JOHN BEL EDWARDS
GOVERNOR

CHUCK CARR BROWN, PH.D.
SECRETARY

State of Louisiana

DEPARTMENT OF ENVIRONMENTAL QUALITY
OFFICE OF THE SECRETARY

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AIR PLANNING SEC.
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Mr. Ron Curry, Administrator
US EPA Region 6, 6RA
1445 Ross Avenue, Suite 1200
Dallas Texas 75202-2733

RE: Louisiana's State Implementation Plan Revisions
Regional Haze Rule Non-EGU Best Available Retrofit Technology

Dear Mr. Curry:

The State of Louisiana has approved and is submitting the State Implementation Plan revision for the Regional Haze Rule as required by the Clean Air Act Amendments of 1990 and 40 CFR 51, Appendix Y.

Please contact the Office of Environmental Services through Vivian H. Aucoin at (225) 219-3482 if you have any questions.

Best wishes and warm personal regards.

Sincerely,

Chuck Carr Brown, Ph.D.
Secretary

8/11/16
Date

Enclosures

Cc: Mark Hansen, EPA Region 6
Guy Donaldson, EPA Region 6

Post Office Box 4301 • Baton Rouge, Louisiana 70821-4301 • Phone 225-219-3953 • Fax 225-219-3971
www.deq.louisiana.gov

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

Regional Haze State Implementation plan

Non-EGU BART Analysis

Submitted to:
EPA Region 6
1445 Ross Avenue, Suite 1200
Dallas TX 75202-2733

Final August 2016

I. Background on the Regional Haze Rule

A. Plan Submission

Pursuant to the requirements of 40 CFR§51.308(a) and (b), the Louisiana Department of Environmental Quality (LDEQ) hereby submits the Regional Haze State Implementation Plan (RH SIP) revision as adopted to meet the requirements of US Environmental Protection Agency's (EPA) Regional Haze rules and to comply with requirements set forth in the Clean Air Act (CAA) Amendments of 1990. The revision will address the core requirements pursuant to §51.308 (d) and the Best Available Retrofit Technology (BART) components of §50.308(e). Regional planning, coordination with other States/Tribes and the Federal Land Manager (FLM), and a commitment to provide future SIP revisions and adequacy determinations will also be addressed. The RH SIP has been adopted in accordance with State laws and rules.

Further, this revision fulfills the requirements of Section 110(a)(2)(d)(i)(II) as it contains adequate provisions prohibiting "any source or other type of emission activity within the State from emitting any air pollutant in amounts which will interfere with measures required to be included in applicable implementation plans for this or any other State under part C to ...protect visibility."

On July 3, 2012, the EPA finalized a partial limited approval and a partial disapproval of a revision to the RH SIP submitted June 13, 2008 that addressed regional haze/visibility for the first period of implementation. (77 FR 39425)

US EPA found that the following elements satisfied the federal requirements insofar as they do not rely on the sulfur dioxide (SO_2) reductions from the Clean Air Interstate Rule (CAIR): the state's identification of affected Class I areas; the establishment of baseline, natural and current visibility conditions, including the Uniform Rate of Progress (URP); coordination of reasonably attributable visibility impairment (RAVI) and RH requirements; the RH monitoring strategy and other SIP requirements under Title 40 of the Code of Federal Regulations [denoted as 40 CFR Part 51.308(d)(4)]; the state's commitment to submit periodic RH SIP revisions and periodic progress reports describing progress towards the state's Reasonable Progress Goals (RPGs); the state's commitment to make a determination of the adequacy of the existing SIP at the time a progress report is submitted; and the state's coordination with the FLMs.

The US EPA further outlined those elements that were included in the partial disapproval. The US EPA found that certain elements of the Best Available Retrofit Technology (BART) evaluations and determinations were not fully adequate to meet the federal regulations. The LDEQ will address only those BART facilities that were not included in the CAIR/CSAPR program or the non-electric generating units (Non-EGUs). This RH SIP submittal is intended to supersede the portions of LDEQ's 2008 SIP submittal addressing non-EGU BART that EPA found deficient in the partial disapproval action at 77 FR 39425.

B. Legal Authority

The Louisiana Environmental Quality Act, La.R.S.30.2001, et seq., (the Act) grants the secretary of the LDEQ specific authority to adopt, amend, or repeal those rules and regulations that are deemed necessary for the protection of the state's environment. Further, the Act provides the secretary with the general power to assure compliance with applicable federal laws and regulations and to assume authority for those delegated programs that exist under the provision of the CAA Amendments of 1990.

C. Public Notice

In accordance with La. R.S. 49:950, et seq., and to comply with 40 CFR§51.285 Public Notification, the LDEQ published a notice seeking comment on this proposed SIP revision on April 20, 2014 in the *Louisiana Register*. A public hearing concerning this proposed SIP was held on May 22, 2014 in the Galvez Building, Oliver Pollock Room C-111 at 602 N. Fifth Street in Baton Rouge, Louisiana. The comment period closed at 4:30 p.m. on May 22, 2014. A second public hearing was held on July 29, 2014; the comment period ended at 4:30 pm on the same day. A copy of the transcript, response to comments received and the notices are included in Appendix A.

Based upon comments and revisions to the previous submittal, the LDEQ is once again seeking public input. A potpourri notice is scheduled to be published on December 20, 2015; the comment period will end at the close of business on January 27, 2016. A copy of the potpourri notice is also included in Appendix A.

D. Commitment to Plan Revision

The consultation process will continue between LDEQ, the states and the FLM as the federal regional haze program progresses. Consultation will also continue between Louisiana and states located in the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) as well as those in the Central States Air Resources Association (CenSARA) that will have information pertinent to the five-year progress reports and development/review of any SIP revisions deemed necessary. This will also provide for consideration of any other programs that are implemented and have the potential to contribute to the impairment of visibility of Class 1 areas.

E. History of Regional Haze

In amendments to the CAA in 1977, Congress added Section 169 (42 U.S.C. 7491), setting forth the following national visibility goal of restoring pristine conditions in national parks and wilderness areas:

> *Congress hereby declares as a national goal the preservation of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas with impairment from man-made air pollution.*

Over the following years, modest steps were taken to address the visibility problems in Class I areas. The control measures taken mainly addressed plume blight from specific pollution sources and did little to address regional haze issues in the Eastern United States. Plume blight occurs when a point source such as a smoke stack emits particulate matter or nitrogen dioxide into a stable atmosphere. These pollutants can form a thin, dark, coherent plume obscuring the view. Blight happens before the plume has been dispersed so widely that it is

indistinct from the background. Both contrast and coloration may vary depending upon the plume constituents, the viewing background, the viewer angle, and the angle of the sun. [1]

In addition to authorizing creation of visibility transport commissions and setting forth their duties, Section 169B(f) of the CAA specifically mandated creation of the Grand Canyon Visibility Transport Commission(Commission) . Following four years of research and policy development the Commission submitted its report to EPA in June 1996. This report, as well as the many research reports prepared by the Commission, contributed invaluable information to EPA in its development of the Federal Regional Haze rule.

EPA's Regional Haze rule was adopted on July 1, 1999, and went into effect on August 30, 1999. The Regional Haze rule aimed to achieve national visibility goals by 2064. This rulemaking addressed the combined visibility effects of various pollution sources over a wide geographic region. This wide reaching pollution strategy meant that many states – even those without Class I Areas – would be required to participate in haze reduction efforts. EPA designated five Regional Planning Organizations (RPO) to assist with the coordination and cooperation needed to address the visibility issue. Those states that make up the midsection of the contiguous United States were designated as Central Regional Air Planning Association (CENRAP). Louisiana is associated with this RPO.

On May 24, 2002 the US Court of Appeals, DC District Court ruled on the challenge brought by the American Corn Growers Association against EPA's Regional Haze rule of 1999. The Court remanded to EPA the BART provisions of the rule, and denied industry's challenge to the haze rule goals of natural visibility and no degradation requirements. EPA proposed revisions to the Regional Haze rule pursuant to the remand. The BART rule was adopted on October 13, 2006 and went into effect on December 12, 2006. To facilitate the review of this SIP by EPA, FLM, stakeholders and the public, a guide is provided in 40 CFR 51.308, *Regional Haze Program Requirements*.

F. Breton National Wilderness Area (Class I)

The state of Louisiana has one Class I area within its borders, namely the *Breton National Wilderness Area (Breton)*. Established in 1904, Breton is the second oldest refuge in the National Wildlife Refuge System, and is comprised of a series of barrier islands including Breton Island and all of the Chandeleur Islands which are located in St. Bernard Parish, Louisiana. President Theodore Roosevelt heard about the destruction of the birds and their eggs on the barrier island chain and soon afterward awarded it Nation Wildlife Refuge status. Breton was the only national refuge that Roosevelt ever visited.[2]

The barrier island chain was formed from the remnants of the Mississippi River's former St. Bernard Delta, which was active 2000 years ago. The size and shape of the barrier islands chain is constantly altered by tropical storms, wind, and tidal action. The area above mean high tide is approximately 6,923 acres; however, Hurricanes

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[1] http://www.fs.fed.us/air/source01.htm#plu

[2] http://www.fws.gov/breton/

Katrina and Rita reduced the islands themselves from 5.64 square miles to two square miles.[3] The refuge is approximately 30 miles off the southeast coast of Louisiana.

A portion of Breton has wilderness status and is classified as a mandatory Class I Federal area. Because of this classification, it is afforded visibility protection by the CAA as amended in 1977. Visibility is a term used to characterize the physical limitations in ambient air quality that affect visual range, contrast and coloration. Visibility limitations may be natural, such as fog and mist, or may be caused by manmade air pollution.

G. Louisiana's Visibility History

The CAA amendments of 1977, especially Section 169A, established the protection of visibility in Class I areas as a national goal. In 1980, the US EPA established a phased regulatory approach to visibility protection. The emphasis of the first phase was to remedy existing and future impairment caused by air emissions. These visibility protection regulations established long-range goals, a planning process, implementation procedures, new source review, and a monitoring strategy for all states containing Class I areas. While these regulations remain unchanged, the 1990 amendments of the CAA reaffirmed the importance of visibility protection.

Louisiana submitted a Part I Visibility Plan on October 9, 1985 that was approved by US EPA in the June 10, 1986 Federal Register (51 FR 20967). The SIP revision, "Protection of Visibility, Proposed Part II – Long Term Strategy," was approved by US EPA in the December 19, 1988 Federal Register (53 FR 50958). The approved SIP met the requirements of 40 CFR § 51.302 and 51.306.

Louisiana submitted an update to this SIP every three years in which the LDEQ reviewed the long-term strategy to ensure that the SIP was adequate for preventing impairment of visibility at Breton in agreement with Phase I US EPA visibility regulations. Further, it was used to provide the public and US EPA a comprehensive analysis of the progress toward the national visibility goal.

In agreement with Louisiana's long-term strategy, a triennial review of emission inventories of stationary sources in parishes within 100-km distance of Breton was performed. The emission data was obtained from certified actuals reported by stationary sources to the LDEQ.

Data collected and analyzed was on pollutants chosen due to their effect on visibility. These pollutants were: total suspended particulates and particulate matter (PM_{10}), sulfur oxides, nitrogen oxides and volatile organic compounds. In the 2003 report, certified actuals were obtained from the Mississippi Department of Environmental Quality for those counties within the 100-km radius of Breton.

H. Class I Areas outside the State Boundaries

Section 51.308(d) directs each state to address regional haze not only for those Class I areas located within its political boundaries, but also those Class I areas that are located outside the political boundary which may be affected by emissions from within the State. The proximity of facilities in central and northern Louisiana could have a visibility impact on Caney Creek Wilderness Area in southwest Arkansas. CALPUFF modeling has shown that, at the present time, these facilities bear no impact. However, Louisiana will continue to follow the protocol for

[3] ibid

permitting new construction and major modifications as is presented in our regulations as well as consultation with the appropriate federal agencies.

II. BART Analysis

On July 3, 2012, the US EPA published in the Federal Register (77 FR 39425) a notice pertaining to the Louisiana RH SIP. In this notice, the EPA finalized a partial disapproval because of deficiencies in the Louisiana RH SIP submittal pertaining to the BART evaluations for four non-electric generation units (non-EGUs) that are subject-to-BART sources. The four non-EGUs are Phillips 66 Company-Alliance Refinery (formerly ConocoPhillips); Mosaic Fertilizer LLC, Uncle Sam Plant; Eco-Services Operations, LLC (formerly Rhodia) and Sid Richardson Carbon Co.

A. Mosaic Fertilizer LLC, Uncle Sam Plant

Mosaic Fertilizer, LLC owns and operates the Uncle Sam Plant (Mosaic) in St. James Parish, Louisiana and produces phosphoric acid and sulfuric acid. In the original RH SIP submittal, Mosaic based its modeling on future controls that were to be installed on the A-Train Sulfuric Acid Stack. Based on the modeling results, the LDEQ listed the facility as passing both the screening modeling as well as the refined modeling. As such, the facility was not required by LDEQ to perform an engineering analysis.

In its finding in 2012, the EPA determined that the state should have identified the Mosaic facility as being subject to BART and made a BART evaluation for the source. The LDEQ agrees that Mosaic should be identified as a BART facility and as such, Mosaic has performed the necessary modeling and 5-factor analysis. Mosaic has determined that no additional emissions control technologies are required to be installed at the plant for BART compliance purposes. The modeling and 5-factor analysis indicated that the existing operations and emissions control technologies represent BART. The report can be found in its entirety in Appendix X1.

In its finding, the US EPA determined that the state should have identified the Mosaic facility as being subject to BART and made a BART evaluation for the source. The LDEQ agrees that Mosaic should be identified as a BART facility. Mosaic has installed controls required by its consent decree for Sulfuric Acid Trains A, D, and E. Train A and D are subject BART but significant reductions have been made on the Train E also. The following is a summary of these controls.

- A scrubber system has been installed on Train A reducing SO_2 emissions by 9,490 tons per year.
- SO_2 emissions from Train D have been reduced by 576 tons per year.

The LDEQ finds that the current controls installed on these sources along with the current operating conditions and permit limits at Mosaic are consistent with the future case modeled by Environ and that the visibility impact from the facility at Breton is less than 0.5 deciviews. Furthermore, LDEQ finds that additional control for SO2 would not provide sufficient visibility benefits to be warranted. LDEQ made this determination based upon the cost of emission reductions and visibility improvements discussion in the 5-factor analysis. Therefore LDEQ finds that Mosaic, with its current controls and operating conditions, has satisfied BART. The emissions limits for Mosaic

under current controls and operating conditions are included in the Administrative Order on Consent in accordance with 40 CFR 51.308(4)(e) and are federally enforceable. (Appendix B)

B. Phillips 66 Company-Alliance Refinery (formerly ConocoPhillips)

The Phillips 66 Company (Phillips 66) operates a refinery near Belle Chasse, Louisiana and is a subject-to-BART source. On December 5, 2005, Phillips 66, the United States of America and the State of Louisiana, entered into a Consent Decree (CD) as part of the National Refinery Iniative for the Belle Chasse (Alliance) Refinery. The BART engineering analysis provided by Phillips 66 utilized emission reductions that are mandated per the CD for the fluidized catalytic cracker (FCCU), the process refinery flares and the crude unit heater. Implementation of these control projects as per the CD emissions reduction requirements have resulted in reducing the overall site visibility impacts. However, the LDEQ did not provide a complete BART evaluation for these units with the applicable emissions limits in the original SIP submittal; Phillips 66 has since provided those documents and they are included in Appendix C.

There are also other units subject to BART, namely the cooling water tower and the gas-fired heaters. LDEQ included an analysis for PM and PM_{10} for the cooling tower and an analysis for NOx for the process heaters. It was determined that there were no cost effective controls; US EPA agreed with the analysis that there were no additional controls required for the units to meet BART.

Phillips 66 has installed controls required by the CD for the fluidized catalytic cracker, process refinery flares and the crude unit heater. The following is a summary of these controls:

- A wet gas scrubber (WGS) was installed on the FCCU in 2009 that reduced SO_2 emissions by 2500 tpy and PM emissions by 220 tpy. Selective Catalytic Reduction (SCR) is scheduled to be installed by 2015 that will reduce NOx emissions by 760 tpy;
- SCR was installed on the crude unit heater in 2009 that reduced NOx emissions by 700 tpy; NOx Continuous Emissions Monitoring was also installed on the unit;
- Flare gas recovery was installed for the process refinery flares in 2011 that reduced NOx emissions by 16 tpy and SO_2 emissions by 330 tpy;
- The Low Pressure and High Pressure Flares meet New Source Performance Standard (NSPS) Subpart J requirements (EQT 308F-D-1 and 309F-D-2);
- The CO Boilers meet NSPS J requirements (EQT 301-B-2A and 301-B-2B);
- Crude Charge Heater meets NSPS J requirements (EQT 191-H-1).

Based on the WGS installation alone, Phillips 66 was able to reduce SO_2 emissions from the 2003 baseline amount of 2,678 tons per year (tpy) to 103 tpy in 2011 from the FCCU. This represents a 96% emissions reduction from the unit. Based on the information above, the LDEQ considers that Phillips 66 has installed the maximum feasible controls available on these sources. The LDEQ finds that the current controls installed at Phillips 66 constitute BART and that this matter has been addressed satisfactorily. The emissions limits for the Phillips 66

facility under current controls and operating conditions are included in the Administrative Order on Consent, Enforcement Tracking No. AE-AOC-14-00211A in accordance with 40 CFR 51.308(4)(e) and are federally enforceable. A complete analysis is included in Appendix C.

C. ECO-SERVICES OPERATIONS, LLC (formerly Rhodia)

The Eco-Services Operations, LLC facility (Eco-Services) is a sulfuric acid plant located in Baton Rouge, Louisiana. The plant produces sulfuric acid by using two sulfuric acid production trains, Unit I and Unit 2. EPA, the LDEQ and Eco-Services entered into a CD, as part of the negotiations between EPA and Eco-Services Operations (Formerly Rhodia) due to violations associated with excess emissions of sulfuric acid mist and sulfur dioxide, requiring a scrubber to be installed on each of the units to control SO_2 emissions.

In the July 23, 2012 action, EPA found that Eco-Services' subject-to-BART unit meets the RH SIP requirements specified in 40 CFR 51.308(1)(ii)(A) for an adequate BART evaluation; however EPA found that the LDEQ failed to include the emissions limits as required. The emissions limits are included in the Administrative Order on Consent Enforcement Tracking No. AE-AOC-14-00957 (AOC) between LDEQ and Eco-Services (See Appendix D).

The analysis takes into account all available control technologies for removing SO_2 at the affected units. These control technologies provide a control efficiency of approximately 94%. There were three abatement alternatives considered: 1) Double Absorption; 2) Sodium Scrubbing (caustic/soda ash); and 3) Ammonia Scrubbing. Caustic scrubbing was found to be the most cost effective option; the scrubbers were installed and total permitted SO_2 emissions were reduced from 8,800 tpy to 1,075 tpy. These controls were phased in beginning November 30, 2009. The first phase was implemented and completed by December 31, 2010; the second phase was completed on April 30, 2012; the third and final phase was completed on May 1, 2012. As shown in the table below, this has produced an 88% reduction in emissions of SO_2 from the facility.

This control not only meets BART but surpasses the control for new facilities under NSPS. LDEQ believes that this source has the most stringent control strategy available and no further BART analysis is necessary. According to 40 CFR Part 51 Appendix Y(IV)(D)(1)(9) since the source will have the most stringent controls available, it is not necessary to comprehensively complete each step of the BART analysis. In the BART analysis, Eco-services identified both a short term and long term limit control level for SO_2. The long term emissions limits for Eco-Services under current controls and operating conditions are included in the Administrative Order on Consent in accordance with 40 CFR 51.308(4)(e) and are federally enforceable. (Appendix D) The short term limit provided in the BART analysis is 3 lbs/ton, consistent with the limits established in the CD. The long term limit in the CD includes an exemption for emissions during startup shutdown and malfunction. However, the short term emissions will be limited by the NSPS for Sulfuric Acid Plants (40 CFR Part 60 Subpart H). This short term limit is applicable at all times and is also adequate to meet BART. LDEQ finds that the current controls in place, along with the federally enforceable limits established in the AOC and through applicability to the NSPS standard, constitutes BART. (Appendix D)

D. Sid Richardson Carbon Co.

The Sid Richardson Carbon Company (Sid Richardson) is a subject-to-BART source located in West Baton Rouge Parish, Louisiana. For the subject-to-BART units at the facility, LDEQ submitted in the original RH SIP a BART engineering analysis; for PM the LDEQ determined that the high efficiency fabric filters already in use at the facility are BART. EPA found that the LDEQ acted within its discretion in making this determination and that the analyses met the BART requirements. However, the EPA found that the engineering analysis for NOx and SO_2 were deficient. While LDEQ indicated that no controls were technically feasible, EPA felt that the record did not provide a sufficient basis for the conclusion. Based on this, the SO_2 BART determination for Sid Richardson was deemed deficient.

The original modeling that was performed showed that the facility had an impact that was above the 0.05 deciview level, the level at which the state determined sources would have the potential to impact one or more Class I areas. Sid Richardson Facility model results were 0.756 deciviews.

In response to the EPA action, Sid Richardson began to revise the BART analysis and update the modeling. The facility requested permission to perform a new round of modeling using the same emissions parameters that were used in the original model utilizing the newest EPA approved methods and guidance documents. Based on this analysis, LDEQ determined the facility is not subject-to-BART.

In this RH SIP, as a result of Sid Richardson's updated the base case modeling, the model results show that the visibility impacts are below the state's established BART threshold of 0.5 dv. A full model report is included in Appendix E.

III. Summary of Emissions Limitation Requirements

In order to comply with 40 CFR 51.308(e), the RH SIP must contain emission limitations representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I area. Based on the information contained in this SIP revision, the LDEQ believes that these requirements have been met for Mosaic, Phillips 66 and Eco-Services, with the inclusion of the AOCs in the respective appendices. In the event of a name change or change of ownership, at least 30 days prior to the execution of any agreement for the transfer of ownership or operation of the BART-eligible source, the responsible entity will provide notice of and a copy of the AOC to the new responsible entity, and shall simultaneously provide written notice of the prospective transfer to EPA Region 6 and LDEQ. LDEQ will enter into an AOC (or other enforceable mechanism) with the new responsible entity as expeditiously as practicable, but no later than 90 days of becoming aware that such name change or change of ownership has occurred. The provisions in the new AOC for the new responsible entity will be no less stringent than the limits in the current AOC. Until the new AOC is issued, the previous responsible entity will be responsible for compliance with the limits in the existing AOC. Each new AOC with a new responsible entity will be provided to EPA as substitute for the existing AOC and will be federally enforceable as part of the SIP. Because AOCs issued

under these circumstances will have identical or more stringent requirements for the BART-eligible source, no formal SIP revision process is necessary.

Facility	Criteria Pollutant	Units	2006	2010	2011	2012
Mosaic Fertilizer LLC – Uncle Sam Plant	Sulfur Dioxide (SO_2)	TPY	6638	9320	2102	770
Phillips 66 Co. Alliance Refinery	Sulfur Dioxide (SO_2)	TPY	2699	1071	1176	431
Eco-Services (Solvay/Rhodia)	Sulfur Dioxide (SO_2)	TPY	8638	9137	3472	1105
Facility	Criteria Pollutant	Units	2006	2010	2011	2012
Mosaic Fertilizer LLC – Uncle Sam Plant	Nitrogen Oxide (NOx)	TPY	59	70	65	65
Phillips 66 Co. Alliance Refinery	Nitrogen Oxide (NOx)	TPY	335	134	139	110
Eco-Services (Solvay/Rhodia)	Nitrogen Oxide (NOx)	TPY	58	69	65	64

Appendix A

Public Notice and Participation

Potpourri

POTPOURRI

Department of Environmental Quality
Office of the Secretary
Legal Division

State Implementation Plan for Regional Haze Program

Under the authority of the Louisiana Environmental Quality Act, R.S. 30:2001 et seq., the secretary gives notice that the Office of Environmental Services, Air Permits Division, will submit to the U.S. Environmental Protection Agency (EPA) a proposed revision to the state implementation plan (SIP) for the Regional Haze Program as required under the Clean Air Act, part C, section 169, and 40 CFR part 51.308. Regional haze is visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area. (1512Pot1)

On July 3, 2012, the EPA made final a partial limited approval and partial disapproval of the original SIP submitted on June 13, 2008. This revision answers the requirements for the four nonelectrical generating unit (nonEGU) facilities that were addressed under the best available retrofit technology (BART) section in the original SIP and that are the subject of the EPA partial disapproval.

All interested persons are invited to submit written comments concerning the SIP revision no later than 4:30 p.m., January 27, 2016, to Vivian H. Aucoin, Office of Environmental Services, P.O. Box 4313, Baton Rouge, LA 70821-4314, fax (225) 219-3156, or e-mail at vivian.aucoin@la.gov. A public hearing will be held upon request. The deadline for requesting a public hearing is January 4, 2016.

A copy of the proposal may be viewed on the LDEQ website or at LDEQ headquarters at 602 North Fifth Street, Baton Rouge, LA 70802.

Herman Robinson, CPM
General Counsel

1512#038

POTPOURRI

Department of Environmental Quality
Office of the Secretary
Legal Division

State Implementation Plan Revision

Under the authority of the Environmental Quality Act, R.S. 30:2051 et seq., the secretary gives notice that the Office of Environmental Services, Air Permits Division, Manufacturing Section, will submit to the Environmental Protection Agency (EPA) a revision to the state implementation plan (SIP) affecting rule revisions to LAC 33:III.Chapter 2. (1512Pot2)

Louisiana is submitting a complete fee Rule package as a replacement for the currently approved fee permit provisions in the SIP, and is withdrawing all submittals of Chapter 2 and 65 (pre-codification) from 1995 to present that have not already been approved into the SIP. In 1993, the state regulations were recodified and fee provisions were moved from Chapter 65 to Chapter 2.

If any party wishes to have a public hearing on this matter, one will be scheduled and the comments gathered at such hearing will be submitted as an addendum to the original submittal. All interested persons are invited to submit written comments concerning revisions no later than 4:30 p.m., January 29, 2016 to Vivian Aucoin, Office of Environmental Services, P.O. Box 4314, Baton Rouge, LA 70821-4314 or faxed to (225) 219-3240 or emailed to vivian.aucoin@la.gov.

A copy of the proposal may be viewed on the LDEQ website or at LDEQ headquarters at 602 North Fifth Street, Baton Rouge, LA 70802.

Herman Robinson, CPM
General Counsel

1512#039

POTPOURRI

Office of the Governor
Coastal Protection and Restoration Authority

Public Hearings State Fiscal Year 2017 Draft Annual Plan

The Louisiana Coastal Protection and Restoration Authority (CPRA), will hold the following public hearings to receive comments and recommendations from the public and from elected officials on Louisiana's draft "Fiscal Year 2017 Annual Plan: Integrated Ecosystem Restoration and Hurricane Protection in Coastal Louisiana":

Jan. 12	5:30 PM Open House 6:00 PM Public Meeting	Lake Charles Civic Center Jean Lafitte Room 900 Lakeshore Drive Lake Charles, LA 70601
Jan. 13	5:30 PM Open House 6:00 PM Public Meeting	Port of New Orleans Auditorium 1350 Port of New Orleans Place New Orleans, LA 70130
Jan. 14	5:30 PM Open House 6:00 PM Public Meeting	Warren J. Harang, Jr. Municipal Auditorium Rosella Room 310 North Canal Boulevard Thibodaux, LA 70301

The CPRA will receive written comments and recommendations on the draft annual plan until February 17, 2016. Written comments should be mailed (to arrive no later than February 17, 2016) to the following address:

Coastal Protection & Restoration Authority
c/o Chuck Perrodin
P.O. Box 44027
Baton Rouge, LA 70804-4027

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS TX 75202-2733

January 27, 2016

Ms. Vivian Aucoin
Air Quality Assessment Division
Office of Environmental Assessment
Louisiana Department of Environmental Quality
P.O. Box 4314
Baton Rouge, LA 70821-4314

Dear Ms. Aucoin:

I am writing in support of the proposed State Implementation Plan (SIP) recently published by the Louisiana Department of Environmental Quality (LDEQ) addressing regional haze from non-electric generating units. We have reviewed the proposal and believe that this action addresses the items that were remaining from the partial limited approval action SIP in July 2012.

We appreciate the responsiveness and efforts of the LDEQ to address issues raised by the EPA as we work towards addressing regional haze in our nation's Class I areas.

Sincerely,

Guy R. Donaldson
Chief
Air Planning Section

POTPOURRI

Department of Environmental Quality
Office of the Secretary
Legal Division

State Implementation Plan (SIP) for Regional Haze Program

Under the authority of the Louisiana Environmental Quality Act, R.S. 30:2001 et seq., the secretary gives notice that the Office of Environmental Services, Air Permits Division, will submit to the U.S. Environmental Protection Agency (US EPA) a proposed revision to the SIP for the Regional Haze Program as required under the Clean Air Act, Part C, Section 169, and 40 CFR Part 51.308. Regional haze is visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area. (1404Pot1)

On July 3, 2012, the US EPA made final a partial limited approval and partial disapproval of the original SIP submitted on June 13, 2008. This revision answers the requirements for the four non-electrical generating units (non-EGUs) facilities that were addressed under the Best Available Retrofit Technology (BART) section in the original SIP and that are the subject of the EPA partial disapproval.

A public hearing will be held at 1:30 pm on May 22, 2014, in the Galvez Building, Oliver Pollock Room C-111, 602 North Fifth Street, Baton Rouge, LA. Individuals with a disability and need accommodation in order to participate, please contact Vivian H. Aucoin at (225) 219-3389 or at the address listed below. Interested persons are invited to attend and submit oral comments on the proposal.

All interested persons are invited to submit written comments concerning the SIP revision no later than 4:30 p.m., May 22, 2014 to Vivian H. Aucoin, Office of Environmental Services, P.O.Box 4313, Baton Rouge, LA 70821-4314 or to Fax (225) 219-3156 or by e-mail to vivian.aucoin@la.gov.

A copy of the SIP revision for the Regional Haze Program may be viewed from 8 a.m. to 4:30 p.m. in the DEQ Public Records Center, Room 127, 602 North Fifth Street, Baton Rouge, LA. The document is available at www/deq.louisiana.gov/portal/Default.aspx?tabid=2381.

Herman Robinson, CPM
Executive Counsel

1404#037

POTPOURRI

Department of Natural Resources
Office of Conservation

Orphaned Oilfield Sites

Office of Conservation records indicate that the oilfield sites listed in the table below have met the requirements as set forth by section 91 of Act 404, R.S. 30:80 et seq., and as such are being declared orphaned oilfield sites.

Operator	Field	District	Well Name	Well Number	Serial Number
Great Southern Oil &Gas Co Inc	Port Barre	L	VUA;A Dezauche et al	001	157891(30)
E. H. Lange, et al	Caddo Pine Island	S	N B Stoer et al	001	38454
John F Mitchell et al	Caddo Pine Island	S	Gamm	001	52096
Choate Oil Corporation	Wildcat-No LA Shreveport Dist	S	Glassell	002	4005
Ken Blake	Wildcat-No La Shreveport Dist	S	Brewton A	001	216804
Cohen & Cheatham	Caddo Pine Island	S	Noel	A-2	40844
S. L. Carruth Jr.	Port Barre	L	C Devillier	001	146849
Cabot Petroleum Corporation	White Castle	L	Baist Cooperage & LBR Co Inc	001	164581(30)
Doran And Braddock	Caddo Pine Island	S	Reuben V Glassell	001	135383
Pilgrim Oil Co.	Wildcat-No LA Shreveport Dist	S	Ramsey	002	4660
TPE Tiger, LLC	Pinewood	L	AUS C RA SUA;Bailey 32	001	220568
TPE Tiger, LLC	Sugartown	L	AUS C RA SUH;Crosby 25	001	221416
TPE Tiger, LLC	Sugartown	L	AUS C RA SUI;Crosby 36 A	001	221647
TPE Tiger, LLC	Chasmore	L	AUS C RA SUE;Churchman 9	001	221976
TPE Tiger, LLC	Chasmore	L	AUS C RA SUF;Crosby 2	001	222061
TPE Tiger, LLC	Chasmore	L	AUS C RA SUH;Stickland 17	001	222352
TPE Tiger, LLC	Sugartown	L	Crosby 25 SWD	001	972762
TPE Tiger, LLC	Chasmore	L	Churchman 9 SWD	001	972789
TPE Tiger, LLC	Chasmore	L	Crosby 2 SWD	001	972798
TPE Tiger, LLC	Chasmore	L	Stickland 17 SWD	001	972799

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

RECEIVED
JUN 18 2014
LA. DEPT. OF ENV. QUALITY
LEGAL DIVISION

Being Conducted by:

DEPARTMENT OF ENVIRONMENTAL QUALITY

FOR

Proposed Amendments to the

State Implementation Plan (SIP)

for

Regional Haze Program

Log No. 1404Pot1

This public hearing was held in connection with the above captioned matter at the Oliver Pollock Room, Galvez Building, 602 N. Fifth Street, Baton Rouge, Louisiana on Thursday, May 22, 2014, commencing at 1:30 p.m.

A P P E A R A N C E S

FOR THE LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY:

MS. SUSAN HAM
HEARING OFFICER
P.O. BOX 4303
602 NORTH 5TH STREET
BATON ROUGE, LOUISIANA 70802
(225) 219-3277

Transcribed by:

Tiffeny Suire Gallardo, CCR
Certified Court Reporter
In and for the State of Louisiana

I N D E X

PAGE

APPEARANCES 2

PROCEEDINGS 4

REPORTER'S CERTIFICATE 7

1 **P R O C E E D I N G S**

2 **MS. HAM:**

3 Good afternoon. My name is
4 Susan Ham, and I'm employed by the
5 Louisiana Department of Environmental
6 Quality. I'll be serving as hearing
7 officer this afternoon to receive
8 comments regarding proposed amendments
9 to the State Implementation Plan (SIP)
10 for Regional Haze Program. This is Log
11 No. 1404Pot1.
12 The comment period for these
13 amendments began on April 20, 2014,
14 when the potpourri notice was published
15 in the *Louisiana Register*. The comment
16 period will close at 4:30 p.m., May 22,
17 2011. It would be helpful to us if all
18 oral comments received today were
19 followed up in writing.
20 This public hearing provides a
21 forum for all interested parties to
22 present comments on the proposed
23 changes. This hearing is not being
24 conducted in a question and answer
25 format. Please remember that the

1 purpose of this public hearing is to
2 allow you, the public, an opportunity
3 to express your thoughts concerning
4 today's proposed amendments.
5 I'll ask that each person
6 commenting come up and sit at the front
7 table and begin by stating his or her
8 name and affiliation for the record.
9 The Office of Environmental
10 Services, Air Permits Division, will
11 submit to the U.S. Environmental
12 Protection Agency (US EPA) a proposed
13 revision to the SIP for the Regional
14 Haze Program as required under the
15 Clean Air Act, Part C, Section 169, and
16 40 CFR Part 51.308. Regional haze is a
17 visibility impairment caused by
18 cumulative air pollutant emissions from
19 numerous sources over a wide geographic
20 area.
21 On July 3, 2012, the US EPA made
22 final a partial limited approval and
23 partial disapproval of the original SIP
24 submitted on June 13, 2008. This
25 revision answers the requirements for

1 the four non-electrical generation
2 units (non-EGUs) facilities that were
3 addressed under the Best Available
4 Retrofit Technology (BART) section of
5 the original SIP and that are the
6 subject of the EPA partial disapproval.
7 Does anyone care to comment on this
8 amendment?
9 (No verbal response.)
10 If not, the hearing on 1404Pot1 is
11 closed. Thank you for your attention
12 and participation. This hearing is
13 closed.
14 **(THE PROCEEDINGS CONCLUDED AT 1:32 P.M.)**
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1 C E R T I F I C A T E

2 This certification is valid only for a
3 transcript accompanied by my original signature
4 and official seal on this page.

5 That this testimony was reported by me in
6 the Stenomask method (voice-writing), was
7 prepared and transcribed by me or under my
8 personal direction and supervision, and is a
9 true and correct transcript to the best of my
10 ability and understanding; that the transcript
11 has been prepared in compliance with transcript
12 format guidelines required by statute or by
13 rules of the board; that I have acted in
14 compliance with the prohibition on contractual
15 relationships, as defined by Louisiana Code of
16 Civil Procedure Article 1434 and in rules and
17 advisory opinions of the board; that I am not
18 related to counsel or to the parties herein; am
19 not otherwise interested in the outcome of this
20 matter; and am a valid member in good standing
21 of the Louisiana State Board of Examiners of
22 Certified Shorthand Reporters.

23

24 TIFFANY SUIRE GALLARDO
25 CERTIFIED COURT REPORTER
26 CERTIFICATION NO. 28014
27

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JUN 18 2014
LA. DEPT. OF ENV. QUALITY
LEGAL DIVISION

In The Matter Of:

Department of Environmental Qualtiy

Public Hearing

May 22, 2014

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There is an item associated with this facility or record which cannot be entered into the Electronic Document Management System (EDMS) because it is in a format which cannot be scanned. Below you will find a description of the item.

- *To request a copy of the item, please complete a Public Records Request form at www.deq.louisiana.gov/prr and include the box number and reference number of the item in your request.*
- *To review the item, please print a copy of this page and visit the DEQ Public Records Center, 602 N. Fifth Street, Baton Rouge, LA, 70802.*
- *DEQ employees may review the item by contacting the Public Records Center.*

For more information, please contact the Public Records Center at (225)219-3172.

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Reference Number:	NP41612
Description::	1 CD
AI:	168759
Submittal ID:	005444226

Detailed description:

Department of Environmental Quality
Public Hearing 5/22/2014

Potpourri

POTPOURRI

Department of Environmental Quality
Office of the Secretary
Legal Division

State Implementation Plan (SIP) for
Regional Haze Program

Under the authority of the Louisiana Environmental Quality Act, R.S. 30:2001 et seq., the secretary gives notice that the Office of Environmental Services, Air Permits Division, will submit to the U.S. Environmental Protection Agency (EPA) a proposed revision to the SIP for the Regional Haze Program as required under the Clean Air Act, Part C, Section 169, and 40 CFR Part 51.308. Regional haze is visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area. (1406Pot1)

On July 3, 2012, the EPA made final a partial limited approval and partial disapproval of the original SIP submitted on June 13, 2008. This revision answers the requirements for the four nonelectrical generating units (nonEGUs) facilities that were addressed under the Best Available Retrofit Technology (BART) section in the original SIP and that are the subject of the EPA partial disapproval. This submittal will only pertain to Mosaic, Uncle Sam Facility.

A public hearing will be held at 1:30 pm on July 29, 2014, in the Galvez Building, Oliver Pollock Room C-111, 602 N. Fifth Street, Baton Rouge, LA. Individuals with a disability and need accommodation in order to participate, please contact Vivian H. Aucoin at (225) 219-3389, or at the address listed below. Interested persons are invited to attend and submit oral comments on the proposal.

All interested persons are invited to submit written comments concerning the SIP revision no later than 4:30 p.m., July 29, 2014 to Vivian H. Aucoin, Office of Environmental Services, Box 4313, Baton Rouge, LA 70821-4314, fax (225) 219-3156, or e-mail at vivian.aucoin@la.gov.

A copy of the SIP revision for the Regional Haze Program may be viewed from 8 a.m. to 4:30 p.m. in the LDEQ Public Records Center, Room 127, 602 N. Fifth Street, Baton Rouge, LA. The document is available at www/deq.louisiana.gov/portal/Default.aspx?tabid=2381.

Herman Robinson, CPM
Executive Counsel

1406#018

POTPOURRI

Department of Health and Hospitals
Behavior Analyst Board

Public Hearing—Substantive Changes to Proposed
Rule, Application Procedures and Board Fees
(LAC 46:VIII.Chapter 3)

The board published a Notice of Intent to promulgate LAC 46.VIII.Chapter 3, Application Procedures and Board Fees, in the April 20, 2014 edition of the *Louisiana Register* (LR 40:853-854). The notice solicited comments. As a result of its analysis of the comments, the board proposes to amend the rule by adding the word "American" as follows: "Submit verification of successful passage of a national exam administered by a nonprofit organization accredited by the National Commission for Certifying Agencies and the American National Standards Institute to credential professional practitioners of behavior analysis related to the principles and practice of the profession of behavior analysis that is approved by the board."

No fiscal or economic impact will result from the amendments proposed in this notice.

Title 46
PROFESSIONAL AND OCCUPATIONAL STANDARDS
Part VIII. Behavior Analysts
Chapter 3. Application Procedures and Board Fees
§301. Application Procedures for Licensure/State Certification/Registration

A. Application and/or Registration

1. An application for a license as a behavior analyst, state certified assistant behavior analyst or registration as a line technician may be submitted after the requirements in R.S. 37:3706-37:3708 are met.

2. Upon submission of application or registration on the forms provided by the board, accompanied by such fee determined by the board, the applicant must attest and acknowledge that the:

a. information provided to the board is true, correct and complete to the best of his knowledge and belief; and

b. the board reserves the right to deny an application in accordance with RS 37:3706-R.S. 37:3708, if the application or any application materials submitted for consideration contain misrepresentations or falsifications.

3. An applicant, who is denied licensure based on the information submitted to the board, may reapply to the board after one year, and having completed additional training, if necessary and having met the requirements of law as defined in the rules and regulations adopted by the board.

ORIGINAL

LOUISIANA DEPARTMENT OF
ENVIRONMENTAL QUALITY

PUBLIC HEARING

The above-entitled cause came in for a Public Hearing at 602 North Fifth Street, Oliver Pollock conference Room, Baton Rouge, Louisiana 70802 on Tuesday, July 29, 2014, commencing at 1:30 p.m.

Reported by:

Tara Torres-Blank
Certified Court Reporter

1 **A P P E A R A N C E S**

2 **The Hearing Officer:**

3 LAURIE JEWELL

4

5

6 **The Court Reporter:**

7 TARA TORRES-BLANK

8

9

10 **I N D E X**

11 Page

12 Caption 1

13 Appearances 2

14 Proceedings 3

15 Reporter's Page 10

16 Reporter's Certificate 11

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1 (The Public Hearing was called to order and
2 proceeded as follows:)
3 Good afternoon. My name is
4 Laurie Jewell and I'm employed by the
5 Louisiana Department of Environmental
6 Quality. I'll be serving as Hearing
7 Officer this afternoon to receive
8 comments regarding the proposed
9 amendments; 1406POT1, AQ344FT, and
10 WQ089FT.
11 The comment period for these
12 amendments began on June 20, 2014,
13 when the notice of intent was
14 published in the Louisiana Register.
15 The comment period will close at 4:30
16 p.m. today, July 29, 2014. It would
17 be helpful to us if all oral comments
18 received today were followed up in
19 writing.
20 This public hearing provides a
21 forum for all interested parties to
22 present comments on the proposed
23 changes. This public hearing is not
24 being conducted in a question and
25 answer format.

1 Please remember that the purpose
2 of this public hearing is to allow
3 you, the public, an opportunity to
4 express your thoughts concerning
5 today's proposed amendments.
6 I'll ask that each person
7 commenting come up and sit at the
8 front table and begin by stating his
9 or her name and affiliation for the
10 Record.
11 The first amendment is designated
12 by the Log Number 1406POT1.
13 Under the authority of the
14 Louisiana Environmental Quality Act,
15 R.S. 30:2001, the secretary has given
16 notice that the Office of
17 Environmental Services, Air Permits
18 Division, will submit to the U.S.
19 Environmental Protection Agency a
20 proposed revision to the SIP for the
21 Regional Haze Program as required
22 under the Clean Air Act, Part C,
23 Section 169, and 40 CFR Part 51.308.
24 Regional haze is visibility
25 impairment caused by the cumulative

air pollutant emissions from numerous sources over a wide geographic area.

On July 3, 201, the EPA made final a partial limited approval and partial disapproval of the original SIP submitted on June 13, 2008.

This revision answers the requirements for the four non-electrical generating units facilities that were addressed under the Best Available Retrofit Technology section in the original SIP and that are the subject of the EPA partial disapproval.

This submittal will only pertain to Mosaic, Uncle Sam Facility.

Does anyone care to comment on this regulation? If not, the hearing on 1406POT1 is closed.

The next amendment is designated by the Log Number AQ344FT.

This rule includes LAC Title 33, Part 3, Chapter 7, Ambient Air Quality, 711.Table 1 and 1A. Also included in this rule is Chapter 9,

1 General Regulations on Control of
2 Emission and Emission Standards,
3 918.B, Table 6.
4 These revisions update the
5 National Ambient Air Quality
6 Standards (NAAQS) for certain
7 criteria pollutants (ozone,
8 particular matter (2.5), nitrogen
9 oxide, lead and sulfur dioxide) and
10 the Louisiana designated non-
11 attainment area for the sulfur
12 dioxide standard.
13 The Clean Air Act directs EPA to
14 propose and promulgate primary and
15 secondary National ambient air
16 quality standards (section 109) and
17 to designate areas following
18 promulgation of a new or revised
19 NAAQS (section 107).
20 To reflect the most current
21 Federal revisions to the NAAQS and
22 non-attainment designated areas as
23 promulgated by EPA. Louisiana is
24 adopting the updated standards and is
25 specifically updating the non-

1 attainment area as it relates to the
2 2010 sulfur dioxide standard.
3 This rule is necessary to
4 maintain equivalency with the federal
5 regulations and/or standards and to
6 enable Louisiana to carry out its
7 duty as required under R.S. Title 30
8 Section 2054 and the provisions of
9 the CAA and State Implementation
10 Plan, (SIP) to implement, maintain
11 and enforce the NAAQS in each
12 affected region within the state.
13 Does anyone care to comment on
14 this regulation? If, not the hearing
15 on AQ344Ft is closed.
16 The last amendment is designated
17 by the Log Number WQ089Ft.
18 This rule is the annual
19 incorporation by reference update of
20 the water regulations. This rule
21 changes the reference dates found in
22 40 CFR Part 136 and 40 CFR Chapter 1,
23 Subchapter N, Parts 401, 405-471 LAC
24 33, Part 9, chapter 40 incorporates
25 the following portions of Federal

1 regulations into the Louisiana water
2 quality regulations.
3 1. 40 CFR Part 136, Guidelines
4 Establishing Test Procedures for the
5 Analysis of Pollutants, July 1, 2012,
6 in its entirety.
7 2. 40 CFR Chapter 1, Subchapter
8 N, Effluent Guidelines and Standards,
9 parts 401 and 405-471, July 1, 2012.
10 This action will incorporate the
11 recently updated Federal regulations
12 into Louisiana's water quality
13 regulations, increasing the
14 enforceability of LPDES permits that
15 include EDA-approved analytical
16 methods and effluent limitations
17 guidelines.
18 The published edition of the 40
19 CFR is regularly updated on July 1st
20 of every calendar year; therefore,
21 this rule will incorporate the date
22 of July 1, 2013 in anticipation for
23 the most recent publication, which
24 will include the above referenced
25 rules.

Does anyone care to comment on this regulation? If not, the hearing on WQ0189Ft is closed.

Thank you for your attention and participation. This hearing is closed.

(This Meeting was concluded at 1:40 p.m.)

1 **R E P O R T E R ' S P A G E**

2 I, Tara Torres-Blank, Certified
3 Court Reporter, in and for the State of
4 Louisiana, the officer, as defined in Rule
5 28 of the Federal Rules of Civil Procedure
6 and/or Article 1434(b) of the Louisiana
7 Code of Civil Procedure, before whom this
8 sworn testimony was taken, do hereby state
9 on the Record:

10 That due to the interaction in the
11 spontaneous discourse of this proceeding,
12 dashes (--) have been used to indicate
13 pauses, changes in thought, and/or
14 talkovers; that same is the proper method
15 for a Court Reporter's transcription of
16 proceeding, and that the dashes (--) do not
17 indicate that words or phrases have been
18 left out of this transcript;

19 That any words and/or names which
20 could not be verified through reference
21 material have been denoted with the phrase
22 "(phonetic)."

