EPA, 74 EGUs at 33 plants have requested participation in the 2020 Rule's cessation subcategory, indicating their intent to retire or convert to non-coal fuels by December 31, 2028. 88 Fed. Reg. at 18,837. Furthermore, coal consumption for U.S. electricity generation has declined by 46 percent from 2013 to 2022[213] and will continue to decline as coal-fired power plants close. In addition, plants that continue to operate have already added scrubbers to comply with the Maximum Achievable Control Technology rule. As a result, there are very few new wet scrubbers that will be added to existing coal-fired plants. In fact, only one new, small coal-fired

[211] EPRI Bromide Report at 3-2.

[212] *Id.*

[213] EIA, *Electricity Data Browser, Data Set – Consumption for Electricity Generation*, http://www.eia.gov/electricity/data/browser/#/topic (last visited May 20, 2023).

unit (17 MW) came online in 2019.[214] Thus, contrary to AWWA's claims, the amount of bromide discharged to surface waters is likely to decrease over time as the use of coal to generate electricity also decreases.

5. The research overestimates in-stream bromide concentrations due to flaws in hydrologic modeling.

Lastly, the research also takes a conservative approach to hydrology and hydraulics, likely overestimating potential bromide impacts. Seasonal variations in rainfall affect the quantity of flow in riverine systems, which has a significant impact on the concentration of bromide in the water. For example, the same discharge of bromide will produce lower concentrations during periods of higher flows and higher concentrations when there are lower flows. Cornwell (2018) used dynamic modeling to address flow variability but only focused on low flow periods, which likely occur only 20 percent of the time.[215] By calculating impacts during periods of low flow, the article exaggerates the likely impacts from bromide discharges the rest of the year. Furthermore, of the recently published articles that focused on impacts of bromide discharged from coal-fired power plants, none of them verify their calculations with sampling of instream data. For example, since 2013, the Ohio River Valley Water Sanitation Commission (ORSANCO) has been collecting bromide samples from 29 locations along the Ohio River and its major tributaries. ORSANCO's publicly available data differ significantly from the data in Cornwell (2018) Figure 2, depicted below.[216]

---

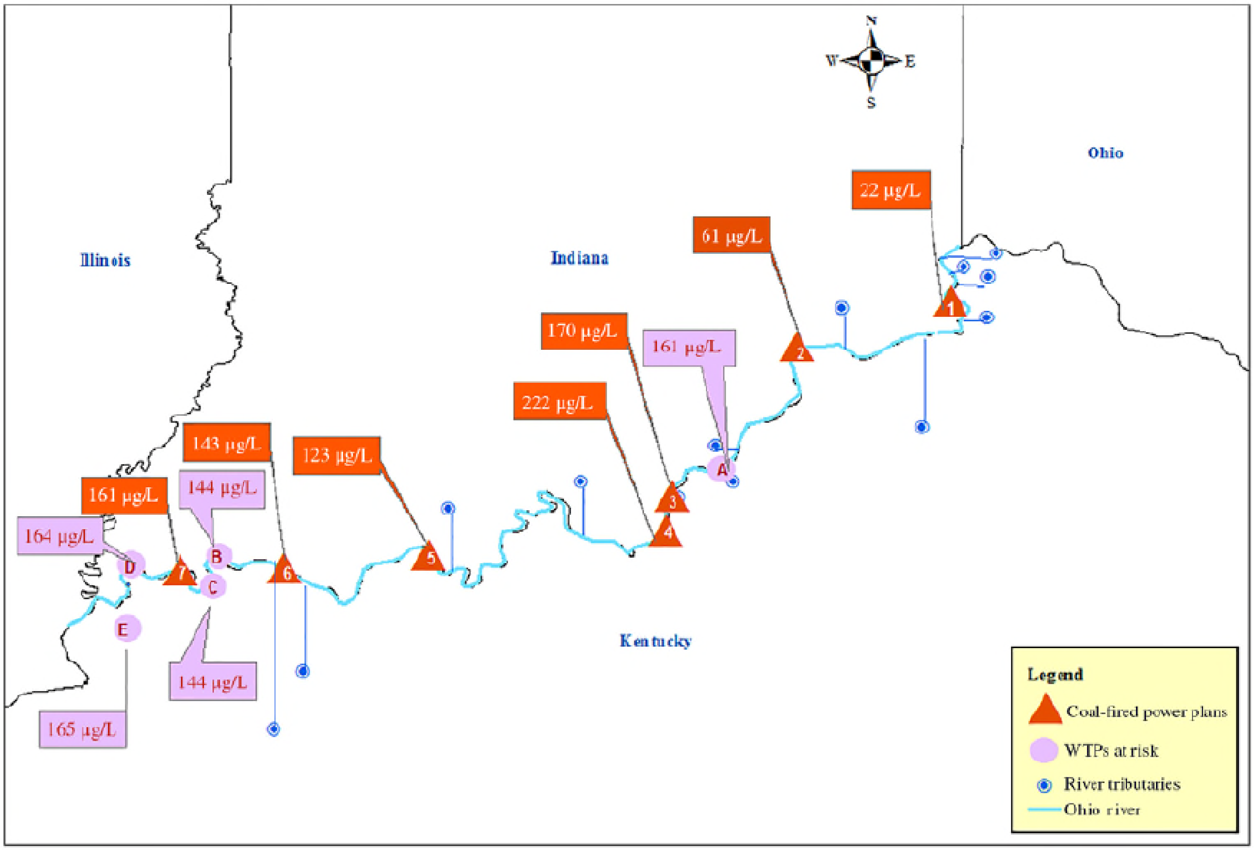
[214] University of Alaska Fairbanks, UAF Heat and Power Plant Major Upgrade Project, (undated).

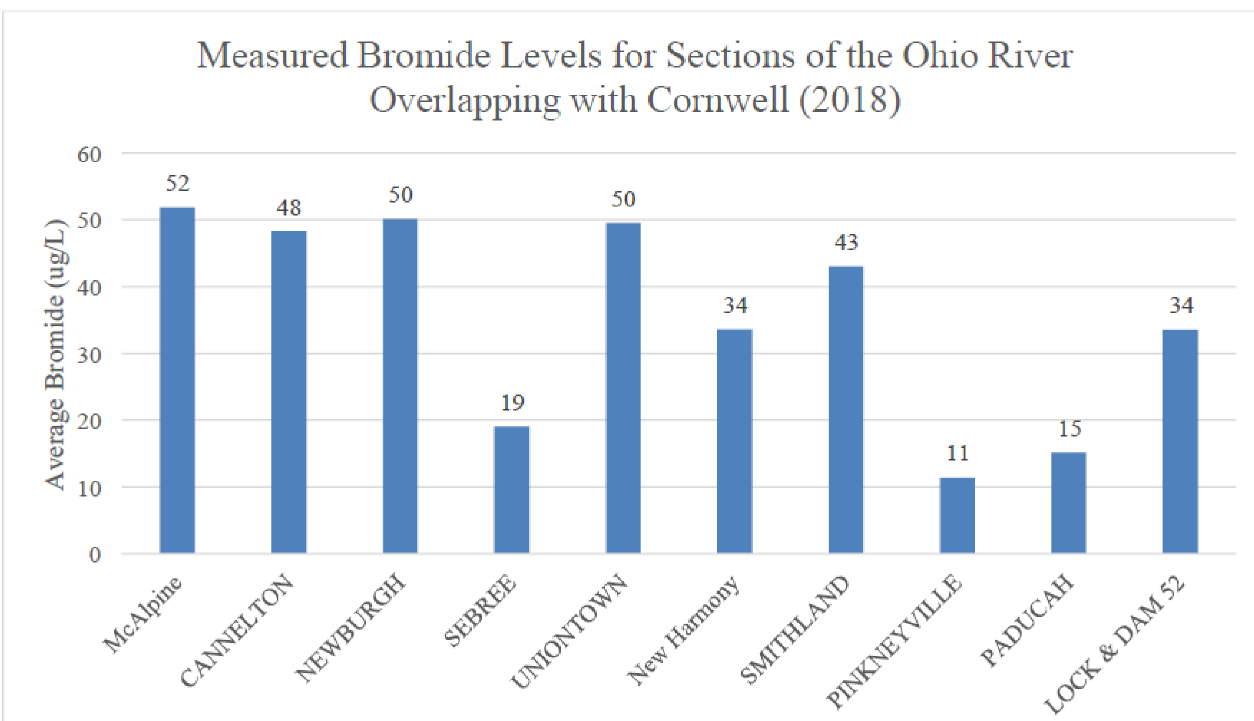
[215] EPRI Bromide Report at 7-2.

[216] ORSANCO's monitoring locations overlap with the locations depicted in Cornwell (2018) Figure 2 but do not correspond directly. For example, the first five ORSANCO monitoring locations, from McAlpine to Uniontown, correspond to various locations between

water treatment plants A through E on the Cornwell (2018) map. The remaining monitoring stations, from New Harmony to Paducah, are located further downstream along the Ohio River.

Cornwell (2018) Figure 2 - Modeled Bromide Values





For example, for ORSANCO's first five monitoring locations, from McAlpine to Uniontown, average bromide levels vary from 19 to 52 μg/L. The corresponding section of the river in Cornwell (2018) is from drinking water treatment plant A to plant E. But Cornwell's modeled bromide values in this section range from 123 to 222 μg/L, significantly higher than the ORSANCO data.

The research has not identified (beyond a few isolated examples) drinking water facilities adversely impacted by bromide discharges. According to EPA's 2015 Rule, one study "showed an increase in bromides at four drinking water utilities' intakes after wastewater from … FGD systems began to be discharged to the rivers." 80 Fed. Reg. at 67,840. However, the same study found increased levels of total trihalomethanes (TTHM) at only one facility. 80 Fed. Reg. at 67,840. Therefore, where it is necessary to bring drinking water treatment facilities into compliance with TTHM requirements, it may be more appropriate and cost-effective to modify the water treatment facility or the water treatment process itself, rather than set a national standard for bromide.

D. Comments on EPA's Proposed Website Reporting Requirements

1. EPA's proposed website reporting requirements are burdensome, unnecessary, and duplicative.

EPA proposes that all reporting and recordkeeping information required under 40 C.F.R. § 423.19 not only be retained by the regulated entity and provided to the permitting authority but that it also be posted to a public website for ten years or the length of the permit plus five years, whichever is longer. This would include, for example, the information submitted with a NOPP and the proposed Annual Combustion Residual Leachate Monitoring Report. The CRL monitoring report, as discussed above, would only be required if the permitting authority determined that CRL releases via groundwater were the functional equivalent of a discharge under *County of Maui*.

The proposed requirements would be burdensome, unnecessary, and inconsistent with the principles of the Paperwork Reduction Act (PRA). The PRA states "[w]ith respect to the collection of information and the control of paperwork, each agency shall ... certify (and provide a record supporting such certification, including public comments received by the agency) that each collection of information ... is not unnecessarily duplicative of information otherwise reasonably accessible to the agency." 44 U.S.C. § 3506(c)(3)(B). "Congress surely prefers agencies to be efficient and avoid unnecessary procedural steps. That is the thrust of the Regulatory Flexibility Act … [and] Paperwork Reduction Act." *Campanale & Sons. Inc. v. Evans*, 311 F.3d 109, 122 (1st Cir. 2002) (Lynch, J., dissenting) (internal citations omitted). EPA also has acknowledged in several instances a central tenet of the PRA is to decrease redundancy and eliminate duplicity. *See e.g.*, 81 Fed. Reg. 57,439, 57,440 (Aug. 23, 2016) ("Comments expressed concern about the duplication and overlap of existing rules created by the proposed rule. … The Agency has reviewed the comments and agrees that the inclusion of [certain] provisions in the proposed rule created repetition and overlap, so they have been removed."); 77 Fed. Reg. 66,432, 66,433 (Nov. 5, 2012) ("Modifying the survey to simultaneously collect information for multiple purposes will increase response rates, reduce duplicity in information collected by respondents, and add convenience to respondents."); 69 Fed. Reg. 57,910, 57,910 (Sept. 28, 2004) ("This action is undertaken to consolidate information requirements for the same industry into one ICR, for simplification and to avoid duplicity.").

EPA's proposed website reporting requirements appear to be inconsistent with the PRA's goal of avoiding unnecessarily duplicative procedural steps and requirements. The creation of either (1) two different websites with substantially similar or identical information or (2) a single CCR/ELG website with substantially similar or identical information posted in the same manner, twice, would be unnecessarily duplicative. If EPA intends to move forward with this requirement, the Agency should clarify how the data proposed to be included on the public website is different than what is required under 40 C.F.R. §§ 257.91 to 257.95.

In addition, the public website requirements under the CCR Rule were required because the CCR Rule is self-implementing. Conversely, ELG requirements are regulated by the state permitting authority via NPDES permit requirements. Thus, no website is necessary to hold permittees accountable—the permitting authority and the potential penalties for non-compliance with the CWA efficiently perform this task.