23 Tara Blank

24 Tara Torres-Blank, CCR
Certified Court Reporter

25

1 **C E R T I F I C A T E**

2 I, Tara Torres-Blank, Certified Court Reporter, in
3 and for the State of Louisiana, as the officer before
4 whom this testimony was taken, do hereby certify that
5 after having first been duly sworn by me upon authority
6 of R.S. 37:2554, did testify as hereinbefore set forth
7 in the foregoing pages;

8 That this testimony was reported by me in the
9 Stenomask method (voice-writing), was prepared and
10 transcribed by me or under my personal direction and
11 supervision, and is a true and correct transcript to the
12 best of my ability and understanding;

13 That the transcript has been prepared in compliance
14 with transcript format guidelines required by statute or
15 by rules of the board, that I have acted in compliance
16 with the prohibition on contractual relationships, as
17 defined by Louisiana Code of Civil Procedure Article
18 1434 and in rules and advisory opinions of the board;

19 That I am not related to counsel or to the parties
20 herein; am not otherwise interested in the outcome of
21 this matter; and am a valid member in good standing of
22 the Louisiana State Board of Examiners of Certified
23 Shorthand Reporters.

24 Tara Blank

25 Tara Torres-Blank (#22012)
Certified Court Reporter

In The Matter Of:

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

PUBLIC HEARING

July 29, 2014

Associated Reporters Incorporated

(225) 216-2036

Original File DEQ72914.TXT

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Appendix B

Mosaic Fertilizer, LLC-Uncle Sam Plant

Administrative Order on Consent,

BART Determination and Evaluation

Mosaic

Mosaic Fertilizer LLC
7250 Highway 44
Uncle Sam, LA 70792
www.mosaicco.com

Tel 225-474-9700
Fax 225-474-4090

LDEQ RECEIVED
2016 JUN 6 PM 2:45

June 6, 2016

Hand Delivered

Ms. Celena Cage
Administrator
Enforcement Division
Louisiana Department of Environmental Quality
P.O. Box 4312
Baton Rouge, LA 70821-4312

RE: Amended Administrative Order on Consent
Enforcement Tracking No. AE-AOC-14-00274A
Agency Interest No. 2532

Dear Ms. Cage:

Please find the enclosed signed Amended Administrative Order on Consent for inclusion in the Regional Haze SIP.

If you or any member of your staff should have any questions in regard to this submittal, please do not hesitate to contact me at (225) 474-1336.

Sincerely,

David Oubre
Manager, Environmental

Attachment

JOHN BEL EDWARDS
GOVERNOR

CHUCK CARR BROWN, PH.D.
SECRETARY

State of Louisiana

DEPARTMENT OF ENVIRONMENTAL QUALITY
OFFICE OF ENVIRONMENTAL COMPLIANCE

RECEIVED
APR 29 2016

April 20, 2016

CERTIFIED MAIL (7004 2510 0006 3853 6521)
RETURN RECEIPT REQUESTED

MOSAIC FERTILIZER, LLC
c/o C T Corporation System
Agent for Service of Process
3867 Plaza Tower Dr.
Baton Rouge, LA 70816

RE: AMENDED ADMINISTRATIVE ORDER ON CONSENT
ENFORCEMENT TRACKING NO. AE-AOC-14-00274A
AGENCY INTEREST NO. 2532

Dear Sir:

Pursuant to the Louisiana Environmental Quality Act (La. R.S. 30:2001, et seq.), the attached **AMENDED ADMINISTRATIVE ORDER ON CONSENT** is hereby served on **MOSAIC FERTILIZER, LLC (RESPONDENT).**

Any questions concerning this action should be directed to Pascal Ojong at (225) 219-4468.

Sincerely,

Celena J. Cage
Administrator
Enforcement Division

CJC/PON/pon
Alt ID No. 2560-00004
Attachment

c: Mosaic Fertilizer, LLC
7250 Louisiana Highway 44
Uncle Sam, Louisiana 70792

STATE OF LOUISIANA
DEPARTMENT OF ENVIRONMENTAL QUALITY

OFFICE OF ENVIRONMENTAL COMPLIANCE

IN THE MATTER OF	*	
	*	
MOSAIC FERTILIZER, LLC	*	**ENFORCEMENT TRACKING NO.**
ST. JAMES PARISH	*	
ALT ID NO. 2560-00004	*	**AE-AOC-14-00274A**
	*	
	*	**AGENCY INTEREST NO.**
	*	
PROCEEDINGS UNDER THE LOUISIANA	*	**2532**
ENVIRONMENTAL QUALITY ACT,	*	
La. R.S. 30:2001, ET SEQ.	*	

AMENDED ADMINISTRATIVE ORDER ON CONSENT

The Louisiana Department of Environmental Quality (the Department) and Mosaic Fertilizer, LLC hereby agree to amend the **ADMINISTRATIVE ORDER ON CONSENT, ENFORCEMENT TRACKING NO. AE-AOC-14-00274** issued to **MOSAIC FERTILIZER, LLC (RESPONDENT)** on June 18, 2014, in the above-captioned matter as follows:

I.

Paragraph I of the **ADMINISTRATIVE ORDER** portion of Administrative Order on Consent, Enforcement Tracking No. AE-AOC-14-00274 is amended to read as follows:

"I.

The Respondent shall comply with the emission limitations set forth below:

Source ID	Source Description	Sulfur Dioxide (SO_2) Limit
EQT 67	A Train Single Absorption H_2SO_4 Plant (EPN S-ATrain1)	1.0 lb/ton of 100% H_2SO_4 produced (3-hr rolling average). This short-term limit does not apply during periods of start-up, shutdown, or malfunction. Start-up shall mean the period of time beginning when the feed of elemental sulfur to the furnace commences and lasting for no more than 4 hours. Shutdown shall mean the cessation of operation of the A Train for any reason and begins at the time the feed of elemental sulfur to the furnace ceases and ends 3 hours later or when the blower is turned off, whichever is earlier. Malfunction shall mean any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner, but shall not include failures that are caused in part by poor maintenance or careless operation.

Source ID	Source Description	Sulfur Dioxide (SO_2) Limit
		Or 4.0 lb/ton of 100% H_2SO_4 produced (3-hr rolling average). This short-term limit applies during periods of start-up, shutdown, or malfunction. Start-up shall mean the period of time beginning when the feed of elemental sulfur to the furnace commences and lasting for no more than 4 hours. Shutdown shall mean the cessation of operation of the A Train for any reason and begins at the time the feed of elemental sulfur to the furnace ceases and ends 3 hours later or when the blower is turned off, whichever is earlier. Malfunction shall mean any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner, but shall not include failures that are caused in part by poor maintenance or careless operation.
EQT 68	A Train Start-Up Burner (EPN S-ATrain2)	0.07 lb/hr (24-hr average)
EQT 72	No. 1 Packaged Steam Boiler (EPN S-Boiler1)	Equipment Shutdown and Removed from Permit
EQT 73	No. 2 Packaged Steam Boiler (EPN S-Boiler2)	Equipment Shutdown and Removed from Permit
EQT 74	D Train Double Absorption H_2SO_4 Plant (EPN S-DTrain1)	2.2 lb/ton of 100% H_2SO_4 produced (365-day rolling average). And 4.0 lb/ton of 100% H2SO4 produced (3-hr rolling average). This short-term limit applies during periods of start-up, shutdown, or malfunction. Start-up shall mean the period of time beginning when the feed of elemental sulfur to the furnace commences and lasting for no more than 4 hours. Shutdown shall mean the cessation of operation of the D Train for any reason and begins at the time the feed of elemental sulfur to the furnace ceases and ends 3 hours later or when the blower is turned off, whichever is earlier. Malfunction shall mean any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner, but shall not include failures that are caused in part by poor maintenance or careless operation.
EQT 75	D Train Start-Up Burner (EPN S-DTrain2)	0.07 lb/hr (24-hr average)
EQT 113 (Formerly EQT 079)	Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-ROCK) *Formerly* Rock Unloading, Handling, Storage, and Transfer (EPN S-ROCK)	None, the emissions unit does not emit SO_2.

Source ID	Source Description	Sulfur Dioxide (SO_2) Limit
EQT 81*	Sulfur Unloading Pit (EPN S-SulfurPit)	2.98 tpy
EQT 82*	Sulfur Storage Tank A (EPN S-SulfurA)	
EQT 83*	Sulfur Storage Tank B (EPN S-SulfurB)	
FUG 002	A Train Fugitive Emissions (EPN S-ATrain3)	Control sulfuric acid train ductwork leaks using a temporary collection system that routes the collected gas back to the sulfuric acid production process.
FUG 003	D Train Fugitive Emissions (EPN S-DTrain3)	Control sulfuric acid train ductwork leaks using a temporary collection system that routes the collected gas back to the sulfuric acid production process.
FUG 004	Dock Fugitive Emissions (EPN S-DockFug)	0.01 tpy

*These pieces of equipment are permitted as one source with a combined cap on emissions

Source ID	Source Description	Particulate Matter ($PM_{2.5}$) Limit
EQT 67	A Train Single Absorption H_2SO_4 Plant (EPN S-ATrain1)	0.15 lb H_2SO_4 / ton of 100% H_2SO_4 produced (3-hr average)
EQT 68	A Train Start-Up Burner (EPN S-ATrain2)	0.89 lb/hr (24-hr average)
EQT 72	No. 1 Packaged Steam Boiler (EPN S-Boiler1)	Equipment Shutdown and Removed from Permit
EQT 73	No. 2 Packaged Steam Boiler (EPN S-Boiler2)	Equipment Shutdown and Removed from Permit
EQT 74	D Train Double Absorption H_2SO_4 Plant (EPN S-DTrain1)	0.15 lb H_2SO_4 / ton of 100% H_2SO_4 produced (3-hr average)
EQT 75	D Train Start-Up Burner (EPN S-DTrain2)	0.89 lb/hr (24-hr average)
EQT 113 (Formerly EQT 079)	Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-ROCK) *Formerly* Rock Unloading, Handling, Storage, and Transfer (EPN S-ROCK)	2.87 tpy (Limit applies during processing of Florida rock only)
EQT 81*	Sulfur Unloading Pit (EPN S-SulfurPit)	1.65 tpy
EQT 82*	Sulfur Storage Tank A (EPN S-SulfurA)	
EQT 83*	Sulfur Storage Tank B (EPN S-SulfurB)	
FUG 002	A Train Fugitive Emissions (EPN S-ATrain3)	None, the emissions unit does not emit $PM_{2.5}$
FUG 003	D Train Fugitive Emissions (EPN S-DTrain3)	None, the emissions unit does not emit $PM_{2.5}$
FUG 004	Dock Fugitive Emissions (EPN S-DockFug)	0.50 tpy

*These pieces of equipment are permitted as one source with a combined cap on emissions

Source ID	Source Description	Particulate Matter (PM_{10}) Limit
EQT 67	A Train Single Absorption H_2SO_4 Plant (EPN S-ATrain1)	0.15 lb H_2SO_4 / ton of 100% H_2SO_4 produced (3-hr average)
EQT 68	A Train Start-Up Burner (EPN S-ATrain2)	0.89 lb/hr (24-hr average)
EQT 72	No. 1 Packaged Steam Boiler (EPN S-Boiler1)	Equipment Shutdown and Removed from Permit
EQT 73	No. 2 Packaged Steam Boiler (EPN S-Boiler2)	Equipment Shutdown and Removed from Permit
EQT 74	D Train Double Absorption H_2SO_4 Plant (EPN S-DTrain1)	0.15 lb H_2SO_4 / ton of 100% H_2SO_4 produced (3-hr average)
EQT 75	D Train Start-Up Burner (EPN S-DTrain2)	0.89 lb/hr (24-hr average)
EQT 113 (Formerly EQT 079)	Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-ROCK) *Formerly* Rock Unloading, Handling, Storage, and Transfer (EPN S-ROCK)	20.74tpy (Limit applies during processing of Florida rock only)
EQT 81*	Sulfur Unloading Pit (EPN S-SulfurPit)	5.55 tpy
EQT 82*	Sulfur Storage Tank A (EPN S-SulfurA)	
EQT 83*	Sulfur Storage Tank B (EPN S-SulfurB)	
FUG 002	A Train Fugitive Emissions (EPN S-ATrain3)	None, the emissions unit does not emit $PM_{2.5}$
FUG 003	D Train Fugitive Emissions (EPN S-DTrain3)	None, the emissions unit does not emit $PM_{2.5}$
FUG 004	Dock Fugitive Emissions (EPN S-DockFug)	0.97 tpy

Source ID	Source Description	Nitrogen Oxide (NO_x) Limit
EQT 67	A Train Single Absorption H_2SO_4 Plant (EPN S-ATrain1)	0.12 lb/ton of 100% H_2SO_4 produced (24-hr average)
EQT 68	A Train Start-Up Burner (EPN S-ATrain2)	32.94 lb/hr (24-hr average)
EQT 72	No. 1 Packaged Steam Boiler (EPN S-Boiler1)	Equipment Shutdown and Removed from Permit
EQT 73	No. 2 Packaged Steam Boiler (EPN S-Boiler2)	Equipment Shutdown and Removed from Permit
EQT 74	D Train Double Absorption H_2SO_4 Plant (EPN S-DTrain1)	0.12 lb/ton of 100% H_2SO_4 produced (24-hr average)
EQT 75	D Train Start-Up Burner (EPN S-DTrain2)	32.94 lb/hr (24-hr average)
EQT 113 (Formerly EQT 079)	Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-ROCK) *Formerly* Rock Unloading, Handling, Storage, and Transfer (EPN S-ROCK)	None, the emissions unit does not emit NOx.

EQT 81	Sulfur Unloading Pit (EPN S-SulfurPit)	None, the emissions unit does not emit NOx.
EQT 82	Sulfur Storage Tank A (EPN S-SulfurA)	None, the emissions unit does not emit NOx.
EQT 83	Sulfur Storage Tank B (EPN S-SulfurB)	None, the emissions unit does not emit NOx.
FUG 002	A Train Fugitive Emissions (EPN S-ATrain3)	None, the emissions unit does not emit NOx.
FUG 003	D Train Fugitive Emissions (EPN S-DTrain3)	None, the emissions unit does not emit NOx.
FUG 004	Dock Fugitive Emissions (EPN S-DockFug)	None, the emissions unit does not emit NOx.

II.

The Department hereby adds Paragraph IX to the **ADMINISTRATIVE ORDER** portion of Administrative Order on Consent, Enforcement Tracking No. AE-AOC-14-00274 to read as follows:

"IX.

The following paragraph addresses transfers of the obligations of this **AMENDED ADMINISTRATIVE ORDER ON CONSENT** and the Facility:

A) The obligations of this **AMENDED ADMINISTRATIVE ORDER ON CONSENT** apply to and are binding upon the Department and upon the Respondent and its officers, employees, agents, subsidiaries, successors, assigns, or other entities or persons otherwise bound by law.

B) Prior to the execution of any agreement for the transfer of ownership or operation of the Facility, the Respondent shall provide notice of and a copy of this **AMENDED ADMINISTRATIVE ORDER ON CONSENT** to the proposed transferee. No transfer of ownership or operation of any portion of the Facility shall relieve the Respondent of its obligation to ensure the terms of this **AMENDED ADMINISTRATIVE ORDER ON CONSENT** are implemented unless, at least 30 days prior to such transfer, the Respondent provides written notice of the prospective transfer to the EPA Region 6 and the Department and the prospective transferee executes an **AMENDED ADMINISTRATIVE ORDER ON CONSENT** with the

Department prior to the effective date of the transfer which provides for continued compliance with these standards. The Notice of Transfer shall clearly identify the parties responsible for any existing violations of this **AMENDED ADMINISTRATIVE ORDER ON CONSENT** and otherwise comply with LAC 33:I.1907. Transfer of ownership or operation of the Facility without complying with this Paragraph constitutes a violation of this **AMENDED ADMINISTRATIVE ORDER ON CONSENT.**"

II.

The Department incorporates all of the remainder of the original **ADMINISTRATIVE ORDER ON CONSENT, ENFORCEMENT TRACKING NO. AE-AOC-14-00274** and **AGENCY INTEREST NO. 2532** as if reiterated herein.

III.

This **AMENDED ADMINISTRATIVE ORDER ON CONSENT** shall be final and effective upon signature by an authorized representative of the Department and signature by the authorized representative of the Respondent.

Baton Rouge, Louisiana, this 20th day of April, 2016.

Lourdes Iturralde
Assistant Secretary
Office of Environmental Compliance

MOSAIC FERTILIZER, LLC

By: _____ Date: 6/6/2016

Name: STEVEN J. SUSICK

Title: G.M. LOUISIANA OPERATIONS

Mosaic Fertilizer, LLC
7250 Highway 44
Uncle Sam, LA 70792
www.mosaicco.com

Tel 225-474-9700
Fax 225-474-4090

September 30, 2015

CERTIFIED MAIL – RETURN RECEIPT REQUESTED **7013 2250 0001 5994 8857**

Mr. Guy Donaldson (6PD-L)
United States Environmental Protection Agency – Region 6
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

SUBJECT: MOSAIC FERTILIZER, LLC – UNCLE SAM PLANT RESPONSE TO SEPTEMBER 1, 2015 CLEAN AIR ACT SECTION 114(a) INFORMATION REQUEST

Dear Mr. Donaldson:

On September 1, 2015, the United States Environmental Protection Agency (EPA), Region 6 emailed an Information Request to the Mosaic Fertilizer, LLC ("Mosaic") Uncle Sam Plant pursuant to Section 114(a) of the Clean Air Act, 42 U.S.C. § 7414(a). The Information Request was served on Mosaic by Certified Mail on September 4, 2015. The EPA Information Request seeks information related to best available retrofit technology (BART) requirements under EPA's Regional Haze Rule, 40 C.F.R. §§ 51.308 and 51.309 in order that EPA may develop a Federal Implementation Plan in the event that the Louisiana Department of Environmental Quality (LDEQ) does not timely amend its State Implementation Plan with regard to Regional Haze to address deficiencies noted by EPA. The Information Request required the requested information to be submitted to the EPA by September 30, 2015. Mosaic has made considerable effort in this short time period to provide timely, useful and complete responses to the Information Request.

Notwithstanding its substantive response to the Information Request, Mosaic makes the following general qualifications and objections to the request:

> Mosaic objects to the Information Request to the extent that it seeks privileged information, including any communications that are protected from disclosure by the attorney-client communication privilege or any communications or documents protected by the attorney work product doctrine.
>
> Mosaic objects to the Information Request to the extent that the information requested is irrelevant or outside the scope of Section 114 of the Clean Air Act, 42 U.S.C. § 7411.

Mosaic objects to the Information Request to the extent that it is vague, unclear, ambiguous, or overly burdensome.

For some of the responses, we have relied on information supplied by third parties over whom Mosaic has no control. In addition, Mosaic has prepared the responses based on reasonable investigation, and the responses may be subject to revision in the event additional or different information or analyses become available. Mosaic specifically disclaims, however, any obligation to update this response to reflect any such additional or different information or analyses.

Mosaic specifically objects to any use of the data by EPA that does not comply with EPA's Cross-Media Electronic Reporting Rule, 40 C.F.R. Part 3, or any internal EPA rules, policies or directives on use of electronic data.

Subject to and without waiving any of the foregoing qualifications and objections, and subject further to the reservations set forth below, Mosaic provides in this response information sought in the Information Request, through the following responses and attachments. Mosaic reserves the right to object to any use of such data by EPA in any future rulemaking, permit, or enforcement proceedings.

Mosaic responds to the September 1, 2015 Information Request as follows:

Request 1. *In reviewing the modeling conducted for the BART analysis submitted to LDEQ on July 17, 2015, the EPA identified that the meteorological data set and computational grid utilized by Mosaic was not the correct data set to utilize, as it was based on a smaller modeling domain and 4km grid rather than the larger modeling domain and 6km grid consistent with the final Sid Richardson modeling analysis. Please conduct CALPUFF modeling and submit the following modeling runs using the final Sid Richardson CALMET files (provided to Mosaic by LDEQ) and the larger CALPUFF modeling domain to ensure plumes that could transport to Breton stay in the modeling domain.*

a. Base case scenario
b. Current controls scenario
c. Current controls scenario with addition of a scrubber on D Train as discussed below.

Response 1. Mosaic has conducted CALPUFF modeling for the three scenarios above using the final updated Sid Richardson CALMET files that were approved by the EPA and the larger CALPUFF modeling domain indicated by the EPA. A description of this CALPUFF modeling analysis and a summary of the modeling results using the protocols as directed by EPA in the Information Request are provided in Section 4 of the attached Mosaic Uncle Sam Plant Best Available Retrofit Technology Analysis, Rev. 1 (Attachment 1). Additionally, electronic copies of the CALPUFF input and output files

used and created in this CALPUFF modeling analysis are contained in Exhibit 11 of Attachment 1.

The following person(s) assisted in the preparation of the response to Request 1: Michael Carbon, Todd Higginbotham, Bart Brashers, and Tim Sturtz with Ramboll Environ US Corporation ("Ramboll Environ"), consultants to Mosaic.

Request 2. *In performing the five-factor analysis for the D Train controls, Mosaic modeled the base case scenario and the current controls scenario. In identifying the available control options, Mosaic identified a scrubber as a potential control. However, Mosaic did not include an analysis of visibility benefit that could be obtained by installing a scrubber. Please model the current control scenario with the addition of a scrubber on the D Train to demonstrate the visibility benefit achieved by installing a scrubber. The delta-deciview benefit from installation of controls should be included in the five-factor BART analysis evaluating SO_2 controls for the D Train.*

Response 2. Mosaic evaluated the visibility improvement that is modelled to occur at the Breton Wilderness Area as a result of equipping the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) with a wet scrubber. The revised 5-factor BART analysis performed for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074), which includes this requested modeled visibility improvement evaluation, is presented in Sections 3.9 and 3.10 and 4 of Attachment 1. In Section 4, Mosaic analysed three scenarios to estimate the visibility improvement: Baseline, With BART, With Bart + D Train Wet Scrubber. The modeling results are presented in Section 4.3 of Attachment 1 and indicate that the visibility improvement between the "With BART" scenario and the "With BART + D Train Wet Scrubber" scenario is only 15% of the visibility improvement between the "Baseline" scenario and the "With BART" scenario. Given the extremely high capital investment cost (estimated $25 Million) for a wet scrubber, and the high annual operating cost (estimated $3.3 Million), it is not cost effective to install and operate a wet scrubber. In summary, Mosaic determined that a wet scrubber does not represent BART for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074).

The following person(s) assisted in the preparation of the response to Request 2: Michael Carbon, Todd Higginbotham, Bart Brashers, and Tim Sturtz with Ramboll Environ, consultants to Mosaic and Maureen Harbourt with Kean Miller LLP, counsel to Mosaic.

Request 3. *Please provide a narrative explanation including supportive information as necessary, for why the E Train is not BART-eligible.*

Response 3. A narrative explanation of why the E Train is not a BART-eligible emissions unit is provided in Section 1.2.1 of Attachment 1. Additionally, supporting information for this determination is contained in Exhibits 1 and 2 of Attachment 1.

The following person(s) assisted in the preparation of the response to Request 3: Todd Higginbotham with Ramboll Environ, consultants to Mosaic.

Request 4. *The emission rates for SO_2 and NOx baseline (pre-consent decree controls/emissions) do not match the values in the LDEQ's Regional Haze SIP from 2008 (Table 9-3). The table has emission totals for the BART units at each facility and lists Mosaic Uncle Sam as 39.16 tpd of SO_2 and 3.34 tpd of NOx. The modeling for baseline emissions are less than these totals at 35.07 tpd of SO_2 and 2.06 tpd of NOx. Please investigate and provide an explanation of these differences. While the larger emissions will not change the subject to BART decision it will impact the delta deciview analysis between baseline and different controls that are evaluated as part of the 5-factor BART analysis. Please provide this information to the EPA for review prior to conducting CALPUFF modeling.*

Response 4. On August 11, 2006, Mosaic submitted an initial list of BART-eligible emissions units for the Uncle Sam Plant to the LDEQ (hereinafter this submittal is referenced as the "August 11, 2006 submittal"). As part of the August 11, 2006 submittal, for each of the listed emissions units, Mosaic indicated the 24-hour maximum sulfur dioxide (SO_2) emission rate and the 24-hour maximum oxides of nitrogen (NOx) emission rate, both in tons per day (tpd), emitted during routine operations (i.e., excluding start-ups, shutdowns, and malfunctions) from 2001 through 2005.

In Table 9.3 of the June 2008 *Louisiana State Implementation Plan Revision for Regional Haze Program*, the LDEQ listed total SO_2 and NOx emission rates for the BART-eligible emissions units at the Uncle Sam Plant as 39.16 tpd and 3.34 tpd, respectively. Mosaic has estimated that the LDEQ calculated these emission rates by summing together the emissions unit-by-emissions unit 24-hour maximum hourly SO_2 and NOx emission rates, respectively, that were identified in the August 11, 2006 submittal.

After the August 11, 2006 submittal, Mosaic determined that several of the emissions units identified as BART-eligible in that submittal were in fact not BART-eligible because they were not "in existence" on August 7, 1977 or they were not stationary sources (i.e., they were "nonroad engines"). This revised determination of BART-eligible emissions units was documented in the June 2007 Best Available Retrofit Technology Analysis that Mosaic submitted to the LDEQ for the Uncle Sam Plant, which the LDEQ included in Appendix G of the June 2008 *Louisiana State Implementation Plan Revision for Regional Haze Program.*

The same BART-eligible emissions units identified for the Uncle Sam Plant in the June 2007 Best Available Retrofit Technology Analysis were evaluated as BART-eligible in the July 2015 Mosaic Uncle Sam Plant Best Available Retrofit Technology Analysis that was recently submitted to the LDEQ. Additionally, the same baseline SO_2 and NOx emission rates were evaluated in the June 2007 Best Available Retrofit Technology

Analysis and the July 2015 Mosaic Uncle Sam Plant Best Available Retrofit Technology Analysis.

Attachment 2 contains an electronic file in which we have calculated the SO_2 and NOx emission rates that the LDEQ listed for the Uncle Sam Plant in Table 9.3 of the June 2008 *Louisiana State Implementation Plan Revision for Regional Haze Program*. In the same electronic file, we have also documented the calculation of the baseline SO_2 and NOx emission rates that we evaluated in the June 2007 Best Available Retrofit Technology Analysis and the July 2015 Mosaic Uncle Sam Plant Best Available Retrofit Technology Analysis.

Attachment 3 contains a copy of the December 21, 1979 preconstruction air permit application requesting authorization for the construction of the Sulfur Surge Tank (EPN S-SurgeTnk, EQT 0084). This air permit application is referenced in the electronic file contained in Attachment 2. Attachment 4 contains a copy of the December 27, 1979 air permit (Permit No. 1312T) that was issued by the predecessor agency to the LDEQ authorizing the construction of the Sulfur Surge Tank (EPN S-SurgeTnk, EQT 0084). This air permit is referenced in the electronic file contained in Attachment 2.

The following person(s) assisted in the preparation of the response to Request 4: Todd Higginbotham and Michael Carbon with Ramboll Environ, consultants to Mosaic, and Greg Davison with Mosaic.

Request 5. *Please recalculate and submit the cost analysis performed based on a 30 year life rather than a 20 year life.*

Response 5. Mosaic disagrees with the EPA that it is appropriate to use a 30-year life when performing the BART cost analyses for the Uncle Sam Plant. In fact, EPA has indicated that a high-end life for a scrubber is 20 years.[1] Nonetheless we have revised the BART analyses previously performed for the Uncle Sam Plant by using a 30-year life, as requested. The assumption of a 30-year life did not change our BART determinations. The results of the revised BART cost analyses are summarized in Section 3 of Attachment 1. The revised BART cost analysis calculations are contained in Exhibits 3 through 10 of Attachment 1. Mosaic reserves all rights to challenge the appropriateness of use of a 30-year life in any BART cost analysis in any FIP, SIP, rulemaking, permitting, or enforcement proceeding.

The following person(s) assisted in the preparation of the response to Request 5: Todd Higginbotham and Michael Carbon with Ramboll Environ, consultants to Mosaic and Maureen Harbourt with Kean Miller LLP, counsel to Mosaic.

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[1] Robert D. Bauman, Chief, Standards Implementation Branch, Office of Air Quality Planning and Standards, EPA to Stephen H. Rothblatt, Chief, Air and Radiation Branch, EPA Region V. July 24, 1987.

Request 6. *The ozone data used for CALPUFF modeling should be hourly monitored ozone data from the years modeled, so the ozone data should be from 2001, 2002 and 2003. A value of 80 ppb should be used to fill in for missing data (CALPUFF setting BCKO3 = 12*80). The EPA has ozone data files that we will provide electronically to Mosaic and their modeling contractors.*

Response 6. Mosaic has conducted CALPUFF modeling using the ozone data files provided by the EPA and a value of 80 parts per billion by volume (ppbv) for missing ozone data. A description of the CALPUFF modeling analysis and a summary of the modeling results are provided in Section 4 of Attachment 1. Additionally, electronic copies of the CALPUFF input and output files used and created in the CALPUFF modeling analysis are contained in Exhibit 11 of Attachment 1. EPA and LDEQ guidance has previously indicated that 40 ppb is an appropriate default value for missing ozone data. Mosaic reserves all rights to challenge the appropriateness of use of 80 ppb as the default for missing ozone data in any future FIP, SIP, rulemaking, permitting, or enforcement proceeding.

The following person(s) assisted in the preparation of the response to Request 6: Michael Carbon, Todd Higginbotham, Bart Brashers, and Tim Sturtz with Ramboll Environ, consultants to Mosaic.

Request 7. *Please submit a revised 5 factor BART analysis addressing the above concerns.*

Response 7. Mosaic has revised the 5-factor BART analyses performed for the BART-eligible emissions units at the Uncle Sam Plant as directed by the EPA in Requests 1 through 6. These revised 5-factor BART analyses are included in Sections 3 and 4 of Attachment 1. Mosaic reserves all rights to challenge the appropriateness of the modeling methodology and input assumptions for the modeling and 5-factor BART analysis in any future FIP, SIP, rulemaking, permitting, or enforcement proceeding.

The following person(s) assisted in the preparation of the response to Request 7: Michael Carbon, Todd Higginbotham, Bart Brashers, and Tim Sturtz with Ramboll Environ, consultants to Mosaic and Maureen Harbourt with Kean Miller LLP, counsel to Mosaic.

Request 8. *Submittal of Modeling*

Modeling submissions must include

- *Modeling Report and Conclusions*
- *All modeling files*

Modeling files must be provided on a hard drive, USB drive, or electronic ftp, and must include all of the following files as applicable:

- *CALMET output files*
- *CALPUFF input, control, and output files*
- *POSTUTIL input, control, and output files*
- *CALPOST input, control, and output files*
- *Executables used.*

Response 8. The CALPUFF modeling report and a summary of the modeling conclusions are provided in Section 4 of Attachment 1. Additionally, electronic copies of the CALPUFF input and output files used and created in the CALPUFF modeling analysis are contained in Exhibit 11 of Attachment 1.

The following person(s) assisted in the preparation of the response to Request 8: Michael Carbon, Todd Higginbotham, Bart Brashers, and Tim Sturtz with Ramboll Environ, consultants to Mosaic.

Attachment 5 contains the Statement of Certification required to be signed and returned with this response.

If you or any member of your staff should have any questions or require additional information in regards to this submittal, please do not hesitate to contact David Oubre at (225) 474-1336. Thank you for your consideration of this submission. We look forward to working with EPA in a cooperative manner in this matter.

Sincerely,

Steve J. Susick
Plant Manager – Louisiana Operations

Attachments

cc: with attachments

LDEQ, Office of Environmental Services **7013 2250 0001 5994 8840**
David Oubre, Mosaic
David Jellerson, Mosaic
Jeff Stewart, Mosaic
Patrick vanderVoorn, Mosaic
Diana Jaglella, Mosaic
Michael Carbon, Ramboll Environ

bcc: with attachments

Steve Chatelain, Mosaic

ATTACHMENT 1

Mosaic Uncle Sam Plant
Best Available Retrofit Technology Analysis, Rev. 1
September 2015

ATTACHMENT 2

Electronic File Response to Request 4

ATTACHMENT 3

December 21, 1979 Preconstruction Air Permit Application Requesting Authorization for the Construction of the Sulfur Surge Tank (EPN S-SurgeTnk, EQT 0084)

ATTACHMENT 4

December 27, 1979 Permit No. 1312T Authorizing Construction of the Sulfur Surge Tank (EPN S-SurgeTnk, EQT 0084)

ATTACHMENT 5

Statement of Certification

ENCLOSURE 3:

Statement of Certification

I certify under penalty of law that I have examined and am familiar with the information in the enclosed documents, including all attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief, true and complete. I am aware that there are significant penalties for knowingly submitting false statements and information, including the possibility of fines or imprisonment pursuant to section 113(c)(2) of the CAA, and 18 US.C. §§ 1001 and 1341.

(Signature)

GENERAL MANAGER LOUISIANA OPERATIONS
(Title)

Potpourri

POTPOURRI

Department of Environmental Quality
Office of the Secretary
Legal Division

State Implementation Plan (SIP) for
Regional Haze Program

Under the authority of the Louisiana Environmental Quality Act, R.S. 30:2001 et seq., the secretary gives notice that the Office of Environmental Services, Air Permits Division, will submit to the U.S. Environmental Protection Agency (EPA) a proposed revision to the SIP for the Regional Haze Program as required under the Clean Air Act, Part C, Section 169, and 40 CFR Part 51.308. Regional haze is visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area. (1406Pot1)

On July 3, 2012, the EPA made final a partial limited approval and partial disapproval of the original SIP submitted on June 13, 2008. This revision answers the requirements for the four nonelectrical generating units (nonEGUs) facilities that were addressed under the Best Available Retrofit Technology (BART) section in the original SIP and that are the subject of the EPA partial disapproval. This submittal will only pertain to Mosaic, Uncle Sam Facility.

A public hearing will be held at 1:30 pm on July 29, 2014, in the Galvez Building, Oliver Pollock Room C-111, 602 N. Fifth Street, Baton Rouge, LA. Individuals with a disability and need accommodation in order to participate, please contact Vivian H. Aucoin at (225) 219-3389, or at the address listed below. Interested persons are invited to attend and submit oral comments on the proposal.

All interested persons are invited to submit written comments concerning the SIP revision no later than 4:30 p.m., July 29, 2014 to Vivian H. Aucoin, Office of Environmental Services, Box 4313, Baton Rouge, LA 70821-4314, fax (225) 219-3156, or e-mail at vivian.aucoin@la.gov.

A copy of the SIP revision for the Regional Haze Program may be viewed from 8 a.m. to 4:30 p.m. in the LDEQ Public Records Center, Room 127, 602 N. Fifth Street, Baton Rouge, LA. The document is available at www/deq.louisiana.gov/portal/Default.aspx?tabid=2381.

Herman Robinson, CPM
Executive Counsel

1406#018

POTPOURRI

Department of Health and Hospitals
Behavior Analyst Board

Public Hearing—Substantive Changes to Proposed
Rule, Application Procedures and Board Fees
(LAC 46:VIII.Chapter 3)

The board published a Notice of Intent to promulgate LAC 46.VIII.Chapter 3, Application Procedures and Board Fees, in the April 20, 2014 edition of the *Louisiana Register* (LR 40:853-854). The notice solicited comments. As a result of its analysis of the comments, the board proposes to amend the rule by adding the word "American" as follows: "Submit verification of successful passage of a national exam administered by a nonprofit organization accredited by the National Commission for Certifying Agencies and the American National Standards Institute to credential professional practitioners of behavior analysis related to the principles and practice of the profession of behavior analysis that is approved by the board."

No fiscal or economic impact will result from the amendments proposed in this notice.

Title 46
PROFESSIONAL AND OCCUPATIONAL STANDARDS
Part VIII. Behavior Analysts
Chapter 3. Application Procedures and Board Fees
§301. Application Procedures for Licensure/State Certification/Registration

A. Application and/or Registration

1. An application for a license as a behavior analyst, state certified assistant behavior analyst or registration as a line technician may be submitted after the requirements in R.S. 37:3706-37:3708 are met.

2. Upon submission of application or registration on the forms provided by the board, accompanied by such fee determined by the board, the applicant must attest and acknowledge that the:

a. information provided to the board is true, correct and complete to the best of his knowledge and belief; and

b. the board reserves the right to deny an application in accordance with RS 37:3706-R.S. 37:3708, if the application or any application materials submitted for consideration contain misrepresentations or falsifications.

3. An applicant, who is denied licensure based on the information submitted to the board, may reapply to the board after one year, and having completed additional training, if necessary and having met the requirements of law as defined in the rules and regulations adopted by the board.

Mosaic Uncle Sam Plant

Agency Interest No. 2532

Best Available Retrofit Technology Analysis, Rev. 1

Prepared for:
Mosaic Fertilizer, LLC
Uncle Sam, Louisiana

Prepared by:
ENVIRON International Corporation
Baton Rouge, Louisiana

Date:
September 2015

Project Number:
26-24607AI

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1 Background and Summary Information

Mosaic Fertilizer, LLC ("Mosaic") owns and operates the Uncle Sam Plant ("plant") located in St. James Parish, Louisiana. As requested by the Louisiana Department of Environmental Quality (LDEQ), Mosaic performed a best available retrofit technology (BART) analysis for each BART-eligible emissions unit at the plant.[1]

Mosaic determined that no additional emissions control technologies are required to be installed at the plant for BART compliance purposes. Instead, Mosaic determined that for the relevant emissions units at the plant the existing operations and emissions control technologies, some of which were recently installed as the result of a Consent Decree that Mosaic entered into with the United States of America and Louisiana in 2009 (hereinafter referenced as the "Consent Decree"),[2] represent BART. Additionally, Mosaic determined that the current operations and emissions control technologies for the relevant emissions units at the plant have resulted in a visibility improvement of 0.42 deciviews[3] (dv) or greater at the Breton Wilderness Area relative to the operations and emissions control technologies that were in place in 2007 when the BART applicability visibility modeling analysis was performed for the plant.[4] Furthermore, this visibility improvement indicates that the BART-eligible emissions units at the plant will not cause or contribute to visibility impairment at the Breton Wilderness Area because the visibility impact is less than the LDEQ BART exemption threshold of 0.5 dv.

1.1 Plant Description

The plant is an agricultural chemical manufacturing complex located along the Mississippi River at 7250 Highway 44, Uncle Sam, Louisiana. The plant produces sulfuric acid, phosphoric acid, and fluorosilicic acid (FSA). In association with these operations, the plant stores and handles sulfuric acid, phosphoric acid, FSA, molten sulfur, phosphate rock, phosphogypsum, lime slurry, and phosphogypsum stack pond water. The major operations located at the plant include three sulfuric acid trains, two phosphoric acid trains, a phosphogypsum stack area and associated ponds, a natural gas fired package boiler, utility (e.g., steam distribution, electricity generation and distribution, water treatment) facilities, and raw material and product storage, handling,

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[1] In 2007, Mosaic was evaluating the application of a wet scrubber on the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) in order to reduce SO_2 emissions from this emissions unit. On June 6, 2007, Mr. James Orgeron of the LDEQ provided Mosaic with a verbal confirmation that a BART analysis would not be required for the plant if Mosaic demonstrated that the application of a wet scrubber on the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) would lower the visibility impact of the plant's BART-eligible emissions units at all Class I areas to below 0.5 dv. On June 15, 2007, Mosaic provided the LDEQ with a source-specific, subject-to-BART refined modeling analysis documenting that the plant's BART-eligible emissions units would result in a visibility impact below 0.5 dv at all Class I areas after the application of a wet scrubber on the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067).

[2] United States of America and State of Louisiana v. Mosaic Fertilizer, LLC, Eastern District of Louisiana, Civil Action No. 2:09-cv-6662, effective December 23, 2009.

[3] A deciview is a unit of visibility proportional to the logarithm of the atmospheric extinction.

[4] The visibility improvement documented here is a comparison of the 8th highest daily visibility impairment impact (98th percentile of values) determined individually for 2001, 2002, and 2003 when modeling "Baseline" emissions and the 8th highest daily visibility impairment impact determined individually for 2001, 2002, and 2003 when modeling "With BART" emissions. See Section 4 of this document.

loading, and unloading facilities. Below we summarize the process descriptions for the Sulfuric Acid Plant and the Phosphoric Acid Plant.

1.1.1 Sulfuric Acid Plant

The Sulfuric Acid Plant consists of three trains: the A, D, and E Trains. The A and D Trains have an average capacity of 2,200 tons per day (tpd) sulfuric acid each, while the E Train has an average capacity of 3,800 tpd sulfuric acid. The A Train is a single absorption unit, while the D and E Trains are double absorption units, and each of these three trains can produce sulfuric acid of approximately 93% to 98% strength.

Molten elemental sulfur, air, and water are the raw materials used to produce sulfuric acid in the three trains. The molten sulfur can be received by truck, railcar, barge, or ship. For each train, the sulfuric acid production process is initiated by injecting air, pre-dried through countercurrent exposure to strong sulfuric acid in a packed drying tower, and molten sulfur into a refractory-lined furnace. The furnace's high temperature causes the auto-ignition of the atomized sulfur, which results in the formation of sulfur dioxide (SO_2) and heat. The hot gas mixture (1,830 to 2,070 °F) exiting the furnace is cooled (705 to 850 °F) in a heat recovery boiler, which generates steam that is used at the plant for process heat transfer purposes and to generate electricity. The SO_2 contained in the cooled gas is then converted to sulfur trioxide (SO_3) in a series of steps by contacting the gas with beds of catalyst. This SO_2-to-SO_3 reaction is not only a critical step in the sulfuric acid production process, but it is also important for air quality emission purposes because a considerable portion of the SO_2 exiting the last catalyst bed is ultimately emitted to the atmosphere if the particular sulfuric acid unit is not equipped with an add-on SO_2 emissions control device because SO_2 emissions are a function of catalyst performance. Because contact with each catalyst bed causes the temperature of the gas mixture to rise, heat exchangers are used to cool the gases after each conversion step. These heat exchangers not only recover energy as steam, but also optimize conditions for the conversion of SO_2 to SO_3.

For the A Train, the gas leaving the last catalyst bed undergoes additional cooling in a heat exchanger before it enters an absorption tower. In the packed bed absorption tower, the gas flows upward, while sulfuric acid flows downward. The SO_3 in the gas is absorbed by the downward flowing sulfuric acid and reacts with the available water in the sulfuric acid solution to form additional sulfuric acid, whereas the SO_2 contained in the gas predominately passes through the tower. The acid concentration of the sulfuric acid solution in the absorption tower is controlled by adding water. Because the A Train is a single absorption unit, the gas from the train's SO_2-to-SO_3 convertors passes through only one absorption tower before exiting the sulfuric acid production process. Prior to the installation of a wet scrubber on the A Train to comply with the requirements of the Consent Decree, the exhaust gas from the train's single absorption tower was emitted to the atmosphere with no additional emissions control. With the installation of the wet scrubber, the exhaust gas from the tower is now treated to substantially reduce SO_2 emissions from the A Train.

As previously mentioned, the D and E Trains are double absorption units. Therefore, each of these units is equipped with a second absorption tower. For the D Train, the process gas is sent through its first absorption tower after passing through the second of four catalyst beds. For the E Train, the gas is sent through its first absorption tower after passing through the third

of four catalyst beds. For both trains, upon leaving the first absorption tower, the gas is reheated and passed through the remaining catalyst bed(s) before being sent to a second absorption tower. The removal of SO_3 from the process gas in the first absorption tower improves the SO_2-to-SO_3 conversion efficiency in the catalyst beds following the tower, which results in considerably reduced SO_2 emissions to the atmosphere when compared to a single absorption unit.

The nominal 600 pounds per square inch, gauge (psig) steam produced in the heat recovery operations of the sulfuric acid trains can be used to drive turbine blower-generator units that generate electricity at the plant. Additionally, steam is exported to the Phosphoric Acid Plant where it is used to evaporate wet-process phosphoric acid.

There is one package boiler related to the Sulfuric Acid Plant that fires natural gas to generate 600 psig steam when the Sulfuric Acid Plant's waste heat boilers are shutdown or are operating at significantly reduced rates.

1.1.2 Phosphoric Acid Plant

Mosaic operates two wet-process phosphoric acid trains in parallel, which produce phosphoric acid (H_3PO_4) by reacting phosphate rock (generally, $Ca_3(PO_4)_2$) with sulfuric acid. The Phosphoric Acid Plant also generates gypsum (calcium sulfate ($CaSO_4$)). The North and South Phosphoric Acid Trains are each capable of producing a maximum of 1,805 tpd of phosphoric acid. In the description below, phosphoric acid is generally discussed in the form of phosphorus pentoxide (P_2O_5) as a reference to the amount of P available to plants, which is expressed as P_2O_5, not phosphoric acid.

For phosphate rock requiring milling prior to being fed to the phosphoric acid units, the rock is primarily transported by conveyor belts from outdoor storage piles to parallel rock silos. From these silos, the rock is fed to parallel ball mills, along with treated, clarified gypsum pond water. The mill product is a slurry of finely ground rock (about 67% solids) in water. This slurry is transferred to a slurry storage tank from which it is metered to compartment No. 1 of a multi-compartment reactor. For phosphate rock not requiring milling prior to being fed to the phosphoric acid units, the rock is transported from outdoor storage piles to the phosphoric acid units in much the same way previously described, except the rock bypasses the ball mills from the rock silos to the slurry operations.

The phosphoric acid reactors at the plant have eight main compartments. Sulfuric acid (93% or 98% strength) is pumped into a mixing "T" where it is dispersed into dilute (22% P_2O_5) recycled weak filtrate from the vacuum filter. This acid mixture discharges into compartment No. 4. Because the dilution of sulfuric acid and its reaction with the phosphate rock generates a considerable amount of heat, the slurry is cooled by recirculating it from compartment No. 7 through a flash cooler, and the cooled slurry is returned back to compartment Nos. 1 and 8. Slurry also enters compartment No. 1 by being recirculated from compartment No. 6. Slurry is pumped from compartment No. 8 to a filter, which separates byproduct gypsum from the phosphoric acid product. The gypsum cake on the filter is discharged and then slurried with recycle pond water. This 38-40% slurry is pumped to the gypsum stack.

Filtered phosphoric acid from both trains is combined into one stream by pumping the acid from the filtrate seal tanks to storage. The phosphoric acid is then clarified before being concentrated in four stages to a "merchant acid" strength of 50-54% P_2O_5. The Phosphoric Acid Plant has eight evaporators, designated 1 through 8. Booster evaporators 7 and 8 operate in parallel to raise acid strength from 27% to 30% P_2O_5. From these evaporators, the acid passes to parallel first stage evaporators 1, 2, and 3 where the acid's strength is raised to 40%. This 40% acid is clarified before sending it to evaporators 4 and 5 where an acid of 46-47% strength is produced. Underflow solids from 40% clarification are thickened through centrifugation before being recycled to filter acid. A last evaporation stage in evaporator 6 raises the acid to its final strength. Towers 4, 5, and 6, which are associated with evaporators 4, 5, and 6, are used to recover FSA from the vapor generated in the three evaporators. Three Swift Towers on the first stage evaporators (evaporators 1, 2, and 3) are not operated to recover FSA, but are flushed with once through pond water. Heated pond water passes through towers 1 and 2, and this material is then used for filter wash water. The vapor evolved from the acid in evaporator 3 is scrubbed with pond water, which is then returned to the pond.

1.2 Regional Haze Rule

Originally, Section 169A of the federal Clean Air Act (CAA) set forth a national goal for the "prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution." There are designated Class I areas across the country, including many well-known national parks and wilderness areas, such as the Grand Canyon, Great Smokies, Shenandoah, Yellowstone, and Yosemite, where visibility is considered to be an important part of the visitor experience. When the initial Class I area visibility protection provisions of the federal CAA were established, it was recognized that visibility problems in Class I areas are caused primarily by emissions of SO_2, oxides of nitrogen (NOx), and particulate matter (PM), especially fine PM. The United States Environmental Protection Agency (EPA) promulgated regulations in 1980 to address visibility impairment at Class I areas that is "reasonably attributable" to one or a small group of sources, but EPA deferred action on regional haze regulations – regulations addressing visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area – until monitoring, modeling, and scientific knowledge about the relationship between pollutants and visibility effects improved.

On July 1, 1999, after evaluating scientific information and policy recommendations on visibility issues that had been developed over more than 20 years, the EPA promulgated rules to address regional haze at Class I areas. These regulations were challenged, and on May 24, 2002, the United States Court of Appeals for the District of Columbia Circuit issued a ruling vacating the Regional Haze Rule in part and sustaining it in part. In response to the court's ruling, on July 6, 2005, the EPA promulgated a revised Regional Haze Rule and guidelines for the implementation of the BART requirements under the Regional Haze Rule.