2. EPA must revise the timeline for notifying EPA of a combined website.

Under the Proposed Rule, facilities that want to combine their CCR and ELG websites must notify EPA "*no later than 60 days after date of publication of [the] final rule*." Proposed 40 C.F.R. § 423.19(c)(2)(i), 88 Fed. Reg. at 18,901 (emphasis added, internal punctuation and capitalization omitted). However, at the time the final rule is promulgated, the state permitting authority likely will not have made a determination as to whether a functional equivalent discharge exists, and thus the permittee will not know whether it is required to submit a CRL monitoring report and whether it intends to post such information on a combined CCR/ELG website. If EPA includes the website reporting requirements in the final rule, a more reasonable approach would be to revise the proposed regulatory text to indicate that the permittee must notify EPA that it intends to combine the CCR and ELG websites 14 days before the combined website is active.

E. EPA Should Defer PFAS Issues to State Permitting Authorities.

The proposal recognizes that EPA has been implementing its October 2021 per- and polyfluoralkyl substances (PFAS) Strategic Roadmap and issued guidance on April 28, 2022, to address PFAS in EPA-issued NPDES permits and, on December 5, 2022, issued similar guidance encouraging States to use their State-issued NPDES permits to address PFAS discharges to waterways and to collect more comprehensive information through monitoring. 88 Fed. Reg. at 18,892. The December 2022 guidance recommends permit conditions for "[a]pplicable [i]ndustrial" direct discharges be implemented by authorized States, "as appropriate, to the fullest extent available under state and local law."[217] The applicable industry categories include those industry categories known or suspected to discharge PFAS. But importantly, EPA did not include electric utilities as an industrial category likely to discharge PFAS. EPA further acknowledges, in the December guidance, that certain States already use their NPDES permit programs to address PFAS discharges.

The ELG proposal correctly notes that the steam electric power sector was not identified in EPA guidance as one of the top PFAS discharges but asserts that PFAS may nevertheless be present in steam electric discharges. 88 Fed. Reg. at 18,892. Yet, despite having focused on PFAS for several years, EPA cites to just one data point where PFAS were found at power plants, and the Agency speculates that "firefighting foam used in exercises or actual fires at steam electric plants *could* contain PFAS." *Id.* (emphasis added).

---

[217] Memorandum from Radhika Fox, Assistant Adm'r, EPA, to EPA Regional Water Div. Dirs., Regions 1–10, Addressing PFAS Discharges in NPDES Permits and Through the Pretreatment Program and Monitoring Programs at 2 (Dec. 5, 2022), https://www.epa.gov/system/files/documents/2022-12/NPDES_PFAS_State%20Memo_December_2022.pdf; 88 Fed. Reg. at 18,892 n.190

UWAG objects to any recommendations for PFAS monitoring or restrictions in a final rule. Instead, it would be appropriate to continue the approach identified in EPA's guidance, which properly recognizes that permitting authorities are best positioned to determine whether PFAS monitoring and any restrictions are appropriate for a particular facility.

F. Provisions Requiring ZLD limits for FGDW and BATW the Day After the Cessation Date Are Not "Costless."

EPA proposes to require permitting authorities to include ZLD for FGDW and BATW effective the day after the date of cessation in the permits for facilities in the proposed Early Adopter subcategory and the 2020 Rule's cessation subcategory. While EPA claims these provisions are "costless," 88 Fed. Reg. at 18,858, there are likely significant costs associated with not being able to discharge FGDW and BATW after ceasing coal burning. With a ZLD in force the next day (*e.g.*, January 1, 2029, or January 1, 2033), a facility probably cannot burn coal all the way to December 31 because all of the FGDW and BATW for that unit must be treated and discharged by no later than December 31. This requirement would back up the retirement date by one or two months to treat and discharge the remaining FGDW and BATW, potentially losing the value of one to two months of power generation and causing some additional, significant costs that EPA has not accounted for in the proposal.

To avoid such costs, EPA should simply require ZLD 120 days after cessation of coal burning. This would allow time for orderly cessation of coal burning with routine discharges and allow time to drain sumps and other collections of wastewater.

XI. EPA's Longstanding View That Endangered Species Act Section 7 Does Not Apply to this Rulemaking Is Correct.

UWAG supports EPA's position that the proposed ELG rule is not subject to Endangered Species Act (ESA) Section 7 consultation. EPA's longstanding interpretation of the CWA correctly maintains that an ELG must be "based upon the performance of specified levels of pollution control technology that is available and economically achievable" and is not a discretionary action subject to ESA Section 7 consultation. 2020 Response to Comments at 2-19. EPA has consistently stated over a 25-year period that it does not have the requisite discretion to engage in ESA Section 7 consultation on an ELG rulemaking.

Consistent with its longstanding interpretation, in this 2023 rulemaking, EPA proposes to take the same view as it did in previous ELG rulemakings that the 2023 ELG rulemaking is not subject to ESA Section 7 consultation.[218] EPA's 2023 memo cites to its 2020 Rule Response to Comments. As EPA explained in 2020, "EPA's long-standing legal position, when the Agency first addressed the question of whether Section 7 applies to establishment of technology-based effluent limitations and standards under the Act, in the context of promulgating 1998 revisions to the ELGs for the Pulp, Paper, and Paperboard Industry ... has been that Section 7 does not apply ... based on the language of the Act's technology-based provisions and is supported by relevant legislative history.[219]

EPA's 25-year legal position is grounded in the text of the statute governing effluent limitation guidelines. As EPA noted, "[t]hese limitations and standards are established based upon the performance of specified levels of pollution control technology that is available and economically achievable." *Id.* Accordingly:

> EPA's discretion to establish limitations based on a technology is limited to considering the factors contained in Clean Water Act sections 301, 304, and 306 and finding that the technology is both available and economically achievable. Under the Act, *any limitations more stringent than those authorized based on technology-based factors in order to provide additional protection of the quality of receiving waters (including protection to listed species or designated critical habitat associated with such quality) may only be imposed outside this*

[218] *See* Memorandum from U.S. EPA, to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819, Endangered Species Act (Mar. 6, 2023), EPA-HQ-OW-2009-0819-9891 (DCN SE10438).

[219] *See* 2020 Response to Comments at 2-19.

> *rulemaking* in the permitting process based on the water quality-based provisions of the Act.

Id. at 2-20 (emphasis added).

EPA's position is further supported by *WildEarth Guardians v. EPA*, 759 F.3d 1196 (10th Cir. 2014), in which the court found that EPA had no duty to consult on promulgation of a Federal Implementation Plan (FIP) to reduce regional haze. The court held that the duty to consult "is bounded by the agency action" and, in this case, EPA's authority was limited to taking actions "necessary or appropriate to protect air quality," which it did by promulgating a FIP to reduce regional haze. *Id.* at 1208–09. EPA's "action" did not trigger ESA consultation requirements. *Id.* at 1209–10. The court rejected Petitioners' argument that EPA had a duty to consult because EPA had discretion to directly regulate mercury and selenium in the FIP, noting that the consultation obligation attaches to the agency action in question, not "everything [the agency] might do." *Id.* at 1209. The court further explained, "the possibility that the EPA would have discretion—in some other regulatory proceeding—to directly regulate mercury and selenium emissions at the Plant did not impose a duty to consult under the ESA before taking the only action under consideration at the time." *Id.* at 1209–10. Similar to the action reviewed in the *WildEarth Guardians* case, in setting an effluent limitation guideline, EPA does not have discretion to impose more stringent requirements to ensure protection of listed species.

For all of these reasons, EPA appropriately determined that it does not have the requisite discretion to engage in ESA Section 7 consultation on this ELG rulemaking.

Reference List

American Electric Power Co., Inc. 2023. *Form 10-Q for the Quarterly Period Ended March 31, 2023* (May 4). https://www.aep.com/investors/financial.

American Water Works Assoc. and Assoc. of Metropolitan Water Agencies. 2018. Letter to the Hon. Scott Pruitt, Adm'r, EPA, Steam Electric Power Plant Effluent Limitations Guidelines Rulemaking and Safe Drinking Water (June 8), DCN SE06903, EPA-HQ-OW-2009-0819-7598.

Behr, Peter. 2022. *U.S. risks power outages as coal, gas plants retire—NERC*, ENERGYWIRE (Dec. 19).

Biden-Harris Transition. 2021. Fact Sheet: List of Agency Actions for Review - Actions Address the COVID-19 Pandemic, Provide Economic Relief, Tackle Climate Change, and Advance Racial Equity (Jan. 20).

Blunt, Katherine and Phred Dvorak. 2022. *Climate Bill's Success Hinges on Timely Renewable Projects Build Out*, WALL ST. J. (Aug. 13). https://www.wsj.com/articles/climate-bills-success-hinges-on-timely-renewable-project-build-out-11660383180.

Brattle. 2023. *Managing Coal Plant Retirements for an Orderly Transition to Decarbonization*. THE BRATTLE GROUP. www.brattle.com/managing-coal-plant-costs/. Last visited May 17, 2023.

Chemnick, Jean, H. Northey, and S. Reilly. 2022. *How Biden Could Close Coal Plants Without CO2 Regulations.* CLIMATEWIRE (Jan. 24). https://www.eenews.net/articles/how-biden-could-close-coal-plants-without-co2-regulations/.

Christie, Mark C., Comm'r, FERC. 2023. Opening Statement, Hearing before the S. Comm. on Energy & Nat. Res. (May 4).

Clark, Kevin. 2022. *Explaining the Delays of U.S. Coal Plant Retirements*, POWER ENGINEERING (Aug. 23). https://www.power-eng.com/coal/explaining-the-delays-of-u-s-coal-plant-retirements/#:~:text=In%20June%2C%20Wisconsin%20utilities%20WEC%20Energy%20Group%20and,challenges%20have%20surfaced%20in%20Missouri%20and%20New%20Mexico. Last visited May 18, 2023.

Cornwell, David A., et al. 2018. *Modeling Bromide River Transport and Bromide Impacts on Disinfection Byproducts*, J. OF THE AM. WATER WORKS ASS'N, Volume 110, Issue 11 (Nov.), DCN SE07937, EPA-HQ-OW-2009-0819-7856.

Dalton, Matthew. 2022. *Nuclear Power is Poised for a Comeback. The Problem is Building the Reactors*, WALL ST. J. (June 23). https://www.wsj.com/articles/nuclear-power-climate-change-russia-energy-11655995024.

Danly, James P., Comm'r, FERC. 2023. Written Testimony before Full Committee Hearing to Conduct Oversight of FERC, Hearing Before the S. Comm. on Energy & Nat. Res. (May 4).

Dominion Energy South Carolina, Inc. 2023. *2023 Integrated Resource Plan* (filed Jan. 30, 2023).

Duke Energy. 2022. Duke Energy Response to Voluntary Information Request (Feb. 28), DCN DCN SE09782, EPA-HQ-OW-2009-0819-9087.

Eastern Research Group, Inc. (ERG). 2018. Memorandum from Sara Bossenbroek and Danielle Lewis to Steam Electric Rulemaking Record - Notes from Meeting with Oasys Water™ (Feb. 16), DCN SE06915, EPA-HQ-OW-2009-0819-7334.

ERG. 2019. Memorandum from Elizabeth Gentile to Steam Electric Rulemaking Record, FGD and Bottom Ash Implementation Timing - FGD and Bottom Ash Implementation Timing - DCN SE08480 (Oct. 17), EPA-HQ-OW-2009-0819-8191.

ERG. 2020. Memorandum from Deb Bartram & Danielle Stewart to Steam Electric Rulemaking Record, Notes from Site Call with Duke Energy's Mayo Steam Station (June 15), DCN SE08964, EPA-HQ-OW-2009-0819-8558.

ERG. 2020. Memorandum from Sara Bossenbroek and Tara Stout to Steam Electric Rulemaking Record, Notes from Meeting with DuPont (June 24), DCN SE08618, EPA-HQ-OW-2009-0819-8887.

ERG. 2020. Memorandum from Sara Bossenbroek & Danielle Stewart to Steam Electric Rulemaking Record, Flue Gas Desulfurization Membrane Filtration with Encapsulation Cost Methodology (Aug. 7), DCN SE08625, EPA-HQ-OW-2009-0819-8695.

ERG. 2020. Memorandum from Danielle Stewart, Sara Bossenbroek, and Blake Fox to Steam Electric Rulemaking Record, Notes from Call with Indianapolis Power & Light – Petersburg Generating Station (Aug. 14), DCN SE09218, EPA-HQ-OW-2009-0819-8891.

ERG. 2020. Memorandum to Steam Electric Rulemaking Record, Technologies for the Treatment of Flue Gas Desulfurization Wastewater - DCN SE09213 (Aug. 20), EPA-HQ-OW-2009-0819-8890.

ERG. 2020. Flue Gas Desulfurization Membrane Filtration With Encapsulation Vendor-Specific Cost Methodology - DCN SE08596, EPA-HQ-OW-2009-0819-8918 (posted Aug. 31).