1.2.1 BART-Eligible Sources

A key component of the Regional Haze Rule is the application of BART to certain existing sources. The first step in determining whether a source is subject to BART under the Regional

Haze Rule is to determine whether the source is a "BART-eligible source." The LDEQ uses the following three-step process to determine whether a source is a BART-eligible source:

- Step 1: Identify the emissions units in the BART categories;
- Step 2: Identify the start-up dates of those emissions units; and
- Step 3: Compare the potential emissions to the 250 tons per year (tpy) cutoff.

In Step1, a stationary source is evaluated to determine whether it contains any emissions units in one or more of the 26 relevant source categories.[5] If the stationary source includes an emissions unit in one or more of these source categories, then Step 2 requires the source to determine whether each such emissions unit began operation after August 7, 1962 and was *in existence*[6] on August 7, 1977. In Step 3, for all of the emissions units meeting the Steps 1 and 2 criteria, add the current potential to emit emission rate of each visibility-impairing pollutant (NOx, PM, and SO_2) separately to determine whether the total potential to emit emission rate from these emissions units equals 250 tpy or more for any visibility-impairing pollutant.

Using this three-step process, Mosaic determined that the following emissions units constitute the BART-eligible source at the plant.

- A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067)
- A Train Start-Up Burner (EPN S-ATrain2, EQT 0068)
- A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002)
- D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074)
- D Train Start-Up Burner (EPN S-DTrain2, EQT 0075)

[5] (1) Fossil-fuel fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input, (2) Coal cleaning plants (thermal dryers), (3) Kraft pulp mills, (4) Portland cement plants, (5) Primary zinc smelters, (6) Iron and steel mill plants, (7) Primary aluminum ore reduction plants, (8) Primary copper smelters, (9) Municipal incinerators capable of charging more than 250 tons of refuse per day, (10) Hydrofluoric, sulfuric, and nitric acid plants, (11) Petroleum refineries, (12) Lime plants, (13) Phosphate rock processing plants, (14) Coke oven batteries, (15) Sulfur recovery plants, (16) Carbon black plants (furnace process), (17) Primary lead smelters, (18) Fuel conversion plants, (19) Sintering plants, (20) Secondary metal production facilities, (21) Chemical process plants, (22) Fossil-fuel boilers of more than 250 million BTUs per hour heat input, (23) Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels, (24) Taconite ore processing facilities, (25) Glass fiber processing plants, and (26) Charcoal production facilities.

[6] *In existence* – means that the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time. (40 CFR 51, subpart P).

- D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003)
- Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113), *formerly* Rock Unloading, Handling, Storage, and Transfer (EPN S-Rock, EQT 0079)
- Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081)
- Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082)
- Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083)
- Dock Fugitive Emissions (EPN S-DockFug, FUG 0004)
- No. 1 Packaged Steam Boiler (EPN S-Boiler1, EQT 0072)
- No. 2 Packaged Steam Boiler (EPN S-Boiler2, EQT 0073)

The emissions units comprising the plant's E Train are not BART-eligible because they were not "in existence" on August 7, 1977. Construction of the E Train began in 1991, as indicated by the January 14, 1991 preconstruction air permit application (Exhibit 1) that was submitted to the LDEQ requesting authorization for construction of this process unit, along with the August 16, 1991 air permit (Permit No. 2091) (Exhibit 2) that was issued by the LDEQ authorizing its construction.

1.2.2 BART Exemption Analysis

Following EPA guidance, the LDEQ established that each BART-eligible source in Louisiana was allowed to determine whether it individually caused or contributed to visibility impairment at any Class I area by modeling specific NOx, direct PM with an aerodynamic diameter less than or equal to a nominal 10 micrometers (µm) (PM_{10}), direct PM with an aerodynamic diameter less than or equal to a nominal 2.5 µm ($PM_{2.5}$), and SO_2 emissions that result from the emissions units constituting the BART-eligible source and comparing the results of this visibility modeling analysis to a specific visibility impairment threshold value. The LDEQ established a visibility impairment threshold value of 0.5 dv for all BART-eligible sources in Louisiana.[7] If the results of this visibility modeling analysis demonstrated a visibility impairment impact less than 0.5 dv at any Class I area, then the particular BART-eligible source would be exempt from BART. Alternatively, if the modeling results demonstrated a visibility impairment impact equal to or greater than 0.5 dv at any Class I area, then the particular BART-eligible source would be subject to BART.

As indicated in Section 4.3 herein, when modeling the "Baseline" NOx, PM_{10}, $PM_{2.5}$, and SO_2 emissions for the emissions units constituting the BART-eligible source at the plant, it was determined that these emissions units would not meet the BART exemption level of 0.5 dv at

[7] The 8th highest daily visibility impairment impacts (98th percentile of values) determined individually for 2001, 2002, and 2003 are compared to 0.5 dv.

the Breton Wilderness Area. Therefore, the emissions units constituting the BART-eligible source are subject to BART.

Table 1.1 below summarizes the emissions units at the plant subject to BART and the BART relevant pollutants emitted by each of these emissions units.

Table 1.1: Summary of Emissions Units and Pollutants Subject to BART

Emissions Unit	Emits NOx?	Emits $PM/PM_{10}/PM_{2.5}$?	Emits SO_2?
A Train Single Absorption H_2SO_4 Plant (EPN S-ATrain1, EQT 0067)	Yes	Yes	Yes
A Train Start-Up Burner (EPN S-ATrain2, EQT 0068)	Yes	Yes	Yes
A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002)	No	No	Yes
D Train Double Absorption H_2SO_4 Plant (EPN S-DTrain1, EQT 0074)	Yes	Yes	Yes
D Train Start-Up Burner (EPN S-DTrain2, EQT 0075)	Yes	Yes	Yes
D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003)	No	No	Yes
Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113)	No	Yes	No
Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081)	No	Yes	Yes
Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082)	No	Yes	Yes
Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083)	No	Yes	Yes
Dock Fugitive Emissions (EPN S-DockFug, FUG 0004)	No	Yes	Yes
No. 1 Packaged Steam Boiler (EPN S-Boiler1, EQT 0072)	Emissions Unit Shut Down and Removed from Title V Permit[8]		
No. 2 Packaged Steam Boiler (EPN S-Boiler2, EQT 0073)	Emissions Unit Shut Down and Removed from Title V Permit[9]		

[8] The No. 1 Packaged Steam Boiler (EPN S-Boiler1, EQT 0072) was removed from the plant's Title V permit with the issuance of Permit No. 2560-00004-V2 on March 20, 2013.

[9] The No. 2 Packaged Steam Boiler (EPN S-Boiler2, EQT 0073) was removed from the plant's Title V permit with the issuance of Permit No. 2560-00004-V2 on March 20, 2013.

2 BART Analysis Process

For each emissions unit subject to BART, the level of control representing BART was determined pursuant to the guidance provided in 40 Code of Federal Regulations (CFR) Part 51, Appendix Y (*Guidelines for BART Determinations Under the Regional Haze Rule*). "BART" is defined at 40 CFR 51.301 as follows.

> *Best Available Retrofit Technology (BART) means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.*

In accordance with this definition, a BART analysis is conducted on a case-by-case basis and a particular BART determination is made taking into account:

- the technologies available;
- the costs of compliance;
- the energy and non-air quality environmental impacts of compliance;
- any air pollution control equipment in use at the emissions unit;
- the remaining useful life of the emissions unit; and
- the degree of visibility improvement that may be expected from the chosen control technology.

Once the level of control representing BART has been identified, the BART emission limitations must be met in a timely manner.

The following steps outline the BART analysis process in more detail.

2.1 Step 1 – Identify All Available Retrofit Control Technologies

The first step in the BART analysis is to define the spectrum of process and/or add-on emissions control alternatives potentially applicable to an emissions unit.[10] Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered. Also, it is not necessary to consider control technologies that require redesign of the source or

[10] "In identifying 'all' options, you must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving." 70 Federal Register 39164 (July 6, 2005).

require that the source be de-rated. Generally, a control technology alternative will fall into one of the following three categories:

- pollution prevention: the use of lower-emitting processes/practices, including the use of control techniques (e.g., low NOx burners) and work practices that prevent the formation of emissions and result in lower "production-specific" emissions;
- use of and, if applicable, improvement of add-on controls; or
- combinations of inherently lower-emitting processes and add-on controls.

Potentially available technology options can be drawn from best available control technology (BACT) or lowest achievable emission rate (LAER) determinations made as part of New Source Review permitting requirements, New Source Performance Standard control technology requirements, and EPA publications.

If an emissions unit subject to BART already has the most stringent available control technology installed, no additional BART analysis is necessary as long as the application of the most stringent available control technology is federally enforceable.

2.2 Step 2 – Eliminate Technically Infeasible Options

The second step is to evaluate the technical feasibility of the alternatives identified in Step 1 and to reject those which are technically infeasible based on engineering evaluation or due to chemical or physical principles. The following criteria are considered in determining technical feasibility: previous commercial scale demonstrations, precedents based on previous permits, and technology transfer from similar emissions units.

When evaluating the technical feasibility of a technology that has been operated successfully on a type of source different than the source type under review, EPA has indicated that the "availability" and "applicability" of the technology to the source type under review should be considered in order to eliminate the technology as technically infeasible. A technology is considered ''available'' if the source may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is ''applicable'' if it can reasonably be installed and operated on the source type under consideration.

2.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

After eliminating technically infeasible control technology options from further review, the next step in the BART analysis is to compare the control effectiveness among feasible technologies using a metric that ensures a fair comparison among options, such as an average steady state emissions level per unit of product produced or processed (e.g., pounds of SO_2 per MMBtu). As part of this step, the performance of control technologies over a wide range of operations must be considered.

2.4 Step 4 – Evaluate Impacts and Document the Results

This step of the BART analysis includes an evaluation of the following four components:

- Control Technology Costs;
- Control Technology Energy Impacts;
- Control Technology Non-Air Quality Environmental Impacts; and
- Remaining Useful Life of Emissions Unit.

Also, the collateral emissions increases associated with the technically feasible control technology options are typically addressed as part of this step.

2.4.1 Control Technology Costs

The control technology cost analysis performed for an emissions unit takes into account the unit's existing emissions performance and the design parameters and effectiveness of each control technology evaluated for the same emissions unit. The control technology costs can be examined in two different ways: (1) the average cost effectiveness and (2) the incremental cost effectiveness.

The average cost effectiveness for a particular control technology is the total annualized costs of that control technology divided by the annual emissions reduction achieved by the same control technology, expressed as dollars ($) per ton:

$$\boldsymbol{Average\ cost\ effectiveness}\ (\$/\boldsymbol{ton}) = \frac{Total\ Annualized\ Costs\ of\ Control\ Option}{(Baseline\ Annual\ Emissions - Control\ Option\ Annual\ Emissions)}$$

BART guidance indicates that the baseline annual emissions are the average actual emissions over the two-year period preceding the BART analysis. Initial guidance provided by the LDEQ and the EPA indicated a BART analysis was not required for the plant; otherwise, the BART analysis would have been completed in 2007. As a result, we generally estimated an emissions unit's baseline annual emissions to equal the average of the 2005 and 2006 annual emissions reported to the LDEQ for the unit. However, there are two departures from this methodology:

- for certain emissions units, the baseline annual emissions were conservatively set equal to the relevant potential to emit emission rate listed in the plant's current Title V permit for the particular unit; and
- for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074), because this emissions unit underwent SO_2 emissions control technology changes in 2011 to comply with relevant SO_2 emission limitations in the Consent Decree, we estimated this emissions unit's baseline annual SO_2 emissions to equal the average of the 2012, 2013, and 2014 annual SO_2 emissions reported to the LDEQ for the unit.

The incremental cost effectiveness calculation compares the costs and performance level of a control option to those of the next most stringent option, as shown in the following formula:

$$\boldsymbol{Incremental\ cost\ effectiveness}\ (\$/\boldsymbol{ton}) = \frac{(Total\ Annualized\ Costs\ of\ Control\ Option - Total\ Annualized\ Costs\ of\ Next\ Control\ Option)}{(Control\ Option\ Annual\ Emissions - Next\ Control\ Option\ Annual\ Emissions)}$$

The incremental cost effectiveness is intended to demonstrate which control technology options provide the most efficient use of resources. Both the average cost effectiveness and the incremental cost effectiveness are considered when making a BART determination.

2.4.2 Control Technology Energy Impacts

The energy impacts, whether energy penalties or benefits, should be evaluated for each control technology option. In general, only direct energy consumption and not indirect energy impacts should be considered. Issues such as the use of locally scarce fuels or whether a given alternative would result in significant economic disruption or unemployment can also be considered in the energy impact analysis. Because energy penalties or benefits can usually be quantified in terms of additional cost or income to the source, energy impacts are also to be factored into the control technology cost analysis.

2.4.3 Control Technology Non-Air Quality Environmental Impacts

An analysis of any environmental impacts other than air quality can be used to evaluate control technology options. Non-air quality impacts can include, but are not limited to, solid or hazardous waste generation, wastewater generation, irreversible or irretrievable commitment of resources (e.g., use of scarce water resources), noise levels, radiant heat, or dissipated electrical energy.

2.4.4 Remaining Useful Life of Emissions Unit

The “remaining useful life”[11] of an emissions unit subject to BART can be taken into account when performing the BART analysis. More specifically, as part of the annualized cost determination for a particular control technology, a time period must be assigned for amortization of the control technology equipment. If the remaining useful life of the relevant emissions unit will clearly exceed this time period, then the unit’s remaining useful life has essentially no effect on the BART determination process. However, if the remaining useful life of the relevant emissions unit is less than the time period that would typically be used for amortizing costs for the particular control technology, then the shorter time period can be used in the control technology amortization calculation. If the use of this shorter time period affects the outcome of the BART determination for the emissions unit, then the projected date for the

[11] “For purposes of these guidelines, the remaining useful life is the difference between:

(1) The date that controls will be put in place[…]; you are conducting the BART analysis; and

(2) The date the facility permanently stops operations.”

(40 CFR part 51, Appendix Y).

unit to permanently stop operations should be assured by a federally enforceable restriction preventing further operation after such date.

2.4.5 Collateral Emissions Increases Associated with Control Technology

Although control technologies are intended to reduce emissions of a specific pollutant, in some cases, the emissions of other pollutants may increase or a new pollutant may be introduced due to the application of a particular control technology. Therefore, as part of this BART analysis, we considered whether collateral emissions increases would occur in association with technically feasible control technology options.

2.5 Step 5 – Evaluate Visibility Impacts

Once the potentially feasible control options have been evaluated, the final step of the BART analysis is to conduct a visibility improvement determination for the emissions units subject to BART. For this step, we used the CALPUFF dispersion model to model the BART-eligible emissions units' NOx, PM_{10}, $PM_{2.5}$, and SO_2 emissions in three scenarios: "Baseline," "With BART," and "With BART + D Train Wet Scrubber."

Because the visibility impact criterion is a calendar day average, the BART visibility impact analysis was performed using the worst-case 24-hour emissions for the emissions units subject to BART. For each of these emissions units, the worst-case calendar day emissions of all BART relevant pollutants were modeled even though it is unlikely all such emissions units will emit worst-case emissions of all BART relevant pollutants on the same day. Therefore, the emissions scenarios modeled for this BART visibility impact analysis are very conservative.

As presented in detail in Section 4 herein, the "With BART" emissions scenario demonstrates a significant improvement in the visibility impact of the BART relevant emissions units at the Breton Wilderness Area. This emissions scenario indicates that the emissions units will have a visibility impact considerably below the BART exemption level of 0.5 dv at the Breton Wilderness Area.

3 BART Determination Analysis

Table 3.1 below summarizes the BART determinations made for the emissions units at the plant subject to BART.

Table 3.1: Summary of BART Determinations

Emissions Unit	Pollutant	Emissions Level	Control Technology
A Train Single Absorption H_2SO_4 Plant (EPN S-ATrain1, EQT 0067)	NOx	0.12 lb per ton of 100% H_2SO_4 produced (24-hr average)	None
	PM_{10}	0.15 lb H_2SO_4 per ton of 100% H_2SO_4 produced (3-hr average)	Mist Eliminator
	$PM_{2.5}$	0.15 lb H_2SO_4 per ton of 100% H_2SO_4 produced (3-hr average)	Mist Eliminator
	SO_2	1.0 lb per ton of 100% H_2SO_4 produced[12] (3-hr rolling average) *or* 4.0 lb per ton of 100% H_2SO_4 produced[13] (3-hr rolling average)	Wet Scrubber
A Train Start-Up Burner (EPN S-ATrain2, EQT 0068)	NOx	32.94 lb/hr (24-hr average)	Good Combustion Practices
	PM_{10}	0.89 lb/hr (24-hr average)	Good Combustion Practices
	$PM_{2.5}$	0.89 lb/hr (24-hr average)	Good Combustion Practices
	SO_2	0.07 lb/hr (24-hr average)	Pipeline Quality Natural Gas Fuel

[12] This short-term limit does not apply during periods of start-up, shutdown, or malfunction. Start-up shall mean the period of time beginning when the feed of elemental sulfur to the furnace commences and lasting for no more than 4 hours. Shutdown shall mean the cessation of operation of the A Train for any reason and begins at the time the feed of elemental sulfur to the furnace ceases and ends 3 hours later or when the blower is turned off, whichever is earlier. Malfunction shall mean any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner, but shall not include failures that are caused in part by poor maintenance or careless operation.

[13] This short-term limit applies during periods of start-up, shutdown, or malfunction. Start-up shall mean the period of time beginning when the feed of elemental sulfur to the furnace commences and lasting for no more than 4 hours. Shutdown shall mean the cessation of operation of the A Train for any reason and begins at the time the feed of elemental sulfur to the furnace ceases and ends 3 hours later or when the blower is turned off, whichever is earlier. Malfunction shall mean any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner, but shall not include failures that are caused in part by poor maintenance or careless operation.

Table 3.1: Summary of BART Determinations

Emissions Unit	Pollutant	Emissions Level	Control Technology
A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002)	SO_2	Control sulfuric acid train ductwork leaks using a temporary collection system that routes the collected gas back to the sulfuric acid production process.	Leak Detection and Repair
D Train Double Absorption H_2SO_4 Plant (EPN S-DTrain1, EQT 0074)	NOx	0.12 lb per ton of 100% H_2SO_4 produced (24-hr average)	None
	PM_{10}	0.15 lb H_2SO_4 per ton of 100% H_2SO_4 produced (3-hr average)	Mist Eliminator
	$PM_{2.5}$	0.15 lb H_2SO_4 per ton of 100% H_2SO_4 produced (3-hr average)	Mist Eliminator
	SO_2	2.2 lb per ton of 100% H_2SO_4 produced (365-day rolling average) *and* 4.0 lb per ton of 100% H_2SO_4 produced (3-hr rolling average)	Double Contact Double Absorption and Cesium-Promoted Catalyst
D Train Start-Up Burner (EPN S-DTrain2, EQT 0075)	NOx	32.94 lb/hr (24-hr average)	Good Combustion Practices
	PM_{10}	0.89 lb/hr (24-hr average)	Good Combustion Practices
	$PM_{2.5}$	0.89 lb/hr (24-hr average)	Good Combustion Practices
	SO_2	0.07 lb/hr (24-hr average)	Pipeline Quality Natural Gas Fuel
D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003)	SO_2	Control sulfuric acid train ductwork leaks using a temporary collection system that routes the collected gas back to the sulfuric acid production process.	Leak Detection and Repair

Table 3.1: Summary of BART Determinations

Emissions Unit	Pollutant	Emissions Level	Control Technology
Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113)	PM_{10}	20.74 tpy (Florida rock only)	Transfer Points: Combination of Partial to Full Enclosure and Minimization of Drop Distance Storage Piles: Wet Storage Piles Haul Roads: Wet Haul Roads
	$PM_{2.5}$	2.87 tpy (Florida rock only)	Transfer Points: Combination of Partial to Full Enclosure and/or Minimization of Drop Distance Storage Piles: Wet Storage Piles Haul Roads: Wet Haul Roads
Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083)	PM_{10}	5.55 tpy[14]	None
Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083)	$PM_{2.5}$	1.65 tpy[15]	None
Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083)	SO_2	2.98 tpy[16]	None
Dock Fugitive Emissions (EPN S-DockFug, FUG 0004)	PM_{10}	0.97 tpy	None
	$PM_{2.5}$	0.50 tpy	None
	SO_2	0.01 tpy	None

[14] These three sources are included in the Sulfur Cap (EPN S-SCAP, GRP 0011). The PM_{10} emissions for these sources are authorized under this emissions cap. Therefore, a single BART PM_{10} emissions level was assigned for the combined sources.

[15] These three sources are included in the Sulfur Cap (EPN S-SCAP, GRP 0011). The $PM_{2.5}$ emissions for these sources are authorized under this emissions cap. Therefore, a single BART $PM_{2.5}$ emissions level was assigned for the combined sources.

[16] These three sources are included in the Sulfur Cap (EPN S-SCAP, GRP 0011). The SO_2 emissions for these sources are authorized under this emissions cap. Therefore, a single BART SO_2 emissions level was assigned for the combined sources.

Table 3.1: Summary of BART Determinations

Emissions Unit	Pollutant	Emissions Level	Control Technology
No. 1 Packaged Steam Boiler (EPN S-Boiler1, EQT 0072)	NOx	0	Emissions Unit Shut Down and Removed from Title V Permit
	PM_{10}	0	Emissions Unit Shut Down and Removed from Title V Permit
	$PM_{2.5}$	0	Emissions Unit Shut Down and Removed from Title V Permit
	SO_2	0	Emissions Unit Shut Down and Removed from Title V Permit
No. 2 Packaged Steam Boiler (EPN S-Boiler2, EQT 0073)	NOx	0	Emissions Unit Shut Down and Removed from Title V Permit
	PM_{10}	0	Emissions Unit Shut Down and Removed from Title V Permit
	$PM_{2.5}$	0	Emissions Unit Shut Down and Removed from Title V Permit
	SO_2	0	Emissions Unit Shut Down and Removed from Title V Permit

Except for the No. 1 Packaged Steam Boiler (EPN S-Boiler1, EQT 0072) and the No. 2 Packaged Steam Boiler (EPN S-Boiler2, EQT 0073), the BART determination analyses performed for these emissions units are presented below.

3.1 A Train Single Absorption H_2SO_4 Plant (EPN S-ATrain1, EQT 0067) NOx BART Analysis

The combustion of sulfur in a sulfuric acid unit is a relatively low temperature process at oxygen levels that are, out of necessity, relatively high. Sulfur is burned in the sulfur furnace with an excess amount of air (generally 10% by volume oxygen or higher in the sulfur furnace combustion gases) at a temperature ranging from 1,800 to 2,000 °F. If the oxygen concentration in the combustion gases is decreased (and, consequently, the SO_2 concentration is increased), the SO_2-to-SO_3 conversion catalyst in the sulfuric acid unit can become ineffective and the SO_2-to-SO_3 conversion efficiency can decrease markedly. The adiabatic flame temperature of sulfur is approximately 75% of the adiabatic flame temperature of natural gas, oil, or coal. Therefore, the NOx concentration in the exhaust gases from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) is inherently quite low. As a result, there has not been much emphasis placed on controlling NOx emissions from sulfur-burning sulfuric acid units.

3.1.1 Step 1 – Identify All Available Retrofit Control Technologies

Available NOx emissions control technologies for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) were determined by searching the EPA's reasonably available control technology (RACT)/BACT/LAER Clearinghouse (RBLC) for control technology determinations made after January 1, 2005 for the following process code.

- Process Code 62.015 – Inorganic Chemicals Manufacturing; Sulfuric Acid Plants

Below is a listing of the NOx emissions control technologies identified under this EPA RBLC process code.

- Selective Catalytic Reduction (SCR)

Although not listed in the results of the above mentioned NOx emissions control technology query of Process Code 62.015 in the RBLC, the following are NOx emissions control technologies that may be considered to be available technologies for the reduction of NOx emissions from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067).

- Flue Gas Recirculation (FGR)/Low NOx Burners (LNBs)/Ultra-Low NOx Burners (ULNBs)
- Selective Non-Catalytic Reduction (SNCR)
- Non-Selective Catalytic Reduction (NSCR)

Below we discuss all of the NOx emissions control technologies that may be considered to be available technologies for the reduction of NOx emissions from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067).

3.1.1.1 SCR

SCR is a post-combustion treatment technology that promotes the selective catalytic chemical reduction of NOx (both nitric oxide and nitrogen dioxide) to molecular nitrogen and water. SCR can achieve NOx emissions reductions of up to 95%; however, NOx emissions reductions between 80 and 90% are typically achieved by this technology. For a combustion device equipped with an SCR system, a reducing agent (aqueous or anhydrous ammonia or urea) is mixed with NOx-containing combustion gases and the resulting mixture is passed through a catalyst bed, which serves to lower the activation energy of the NOx reduction reactions. In the catalyst bed, the NOx and ammonia contained in the combustion gas-reagent mixture are adsorbed onto the SCR catalyst surface to form an activated complex and then the catalytic reduction of NOx occurs, resulting in the production of nitrogen and water from NOx. The nitrogen and water products of the SCR reaction are desorbed from the catalyst surface into the combustion exhaust gas passing through the catalyst bed. From the SCR catalyst bed, the treated combustion exhaust gas is emitted to the atmosphere. SCR systems can effectively operate at a temperature above 350 °F and below 1,100 °F, with a more refined temperature window dependent on the composition of the catalyst used in the SCR system.

3.1.1.2 FGR, LNBs, and ULNBs

FGR, LNBs, and ULNBs have been grouped together because they are best represented as a category of combustion technique NOx emissions control technologies. Additionally, ULNB and LNB terminology can be interchangeable. For instance, in the case of two different burners achieving the same NOx emissions level in identical applications, one of the burners may be referenced as an LNB while the second burner is referenced as an ULNB. Furthermore, in

regard to FGR, some of the LNB and ULNB designs incorporate FGR. Combustion technique NOx control technologies typically achieve a 60 to 90% reduction in NOx emissions when applied to a gaseous fuel external combustion device equipped with conventional burners.

Combustion technique NOx control technologies incorporate one or more of the following concepts: 1) lower the flame temperature; 2) create a fuel rich condition at the maximum flame temperature; or 3) lower the residence time under which oxidizing conditions exist. LNBs/ULNBs are available in a variety of configurations and burner types. In LNBs/ULNBs, fuel and air are often pre-mixed prior to combustion, resulting in a lower and more uniform flame temperature. Pre-mix burners may require the aid of a blower to mix the fuel with air before combustion takes place. Therefore, in a retrofit scenario, the conversion of an existing natural draft external combustion device to a mechanical draft design can be costly due to technical difficulties and the potential for extensive physical changes to the combustion device.

FGR, recycling a portion of a combustion device's exhaust gases back into the unit's burner(s), is a common design feature of LNBs and ULNBs because this feature reduces the burner flame temperature. There are two types of FGR – internal FGR or external FGR. Internal FGR involves recirculating hot flue gas from the combustion device into the combustion zone using burner design features. External FGR requires the use of hot-side fans and ductwork to route a portion of the flue gas in the stack back to the burner windbox. Internal FGR is more commonly used because it has fewer operational constraints and it does not require the capital and operating costs associated with the additional fan and ductwork components that are part of an external FGR system. Either in addition to or in place of the use of FGR to introduce flue gas as a diluent to the combustion process, steam can be used as a diluent to reduce flame temperature.

LNBs/ULNBs can also use staged combustion, which is characterized by a fuel rich zone to start combustion and to stabilize the combustion device flame and a fuel lean zone to complete combustion and to reduce the peak flame temperature. These types of burners can also be designed to spread flames over a larger area to reduce hot spots and lower NOx emissions. ULNBs require sophisticated process controls to stabilize the flame and maintain emissions levels and efficiency across a wide range of turndown ratios that is sufficient for the demands of the particular operation.

3.1.1.3 SNCR

SNCR is a post-combustion treatment technology that is effectively a partial SCR system. For a combustion device equipped with an SNCR system, a reducing agent (aqueous or anhydrous ammonia or urea) is mixed with NOx-containing combustion gases and a portion of the NOx (both nitric oxide and nitrogen dioxide) reacts with the reducing agent to form molecular nitrogen and water; however, as indicated by its name, SNCR does not utilize a catalyst to promote the chemical reduction of NOx. Because SNCR does not incorporate the use of a catalyst, the NOx emissions reduction effectiveness of this technology is generally quite a bit lower than SCR and the operating constraints of an SNCR system are typically greater than that of an SCR system. Moreover, in a retrofit scenario, these comparative deficiencies tend to be worse for an SNCR system.

The NOx reduction reactions in an SNCR system occur at high temperatures because a catalyst is not used. In this regard, SNCR typically requires thorough mixing of the reagent in the upper combustion chamber of an external combustion device and this technology requires at least 0.5 seconds of residence time at a temperature above 1,600 °F and below 2,100 °F. Furthermore, a combustion device equipped with SNCR technology may require multiple reagent injection locations because the optimum location (temperature profile) for reagent injection may change depending on the load at which the combustion device is operating.

Regarding the 1,600 °F to 2,100 °F temperature window that is generally applicable to an SNCR system, at temperatures below 1,600 °F, the desired NOx reduction reactions will not effectively occur and much of the injected reagent will be emitted to the atmosphere along with the mostly uncontrolled NOx emissions. On the other hand, at temperatures above 2,100 °F, the desired NOx reduction reactions will not effectively occur and the ammonia or urea reagent will begin to react with available oxygen to generate additional NOx emissions.

3.1.1.4 NSCR

NSCR is a post-combustion treatment technology that promotes the catalytic chemical reduction of NOx (both nitric oxide and nitrogen dioxide) to molecular nitrogen and water. NSCR has been applied to nitric acid plants and rich burn (0.3 to 0.5% by volume excess oxygen) and stoichiometric internal combustion engines to reduce NOx emissions. For those source types, NSCR typically achieves an 80-95% reduction in NOx emissions.

NSCR uses a reducing agent (hydrocarbon, hydrogen, or CO), which can be inherently contained in the exhaust gas due to rich combustion conditions or injected into the exhaust gas, to react in the presence of a catalyst with a portion of the NOx contained in the source's exhaust gas to generate molecular nitrogen and water. NSCR systems can effectively operate at a temperature above 725 °F and below 1,200 °F, with a more refined temperature window dependent on the source type and the composition of the catalyst used in the NSCR system.

3.1.2 Step 2 – Eliminate Technically Infeasible Options

In Step 1, available NOx emissions control technologies were identified for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067). Below we discuss which of these technologies is believed to be technically infeasible for the control of NOx emissions from this emissions unit.

3.1.2.1 FGR, LNBs, and ULNBs

ENVIRON is not aware of the commercial application of FGR on a molten sulfur burner or the commercial availability of molten sulfur burners represented as an LNB or ULNB. Sulfur is burned in the A Train sulfur furnace with an excess amount of air so that the oxygen content in the sulfur furnace combustion gases is 10% by volume or higher to ensure proper conversion of SO_2 to SO_3 in the downstream convertors of the A Train. Therefore, FGR and low excess air principles of certain LNBs and ULNBs would not be in alignment with the integral process operations of the A Train sulfur furnace.

Furthermore, at approximately 3,090 °F, the adiabatic flame temperature of sulfur is approximately 75% of the adiabatic flame temperature of natural gas, oil, or coal. As a result,

the primary NOx generation mechanism for natural gas, oil, and coal combustion – thermal NOx – that is addressed by LNBs and ULNBs would not be expected to be as prevalent when combusting molten sulfur. This concept is supported by the low NOx concentration in the combustion gases of the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067). For example, the average NOx concentration measured from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) during a July 28, 2011 stack test was approximately 13 parts per million by volume (ppmv), dry at 3% by volume oxygen, which is comparable to the NOx emissions performance of natural gas ULNBs.

Based on these factors, we do not believe it is technically feasible to use FGR/LNBs/ULNBs to control NOx emissions from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067).

3.1.2.2 SNCR

ENVIRON is not aware of the commercial application of SNCR on a sulfuric acid plant. SNCR requires at least 0.5 seconds of residence time at a relatively high temperature (1,600 to 2,100 °F) for the SNCR NOx reduction reaction to effectively occur, which means multiple reducing reagent injection points would be expected to be needed in the A Train sulfur furnace to account for temperature profile variations associated with fluctuating sulfur combustion rates. However, the injection of ammonia or urea, which decomposes to ammonia, at this point in the A Train process where there are excessive SO_2 concentrations (SO_2 concentrations are up to 10% by volume, which is 20 to 30 times higher than the SO_2 concentrations in a coal- or oil-fired boiler) would negatively impact the effectiveness of the SNCR NOx reduction reaction. Additionally, unreacted ammonia from the SNCR reaction and the considerable amounts of SO_3 generated in the A Train would provide for the generation of ammonium sulfates, which would negatively impact the SO_2-to-SO_3 convertor catalyst if these sulfate compounds were to collect on the surface of this catalyst, resulting in degraded sulfuric acid production performance and increased SO_2 emissions, as well as negatively impact the quality of the sulfuric acid product if these sulfate compounds were absorbed into the sulfuric acid.

Furthermore, the low NOx concentration in the combustion gases of the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) (approximately 13 ppmv, dry at 3% by volume oxygen, as measured during a July 28, 2011 stack test) would negatively impact the NOx control effectiveness of SNCR for this emissions unit. At sufficiently high temperatures and baseline NOx levels below the “critical” or equilibrium NOx concentration, the injection of ammonia or urea into the combustion gases of a source will result in increased NOx levels. For typical coal- and oil-fired steam boilers, critical NOx levels have been documented to range from 70 to 90 ppmv. These concentrations are considerably higher than the NOx concentrations expected for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067). Therefore, the installation of an SNCR system on the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) would have the potential to result in additional NOx emissions to the atmosphere.

Lastly, at elevated temperatures, the relatively high oxygen concentrations (10% by volume or higher) in the A Train sulfur furnace would have the potential to reduce the effectiveness of the SNCR NOx reduction reaction. During a July 28, 2011 stack test, the A Train Single Absorption

H2SO4 Plant (EPN S-ATrain1, EQT 0067) exhaust gas average oxygen concentration was approximately 8.2% by volume, which supports the fact that the A Train sulfur furnace is operated at relatively high oxygen levels.

Based on these factors, we do not believe it is technically feasible to use SNCR to control NOx emissions from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067).

3.1.2.3 NSCR

ENVIRON is not aware of the commercial application of NSCR on a sulfuric acid plant. Sulfur is burned in the A Train sulfur furnace with a considerable amount of excess air so that the oxygen content in the combustion gases is 10% by volume or higher to ensure proper conversion of SO_2 to SO_3 in the downstream convertors of the A Train. Additionally, the temperature of the exhaust gases from the stack of the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) are generally less than 100 °F, as demonstrated by the 91 °F average temperature measured during a July 28, 2011 stack test. Although there are locations in the A Train where temperature profiles would be closer to the 725 to 1,200 °F temperature window necessary for the application of an NSCR system, the amount of oxygen present throughout the A Train process makes the application of NSCR to control NOx emissions from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) technically infeasible.

3.1.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The only remaining NOx emissions control technology for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) is SCR.

3.1.4 Step 4 – Evaluate Impacts and Document the Results

Below we evaluate the NOx emissions control technologies determined to be technically feasible for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) and document our BART determination for this emissions unit.

3.1.4.1 SCR

Although considerable technical feasibility questions remain regarding the installation and operation of an SCR system on the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067), we have conservatively estimated that it would be technically feasible in this application.

As indicated in Exhibit 3, we conservatively estimated that the retrofit of the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) with an SCR system would result in a cost effectiveness equal to approximately $28,192 per ton of NOx emissions reduction, which we do not believe to be cost effective.

The installation of an SCR system on the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) would likely require additional energy as a result of the need for a larger fan or an additional fan due to an increase in pressure drop through the A Train that would be caused by the SCR catalyst beds. Additionally, reagent pumps would require electricity, and there would likely be electricity or steam requirements associated with heating the SCR system reagent. Furthermore, the SCR catalyst would periodically require replacement, which would

result in spent catalyst waste. This waste stream may represent hazardous waste depending on the composition of the catalyst and the components from the combustion gases of the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) collected on the catalyst during its use. Lastly, with respect to collateral emissions that may result from the installation and operation of an SCR system on the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067), there would be the potential for ammonia emissions to the atmosphere from the SCR system. The A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) does not currently emit ammonia.

Because SCR technology was determined not to be cost effective for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067), Mosaic proposes that current design and operations represent BART for NOx emissions from this emissions unit.

3.2 A Train Single Absorption H_2SO_4 Plant (EPN S-ATrain1, EQT 0067) PM/PM_{10}/$PM_{2.5}$ BART Analysis

PM emissions from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) are estimated to equal 100% of the emissions unit's sulfuric acid mist emissions. The PM_{10} and $PM_{2.5}$ emissions from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) are condensable PM, and based on emissions testing conducted on October 30, 1992, at the New Wales Plant in Mulberry, Florida, approximately 67.2% of the sulfuric acid mist emissions from the unit is expected to be PM_{10} and approximately 36.7% of the sulfuric acid mist emissions from the unit is expected to be $PM_{2.5}$.

3.2.1 Step 1 – Identify All Available Retrofit Control Technologies

Available PM emissions control technologies for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) were determined by searching the EPA's RBLC for control technology determinations made after January 1, 2005 for the following process code.

- Process Code 62.015 – Inorganic Chemicals Manufacturing; Sulfuric Acid Plants

Below is a listing of the PM emissions control technologies identified under this EPA RBLC process code.

- Mist Eliminator
- Wet Electrostatic Precipitator (Wet ESP)

Although not listed in the results of the above mentioned PM emissions control technology query of Process Code 62.015 in the RBLC, the following are PM emissions control technologies that may be considered to be available technologies for the reduction of PM emissions from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067).

- Fabric Filter
- Wet Scrubber
- Cyclone

Below we discuss all of the PM emissions control technologies that may be considered to be available technologies for the reduction of PM emissions from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067).

3.2.1.1 Mist Eliminator

A mist eliminator is an impingement separator that removes liquid particles entrained in a gaseous stream due to the impingement of the entrained particles on the surface of the mist eliminator and the retention of these liquid particles on the surface until multiple particles coalesce into particles of sufficient size that are able to fall back against the flowing gas stream and collect at a location below the mist eliminator. For the high efficiency removal of submicron liquid particles from a gaseous stream, Brownian diffusion mist eliminators are used. “Brownian diffusion” is the random movement of submicron particles in a gaseous stream as these particles collide with gas molecules. Mist eliminators can be wire mesh, fiber packs/pads, baffle-type, or cyclonic. Mist eliminators require little operation and maintenance attention.

3.2.1.2 Wet ESP

An ESP is a PM emissions control device that uses electrical forces to remove PM from a flowing gaseous stream and onto collector plates. The PM contained in the gaseous stream is given an electric charge by passing the gaseous stream through a corona, a region in which gaseous ions flow. The PM collected on the collector plates must be periodically removed from these plates without reentraining this PM into the gas stream that is being treated by the ESP. This collector plate cleaning process can be accomplished by knocking the collected PM loose from the plates, allowing the collected PM to slide down into a hopper from which the PM is periodically removed. An ESP can also use a washing technique to remove the collected PM from the collector plates. This type of ESP is referenced as a “wet ESP.” ESPs can be configured in several ways, including a plate-wire ESP, a flat-plate ESP, and a tubular ESP.

3.2.1.3 Fabric Filter

A fabric filter removes PM from a gas stream by passing this stream through a porous fabric. During operation, the fabric filter becomes coated to some degree with the PM that is contained in the gaseous stream being treated and this coating (“cake”) actually performs much of the filtration. For an emissions unit having a considerable volume of exhaust, the fabric filter system is typically referenced as a “baghouse” because the configuration of the fabric filter used in this system is a cylindrical bag. A baghouse is comprised of multiple bags with the number of these bags generally dependent on the volume of the gaseous stream to be treated, the PM loading of this gaseous stream, and the design of the baghouse. The two most common baghouse designs today are the reverse-air and pulse-jet types, with these names indicative of the type of bag cleaning system used in the baghouse.

3.2.1.4 Wet Scrubber

A wet scrubber is a PM emissions control device that uses absorption to remove PM from a gaseous stream. Absorption is primarily a physical process, but can include a chemical component, in which a pollutant in a gas phase is contacted with a scrubbing liquid and dissolved in this liquid phase. A key component dictating the performance of a wet scrubber is the solubility of the pollutant of concern in the scrubbing liquid. Water is commonly used as the

scrubbing liquid in a wet scrubber used for PM emissions control, but other materials can be used depending on the type of PM or other pollutant(s) to be removed from the gaseous stream undergoing treatment. There are several types of wet scrubbers, including packed-bed counterflow scrubbers, packed-bed cross-flow scrubbers, bubble plate scrubbers, and tray scrubbers. All wet scrubber designs incorporate mist eliminators or entrainment separators to remove entrained droplets from the exhaust gas of the scrubber.

3.2.1.5 Cyclone

A cyclone is the most common type of inertial separator used to collect medium-sized and coarse PM from gaseous streams. The PM contained in a gaseous stream treated in a cyclone move outward under the influence of centrifugal force until this PM contacts the wall of the cyclone. This PM is then carried downward by gravity along the wall of the cyclone and collected in a hopper located at the bottom of the cyclone. Although cyclones provide a mechanically simple option for the removal of larger PM from gaseous streams, they do not typically provide sufficient PM removal for smaller diameter PM (i.e., PM smaller than PM_{10}-PM_{15}). Instead, these devices are typically used as precleaners to remove larger PM upstream of more efficient PM emissions control devices.

As noted above, certain mist eliminators are cyclonic devices. However, these cyclonic mist eliminators typically incorporate design features beyond the traditional cyclonic PM emissions control device, such as fiber packs/pads; they are comprised of several cyclones in parallel; and they are generally not very effective in controlling PM less than 10 µm in diameter.

3.2.2 Step 2 – Eliminate Technically Infeasible Options

In Step 1, available PM emissions control technologies were identified for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067). Below we discuss which of these technologies is believed to be technically infeasible for the control of PM emissions from this emissions unit.

3.2.2.1 Fabric Filter

The PM emissions from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) are liquid PM. As a result, a fabric filter is not believed to be technically feasible for the control of PM emissions from this emissions unit.

3.2.2.2 Wet Scrubber

A wet scrubber is not believed to be technically feasible for the control of PM emissions from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) because currently the PM emissions from this emissions unit are liquid PM following a wet scrubber. As previously noted, a wet scrubber must incorporate a mist eliminator or entrainment separator to remove entrained droplets from the vapor stream exiting the scrubber. Therefore, the installation of another wet scrubber would not be expected to result in a considerable reduction in the amount of PM emissions from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067).

3.2.2.3 Cyclone

As indicated above, the PM emissions from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) are primarily less than 10 µm in diameter, with a considerable portion of this PM less than 2.5 µm in diameter. As a result, a cyclone is not believed to be technically feasible for the control of PM emissions from this emissions unit.

3.2.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The following PM emissions control technologies represent those considered to be technically feasible for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067). These technologies are listed from the highest to lowest potential PM emissions control capability.

- Wet ESP – up to 99%
- Mist Eliminator – varies

3.2.4 Step 4 – Evaluate Impacts and Document the Results

Below we evaluate the PM emissions control technologies determined to be technically feasible for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) and document our BART determination for this emissions unit.

3.2.4.1 Wet ESP

As indicated in Exhibit 4, we conservatively estimated that the retrofit of the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) with a wet ESP would result in a cost effectiveness equal to approximately $19,151 per ton of PM emissions reduction, which we do not believe to be cost effective. Moreover, with respect to PM_{10} and $PM_{2.5}$ emissions, this technology would be even less cost effective because the baseline PM_{10} and $PM_{2.5}$ emissions were estimated to be a fraction of the PM emitted by the emissions unit.

The installation of a wet ESP on the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) would require a considerable amount of additional electricity to power the ESP. Also, additional electricity would be expected to be required as a result of the need for a larger fan or an additional fan due to an increase in pressure drop through the A Train that would be caused by the wet ESP. Furthermore, a wet ESP would generate a new liquid waste stream at the plant.

Because wet ESP technology was determined not to be cost effective for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067), Mosaic proposes that this technology does not represent BART for PM emissions from this emissions unit.

3.2.4.2 Mist Eliminator

The A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) is already equipped with a mist eliminator for the control of PM emissions. As demonstrated during a July 28, 2011 stack test, this mist eliminator easily demonstrates compliance with the 0.15 lb of H_2SO_4 per ton of 100% H_2SO_4 produced (3-hr average) emission limitation of 40 CFR part 60, subpart H, which is applicable to the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067).

Furthermore, a 0.15 lb of H_2SO_4 per ton of 100% H_2SO_4 produced emission limitation is the BACT limitation documented for many of the sulfuric acid production units listed in the RBLC. Therefore, Mosaic proposes that a mist eliminator represents BART for PM emissions from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067).

3.3 A Train Single Absorption H_2SO_4 Plant (EPN S-ATrain1, EQT 0067) SO_2 BART Analysis

As a result of the Consent Decree, Mosaic recently equipped the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) with a wet scrubber to control SO_2 emissions. This wet scrubber was put into service on February 24, 2011. As indicated by the SO_2 emissions reduction performance required by the Consent Decree for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) wet scrubber, this technology represents the top performing SO_2 emissions control technology for this type of sulfuric acid unit. Many sulfuric acid production units operated by several different companies are now subject to SO_2 emission limitations under federal consent decrees, but the SO_2 emission limitations required by the Consent Decree for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) are believed to be the most stringent of these limitations.

In the *Guidelines for BART Determinations Under the Regional Haze Rule*, EPA indicates that if an emissions unit that is subject to BART has a control technology already in place which is the most stringent control technology available, then it is not necessary to comprehensively complete each of the BART analysis steps for that emissions unit if the most stringent control technology available is made federally enforceable for the purpose of implementing BART.[17] Because the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) is equipped with the most stringent control technology available for SO_2 emissions from this type of sulfuric acid production unit (a wet scrubber), and the emission limitations associated with the application of this control technology are federally enforceable (and will be federally enforceable for BART purposes), a wet scrubber represents BART for the SO_2 emissions from the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) and the SO_2 BART determination analysis for this emissions unit is complete.

3.4 A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) NOx BART Analysis

The A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) combusts natural gas only and it is permitted for a rating of 100 MMBtu/hr. The location of this start-up burner is in the sulfur furnace of the A Train. During the A Train start-up mode, the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) is used to heat the unit's sulfur burner to a temperature that will allow for the ignition of the molten sulfur that must be combusted at the sulfur burner to generate SO_2, which is eventually converted to sulfuric acid product, as well as to heat catalyst components downstream of the sulfur furnace to appropriate operating temperatures. Due to this start-up specific purpose of the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), it is permitted to operate only 105 hours per year.

NOx is formed by three mechanisms that are characterized as follows: thermal NOx, fuel NOx, and prompt NOx. In natural gas combustion, NOx is primarily produced via the thermal and

[17] 70 Federal Register 39165 (July 6, 2005).

prompt NOx mechanisms. Thermal NOx results from the high temperature thermal dissociation and subsequent reaction of combustion air molecular nitrogen and oxygen. Thermal NOx tends to be generated in the high temperature zone near the burner of an external combustion device. The rate of thermal NOx generation is affected by the following three factors: oxygen concentration, peak temperature, and the duration at peak temperature. As these three factors increase in value, the rate of thermal NOx generation correspondingly increases.

Fuel NOx is formed by the direct oxidation of nitrogen-containing compounds that may be contained in a fuel stream. Therefore, fuel NOx emissions increase in association with an increase in the quantity of nitrogen-containing compounds present in a fuel. The natural gas combusted by the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) does not contain an appreciable amount of fuel-bound nitrogen.

Prompt NOx occurs at the flame front through the relatively fast reaction between nitrogen and oxygen molecules in the combustion air and fuel hydrocarbon radicals that are intermediate species formed during the combustion process. Prompt NOx levels are usually a small fraction of overall NOx emissions levels in natural gas-fired combustion equipment. However, because the prompt NOx mechanism can become a considerable factor in lower temperature combustion processes indicative of combustion technique NOx control technologies (LNBs/ULNBs), NOx generated via this mechanism can represent a considerable portion of the NOx emissions resulting from certain LNBs/ULNBs.

3.4.1 Step 1 – Identify All Available Retrofit Control Technologies

There are a variety of technology options available for controlling NOx emissions from an external combustion device such as the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068). These available technologies can involve combustion controls that reduce NOx formation or add-on control devices that reduce NOx after it is formed. Combinations of combustion controls and add-on controls can also be used to reduce NOx emissions.

In consideration of the fuel (natural gas) that is combusted in the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) and the permitted rating of this combustion device, available NOx emissions control technologies were determined by searching the EPA's RBLC for control technology determinations made after January 1, 2005 for the following process code.