ERG. 2020. Memorandum to Steam Electric Rulemaking Record - Generating Unit-Level Compliance Costs and Pollutant Loadings - DCN SE08638 (Aug. 31), EPA-HW-OW-2009-0819-8934.

ERG. 2023. Combustion Residual Leachate (CRL) Proposed Rule Cost Database (Feb. 28), DCN SE10420, EPA-HQ-OW-2009-0819-9958.

Electric Power Research Institute (EPRI). 2015. *Coal Combustion Residuals Leachate Management: Characterization of Leachate Quality and Evaluation of Leachate Minimization and Management Methods*. EPRI, Palo Alto, CA. 3002006283. DCN SE10386, EPA-HQ-OW-2009-0819-9639.

EPRI. 2016. *Guidance Document for Management of Closed-Loop Bottom Ash Handling Water in Compliance with the 2015 Effluent Limitations Guidelines*. EPRI, Palo Alto, CA. 3002008345. DCN SE06963, EPA-HQ-OW-2009-0819-7362.

EPRI. 2018. *Closed-Loop Bottom Ash Transport Water: Costs and Benefits to Managing Purges*. EPRI, Palo Alto, CA. 3002013706. DCN SE06920, EPA-HQ-OW-2009-0819-7346.

EPRI. 2019. *Impacts of Bromide from Power Plants on Downstream Disinfection Byproduct Formation: A Literature Review*. EPRI, Palo Alto, CA. 3002017477.

EPRI. 2019. *Considerations for Treating Flue Gas Desulfurization Wastewater Using Member and Paste Encapsulation Technologies*. EPRI, Palo Alto, CA. 3002017134. DCN SE10396, EPA-HQ-OW-2009-0819-9672.

EPRI. 2022. *Potential Challenges in Landfill Water Management, Technical Brief – Coal Combustion Products Management*. EPRI, Palo Alto, CA. 3002024772.

EPRI. 2023. *Considerations for Concentrate Management from Wastewater Volume Reduction Technologies.* EPRI, Palo Alto, CA. 3002024773.

EPRI. 2023. Comments on Proposed Effluent Limitations Guidelines Rule, EPA-HQ-OW-2009-0819 (May 26).

Electric Reliability Council of Texas, Inc., Midcontinent Independent System Operator, Inc., PJM Interconnection, L.L.C., and Southwest Power Pool, Inc. 2022. Comments on EPA's Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard (June 21), EPA-HQ-OAR-2021-0668-0413.

Ellison, Kirk. 2019. *Landfill Sequestration of Brine: Research Updates*, 2019 World of Coal Ash Conference, May 13-16, 2019, DCN SE08655A023, EPA-HQ-OW-2009-0819-8721-ATT23

Flessner, Dave. 2023. *TVA turns to the sun for more power but supply chain woes undermine some projects*, CHATTANOOGA TIMES FREE PRESS (May 2). https://www.timesfreepress.com/news/2023/may/02/tva-turns-sun-more-power-supply-chain-woes-tfp/.

Friedman, Lisa. 2022. *EPA Describes How It Will Regulate Power Plants After Supreme Court Setback*. N.Y. TIMES (July 7). https://www.nytimes.com/2022/07/07/climate/epa-greenhouse-gas-power-plant-regulations.html.

GenOn. 2020. Press Release: GenOn Holdings, Inc. Announces Retirement of Chalk Point Coal Units (Aug. 10), DCN SE09604, EPA-HQ-OW-2009-0819-9101.

Gheorghiu, Iulia. 2019. *Transitioning US to 100% renewables by 2030 will cost $4.5 trillion: Wood Mackenzie*, UTILITY DIVE (June 28). https://www.utilitydive.com/news/transitioning-us-to-100-renewables-by-2030-will-cost-rate-payers-45t-wo/557832/. Last visited May 18, 2023.

Good, Kelly D. & Jeanne M. VanBriesen. 2019. *Coal-Fired Power Plant Wet Flue Gas Desulfurization Bromide Discharges to U.S. Watersheds and Their Contributions to Drinking Water Sources*. 53 ENVTL. SCI. & TECH. 213-23. https://doi.org/10.1021/acs.est.8b03036.

Hendricks, Scott, 2020. Letter to Richard Benware, EPA, re: Georgia Power's VSEP Pilot at Plant Scherer and Status of Membrane/Paste Encapsulation Preliminary Research (Apr. 30), DCN SE08619A1, EPA-HQ-OW-2009-0819-8888-ATT1.

Hopey, Don. 2013. *New Castle power plant switching to natural gas.* PITTSBURGH POST-GAZETTE (June 25).

Hunnicutt, Trevor. 2022. *Biden comments on coal-fired plants slammed by Manchin ahead of U.S. midterms*. REUTERS (Nov. 5). https://www.reuters.com/world/us/biden-comments-coal-fired-plants-slammed-by-manchin-ahead-us-midterms-2022-11-05/#:~:text=%22We're%20going%20to%20be,say%20is%20their%20top%20concern.

Hydrometrics, Inc. 2021. *Performance Evaluation Report Plant Site Remedy - 2021 Colstrip Steam Electric Station, Colstrip, Montana* (Oct.). https://deq.mt.gov/Files/DEQAdmin/MFS/Colstrip/ColstripAOCPlantsiteRemedyPerformanceEvaluationReport2021%2010%208%2021.pdf.

Kaeding, Danielle. 2022. *$90M in new pollution controls approved for coal plant in southeastern Wisconsin: Groups critical of costly investment in plant as it transitions to natural gas.* WISCONSIN PUBLIC RADIO (Jan. 17). www.wpr.org/90m-new-pollution-controls-approved-coal-plant-southeastern-wisconsin. Last visited May 17, 2023.

Kentucky PSC. 2021. News Release – PSC Issues Order in Kentucky Power's Request for Mitchell Generating Station Environmental Compliance Projects (July 16).

Longview Water Balance Diagram (Dec. 20, 2019), https://apps.dep.wv.gov/webapp/_dep/securearea/Application/AppIndex.cfm

Manufacturing Tomorrow. 2022. *How Will Labor Shortages Impact Metal Fabrication in 2022?* (Mar. 7). https://www.manufacturingtomorrow.com/story/2022/02/howwill-labor-shortages-impact-metal-fabrication-in-2022/18341/. Last visited May 18, 2023.

McKinsey & Co. 2021. *Solving the net-zero equation: Nine requirements for a more orderly transition* (Oct. 27). www.mckinsey.com/business-functions/sustainability/our-insights/solving-the-net-zero-equation-nine-requirements-for-a-more-orderly-transition. Last visited May 17, 2023.