- Process Code 12.310 – Industrial-Size Boilers/Furnaces (>100 MMBtu/hr); Gaseous Fuel and Gaseous Fuel Mixtures (>100 MMBtu/hr); Natural Gas (Includes Propane and Liquefied Petroleum Gas)

Below is a listing of the NOx emissions control technologies identified under this EPA RBLC process code.

- FGR/LNBs/ULNBs

Although not listed in the results of the above mentioned NOx emissions control technology query of Process Code 12.310 in the RBLC, the following are NOx emissions control

technologies that may be considered to be available technologies for the reduction of NOx emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

- SCR
- SNCR
- NSCR

Below we discuss all of the NOx emissions control technologies that may be considered to be available technologies for the reduction of NOx emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

3.4.1.1 FGR, LNBs, and ULNBs

Please see Section 3.1.1.2 herein for a discussion of FGR, LNBs, and ULNBs.

3.4.1.2 SCR

Please see Section 3.1.1.1 herein for a discussion of SCR.

3.4.1.3 SNCR

Please see Section 3.1.1.3 herein for a discussion of SNCR.

3.4.1.4 NSCR

Please see Section 3.1.1.4 herein for a discussion of NSCR.

3.4.2 Step 2 – Eliminate Technically Infeasible Options

In Step 1, available NOx emissions control technologies were identified for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068). Below we discuss which of these technologies is believed to be technically infeasible for the control of NOx emissions from this emissions unit.

3.4.2.1 SCR

The NOx emissions control effectiveness of an SCR system is limited during the start-up operations of the combustion device on which it is installed because the temperature of the SCR system must be at a minimum temperature in order for the SCR system to effectively operate. The A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) is operated only during the A Train start-up mode to heat the unit's sulfur burner and catalyst components downstream of the sulfur furnace to appropriate operating temperatures. For an SCR system installed on a combustion device that incorporates heat recovery equipment (e.g., steam generation heat exchangers, process catalyst beds), several hours can be required to heat the SCR system to the minimum effective temperature status after the combustion device is put into operation in a warm start-up scenario. Even more time would be required to heat the SCR system to the minimum effective temperature status after the combustion device is put into operation in a cold start-up scenario. Because of the limited NOx reduction capability of an SCR system and its potential for excessive ammonia emissions to the atmosphere when operating below a minimum set point temperature, many SCR systems are integrated with a process control system that uses a

minimum operating temperature as measured at the combustion device exit to determine when the SCR system can be put into operation.

At 200 °F, the temperature of the exhaust gases in the stack of the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) would be less than the 350 to 400 °F temperature necessary to properly operate an SCR system. Additionally, for much of the operating period of the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), the exhaust gases in the stack of this start-up burner would be unsteady at even lower temperatures. Due to this temperature deficiency, in combination with the intermittent start-up (non-steady state) operating nature of the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), it is not technically feasible to install and operate an SCR system for the control of NOx emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

3.4.2.2 SNCR

As previously indicated, the effective operating temperature of an SNCR system is 1,600 to 2,100 °F. This high temperature typically requires the SNCR system to be integrated into the upper firebox region of an external combustion device. Due to the elevated operating temperature constraint of an SNCR system, this system requires a reasonable amount of time to reach the minimum effective temperature status when the combustion device on which it is installed is put into operation. Therefore, during the start-up mode of a combustion device equipped with an SNCR system, the level of NOx emissions control of the SNCR system would be low and unstable, along with the potential for relatively excessive amounts of unreacted ammonia to pass through the system and to be emitted to the atmosphere. In fact, as noted above for SCR systems, many SNCR systems are integrated with a process control system that uses a minimum operating temperature as measured at the combustion device exit to determine when the SNCR system can be put into operation.

The A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) is operated only during the A Train start-up mode to heat the unit's sulfur burner and catalyst components downstream of the sulfur furnace to appropriate operating temperatures. The sulfur burner in the A Train sulfur furnace is typically not heated above 1,650 °F, while the catalyst components downstream of the sulfur burner are heated to much lower temperatures. When the sulfur burner and downstream catalyst component reach appropriate temperatures, the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) is shut down. For much of the operating period of the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), the temperature in the sulfur furnace would be considerably insufficient to properly operate an SNCR system, and the completion of the operating period of this start-up burner would be only at the low end of the effective operating temperature range of an SNCR system. Due to this temperature deficiency, in combination with the intermittent start-up (non-steady state) operating nature of the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), it is not technically feasible to install and operate an SNCR system for the control of NOx emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

3.4.2.3 NSCR

At 200 °F, the temperature of the exhaust gases in the stack of the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) would be considerably insufficient to properly operate an NSCR system, which requires a temperature in the range of 725 °F to 1,200 °F. As discussed above,

this temperature range would be achieved in the sulfur furnace area of the A Train near the completion of the operating period of the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068). Additionally, the exhaust gases from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) typically contain oxygen at a concentration greater than 5% by volume, which is considerably greater than 0.5%, the upper end of the oxygen level suitable for the effective operation of an NSCR system. Due to these factors, in combination with the intermittent start-up (non-steady state) operating nature of the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), it is not technically feasible to install and operate an NSCR system for the control of NOx emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

3.4.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The only remaining NOx emissions control technology determined to be technically feasible for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) is FGR/LNBs/ULNBs.

3.4.4 Step 4 – Evaluate Impacts and Document the Results

Below we evaluate the NOx emissions control technologies determined to be technically feasible for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) and document our BART determination for this emissions unit.

3.4.4.1 FGR, LNBs, and ULNBs

Although the purpose and operation of the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) are considerably different than the purpose and operation of a burner in a traditional boiler or process heater, we have conservatively estimated that it would be technically feasible to replace the existing start-up burner with an LNB or ULNB, with minor changes to the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) combustion air equipment, burner control systems, and other ancillary equipment.

As indicated in Exhibit 5, using a ULNB cost estimation technique documented in EPA's *Petroleum Refinery Tier 2 BACT Analysis Report*,[18] we conservatively estimated that the retrofit of the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) with this type of burner would result in a cost effectiveness equal to approximately $10,024 per ton of NOx emissions reduction, which we do not believe to be cost effective. The installation and operation of an FGR system in association with the current burner of the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) or the replacement of this emissions unit's current burner with an LNB would result in a comparable cost effectiveness for the unit.

We conservatively estimated that the LNB/ULNB option for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) would not have any negative energy impacts even though LNBs and ULNBs can result in a reduction in the energy efficiency or rating of a combustion device in retrofit scenarios. More specifically, in certain LNB/ULNB retrofit situations, without making relatively extensive changes to the relevant existing combustion device, the process rating of such device may be lowered due to burner arrangement and firebox space limitations. External

[18] EPA. Manufacturing Branch. Manufacturing, Energy and Transportation Division. *Petroleum Refinery Tier 2 BACT Analysis Report*. January 16, 2001.

FGR would require an additional fan that would consume additional energy when compared to the current configuration of the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

An FGR/LNB/ULNB option for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) would not be expected to result in any non-air quality environmental impacts. With respect to collateral emissions that may result in an FGR/LNB/ULNB retrofit scenario for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), although current FGR/LNB/ULNB technologies are capable of achieving low carbon monoxide (CO) emission rates at normal to maximum design rates, these technologies would be expected to generate higher CO emissions levels than conventional burners when operated at lower operating rates.

Because FGR/LNB/ULNB technology was determined not to be cost effective for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), Mosaic proposes that good combustion practices represent BART for NOx emissions from this emissions unit.

3.5 A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) PM/PM_{10}/$PM_{2.5}$ BART Analysis

PM emissions occur from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) as a result of the incomplete combustion of natural gas. PM from natural gas combustion has been estimated to be less than 1 µm in size and this PM is comprised of both filterable and condensable components. However, filterable PM emissions are typically low for natural gas combustion.

Incomplete combustion in a gaseous fuel combustion device such as the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) can occur because of inadequate fuel-air mixing and improper combustion mechanisms. These causes of incomplete combustion can be associated with poor burner/combustion device design, operation, and/or maintenance.

3.5.1 Step 1 – Identify All Available Retrofit Control Technologies

In consideration of the fuel (natural gas) that is combusted in the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) and the permitted rating of this combustion device, available PM emissions control technologies were determined by searching the EPA's RBLC for control technology determinations made after January 1, 2005 for the following process code.

- Process Code 12.310 – Industrial-Size Boilers/Furnaces (>100 MMBtu/hr); Gaseous Fuel and Gaseous Fuel Mixtures (>100 MMBtu/hr); Natural Gas (Includes Propane and Liquefied Petroleum Gas)

Below is a listing of the PM emissions control technologies identified under this EPA RBLC process code.

- Good Combustion Practices

Although not listed in the results of the above mentioned PM emissions control technology query of Process Code 12.310 in the RBLC, the following are PM emissions control

technologies that may be considered to be available technologies for the reduction of PM emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

- ESP
- Fabric Filter
- Wet Scrubber
- Cyclone

Below we discuss all of the PM emissions control technologies that may be considered to be available technologies for the reduction of PM emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

3.5.1.1 Good Combustion Practices

Good combustion practices for a gaseous fuel burner provide the proper air-to-fuel ratio, residence time, temperature, and combustion zone turbulence essential to achieving low PM emission levels from such a source. Incomplete combustion of hydrocarbons present in the natural gas used by this combustion source can result in elevated PM emissions, and incomplete combustion in this case can occur because of poor fuel-air mixing and improper combustion mechanisms.

3.5.1.2 ESP

Please see Section 3.2.1.2 herein for a discussion of an ESP.

3.5.1.3 Fabric Filter

Please see Section 3.2.1.3 herein for a discussion of a fabric filter.

3.5.1.4 Wet Scrubber

Please see Section 3.2.1.4 herein for a discussion of a wet scrubber.

3.5.1.5 Cyclone

Please see Section 3.2.1.5 herein for a discussion of a cyclone.

3.5.2 Step 2 – Eliminate Technically Infeasible Options

In Step 1, available PM emissions control technologies were identified for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068). Below we discuss which of these technologies is believed to be technically infeasible for the control of PM emissions from this emissions unit.

3.5.2.1 ESP

ENVIRON is not aware of the commercial application of an ESP on a comparable natural gas combustion device. The PM emitted by the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) is generally less than 10 µm in diameter and a considerable portion of this PM is condensable in nature with a diameter less than 1 µm. Additionally, the combustion gases from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) are estimated to have a PM

concentration of less than 0.006 grains per dry standard cubic feet at 0% oxygen, which is lower than the outlet PM concentration from many of the ESPs installed on coal-fired combustion devices, meaning there is a degree of uncertainty in regard to the PM emissions reduction effectiveness of an ESP in this application.

Due to the PM loading characteristics of the combustion gases from the natural gas-fired A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), the intermittent start-up (non-steady state) operating nature of the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), and the lack of technical knowledge of the effectiveness of the installation and operation of an ESP on a comparable natural gas combustion device, we do not believe it is technically feasible to use an ESP to control the PM emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

3.5.2.2 Fabric Filter

A fabric filter is not believed to be technically feasible for the control of PM emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) due to the particle size distribution characteristics of the PM emitted from this emissions unit and the considerably low PM concentration in the unit's exhaust stream, as indicated by the low potential to emit PM emission rate of this unit. The PM emitted by the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) is generally less than 10 µm in diameter and a considerable portion of this PM is condensable in nature with a diameter less than 1 µm, both of which would considerably limit the effectiveness of a fabric filter, especially in consideration of the important contribution the filter cake makes to the effectiveness of a fabric filter. Because of these PM and PM loading characteristics of the combustion gases from the natural gas-fired A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), ENVIRON is not aware of the commercial application of a fabric filter on a comparable natural gas combustion device. Based on these factors, we do not believe it is technically feasible to use a fabric filter to control PM emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

3.5.2.3 Wet Scrubber

A wet scrubber is not believed to be technically feasible for the control of PM emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) due to the particle size distribution characteristics of the PM emitted from this emissions unit and the considerably low PM concentration in the unit's exhaust stream, as the PM concentration is less than 0.006 grains of PM per dry standard cubic feet of combustion gases at 0% oxygen. The PM emitted by the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) is generally less than 10 µm in diameter, with a considerable portion less than 1 µm in diameter, which would require a significant pressure drop across a wet scrubber to provide any reasonable amount of PM emissions control. Additionally, the amount of carryover PM discharged to the atmosphere from a wet scrubber in this application would be comparable to the amount of PM that is currently emitted by the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), which would result in no practical amount of PM emissions reduction. Furthermore, the universal practice of not using a wet scrubber for a natural gas-fired external combustion device indicates that it is not practical to use this technology on the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068). Based on these factors, we do not believe it is technically feasible to use a wet scrubber to control PM emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

3.5.2.4 Cyclone

A cyclone is not believed to be technically feasible for the control of PM emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) due to the particle size distribution characteristics of the PM emitted from this emissions unit and the considerably low PM concentration in the unit's exhaust stream, as indicated by the low potential to emit PM emission rate of the unit. The PM emitted by the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) is generally less than 10 µm in diameter, which would significantly limit the effectiveness of a cyclone due to this device relying entirely on inertial separation caused by centrifugal forces. Furthermore, the universal practice of not using a cyclone for a natural gas-fired external combustion device indicates that it is not practical to use this technology on the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068). Based on these factors, we do not believe it is technically feasible to use a cyclone to control PM emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

3.5.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The only remaining PM emissions control technology determined to be technically feasible for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) is good combustion practices.

3.5.4 Step 4 – Evaluate Impacts and Document the Results

Mosaic proposes that good combustion practices represent BART for PM emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

3.6 A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) SO_2 BART Analysis

For the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), emissions of SO_2 result from the oxidation of sulfur-containing compounds contained in the natural gas combusted by the emissions unit. The sulfur content of the fuel combusted by a combustion device directly influences the quantity of SO_2 emissions generated by that combustion device. In practice, SO_2 emissions resulting from the combustion of a gaseous fuel are primarily controlled by limiting its sulfur content, not by scrubbing the exhaust gases from the device combusting the same fuel.

3.6.1 Step 1 – Identify All Available Retrofit Control Technologies

In consideration of the fuel (natural gas) that is combusted in the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) and the permitted rating of this combustion device, available SO_2 emissions control technologies were determined by searching the EPA's RBLC for control technology determinations made after January 1, 2005 for the following process code.

- Process Code 12.310 – Industrial-Size Boilers/Furnaces (>100 MMBtu/hr); Gaseous Fuel and Gaseous Fuel Mixtures (>100 MMBtu/hr); Natural Gas (Includes Propane and Liquefied Petroleum Gas)

Below is a listing of the SO_2 emissions control technologies identified under this EPA RBLC process code.

- Low Sulfur Fuel (the low sulfur content can occur due to a gaseous fuel being inherently low in sulfur or due to a gaseous fuel undergoing treatment to remove sulfur compounds present in the fuel)

Although not listed in the results of the above mentioned SO_2 emissions control technology query of Process Code 12.310 in the RBLC, the following are SO_2 emissions control technologies that may be considered to be available technologies for the reduction of SO_2 emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

- Flue Gas Desulfurization

Below we discuss all of the SO_2 emissions control technologies that may be considered to be available technologies for the reduction of SO_2 emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

3.6.1.1 Low Sulfur Fuel

For gaseous fuels comprised of appreciable amounts of sulfur-containing compounds, there are many physical absorption and chemical treatment techniques available to remove the sulfur-containing compounds from the fuel. Examples of these techniques are amine absorption, caustic wash, the Rectisol process, and LO-CAT®.

The amine absorption process is the most widely used technique for the removal of sulfur-containing compounds from a gaseous fuel. Amine absorption is a chemical absorption process by which hydrogen sulfide is scrubbed (mercaptans and carbonyl sulfide that may be present are also partially scrubbed) from a gaseous fuel using a water solution of organic amine (alkanolamines) in a packed or tray tower. Alkanolamines used in the amine absorption process are categorized as being primary, secondary, or tertiary, depending upon the number of organic groups attached to the central nitrogen atom. The amine solution is a weak organic base and the hydrogen sulfide contained in the gaseous fuel is acidic. The hydrogen sulfide readily dissolves in the amine solution and the acidic hydrogen sulfide reacts with the basic organic amine to form an acid-base complex (salt), thus removing hydrogen sulfide from the gaseous fuel. The amine solution high in salt content exits the amine treatment scrubber and is then sent to a stripping tower where it is heated to elevated temperatures, resulting in the reversal of the chemical absorption reactions that occurred in the amine treatment scrubber such that the hydrogen sulfide is released from the amine solution. The overhead stream from this stripping operation, which contains hydrogen sulfide and is referenced as “acid gas,” is typically routed to a sulfur recovery operation where the sulfur contained in the acid gas is almost entirely recovered as elemental sulfur. The regenerated amine solution exiting the stripping tower is recycled back to the amine treatment scrubber to be reused in the sulfur-containing compound removal process.

Pipeline quality natural gas has typically been treated using one or more sulfur removal techniques, most often amine absorption. Therefore, pipeline quality natural gas has already undergone desulfurization before it is received by a customer, as indicated by the low sulfur content of this gaseous fuel. For example, the natural gas combusted in the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) is estimated to have a sulfur content of less than 4 ppmv.

3.6.1.2 Flue Gas Desulfurization

Flue gas desulfurization is commonly used to reduce SO_2 emissions from coal-fired and oil-fired combustion sources due to the relatively high concentration of SO_2 (thousands of ppmv) contained in the exhaust gases from these sources. Flue gas desulfurization consists of wet, semi-dry, and dry scrubbers. In a wet scrubber, an aqueous slurry of sorbent is injected into the exhaust gases and the SO_2 contained in these gases dissolves into the slurry droplets where it reacts with the alkaline present in the slurry. The treated exhaust gases pass through a mist eliminator before being emitted to the atmosphere in order to remove any entrained slurry droplets. The slurry falls to the bottom of the scrubber and is either collected to be regenerated and recycled or removed from the scrubber system as a waste or byproduct.

Semi-dry scrubbers are similar to wet scrubbers, but the slurry has a higher sorbent concentration, which results in the complete evaporation of the water in the slurry and the formation of a dry spent sorbent material that is entrained in the treated exhaust gases. This dry spent sorbent is removed from the treated exhaust gases using a baghouse or ESP. In a dry scrubber, a dry sorbent material is pneumatically injected into the exhaust gases and the dry spent sorbent material entrained in the treated exhaust gases is removed using a baghouse or ESP. Semi-dry and dry scrubbers typically achieve lower SO_2 control efficiencies than wet scrubbers.

3.6.2 Step 2 – Eliminate Technically Infeasible Options

In Step 1, available SO_2 emissions control technologies were identified for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068). Below we discuss which of these technologies is believed to be technically infeasible for the control of SO_2 emissions from this emissions unit.

3.6.2.1 Flue Gas Desulfurization

Flue gas desulfurization is not believed to be technically feasible for the control of SO_2 emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) due to the low SO_2 concentration of the exhaust gases from this emissions unit. The SO_2 concentration in the unit's exhaust gases are below the levels exiting many of today's operating flue gas desulfurization scrubbers, which indicates that it would not be technically feasible to install and operate a flue gas desulfurization scrubber to appreciably reduce the SO_2 emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068). Furthermore, the universal practice of not using flue gas desulfurization to control SO_2 emissions from a natural gas-fired external combustion device indicates that it is not practical to use this technology on the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

3.6.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The only remaining SO_2 emissions control technology for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068) is the combustion of low sulfur fuel.

3.6.4 Step 4 – Evaluate Impacts and Document the Results

Mosaic proposes that the combustion of pipeline quality natural gas represents BART for SO_2 emissions from the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068).

3.7 A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002) SO_2 BART Analysis

An extensive amount of ductwork connects the major components of the A Train, and the process gases contained in this ductwork from the sulfur furnace to the absorption column of the A Train are comprised of varying concentrations of SO_2. Fugitive SO_2 emissions result from the A Train ductwork as a result of leaks that periodically develop in this ductwork.

3.7.1 Step 1 – Identify All Available Retrofit Control Technologies

We searched under the following process codes included in the EPA's RBLC for any SO_2 emissions control technology determinations made after January 1, 2005 for equipment leaks and did not identify any such determination.

- Process Code 50.006 – Petroleum/Natural Gas Production and Refining; Petroleum Refining Treating Processes (hydrotreating, acid gas removal, SRU's, etc.)
- Process Code 62.015 – Inorganic Chemicals Manufacturing; Sulfuric Acid Plants
- Process Code 62.019 – Inorganic Chemicals Manufacturing; Sulfur Recovery (except 50.006)

Although not listed in the results of the above mentioned SO_2 emissions control technology query of Process Codes 50.006, 62.015, and 62.019 in the RBLC, the following is an SO_2 emissions control technology that may be considered to be an available technology for the reduction of SO_2 emissions from A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002).

- Leak Detection and Repair

Below we discuss this SO_2 emissions control technology.

3.7.1.1 Leak Detection and Repair

Leak detection and repair is the primary technique used to reduce equipment leak emissions. A leak detection and repair program is used to identify piping and ductwork components that are emitting sufficient amounts of material to warrant reduction of the emissions through repair (or replacement), and the effectiveness of these programs has been well established throughout many different industries over several decades. A component may be checked for leakage by visual, audible, olfactory, or instrument techniques.

3.7.2 Step 2 – Eliminate Technically Infeasible Options

In Step 1, we identified leak detection and repair as the only available SO_2 emissions control technology for A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002). This technology is considered to be technically feasible for the emissions unit.

3.7.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The only SO_2 emissions control technology for A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002) is leak detection and repair.

3.7.4 Step 4 – Evaluate Impacts and Document the Results

Below we evaluate the SO_2 emissions control technology determined to be technically feasible for A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002) and document our BART determination for this emissions unit.

3.7.4.1 Leak Detection and Repair

Leaks in the ductwork of the A Train are detected by visible inspection. Operators and insulation personnel conduct daily walkthroughs in the A Train area and they look for leaks in the A Train ductwork as part of these walkthroughs. When a leak in the ductwork of the A Train is detected, temporary ductwork and a vacuum are used to route the leak from the ductwork into the A Train combustion air system so that the leak is mostly returned to the A Train until the leaking ductwork is repaired.

Mosaic proposes that current leak detection and repair practices represent BART for SO_2 emissions for A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002).

3.8 D Train Double Absorption H_2SO_4 Plant (EPN S-DTrain1, EQT 0074) NOx BART Analysis

For the reasons discussed above in Section 3.1, the NOx concentration in the exhaust gases from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) is inherently quite low. As a result, there has not been much emphasis placed on controlling NOx emissions from sulfur-burning sulfuric acid units.

3.8.1 Step 1 – Identify All Available Retrofit Control Technologies

As identified above in Section 3.1.1 for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067), the following are the NOx emissions control technologies that may be considered to be available technologies for the reduction of NOx emissions from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074).

- SCR
- FGR/LNBs/ULNBs
- SNCR
- NSCR

Below we discuss these NOx emissions control technologies.

3.8.1.1 SCR

Please see Section 3.1.1.1 herein for a discussion of SCR.

3.8.1.2 FGR, LNBs, and ULNBs

Please see Section 3.1.1.2 herein for a discussion of FGR, LNBs, and ULNBs.

3.8.1.3 SNCR

Please see Section 3.1.1.3 herein for a discussion of SNCR.

3.8.1.4 NSCR

Please see Section 3.1.1.4 herein for a discussion of NSCR.

3.8.2 Step 2 – Eliminate Technically Infeasible Options

In Step 1, available NOx emissions control technologies were identified for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074). Below we discuss which of these technologies is believed to be technically infeasible for the control of NOx emissions from this emissions unit.

3.8.2.1 FGR, LNBs, and ULNBs

ENVIRON is not aware of the commercial application of FGR on a molten sulfur burner or the commercial availability of molten sulfur burners represented as an LNB or ULNB. Sulfur is burned in the D Train sulfur furnace with an excess amount of air so that the oxygen content in the sulfur furnace combustion gases is 10% by volume or higher to ensure proper conversion of SO_2 to SO_3 in the downstream convertors of the D Train. Therefore, FGR and low excess air principles of certain LNBs and ULNBs would not be in alignment with the integral process operations of the D Train sulfur furnace.

Furthermore, at approximately 3,090 °F, the adiabatic flame temperature of sulfur is approximately 75% of the adiabatic flame temperature of natural gas, oil, or coal. As a result, the primary NOx generation mechanism for natural gas, oil, and coal combustion – thermal NOx – that is addressed by LNBs and ULNBs would not be expected to be as prevalent when combusting molten sulfur. This concept is supported by the low NOx concentration in the combustion gases of the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074). For example, the average NOx concentration measured from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) during a September 22, 2011 stack test was approximately 11 ppmv, dry at 3% by volume oxygen, which is comparable to the NOx emissions performance of natural gas ULNBs.

Based on these factors, we do not believe it is technically feasible to use FGR/LNBs/ULNBs to control NOx emissions from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074).

3.8.2.2 SNCR

ENVIRON is not aware of the commercial application of SNCR on a sulfuric acid plant. SNCR requires at least 0.5 seconds of residence time at a relatively high temperature (1,600 to 2,100 °F) for the SNCR NOx reduction reaction to effectively occur, which means multiple reducing reagent injection points would be expected to be needed in the D Train sulfur furnace to account for temperature profile variations associated with fluctuating sulfur combustion rates. However, the injection of ammonia or urea, which decomposes to ammonia, at this point in the D Train process where there are excessive SO_2 concentrations (SO_2 concentrations are up to 12% by volume, which is 20 to 30 times higher than the SO_2 concentrations in a coal- or oil-fired boiler)

would negatively impact the effectiveness of the SNCR NOx reduction reaction. Additionally, unreacted ammonia from the SNCR reaction and the considerable amounts of SO_3 generated in the D Train would provide for the generation of ammonium sulfates, which would negatively impact the SO_2-to-SO_3 convertor catalyst if these sulfate compounds were to collect on the surface of this catalyst, resulting in degraded sulfuric acid production performance and increased SO_2 emissions, as well as negatively impact the quality of the sulfuric acid product if these sulfate compounds were absorbed into the sulfuric acid.

Furthermore, the low NOx concentration in the combustion gases of the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) (approximately 11 ppmv, dry at 3% by volume oxygen, as measured during a September 22, 2011 stack test) would negatively impact the NOx control effectiveness of SNCR for this emissions unit. At sufficiently high temperatures and baseline NOx levels below the “critical” or equilibrium NOx concentration, the injection of ammonia or urea into the combustion gases of a source will result in increased NOx levels. For typical coal- and oil-fired steam boilers, critical NOx levels have been documented to range from 70 to 90 ppmv. These concentrations are considerably higher than the NOx concentrations expected for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074). Therefore, the installation of an SNCR system on the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) would have the potential to result in additional NOx emissions to the atmosphere.

Lastly, at elevated temperatures, the relatively high oxygen concentrations (10% by volume or higher) in the D Train sulfur furnace would have the potential to reduce the effectiveness of the SNCR NOx reduction reaction. During a September 22, 2011 stack test, the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) exhaust gas average oxygen concentration was approximately 6.1% by volume, which supports the fact that the D Train sulfur furnace is operated at relatively high oxygen levels.

Based on these factors, we do not believe it is technically feasible to use SNCR to control NOx emissions from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074).

3.8.2.3 NSCR

ENVIRON is not aware of the commercial application of NSCR on a sulfuric acid plant. Sulfur is burned in the D Train sulfur furnace with a considerable amount of excess air so that the oxygen content in the combustion gases is 10% by volume or higher to ensure proper conversion of SO_2 to SO_3 in the downstream convertors of the D Train. Additionally, the temperature of the exhaust gases from the stack of the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) are generally less than 200 °F, as demonstrated by the 157 °F average temperature measured during a September 22, 2011 stack test. Although there are locations in the D Train where temperature profiles would be closer to the 725 to 1,200 °F temperature window necessary for the application of an NSCR system, the amount of oxygen present throughout the D Train process makes the application of NSCR to control NOx emissions from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) technically infeasible.

3.8.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The only remaining NOx emissions control technology for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) is SCR.

3.8.4 Step 4 – Evaluate Impacts and Document the Results

Below we evaluate the NOx emissions control technologies determined to be technically feasible for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) and document our BART determination for this emissions unit.

3.8.4.1 SCR

Although considerable technical feasibility questions remain regarding the installation and operation of an SCR system on the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074), we have conservatively estimated that it would be technically feasible in this application.

As indicated in Exhibit 6, we conservatively estimated that the retrofit of the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) with an SCR system would result in a cost effectiveness equal to approximately $17,325 per ton of NOx emissions reduction, which we do not believe to be cost effective.

The installation of an SCR system on the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) would likely require additional energy as a result of the need for a larger fan or an additional fan due to an increase in pressure drop through the D Train that would be caused by the SCR catalyst beds. Additionally, reagent pumps would require electricity, and there would likely be electricity or steam requirements associated with heating the SCR system reagent. Furthermore, the SCR catalyst would periodically require replacement, which would result in spent catalyst waste. This waste stream may represent hazardous waste depending on the composition of the catalyst and the components from the combustion gases of the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) collected on the catalyst during its use. Lastly, with respect to collateral emissions that may result from the installation and operation of an SCR system on the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074), there would be the potential for ammonia emissions to the atmosphere from the SCR system. The D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) does not currently emit ammonia.

Because SCR technology was determined not to be cost effective for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074), Mosaic proposes that current design and operations represent BART for NOx emissions from this emissions unit.

3.9 D Train Double Absorption H_2SO_4 Plant (EPN S-DTrain1, EQT 0074) $PM/PM_{10}/PM_{2.5}$ BART Analysis

PM emissions from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) are estimated to equal 100% of the emissions unit's sulfuric acid mist emissions. The PM_{10} and $PM_{2.5}$ emissions from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) are condensable PM, and based on emissions testing conducted on October 30, 1992, at the

Mosaic New Wales Plant in Mulberry, Florida, approximately 67.2% of the sulfuric acid mist emissions from the unit is expected to be PM_{10} and approximately 36.7% of the sulfuric acid mist emissions from the unit is expected to be $PM_{2.5}$.

3.9.1 Step 1 – Identify All Available Retrofit Control Technologies

As identified above in Section 3.2.1 for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067), the following are the PM emissions control technologies that may be considered to be available technologies for the reduction of PM emissions from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074).

- Mist Eliminator
- Wet ESP
- Fabric Filter
- Wet Scrubber
- Cyclone

Below we discuss these PM emissions control technologies.

3.9.1.1 Mist Eliminator

Please see Section 3.2.1.1 herein for a discussion of a mist eliminator.

3.9.1.2 Wet ESP

Please see Section 3.2.1.2 herein for a discussion of a wet ESP.

3.9.1.3 Fabric Filter

Please see Section 3.2.1.3 herein for a discussion of a fabric filter.

3.9.1.4 Wet Scrubber

Please see Section 3.2.1.4 herein for a discussion of a wet scrubber.

3.9.1.5 Cyclone

Please see Section 3.2.1.5 herein for a discussion of a cyclone.

3.9.2 Step 2 – Eliminate Technically Infeasible Options

In Step 1, available PM emissions control technologies were identified for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074). Below we discuss which of these technologies is believed to be technically infeasible for the control of PM emissions from this emissions unit.

3.9.2.1 Fabric Filter

The PM emissions from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) are liquid PM. As a result, a fabric filter is not believed to be technically feasible for the control of PM emissions from this emissions unit.

3.9.2.2 Wet Scrubber

A wet scrubber is not believed to be technically feasible for the control of PM emissions from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) because currently the PM emissions from this emissions unit are liquid PM following a wet scrubber. As previously noted, a wet scrubber must incorporate a mist eliminator or entrainment separator to remove entrained droplets from the vapor stream exiting the scrubber. Therefore, the installation of another wet scrubber would not be expected to result in a considerable reduction in the amount of PM emissions from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074).

3.9.2.3 Cyclone

As indicated above, the PM emissions from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) are primarily less than 10 µm in diameter, with a considerable portion of this PM less than 2.5 µm in diameter. As a result, a cyclone is not believed to be technically feasible for the control of PM emissions from this emissions unit.

3.9.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The following PM emissions control technologies represent those considered to be technically feasible for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074). These technologies are listed from the highest to lowest potential PM emissions control capability.

- Wet ESP – up to 99%
- Mist Eliminator – varies

3.9.4 Step 4 – Evaluate Impacts and Document the Results

Below we evaluate the PM emissions control technologies determined to be technically feasible for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) and document our BART determination for this emissions unit.

3.9.4.1 Wet ESP

As indicated in Exhibit 7, we conservatively estimated that the retrofit of the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) with a wet ESP would result in a cost effectiveness equal to approximately $19,151 per ton of PM emissions reduction, which we do not believe to be cost effective. Moreover, with respect to PM_{10} and $PM_{2.5}$ emissions, this technology would be even less cost effective because the baseline PM_{10} and $PM_{2.5}$ emissions were estimated to be a fraction of the PM emitted by the emissions unit.

The installation of a wet ESP on the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) would require a considerable amount of additional electricity to power the ESP. Also, additional electricity would be expected to be required as a result of the need for a larger

fan or an additional fan due to an increase in pressure drop through the D Train that would be caused by the wet ESP. Furthermore, the wet ESP would generate a new liquid waste stream at the plant.

Because wet ESP technology was determined not to be cost effective for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074), Mosaic proposes that this technology does not represent BART for PM emissions from this emissions unit.

3.9.4.2 Mist Eliminator

The D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) is already equipped with a mist eliminator for the control of PM emissions. As demonstrated during a September 22, 2011 stack test, this mist eliminator easily demonstrates compliance with the 0.15 lb of H_2SO_4 per ton of 100% H_2SO_4 produced (3-hr average) emission limitation of 40 CFR part 60, subpart H, which is applicable to the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074). Furthermore, a 0.15 lb of H_2SO_4 per ton of 100% H_2SO_4 produced emission limitation is the BACT limitation documented for many of the sulfuric acid production units listed in the RBLC. Therefore, Mosaic proposes that a mist eliminator represents BART for PM emissions from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074).

3.10 D Train Double Absorption H_2SO_4 Plant (EPN S-DTrain1, EQT 0074) SO_2 BART Analysis

SO_2 emissions result from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) due to the incomplete oxidation of SO_2 to SO_3 in the SO_2-to-SO_3 convertors of the D Train. However, the D Train is a double contact double absorption sulfuric acid unit, which means that the unit's SO_2-to-SO_3 conversion occurs at an optimal level relative to a single absorption design sulfuric acid unit, resulting in significantly lower SO_2 emissions compared to a single absorption design sulfuric acid unit. Additionally, to assist in the achievement of the SO_2 emission limitations required by the Consent Decree for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074), Mosaic spent greater than $15,000,000 on the D Train in the 2011 timeframe and it has begun to use cesium-promoted catalyst in the D Train.

3.10.1 Step 1 – Identify All Available Retrofit Control Technologies

Available SO_2 emissions control technologies for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) were determined by searching the EPA's RBLC for control technology determinations made after January 1, 2005 for the following process code.

- Process Code 62.015 – Inorganic Chemicals Manufacturing; Sulfuric Acid Plants

Below is a listing of the SO_2 emissions control technologies identified under this EPA RBLC process code.

- Wet Scrubber
- Double Contact Double Absorption Technology
- Cesium-Promoted Catalyst

Below we discuss these SO_2 emissions control technologies.

3.10.1.1 Wet Scrubber

In a wet scrubber, an aqueous slurry of sorbent is injected into the exhaust gases and the SO_2 contained in these gases dissolves into the slurry droplets where it reacts with the alkaline present in the slurry. The treated exhaust gases pass through a mist eliminator before being emitted to the atmosphere in order to remove any entrained slurry droplets. The slurry falls to the bottom of the scrubber and is either collected to be regenerated and recycled or removed from the scrubber system as a waste or byproduct. Scrubbing liquids that have a potential for reducing SO_2 emissions include sodium hydroxide, sodium carbonate, calcium hydroxide, calcium carbonate, and hydrogen peroxide. There are several types of wet scrubbers, including packed-bed counterflow scrubbers, packed-bed cross-flow scrubbers, bubble plate scrubbers, and tray scrubbers.

3.10.1.2 Double Contact Double Absorption Technology

A double contact double absorption design sulfuric acid unit can result in an SO_2-to-SO_3 conversion equal to or greater 99.6%. The double contact double absorption design improves SO_2-to-SO_3 conversion relative to a single absorption design by removing SO_3 from the process gas stream at the first absorption stage, thereby bringing about a considerable shift in the reaction equilibrium towards the formation of SO_3, which results in considerably higher overall SO_2-to-SO_3 conversion efficiencies when the process gas exiting the first absorber is passed through one or two secondary convertor catalyst beds. The SO_3 formed in the secondary stage is absorbed in the unit's second absorber to generate sulfuric acid.

The double contact double absorption design offers the following advantages over caustic wet scrubber SO_2 control technologies:

- No caustic waste stream is produced;
- There are no new operating processes that plant personnel must become familiar with;
- The process permits higher inlet SO_2 concentrations resulting in a reduction in equipment size;
- There is no reduction in overall sulfuric acid unit operating time or efficiency; and
- There is no increase in manpower requirements.

3.10.1.3 Cesium-Promoted Catalyst

Vanadium-based sulfuric acid catalyst are utilized to oxidize SO_2 to SO_3. Standard sulfuric acid catalyst is comprised of potassium and vanadium salts supported on a silica carrier. Cesium-promoted sulfuric acid catalyst is very similar to the standard potassium-promoted catalyst, but some of the potassium promoter is replaced with cesium. The cesium helps to prevent catalyst deactivation at lower operating temperatures. Through the use of cesium-promoted catalyst in the fourth pass, it is possible to increase the SO_2-to-SO_3 conversion through a double absorption sulfuric acid unit, resulting in lower SO_2 emissions. Lower final catalyst bed inlet

temperatures allow for greater SO_2-to-SO_3 conversion because a lower temperature favors the formation of SO_3 due to the fact that the SO_2-to-SO_3 conversion is an exothermic process. The high conversion levels possible with cesium-promoted catalysts are either unattainable with conventional potassium-promoted catalysts or would require considerable volumes of the conventional potassium-promoted catalysts.

3.10.2 Step 2 – Eliminate Technically Infeasible Options

In Step 1, available SO_2 emissions control technologies were identified for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074). Each of these technologies was determined to be technically feasible for the control of SO_2 emissions from this emissions unit.

3.10.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The following SO_2 emissions control technologies represent those considered to be technically feasible for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074). These technologies are listed from the highest to lowest potential SO_2 emissions control capability.

- Wet Scrubber – 95%
- Double Contact Double Absorption – up to 75%
- Cesium-Promoted Catalyst – varies depending on the specific cesium-promoted catalyst, as well as operating temperature changes that may occur in association with the use of a cesium-promoted catalyst

3.10.4 Step 4 – Evaluate Impacts and Document the Results

Below we evaluate the SO_2 emissions control technologies determined to be technically feasible for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) and document our BART determination for this emissions unit.

3.10.4.1 Wet Scrubber

As indicated in Exhibit 8, we estimated that the retrofit of the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) with a wet scrubber would result in a cost effectiveness equal to approximately $7,091 per ton of SO_2 emissions reduction, which we do not believe to be cost effective.[19]

The installation of a wet scrubber on the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) may require additional energy as a result of the need for a larger fan or an additional fan due to an increase in pressure drop through the D Train that would be caused by the wet scrubber. Additionally, fresh and spent scrubbing medium pumps would require electricity. Furthermore, spent scrubbing medium would have the potential to represent a significant amount of newly generated waste.

[19] Mosaic believes a more appropriate equipment life for a wet scrubber in this application would be 20 years, thus as documented in Exhibit 8 a more realistic cost effectiveness would be $7,826 per ton of SO_2 emissions reduction.

Because wet scrubber technology was determined not to be cost effective for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074), Mosaic proposes that this technology does not represent BART for SO_2 emissions from this emissions unit.

3.10.4.2 Double Contact Double Absorption Technology

The D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) is a double contact double absorption design sulfuric acid unit. Additionally, as noted above, Mosaic recently spent a considerable amount of money on the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) in its efforts to comply with applicable SO_2 emission limitation requirements of the Consent Decree. Mosaic proposes that a double contact double absorption design, in combination with the use of cesium catalyst for a portion of the unit's SO_2-to-SO_3 conversion catalyst, represents BART for SO_2 emissions from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074).

3.10.4.3 Cesium-Promoted Catalyst

The D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) uses cesium-promoted catalyst for a portion of the unit's SO_2-to-SO_3 conversion catalyst. Additionally, as noted above, Mosaic recently spent a considerable amount of money on the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) in its efforts to comply with applicable SO_2 emission limitation requirements of the Consent Decree. Mosaic proposes that the use of cesium-promoted catalyst for a portion of the unit's SO_2-to-SO_3 conversion catalyst, in combination with a double contact double absorption design, represents BART for SO_2 emissions from the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074).

3.11 D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) NOx BART Analysis

The D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) combusts natural gas only and it is permitted at a rating of 100 MMBtu/hr. The location of this start-up burner is in the sulfur furnace of the D Train. During the D Train start-up mode, the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) is used to heat the unit's sulfur burner to a temperature that will allow for the ignition of the molten sulfur that must be combusted at the sulfur burner to generate SO_2, which is eventually converted to sulfuric acid product, as well as to heat catalyst components downstream of the sulfur furnace to appropriate operating temperatures. Due to this start-up specific purpose of the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075), it is permitted to operate only 105 hours per year.

3.11.1 Step 1 – Identify All Available Retrofit Control Technologies

As identified above in Section 3.4 for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), the following are the NOx emissions control technologies that may be considered to be available technologies for the reduction of NOx emissions from the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075).

- FGR/LNBs/ULNBs
- SCR
- SNCR

- NSCR

Below we discuss these NOx emissions control technologies.

3.11.1.1 FGR, LNBs, and ULNBs

Please see Section 3.1.1.2 herein for a discussion of FGR, LNBs, and ULNBs.

3.11.1.2 SCR

Please see Section 3.1.1.1 herein for a discussion of SCR.

3.11.1.3 SNCR

Please see Section 3.1.1.3 herein for a discussion of SNCR.

3.11.1.4 NSCR

Please see Section 3.1.1.4 herein for a discussion of NSCR.

3.11.2 Step 2 – Eliminate Technically Infeasible Options

In Step 1, available NOx emissions control technologies were identified for the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075). Below we discuss which of these technologies is believed to be technically infeasible for the control of NOx emissions from this emissions unit.

3.11.2.1 SCR

The NOx emissions control effectiveness of an SCR system is limited during the start-up operations of the combustion device on which it is installed because the temperature of the SCR system must be at a minimum temperature in order for the SCR system to effectively operate. The D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) is operated only during the D Train start-up mode to heat the unit's sulfur burner and catalyst components downstream of the sulfur furnace to appropriate operating temperatures. For an SCR system installed on a combustion device that incorporates heat recovery equipment (e.g., steam generation heat exchangers, process catalyst beds), several hours can be required to heat the SCR system to the minimum effective temperature status after the combustion device is put into operation in a warm start-up scenario. Even more time would be required to heat the SCR system to the minimum effective temperature status after the combustion device is put into operation in a cold start-up scenario. Because of the limited NOx reduction capability of an SCR system and its potential for excessive ammonia emissions to the atmosphere when operating below a minimum set point temperature, many SCR systems are integrated with a process control system that uses a minimum operating temperature as measured at the combustion device exit to determine when the SCR system can be put into operation.

At 180 °F, the temperature of the exhaust gases in the stack of the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) would be less than the 350 to 400 °F temperature necessary to properly operate an SCR system. Additionally, for much of the operating period of the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075), the exhaust gases in the stack of this start-up burner would be unsteady at even lower temperatures. Due to this temperature deficiency, in combination with the intermittent start-up (non-steady state) operating nature of the D Train

Start-Up Burner (EPN S-DTrain2, EQT 0075), it is not technically feasible to install and operate an SCR system for the control of NOx emissions from the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075).

3.11.2.2 SNCR

The effective operating temperature of an SNCR system is 1,600 to 2,100 °F. This high temperature typically requires the SNCR system to be integrated into the upper firebox region of an external combustion device. Due to the elevated operating temperature constraint of an SNCR system, this system requires a reasonable amount of time to reach the minimum effective temperature status when the combustion device on which it is installed is put into operation. Therefore, during the start-up mode of a combustion device equipped with an SNCR system, the level of NOx emissions control of the SNCR system would be low and unstable, along with the potential for relatively excessive amounts of unreacted ammonia to pass through the system and to be emitted to the atmosphere. In fact, as noted above for SCR systems, many SNCR systems are integrated with a process control system that uses a minimum operating temperature as measured at the combustion device exit to determine when the SNCR system can be put into operation.

The D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) is operated only during the D Train start-up mode to heat the unit's sulfur burner and catalyst components downstream of the sulfur furnace to appropriate operating temperatures. The sulfur burner in the D Train sulfur furnace is typically not heated above 1,650 °F, while the catalyst components downstream of the sulfur burner are heated to much lower temperatures. When the sulfur burner and downstream catalyst component reach appropriate temperatures, the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) is shut down. For much of the operating period of the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075), the temperature in the sulfur furnace would be considerably insufficient to properly operate an SNCR system, and the completion of the operating period of this start-up burner would be only at the low end of the effective operating temperature range of an SNCR system. Due to this temperature deficiency, in combination with the intermittent start-up (non-steady state) operating nature of the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075), it is not technically feasible to install and operate an SNCR system for the control of NOx emissions from the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075).

3.11.2.3 NSCR

At 180 °F, the temperature of the exhaust gases in the stack of the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) would be considerably insufficient to properly operate an NSCR system, which requires a temperature in the range of 725 °F to 1,200 °F. As discussed above, this temperature range would be achieved in the sulfur furnace area of the D Train near the completion of the operating period of the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075). Additionally, the exhaust gases from the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) typically contain oxygen at a concentration greater than 4% by volume, which is considerably greater than 0.5%, the upper end of the oxygen level suitable for the effective operation of an NSCR system. Due to these factors, in combination with the intermittent start-up (non-steady state) operating nature of the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075), it is not

technically feasible to install and operate an NSCR system for the control of NOx emissions from the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075).

3.11.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The only remaining NOx emissions control technology determined to be technically feasible for the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) is FGR/LNBs/ULNBs.

3.11.4 Step 4 – Evaluate Impacts and Document the Results

Below we evaluate the NOx emissions control technologies determined to be technically feasible for the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) and document our BART determination for this emissions unit.

3.11.4.1 FGR, LNBs, and ULNBs

Although the purpose and operation of the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) is considerably different than the purpose and operation of a burner in a traditional boiler or process heater, we have conservatively estimated that it would be technically feasible to replace the existing start-up burner with an LNB or ULNB, with minor changes to the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) combustion air equipment, burner control systems, and other ancillary equipment.

As indicated in Exhibit 9, using a ULNB cost estimation technique documented in EPA's *Petroleum Refinery Tier 2 BACT Analysis Report*, we conservatively estimated that the retrofit of the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) with this type of burner would result in a cost effectiveness equal to approximately $24,760 per ton of NOx emissions reduction, which we do not believe to be cost effective. The installation and operation of an FGR system in association with the current burner of the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) or the replacement of this emissions unit's current burner with an LNB would result in a comparable cost effectiveness for the unit.

We conservatively estimated that the LNB/ULNB option for the D Train Start-Up Burner (EPN S-ATrain2, EQT 0075) would not have any negative energy impacts even though LNBs and ULNBs can result in a reduction in the energy efficiency or rating of a combustion device in retrofit scenarios. More specifically, in certain LNB/ULNB retrofit situations, without making relatively extensive changes to the relevant existing combustion device, the process rating of such device may be lowered due to burner arrangement and firebox space limitations. External FGR would require an additional fan that would consume additional energy when compared to the current configuration of the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075).

An FGR/LNB/ULNB option for the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) would not be expected to result in any non-air quality environmental impacts. With respect to collateral emissions that may result in an FGR/LNB/ULNB retrofit scenario for the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075), although current FGR/LNB/ULNB technologies are capable of achieving low CO emission rates at normal to maximum design rates, these technologies would be expected to generate higher CO emissions levels than conventional burners when operated at lower operating rates.

Because FGR/LNB/ULNB technology was determined not to be cost effective for the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075), Mosaic proposes that good combustion practices represent BART for NOx emissions from this emissions unit.

3.12 D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) $PM/PM_{10}/PM_{2.5}$ BART Analysis

PM emissions occur from the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) as a result of the incomplete combustion of natural gas. PM from natural gas combustion has been estimated to be less than 1 µm in size and this PM is comprised of both filterable and condensable components. However, filterable PM emissions are typically low for natural gas combustion.

3.12.1 Step 1 – Identify All Available Retrofit Control Technologies

As identified above in Section 3.5 for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), the following are the PM emissions control technologies that may be considered to be available technologies for the reduction of PM emissions from the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075).

- Good Combustion Practices
- ESP
- Fabric Filter
- Wet Scrubber
- Cyclone

Below we discuss these PM emissions control technologies.

3.12.1.1 Good Combustion Practices

Please see Section 3.5.1.1 herein for a discussion of good combustion practices.

3.12.1.2 ESP

Please see Section 3.2.1.2 herein for a discussion of an ESP.

3.12.1.3 Fabric Filter

Please see Section 3.2.1.3 herein for a discussion of a fabric filter.

3.12.1.4 Wet Scrubber

Please see Section 3.2.1.4 herein for a discussion of a wet scrubber.

3.12.1.5 Cyclone

Please see Section 3.2.1.5 herein for a discussion of a cyclone.

3.12.2 Step 2 – Eliminate Technically Infeasible Options

In Step 1, available PM emissions control technologies were identified for the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075). Below we discuss which of these technologies is believed to be technically infeasible for the control of PM emissions from this emissions unit.

3.12.2.1 ESP

For the same reasons discussed in Section 3.5.2.1 herein for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), we do not believe it is technically feasible to use an ESP to control the PM emissions from the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075).

3.12.2.2 Fabric Filter

For the same reasons discussed in Section 3.5.2.2 herein for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), we do not believe it is technically feasible to use a fabric filter to control the PM emissions from the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075).

3.12.2.3 Wet Scrubber

For the same reasons discussed in Section 3.5.2.3 herein for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), we do not believe it is technically feasible to use a wet scrubber to control the PM emissions from the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075).

3.12.2.4 Cyclone

For the same reasons discussed in Section 3.5.2.4 herein for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), we do not believe it is technically feasible to use a cyclone to control the PM emissions from the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075).

3.12.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The only remaining PM emissions control technology determined to be technically feasible for the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) is good combustion practices.

3.12.4 Step 4 – Evaluate Impacts and Document the Results

Mosaic proposes that good combustion practices represent BART for PM emissions from the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075).

3.13 D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) SO_2 BART Analysis

For the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075), emissions of SO_2 result from the oxidation of sulfur-containing compounds contained in the natural gas combusted by the emissions unit. The sulfur content of the fuel combusted by a combustion device directly influences the quantity of SO_2 emissions generated by that combustion device. In practice, SO_2 emissions resulting from the combustion of a gaseous fuel are primarily controlled by limiting its sulfur content, not by scrubbing the exhaust gases from the device combusting the same fuel.

3.13.1 Step 1 – Identify All Available Retrofit Control Technologies

As identified above in Section 3.6 for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), the following are the SO_2 emissions control technologies that may be considered to be available

technologies for the reduction of SO_2 emissions from the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075).

- Low Sulfur Fuel
- Flue Gas Desulfurization

Below we discuss these SO_2 emissions control technologies.

3.13.1.1 Low Sulfur Fuel

Please see Section 3.6.1.1 herein for a discussion of low sulfur fuel.

3.13.1.2 Flue Gas Desulfurization

Please see Section 3.6.1.2 herein for a discussion of flue gas desulfurization.

3.13.2 Step 2 – Eliminate Technically Infeasible Options

In Step 1, available SO_2 emissions control technologies were identified for the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075). Below we discuss which of these technologies is believed to be technically infeasible for the control of SO_2 emissions from this emissions unit.

3.13.2.1 Flue Gas Desulfurization

For the same reasons discussed in Section 3.6.2.1 herein for the A Train Start-Up Burner (EPN S-ATrain2, EQT 0068), we do not believe it is technically feasible to use flue gas desulfurization to control the SO_2 emissions from the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075).

3.13.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The only remaining SO_2 emissions control technology for the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075) is the combustion of low sulfur fuel.

3.13.4 Step 4 – Evaluate Impacts and Document the Results

Mosaic proposes that the combustion of pipeline quality natural gas represents BART for SO_2 emissions from the D Train Start-Up Burner (EPN S-DTrain2, EQT 0075).

3.14 D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003) SO_2 BART Analysis

An extensive amount of ductwork connects the major components of the D Train, and the process gases contained in this ductwork from the sulfur furnace to the absorption column of the D Train are comprised of varying concentrations of SO_2. Fugitive SO_2 emissions result from the D Train ductwork as a result of leaks that periodically develop in this ductwork.

3.14.1 Step 1 – Identify All Available Retrofit Control Technologies

As identified above in Section 3.7 for A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002), the following is an SO_2 emissions control technology that may be considered to be an available technology for the reduction of SO_2 emissions from D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003).

- Leak Detection and Repair

Below we discuss this SO_2 emissions control technology.

3.14.1.1 Leak Detection and Repair

Please see Section 3.7.1.1 herein for a discussion of leak detection and repair.

3.14.2 Step 2 – Eliminate Technically Infeasible Options

In Step 1, we identified leak detection and repair as the only available SO_2 emissions control technology for D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003). This technology is considered to be technically feasible for this emissions unit.

3.14.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The only SO_2 emissions control technology for D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003) is leak detection and repair.

3.14.4 Step 4 – Evaluate Impacts and Document the Results

Below we evaluate the SO_2 emissions control technology determined to be technically feasible for D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003) and document our BART determination for this emissions unit.

3.14.4.1 Leak Detection and Repair

Leaks in the ductwork of the D Train are detected by visible inspection. Operators and insulation personnel conduct daily walkthroughs in the D Train area and they look for leaks in the D Train ductwork as part of these walkthroughs. When a leak in the ductwork of the D Train is detected, temporary ductwork and a vacuum are used to route the leak from the ductwork into the D Train combustion air system so that the leak is mostly returned to the D Train until the leaking ductwork is repaired.

Mosaic proposes that current leak detection and repair practices represent BART for SO_2 emissions for D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003).

3.15 Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113) PM/PM_{10}/$PM_{2.5}$ BART Analysis

PM, PM_{10}, and $PM_{2.5}$ emissions occur from the Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113) due to the following PM emissions generating activities that are primarily fugitive in nature and related to the unloading of phosphate rock at the plant and the subsequent rock movement and storage events that occur at the plant until the rock is ultimately fed to the phosphoric acid units: barge/ship unloading operations, dump truck loading/unloading operations, pay loader unloading operations, conveyor belt transfer points, stacker operations, reclaimer operations, vehicle travel activities, and storage pile wind erosion.

3.15.1 Step 1 – Identify All Available Retrofit Control Technologies

Below is a listing of the available PM emissions control technologies for the Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113) emission source.

- Enclose Conveyor Belt Transfer Points and Equip with a Control Device
- Wet Storage Piles
- Enclose Storage Piles
- Wet Unpaved Roads
- Pave Unpaved Roads

3.15.1.1 Enclose Conveyor Belt Transfer Points and Equip with a Control Device

Enclosing a conveyor belt-to-conveyor belt transfer point significantly reduces or eliminates the wind exposure of the falling aggregate at the transfer point. Among other factors, the amount of PM emissions occurring at a transfer (drop) point is dependent on the wind speed at the transfer point. Therefore, reducing or eliminating wind exposure minimizes the amount of PM emissions that may occur at a transfer point.

When a transfer point is partially or fully enclosed, a baghouse can be used to collect the airborne PM that is generated as a result of the transfer operation. Alternatively, a liquid spray system can be used to suppress PM from becoming airborne during the transfer operation. The wetting agent in the liquid spray system can be water or a combination of water and a chemical surfactant. A surfactant reduces the amount of liquid needed to achieve adequate dust suppression.

3.15.1.2 Wet Storage Piles

When freshly processed aggregate is loaded onto a storage pile, the potential for dust emissions is at a maximum. Fines on the surface of the storage pile are easily disaggregated and released to the atmosphere upon exposure to high winds. However, moisture causes aggregation and cementation of aggregate fines to the surface of larger aggregate particles. This crusting of the storage pile surface binds the erodible material, thus reducing the erosion potential of the storage pile. Therefore, the periodic wetting of the surface of a storage pile reduces the potential PM emissions that may result from wind erosion. Specifically, the periodic wetting of a storage pile can reduce PM_{10} emissions by 90%.[20]

3.15.1.3 Enclose Storage Piles

Dust emissions may be generated by wind erosion of open storage piles. These emissions sources are typically characterized by nonhomogeneous surfaces impregnated with non-erodible elements (particles larger than approximately 1 centimeter in diameter). Because erosion potential has been found to increase rapidly with increasing wind speed, PM emissions

[20] Countess Environmental for Western Governors' Association. *WRAP Fugitive Dust Handbook*. September 7, 2006. p. 9-9.

resulting from storage pile wind erosion can be reduced if the exposure of the pile to high wind speed gusts is reduced. In this regard, a control option for a storage pile is to enclose the pile. This enclosure can be a full or partial enclosure. Based on study results published in 2003 by Sierra Research, a 3-sided enclosure with 50% porosity can reduce PM_{10} emissions by 75%.[21]

3.15.1.4 Wet Unpaved Roads

Watering (or applying chemical dust suppressants on) unpaved roads is potentially applicable to most industrial roads at moderate to low costs. Watering increases the moisture content of the road surface, which in turn causes particles to conglomerate and reduces their likelihood of becoming suspended when vehicles pass over the surface. Chemical dust suppressants cause road surface particles to bind together, creating a road surface with a reduced dusting potential, similar to a paved road.

For watering, the PM emissions control efficiency depends on how fast the road dries after water is added, which in turn depends on: the amount of water added during each watering event; the period of time between watering events; the weight, speed, and number of vehicles traveling over the watered road during the period between watering events; and meteorological conditions (temperature, wind speed, cloud cover, etc.) that affect evaporation during the period between watering events. Ultimately, the higher the moisture content of the roads the higher the PM emissions control efficiency.

3.15.1.5 Pave Unpaved Roads

When a vehicle travels on an unpaved surface, the force of the wheels on the road surface causes pulverization of surface material. Particles are lifted and dropped from the rolling wheels, and the road surface can be exposed to air currents in turbulent shear with the surface. The quantity of dust emissions from a given segment of unpaved road has been determined to vary linearly with the volume of road traffic.

In comparison to watering or applying chemical dust suppressants, paving an unpaved road is a relatively permanent control option that does not require periodic retreatment. However, paving unpaved roads is quite expensive and is normally most applicable to relatively short stretches of unpaved road with at least several hundred vehicle passes per day. Furthermore, if the newly paved road is located near unpaved areas or is used to transport material that may spill onto the paved road, then the application of water or a chemical dust suppressant would potentially need to be required to reduce PM emissions from the paved road, effectively resulting in the same work practices that would be associated with the originally unpaved road.

3.15.2 Step 2 – Eliminate Technically Infeasible Options

In Step 1, available PM emissions control technologies were identified for the Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113). Below we discuss which of these technologies is believed to be technically infeasible for the control of PM emissions from this source.

[21] Ibid.

3.15.2.1 Enclose Storage Piles

The location of phosphate rock storage piles at the plant frequently changes in association with the variety of phosphate rock being received at the plant and the relative amounts of the different phosphate rocks used at the plant. Additionally, the size of the phosphate rock storage piles can vary significantly in association with changes in the availability of the different phosphate rocks and market conditions. Due to the dynamic nature of the phosphate rock storage pile locations and sizes, we do not believe it is practical to effectively enclose these storage piles. Therefore, we do not believe it is technically feasible to enclose the phosphate rock storage piles at the plant.

3.15.2.2 Pave Unpaved Roads

In association with the changing location and size of the phosphate rock storage piles at the plant, the location and extent of the haul roads used to transport phosphate rock at the plant are routinely changing. Additionally, there is flexibility in the delivery of phosphate rock to the plant, which causes even further changes in the location and routing of the haul roads used to move phosphate rock around the plant. Because the location and route of the unpaved phosphate rock haul roads change in association with many operating and phosphate rock delivery factors, we do not believe it is practical to effectively pave these unpaved roads. Therefore, we do not believe it is technically feasible to pave the unpaved phosphate rock haul roads at the plant.

3.15.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

The following PM emissions control technologies represent those considered to be technically feasible for the Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113). Below we indicate the potential PM emissions control capability of each technology.

- Enclose Conveyor Belt Transfer Points and Equip with a Control Device – up to 99%
- Wet Storage Piles – 90%
- Wet Unpaved Roads – varies

3.15.4 Step 4 – Evaluate Impacts and Document the Results

Below we evaluate the PM emissions control technologies determined to be technically feasible for the Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113) and document our BART determination for this source.

3.15.4.1 Enclose Conveyor Belt Transfer Points and Equip with a Control Device

As indicated in Exhibit 10, we conservatively estimated that the retrofit of the worst-case potential to emit conveyor belt transfer point inventoried under Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113) with a baghouse would result in a cost effectiveness equal to approximately $7,796 per ton of PM emissions reduction, which we do not believe to be cost effective. Moreover, with respect to PM_{10} and $PM_{2.5}$ emissions, the cost effectiveness ratio for this technology would be at least twice as high as that estimated for

PM because the baseline PM_{10} and $PM_{2.5}$ emissions were estimated to be a fraction of the PM emitted at the transfer point.

The installation of a baghouse would require energy as a result of the need for a fan. A baghouse would not be expected to result in any notable waste streams or collateral emissions.

Because the installation of a baghouse was determined not to be cost effective for the worst-case potential to emit conveyor belt transfer point inventoried under Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113), Mosaic proposes that current design and operations represent BART for the PM emissions from the transfer point operations inventoried under this source. The current design and operations for the conveyor belt transfer points incorporate a combination of partial to full enclosures and/or the minimization of drop distances.

3.15.4.2 Wet Storage Piles

Mosaic proposes that the watering of the phosphate rock storage piles at the plant represents BART for the PM emissions resulting from these storage piles.

3.15.4.3 Wet Unpaved Roads

Mosaic proposes that the watering of the phosphate rock haul roads at the plant represents BART for the PM emissions resulting from these roads.

3.16 Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) PM/PM_{10}/$PM_{2.5}$ BART Analysis

The roofs of molten sulfur storage vessels are equipped with at least one, and typically with two or more vents, to provide for vessel vapor space venting that is necessary:

- Due to the thermal expansion and contraction of the stored molten sulfur caused by temperature fluctuations;
- To prevent the possible accumulation of an explosive amount of hydrogen sulfide in the vapor space; and
- To prevent anaerobic conditions that provide for the formation of iron sulphide, which is a pyrophoric material that can form from the reaction between hydrogen sulfide and the iron of the storage vessel.

The vapor in the vapor space of the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) contains sulfur particles. Therefore, PM emissions result from these vessels when vapor is emitted to the atmosphere from the vessels.

Because the potential to emit PM emission rates from the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) are permitted under an emissions cap – Sulfur CAP (EPN S-SCAP,

GRP 0011) – and the same type of PM emissions control device would be used for each of these emissions units, we have performed a BART determination analysis for this collection of molten sulfur vessels.

3.16.1 Step 1 – Identify All Available Retrofit Control Technologies

We searched under the following process codes included in the EPA's RBLC for any PM emissions control technology determinations made after January 1, 2005 for sulfur pits and sulfur storage tanks and did not identify any such determination.

- Process Code 50.006 – Petroleum/Natural Gas Production and Refining; Petroleum Refining Treating Processes (hydrotreating, acid gas removal, SRU's, etc.)
- Process Code 62.015 – Inorganic Chemicals Manufacturing; Sulfuric Acid Plants
- Process Code 62.019 – Inorganic Chemicals Manufacturing; Sulfur Recovery (except 50.006)
- Process Code 62.020 – Inorganic Chemicals Manufacturing; Inorganic Liquid/Gas Storage & Handling

Although no PM emissions control technology determinations were identified for sulfur pits and sulfur storage tanks under these EPA RBLC process codes, we evaluated the cost for the installation of a collection system that could be used to route the vents from the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) to a PM emissions control device, such as a wet scrubber.

3.16.2 Step 2 – Eliminate Technically Infeasible Options

As indicated in Step 1, we have assumed that an emissions control system comprised of a vent collection component and an associated emissions control device is technically feasible for the control of PM emissions from the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083).

3.16.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

We have estimated that an emissions control system comprised of a vent collection component and an associated emissions control device would reduce PM emissions from the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) by 95%.

3.16.4 Step 4 – Evaluate Impacts and Document the Results

The Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081) is permitted for a molten sulfur throughput of 600,000 long tons per year (ltpy), or approximately 1,644 long tons per day (ltpd) when this annual amount is equally distributed over 365 days per year. Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082) and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) are collectively permitted for a molten sulfur throughput of 750,000 ltpy, or approximately 2,055 ltpd

when this annual amount is equally distributed over 365 days per year. Additionally, air quality permitting records indicate that the nominal molten sulfur level for Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082) is 3,000 long tons, while the nominal molten sulfur level indicated for Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) is 6,000 long tons. These molten sulfur pit and molten sulfur storage vessel facilities are representative of molten sulfur facilities that may be located at a 500 ltpd or more sulfur recovery plant.

As indicated by the EPA as part of the recent rulemaking process for 40 CFR part 60, subpart Ja, the capital cost for the installation and operation of a vent collection system on the molten sulfur pits and the molten sulfur storage tanks downstream of these sulfur pits at a model 500 ltpd sulfur recovery plant at a petroleum refinery was estimated to be approximately $2,000,000, while the annualized cost for this system was estimated to be approximately $220,000 per year.[22] Note that we do not believe these cost estimates include the cost for the installation and operation of an emissions control device, such as a wet scrubber. Instead, it appears EPA's evaluation assumed that the collected vents would be routed to the model petroleum refinery's sulfur recovery plant for processing into sulfur rather than being routed to a newly installed emissions control device.

If we conservatively assume that a $220,000 per year vent collection system, as estimated by the EPA, would result in a 95% reduction in the combined 15.00 tpy contribution of the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) to the 17.78 tpy potential to emit PM emission rate of the Sulfur CAP (EPN S-SCAP, GRP 0011), then a reduction of 14.25 tpy of PM at an annual cost of $220,000 would result in a cost effectiveness of approximately $15,439 per ton, which is an amount that we do not believe to be cost effective. Again, EPA's $220,000 per year cost estimate does not include the capital and operating costs that would be associated with the necessary installation of a PM emissions control device at the plant. Thus, the installation of a vent collection system <u>and</u> a PM emissions control device would be even less cost effective.

Our determination that it would not be cost effective to install and operate a vent collection and control system on the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) is consistent with EPA's determination that molten sulfur storage tanks located after the molten sulfur pits of a sulfur recovery plant at a petroleum refinery are not required to be controlled for 40 CFR part 60, subpart Ja purposes because it is not cost effective to control the emissions from such storage tanks.

Because a vent collection and control system was determined not to be cost effective for the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083), Mosaic proposes that current design and operations represent BART for PM emissions from these emissions units.

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[22] Kristin Parrish, RTI International to Bob Lucas, EPA. *Memorandum: Final Impacts Analysis for SO_2 Emissions from Sulfur Recovery Plants*. March 17, 2008. p. 6-7.

3.17 Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) SO_2 BART Analysis

As discussed above in Section 3.16, molten sulfur storage vessels vent to the atmosphere due to multiple factors. The vapor in the vapor space of the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) contains SO_2, which can result from the release of SO_2 that is dissolved in the molten sulfur contained in these vessels or can occur due to the oxidation of sulfur-containing compounds present in the vapor space of the same vessels. Therefore, SO_2 emissions result from the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) when vapor is emitted to the atmosphere from these vessels.

Because the potential to emit SO_2 emission rates from the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) are permitted under an emissions cap – Sulfur CAP (EPN S-SCAP, GRP 0011) – and the same type of SO_2 emissions control device would be used for each of these emissions units, we have performed a BART determination analysis for this collection of molten sulfur vessels.

3.17.1 Step 1 – Identify All Available Retrofit Control Technologies

We searched under the following process codes included in the EPA's RBLC for any SO_2 emissions control technology determinations made after January 1, 2005 for sulfur pits and sulfur storage tanks and did not identify any such determination.

- Process Code 50.006 – Petroleum/Natural Gas Production and Refining; Petroleum Refining Treating Processes (hydrotreating, acid gas removal, SRU's, etc.)
- Process Code 62.015 – Inorganic Chemicals Manufacturing; Sulfuric Acid Plants
- Process Code 62.019 – Inorganic Chemicals Manufacturing; Sulfur Recovery (except 50.006)
- Process Code 62.020 – Inorganic Chemicals Manufacturing; Inorganic Liquid/Gas Storage & Handling

Although no SO_2 emissions control technology determinations were identified for sulfur pits and sulfur storage tanks under these EPA RBLC process codes, we evaluated the cost for the installation of a collection system that could be used to route the vents from the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) to an SO_2 emissions control device, such as a wet scrubber.

3.17.2 Step 2 – Eliminate Technically Infeasible Options

As indicated in Step 1, we have assumed that an emissions control system comprised of a vent collection component and an associated emissions control device is technically feasible for the

control of SO_2 emissions from the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083).

3.17.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

We have estimated that an emissions control system comprised of a vent collection component and an associated emissions control device would reduce SO_2 emissions from the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) by 95%.

3.17.4 Step 4 – Evaluate Impacts and Document the Results

As noted above in Section 3.16.4, the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) are representative of molten sulfur facilities that may be located at a 500 ltpd or more sulfur recovery plant at a petroleum refinery. Also, in Section 3.16.4 above, we documented that the EPA estimated a capital cost of approximately $2,000,000 for the installation and operation of a vent collection system on the molten sulfur pits and the molten sulfur storage tanks downstream of these sulfur pits at a model 500 ltpd sulfur recovery plant, while the annualized cost for this system was estimated by the EPA to be approximately $220,000 per year. Furthermore, as previously noted, we do not believe these cost estimates include the cost for the installation and operation of an emissions control device, such as a wet scrubber, because it appears EPA's evaluation assumed that the collected vents would be routed to the model petroleum refinery's sulfur recovery plant for processing into sulfur rather than being routed to a newly installed emissions control device.

If we conservatively assume that a $220,000 per year vent collection system, as estimated by the EPA, would result in a 95% reduction in the combined 2.98 tpy contribution of the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) to the 3.54 tpy potential to emit SO_2 emission rate of the Sulfur CAP (EPN S-SCAP, GRP 0011), then a 2.83 tpy SO_2 emissions reduction at an annual cost of $220,000 would result in a cost effectiveness of approximately $77,739 per ton, which is an amount that we do not believe to be cost effective. Again, EPA's $220,000 per year cost estimate does not include the capital and operating costs that would be associated with the necessary installation of an SO_2 emissions control device at the plant. Thus, the installation of a vent collection system <u>and</u> an SO_2 emissions control device would be even less cost effective.

Our determination that it would not be cost effective to install and operate a vent collection and control system on the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083) is consistent with EPA's determination that molten sulfur storage tanks located after the molten sulfur pits of a sulfur recovery plant at a petroleum refinery are not required to be controlled for 40 CFR part 60, subpart Ja purposes because it is not cost effective to control the emissions from such storage tanks.

Because a vent collection and control system was determined not to be cost effective for the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083), Mosaic proposes that current design and operations represent BART for SO_2 emissions from these emissions units

3.18 Dock Fugitive Emissions (EPN S-DockFug, FUG 0004) PM/PM_{10}/$PM_{2.5}$ BART Analysis

During the loading of molten sulfur into marine vessels at the plant's dock, the displaced vapor from these vessels is vented to the atmosphere. This displaced vapor contains sulfur particles. Therefore, PM emissions result from the loading of molten sulfur into marine vessels at the plant's dock.

Additionally, during the loading of phosphoric acid and sulfuric acid into marine vessels at the dock, a portion of the phosphoric acid and the sulfuric acid loaded into these vessels volatilizes into the vapor displaced from the vessels during the loading process. The phosphoric acid and sulfuric acid contained in the displaced vapor from the marine vessels were estimated to represent condensable PM emissions.

3.18.1 Step 1 – Identify All Available Retrofit Control Technologies

We searched under the following process codes included in the EPA's RBLC for any PM emissions control technology determinations made after January 1, 2005 for molten sulfur loading, sulfuric acid loading, and phosphoric acid loading and did not identify any such determination.

- Process Code 50.006 – Petroleum/Natural Gas Production and Refining; Petroleum Refining Treating Processes (hydrotreating, acid gas removal, SRU's, etc.)
- Process Code 62.010 – Inorganic Chemicals Manufacturing; Phosphoric Acid Manufacturing
- Process Code 62.015 – Inorganic Chemicals Manufacturing; Sulfuric Acid Plants
- Process Code 62.019 – Inorganic Chemicals Manufacturing; Sulfur Recovery (except 50.006)
- Process Code 62.020 – Inorganic Chemicals Manufacturing; Inorganic Liquid/Gas Storage & Handling

Although no PM emissions control technology determinations were identified for molten sulfur loading, sulfuric acid loading, and phosphoric acid loading under these EPA RBLC process codes, we evaluated the cost for the installation of a collection system that could be used to route the vents from the marine vessel loading of molten sulfur, sulfuric acid, and phosphoric acid at the plant's dock to a PM emissions control device, such as a wet scrubber.

3.18.2 Step 2 – Eliminate Technically Infeasible Options

As indicated in Step 1, we have assumed that an emissions control system comprised of a vent collection component and an associated emissions control device is technically feasible for the control of PM emissions for Dock Fugitive Emissions (EPN S-DockFug, FUG 0004).

3.18.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

We have estimated that an emissions control system comprised of a vent collection component and an associated emissions control device would reduce PM emissions for Dock Fugitive Emissions (EPN S-DockFug, FUG 0004) by 95%.

3.18.4 Step 4 – Evaluate Impacts and Document the Results

Dock Fugitive Emissions (EPN S-DockFug, FUG 0004) is permitted for a molten sulfur loading rate of 201,600 ltpy, or approximately 553 ltpd when this annual amount is equally distributed over 365 days per year. The venting that occurs from loading this amount of molten sulfur into marine vessels at the plant is believed to be conservatively represented by the molten sulfur storage tanks that may be located at a 10 ltpd or more sulfur recovery plant at a petroleum refinery.

As indicated by the EPA as part of the recent rulemaking process for 40 CFR part 60, subpart Ja, the capital cost for the installation and operation of a vent collection system on the molten sulfur storage tanks downstream of the molten sulfur pits at a model 10 ltpd sulfur recovery plant, the smallest model sulfur recovery plant evaluated by the EPA, was estimated to be approximately $80,000, while the annualized cost for this system was estimated to be approximately $24,000 per year.[23] Note that we do not believe these cost estimates include the cost for the installation and operation of an emissions control device, such as a wet scrubber. Instead, it appears EPA's evaluation assumed that the collected vents would be routed to the model petroleum refinery's sulfur recovery plant for processing into sulfur rather than being routed to a newly installed emissions control device. Furthermore, the use of this cost information does not take into account any additional costs that may be required for the vent collection system due to other technical factors that may be introduced by the need to also handle sulfuric acid PM and phosphoric acid PM or due to extra technical factors associated with the dock and marine vessel features of this scenario.

If we conservatively assume that a $24,000 per year vent collection system, as estimated by the EPA, would result in a 95% reduction in the 0.97 tpy potential to emit PM emission rate for Dock Fugitive Emissions (EPN S-DockFug, FUG 0004), then a 0.92 tpy PM emissions reduction at an annual cost of $24,000 would result in a cost effectiveness of approximately $26,087 per ton, which is an amount that we do not believe to be cost effective. Again, this $24,000 per year cost estimate does not include the capital and operating costs that would be associated with the necessary installation of a PM emissions control device at the plant. Thus, the installation of a vent collection system <u>and</u> a PM emissions control device would be even less cost effective.

[23] Kristin Parrish, RTI International to Bob Lucas, EPA. *Memorandum: Final Impacts Analysis for SO_2 Emissions from Sulfur Recovery Plants*. March 17, 2008. p. 6-7.

Our determination that it would not be cost effective to install and operate a vent collection and control system for the loading of molten sulfur into marine vessels at the plant, as well as for the loading of sulfuric acid and phosphoric acid into marine vessels at the plant, is consistent with EPA's determination that molten sulfur loading facilities located after the molten sulfur pits of a sulfur recovery plant at a petroleum refinery are not required to be controlled for 40 CFR part 60, subpart Ja purposes because it is not cost effective to control the emissions from such loading facilities.

Because a vent collection and control system was determined not to be cost effective for Dock Fugitive Emissions (EPN S-DockFug, FUG 0004), Mosaic proposes that current design and operations represent BART for PM emissions from this emissions unit.

3.19 Dock Fugitive Emissions (EPN S-DockFug, FUG 0004) SO_2 BART Analysis

During the loading of molten sulfur into marine vessels at the plant's dock, the displaced vapor from these vessels is vented to the atmosphere. This displaced vapor contains SO_2. Therefore, SO_2 emissions result from the loading of molten sulfur into marine vessels at the plant's dock.

3.19.1 Step 1 – Identify All Available Retrofit Control Technologies

We searched under the following process codes included in the EPA's RBLC for any SO_2 emissions control technology determinations made after January 1, 2005 for molten sulfur loading and did not identify any such determination.

- Process Code 50.006 – Petroleum/Natural Gas Production and Refining; Petroleum Refining Treating Processes (hydrotreating, acid gas removal, SRU's, etc.)
- Process Code 62.015 – Inorganic Chemicals Manufacturing; Sulfuric Acid Plants
- Process Code 62.019 – Inorganic Chemicals Manufacturing; Sulfur Recovery (except 50.006)
- Process Code 62.020 – Inorganic Chemicals Manufacturing; Inorganic Liquid/Gas Storage & Handling

Although no SO_2 emissions control technology determinations were identified for molten sulfur loading under these EPA RBLC process codes, we evaluated the cost for the installation of a collection system that could be used to route the vents from the marine vessel loading of molten sulfur at the plant's dock to an SO_2 emissions control device, such as a wet scrubber.

3.19.2 Step 2 – Eliminate Technically Infeasible Options

As indicated in Step 1, we have assumed that an emissions control system comprised of a vent collection component and an associated emissions control device is technically feasible for the control of SO_2 emissions for Dock Fugitive Emissions (EPN S-DockFug, FUG 0004).

3.19.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

We have estimated that an emissions control system comprised of a vent collection component and an associated emissions control device would reduce SO_2 emissions for Dock Fugitive Emissions (EPN S-DockFug, FUG 0004) by 95%.

3.19.4 Step 4 – Evaluate Impacts and Document the Results

Dock Fugitive Emissions (EPN S-DockFug, FUG 0004) is permitted for a molten sulfur loading rate of 201,600 ltpy, or approximately 553 ltpd when this annual amount is equally distributed over 365 days per year. As indicated above in Section 3.18.4, the venting that occurs from loading this amount of molten sulfur into marine vessels at the plant is believed to be conservatively represented by the molten sulfur storage tanks that may be located at a 10 ltpd or more sulfur recovery plant at a petroleum refinery.

As presented above in Section 3.18.4, the EPA estimated a capital cost of approximately $80,000 for the installation and operation of a vent collection system on the molten sulfur storage tanks downstream of the molten sulfur pits at a model 10 ltpd sulfur recovery plant, while the annualized cost for this system was estimated by the EPA to be approximately $24,000 per year. As previously noted, we do not believe these cost estimates include the cost for the installation and operation of an emissions control device, such as a wet scrubber, because it appears EPA's evaluation assumed that the collected vents would be routed to the model petroleum refinery's sulfur recovery plant for processing into sulfur rather than being routed to a newly installed emissions control device.

If we conservatively assume that a $24,000 per year vent collection system, as estimated by the EPA, would result in a 95% reduction in the 0.014 tpy potential to emit SO_2 emission rate for Dock Fugitive Emissions (EPN S-DockFug, FUG 0004), then a 0.013 tpy SO_2 emissions reduction at an annual cost of $24,000 would result in a cost effectiveness of approximately $1,846,154 per ton, which is an amount that we do not believe to be cost effective.

Our determination that it would not be cost effective to install and operate a vent collection and control system for the loading of molten sulfur into marine vessels at the plant is consistent with EPA's determination that molten sulfur loading facilities located after the molten sulfur pits of a sulfur recovery plant at a petroleum refinery are not required to be controlled for 40 CFR part 60, subpart Ja purposes because it is not cost effective to control the emissions from such loading facilities.

Because a vent collection and control system was determined not to be cost effective for Dock Fugitive Emissions (EPN S-DockFug, FUG 0004), Mosaic proposes that current design and operations represent BART for SO_2 emissions from this emissions unit.

4 Visibility Impacts Analysis

The fifth and final step of a BART analysis is to determine the visibility improvement resulting from the application of BART on the emissions units constituting the particular BART-eligible source under review. For this BART analysis, the following three scenarios were analyzed to determine the visibility improvement resulting from the application of BART on the relevant emissions units at the plant.

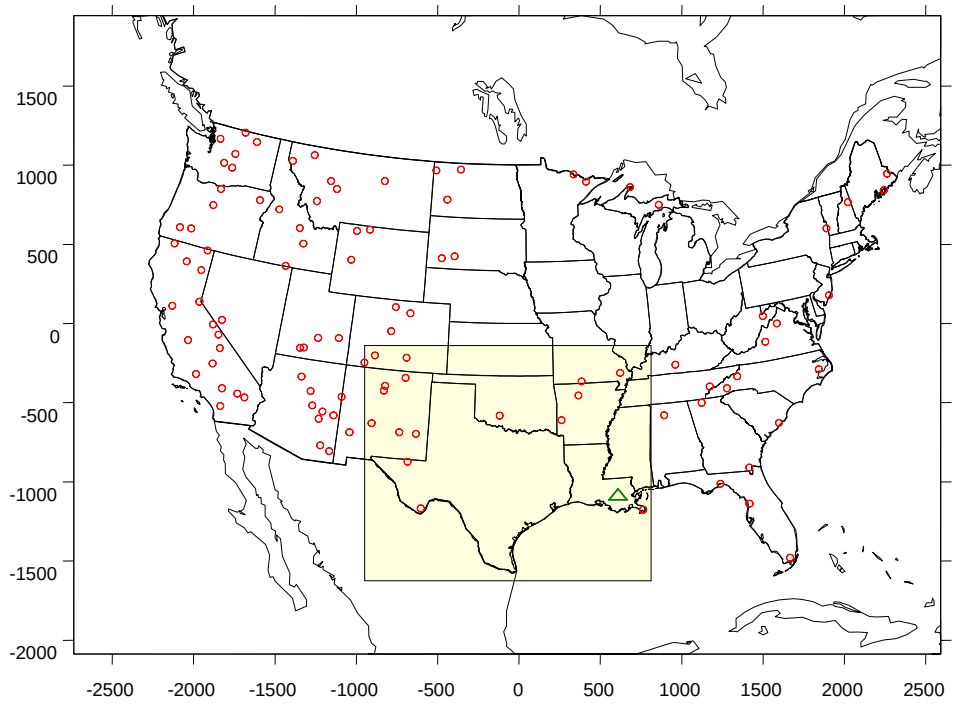
- "Baseline"
- "With BART"
- "With BART + D Train Wet Scrubber"

The "Baseline" scenario represents the emissions and characteristics of the BART-eligible emissions units prior to the application of BART. The "With BART" scenario represents the emissions and characteristics of the same emissions units after the application of BART, as demonstrated by Mosaic herein. Finally, the "With BART + D Train Wet Scrubber" scenario is the same as the "With BART" scenario, except certain stack characteristics and the SO_2 emission rate of the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) were altered as part of a demonstration to show that the installation of a wet scrubber on this emissions unit for SO_2 emissions reduction purposes does not represent BART for the unit because of the considerable cost necessary to construct and operate the wet scrubber on the unit relative to the limited visibility improvement estimated to result from the operation of the wet scrubber when compared to the "With BART" scenario.

4.1 Class I Areas

Figure 4.1 below shows the location of the Central States Regional Air Planning Association (CENRAP) South Domain (yellow box), Class I areas (red circles) and the plant (green triangle). Lambert Conformal Conic (LCC) projection coordinates are shown in this figure.

Figure 4.1: CENRAP South Domain



The plant is located approximately 180 kilometers (km) from the Breton Wilderness Area, the closest Class I area to the plant. There are no other Class I areas located within 300 km of the plant. The next closest Class I area to the plant is the Caney Creek Wilderness Area in Arkansas, which is located approximately 560 km away. As agreed to by the LDEQ, the visibility impacts modeling analysis performed for the plant is limited to the Breton Wilderness Area.

4.2 Air Quality Model and Inputs

We used the CALPUFF dispersion model to perform the visibility impacts modeling analysis. The CALPUFF dispersion model inputs and the meteorological processor used in this analysis are described below. The visibility impacts modeling analysis methods employed conform to LDEQ guidelines.

4.2.1 Modeling Domain

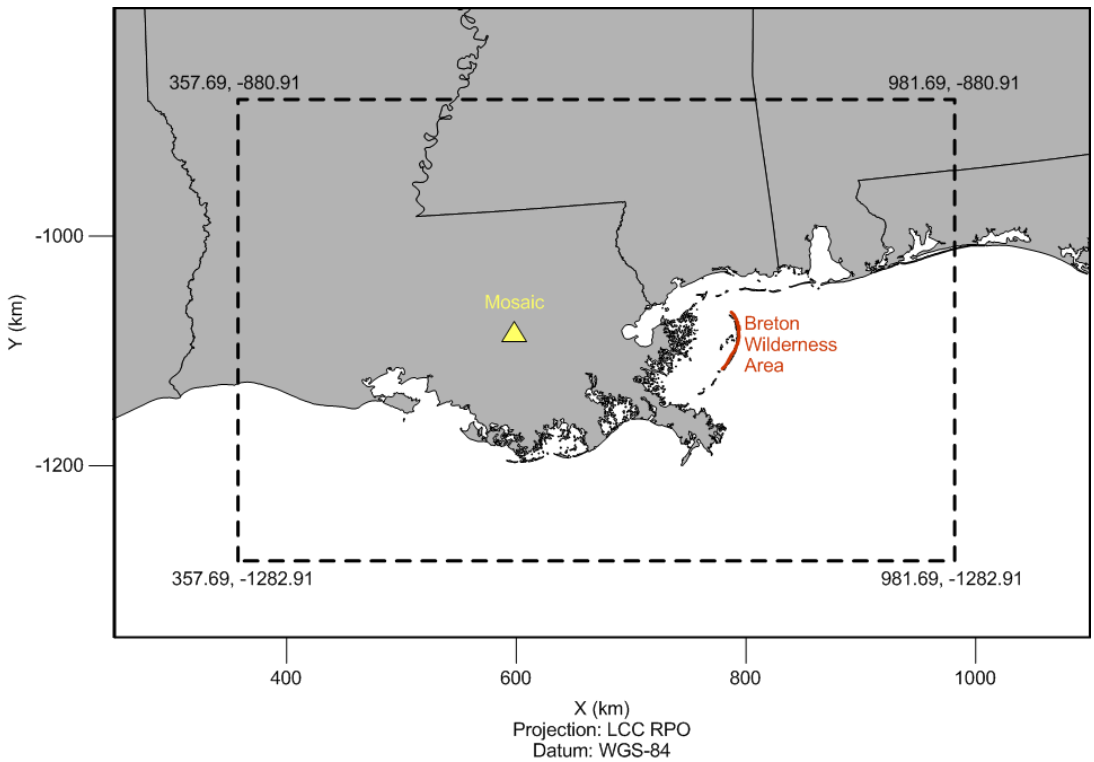
The visibility impacts modeling analysis was conducted on a portion of the CENRAP South Domain, using 6 km grid spacing. The domain extends at least 150 km to the east and south of the Breton Wilderness Area. The domain, in LCC "RPO" projection with the origin at 40°N, 97°W and true latitudes of 33°N and 45°N, are as follows.

- SW Corner (1,1): 357.69 km, -1282.92 km
- NX, NY: 104, 67
- DX, DY: 6 km, 6 km

- DATUM: WGS-84

Figure 4.2 below shows the location of the CALPUFF refined modeling domain (dashed box), the relevant Class I area (red area), and the plant (yellow triangle). The figure coordinates are in LCC projection.

Figure 4.2: CALPUFF Modeling Domain



4.2.2 Meteorological Modeling (CALMET)

For this modeling analysis, we used CALMET modeling data provided to us by the LDEQ in August 2015. These CALMET data files were submitted to the LDEQ by the Sid Richardson Carbon and Energy Company ("Sid Richardson") as part of the most recent BART exemption visibility modeling analysis that Sid Richardson performed for its Addis, Louisiana carbon black plant. The CALMET modeling domain used by Sid Richardson encompasses both the plant and the Breton Wilderness Area. Furthermore, the LDEQ and the EPA approved the CALMET data files that were most recently used by Sid Richardson. Therefore, these CALMET data files are appropriate to use in this visibility impacts modeling analysis.

4.2.3 CALPUFF System Implementation

There are three main components to the CALPUFF model:

- Meteorological Data Modeling (CALMET);
- Dispersion Modeling (CALPUFF); and

- Post-Processing (POSTUTIL/CALPOST).

The versions of the modeling components that were used in this modeling analysis are presented in Table 4.1. CALMM5 data was originally provided by CENRAP.

Table 4.1: CALPUFF Modeling Components

Processor	Version	Level
TERREL	3.311	30709
CTGCOMP	2.42	30709
CTGPROC	2.42	30709
MAKEGEO	2.22	30709
CALMM5	2.4	50413
CALMET	5.8.4	130731
CALPUFF	5.8.4	130731
POSTUTIL	1.56	70627
CALPOST	6.221	80724

In general, the default CALPUFF options were used in the visibility impacts modeling analysis. The 2001 baseline CALPUFF input control file, providing the ubiquitous model options for the "Baseline," "With BART," and "With BART + D Train Wet Scrubber" scenarios, is presented in Exhibit 11.

4.2.4 Emissions Unit Parameters

Only the emissions units constituting the BART-eligible source that emit BART relevant pollutants were included in the visibility impacts modeling analysis. There are 13 such emissions units in the "Baseline" scenario and 11 emissions units in the "With BART" and the "With BART + D Train Wet Scrubber" scenarios. Emissions unit parameters required for CALPUFF modeling are source location coordinates, stack height above ground, base elevation above sea level, inside stack diameter, exit gas flow rate, and exit gas temperature.

CENRAP and BART guidance recognize that downwash is important only at short distances (within 20 km) and recommends the use of building downwash algorithms for consistency purposes only if the data are available. Downwash data are not readily available for the plant and, given the considerable distance to the nearest Class I area (180 km), there are no technical reasons to include the effects of building downwash in this visibility modeling analysis.

The emissions unit parameters used in the "Baseline" scenario are presented below in Table 4.2.

Table 4.2: Emissions Unit Parameters – "Baseline" Scenario

Emissions Unit	LCC Coordinates X (km)	LCC Coordinates Y (km)	Stack Height (m)	Base Elevation (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp. (°K)
A Train Single Absorption H_2SO_4 Plant (EPN S-ATrain1, EQT 0067)	598.57	-1082.83	60.96	7.20	1.52	35.90	361.00
A Train Start-Up Burner (EPN S-ATrain2, EQT 0068)	598.57	-1082.84	10.36	7.20	0.76	55.78	366.48
A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002)	598.57	-1082.81	1.00	7.20	0.001	0.001	293.00
D Train Double Absorption H_2SO_4 Plant (EPN S-DTrain1, EQT 0074)	598.62	-1082.95	48.77	7.20	1.83	19.20	349.82
D Train Start-Up Burner (EPN S-DTrain2, EQT 0075)	598.62	-1082.95	9.14	7.20	0.76	54.86	355.37
D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003)	598.62	-1082.93	1.00	7.20	0.001	0.001	293.00
Rock Unloading, Handling, Storage, and Transfer (EPN S-Rock, EQT 0079)[24]	598.36	-1082.77	1.00	7.20	0.001	0.001	293.00
Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081)	598.48	-1082.80	1.01	7.20	0.34	0.03	405.37
Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082)	598.49	-1082.79	13.05	7.20	0.40	0.03	416.48
Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083)	598.50	-1082.83	12.77	7.20	0.40	0.03	416.48

[24] This emissions unit is referenced as Rock Unloading, Handling, Storage, and Transfer (EPN S-Rock, EQT 0079) in the "Baseline" scenario, while it is referenced as Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113) in the "With BART" and the "With BART + D Train Wet Scrubber" scenarios. The two references are close to representing the same emissions generating activities. In 2013, as part of a decision to group all phosphate rock transfer, storage, and handling emissions generating operations at the plant into a single source, Rock Unloading, Handling, Storage, and Transfer (EPN S-Rock, EQT 0079) was deleted from the plant's Title V permit and Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113) was added to the same permit.

Table 4.2: Emissions Unit Parameters – "Baseline" Scenario

Emissions Unit	LCC Coordinates X (km)	LCC Coordinates Y (km)	Stack Height (m)	Base Elevation (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp. (°K)
Dock Fugitive Emissions (EPN S-DockFug, FUG 0004)	597.97	-1082.89	1.00	7.20	0.001	0.001	293.00
No. 1 Packaged Steam Boiler (EPN S-Boiler1, EQT 0072)	598.68	-1082.81	19.81	7.20	1.83	22.10	672.00
No. 2 Packaged Steam Boiler (EPN S-Boiler2, EQT 0073)	598.67	-1082.79	19.81	7.20	1.83	22.10	672.00

The emissions unit parameters used in the "With BART" and the "With BART + D Train Wet Scrubber" scenarios are presented below in Table 4.3. Except for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074), the parameters for the emissions units are the same for the "With BART" and the "With BART + D Train Wet Scrubber" scenarios.

Table 4.3: Emissions Unit Parameters – "With BART" and "With BART + D Train Wet Scrubber" Scenarios

Emissions Unit	LCC Coordinates X (km)	LCC Coordinates Y (km)	Stack Height (m)	Base Elevation (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp. (°K)
A Train Single Absorption H_2SO_4 Plant (EPN S-ATrain1, EQT 0067)	598.57	-1082.83	45.72	7.20	1.83	19.51	307.04
A Train Start-Up Burner (EPN S-ATrain2, EQT 0068)	598.57	-1082.84	10.36	7.20	0.76	55.78	366.48
A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002)	598.57	-1082.81	1.00	7.20	0.001	0.001	293.00
D Train Double Absorption H_2SO_4 Plant (EPN S-DTrain1, EQT 0074)[25]	598.62 **[598.62]**	-1082.95 **[-1082.95]**	48.77 **[48.77]**	7.20 **[7.20]**	1.83 **[1.83]**	19.20 **[16.85]**	349.82 **[307.04]**

[25] The values without brackets are the stack parameters used in the "With BART" scenario. The bold values in brackets are the stack parameters used in the "With BART + D Train Wet Scrubber" scenario. The exit temperature used in the "With BART + D Train Wet Scrubber" scenario was estimated to equal the exit temperature used for the A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) in the "With BART" scenario because the A Train

Table 4.3: Emissions Unit Parameters – "With BART" and "With BART + D Train Wet Scrubber" Scenarios

Emissions Unit	LCC Coordinates X (km)	LCC Coordinates Y (km)	Stack Height (m)	Base Elevation (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp. (°K)
D Train Start-Up Burner (EPN S-DTrain2, EQT 0075)	598.62	-1082.95	9.14	7.20	0.76	54.86	355.37
D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003)	598.62	-1082.93	1.00	7.20	0.001	0.001	293.00
Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113)[26]	598.36	-1082.77	1.00	7.20	0.001	0.001	293.00
Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081)	598.48	-1082.80	1.01	7.20	0.34	0.03	405.37
Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082)	598.49	-1082.79	13.05	7.20	0.40	0.03	416.48
Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083)	598.50	-1082.83	12.77	7.20	0.40	0.03	416.48
Dock Fugitive Emissions (EPN S-DockFug, FUG 0004)	597.97	-1082.89	1.00	7.20	0.001	0.001	293.00
No. 1 Packaged Steam Boiler (EPN S-Boiler1, EQT 0072)[27]	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) is equipped with a wet scrubber in the "With BART" scenario.

[26] This emissions unit is referenced as Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113) in the "With BART" and the "With BART + D Train Wet Scrubber" scenarios, while it is referenced as Rock Unloading, Handling, Storage, and Transfer (EPN S-Rock, EQT 0079) in the "Baseline" scenario. The two references are close to representing the same emissions generating activities. In 2013, as part of a decision to group all phosphate rock transfer, storage, and handling emissions generating operations at the plant into a single source, Rock Unloading, Handling, Storage, and Transfer (EPN S-Rock, EQT 0079) was deleted from the plant's Title V permit and Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113) was added to the same permit.