McVety, Molly. 2022. *Indian River Power Plant shutdown delayed for 4 years. Why your electric bill will rise?* DELAWARE ONLINE (Aug. 3). https://www.delawareonline.com/story/news/local/2022/08/03/coal-powered-indian-river-power-plant-shutdown-delayed/65384383007/. Last visited May 18, 2023.

National Assoc. of Regulatory Utility Commissioners (NARUC). 2020. *Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices* (Jan.).

National Rural Electric Cooperative Association. 2023. Fact Sheet: America's Electric Cooperatives (Apr.). https://www.electric.coop/wp-content/uploads/2023/04/2023_NCS5233_Coop_FactsAndFigures_4.10.23_v3.pdf.

NBC Bay Area. 2022. *PG&E Supply Chain Challenges Could Mean Longer Outages: Report* (Oct. 11). https://www.nbcbayarea.com/investigations/pge-warns-supply-chain-shortages-could-trigger-prolonged-outages/3027640/. Last viewed May 18, 2023.

Nebrig, H.A., Xinjun Teng, and David Downs. 2011. "Preliminary Assessment of a Thermal Zero Liquid Discharge Strategy for Coal-Fired Power Plants," presented at the International Water Conference, November 13-17, 2011, Paper 11-36.

North American Electric Reliability Corporation (NERC). 2019. *Summer Reliability Assessment* (June).

NERC. 2022. *2022 Long-Term Reliability Assessment* (Dec.).

NERC. 2023. *Summer Reliability Assessment* (May).

NERC. 2023. Press Release: Two-thirds of North America Faces Reliability Challenges in the Event of Widespread Heatwaves (May 17).

Patel, Sonal. 2020. *AEP Will Shutter Nearly Half its Giant Coal PowerFleet – 5.6 GW – by 2030*, POWER MAGAZINE (Nov. 10), DCN SE09602, EPA-HQ-OW-2009-0819-9099.

PJM. 2023. *Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Feb. 24).

Reynolds, Travis and Cuong Pham. 2019. "Iatan SDE Design, Operation, Maintenance, and Operating Costs," presentation at International Water Conference 19-05.

Sargent & Lundy, LLC. 2015. Sargent & Lundy Webinar - Steam Electric Effluent Limitations Guidelines (Oct. 29), DCN SE10289, EPA-HQ-OW-2009-0819-9659.

Senior, Constance L., S. Thorneloe, B. Khan, and D. Goss. 2009. *Fate of Mercury Collected from Air Pollution Control Devices*, EM: AIR & WASTE MGMT. ASS'N'S MAGAZINE FOR ENVTL. MANAGERS 15-21 (July).

Sherrick, Brian D. Testimony on behalf of Appalachian Power Co. and wheeling Power Co., before Public Service Commission of W. Va., Company Exhibit BDS-D3, No. 20-____ (undated)

Southern Company. 2021. Third Quarter 2021 Earnings Conference Call (Nov. 4), DCN SE09636, EPA-HQ-OW-2009-0819-9231.

Stevens, Derek, Ph.D., Cheng Yang, Ph.D., and Brandon Kern. Case Studies & Analysis of Reverse Osmosis to Treat Flue Gas Desulfurization Wastewater, IWC 17-74, DCN SE08618A3, EPA-HQ-OW-2009-0819-8887 Attachment 3.

Tetra Tech, EUCI, and OUC. 2013. "Orlando Coal Ash Landfill: A Case History for Designing and Building New Coal Ash Landfills," presented by Mohamad Alhawaree (June 10-11).

United Nations Environment Programme Finance Initiative. 2021. *Decarbonisation and Disruption: Understanding the financial risks of a disorderly transition using climate scenarios*. BANKING, CLIMATE CHANGE, PUBLICATIONS (Feb.). https://www.unepfi.org/industries/banking/decarbonisation-and-disruption/.

United States Dep't of Energy, Office of State and Community Energy Programs. 2023. *Low-Income Community Energy Solutions: Why Institute a Low-Income Lens for Energy?* www.energy.gov/eere/slsc/low-income-community-energy-solutions. Last visited May 25, 2023.

United States Energy Information Administration (EIA). Glossary, https://www.eia.gov/tools/glossary/index.php?id=S. Last visited May 17, 2023.

EIA. 2019. *More U.S. coal-fired power plants are decommissioning as retirements continue*. TODAY IN ENERGY (July 26).

EIA. *Electricity Data Browser, Data Set – Consumption for Electricity Generation*. http://www.eia.gov/electricity/data/browser/#/topic. Last visited May 25, 2023.

United States Environmental Protection Agency (EPA). 1974. Development Document for Proposed Effluent Limitations Guidelines and New Source Performance Standard for the Steam Electric Power Generating Point Source Category, EPA 440/1-73-029 (March), EPA-HQ-OW-2009-0819-5450-Att18.

EPA. 1974. Development Document for Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Power Generating Point Source Category, EPA 440/1-74 029-a. (Oct.), EPA-HQ-OW-2009-0819-8721-Att34.

EPA. 1982. Development Document for Final Effluent Limitations Guidelines, New Source Performance Standards, and Pretreatment Standards for the Steam Electric Point Source Category, EPA-440/1-82/029, EPA-HQ-OW-2009-0819-2186 (Nov.).

EPA. 2012. Toxic Weighting Factors Methodology, EPA-820-R-12-005 (Mar).

EPA. 2013. Technical Development Document for the Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-13-002 (Apr.), DCN SE01964, EPA-HQ-OW-2009-0819-2257.

EPA. 2015. Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-15-007 (Sept.), DCN SE05904, EPA-HQ-OW-2009-0819-6432.

EPA. 2015. Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category: EPA's Response to Public Comments (Sept.), DCN SE05958, EPA-HQ-OW- 2009-0819-6469.

EPA. 2016. Definition and Procedure for the Determination of the Method Detection Limit, Revision 2, EPA 821-R-16-006 (Dec.).

EPA. 2018. Letter from Robert K. Wood, Dir., Eng'r & Analysis Div., EPA, to Mark McCullough, Executive Vice President – Generation, American Electric Power (Jan. 3), DCN SE06675, EPA-HQ-OW-2009-0819-7296.

EPA. 2018. Final 2016 Effluent Guidelines Program Plan 2016 (Apr.), EPA-HQ-OLEM-2017-0286-2232.

EPA. 2021. Press Release - EPA Announces Intent to Bolster Limits on Water Pollution from Power Plants (July 26).

EPA. 2020. Response to Public Comments for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Aug.), DCN SE08615, EPA-HQ-OW-2009-0819-9015.