[27] The No. 1 Packaged Steam Boiler (EPN S-Boiler1, EQT 0072) was shut down and removed from the plant's Title V permit with the issuance of Permit No. 2560-00004-V2 on March 20, 2013. Therefore, this emissions unit was not included in the "With BART" and the "With BART + D Train Wet Scrubber" scenarios.

Table 4.3: Emissions Unit Parameters – "With BART" and "With BART + D Train Wet Scrubber" Scenarios

Emissions Unit	LCC Coordinates		Stack Height (m)	Base Elevation (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp. (°K)
	X (km)	Y (km)					
No. 2 Packaged Steam Boiler (EPN S-Boiler2, EQT 0073)[28]	N/A	N/A	N/A	N/A	N/A	N/A	N/A

4.2.5 Emission Rates

LDEQ and CENRAP guidance identifies the following priority approach for determining maximum 24-hour actual emission rates to be used in a BART visibility impacts modeling analysis:

1. Continuous emissions monitoring (CEMs) data;
2. Facility emissions tests;
3. Emission factors;
4. Permit limits; or lastly,
5. Potential to emit.

Except as follows, for the "Baseline" scenario, worst-case 24-hour emissions were estimated to equal relevant hourly maximum or maximum 3-hour rolling average potential to emit emission rates listed for the BART-eligible emissions units in Permit No. 2560-00004-V1, which are the maximum short-term potential to emit rates in effect before the application of the proposed BART controls.

- A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067) PM_{10} emission rate: Permit No. 2560-00004-V1 does not list any potential to emit PM_{10} emission rates for the emissions unit. Therefore, we estimated an hourly maximum potential to emit PM_{10} emission rate for the unit using the same methodology that was used to estimate the hourly maximum potential to emit PM_{10} emission rate listed for the unit in Permit No. 2560-00004-V2. Specifically, we estimated the emissions unit's hourly maximum potential to emit PM_{10} emission rate to equal 67.2% of the hourly maximum potential to emit sulfuric acid emission rate listed for the unit in Permit No. 2560-00004-V1.
- D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) PM_{10} emission rate: Permit No. 2560-00004-V1 does not list any potential to emit PM_{10} emission rates

[28] The No. 2 Packaged Steam Boiler (EPN S-Boiler2, EQT 0073) was shut down and removed from the plant's Title V permit with the issuance of Permit No. 2560-00004-V2 on March 20, 2013. Therefore, this emissions unit was not included in the "With BART" and the "With BART + D Train Wet Scrubber" scenarios.

for the emissions unit. Therefore, we estimated an hourly maximum potential to emit PM_{10} emission rate for the unit using the same methodology that was used to estimate the hourly maximum potential to emit PM_{10} emission rate listed for the unit in Permit No. 2560-00004-V2. Specifically, we estimated the emissions unit's hourly maximum potential to emit PM_{10} emission rate to equal 67.2% of the hourly maximum potential to emit sulfuric acid emission rate listed for the unit in Permit No. 2560-00004-V1.

- $PM_{2.5}$ emission rates for all BART-eligible emissions units, except for Rock Unloading, Handling, Storage, and Transfer (EPN S-Rock, EQT 0079), Dock Fugitive Emissions (EPN S-DockFug, FUG 0004), No. 1 Packaged Steam Boiler (EPN S-Boiler1, EQT 0072), and No. 2 Packaged Steam Boiler (EPN S-Boiler2, EQT 0073): Permit No. 2560-00004-V1 does not list potential to emit $PM_{2.5}$ emission rates for these BART-eligible emissions units. Therefore, we estimated an hourly maximum potential to emit $PM_{2.5}$ emission rate for each of the units using the same methodology that was used to estimate the hourly maximum potential to emit $PM_{2.5}$ emission rate listed for the relevant unit in Permit No. 2560-00004-V2.

- Rock Unloading, Handling, Storage, and Transfer (EPN S-Rock, EQT 0079) $PM_{2.5}$ emission rate: Permit No. 2560-00004-V1 does not list any potential to emit $PM_{2.5}$ emission rates for the emissions unit. Therefore, we conservatively estimated the unit's hourly maximum potential to emit $PM_{2.5}$ emission rate to equal the hourly maximum potential to emit PM_{10} emission rate listed for the unit in Permit No. 2560-00004-V1.

- Dock Fugitive Emissions (EPN S-DockFug, FUG 0004) $PM_{2.5}$ emission rate: Permit No. 2560-00004-V1 does not list any potential to emit $PM_{2.5}$ emission rates for the emissions unit. Therefore, we conservatively estimated the unit's hourly maximum potential to emit $PM_{2.5}$ emission rate to equal the hourly maximum potential to emit PM_{10} emission rate listed for the unit in Permit No. 2560-00004-V1.

- No. 1 Packaged Steam Boiler (EPN S-Boiler1, EQT 0072) $PM_{2.5}$ emission rate: Permit No. 2560-00004-V1 does not list any potential to emit $PM_{2.5}$ emission rates for the emissions unit. Therefore, we conservatively estimated the unit's hourly maximum potential to emit $PM_{2.5}$ emission rate to equal the hourly maximum potential to emit PM_{10} emission rate listed for the unit in Permit No. 2560-00004-V1.

- No. 2 Packaged Steam Boiler (EPN S-Boiler2, EQT 0073) $PM_{2.5}$ emission rate: Permit No. 2560-00004-V1 does not list any potential to emit $PM_{2.5}$ emission rates for the emissions unit. Therefore, we conservatively estimated the unit's hourly maximum potential to emit $PM_{2.5}$ emission rate to equal the hourly maximum potential to emit PM_{10} emission rate listed for the unit in Permit No. 2560-00004-V1.

Except as follows, for the "With BART" scenario, worst-case 24-hour emissions were estimated to equal relevant hourly maximum or maximum 3-hour rolling average potential to emit emission rates listed for the BART-eligible emissions units in Permit No. 2560-00004-V2, which are the maximum short-term potential to emit rates in effect after the application of the proposed BART controls.

- A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002) SO_2 emission rate: Permit No. 2560-00004-V2 does not list an hourly maximum potential to emit SO_2 emission rate for the emissions unit. However, an hourly maximum potential to emit SO_2 emission rate was represented for the unit in the permit application that resulted in the issuance of Permit No. 2560-00004-V2. Therefore, we used this hourly maximum potential to emit SO_2 emission rate for the unit.

- D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003) SO_2 emission rate: Permit No. 2560-00004-V2 does not list an hourly maximum potential to emit SO_2 emission rate for the emissions unit. However, an hourly maximum potential to emit SO_2 emission rate was represented for the unit in the permit application that resulted in the issuance of Permit No. 2560-00004-V2. Therefore, we used this hourly maximum potential to emit SO_2 emission rate for the unit.

The emission rates for the "With BART + D Train Wet Scrubber" scenario are the same as those for the "With BART" scenario, except for the following.

- D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) SO_2 emission rate: The SO_2 emission rate for this emissions unit in the "With BART + D Train Wet Scrubber" scenario was calculated by estimating the wet scrubber would achieve a 95% reduction in the SO_2 emission rate documented for the emissions unit in the "With BART" scenario.

For the three visibility model scenarios, it was very conservative to assume that respective hourly maximum or maximum 3-hour rolling average potential to emit emission rates would occur the entire day for each day of the year for each BART-eligible emissions unit.

Table 4.4 below summarizes the NOx, PM_{10}, $PM_{2.5}$, and SO_2 emission rates modeled in the "Baseline," "With BART," and "With BART + D Train Wet Scrubber" scenarios.

Table 4.4: Emissions Unit Emission Rates – "Baseline," "With BART," and "With BART + D Train Wet Scrubber" Scenarios

	NOx (lb/hr)		PM_{10} (lb/hr)		$PM_{2.5}$ (lb/hr)		SO_2 (lb/hr)	
Emissions Unit	**"Baseline"**	**"With BART"/ "With BART + D Train Wet Scrubber"**	**"Baseline"**	**"With BART"/ "With BART + D Train Wet Scrubber"**	**"Baseline"**	**"With BART"/ "With BART + D Train Wet Scrubber"**	**"Baseline"**	**"With BART"/ "With BART + D Train Wet Scrubber"**
A Train Single Absorption H_2SO_4 Plant (EPN S-ATrain1, EQT 0067)	10.00	11.00	28.00	9.24	15.29	5.05	2,250.16	91.67
A Train Start-Up Burner (EPN S-ATrain2, EQT 0068)	32.31	32.94	0.88	0.89	0.88	0.89	0.07	0.07

Table 4.4: Emissions Unit Emission Rates – "Baseline," "With BART," and "With BART + D Train Wet Scrubber" Scenarios

Emissions Unit	NOx (lb/hr)		PM_{10} (lb/hr)		$PM_{2.5}$ (lb/hr)		SO_2 (lb/hr)	
	"Baseline"	"With BART"/ "With BART + D Train Wet Scrubber"	"Baseline"	"With BART"/ "With BART + D Train Wet Scrubber"	"Baseline"	"With BART"/ "With BART + D Train Wet Scrubber"	"Baseline"	"With BART"/ "With BART + D Train Wet Scrubber"
A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002)	N/A	N/A	N/A	N/A	N/A	N/A	115.69	115.08
D Train Double Absorption H_2SO_4 Plant (EPN S-DTrain1, EQT 0074)[29]	11.25	11.25 **[11.25]**	9.45	9.45 **[9.45]**	5.16	5.16 **[5.16]**	375.00	328.13 **[16.41]**
D Train Start-Up Burner (EPN S-DTrain2, EQT 0075)	32.31	32.94	0.88	0.89	0.88	0.89	0.07	0.07
D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003)	N/A	N/A	N/A	N/A	N/A	N/A	186.88	185.91
Rock Unloading, Handling, Storage, and Transfer (EPN S-Rock, EQT 0079)/ Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113)	N/A	N/A	1.81	5.68	1.81	0.79	N/A	N/A
Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081)	N/A	N/A	0.44	0.44	0.13	0.13	0.13	0.13
Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082)	N/A	N/A	0.98	0.98	0.29	0.29	0.28	0.28
Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083)	N/A	N/A	0.98	0.98	0.29	0.29	0.28	0.28

[29] The values without brackets are the emission rates used in the "With BART" scenario. The bold values in brackets are the emission rates used in the "With BART + D Train Wet Scrubber" scenario. The "With BART + D Train Wet Scrubber" scenario SO_2 emission rate was calculated by estimating the wet scrubber would achieve a 95% reduction in the "With BART" scenario SO_2 emission rate.

Table 4.4: Emissions Unit Emission Rates – "Baseline," "With BART," and "With BART + D Train Wet Scrubber" Scenarios

Emissions Unit	NOx (lb/hr)		PM_{10} (lb/hr)		$PM_{2.5}$ (lb/hr)		SO_2 (lb/hr)	
	"Baseline"	"With BART"/ "With BART + D Train Wet Scrubber"	"Baseline"	"With BART"/ "With BART + D Train Wet Scrubber"	"Baseline"	"With BART"/ "With BART + D Train Wet Scrubber"	"Baseline"	"With BART"/ "With BART + D Train Wet Scrubber"
Dock Fugitive Emissions (EPN S-DockFug, FUG 0004)	N/A	N/A	0.69	1.16	0.69	0.59	0.14	0.14
No. 1 Packaged Steam Boiler (EPN S-Boiler1, EQT 0072)	43.08	0	1.17	0	1.17	0	0.09	0
No. 2 Packaged Steam Boiler (EPN S-Boiler2, EQT 0073)	43.08	0	1.17	0	1.17	0	0.09	0

The species included in the visibility impacts modeling analysis are listed in Table 4.5 below.

Table 4.5: Species Included in the Visibility Impacts Modeling Analysis

Species	Modeled?	Directly Emitted?	Mode of Use
SO_2	Yes	Yes	Computed-gas
Particulate Sulfate (SO_4)	Yes	Yes	Computed-particle
NOx	Yes	Yes	Computed-gas
Nitric Acid (HNO_3)	Yes	No	Computed-gas
Particulate Nitrate (NO_3)	Yes	Yes	Computed-particle
Particulate Elemental Carbon (EC)	Yes	Yes	Computed-particle
Particulate Organic Carbon (OC)	Yes	Yes	Computed-particle
Fine Particulate Matter (PMF), ("$PM_{2.5}$")	Yes	Yes	Computed-particle
Coarse Particulate Matter (PMC), ("$PM_{10-2.5}$")	Yes	Yes	Computed-particle

Source classification codes (SCCs) and output from the Sparse Matrix Operator Kernel Emissions (SMOKE) program were used to refine the estimate of PM species into SO_4, NO_3,

EC, OC, and unspecified fine particulate matter (PMF). CALPUFF computes concentrations of HNO_3. The select SMOKE profiles used for each emissions unit in this visibility impacts modeling analysis are provided in Table 4.6.

Table 4.6: SMOKE Profiles Used in the Visibility Impacts Modeling Analysis

Emissions Unit	SCC	SMOKE
A Train Single Absorption H_2SO_4 Plant (EPN S-ATrain1, EQT 0067)	30102304	22013
A Train Start-Up Burner (EPN S-ATrain2, EQT 0068)	10200602	22004
A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002)	30102322	22013
D Train Double Absorption H_2SO_4 Plant (EPN S-DTrain1, EQT 0074)	30102304	22013
D Train Start-Up Burner (EPN S-DTrain2, EQT 0075)	10200602	22004
D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003)	30102322	22013
Rock Unloading, Handling, Storage, and Transfer (EPN S-Rock, EQT 0079)/ Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113)	30501903	22040
Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081)	30103205[30]	22013
Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082)	30103205	22013
Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083)	30103205	22013
Dock Fugitive Emissions (EPN S-DockFug, FUG 0004)	30102399	22013
No. 1 Packaged Steam Boiler (EPN S-Boiler1, EQT 0072)	10200601	22004
No. 2 Packaged Steam Boiler (EPN S-Boiler2, EQT 0073)	10200601	22004

Particle size parameters are used by the CALPUFF model for dry and wet deposition of particles. Default values for "aerosol" species (e.g., SO_4, NO_3, and $PM_{2.5}$) of 0.48 µm geometric mass mean diameter and 2.0 µm geometric standard deviation were used in this analysis.

[30] SCC 30103205, which applies to the Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081), Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082), and Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083), does not correspond to a SMOKE profile. Therefore, the SMOKE profile used for these emissions units is the same profile that applies to Dock Fugitive Emissions (EPN S-DockFug, FUG 0004).

Table 4.7 below summarizes the emission rates input into the CALPUFF model for the "Baseline" scenario.

Table 4.7: Modeled Emission Rates (g/s) – "Baseline" Scenario

Emissions Unit	SO_2	SO_4	NOx	HNO_3	NO_3	EC	OC	PMC	PMF
A Train Single Absorption H_2SO_4 Plant (EPN S-ATrain1, EQT 0067)	283.52	0.044	1.26	0	5.23E-03	0	0	1.60	1.86
A Train Start-Up Burner (EPN S-ATrain2, EQT 0068)	0.0088	0.016	4.07	0	4.73E-04	0	0.067	0	0.022
A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002)	14.58	0	0	0	0	0	0	0	0
D Train Double Absorption H_2SO_4 Plant (EPN S-DTrain1, EQT 0074)	47.25	0.015	1.42	0	1.76E-03	0	0	0.54	0.63
D Train Start-Up Burner (EPN S-DTrain2, EQT 0075)	0.0088	0.016	4.07	0	4.73E-04	0	0.067	0	0.022
D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003)	23.55	0	0	0	0	0	0	0	0
Rock Unloading, Handling, Storage, and Transfer (EPN S-Rock, EQT 0079)	0	0.023	0	0	4.77E-04	3.35E-04	0.014	0	0.18
Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081)	0.016	3.73E-04	0	0	4.44E-05	0	0	0.039	0.016
Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082)	0.035	8.32E-04	0	0	9.91E-05	0	0	0.087	0.035
Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083)	0.035	8.32E-04	0	0	9.91E-05	0	0	0.087	0.035
Dock Fugitive Emissions (EPN S-DockFug, FUG 0004)	0.018	1.98E-03	0	0	2.36E-04	0	0	0	0.084
No. 1 Packaged Steam Boiler (EPN S-Boiler1, EQT 0072)	0.011	0.021	5.43	0	6.28E-04	0	0.088	0	0.029
No. 2 Packaged Steam Boiler (EPN S-Boiler2, EQT 0073)	0.011	0.021	5.43	0	6.28E-04	0	0.088	0	0.029

Table 4.8 below summarizes the emission rates input into the CALPUFF model for the "With BART" and the "With BART + D Train Wet Scrubber" scenarios. Except for the D Train Double

Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074), the emission rates for the emissions units are the same for the "With BART" and the "With BART + D Train Wet Scrubber" scenarios.

Table 4.8: Modeled Emission Rates (g/s) – "With BART" and "With BART + D Train Wet Scrubber" Scenarios

Emissions Unit	SO_2	SO_4	NOx	HNO_3	NO_3	EC	OC	PMC	PMF
A Train Single Absorption H_2SO_4 Plant (EPN S-ATrain1, EQT 0067)	11.55	0.014	1.39	0	1.73E-03	0	0	0.53	0.61
A Train Start-Up Burner (EPN S-ATrain2, EQT 0068)	0.0088	0.016	4.15	0	4.78E-04	0	0.067	0	0.022
A Train Fugitive Emissions (EPN S-ATrain3, FUG 0002)	14.50	0	0	0	0	0	0	0	0
D Train Double Absorption H_2SO_4 Plant (EPN S-DTrain1, EQT 0074)[31]	41.34 **[2.07]**	0.015 **[0.015]**	1.42 **[1.42]**	0 **[0]**	1.76E-03 **[1.76E-03]**	0 **[0]**	0 **[0]**	0.54 **[0.54]**	0.63 **[0.63]**
D Train Start-Up Burner (EPN S-DTrain2, EQT 0075)	0.0088	0.016	4.15	0	4.78E-04	0	0.067	0	0.022
D Train Fugitive Emissions (EPN S-DTrain3, FUG 0003)	23.42	0	0	0	0	0	0	0	0
Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113)	0	0.010	0	0	2.08E-04	1.46E-03	6.28E-03	0.62	0.078
Sulfur Unloading Pit (EPN S-SulfurPit, EQT 0081)	0.016	3.73E-04	0	0	4.44E-05	0	0	0.039	0.016
Sulfur Storage Tank A (EPN S-SulfurA, EQT 0082)	0.035	8.32E-04	0	0	9.91E-05	0	0	0.087	0.035
Sulfur Storage Tank B (EPN S-SulfurB, EQT 0083)	0.035	8.32E-04	0	0	9.91E-05	0	0	0.087	0.035
Dock Fugitive Emissions (EPN S-DockFug, FUG 0004)	0.018	1.69E-03	0	0	2.02E-04	0	0	0.072	0.072

[31] The values without brackets are the emission rates used in the "With BART" scenario. The bold values in brackets are the emission rates used in the "With BART + D Train Wet Scrubber" scenario. The "With BART + D Train Wet Scrubber" scenario SO_2 emission rate was calculated by estimating the wet scrubber would achieve a 95% reduction in the "With BART" scenario SO_2 emission rate.

Table 4.8: Modeled Emission Rates (g/s) – "With BART" and "With BART + D Train Wet Scrubber" Scenarios

Emissions Unit	SO_2	SO_4	NOx	HNO_3	NO_3	EC	OC	PMC	PMF
No. 1 Packaged Steam Boiler (EPN S-Boiler1, EQT 0072)	0	0	0	0	0	0	0	0	0
No. 2 Packaged Steam Boiler (EPN S-Boiler2, EQT 0073)	0	0	0	0	0	0	0	0	0

4.2.6 Ozone and Ammonia Concentrations

Ozone and ammonia concentrations may be input into the CALPUFF model as either hourly or monthly background values. All of the ozone data used in the visibility impacts modeling analysis was acquired from the EPA. Ammonia concentrations were assumed to be temporally and spatially invariant and were fixed at 3 parts per billion across the entire modeling domain for all months.

4.2.7 Receptors

Receptors are locations where model results are calculated and are provided in the CALPUFF output files. Receptor locations were derived from the National Park Service (NPS) Class I area receptor database.[32]

4.2.8 Post-Processing (POSTUTIL and CALPOST)

CALPUFF modeling results are in units of micrograms per cubic meter ($\mu g/m^3$). For this modeling analysis, the hourly concentration outputs from the CALPUFF model were processed using POSTUTIL and CALPOST to determine impacts on visibility. POSTUTIL uses the output concentration file from CALPUFF and recalculates the HNO_3 and NO_3 partition based on total available SO_4 and ammonia. The CALPUFF output files were post-processed using CALPOST to determine visibility impacts in dv. CALPOST uses the concentration file processed through POSTUTIL, along with relative humidity data, to perform visibility calculations. Examples of the POSTUTIL and CALPOST control file inputs are presented in Exhibit 11. These files demonstrate the options used for all scenarios.

Light extinction must be determined to calculate visibility. CALPOST has eight methods for computing light extinction. In this modeling analysis, we used Method 8, which computes extinction from speciated PM with monthly Class I area-specific relative humidity adjustment factors capped at 95%. Relative humidity adjustment factors [*f*(RH)s] were applied to SO_4 and

[32] http://www2.nature.nps.gov/air/maps/receptors/index.cfm.

NO_3 concentration outputs from CALPUFF. Relative humidity adjustment factors were obtained from FLAG (2010).[33]

Perceived visibility obscuration in dv is derived from the light extinction coefficient. The visibility change related to background is calculated using the modeled and established natural visibility conditions. For this modeling analysis, daily visibility is expressed as a change in dv compared to natural visibility conditions. Natural visibility conditions for the Breton Wilderness Area were based on the annual average natural levels of aerosol components documented for this Class I area in FLAG (2010).

4.3 Visibility Impacts Analysis Results

The results of the visibility impacts modeling analysis are summarized in Table 4.9 below.

Table 4.9: Summary of Visibility Impacts Modeling Analysis Results (deciviews)

Visibility Impairment Impact Ranking	"Baseline"			"With BART"			"With BART + D Train Wet Scrubber"		
	2001	2002	2003	2001	2002	2003	2001	2002	2003
1st Highest	1.264	2.544	1.284	0.326	0.699	0.312	0.183	0.385	0.187
2nd Highest	1.108	1.669	1.139	0.292	0.421	0.293	0.166	0.258	0.173
3rd Highest	1.083	1.666	0.925	0.253	0.381	0.281	0.155	0.229	0.157
4th Highest	0.869	1.428	0.902	0.209	0.378	0.271	0.127	0.204	0.156
5th Highest	0.859	1.229	0.842	0.207	0.366	0.206	0.124	0.177	0.121
6th Highest	0.773	1.178	0.833	0.203	0.272	0.191	0.117	0.139	0.113
7th Highest	0.732	0.966	0.799	0.196	0.225	0.178	0.106	0.127	0.104
8th Highest (98th Percentile)	***0.565***	***0.895***	***0.711***	***0.148***	***0.214***	***0.172***	***0.094***	***0.120***	***0.103***

As demonstrated by these results, the 8th highest daily visibility impairment impacts at the Breton Wilderness Area for the "With BART" scenario are considerably below 0.5 dv, the visibility threshold value indicating whether a BART-eligible source would individually cause or contribute to visibility impairment at a Class I area. Additionally, a comparison of the visibility impacts modeling results for the "Baseline" scenario and the "With BART" scenario indicates that the BART controls proposed for the BART-eligible emissions units at the plant significantly reduce any visibility impairment that may occur at the Breton Wilderness Area as a result of the operation of these units.

[33] United States Forest Service - Air Quality Program, National Park Service - Air Resources Division, and United States Fish and Wildlife Service - Air Quality Branch. *Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report – Revised*. October 2010.

In regard to the "With BART + D Train Wet Scrubber" scenario, while the modeling results for this scenario indicate an improvement in visibility impairment at the Breton Wilderness Area comparative to the "With BART" scenario, Mosaic estimated that this relatively marginal improvement,[34] would require an additional capital investment of almost $25,000,000 and result in an annual cost of approximately $3,323,000. This additional capital investment would result in a cost effectiveness of approximately $347,222,222 per dv improvement over the "With BART" scenario.[35] Due to these high costs, as discussed in Section 3.10 herein, we do not believe it is cost effective to install and operate a wet scrubber on the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) for BART purposes. In sum, in consideration of the significant cost required for the installation and operation of a wet scrubber on the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074) and the relatively marginal visibility improvement estimated to result from the application of this technology on the same emissions unit, we do not believe a wet scrubber represents BART for the D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074).

An archive of the visibility impacts analysis modeling files is contained in Exhibit 11. In this exhibit is a flash drive with electronic copies of the CALPUFF input and output files used and created in this modeling analysis. Also, a table is included in the same exhibit explaining the file name structure for the electronic modeling files.

[34] The visibility improvement between the "With BART" and the "With BART + D Train Wet Scrubber" scenarios is, on average, only approximately 15% of the visibility improvement between the "Baseline" and the "With BART" scenarios.

[35] $25,000,000 / (0.178 dv - 0.106 dv) = $347,222,222/dv

Exhibit 1

January 14, 1991 Preconstruction Air Permit Application Requesting Authorization for the Construction of the E Train

R-5986

AGRICO
Division of Freeport-McMoRan Resource Partners

Agrico Chemical Company
A Division of Freeport-McMoRan Resource Partners,
Limited Partnership
Highway 44
Uncle Sam, LA 70792-9999

Harlan R. Chance
Plant Manager
Telephone: 504-562-3501

St. James

RECEIVED
JAN 17 1991
LA. DEPARTMENT OF
ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

requested Variance 2/91 BH

January 14, 1991

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Dr. Mike McDaniel
Assistant Secretary LDEQ
Air Quality Division
P. O. Box 44096
Baton Rouge, LA 70804

P 580 255 325

Dear Dr. McDaniel:

Enclosed please find a completed permit application submitted in consultation with members of your staff for Agrico's proposed "E" train sulfuric acid production plant at the company's Uncle Sam facility in St. James Parish.

We are proud to submit this application which, upon permit issuance and construction of "E" train, will result in the reduction of sulfur dioxide emissions by 52% and acid mist by 41% from this facility. These are major reductions representing expenditures of approximately $40 million by Agrico and Freeport-McMoRan. They are only part of the company's committment to St. James Parish and the State of Louisiana to continue operating in an environmentally and economically responsible manner. This commitment includes reductions of air emissions and water dischargers where they are meaningful and economically responsible.

These reductions are important to the company, the Parish and the State of Louisiana. The recently enacted reauthorization of the federal Clean Air Act which appeared in the Federal Register on November 15 of this year, particularly that section related to acid rain, provides for credits to the company and the State for reductions such as those involved in "E" train project. By this letter, we request the Louisiana DEQ take whatever measures are necessary and provided for under both State and Federal laws and regulations to "bank" these credits for Agrico and the State.

This is particularly important for our company's future ability to expand as well as the State's ability to provide for this expansion since the Clean Air Act renewal appears to establish a cap or ceiling at existing levels for sulfur dioxide and other emissions in the State. This cap can act to restrict future economic growth and it is important that we retain as much flexibility as possible.

Further, the Louisiana Department of Economic Development recently issued a Declaration of Emergency, Title 13, Part 1, Subpart 1. Finance; Chapter 21 Environmental Criteria for Rating Tax Exemptions. Section 2107, A.1. provides credits for emissions reduction projects as part of the industrial tax exemption program. We hereby request that the project described in the enclosed permit application be approved as a "DEQ approved emissions reduction plan" under the Declaration of Emergency.

By separate letter we have submitted computer modeling supporting the permit application and ask that it be appended to this application and reviewed together with the application.

If you have any questions concerning this material, please call Susan Stewart at 473-4271.

John Wylie (504) 562-3501 ext. 289

Sincerely,

Harlan R. Clare

HRC:wb
Attachments

cc: Mr. Gus Von Bodungen P 580 255 327
Mr. Larry Devillier P 580 255 326

Department of Environmental Quality
Air Quality Division
P.O. Box 44096
Baton Rouge, LA 70804
(504) 342-1206

LOUISIANA
Application for Approval of Emissions of Air Pollutants

RECEIVED JAN 1 LA. DEPT. OF ENVIRONMENTAL QUALITY AIR QUALITY DIVISION

1 Please Type or Print	Company Name: Agrico Chemical Company	For Permit Section Use Only
	Parent Company (if Company Name given above is a division): Freeport McMoRan Resource Partners	
	Plant name (if any): Uncle Sam Plant	
	Nearest town: Convent — Parish where located: St. James	

2 PROPOSED ACTION Give a brief description of proposed action. Attach flow diagrams, illustrations required to convey an understanding.

Construct a new double absorption Sulfuric Acid Plants("E" Train) which will replaces two existing Single-Absorption Sulfuric Acid Plant ("B" and "C" Trains).

3 OWNERSHIP AND USE OF ADJOINING PROPERTY [X] Map or description attached. Consult instructions

Ownership of the adjoining property is outlined on the attached map. Most of the surrounding properties are dedicated to Agriculture.

4 TYPE OF APPLICATION

- [ ] a. Entirely new facility
- [X] b. Modification or expansion of existing facility
- [ ] c. Reconciliation
- [X] d. Previously grandfathered or exempted

Note: A completed Emission Inventory Questionnaire (EIQ) that reflects projected emissions from your facility as a whole after the project described in this application becomes operational must be submitted with this application. If you are submitting an application that is for modification or expansion of an existing facility, the Department of Environmental Quality must also have an EIQ for existing emissions. If you have already submitted an EIQ that is on file with the Department, it may fulfil this requirement. Consult instructions for further details.

5. KEY DATES

Estimated date construction will commence: 3-1991 Estimated date operation will commence: 3-1992

8 PERSONNEL & CERTIFICATION

a. Manager of facility on location at plant site

Name	Harlan R. Chance
Title	Plant Manager
Company	Agrico Chemical Company
Suite, mail drop, or division	Uncle Sam Plant
Street or P.O. Box	
City / State / Zip	Uncle Sam / LA / 70792
Business phone	(504)562-3501

b. Person to contact at site about air pollution control

Name	John W. Wen
Title	Environmental Supervisor
Company	Agrico Chemical Company
Suite, mail drop, or division	
Business phone	(504) 562-3501

c. Headquarters or other off-site contact (see instructions)

Name	
Title	
Company	
Suite, mail drop, or division	
Street or P.O. Box	
City / State / Zip	
Business phone	

d. Person who prepared this report

☐ a ☒ b ☐ c ☐ other (specify below)

Name	John W. Wen
Title	Environmental Supervisor
Company	Agrico Chemical Company
Suite, mail drop, or division	Uncle Sam Plant
Street or P.O. Box	
City / State / Zip	Uncle Sam / LA / 70792
Business phone	(504) 562-3501

I certify, under the provisions in Louisiana and United States law which provide criminal penalties for false statements, that this Emission Inventory Questionnaire, including all attachments thereto, contains information which is true and correct to the best of my knowledge and belief.

Signature of manager or other company agent: Harlan R. Chance

Date: 1/15/91

Printed or typed name

9 HISTORY OF PERMITTED EMISSIONS

List each emission level from facility permits. Group by pollutant and show totals. Consult instructions.

Permit number	Date permit issued	Pollutant	Permitted Emission Rate (tons/yr)
A-B-C Single Absorption	1967	SO_2	2000 ppm *
Sulfuric Acid Plant			
Grandfathered			
*A-B-C trains were "Grandfathered" and do not have a			
permit. However, the three trains were operated under			
guideline of not exceeding 2000 ppm SO_2 by volume.			
D, Double Absorption	7/13/72	SO_2	1168 **
Sulfuric Acid Plant			
New Source Std.			
Permit No. 116		Sulfuric Acid Mist	44 **
**D train was permitted in 1972, based on new sulfuric			
acid train specified in 40 CFR Part 60 Subpart H, i.e.,			
4.0 lbs. SO_2/ton of 100% H_2SO_4 and 0.15 lb. of acid			
mist/ton of 100% H_2SO_4. The permitted emission rates are			
calculated based on 1600 T/Day H_2SO_4.			
A-B-C-D Trains	Refer to	Particular matter	0.01 ***
	* & **	Nitrogen Oxide	0.65 ***
		Carbon Monoxide	0.02 ***
		Total Hydrocarbon	0.001 ***
***These per train emissions were based on approximately 100 hours			
of heat-up per train per year using natural gas.			

8 EMISSION SOURCES
List each emission source. Use unique ID numbers. Consult instructions.

Source ID number	Descriptive name of source
13	Sulfuric Acid Plant, Contact Process
14	Not Applicable
15	Not Applicable
16	Sulfuric Acid Plant, Double Contact Process
37	Sulfuric Acid Plant, Double Contact Process

8 EMISSIONS BY POLLUTANT

List each emission from all sources. Group by pollutant. Show total tons/yr for each pollutant. Consult instructions.

Point Source ID number	Pollutant (List individual toxics and non-criteria hydrocarbons separately)	Permitted Emission Rate Before		Permitted Emission Rate After	
		lbs/hr	tons/yr	lbs/hr	tons/yr
13	Sulfur Dioxide	2138	9339	2,250	~~9,859~~ 9828.0
14		2138	9339	NA	NA
15		2138	9339	NA	NA
16		317	1385	334	1455
37		NA	NA	633	2766
	Total Sulfur Dioxide	6731	29,402	3,217	14,080
13	Sulfuric Acid Mist	40	175	41.7	182
14		40	175	NA	NA
15		40	175	NA	NA
16		12	53	12.6	55
37		NA	NA	23.8	104
	Total Sulfuric Acid Mist	132	578	78.1	341
13	SO_2 Fugitive	0.44	1.9	0.44	1.9
14		0.44	1.9	NA	NA
15		0.44	1.9	NA	NA
16		0.44	1.9	0.44	1.9
37		NA	NA	0.44	1.9
	Total SO_2 fugitive	1.76	7.6	1.32	5.7
13	SO_3 fugitive	1.0	4.4	1.0	4.4
14		1.0	4.4	NA	NA
15		1.0	4.4	NA	NA
16		1.0	4.4	1.0	4.4
37		NA	NA	1.0	4.4
	Total SO_3 fugitive	4.0	17.6	3.0	13.2
13	Particulates	0.2	0.01*	0.2	0.01*
14		0.2	0.01*	NA	NA
15		0.2	0.01*	NA	NA
16		0.2	0.01*	0.2	0.01*
37		NA	NA	0.62	0.015**
	Total Particulates	0.8	0.04	1.02	0.035
13	Nitrogen Oxide	13.4	0.65*	13.4	0.65*
14		13.4	0.65*	NA	NA
15		13.4	0.65*	NA	NA
16		13.4	0.65*	13.4	0.65*
37		NA	NA	43.3	1.04**
	Total Nitrogen Oxide	53.6	2.6	70.1	2.34
13	Hydrocarbons	0.02	0.001*	0.02	0.001*
14		0.02	0.001*	NA	NA
15		0.02	0.001*	NA	NA
16		0.02	0.001*	0.02	0.001*
37		NA	NA	0.062	0.0015**
	Total Hydrocarbons	0.08	0.004	0.102	0.0035

*Based on 100 hours heat-up utilizing natural gas.

**Based on 48 hours heat-up utilizing natural gas.

9 EMISSIONS BY POLLUTANT

List each emission from all sources. Group by pollutant. Show total tons/yr for each pollutant. Consult instructions.

Point Source ID number	Pollutant (List individual toxics and non-criteria hydrocarbons separately)	Permitted Emission Rate Before		Permitted Emission Rate After	
		lbs/hr	tons/yr	lbs/hr	tons/yr
13	Carbon Monoxide	0.3	0.02*	0.3	0.02*
14		0.3	0.02*	NA	NA
15		0.3	0.02*	NA	NA
16		0.3	0.02*	0.3	0.02*
37		NA	NA	1.05	0.025**
	Total Carbon Monoxide	1.2	0.08	1.65	0.065

*Based on 100 hours heat-up utilizing natural gas.

**Based on 48 hours heat-up utilizing natural gas.

9 PROPOSED AIR POLLUTION CONTROL MEASURES

Source ID number	Air pollution control measures
13	Sulfuric Acid Plant, Contact Process, Containing Mist Eliminators
14	Not Applicable
15	Not Applicable
16	Sulfuric Acid Plant, Double Contact Process, Containing Mist Eliminators
37	Sulfuric Acid Plant, Double Contact Process, Containing Mist Eliminators

10 APPLICABLE REGULATIONS

List state and federal pollution abatement programs and describe how compliance with these programs will be achieved.

"E" Train which will replace the existing "B" and "C" Trains, will comply with Section LAC 33:III.3230, 3231, 3232, 3233, 3234 and 3235. "E" train will also comply with LAC 33:III.1503

"D" train will also comply with the same regulation as "E" train.

"A" train will comply with LAC 33.III.1503.

11 PERSONNEL

a. Responsible Officer

Name	Harlan R. Chance
Title	Plant Manager
Company	Agrico Chemical Company
Suite, mail drop, or division	Uncle Sam Plant
Street or P.O. Box	
City	Uncle Sam
State	LA
Zip	70792
Business phone	(504) 562-3501

b. Professional Engineer

Name	T. A. Hertwig
Title	Sr. Process Engineer
Company	Agrico Chemical Company
Suite, mail drop, or division	Uncle Sam Plant
Street or P.O. Box	
City	Uncle Sam
State	LA
Zip	70792
Business phone	(504) 562-3501

Signature of responsible officer(s)	Harlan R. Chance
Date	1/15/91
Date	

Signature of Professional Engineer	TAHertwig
Date	1/14/91
Registration No.	State of Registration
19230	LA

Department of Environmental Quality
Air Quality Division
P.O. Box 44096
Baton Rouge, LA 70804
(504) 342-1206

LOUISIANA

SINGLE POINT SOURCE / AREA SOURCE
Emission Inventory Questionnaire (EIQ)
for Air Pollutants

Company Name	Plant location and name (if any)	Date of submittal
Agrico Chemical Company - Uncle Sam Plant	Highway 44, Uncle Sam, LA 70792	

Source ID number	Descriptive name of the equipment served by this stack or vent	Location of stack or vent (see instructions on how to determine location of area sources)
13	"A" Train Single Absorption Sulfuric Acid Plt.	UTM zone no. ☒ 15 ☐ 16 Horizontal coordinate 709379 m E Vertical coordinate 3324786 m N

Stack and Discharge Physical Characteristics	Height of stack above grade (ft)	Diameter (ft) or stack discharge area (ft²)	Stack gas exit temperature (°F)	Stack gas flow at process conditions, not at standard (ft³/min)	Stack gas exit velocity (ft/sec)	For tanks, list volume (gals)
	200	5 ☒ ft ☐ ft²	190	138,631	117	

Fuel — Type of fuel used and heat input (see instructions)

	Type of fuel	Heat input (MM BTU/hr)
a	Sulfur	168
b	Natural Gas	100
c		

Operating Characteristics

Percent of annual throughput of pollutants through this emission point				Normal operating time of this point			Normal operating rate
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	hrs/day	days/week	weeks/year	
25	25	25	25	24	7	52	2,000 TPD

Air Pollutant Specific Information

Pollutant	Control equipment code	Control equipment efficiency	Emission Rate Average (lbs/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Emission estimation method	Add, change, or delete code	Concentration in gases exiting at stack	
particulate matter			0.2	0.2	0.01*	3			gr/std ft³
sulfur dioxide	043		2,250	2,250	9,828	1,3	Change	2,000	ppm by vol
nitrogen dioxide			13.4	13.4	0.65*	3			ppm by vol
carbon monoxide			0.3	0.3	0.02*	3			ppm by vol
total NM/NE HC (excl. those listed below)			0.06	0.06	0.001*	3			ppm by vol
H2SO4 Acid Mist	014		41.7	41.7	182	1,3	Change		ppm by vol
									ppm by vol
									ppm by vol
			*Base on 100 hours of heat-up using natural gas.						ppm by vol
									ppm by vol
									ppm by vol
									ppm by vol
									ppm by vol

Department of Environmental Quality
Air Quality Division
P.O. Box 44096
Baton Rouge, LA 70804
(504) 342-1206

LOUISIANA

SINGLE POINT SOURCE / AREA SOURCE
Emission Inventory Questionnaire (EIQ)
for Air Pollutants

Company Name	Plant location and name (if any)	Date of submittal
Agrico Chemical Company - Uncle Sam Plant	Highway 44, Uncle Sam, LA 70792	

Source ID number	Descriptive name of the equipment served by this stack or vent	Location of stack or vent (see instructions on how to determine location of area sources)
14	"B" Sulfuric Single Absorption Sulfuric Acid Plt.	UTM zone no. ☒ 15 ☐ 16 Horizontal coordinate 709391 m E Vertical coordinate 3324742 m N

Stack and Discharge Physical Characteristics	Height of stack above grade (ft)	Diameter (ft) or stack discharge area (ft²) ☒ ft ☐ ft²	Stack gas exit temperature (°F)	Stack gas flow at process conditions, not at standard (ft³/min)	Stack gas exit velocity (ft/sec)	For tanks, flat volume (gals)
	200	5	190	125,000	112	-

Fuel	Type of fuel used and heat input (see instructions)		Operating Characteristics	Percent of annual throughput of pollutants through this emission point				Normal operating time of this point			Normal operating rate
		Type of fuel	Heat input (MM BTU/hr)		Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	hrs/day	days/week	weeks/year	
	a	Sulfur	168		25	25	25	25	24	7	52	1900 TPD
	b	Natural Gas	100									
	c											

Air Pollutant Specific Information

Pollutant	Control equipment code	Control equipment efficiency	Emission Rate Average (lbs/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Emission estimation method	Add, change, or delete code	Concentration in gases exiting at stack
particulate matter			0.2	0.2	0.01*	3	Delete	grs/std ft³
sulfur dioxide	043		1,870	2,138	9,339	1,3	Delete	1,848 ppm by vol
nitrogen dioxide			13.4	13.4	0.65*	3	Delete	ppm by vol
carbon monoxide			0.3	0.3	0.02*	3	Delete	ppm by vol
total NM/NE HC (excl. those listed below)			0.02	0.02	0.001*	3	Delete	ppm by vol
H2SO4 Acid Mist	014		24	40	175max	1,3	Delete	ppm by vol
					105avg	1,3	Delete	ppm by vol
								ppm by vol
			*Base on 100 hours of heat-up with natural gas.					ppm by vol
								ppm by vol
			This train will be replaced by the the new "E"					ppm by vol
			Sulphuric Acid Train.					ppm by vol
								ppm by vol

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Air Quality Division
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Baton Rouge, LA 70804
(504) 342-1206

LOUISIANA

SINGLE POINT SOURCE / AREA SOURCE
Emission Inventory Questionnaire (EIQ)
for Air Pollutants

Company Name	Plant location and name (if any)	Date of submittal
Agrico Chemical Company - Uncle Sam Plant	Highway 44, Uncle Sam, LA 70792	

Source ID number	Descriptive name of the equipment served by this stack or vent	Location of stack or vent (see instructions on how to determine location of area sources)
15	"C" Train Single Absorption Sulfuric Acid Plt.	UTM zone no. ☒ 15 ☐ 16 Horizontal coordinate 709404 m E Vertical coordinate 3324698 m N

Stack and Discharge Physical Characteristics	Height of stack above grade (ft)	Diameter (ft) or stack discharge area (ft²)	Stack gas exit temperature (°F)	Stack gas flow at process conditions, not at standard (ft³/min)	Stack gas exit velocity (ft/sec)	For tanks, list volume (gals)
	200	5 ☒ ft ☐ ft²	190	125,000	112	-

Fuel	Type of fuel used and heat input (see instructions)		Operating Characteristics	Percent of annual throughput of pollutants through this emission point				Normal operating time of this point			Normal operating rate
		Type of fuel	Heat input (MM BTU/hr)		Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	hrs/day	days/week	weeks/year	
	a	Sulfur	168		25	25	25	25	24	7	52	1900 TPD
	b	Natural Gas	100									
	c											

Air Pollutant Specific Information

Pollutant	Control equipment code	Control equipment efficiency	Emission Rate Average (lbs/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Emission estimation method	Add, change, or delete code	Concentration in gases exiting at stack
particulate matter			0.2	0.2	0.01*	3	Delete	grs/dcf ft³
sulfur dioxide	043		1,870	2,138	9,339	1,3	Delete	1,848 ppm by vol
nitrogen dioxide			13.4	13.4	0.65*	3	Delete	ppm by vol
carbon monoxide			0.3	0.3	0.02*	3	Delete	ppm by vol
total NM/NE HC (excl. those listed below)			0.02	0.02	0.001*	3	Delete	ppm by vol
H2SO4 Acid Mist	014		24	40	175max.	1,3	Delete	ppm by vol
					105avg.	1,3		ppm by vol
								ppm by vol
								ppm by vol
			*Base on 100 hours of heat-up with natural gas.					ppm by vol
								ppm by vol
			This train will be replaced by the new "E"					ppm by vol
			Sulphuric Acid Train.					ppm by vol

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for Air Pollutants

Company Name	Plant location and name (if any)	Date of submittal
Agrico Chemical Company - Uncle Sam Plant	Highway 44, Uncle Sam, LA 70792	

Source ID number	Descriptive name of the equipment served by this stack or vent	Location of stack or vent (see instructions on how to determine location of area sources)
16	"D" Train Double Absorption Sulfuric Acid Plt.	UTM zone no. ☒ 15 ☐ 16 Horizontal coordinate 709437 m E Vertical coordinate 3324616 m N

Stack and Discharge Physical Characteristics	Height of stack above grade (ft)	Diameter (ft) or stack discharge area (ft²) ☒ ft ☐ ft²	Stack gas exit temperature (°F)	Stack gas flow at process conditions, not at standard (ft³/min)	Stack gas exit velocity (ft/sec)	For tanks, list volume (gals)
	160	6	170	107,582	63	

Fuel		Type of fuel	Heat input (MM BTU/hr)
	a	Sulfur	168
	b	Natural Gas	100
	c		

Operating Characteristics	Percent of annual throughput of pollutants through this emission point				Normal operating time of this point			Normal operating rate
	Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	hrs/day	days/week	weeks/year	
	25	25	25	25	24	7	52	2000 TPD

Air Pollutant Specific Information

Pollutant	Control equipment code	Control equipment efficiency	Emission Rate Average (lbs/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Emission estimation method	Add, change, or delete code	Concentration in gases exiting at stack	
particulate matter			0.2	0.2	0.01*	3			gr/std ft³
sulfur dioxide	044		333	333	1.455	1.3	Change	371	ppm by vol
nitrogen dioxide			13.4	13.4	0.65*	3			ppm by vol
carbon monoxide			0.3	0.3	0.02*	3			ppm by vol
total NM/NE HC (excl. those listed below)			0.02	0.02	0.001*	3			ppm by vol
H2SO4 Acid Mist	014		11.5	12.6	55	1.3	Change		ppm by vol
									ppm by vol
									ppm by vol
									ppm by vol
			*Base on 100 hours heat-up with natural gas.						ppm by vol
									ppm by vol
									ppm by vol
									ppm by vol

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for Air Pollutants

Company Name	Plant location and name (if any)	Date of submittal
Agrico Chemical Company - Uncle Sam Plant	Highway 44, Uncle Sam, LA 70792	

Source ID number	Descriptive name of the equipment served by this stack or vent	Location of stack or vent (see instructions on how to determine location of area sources)
33	Fugitives "A" Train Single Absorption Sulfuric Acid Plt.	UTM zone no. ☒ 15 ☐ 16 Horizontal coordinate 709379 m E Vertical coordinate 3324786 m N

Stack and Discharge Physical Characteristics	Height of stack above grade (ft)	Diameter (ft) or stack discharge area (ft²) ☒ ft ☐ ft²	Stack gas exit temperature (°F)	Stack gas flow at process conditions, not at standard (ft³/min)	Stack gas exit velocity (ft/sec)	For tanks, list volume (gals)
	200	5	190	138,631	118	

Fuel — Type of fuel used and heat input (see instructions)

	Type of fuel	Heat input (MM BTU/hr)
a	Sulfur	168
b	Natural Gas	100
c		

Operating Characteristics

Percent of annual throughput of pollutants through this emission point				Normal operating time of this point			Normal operating rate
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	hrs/day	days/week	weeks/year	
25	25	25	25	24	7	52	2,000 TPD

Air Pollutant Specific Information

Pollutant	Control equipment code	Control equipment efficiency	Emission Rate Average (lbs/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Emission estimation method	Add, change, or delete code	Concentration in gases exiting at stack
particulate matter								gr/std ft³
sulfur dioxide								ppm by vol
nitrogen dioxide								ppm by vol
carbon monoxide								ppm by vol
total NM/NE HC (excl. those listed below)								ppm by vol
								ppm by vol
Fugitive SO_2	000		0.44	1.55	1.9	4	Change	ppm by vol
Fugitive SO_3	000		1.00	1.94	4.4	4	Change	ppm by vol
								ppm by vol
								ppm by vol
								ppm by vol
								ppm by vol
								ppm by vol

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for Air Pollutants

Company Name	Plant location and name (if any)	Date of submittal
Agrico Chemical Company - Uncle Sam Plant	Highway 44, Uncle Sam, LA 70792	

Source ID number	Descriptive name of the equipment served by this stack or vent	Location of stack or vent (see instructions on how to determine location of area sources)
34	"B" Train Single Absorption Sulfuric Acid Plt.	UTM zone no. ☒ 15 ☐ 16 — Horizontal coordinate 709391 m E — Vertical coordinate 3324742 m N

Stack and Discharge Physical Characteristics	Height of stack above grade (ft)	Diameter (ft) or stack discharge area (ft²) ☒ ft ☐ ft²	Stack gas exit temperature (°F)	Stack gas flow at process conditions, not at standard (ft³/min)	Stack gas exit velocity (ft/sec)	For tanks, list volume (gals)
	200	5	190	115,000	98	

Fuel — Type of fuel used and heat input (see instructions)

	Type of fuel	Heat input (MM BTU/hr)
a	Sulfur	168
b	Natural Gas	100
c		

Operating Characteristics

Percent of annual throughput of pollutants through this emission point				Normal operating time of this point			Normal operating rate
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	hrs/day	days/week	weeks/year	
25	25	25	25	24	7	52	2,000 TPD

Air Pollutant Specific Information

Pollutant	Control equipment code	Control equipment efficiency	Emission Rate Average (lbs/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Emission estimation method	Add, change, or delete code	Concentration in gases exiting at stack
particulate matter								gr/std ft³
sulfur dioxide								ppm by vol
nitrogen dioxide								ppm by vol
carbon monoxide								ppm by vol
total NM/NE HC (excl. those listed below)								ppm by vol
								ppm by vol
Fugitive SO_2	000		0.44	1.55	1.9	4	Delete	ppm by vol
Fugitive SO_3	000		1.00	1.94	4.4	4	Delete	ppm by vol
								ppm by vol
								ppm by vol
								ppm by vol
								ppm by vol
								ppm by vol

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SINGLE POINT SOURCE / AREA SOURCE
Emission Inventory Questionnaire (EIQ)
for Air Pollutants

Company Name	Plant location and name (if any)	Date of submittal
Agrico Chemical Company - Uncle Sam Plant	Highway 44, Uncle Sam, LA 70792	

Source ID number	Descriptive name of the equipment served by this stack or vent	Location of stack or vent (see instructions on how to determine location of area sources)
35	"C" Train Single Absorption Sulfuric Acid Plt.	UTM zone no. ☒ 15 ☐ 16 — Horizontal coordinate 709404 m E — Vertical coordinate 3324698 m N

Stack and Discharge Physical Characteristics	Height of stack above grade (ft)	Diameter (ft) or stack discharge area (ft²) ☒ ft ☐ ft²	Stack gas exit temperature (°F)	Stack gas flow at process conditions, not at standard (ft³/min)	Stack gas exit velocity (ft/sec)	For tanks, list volume (gals)
	200	5	190	115,000	98	

Fuel		Type of fuel used and heat input (see instructions)		Operating Characteristics	Percent of annual throughput of pollutants through this emission point				Normal operating time of this point			Normal operating rate
		Type of fuel	Heat input (MM BTU/hr)		Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	hrs/day	days/week	weeks/year	
	a	Sulfur	168		26	26	22	26	24	7	52	2,000 TPD
	b	Natural Gas	100									
	c											

Air Pollutant Specific Information

Pollutant	Control equipment code	Control equipment efficiency	Emission Rate Average (lbs/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Emission estimation method	Add, change, or delete code	Concentration in gases exiting at stack
particulate matter								gr/std ft³
sulfur dioxide								ppm by vol
nitrogen dioxide								ppm by vol
carbon monoxide								ppm by vol
total NM/NE HC (excl. those listed below)								ppm by vol
								ppm by vol
Fugitive SO_2	000		0.44	1.55	1.9	4	Delete	ppm by vol
Fugitive SO_3	000		1.00	1.94	4.4	4	Delete	ppm by vol
								ppm by vol
								ppm by vol
								ppm by vol
								ppm by vol
								ppm by vol

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for Air Pollutants

Company Name	Plant location and name (if any)	Date of submittal
Agrico Chemical Company - Uncle Sam Plant	Highway 44, Uncle Sam, LA 70792	

Source ID number	Descriptive name of the equipment served by this stack or vent	Location of stack or vent (see instructions on how to determine location of area sources)
36	"D" Train Double Absorption Sulfuric Acid Plt.	UTM zone no. ☒ 15 ☐ 16 Horizontal coordinate 709437 m E Vertical coordinate 3324616 m N

Stack and Discharge Physical Characteristics	Height of stack above grade (ft)	Diameter (ft) or stack discharge area (ft²) ☒ ft ☐ ft²	Stack gas exit temperature (°F)	Stack gas flow at process conditions, not at standard (ft³/min)	Stack gas exit velocity (ft/sec)	For tanks, list volume (gals)
	150	6	170	107,582	63	

Fuel — Type of fuel used and heat input (see instructions)

	Type of fuel	Heat input (MM BTU/hr)
a	Sulfur	168
b	Natural Gas	100
c		

Operating Characteristics

Percent of annual throughput of pollutants through this emission point				Normal operating time of this point			Normal operating rate
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	hrs/day	days/week	weeks/year	
25	25	25	25	24	7	52	2,000 TPD

Air Pollutant Specific Information

Pollutant	Control equipment code	Control equipment efficiency	Emission Rate Average (lbs/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Emission estimation method	Add, change, or delete code	Concentration in gases exiting at stack
particulate matter								gr/std ft³
sulfur dioxide								ppm by vol
nitrogen dioxide								ppm by vol
carbon monoxide								ppm by vol
total NM/NE HC (excl. those listed below)								ppm by vol
								ppm by vol
Fugitive SO_2	000		0.44	1.55	1.9	4	Change	ppm by vol
Fugitive SO_3	000		1.00	1.94	4.4	4	Change	ppm by vol
								ppm by vol
								ppm by vol
								ppm by vol
								ppm by vol
								ppm by vol

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Air Quality Division
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LOUISIANA

SINGLE POINT SOURCE / AREA SOURCE
Emission Inventory Questionnaire (EIQ)
for Air Pollutants

Company Name	Plant location and name (if any)	Date of submittal

Source ID number	Descriptive name of the equipment served by this stack or vent	Location of stack or vent (see instructions on how to determine location of area sources)
37	"E" Train Double Absorption Sulfuric Acid Plt.	UTM zone no. ☒ 15 ☐ 16 Horizontal coordinate 708538 m E Vertical coordinate 3325050 m N

Stack and Discharge Physical Characteristics	Height of stack above grade (ft)	Diameter (ft) or stack discharge area (ft²)	Stack gas exit temperature (°F)	Stack gas flow at process conditions, not at standard (ft³/min)	Stack gas exit velocity (ft/sec)	For tanks, list volume (gals)
	164	9.75 ☒ ft ☐ ft²	180	182,098	40.65	

Fuel	Type of fuel used and heat input (see instructions)		Operating Characteristics	Percent of annual throughput of pollutants through this emission point				Normal operating time of this point			Normal operating rate
	Type of fuel	Heat input (MM BTU/hr)		Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	hrs/day	days/week	weeks/year	
a	Sulfur	414		25	25	25	25	24	7	52	3800 TPD
b	Natural Gas	100									
c											

Air Pollutant Specific Information

Pollutant	Control equipment code	Control equipment efficiency	Emission Rate Average (lbs/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Emission estimation method	Add, change, or delete code	Concentration in gases exiting at stack	
particulate matter			0.62	0.62	0.015*	6.3	add		gr/std ft³
sulfur dioxide	044	99.7	633.3	633.3	2766	6	add	413.6	ppm by vol
nitrogen dioxide			43.3	43.3	1.04*	6.3	add		ppm by vol
carbon monoxide			1.05	1.05	0.025*	6.3	add		ppm by vol
total NM/NE HC (excl. those listed below)			0.062	0.062	0.0015*	6.3	add		ppm by vol
H2SO4 Acid Mist	014	99	23.8	23.8	104	6.3	add		ppm by vol
									ppm by vol
									ppm by vol
									ppm by vol
									ppm by vol
									ppm by vol
									ppm by vol
									ppm by vol

*Based on 48 hours heat up with Natural Gas
This new train if permitted will replace two
single absorption plants (B&C)

Exhibit 2

August 16, 1991 Permit No. 2091
Authorizing Construction of the E Train

State of Louisiana

Department of Environmental Quality

BUDDY ROEMER
Governor

PAUL TEMPLET
Secretary

Mr. Harlan Chance
Plant Manager
Agrico Chemical Company
Hwy 44
Uncle Sam, LA 70792-9999

Dear Mr. Chance:

RE: Permit, E Train Sulfuric Acid Plant, Agrico Chemical Company, Uncle Sam Facility, St. James Parish, Louisiana

This is to inform you that the permit request for the above referenced facility has been approved under LAC 33:III.505. The submittal was approved on the basis of the emissions reported and the approval in no way guarantees the design scheme presented will be capable of controlling the emissions as to the types and quantities stated. A new application must be submitted if the reported emissions are exceeded after operation begins. The synopsis, data sheets and conditions are attached herewith.

It will be considered a violation of the permit if all proposed control measures and/or equipment are not installed and properly operated and maintained as specified in the application.

The permit number cited below should be referenced in future correspondence regarding this facility.

Done this 16th day of August, 1991.

Permit No.: 2091

Very truly yours,

Mike D. McDaniel

Mike D. McDaniel, Ph.D.
Assistant Secretary

MMcD/PH/twr

cc: Capital Regional Office

DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY REGULATORY DIVISION
BRIEFING SHEET

AGRICO CHEMICAL COMPANY
UNCLE SAM, ST. JAMES PARISH, LOUISIANA

I. BACKGROUND

Agrico Chemical Company operates the Uncle Sam Facility in St. James Parish. Within the facility, sulfuric acid plants have been in operation since 1967. Trains A, B, and C are single absorption sulfuric acid plants currently under grandfather status. Train D is a double absorption sulfuric acid plant under Permit No. 116 issued July 13, 1972.

Agrico requests a permit to build a new double absorption sulfuric acid plant, E Train, to replace B and C Trains. This project will result in a significant reduction in SO_2 and sulfuric acid mist. This permit serves to consolidate the emission points from all of the sulfuric acid plants at Uncle Sam.

II. ORIGIN

A permit application and Emissions Inventory Questionnaire were submitted on January 7, 1991. Additional information was submitted on March 26 and July 3, 1991. A variance to construct was issued April 8, 1991.

III. DESCRIPTION

Agrico Chemical Company operates an agricultural chemical plant which produces sulfuric acid as a raw material for production of phosphoric acid, a chemical used in fertilizers and cattle feed.

Fresh molten sulfur is oxidized in furnaces at 1800°F to form SO_2. The SO_2 gas stream is converted to SO_3 by four passes through a vanadium pentoxide (V_2O_5) catalyst converter. The SO_3 stream is absorbed in sulfuric acid and water to produce a 98% sulfuric acid product.

The proposed project consists of building a new double absorption sulfuric acid plant, E Train, and removing two single absorption trains, B and C. E Train shall have

a capacity of 3800 ton/day of H_2SO_4. Trains A and D shall both operate at 2000 ton/day of H_2SO_4. This will increase production capability by 13.5% while significantly reducing emissions of SO_2 and H_2SO_4 mist. The following shows the increase in emissions, based on EPA criteria, due to the project and the (1986-1991) contemporaneous decreases* relied on for the netting out process.

EMISSIONS (TPY)

Pollutant	Project Increases	Contemporaneous	Net Change	de minimus
PM_{10}	0.015	-	-	15
SO_2	4433.7	-17,464	-13,030.3	40
NO_x	1.0	-	-	40
VOC	0.0015	-	-	40
CO	0.025	-	-	100

* Emissions of SO_2 did not increase within the contemporaneus period.

Estimated emissions for the sulfuric acid plants are as follows:

EMISSIONS (TPY)

Pollutant	Before**	Permitted After	Change
PM_{10}	0.04	0.035	- 0.005
NO_x	2.6	2.3	- 0.3
VOC	0.004	0.0035	- 0.0005
CO	0.08	0.065	- 0.015
Methane	0.005	0.004	- 0.001
H_2SO_4 mist	525.0	341.0	- 184.0
SO_2	27085.0	14054.7	-13030.3
SO_3	17.6	13.2	- 4.4

* Actual emission

DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY REGULATORY DIVISION
BRIEFING SHEET

AGRICO CHEMICAL COMPANY
UNCLE SAM, ST. JAMES PARISH, LOUISIANA

The D Train sulfuric acid plant and the new E Train sulfuric acid plant shall comply with New Source Performance Standards (NSPS), 40 CFR 60, Subpart H-Standards of Performance for Sulfuric Acid Plants.

Modeling using ISCST for SO_2 was performed using 1988 MET data from Moisant Airport and Bootheville. The results indicated concentrations of 821.3 ug/m^3 (3 hr average), 166.98 ug/m^3 (24 hr average), and 15 ug/m^3 (annual average). These concentrations are well below the NAAQS of 1300 ug/m^3, 355 ug/m^3, and 80 ug/m^3 for 3 hr, 24 hr and annual averages, respectively.

IV. TYPE OF REVIEW

This application was reviewed for compliance with the Louisiana Air Quality Regulations and New Source Performance Standards. Prevention of Significant Deterioration, LESHAP, and Air Toxics Programs do not apply.

V. PUBLIC NOTICE

Public notice is not required for a modification which results in a decrease in emissions.

SPECIFIC CONDITIONS

AGRICO CHEMICAL COMPANY
UNCLE SAM, ST. JAMES PARISH, LOUISIANA

1. Both D Train and E Train Double Absorption Sulfuric Acid Plants, Emission Points 16 and 37, shall comply with all applicable provisions of New Source Performance Standards, 40 CFR 60, Subpart H-Standards of Performance for Sulfuric Acid Plants.

2. The permittee shall submit an annual report listing the amount and duration of any exceedance of the SO_2 and H_2SO_4 acid mist limits on each February 15 for the previous calandar year.

LOUISIANA AIR EMISSION PERMIT
GENERAL CONDITIONS

I. This permit is issued on the basis of the emissions reported in the application for approval of emissions and in no way guarantees that the design scheme presented will be capable of controlling the emissions to the type and quantities stated. Failure to install, properly operate and/or maintain all proposed control measures and/or equipment as specified in the application and supplemental information shall be considered a violation of the permit and LAC 33:III.505. If the emissions are determined to be greater than those allowed by the permit or if proposed control measures and/or equipment are not installed or do not perform according to design efficiency, an application to modify the permit must be submitted.

II. The permittee is subject to all applicable provisions of the Louisiana Air Quality Regulations. Violation of the terms and conditions of the permit constitutes a violation of these regulations.

III. The permit application and the attached data sheets establish the emission and operating limitations and are a part of the permit. The synopsis and data sheets are based on the application and Emission Inventory Questionnaire submitted January 7, 1991 and additional information submitted on March 26 and July 3, 1991.

IV. This permit shall become invalid, for the sources not constructed, if:
(a) construction is not commenced, or binding agreements or contractual obligations to undertake a program of construction of the project are not entered into, within two (2) years (18 months for PSD permits) after issuance of this permit, or;
(b) if construction is discontinued for a period of two (2) years (18 months for PSD permits) or more.

The administrative authority may extend this time period upon a satisfactory showing that an extension is justified.

This provision does not apply to the time period between construction of the approved phases of a phased construction project. However, each phase must commence construction within two (2) years (18 months for PSD permits) of its projected and approved commencement date.

V. The permittee shall submit semi-annual reports of progress outlining the status of construction, noting any design changes, modifications or alterations in the construction schedule which have or may have an effect on the emission rates or ambient air quality levels. These reports shall continue to be submitted until such time as construction is certified as being complete. Furthermore, for any

significant change in the design, prior approval shall be obtained from the Louisiana Air Quality Regulatory Division.

VI. The permittee shall notify the Department of Environmental Quality, Air Quality Regulatory Division within ten (10) calendar days from the date that construction is certified as complete and the estimated date of start-up of operation. The appropriate Regional Office shall also be so notified within the same time frame.

VII. Any emissions testing performed for purposes of demonstrating compliance with the limitations set forth in paragraph III shall be conducted in accordance with the methods described in the Division's test manual or any other methods approved by the U.S. EPA. Any deviation from or modification of the methods used for testing shall have prior approval from the Louisiana Air Quality Regulatory Division.

VIII. The emission testing described in paragraph VII above, or established in the specific conditions of this permit, shall be conducted within sixty (60) days after achieving normal production rate, but in no event later than 180 days after initial start-up (or restart-up after modification). The Air Quality Compliance Division Surveillance Section shall be notified at least (30) days prior to testing and shall be given the opportunity to conduct a pretest meeting and observe the emission testing. The test results shall be submitted to the Air Quality Regulatory Division within forty-five (45) days after the complete testing. As required by LAC 33:III.913, the permittee shall provide necessary sampling port in stacks or ducts and such other safe and proper sampling and testing facilities for proper determination of the emission limits.

IX. The permittee shall, within 180 days after start-up of each project or unit, report to the Louisiana Air Quality Regulatory Division any significant difference in operating emission rates as compared to those limitations specified in paragraph III. This report shall also include, but not be limited to , malfunctions and upsets.

X. The permittee shall retain records of all information resulting from monitoring activities and information indicating operating parameters as specified in the specific conditions of this permit for a minimum of at least two (2) years.

XI. If for any reason the permittee does not comply with, or will not be able to comply with, the emission limitations specified in this permit, the permittee shall provide the Air Quality Regulatory Division with the following

information in writing within five (5) days of such conditions:

a. Description of noncomplying emission(s);
b. Cause of noncompliance;
c. Anticipated time the noncompliance is expected to continue, or, if corrected, the duration of the period of noncompliance;
d. Steps taken by the permittee to reduce and eliminate the noncomplying emissions; and
e. Steps taken by the permittee to prevent recurrences of the noncomplying emissions.

XII. Permittee shall allow the authorized officers and employees of the Department of Environmental Quality, at all reasonable times and upon presentation of identification, to:

1) Enter upon the permittee's premises where regulated facilities are located, regulated activities are conducted or where records required under this permit are kept;

2) Have access to and copy any records that are required to be kept under the terms and conditions of this permit, the Louisiana Air Quality Regulations, or the Act;

3) Inspect any facilities, equipment (including monitoring methods and an operation and maintenance inspection), or operations regulated under this permit; and,

4) Sample or monitor, for the purpose of assuring compliance with this permit or as otherwise authorized by the Act or regulations adopted thereunder, any substances or parameters at any location.

XIII. If samples are taken under Section XII. 4) above, the officer or employee obtaining such samples shall give the owner, operator or agent in charge a receipt describing the sample obtained. If requested prior to leaving the premises, a portion of each sample equal in volume or weight to the portion retained shall be given to the owner, operator or agent in charge. If an analysis is made of such samples, a copy of the analysis shall be furnished promptly to the owner, operator or agency in charge.

XIV. The permittee shall allow authorized officers and employees of the Department of Environmental Quality, upon presentation of identification, to enter upon the permittee's premises to investigate potential or alleged violations of the Act or the rules and regulations adopted

thereunder. In such investigations, the permittee shall be notified at the time entrance is requested of the nature of the suspected violation. Inspections under this subsection shall be limited to the aspects of alleged violations. However, this shall not in any way preclude prosecution of all violations found.

XV. The permittee shall comply with the reporting requirements specified under LAC 33:III.918 as well as notification requirements specified under LAC 33:III.927.

XVI. In the event of any change in ownership of the source described in this permit, the permittee and the succeeding owner shall notify the Louisiana Air Quality Regulatory Division, within ninety (90) days after the event, to amend this permit.

AIR QUALITY DATA SHEET
PAGE 1

AGRICO CHEMICAL COMPANY
UNCLE SAM, ST. JAMES PARISH, LOUISIANA

Location of plant: 15 UTM: 709.4 Km E 3324.7 Km N

Description of location: Hwy 44 near Uncle Sam, LA.

Estimated starting date of construction 4/15/91

Estimated starting operation will begin 4/92

Type of Dispersion Calculations Used: ISCST (SO_2-3 hr, 24 hr) ISCLT (SO_2-Annual)

EFFECTS ON AMBIENT AIR

Pollutant	Time Period	Calculated Maximum Ground Level Concentration	Louisiana Air Quality Standard (NAAQS)
SO_2	3hr	821.3 ug/m^3	1300 ug/m^3
SO_2	24 hr	166.98 ug/m^3	355 ug/m^3
SO_2	Annual	15.0 ug/m^3	80 ug/m^3

NEW_____ OR MODIFIED x EMISSION SOURCES Sulfuric Acid Plants (Type of Source)

Emission Point No.	Description	Operating Rate (Max)	Operating Schedule H/D	D/W	W/Y
13	A Train Single Absorption Sulfuric Acid Plant	2000 TPD H_2SO_4	24	7	52
14	B Train Single Absorption Sulfuric Acid Plant	DELETE	-	-	-
15	C Train Single Absorption Sulfuric Acid Plant	DELETE	-	-	-
16	D Train Double Absorption Sulfuric Acid Plant	2000 TPD H_2SO_4	24	7	52
33	A Train fugitives	NA	24	7	52
34	B Train Fugitives	DELETE	-	-	-

AIR QUALITY DATA SHEET
PAGE 1 (CONTINUED)

AGRICO CHEMICAL COMPANY
UNCLE SAM, ST. JAMES PARISH, LOUISIANA

Emission Point No.	Description	Operating Rate (Max)	Operating Schedule H/D	D/W	W/Y
35	C Train Fugitives	DELETE	-	-	-
36	D Train Fugitives	NA	24	7	52
37	E Train Double Absorption Sulfuric Acid Plant	3800 TPD H_2SO_4	24	7	52
38	E Train Fugitives	NA	24	7	52

AIR QUALITY DATA SHEET
PAGE 2

AGRICO CHEMICAL COMPANY
UNCLE SAM, ST. JAMES PARISH, LOUISIANA

MAXIMUM/AVERAGE EMISSION RATES ARE LISTED IN LB/HR

Emission Point No.	Permitted Emissions PM-10	SO_2	NO_x	VOC	CO	OTHER	HEIGHT Feet	TEMP. °F	FLOW RATE CFM
13	0.2	2250.0	13.4	0.06	0.3	H_2SO_4 Acid Mist 41.7 Methane 0.06	200	190	138.630
16	0.2	333.0	13.4	0.02	0.3	H_2SO_4 Acid Mist 11.5 Methane 0.06	160	170	107.580
33	-	1.6 /0.44	-	-	-	SO_3 1.9/1.0	NA	170	NA
36	-	1.6 /0.44	-	-	-	SO_3 1.9/1.0	NA	170	NA
37	0.62	633.3	43.3	0.062	1.1	H_2SO_4 Acid Mist 23.8 Methane 0.064	164	180	182.100
38	-	1.6 /0.44	-	-	-	SO_3 1.9/1.0	NA	180	NA

AIR QUALITY DATA SHEET
PAGE 3

AGRICO CHEMICAL COMPANY
UNCLE SAM, ST. JAMES PARISH, LOUISIANA

Emission Point No.	TONS PER YEAR PM-10	SO_2	NO_x	VOC	CO	OTHER
13	0.01	9828.0	0.65	0.001	0.02	H_2SO_4 acid mist 182.0
						Methane 0.001
16	0.01	1455.0	0.65	0.001	0.02	H_2SO_4 acid mist 55.0
						Methane 0.001
33	-	1.9	-	-	-	SO_3 4.4
36	-	1.9	-	-	-	SO_3 4.4
37	0.015	2766.0	1.0	0.0015	0.025	H_2SO_4 acid mist 104.0
						Methane 0.002
38	-	1.9	-	-	-	SO_3 4.4
Total	0.035	14,054.7	2.3	0.0035	0.065	H_2SO4 acid mist 341.0
						Methane 0.004
						SO_3 13.2

Exhibit 3

A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067): BART Cost Effectiveness Calculation for SCR

Client: Mosaic Fertilizer, LLC - Uncle Sam Plant
Subject: BART Cost Effectiveness Calculation

Signature: Todd Higginbotham
Emissions Unit: A Train Single Absorption H2SO4 Plant
Emissions Unit ID: EPN S-ATrain1
Control Technology: SCR
Final: September 3, 2015

1. Design Parameters

Heat Input Rate (Q_B):	235.9	MMBtu/hr	Sulfur combustion rate estimated based on sulfuric acid production rate of 2,200 tpd and sulfur heat of combustion of 3,940 Btu/lb
Capacity Factor (CF):	1.0		Assumed continuous operation
Baseline NOx in Flue Gas (NOx_{in}):	0.035	lb/MMBtu	Calculated by dividing Permit No. 2560-00004-V2 hourly average potential to emit rate by heat input rate indicated above
Overall Controlled NOx Level:	0.0035	lb/MMBtu	
SCR NOx Removal Efficiency (η_{NOx}):	90%		Assumed control efficiency
Actual Stoichiometric Ratio (ASR):	1.05		USEPA 2002, Section 4.2, Ch. 2, Equation 2.11
Ammonia Slip (Slip):	7	ppmv	Assumed based on EPA's Air Pollution Control Technology Fact Sheet for SCR, which states, "In the U.S., permitted ammonia slip levels are typically 2 to 10 ppm."
Number of SCR Reaction Chambers (n_{SCR}):	1		USEPA 2002, Section 4.2, Ch. 2, page 2-34
Temperature of Exhaust Gas (T):	700	°F	Conservative estimate, which would require the flue gas to be heated if the SCR is placed after the wet gas scrubber
Flue Gas Flow Rate ($q_{fluegas}$):	120,000	ft^3/min	Average exhaust flow rate measured during a July 28, 2011 stack test of the emissions unit - 109,350 acfm
Volume of Catalyst ($Vol_{catalyst}$):	622	ft^3	USEPA 2002, Section 4.2, Ch. 2, Equation 2.19
NOx Efficiency Adjustment Factor (η_{adj}):	1.24		USEPA 2002, Section 4.2, Ch. 2, Equation 2.20
Inlet NOx Adjustment Factor (NOx_{adj}):	0.86		USEPA 2002, Section 4.2, Ch. 2, Equation 2.21
Ammonia Slip Adjustment Factor ($Slip_{adj}$):	0.9		USEPA 2002, Section 4.2, Ch. 2, Equation 2.22
Sulfur Content of Fuel:	0		Conservative estimate
Sulfur in Fuel Adjustment Factor (S_{adj}):	0.96		USEPA 2002, Section 4.2, Ch. 2, Equation 2.23
Temperature Adjustment Factor (T_{adj}):	1.03		USEPA 2002, Section 4.2, Ch. 2, Equation 2.24
Catalyst Cross-Sectional Area ($A_{catalyst}$):	125	ft^2	USEPA 2002, Section 4.2, Ch. 2, Equation 2.25 (superficial velocity = 16 ft/s)
SCR Reactor Cross-Sectional Area (A_{SCR}):	144	ft^2	USEPA 2002, Section 4.2, Ch. 2, Equation 2.26
Number of Catalyst Layers (n_{layer}):	2		USEPA 2002, Section 4.2, Ch. 2, Equation 2.28 (minimum of 2 layers, nominal catalyst height of 3.1 ft)
Total Catalyst Layers (including empty layers) (n_{total}):	3		USEPA 2002, Section 4.2, Ch. 2, Equation 2.30 (1 empty layer)
Height of One Catalyst Layer (h_{layer}):	3.49	ft	USEPA 2002, Section 4.2, Ch. 2, Equation 2.29
Height of SCR Reactor (h_{SCR}):	40.5	ft	USEPA 2002, Section 4.2, Ch. 2, Equation 2.31 (c1 = 7 and c2 = 9)
Molecular Weight of NO2 (M_{NOx}):	46.01	g/g-mol	
Molecular Weight of Ammonia ($M_{reagent}$):	17.03	g/g-mol	
Mass Flow of Reagent ($m_{reagent}$):	2.9	lb/hr	USEPA 2002, Section 4.2, Ch. 2, Equation 2.32
Aqueous Ammonia Concentration by Weight (C_{sol}):	29%		
Mass Flow of Aqueous Reagent Solution (m_{sol}):	10.0	lb/hr	USEPA 2002, Section 4.2, Ch. 2, Equation 2.33
Specific Volume of Aqueous Reagent Solution (v_{sol}):	7.481	gal/ft^3	USEPA 2002, Section 4.2, Ch. 2, page 2-40
Density of Aqueous Reagent Solution (ρ_{sol}):	56.0	lb/ft^3	USEPA 2002, Section 4.2, Ch. 2, page 2-40
Solution Volume Flow Rate (q_{sol}):	1.33	gal/hr	USEPA 2002, Section 4.2, Ch. 2, Equation 2.34
Tank Volume for Reagent Storage (TV):	447	gallons	USEPA 2002, Section 4.2, Ch. 2, Equation 2.35 (14-day supply of reagent)
Baseline NOx Emission Rate (Baseline):	16.61	tpy	(Average of NOx emissions documented in 2005 and 2006 reporting year emissions inventories for the emissions unit)
NOx Emissions Reduction:	14.94	tpy	= Baseline * η_{NOx}

Client: Mosaic Fertilizer, LLC - Uncle Sam Plant
Subject: BART Cost Effectiveness Calculation

Signature: Todd Higginbotham
Emissions Unit: A Train Single Absorption H2SO4 Plant
Emissions Unit ID: EPN S-ATrain1
Control Technology: SCR
Final: September 3, 2015

2. Economic Factors

Equipment Life (n):	30	years	
Annual Interest Rate (I):	7.00%		
Capital Recovery Factor (CRF):	0.081		= (I * (1 + I)^n) / ((1 + I)^n - 1)
Operating Life of Catalyst (Y):	4	years	
	35,040	hours	
Catalyst Future Worth Factor (FWF):	0.23		= I * (1 / ((1 + I)^Y - 1))
Cost of Fuel:	-	$/Mft^3	
Cost of 29% Aqueous Ammonia:	0.2	$/lb	
Cost of Electricity:	-	$/kW	

3. Total Capital Investment (TCI)	**$3,203,176**		= DC + IC
Direct Capital Costs (DC):	$2,209,087		= Q_B * (3,380 + Adjustment for SCR reactor height + Adjustment for ammonia flow rate) * $(3{,}500/Q_B)^{0.35}$ + Capital cost for initial catalyst (USEPA 2002, Section 4.2, Ch. 2, Equation 2.36)
Adjustment for SCR Reactor Height:	$60	$/MMBtu/hr	= (6.12 * h_{SCR}) - 187.9 (USEPA 2002, Section 4.2, Ch. 2, Equation 2.37)
Adjustment for Ammonia Flow Rate:	-$42	$/MMBtu/hr	= (411 * ($m_{reagent}/Q_B$)) - 47.3 (USEPA 2002, Section 4.2, Ch. 2, Equation 2.38)
Initial Catalyst Cost:	$240	$/ft^3	USEPA 2002, Section 4.2, Ch. 2, page 2-43
Capital Cost for Initial Catalyst:	$149,349		= $Vol_{catalyst}$ * Initial Catalyst Cost
Indirect Capital Costs (IC):	$994,089		= CE + E&S + Contract + SU + PC
Construction Expenses (CE):	$220,909		= 0.10 * DC
Engineering and Supervision (E&S):	$220,909		= 0.10 * DC
Contractor Fees (Contract):	$110,454		= 0.05 * DC
Start-up (SU):	$110,454		= 0.05 * DC
Project Contingency (PC):	$331,363		= 0.15 * DC

4. Total Annual Cost (TAC)	**$421,315**		= DAC + IAC
Direct Annual Costs (DAC):	$99,119		= Maint + Elec + Reag + Cat + Fuel
Maintenance (Maint):	$48,048		= 0.015 * TCI
Electricity (Elec):	$0		(Conservatively assumed to be 0)
Reagent (Reag):	$17,433		= m_{SOL} * 8,760 hr/yr * $/lb
Catalyst Replacement (Cat):	$33,638		= $Vol_{catalyst}$ * $/ft3 * FWF
Fuel Penalty Cost (Fuel):	$0		
Indirect Annual Costs (IAC):	$322,196		= TIA + CR
Taxes/Insurance/Administration (TIA):	$64,064		= 0.02 * TCI
Capital Recovery (CR):	$258,132		= TCI * CRF

5. Cost Effectiveness

Cost Effectiveness of Control Technology:	28,192	$/ton	= TAC / Emissions Reduction, in tpy

Exhibit 4

A Train Single Absorption H2SO4 Plant (EPN S-ATrain1, EQT 0067): BART Cost Effectiveness Calculation for Wet ESP

Client: Mosaic Fertilizer, LLC - Uncle Sam Plant
Subject: BART Cost Effectiveness Calculation

Signature: Todd Higginbotham
Emissions Unit: A Train Single Absorption H2SO4 Plant
Emissions Unit ID: EPN S-ATrain1
Control Technology: Wet ESP
Final: September 3, 2015

1. Design Parameters

Exhaust Flow Rate:	120,000	ft^3/min	Average exhaust flow rate measured during a July 28, 2011 stack test of the emissions unit - 109,350 acfm
Capacity Factor (CF):	1.0		Assumed continuous operation
Wet ESP PM Removal Efficiency (η_{PM}):	99%		Assumed control efficiency
Number of Wet ESP Modules:	6		USEPA 2002, Section 6, Ch. 3, page 3-41 (20,000 ft^3/min per module; 95% PM control efficiency)
Baseline PM Emission Rate (Baseline):	60.23	tpy	(Potential to emit H_2SO_4 emission rate listed in the plant's current Title V permit, 2560-00004-V2. PM emissions were estimated to equal 100% of the emissions unit's H_2SO_4 emissions.)[1]
PM Emissions Reduction:	59.63	tpy	= Baseline * η_{PM}

2. Economic Factors

Equipment Life (n):	30	years	
Annual Interest Rate (I):	7.00%		
Capital Recovery Factor (CRF):	0.081		= (I * (1 + I)^n) / ((1 + I)^n - 1)
Wet ESP Cost per "Shop Assembled" Module:	$451,000		USEPA 2002, Section 6, Ch. 3, page 3-41 (20,000 ft^3/min; 95% efficiency)
Cost of Electricity:	-	$/kW	
Retrofit Multiplier:	1.4		USEPA 2002, Section 6, Ch. 3, page 3-41 ("Costs are site-specific; however, for estimating purposes, a retrofit multiplier of 1.3 to 1.5 applied to the total capital investment can be used.")

3. Total Capital Investment (TCI)	**$9,879,390**	= DC + IC
Direct Capital Costs (DC):	$5,332,444	= PEC + Install
Total Purchased Equipment Cost (PEC):	$3,193,080	= Wet ESP + Instr + ST + Fr
Wet ESP:	$2,706,000	= $451,000 * 6 Wet ESP Modules
Instrumentation (Instr):	$270,600	= 0.1 * Wet ESP (USEPA 2002, Section 6, Ch. 3, page 3-46)
Sales Tax (ST):	$81,180	= 0.03 * Wet ESP (USEPA 2002, Section 6, Ch. 3, page 3-46)
Freight (Fr):	$135,300	= 0.05 * Wet ESP (USEPA 2002, Section 6, Ch. 3, page 3-46)
Total Purchased Equipment Installation (Install):	$2,139,364	= 0.67 * PEC (USEPA 2002, Section 6, Ch. 3, page 3-46)
Indirect Capital Costs (IC):	$1,724,263	= CE + E&S + Contract + SU + PC
Construction Expenses (CE):	$638,616	= 0.2 * PEC (USEPA 2002, Section 6, Ch. 3, page 3-46)
Engineering and Supervision (E&S):	$638,616	= 0.2 * PEC (USEPA 2002, Section 6, Ch. 3, page 3-46)
Contractor Fees (Contract):	$319,308	= 0.1 * PEC (USEPA 2002, Section 6, Ch. 3, page 3-46)
Start-up (SU):	$31,931	= 0.01 * PEC (USEPA 2002, Section 6, Ch. 3, page 3-46)
Project Contingency (PC):	$95,792	= 0.03 * PEC (USEPA 2002, Section 6, Ch. 3, page 3-46)

Client: Mosaic Fertilizer, LLC - Uncle Sam Plant
Subject: BART Cost Effectiveness Calculation

Signature: Todd Higginbotham
Emissions Unit: A Train Single Absorption H2SO4 Plant
Emissions Unit ID: EPN S-ATrain1
Control Technology: Wet ESP
Final: September 3, 2015

4. Total Annual Cost (TAC)	**$1,141,923**	= DAC + IAC
Direct Annual Costs (DAC):	$148,191	= Maint + Elec + Waste
Maintenance (Maint):	$148,191	= 0.015 * TCI
Electricity (Elec):	$0	(Conservatively assumed to be 0)
Waste Disposal (Waste):	$0	(Conservatively assumed to be 0)
Indirect Annual Costs (IAC):	$993,732	= TIA + CR
Taxes/Insurance/Administration (TIA):	$197,588	= 0.02 * TCI
Capital Recovery (CR):	$796,144	= TCI * CRF

5. Cost Effectiveness

Cost Effectiveness of Control Technology:	19,151 $/ton	= TAC / Emissions Reduction, in tpy

6. Notes

1. No PM or H_2SO_4 emissions were reported for the emissions unit for 2005. 23.16 tpy of H_2SO_4 emissions were reported for the emissions unit for 2006, which means the unit was estimated to emit 23.16 tpy of PM in 2006. A review of the plant's 2005-2014 emissions inventories indicates that the highest annual H_2SO_4 emission rate reported for the emissions unit is 45.91 tpy for 2010. Additionally, due to the Consent Decree, the emissions unit's potential to emit H_2SO_4 emission rate was reduced from 182.5 tpy to 60.23 tpy with the issuance of Permit No. 2560-00004-V2 on March 20, 2013.

Exhibit 5

A Train Start-Up Burner (EPN S-ATrain2, EQT 0068): BART Cost Effectiveness Calculation for ULNB

Client: Mosaic Fertilizer, LLC - Uncle Sam Plant
Subject: BART Cost Effectiveness Calculation

Signature: Todd Higginbotham
Emissions Unit: A Train Start-Up Burner
Emissions Unit ID: EPN S-ATrain2
Control Technology: ULNB
Final: September 3, 2015

1. Design Parameters			
ULNB NOx Reduction Efficiency (η_{NOx}):	90%		(Conservative estimate)
Fuel:	Natural Gas		
Fuel High Heating Value:	1,020	Btu/scf	
Fuel Wet F Factor:	10,610	wscf/MMBtu	
Fuel Dry F Factor:	8,710	dscf/MMBtu	
Baseline NOx Emission Rate (Baseline):	1.24	tpy	(Average of NOx emissions documented in 2005 and 2006 reporting year emissions inventories for the emissions unit)
NOx Emissions Reduction:	1.11	tpy	= Baseline * η_{NOx}
2. Economic Factors			
Equipment Life (n):	30	years	
Annual Interest Rate (I):	7.00%		
Capital Recovery Factor (CRF):	0.081		= (I * (1 + I)^n) / ((1 + I)^n - 1)
Cost of Electricity:	-	$/kW	
3. Total Capital Investment (TCI)	**$138,261**		= DC + IC
Direct Capital Costs (DC):	$95,352		= PEC + Install + Instr + Pipe + Elec + ST + Fr
Total Purchased Equipment Cost (PEC):	$58,498		= ULNB + Ancill
Ultra-Low NOx Burner (ULNB):	$46,799		= see Note 1
Ancillary ULNB Equipment (Ancill):	$11,700		= 0.25 * ULNB
Total Purchased Equipment Installation (Install):	$14,625		= 0.25 * PEC
Control/Instrumentation (Instr):	$5,850		= 0.10 * PEC
Piping (Pipe):	$5,850		= 0.10 * PEC
Electrical Equipment (Elec):	$5,850		= 0.10 * PEC
Sales Tax (ST):	$1,755		= 0.03 * PEC
Freight (Fr):	$2,925		= 0.05 * PEC
Indirect Capital Costs (IC):	$42,908		= CE + E&S + Contract + SU + PC
Construction Expenses (CE)	$9,535		= 0.10 * DC
Engineering and Supervision (E&S)	$9,535		= 0.10 * DC
Contractor Fees (Contract)	$4,768		= 0.05 * DC
Start-up (SU)	$4,768		= 0.05 * DC
Project Contingency (PC)	$14,303		= 0.15 * DC
4. Total Annual Cost (TAC)	**$11,142**		= DAC + IAC
Direct Annual Costs (DAC):	$0		= Maint + Elec
Maintenance (Maint):	$0		(Conservatively estimated 0 difference between current burner and ULNB)
Electricity (Elec):	$0		(Conservatively estimated 0 difference between current burner and ULNB)
Indirect Annual Costs (IAC):	$11,142		= TIA + CR
Taxes/Insurance/Administration (TIA):	$0		(Conservatively estimated 0 difference between current burner and ULNB)
Capital Recovery (CR):	$11,142		= TCI * CRF

5. Cost Effectiveness

Cost Effectiveness of Control Technology:	10,024 $/ton	= TAC / Emissions Reduction, in tpy

6. Notes

1. Burner Cost = $5,000 * $N^{0.9}$ / N, where N equals the number of burners in the external combustion device. In developing this equation, each burner was assumed to be approximately 10 MMBtu/hr in size. Therefore, when applying this equation to the A Train Start-Up Burner (EPN S-ATrain2), it was assumed that this source would require 12 burners.

   EPA. Manufacturing Branch. Manufacturing, Energy and Transportation Division. *Petroleum Refinery Tier 2 BACT Analysis Report* . January 16, 2001. p. 3-21.

Exhibit 6

D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074): BART Cost Effectiveness Calculation for SCR

Client: Mosaic Fertilizer, LLC - Uncle Sam Plant
Subject: BART Cost Effectiveness Calculation

Signature: Todd Higginbotham
Emissions Unit: D Train Double Absorption H2SO4 Plant
Emissions Unit ID: EPN S-DTrain1
Control Technology: SCR
Final: September 3, 2015

1. Design Parameters

Heat Input Rate (Q_B):	241.2	MMBtu/hr	Sulfur combustion rate estimated based on sulfuric acid production rate of 2,250 tpd and sulfur heat of combustion of 3,940 Btu/lb
Capacity Factor (CF):	1.0		Assumed continuous operation
Baseline NOx in Flue Gas (NOx_{in}):	0.034	lb/MMBtu	Calculated by dividing Permit No. 2560-00004-V2 hourly average potential to emit rate by heat input rate indicated above
Overall Controlled NOx Level:	0.0034	lb/MMBtu	
SCR NOx Removal Efficiency (η_{NOx}):	90%		Assumed control efficiency
Actual Stoichiometric Ratio (ASR):	1.05		USEPA 2002, Section 4.2, Ch. 2, Equation 2.11
Ammonia Slip (Slip):	7	ppmv	Assumed based on EPA's Air Pollution Control Technology Fact Sheet for SCR, which states, "In the U.S., permitted ammonia slip levels are typically 2 to 10 ppm."
Number of SCR Reaction Chambers (n_{SCR}):	1		USEPA 2002, Section 4.2, Ch. 2, page 2-34
Temperature of Exhaust Gas (T):	700	°F	Conservative estimate, which would require the flue gas to be heated if the SCR is placed after the wet gas scrubber
Flue Gas Flow Rate ($q_{fluegas}$):	115,000	ft^3/min	Average exhaust flow rate measured during a September 22, 2011 stack test of the emissions unit - 103,688 acfm
Volume of Catalyst ($Vol_{catalyst}$):	636	ft^3	USEPA 2002, Section 4.2, Ch. 2, Equation 2.19
NOx Efficiency Adjustment Factor (η_{adj}):	1.24		USEPA 2002, Section 4.2, Ch. 2, Equation 2.20
Inlet NOx Adjustment Factor (NOx_{adj}):	0.86		USEPA 2002, Section 4.2, Ch. 2, Equation 2.21
Ammonia Slip Adjustment Factor ($Slip_{adj}$):	0.9		USEPA 2002, Section 4.2, Ch. 2, Equation 2.22
Sulfur Content of Fuel:	0		Conservative estimate
Sulfur in Fuel Adjustment Factor (S_{adj}):	0.96		USEPA 2002, Section 4.2, Ch. 2, Equation 2.23
Temperature Adjustment Factor (T_{adj}):	1.03		USEPA 2002, Section 4.2, Ch. 2, Equation 2.24
Catalyst Cross-Sectional Area ($A_{catalyst}$):	120	ft^2	USEPA 2002, Section 4.2, Ch. 2, Equation 2.25 (superficial velocity = 16 ft/s)
SCR Reactor Cross-Sectional Area (A_{SCR}):	138	ft^2	USEPA 2002, Section 4.2, Ch. 2, Equation 2.26
Number of Catalyst Layers (n_{layer}):	2		USEPA 2002, Section 4.2, Ch. 2, Equation 2.28 (minimum of 2 layers, nominal catalyst height of 3.1 ft)
Total Catalyst Layers (including empty layers) (n_{total}):	3		USEPA 2002, Section 4.2, Ch. 2, Equation 2.30 (1 empty layer)
Height of One Catalyst Layer (h_{layer}):	3.66	ft	USEPA 2002, Section 4.2, Ch. 2, Equation 2.29
Height of SCR Reactor (h_{SCR}):	41.0	ft	USEPA 2002, Section 4.2, Ch. 2, Equation 2.31 (c1 = 7 and c2 = 9)
Molecular Weight of NO2 (M_{NOx}):	46.01	g/g-mol	
Molecular Weight of Ammonia ($M_{reagent}$):	17.03	g/g-mol	
Mass Flow of Reagent ($m_{reagent}$):	2.9	lb/hr	USEPA 2002, Section 4.2, Ch. 2, Equation 2.32
Aqueous Ammonia Concentration by Weight (C_{sol}):	29%		
Mass Flow of Aqueous Reagent Solution (m_{sol}):	10.0	lb/hr	USEPA 2002, Section 4.2, Ch. 2, Equation 2.33
Specific Volume of Aqueous Reagent Solution (v_{sol}):	7.481	gal/ft^3	USEPA 2002, Section 4.2, Ch. 2, page 2-40
Density of Aqueous Reagent Solution (ρ_{sol}):	56.0	lb/ft^3	USEPA 2002, Section 4.2, Ch. 2, page 2-40
Solution Volume Flow Rate (q_{sol}):	1.33	gal/hr	USEPA 2002, Section 4.2, Ch. 2, Equation 2.34
Tank Volume for Reagent Storage (TV):	447	gallons	USEPA 2002, Section 4.2, Ch. 2, Equation 2.35 (14-day supply of reagent)
Baseline NOx Emission Rate (Baseline):	27.45	tpy	(Average of NOx emissions documented in 2005 and 2006 reporting year emissions inventories for the emissions unit)
NOx Emissions Reduction:	24.71	tpy	= Baseline * η_{NOx}

Client: Mosaic Fertilizer, LLC - Uncle Sam Plant
Subject: BART Cost Effectiveness Calculation

Signature: Todd Higginbotham
Emissions Unit: D Train Double Absorption H2SO4 Plant
Emissions Unit ID: EPN S-DTrain1
Control Technology: SCR
Final: September 3, 2015

2. Economic Factors

Equipment Life (n):	30	years	
Annual Interest Rate (I):	7.00%		
Capital Recovery Factor (CRF):	0.081		= (I * (1 + I)^n) / ((1 + I)^n - 1)
Operating Life of Catalyst (Y):	4	years	
	35,040	hours	
Catalyst Future Worth Factor (FWF):	0.23		= I * (1 / ((1 + I)^Y - 1))
Cost of Fuel:	-	$/Mft^3	
Cost of 29% Aqueous Ammonia:	0.2	$/lb	
Cost of Electricity:	-	$/kW	

3. Total Capital Investment (TCI)	**$3,254,608**		= DC + IC
Direct Capital Costs (DC):	$2,244,557		= Q_B * (3,380 + Adjustment for SCR reactor height + Adjustment for ammonia flow rate) * $(3{,}500/Q_B)^{0.35}$ + Capital cost for initial catalyst (USEPA 2002, Section 4.2, Ch. 2, Equation 2.36)
Adjustment for SCR Reactor Height:	$63	$/MMBtu/hr	= (6.12 * h_{SCR}) - 187.9 (USEPA 2002, Section 4.2, Ch. 2, Equation 2.37)
Adjustment for Ammonia Flow Rate:	-$42	$/MMBtu/hr	= (411 * ($m_{reagent}/Q_B$)) - 47.3 (USEPA 2002, Section 4.2, Ch. 2, Equation 2.38)
Initial Catalyst Cost:	$240	$/ft^3	USEPA 2002, Section 4.2, Ch. 2, page 2-43
Capital Cost for Initial Catalyst:	$152,700		= $Vol_{catalyst}$ * Initial Catalyst Cost
Indirect Capital Costs (IC):	$1,010,051		= CE + E&S + Contract + SU + PC
Construction Expenses (CE):	$224,456		= 0.10 * DC
Engineering and Supervision (E&S):	$224,456		= 0.10 * DC
Contractor Fees (Contract):	$112,228		= 0.05 * DC
Start-up (SU):	$112,228		= 0.05 * DC
Project Contingency (PC):	$336,684		= 0.15 * DC

4. Total Annual Cost (TAC)	**$428,014**		= DAC + IAC
Direct Annual Costs (DAC):	$100,645		= Maint + Elec + Reag + Cat + Fuel
Maintenance (Maint):	$48,819		= 0.015 * TCI
Electricity (Elec):	$0		(Conservatively assumed to be 0)
Reagent (Reag):	$17,433		= m_{SOL} * 8,760 hr/yr * $/lb
Catalyst Replacement (Cat):	$34,392		= $Vol_{catalyst}$ * $/ft3 * FWF
Fuel Penalty Cost (Fuel):	$0		
Indirect Annual Costs (IAC):	$327,369		= TIA + CR
Taxes/Insurance/Administration (TIA):	$65,092		= 0.02 * TCI
Capital Recovery (CR):	$262,277		= TCI * CRF

5. Cost Effectiveness

Cost Effectiveness of Control Technology:	17,325	$/ton	= TAC / Emissions Reduction, in tpy

Exhibit 7

D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074): BART Cost Effectiveness Calculation for Wet ESP

Client: Mosaic Fertilizer, LLC - Uncle Sam Plant
Subject: BART Cost Effectiveness Calculation

Signature: Todd Higginbotham
Emissions Unit: D Train Double Absorption H2SO4 Plant
Emissions Unit ID: EPN S-DTrain1
Control Technology: Wet ESP
Final: September 3, 2015

1. Design Parameters

Exhaust Flow Rate:	115,000	ft^3/min	Average exhaust flow rate measured during a September 22, 2011 stack test of the emissions unit - 103,688 acfm
Capacity Factor (CF):	1.0		Assumed continuous operation
Wet ESP PM Removal Efficiency (η_{PM}):	99%		Assumed control efficiency
Number of Wet ESP Modules:	6		USEPA 2002, Section 6, Ch. 3, page 3-41 (20,000 ft^3/min per module; 95% PM control efficiency)
Baseline PM Emission Rate (Baseline):	60.23	tpy	(Potential to emit H_2SO_4 emission rate listed in the plant's current Title V permit, 2560-00004-V2. PM emissions were estimated to equal 100% of the emissions unit's H_2SO_4 emissions.)[1]
PM Emissions Reduction:	59.63	tpy	= Baseline * η_{PM}

2. Economic Factors

Equipment Life (n):	30	years	
Annual Interest Rate (I):	7.00%		
Capital Recovery Factor (CRF):	0.081		= (I * (1 + I)^n) / ((1 + I)^n - 1)
Wet ESP Cost per "Shop Assembled" Module:	$451,000		USEPA 2002, Section 6, Ch. 3, page 3-41 (20,000 ft^3/min; 95% efficiency)
Cost of Electricity:	-	$/kW	
Retrofit Multiplier:	1.4		USEPA 2002, Section 6, Ch. 3, page 3-41 ("Costs are site-specific; however, for estimating purposes, a retrofit multiplier of 1.3 to 1.5 applied to the total capital investment can be used.")