EPA. 2020. Supplemental Technical Development Document for Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-20-001 (Aug.), DCN SE08650, EPA-HQ-OW-2009-0819-8935

EPA. 2020. Memorandum from Richard Benware to Steam Electric Rulemaking Record , Steam Electric Effluent Guidelines Reconsideration – Evaluation of Final Rule Subcategories (Aug. 31), DCN SE09071, EPA-HQ-OW-2009-0819-8964.

EPA. 2021. Consolidated notes from March 11, 2021, meeting with Environmental Petitioners in *Appalachian Voices v. EPA,* No. 20-2187 (4th Cir.), FOIA EPA-2022-003242, 063022 Responsive Documents 1, ED_006652_00039079-00001.

EPA. 2021. Agenda for June 14, 2021 1pm Meeting w/ Melissa & Benita on Steam Electric, Steam Electric 2020 Rule Discussion (June 14), FOIA EPA-2022-003242, 063022 Response Documents 2, ED_006652_00039277-00001.

EPA. 2021. Memorandum from Radhika Fox, OW, EPA, Briefing Memo, Memorandum for the Administrator, Steam Electric Reconsideration Option Selection (June 29), FOIA EPA-2022-003242, 063022 Response Documents 2, ED_006652_00039279-00001.

EPA. 2021. Letter from Robert K. Wood, Dir., Eng'g & Analysis Div., to Jeffrey Hanson, Dir., Envt. Servs. & Corp. Sustainability, Alliant Energy Corp. Services, Inc. (Dec. 21), DCN SE09689, EPA-HQ-OW-2009-0819-9697.

EPA. 2022. Memorandum to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819, Notes from Meeting with Burns & McDonnell on September 10, 2021 (Jan. 14), DCN SE10248, EPA-HQ-OW-2009-0819-9653.

EPA. 2022. Memorandum to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819 - Notes from Meeting with EPA, UCC, and ERG on August 26, 2021 (Jan. 14), DCN SE10368, EPA-HQ-2009-0819-9696.

EPA. 2022. Memorandum from Richard Benware, Steam Electric ELG Team Leader, Eng'r & Analysis Div., Office of Sci. & Tech., U.S. EPA Office of Water, thru Robert Wood, Dir., Eng'r & Analysis Div., Office of Sci. & Tech., U.S. EPA Office of Water, Posting EPA-HQ-OW-2009-0819 to Regulations.gov for Public Access (Feb. 1), EPA-HQ-OW-2009-0819-9017.

EPA. 2022. 063022 EPA-2022-003242 Responsive Documents 1 (released July 4, 2022).

EPA. 2022. 063022 EPA-2022-003242 Responsive Documents 2 (released July 4, 2022).

EPA. 2022. Memorandum to Steam Electric Record – EPA-HQ-OW-2009-0819 - Flue Gas Desulfurization Flow Methodology for Compliance Costs and Pollutant Loadings (Sept. 12), DCN SE10287, EPA-HQ-OW-2009-0819-9379.

EPA. 2022. Memorandum to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819, Notes from Vendor Call with New Logic on October 1, 2021 (Sept. 26), DCN SE10290, EPA-HQ-OW-2009-0819-9380.

EPA. 2022. Memorandum to Steam Electric Record – EPA-HQ-OW-2009-0819, Notes from Vendor Call with DuPont October 29 and December 8, 2021 (Nov. 14), DCN SE10245, EPA-HQ-OW-2009-0819-9378.

EPA. 2022. Memorandum from Radhika Fox, Assistant Adm'r, EPA, to EPA Regional Water Div. Dirs., Regions 1–10, Addressing PFAS Discharges in NPDES Permits and Through the Pretreatment Program and Monitoring Programs (Dec. 5). https://www.epa.gov/system/files/documents/2022-12/NPDES_PFAS_State%20Memo_December_2022.pdf.

EPA. 2022. Memorandum - Combustion Residual Leachate Analytical Data Evaluation (Dec. 13), DCN SE10249, EPA-HQ-OW-2009-0819-9637.

EPA. 2022. Memorandum to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819, Spray Dryer Evaporator Cost Methodology - DCN SE10247 (Dec. 13), EPA-HQ-OW-2009-0819-9684.

EPA. 2022. Memorandum from EPA to Steam Electric Record, Notes from Call with City Water, Light, and Power on November 15, 2021 (Dec. 22), DCN SE10256, EPA-HQ-OW-2009-0819-9377.

EPA. 2023. Technical Development Document for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Feb.), DCN SE10372, EPA-HQ-OW-2009-0819-9950.

EPA. 2023. Memorandum to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819, Update to Industry Profile for the 2023 Steam Electric Power Generating Effluent Guidelines Proposed Rule - DCN SE10241 (Feb. 7), EPA-HQ-OW-2009-0819-9622.

EPA. 2023. CCR Lined Landfill Sensitivity Analysis (Feb. 13), DCN SE10411, EPA-HQ-OW-2009-0819-9646.

EPA. 2023. Legacy Surface Impoundment Leachate Sensitivity Analysis (Feb. 14), DCN SE10415, EPA-HQ-OW-2009-0819-9645.

EPA. 2023. Memorandum to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819 - Technologies for the Treatment of Flue Gas Desulfurization Wastewater, Coal Combustion Residual Leachate, and Pond Dewatering - DCN SE10281 (Feb. 15), EPA-HQ-OW-2009-0819-9656.

EPA. 2023. Memorandum to Steam Electric Record – EPA-HQ-OW-2009-0819, Notes from Meetings with UCC Environmental June 10 and October 13, 2022 and Other UCC Correspondence (Feb. 15), DCN SE10457, EPA-HQ-OW-2009-0819-9963.

EPA. 2023. Memorandum to ELG Planning Record: EPA-HQ-OW-2009-0819, Notes from Meeting with BKT - April 9, 2021 (Feb. 21), DCN SE10253, EPA-HQ-OW-2009-0819-9560.

EPA. 2023. FGD Wastewater Proposed Rule Cost Database (Feb. 23), DCN SE10416, EPA-HQ-OW-2009-0819-9955.

EPA. 2023. Memorandum to Steam Electric Rulemaking Record - EPA-HQ-OW-2009-0819, 2023 Steam Electric Supplemental Proposed Rule: Fly Ash Availability, DCN SE10242 (Feb. 27), EPA-HQ-OW-2009-0819-9685.

EPA. 2023. Regulatory Impact Analysis for Proposed Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-23-002 (Feb. 28).

EPA. 2023. Memorandum to Steam Electric Rulemaking Record – EPA-HQ-OW-2009-0819 - Generating Unit-Level Costs and Loadings Estimates by Regulatory Option for the 2023 Proposed Rule (Feb. 28), DCN SE10381, EPA-HQ-OW-2009-0819-9686.

EPA. 2023. Benefit and Cost Analysis for Proposed Supplemental ELGs and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-23-003 (Feb. 28).

EPA. 2023. Memorandum to Steam Electric Rulemaking Record - Endangered Species Act (Mar. 6), DCN SE10438, EPA-HQ-OW-2009-0819-9891.

EPA. 2023. Memorandum to Steam Electric Rulemaking Record - EPA-HQ-OW-2009-0819, Evaluation of Potential CRL in Groundwater (Mar. 23), DCN SE10250, EPA-HQ-OW-2009-0819-9678.

United States Office of Management and Budget. 2003. Circular A-4, Regulatory Analysis (Sept. 17). https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/.

University of Alaska Fairbanks. *UAF Heat and Power Plant Major Upgrade Project* (undated). https://www.uaf.edu/heatandpower/files/CHP_briefing_2013.pdf.

UTILITY DIVE. 2023. *Electricity prices surged 14.3% in 2022, double overall inflation: US report* (Jan. 19). https://www.utilitydive.com/news/electricity-prices-inflation-consumer-price-index/640656/. Last visited May 18, 2023.

Utility Water Act Group (UWAG). 2017. Petition for Rulemaking to Reconsider and Administratively Stay the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Final Rule, 80 Fed. Reg. 67,838-903 (Nov. 3, 2015) (Mar. 24), EPA-HQ-OW-2009-0819-6478.

UWAG. 2020. Comments on EPA’s Proposed Rule: Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 84 Fed. Reg. 64,620 (Nov. 22, 2019), EPA-HQ-OW-2009-0819-8456 (Jan. 21).

UWAG. 2021. Comments in Response to EPA’s Preliminary Effluent Guidelines Program Plan 15, EPA-HQ-OW-2021-0547-0465 (Oct. 14).

UWAG. 2023. Cost Comparison for Installing membrane Filtration Treatment (submitted to U.S. Office of Management and Budget (OMB)) (Feb. 7).

UWAG. 2023. Letter to EPA - Request for 60-Day Extension of Comment Deadline for Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Category (Mar. 29), EPA-HQ-OW-2009-0819-9981.

VanBriesen, Jeanne M., Ph.D., P.E. 2019. *Methods to Assess Anthropogenic Bromide Loads from Coal-Fired Power Plants and Their Potential Effect on Downstream Drinking Water Utilities* (Dec.). www.awwa.org/Portals/0/AWWA/ETS/Resources/17861ManagingBromideREPORT.pdf?ver=2020-01-09-151706-107.

Water Solutions. 2019. *Possibility flows with us; MLD-ZLD Flue-gas Desulfurization Wastewater Treatment*, DCN SE08618A1, EPA-HQ-OW-2009-0819-8887 Attachment 1.

World Health Organization. 2003. *Total dissolved solids in Drinking-water, Background document for development of WHO Guidelines for Drinking-water Quality*, WHO/SDE/WSH/03.04/16. https://cdn.who.int/media/docs/default-source/wash-documents/wash-chemicals/tds.pdf?sfvrsn=3e6d651e_4. Last visited May 23, 2023.

PUBLIC UTILITY/PUBLIC SERVICE COMMISSION PROCEEDINGS

In re Petition of Appalachian Power Co., No. 20-1040-E-CN (W. Va. PSC)

Commission Order, *In re Appalachian Power Co. and Wheeling Power Co. Application for Certificate of Public Convenience*, No. 20-1040-E-CN, (W. Va. Public Service Commission (PSC) Aug. 4, 2021).

Commission Order, *In re Appalachian Power Co. and Wheeling Power Co. Application for Certificate of Public Convenience*, No. 20-1040-E-CN, (W. Va. PSC Oct. 12, 2021).

In re Petition of Appalachian Power Co. , No. PUR-2020-00258 (Va. State Corp. Comm'n)

Order Granting Rate Adjustment Clause, *In re Appalachian Power Co*., No. PUR-2020-00258 (Va. State Corp. Comm'n Aug. 23, 2021).

In re Petition of Appalachian Power Co. , No. PUR-2022-00001 (Va. State Corp. Comm'n)

Final Order, *In re Petition of Appalachian Power Co*., No. PUR-2022-00001, (Va. State Corp. Comm'n Nov. 21, 2022).

In re *Electronic Application of Kentucky Power Company,* No. 2021-00004 (Ky. PSC)

Commission Order, *In re Electronic Application of Kentucky Power Company for Approval of a Certificate of Public Convenience and Necessity for Environmental Project Construction at the Mitchell Generating Station, An Amended Environmental Compliance Plan, and Revised Environmental Surcharge Tariff Sheets*, No. 2021-00004 (Ky. PSC July 15, 2021).

In re *Electronic Application of Louisville Gas and Electric and Kentucky Utilities Companies*, Nos. 2020-00060 and 2020-00061 (Ky. PSC

Direct Testimony of Robert M. Conroy, Vice President, State Regulation & Rates, Kentucky Utilities Co., Louisville Gas & Elec. Co., Exhibit RSS-2, *In re Electronic Application of Louisville Gas and Electric and Kentucky Utilities Companies for Approval of Their 2020 Compliance Plan for Recovery by Environmental Surcharge,* Nos. 2020-00060 and 2020-00061 (Ky. PSC Mar. 31, 2020).

In re Joint Application of Wisconsin Electric Power et al., No. 5-CE-152 (Wis. PSC)

Final Decision, *In re Joint Application of Wisconsin Electric Power et al., for a Certificate of Authority to Construct a New Wastewater Treatment System at the Elm Road Generating Station, Milwaukee Cnty, Wis.*, No. 5-CE-152 (Wis. PSC Dec. 14, 2021).

In re Petition of Monongahela Power Co. & Potomac Edison Co., No. 21-0857-E-CN (W. Va. PSC)

Petition for Approval of an ELG Project and Related Surcharge at Exhibit DVS-D, 4-5 of 12 and 9 of 12, *In re Monongahela Power Co. & The Potomac Edison Co.*, No. 21-0857-E-CN (W. Va. PSC Dec. 17, 2021).

OTHER PROCEEDINGS

County of Maui v. Hawai'I Wildlife Fund, No. 18-260

Brief of *Amici Curiae* State of West Virginia et al. in Support of Petitioner, *County of Maui v. Hawai'I Wildlife Fund*, No. 18-260 (Sup. Ct. May 16, 2019).