3. Total Capital Investment (TCI)	**$9,879,390**	= DC + IC
Direct Capital Costs (DC):	$5,332,444	= PEC + Install
Total Purchased Equipment Cost (PEC):	$3,193,080	= Wet ESP + Instr + ST + Fr
Wet ESP:	$2,706,000	= $451,000 * 6 Wet ESP Modules
Instrumentation (Instr):	$270,600	= 0.1 * Wet ESP (USEPA 2002, Section 6, Ch. 3, page 3-46)
Sales Tax (ST):	$81,180	= 0.03 * Wet ESP (USEPA 2002, Section 6, Ch. 3, page 3-46)
Freight (Fr):	$135,300	= 0.05 * Wet ESP (USEPA 2002, Section 6, Ch. 3, page 3-46)
Total Purchased Equipment Installation (Install):	$2,139,364	= 0.67 * PEC (USEPA 2002, Section 6, Ch. 3, page 3-46)
Indirect Capital Costs (IC):	$1,724,263	= CE + E&S + Contract + SU + PC
Construction Expenses (CE):	$638,616	= 0.2 * PEC (USEPA 2002, Section 6, Ch. 3, page 3-46)
Engineering and Supervision (E&S):	$638,616	= 0.2 * PEC (USEPA 2002, Section 6, Ch. 3, page 3-46)
Contractor Fees (Contract):	$319,308	= 0.1 * PEC (USEPA 2002, Section 6, Ch. 3, page 3-46)
Start-up (SU):	$31,931	= 0.01 * PEC (USEPA 2002, Section 6, Ch. 3, page 3-46)
Project Contingency (PC):	$95,792	= 0.03 * PEC (USEPA 2002, Section 6, Ch. 3, page 3-46)

Client: Mosaic Fertilizer, LLC - Uncle Sam Plant
Subject: BART Cost Effectiveness Calculation

Signature: Todd Higginbotham
Emissions Unit: D Train Double Absorption H2SO4 Plant
Emissions Unit ID: EPN S-DTrain1
Control Technology: Wet ESP
Final: September 3, 2015

4. Total Annual Cost (TAC)	**$1,141,923**	= DAC + IAC
Direct Annual Costs (DAC):	$148,191	= Maint + Elec + Waste
Maintenance (Maint):	$148,191	= 0.015 * TCI
Electricity (Elec):	$0	(Conservatively assumed to be 0)
Waste Disposal (Waste):	$0	(Conservatively assumed to be 0)
Indirect Annual Costs (IAC):	$993,732	= TIA + CR
Taxes/Insurance/Administration (TIA):	$197,588	= 0.02 * TCI
Capital Recovery (CR):	$796,144	= TCI * CRF

5. Cost Effectiveness

Cost Effectiveness of Control Technology:	19,151 $/ton	= TAC / Emissions Reduction, in tpy

6. Notes

1. No PM or H_2SO_4 emissions were reported for the emissions unit for 2005. 46.51 tpy of H_2SO_4 emissions were reported for the emissions unit for 2006, which means the unit was estimated to emit 46.51 tpy of PM in 2006. A review of the plant's 2005-2014 emissions inventories indicates that the highest annual H_2SO_4 emission rate reported for the emissions unit is 47.07 tpy for 2009.

Exhibit 8

D Train Double Absorption H2SO4 Plant (EPN S-DTrain1, EQT 0074): BART Cost Effectiveness Calculation for Wet Scrubber

Client: Mosaic Fertilizer, LLC - Uncle Sam Plant
Subject: BART Cost Effectiveness Calculation

Signature: Todd Higginbotham
Emissions Unit: D Train Double Absorption H2SO4 Plant
Emissions Unit ID: EPN S-DTrain1
Control Technology: Wet Scrubber
Final: September 3, 2015

1. Design Parameters

Capacity Factor (CF):	1.0		Assumed continuous operation
Wet Scrubber SO_2 Removal Efficiency (η_{SO2}):	95%		Assumed control efficiency
Baseline SO_2 Emission Rate (Baseline):	493.30	tpy	(Average of SO_2 emissions documented in 2012, 2013, and 2014 reporting year emissions inventories for the emissions unit)[1]
SO_2 Emissions Reduction:	468.64	tpy	= Baseline * η_{SO2}

2. Economic Factors

Equipment Life (n):	30	years	
Annual Interest Rate (I):	7.00%		
Capital Recovery Factor (CRF):	0.081		= (I * (1 + I)^n) / ((1 + I)^n - 1)

3. Total Capital Investment (TCI)	**$24,940,000**	= TCI-A Train + PC
TCI for A Train Wet Scrubber (TCI-A Train):	$23,200,000	= TCI for the A Train wet scrubber installed in 2010[2]
Project Contingency (PC):	$1,740,000	= 0.075 * TCI-A Train

4. Total Annual Cost (TAC)	**$3,323,116**	= DAC + IAC
Direct Annual Costs (DAC):	$814,491	= Oper Lab + Oper Mat + Elec + Maint + Waste
Operating Labor (Oper Lab):	$14,691	= Op + Super
Operator (Op):	$12,775	= 0.5 hr/shift * 2 shifts/day * 365 days/yr * $35/hr
Supervisor (Super):	$1,916	= 0.15 * Op
Operating Materials (Oper Mat):	$197,700	= 1/2 of caustic, chemicals cost for A Train wet scrubber equipment[3]
Electricity (Elec):	$175,600	= electricity cost for A Train wet scrubber equipment
Maintenance (Maint):	$426,500	= maintenance cost for A Train wet scrubber equipment
Waste Disposal (Waste):	$0	(Conservatively assumed to be 0)
Indirect Annual Costs (IAC):	$2,508,625	= TIA + CR
Taxes/Insurance/Administration (TIA):	$498,800	= 0.02 * TCI
Capital Recovery (CR):	$2,009,825	= TCI * CRF

5. Cost Effectiveness

Cost Effectiveness of Control Technology:	7,091	$/ton	= TAC / Emissions Reduction, in tpy

6. Notes

1. Because this emissions unit underwent SO_2 emissions control technology changes in 2011 to comply with relevant SO_2 emissions limitations in the Consent Decree, we estimated this emissions unit's baseline annual SO_2 emissions to equal the average of the 2012, 2013, and 2014 annual SO_2 emissions reported to the LDEQ for the unit.
2. The A Train is documented to have a maximum daily H_2SO_4 production rate of 2,200 tons of 100% H_2SO_4, and the D Train is documented to have a maximum daily H_2SO_4 production rate of 2,250 tons of 100% H_2SO_4. Therefore, the recent capital expenditure required for the construction of the A Train wet scrubber and its associated equipment provides a reasonable capital cost estimate for the construction of a wet scrubber on the D Train.
3. The caustic and chemicals cost for a D Train wet scrubber was estimated to be one-half of the caustic and chemicals cost experienced by the A Train wet scrubber due to the lower SO_2 concentration in the D Train exhaust stream versus the A Train exhaust stream.

Client: Mosaic Fertilizer, LLC - Uncle Sam Plant
Subject: BART Cost Effectiveness Calculation

Signature: Todd Higginbotham
Emissions Unit: D Train Double Absorption H2SO4 Plant
Emissions Unit ID: EPN S-DTrain1
Control Technology: Wet Scrubber
Final: September 3, 2015

1. Design Parameters

Capacity Factor (CF):	1.0		Assumed continuous operation
Wet Scrubber SO_2 Removal Efficiency (η_{SO2}):	95%		Assumed control efficiency
Baseline SO_2 Emission Rate (Baseline):	493.30	tpy	(Average of SO_2 emissions documented in 2012, 2013, and 2014 reporting year emissions inventories for the emissions unit)[1]
SO_2 Emissions Reduction:	468.64	tpy	= Baseline * η_{SO2}

2. Economic Factors

Equipment Life (n):	20	years	
Annual Interest Rate (I):	7.00%		
Capital Recovery Factor (CRF):	0.094		= (I * (1 + I)^n) / ((1 + I)^n - 1)

3. Total Capital Investment (TCI)	**$24,940,000**	= TCI-A Train + PC
TCI for A Train Wet Scrubber (TCI-A Train):	$23,200,000	= TCI for the A Train wet scrubber installed in 2010[2]
Project Contingency (PC):	$1,740,000	= 0.075 * TCI-A Train

4. Total Annual Cost (TAC)	**$3,667,451**	= DAC + IAC
Direct Annual Costs (DAC):	$814,491	= Oper Lab + Oper Mat + Elec + Maint + Waste
Operating Labor (Oper Lab):	$14,691	= Op + Super
Operator (Op):	$12,775	= 0.5 hr/shift * 2 shifts/day * 365 days/yr * $35/hr
Supervisor (Super):	$1,916	= 0.15 * Op
Operating Materials (Oper Mat):	$197,700	= 1/2 of caustic, chemicals cost for A Train wet scrubber equipment[3]
Electricity (Elec):	$175,600	= electricity cost for A Train wet scrubber equipment
Maintenance (Maint):	$426,500	= maintenance cost for A Train wet scrubber equipment
Waste Disposal (Waste):	$0	(Conservatively assumed to be 0)
Indirect Annual Costs (IAC):	$2,852,960	= TIA + CR
Taxes/Insurance/Administration (TIA):	$498,800	= 0.02 * TCI
Capital Recovery (CR):	$2,354,160	= TCI * CRF

5. Cost Effectiveness

Cost Effectiveness of Control Technology:	7,826	$/ton	= TAC / Emissions Reduction, in tpy

6. Notes

1. Because this emissions unit underwent SO_2 emissions control technology changes in 2011 to comply with relevant SO_2 emissions limitations in the Consent Decree, we estimated this emissions unit's baseline annual SO_2 emissions to equal the average of the 2012, 2013, and 2014 annual SO_2 emissions reported to the LDEQ for the unit.
2. The A Train is documented to have a maximum daily H_2SO_4 production rate of 2,200 tons of 100% H_2SO_4, and the D Train is documented to have a maximum daily H_2SO_4 production rate of 2,250 tons of 100% H_2SO_4. Therefore, the recent capital expenditure required for the construction of the A Train wet scrubber and its associated equipment provides a reasonable capital cost estimate for the construction of a wet scrubber on the D Train.
3. The caustic and chemicals cost for a D Train wet scrubber was estimated to be one-half of the caustic and chemicals cost experienced by the A Train wet scrubber due to the lower SO_2 concentration in the D Train exhaust stream versus the A Train exhaust stream.

Exhibit 9

D Train Start-Up Burner (EPN S-DTrain2, EQT 0075): BART Cost Effectiveness Calculation for ULNB

Client: Mosaic Fertilizer, LLC - Uncle Sam Plant
Subject: BART Cost Effectiveness Calculation

Signature: Todd Higginbotham
Emissions Unit: D Train Start-Up Burner
Emissions Unit ID: EPN S-DTrain2
Control Technology: ULNB
Final: September 3, 2015

1. Design Parameters			
ULNB NOx Reduction Efficiency (η_{NOx}):	90%		(Conservative estimate)
Fuel:	Natural Gas		
Fuel High Heating Value:	1,020	Btu/scf	
Fuel Wet F Factor:	10,610	wscf/MMBtu	
Fuel Dry F Factor:	8,710	dscf/MMBtu	
Baseline NOx Emission Rate (Baseline):	0.50	tpy	(Average of NOx emissions documented in 2005 and 2006 reporting year emissions inventories for the emissions unit)
NOx Emissions Reduction:	0.45	tpy	= Baseline * η_{NOx}
2. Economic Factors			
Equipment Life (n):	30	years	
Annual Interest Rate (I):	7.00%		
Capital Recovery Factor (CRF):	0.081		= (I * (1 + I)^n) / ((1 + I)^n - 1)
Cost of Electricity:	-	$/kW	
3. Total Capital Investment (TCI)	**$138,261**		= DC + IC
Direct Capital Costs (DC):	$95,352		= PEC + Install + Instr + Pipe + Elec + ST + Fr
Total Purchased Equipment Cost (PEC):	$58,498		= ULNB + Ancill
Ultra-Low NOx Burner (ULNB):	$46,799		= see Note 1
Ancillary ULNB Equipment (Ancill):	$11,700		= 0.25 * ULNB
Total Purchased Equipment Installation (Install):	$14,625		= 0.25 * PEC
Control/Instrumentation (Instr):	$5,850		= 0.10 * PEC
Piping (Pipe):	$5,850		= 0.10 * PEC
Electrical Equipment (Elec):	$5,850		= 0.10 * PEC
Sales Tax (ST):	$1,755		= 0.03 * PEC
Freight (Fr):	$2,925		= 0.05 * PEC
Indirect Capital Costs (IC):	$42,908		= CE + E&S + Contract + SU + PC
Construction Expenses (CE)	$9,535		= 0.10 * DC
Engineering and Supervision (E&S)	$9,535		= 0.10 * DC
Contractor Fees (Contract)	$4,768		= 0.05 * DC
Start-up (SU)	$4,768		= 0.05 * DC
Project Contingency (PC)	$14,303		= 0.15 * DC
4. Total Annual Cost (TAC)	**$11,142**		= DAC + IAC
Direct Annual Costs (DAC):	$0		= Maint + Elec
Maintenance (Maint):	$0		(Conservatively estimated 0 difference between current burner and ULNB)
Electricity (Elec):	$0		(Conservatively estimated 0 difference between current burner and ULNB)
Indirect Annual Costs (IAC):	$11,142		= TIA + CR
Taxes/Insurance/Administration (TIA):	$0		(Conservatively estimated 0 difference between current burner and ULNB)
Capital Recovery (CR):	$11,142		= TCI * CRF

5. Cost Effectiveness

Cost Effectiveness of Control Technology:	24,760 $/ton	= TAC / Emissions Reduction, in tpy

6. Notes

1. Burner Cost = $5,000 * $N^{0.9}$ / N, where N equals the number of burners in the external combustion device. In developing this equation, each burner was assumed to be approximately 10 MMBtu/hr in size. Therefore, when applying this equation to the D Train Start-Up Burner (EPN S-DTrain2), it was assumed that this source would require 12 burners.

   EPA. Manufacturing Branch. Manufacturing, Energy and Transportation Division. *Petroleum Refinery Tier 2 BACT Analysis Report* . January 16, 2001. p. 3-21.

Exhibit 10

Phosphate Rock Transfer, Storage, and Handling Operations (EPN P-Rock, EQT 0113): BART Cost Effectiveness Calculation for Baghouse

Client: Mosaic Fertilizer, LLC - Uncle Sam Plant
Subject: BART Cost Effectiveness Calculation

Signature: Todd Higginbotham
Emissions Unit: Phosphate Rock Transfer, Storage and Handling Operations
Emissions Unit ID: EPN P-Rock
Control Technology: Baghouse
Final: September 3, 2015

1. Design Parameters

Flow Rate:	500-1,000	ft^3/min	Estimate
Fan Size:	2.5	hp	Estimate
Capacity Factor (CF):	1.0		Assumed continuous operation
Baghouse PM Removal Efficiency (η_{PM}):	99%		Assumed control efficiency
Baseline PM Emission Rate (Baseline):	0.80	tpy	(Highest potential to emit emission rate for a phosphate rock conveyor belt transfer point)
PM Emissions Reduction:	0.79	tpy	= Baseline * η_{PM}

2. Economic Factors

Equipment Life (n):	30	years	
Annual Interest Rate (I):	7.00%		
Capital Recovery Factor (CRF):	0.081		= (I * (1 + I)^n) / ((1 + I)^n - 1)
Cost of Electricity:	0.07	$/kW	

3. Total Capital Investment (TCI)	**$29,358**	= DC + IC
Direct Capital Costs (DC):	$20,532	= PEC + Install
Total Purchased Equipment Cost (PEC):	$11,800	= BH + Instr + ST + Fr
Baghouse and Ancillary Equipment (BH):	$10,000	Conservative estimate
Instrumentation (Instr):	$1,000	= 0.1 * BH (USEPA 2002, Section 6, Ch. 1, page 1-45)
Sales Tax (ST):	$300	= 0.03 * BH (USEPA 2002, Section 6, Ch. 1, page 1-45)
Freight (Fr):	$500	= 0.05 * BH (USEPA 2002, Section 6, Ch. 1, page 1-45)
Total Purchased Equipment Installation (Install):	$8,732	= 0.74 * PEC (USEPA 2002, Section 6, Ch. 1, page 1-45)
Indirect Capital Costs (IC):	$8,826	= CE + E&S + Contract + SU + PC
Construction Expenses (CE)	$2,360	= 0.20 * PEC (USEPA 2002, Section 6, Ch. 1, page 1-45)
Engineering and Supervision (E&S)	$1,180	= 0.10 * PEC (USEPA 2002, Section 6, Ch. 1, page 1-45)
Contractor Fees (Contract)	$1,180	= 0.10 * PEC (USEPA 2002, Section 6, Ch. 1, page 1-45)
Start-up (SU)	$1,027	= 0.05 * DC
Project Contingency (PC)	$3,080	= 0.15 * DC
4. Total Annual Cost (TAC)	**$6,151**	= DAC + IAC
Direct Annual Costs (DAC):	$3,198	= OL & Mat + Maint + Elec + Waste
Operating Labor and Materials (OL & Mat):	$1,468	= 0.05 * TCI
Maintenance (Maint):	$587	= 0.02 * TCI
Electricity (Elec):	$1,143	= Fan hp * 745.7 W/hp * 8,760 hr/yr * 1 kW/1,000 W * $/kW
Waste Disposal (Waste):	$0	(Conservatively assumed to be 0)
Indirect Annual Costs (IAC):	$2,953	= TIA + CR
Taxes/Insurance/Administration (TIA):	$587	= 0.02 * TCI
Capital Recovery (CR):	$2,366	= TCI * CRF

5. Cost Effectiveness

Cost Effectiveness of Control Technology:	7,796	$/ton	= TAC / Emissions Reduction, in tpy

Exhibit 11

CALPUFF Files for Visibility Impacts Modeling Analysis

Appendix C

Phillips 66/ Alliance Refinery

Administrative Order on Consent,

BART Determination and Evaluation

KYLE B. BEALL
ATTORNEY AT LAW

628 North Boulevard
Baton Rouge, LA 70802
tel 225-336-8450

bealllaw.net

May 11, 2016

Ms. Vivian Aucoin
Office of Environmental Services
Department of Environmental Quality
P.O. Box 4313
Baton Rouge, Louisiana 70821-4313

HAND-DELIVERED

Re: Amended Administrative Order on Consent
Phillips 66 Company – Alliance Refinery (Plaquemines Parish)
Enforcement Tracking No. AE-AOC-14-00211A
Agency Interest No. 2418

Dear Ms. Aucoin:

I have attached the *Amended Administrative Order on Consent* entered between Phillips 66 Company and the Louisiana Department of Environmental Quality. This document contains the original signatures of both parties.

If you have any questions on this matter, I can be reached at (225)336-8450.

Very truly yours,

Kyle Beall

Kyle B. Beall

Attachment

cc: Steve Johnson
Linda Hester

JOHN BEL EDWARDS
GOVERNOR

CHUCK CARR BROWN, PH.D.
SECRETARY

State of Louisiana

DEPARTMENT OF ENVIRONMENTAL QUALITY
OFFICE OF ENVIRONMENTAL COMPLIANCE

CERTIFIED MAIL (7004 2510 0006 3853 6279)
RETURN RECEIPT REQUESTED

PHILLIPS 66 COMPANY
c/o Corporation Service Company
Agent for Service of Process
501 Louisiana Avenue
Baton Rouge, Louisiana 70802

RE: AMENDED ADMINISTRATIVE ORDER ON CONSENT
ENFORCEMENT TRACKING NO. AE-AOC-14-00211A
AGENCY INTEREST NO. 2418

Dear Sir:

Pursuant to the Louisiana Environmental Quality Act (La. R.S. 30:2001, et seq.), the attached **AMENDED ADMINISTRATIVE ORDER ON CONSENT** is hereby served on **PHILLIPS 66 COMPANY (RESPONDENT)**.

Any questions concerning this action should be directed to Alissa Cockerham at (225) 219-3785.

Sincerely,

Celena J. Cage
Administrator
Enforcement Division

CJC/ARC/arc
Alt ID No. 2240-00003
Attachment

c: Phillips 66 Alliance Refinery
c/o Laurence R. Poche
P.O. Box 176
Belle Chasse, LA 70037

STATE OF LOUISIANA
DEPARTMENT OF ENVIRONMENTAL QUALITY

OFFICE OF ENVIRONMENTAL COMPLIANCE

IN THE MATTER OF	*	
	*	
PHILLIPS 66 COMPANY	*	**ENFORCEMENT TRACKING NO.**
PLAQUEMINES PARISH	*	
ALT ID NO. 2240-00003	*	**AE-AOC-14-00211A**
	*	
	*	**AGENCY INTEREST NO.**
	*	
PROCEEDINGS UNDER THE LOUISIANA	*	**2418**
ENVIRONMENTAL QUALITY ACT,	*	
La. R.S. 30:2001, ET SEQ.	*	

AMENDED ADMINISTRATIVE ORDER ON CONSENT

The Louisiana Department of Environmental Quality (the Department) hereby amends the **ADMINISTRATIVE ORDER ON CONSENT, ENFORCEMENT TRACKING NO. AE-AOC-14-00211** issued to **PHILLIPS 66 COMPANY (RESPONDENT)** on September 3, 2014 in the above-captioned matter as follows:

I.

The Department hereby amends Paragraph I of the **ADMINISTRATIVE ORDER** portion of the Administrative Order on Consent, Enforcement Tracking No. AE-AOC-14-00211 to read as follows:

"I.

The Respondent shall comply with the emissions limitations set forth below:

Source ID	Source Description	Sulfur Dioxide (SO_2)	
		Limit	Citation
308F-D-1*	Low Pressure Flare	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2779-V3 Specific Requirement No. 1
308F-D-2	High Pressure Flare	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2779-V3 Specific Requirement Nos. 55 and 56
301-B-2A**	CO Boiler	SO_2 < =50 ppmv on 7 day rolling average at 0% O_2	NSPS J; CD; Permit 1810-V6 Specific Requirement Nos. 35, 36, 110, and 111
		SO_2 < =25 ppmdv on 365 day rolling average at 0% O_2	
301-B-2B**	CO Boiler	SO_2 < =50 ppmdv on 7 day rolling average at 0% O_2	NSPS J; CD; Permit 1810-V6 Specific Requirement Nos. 57, 58, 110, and 111
		SO_2 < =25 ppmdv on 365 day rolling average at 0% O_2	

Source ID	Source Description	Sulfur Dioxide (SO_2)	
		Limit	Citation
191-H-1	Crude Charge Heater	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2180-V4 Specific Requirement No. 1
292-H-1	Light Distillate Gulfiner Reactor Heater	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2113-V3 Specific Requirement No. 1
292-H-2	Light Distillate Gulfiner Stabilizer Heater	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2113-V3 Specific Requirement No. 6
1291-H-2/3	FCCU Light/Heavy Feed Heater	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 1810-V6 Specific Requirement No. 2
191-H-2	Vacuum Charge Heater	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2180-V4 Specific Requirement No. 17
891-H-1	Delayed Coker Charge Heater	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2511-V4 Specific Requirement No. 1
491-H-1	Alkylation Isostripper Reboiler	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2512-V3 Specific Requirement No. 1
491-H-2	Alkylation Depropanizer Reboiler	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2512-V3 Specific Requirement No. 15
100-H-1	Coker Charge Storage Heater	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2513-V7 Specific Requirement No. 262
293-H-1	Heavy Distillate Gulfiner Reactor Feed Heater	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2593-V3 Specific Requirement No. 1
293-H-2	Heavy Distillate Gulfiner Stabilizer Reboiler	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2593-V3 Specific Requirement No. 7
1391-H-1	Catalytic Reformer Feed Heater No. 1	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2775-V3 Specific Requirement No. 16
1391-H-2/3	Catalytic Reformer Feed Heater No. 2&3	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2775-V3 Specific Requirement No. 25
1391-H-4	Depentanizer Reboiler	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2775-V3 Specific Requirement No. 34
1391-H-5	Dry Reactivation Heater	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2775-V3 Specific Requirement No. 43
1791-H-1	Reformate Splitter Reboiler	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2775-V3 Specific Requirement No. 48
1792-H-1	Hydroealkylation Charge Heater	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2775-V3 Specific Requirement No. 54
291-H-1	Naphfiner Reactor Feed Heater	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2775-V3 Specific Requirement No. 1
291-H-2	Naphfiner Deisohexanizer Reboiler	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2775-V3 Specific Requirement No. 7
303-R-1	Cooling Water Tower No. 1	No SO_2 Emissions from this source	Permit 2778-V2
406-D-15	Product Dock No. 1 MVR Loading	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour	NSPS J; CD; Permit

Source ID	Source Description	Sulfur Dioxide (SO_2)	
		Limit	Citation
		rolling average.	2313-V4 Specific Requirement No. 1
406-D-16	Product Dock No. 2 MVR Loading	Fuel Gas: Hydrogen sulfide <=0.1 gr/dscf on a 3-hour rolling average.	NSPS J; CD; Permit 2313-V4 Specific Requirement No. 26
891-CP	Coke Transfer and Storage	No SO_2 Emissions from this source	Permit 2511-V4

*Use of a FGRS on a flare obviates the need to continuously monitor and maintain records of hydrogen sulfide in the gas otherwise required by 40 CFR 60.105(a)(4) and 60.7

**301-B-2A & 301-B-2B vents to Wet Gas Scrubber & is combined with the CO Boiler Stub Vents and FCC Regenerator Vent

Source ID	Source Description	Particulate Matter (PM)	
		Limit	Citation
301-B-2A*	CO Boiler	≤0.5 lb PM/1000 lb of coke burn on a 3-hr average basis.	LAC 33:III.1313.C Permit 1810-V6 Specific Requirement Nos. 34 and 109
301-B-2B*	CO Boiler	≤0.5 lb PM/1000 lb of coke burn on a 3-hr average basis.	LAC 33:III.1313.C Permit 1810-V6 Specific Requirement Nos. 56 and 109
191-H-1	Crude Charge Heater	0.00745 lb/MMBTU AP-42	Permit app 2180-V4
292-H-1	Light Distillate Gulfiner Reactor Heater	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III.1313.C Permit 2113-V3 Specific Requirement No. 5
292-H-2	Light Distillate Gulfiner Stabilizer Heater	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III.1313.C Permit 2113-V3 Specific Requirement No. 10
1291-H-2/3	FCCU Light/Heavy Feed Heater	0.00745 lb/mm BTU AP-42	Permit app 1810-V6
191-H-2	Vacuum Charge Heater	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III.1313.C Permit 2180-V4 Specific Requirement No. 22
891-H-1	Delayed Coker Charge Heater	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III 1313C Permit 2511-V4 Specific Requirement No. 6
491-H-1	Alkylation Isostripper Reboiler	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III.1313.C Permit 2512-V3 Specific Requirement No. 6
491-H-2	Alkylation Depropanizer Reboiler	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III.1313.C Permit 2512-V3 Specific Requirement No. 20
100-H-1	Coker Charge Storage Heater	0.0075 lb/mmBTU AP-42	Permit app 2513-V7
293-H-1	Heavy Distillate Gulfiner Reactor Feed Heater	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III.1313.C Permit 2593-V3 Specific Requirement No. 5
293-H-2	Heavy Distillate Gulfiner Stabilizer Reboiler	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III.1313.C Permit 2593-V3 Specific Requirement No. 11
1391-H-1	Catalytic Reformer Feed Heater No. 1	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III 1313C Permit 2775-V3 Specific Requirement

Source ID	Source Description	Particulate Matter (PM)	
		Limit	Citation
			No. 20
1391-H-2/3	Catalytic Reformer Feed Heater No. 2&3	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III 1313C Permit 2775-V3 Specific Requirement No. 29
1391-H-4	Depentanizer Reboiler	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III 1313C Permit 2775-V3 Specific Requirement No. 38
1391-H-5	Dry Reactivation Heater	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III 1313C Permit 2775-V3 Specific Requirement No. 47
1791-H-1	Reformate Splitter Reboiler	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III 1313C Permit 2775-V3 Specific Requirement No. 52
1792-H-1	Hydroealkylation Charge Heater	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III 1313C Permit 2775-V3 Specific Requirement No. 58
291-H-1	Naphfiner Reactor Feed Heater	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III 1313C Permit 2775-V3 Specific Requirement No. 5
291-H-2	Naphfiner Deisohexanizer Reboiler	Total suspended particulate matter <=0.6lb/MMBTU of heat input	LAC 33:III 1313C Permit 2775-V3 Specific Requirement No. 11
303-R-1	Cooling Water Tower No. 1	1.7 lb/Mgal cooling water circulation AP-42.	Permit app 2778-V2
406-D-15	Product Dock No. 1 MVR Loading	0.00745 lb/mmBTU AP-42	Permit app 2313-V4
406-D-16	Product Dock No. 2 MVR Loading	0.00745 lb/mmBTU AP-42	Permit app 2313-V4
891-CP	Coke Transfer and Storage	Opacity<=20%	LAC 33:III.1311.C Permit 2511-V4 Specific Requirement No. 9

*301-B-2A & 301-B-2B vents to Wet Gas Scrubber & is combined with the CO Boiler Stub Vents and FCC Regenerator Vent

Source ID	Source Description	Nitrogen Oxide (NO_X)	
		Limit	Citation
308F-D-1	Low Pressure Flare	Comply with NSPS A	NSPS A; CD; Permit 2779-V3 Specific Requirement Nos. 2-8
308F-D-2	High Pressure Flare	Comply with NSPS A	NSPS A; CD; Permit 2779-V3 Specific Requirement Nos. 57-63
301-B-2A*	CO Boiler	NO_X <=40 ppmv on 7 day rolling average at 0% O_2 [Effective January 1, 2015]	NSPS J; CD Paragraph 27
		NO_X < =20 ppmdv on 365 day rolling average at 0% O_2 [Effective January 1, 2015]	
301-B-2B*	CO Boiler	NO_X <=40 ppmv on 7 day rolling average at 0% O_2 [Effective January 1, 2015]	NSPS J; CD; Paragraph 27
		NO_X < =20 ppmdv on 365 day rolling average at 0% O_2 [Effective January 1, 2015]	
191-H-1	Crude Charge Heater	0.0185 lb/mmBTU on a 365 day rolling average	CD; Permit 2180-V4 Specific Requirement No. 11
292-H-1	Light Distillate Gulfiner Reactor Heater	0.098 lb/mmBTU AP-42	Permit app 2113-V3
292-H-2	Light Distillate Gulfiner Stabilizer Heater	0.098 lb/mmBTU AP-42	Permit app 2113-V3
1291-H-2/3	FCCU Light/Heavy Feed Heater	0.04 lb/mmBTU on a 365 day rolling average	CD; Permit 1810-V6 Specific Requirement No. 10
191-H-2	Vacuum Charge Heater	0.16 lb/mmBTU stack test	Permit app 2180-V4
891-H-1	Delayed Coker Charge Heater	0.169 lb/mmBTU stack test	Permit app 2511-V4
491-H-1	Alkylation Isostripper Reboiler	0.04 lb/mmBTU on a 365 day rolling average	CD; Permit 2512-V3 Specific Requirement No. 8
491-H-2	Alkylation Depropanizer Reboiler	0.04 lb/mmBTU on a 365 day rolling average	CD; Permit 2512-V3 Specific Requirement No. 25
100-H-1	Coker Charge Storage Heater	0.098 lb/mmBTU AP-42	Permit app 2513-V7
293-H-1	Heavy Distillate Gulfiner Reactor Feed Heater	0.098 lb/mmBTU AP-42	Permit app 2593-V3
293-H-2	Heavy Distillate Gulfiner Stabilizer Reboiler	0.098 lb/mmBTU AP-42	Permit app 2593-V3
1391-H-1	Catalytic Reformer Feed Heater No. 1	0.04 lb/mmBTU on a 365 day rolling average	CD; Permit 2775-V4 Specific Requirement No. 22
1391-H-2/3	Catalytic Reformer Feed Heater No. 2&3	0.04 lb/mmBTU on a 365 day rolling average	CD; Permit 2775-V4 Specific Requirement No. 31
1391-H-4	Depentanizer Reboiler	0.04 lb/mmBTU on a 365 day rolling average	CD; Permit 2775-V4 Specific Requirement No. 40
1391-H-5	Dry Reactivation Heater	0.098 lb/mmBTU AP-42	Permit app 2775-V4
1791-H-1	Reformate Splitter Reboiler	0.187 lb/mmBTU stack test	Permit app 2775-V4
1792-H-1	Hydroealkylation Charge Heater	0.04 lb/mmBTU on a 365 day rolling average	CD; Permit 2775-V4 Specific Requirement No. 60
291-H-1	Naphiner Reactor Feed Heater	0.098 lb/mmBTU AP-42	Permit app 2775-V4
291-H-2	Naphiner Deisohexanizer Reboiler	0.04 lb/mmBTU on a 365 day rolling average	CD; Permit 2775-V4 Specific Requirement No. 13
303-R-1	Cooling Water Tower No. 1	no NO_X emissions	Permit 2778-V1
406-D-15	Product Dock No. 1 MVR Loading	0.098 lb/mmBTU AP-42	Permit app 2313-V4

Source ID	Source Description	Nitrogen Oxide (NO_X)	
		Limit	Citation
406-D-16	Product Dock No. 2 MVR Loading	0.098 lb/mmBTU AP-42	Permit app 2313-V4
891-CP	Coke Transfer and Storage	no NO_X emissions	Permit 2511-V4

*301-B-2A & 301-B-2B vent to a Wet Gas Scrubber & after January 1, 2015 a Selective Catalytic Reduction (SCR) NOx control device remaining combined with the CO Boiler Stub Vents & FCC Regenerator Vent"

II.

The Department hereby adds Paragraph IX of the **ADMINISTRATIVE ORDER** portion of Administrative Order on Consent, Enforcement Tracking No. AE-AOC-14-00211 to read as follows:

"IX.

The following paragraph addresses transfers of the obligations of this **AMENDED ADMINISTRATIVE ORDER ON CONSENT** and the Facility:

A) The obligations of this **AMENDED ADMINISTRATIVE ORDER ON CONSENT** apply to and are binding upon the United States and the State Parties and upon the Respondent and its officers, employees, Agents, subsidiaries, successors, assigns, or other entities or persons otherwise bound by law.

B) Prior to the execution of any agreement for the transfer of ownership or operation of the Facility, the Respondent shall provide notice of and a copy of this **AMENDED ADMINISTRATIVE ORDER ON CONSENT** to the proposed transferee. No transfer of ownership or operation of any portion of the Facility shall relieve the Respondent of its obligation to ensure that the terms of this **AMENDED ADMINISTRATIVE ORDER ON CONSENT** is implemented unless at least 30 days prior to such transfer, the Respondent provides written notice of the prospective transfer to the EPA Region 6 and the Department and the prospective transferee executes an **AMENDED ADMINISTRATIVE ORDER ON CONSENT** with the Department prior to the effective date of the transfer providing for continued compliance with these standards. The Notice of Transfer shall clearly identify the

parties responsible for any existing violations of this **AMENDED ADMINISTRATIVE ORDER ON CONSENT** and otherwise comply with LAC 33:I.1907. Any attempt to transfer ownership or operation of the Facility without complying with this Paragraph constitutes a violation of this **AMENDED ADMINISTRATIVE ORDER ON CONSENT**."

III.

The Department incorporates all of the remainder of the original **ADMINISTRATIVE ORDER ON CONSENT, ENFORCEMENT TRACKING NO. AE-AOC-14-00211** and **AGENCY INTEREST NO. 2418** as if reiterated herein.

IV.

This **AMENDED ADMINISTRATIVE ORDER ON CONSENT** shall be final and effective upon signature by an authorized representative of the Department and signature by the authorized representative of the Respondent.

Baton Rouge, Louisiana, this 1 day of March, 2016.

Lourdes Iturralde
Assistant Secretary
Office of Environmental Compliance

PHILLIPS 66 COMPANY

By: N. S. Faulkner

Date: 4/29/16

Name: N. S. FAULKNER

Title: ALLIANCE REFINERY MANAGER

Laurence Poche'
Environmental Superintendent
Health, Safety & Environmental Department

PHILLIPS 66
Alliance Refinery
15551 Highway 23 S
P.O. Box 176
Belle Chasse, LA 70037
Phone 504-656-3212

DEQ - OES
2014 JAN 31 AM 8:18

CERTIFIED MAIL, RETURN RECEIPT REQUESTED
7012 3460 0002 4202 8650

Ms. Vivian Aucoin
Louisiana Department of Environmental Quality
Air Permits Division
P.O. Box 4313
Baton Rouge, LA 70821-4313

January 27, 2014

RE: Clarification to Best Available Retrofit Technology (BART) Demonstration
Phillips 66 Company – Alliance Refinery
Belle Chasse, Louisiana
Agency Interest No. 2418

Dear Ms. Aucoin:

This letter is submitted by the Phillips 66 Company Alliance Refinery and concerns the Regional Haze State Implementation Plan (RH SIP) that is being prepared by the Louisiana Department of Environmental Quality (LDEQ) for the state of Louisiana.

As you are aware, on July 3, 2012, the U.S. Environmental Protection Agency (EPA), issued a final rule entitled "Approval and Promulgation of Implementation Plans; Louisiana; Regional Haze State Implementation Plan" pursuant to its statutory authority in Section 169A of the Clean Air Act. (77 Fed. Reg. 39,425). In this final rule, the EPA requested, among other things, that the LDEQ provide additional information to support the Department's conclusion concerning the BART determination for the Alliance Refinery. *See,* 77 Fed. Reg. at 39,431-32.

The attached document provides additional information on the BART demonstration for the Alliance Refinery. Per our earlier discussions, it is our understanding that Phillips 66 and the LDEQ will enter an Administrative Order on Consent (AOC) that will specify the federally-enforceable limits for each BART-affected unit at the refinery.

We appreciate the assistance by the LDEQ and the EPA on this SIP process. If you have further questions about this matter, please do not hesitate to contact me at (504)656-3212.

Sincerely yours,

Laurence R. Poché

Laurence R. Poché

Attachment

cc: Ellen Belkin, U.S. EPA Region 6

A10-14
HSE460 E+10Y/LRP

Phillips 66 Company

Clarification to Best Available Retrofit Technology (BART) Demonstration

Alliance Refinery
Belle Chasse, Louisiana

January 2014

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SECTION 1
BACKGROUND AND PURPOSE

This document is prepared to clarify certain information provided by ConocoPhillips Company in June 2007 as a part of the Best Available Retrofit Technology (BART) demonstration for the Alliance Refinery. Phillips 66 Company now owns and operates the Alliance Refinery. In a final rule published in the Federal Register on July 3, 2012 (*See,* 77 Fed. Reg. 39425), the U.S. Environmental Protection Agency (EPA) issued a partial approval and partial disapproval of the Regional Haze (RH) State Implementation Plan (SIP) for Louisiana.

With respect to the RH SIP elements that concern the Phillips 66 Alliance Refinery (Alliance), the EPA requested additional analysis for certain components of the Alliance BART demonstration submitted in June of 2007. While Alliance agrees with the comments submitted by the LDEQ in response to the proposal published by the EPA on February 28, 2012 (77 Fed. Reg. 11839), this document is nevertheless submitted to respond to EPA's final rule and specifically to Comments 9 and 10 set forth therein. Specifically, this document provides additional information on the following elements of the BART demonstration:

- Additional information on the baseline emissions used in the Alliance BART demonstration submitted in June 2007;
- Updates to emission control technologies applied to or planned for certain emissions units (which were in the preliminary stages of design at the time of Alliance's June 2007 BART submittal).
- Where applicable, verification that the control technologies and emission limits for SO_2, NO_x, and PM selected for the emissions units are among the most stringent;
- A formal analysis of controls selected for the emission units using the factors specified in 40 CFR 51.308(e)(1)(ii)(A); and
- Confirmation of the enforceability of the emission limits for the BART-affected units operated at the Alliance Refinery.

In the proposed and final rules, EPA referenced five BART-affected units at the Alliance Refinery. However, two of the subject emissions units (carbon monoxide (CO) boilers) were combined into a single stream in 2009 and are now routed through one Wet Gas Scrubber (WGS) control device. Hence, discussion of two subject-to-BART units, the CO boilers, will be addressed together within this document as follows:

- EQT 192 – EIQ 301-V-20: FCCU Regenerator Vent Wet Gas Scrubber (formerly EQT 69 and EQT 70 – EIQ 301-B-2A and 301-B-2B: CO Boilers);
- EQT 147 – EIQ 191-H-1: Crude Charge Heater;
- EQT 151 – EIQ 308F-D-1: Low Pressure Flare; and
- EQT 152 – EIQ 308F-D-2: High Pressure Flare.

SECTION 2
SUMMARY OF THE ORIGINAL ALLIANCE BART DEMONSTRATION DATA SUBMITTED IN JUNE 2007

Table 1 shows certain key data and modeling inputs and outputs from the original Alliance BART demonstration. As discussed in Section 1 above, the two CO Boiler emissions units listed in Table 1 will be discussed together in this document. These units are represented in the third row of Table 1 below (the Wet Gas Scrubber – WGS).

Table 1
Key Data and Modeling Inputs and Outputs from the Original Alliance BART Demonstration Submitted in June 2007

Emissions Unit	BART Pollutant	BART CALPUFF Baseline Modeling Input (lb/hr)	CALPUFF Baseline Modeling Visibility Impact (98th Percentile DV Value)	BART CALPUFF Post-Control Modeling Input (lb/hr)	CALPUFF Post-Control Modeling Visibility Impact (98th Percentile DV Value)
FCCU Regenerator Vent - EQT 069 (Was CO Boilers: 301-B-2A)	SO_2	550.24	0.53	275.12	0.34
	PM	48.33		48.33	
	NO_x	151.84		151.84	
FCCU Regenerator Vent - EQT 070 (Was CO Boilers: 301-B-2B)	SO_2	550.24	0.53	275.12	0.34
	PM	48.33		48.33	
	NO_x	151.57		151.57	
FCCU Regenerator Vent - EQT 192 (Now Wet Gas Scrubber: 301-V-20)	SO_2	1,100.47	0.53 & 0.53	550.24	0.34 & 0.34
	PM	96.67		96.67	
	NO_x	303.41		303.41	
Crude Charge Heater - EQT 147 (191-H-1)	SO_2	157.08	0.26	157.08	Not Remodeled
	PM	9.17		9.17	
	NO_x	324.26		324.26	
Low Pressure Flare - EQT 151 (308F-D-1)	SO_2	1,873.93	1.03	44.00	0.032
	PM	0.04		0.04	
	NO_x	26.64		26.64	
High Pressure Flare - EQT 152 (308F-D-2)	SO_2	500.63	0.36	43.92	0.037
	PM	0.04		0.04	
	NO_x	11.02		11.02	

SECTION 3
COMMENTS BY ALLIANCE ON BART REQUIREMENTS AND POLICIES

This section reviews the BART regulatory requirements and policies, and the overall basis for the BART determinations made for the Alliance Refinery. The following sections review the specific determinations for each BART-affected unit.

3.1 Determination of Control Technologies – Addressing EPA's Request for an Analysis of Controls Using the Factors Specified in 40 CFR 51.308(e)(1)(ii)(A)

The factors as required by 40 CFR 51.308(e)(1)(ii)(A) include:

- The control technology available;
- The costs of compliance;
- The energy and non-air quality environmental impacts of compliance,
- Any pollution control equipment in use at the source,
- The remaining useful life of the source, and
- The degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

As the LDEQ stated in its correspondence to EPA, dated March 29, 2012, when facilities use or plan to use the most stringent control technology available, then no further analysis of the BART factors specified in 40 CFR 51.308(e)(1)(ii)(A) is required. This BART procedural exemption is found in 40 CFR 51 Appendix Y(IV)(D)(1)(9):

> "9. If you find that a BART source has controls already in place which are the most stringent controls available (note that this means that all possible improvements to any control devices have been made), then it is not necessary to comprehensively complete each following step of the BART analysis in this section. As long these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source, you may skip the remaining analyses in this section, including the visibility analysis in step 5. Likewise, if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses in this section."

Alliance relied on this BART procedural exemption documented above to streamline the original BART demonstration. Nevertheless, Alliance is providing further information to definitively demonstrate that the emission controls required by the Alliance Refinery Consent Decree (Civil Action No. H-05-0258) do, in fact, represent controls that are among the most stringent available

controls. Alliance is also updating emission control efficiencies based on the latest available data.

3.2 BART Emission Controls Enforceability- Addressing EPA's Concerns on Federally Enforceability

Alliance acknowledges the regional haze requirement that having Consent Decree emissions limits requirements incorporated into a federally-enforceable Administrative Order on Consent (AOC) makes the specified BART controls federally-enforceable for BART.

SECTION 4
BART EMISSIONS UNIT: FCCU REGENERATOR VENT

As previously noted, at the time Alliance prepared its original BART demonstration submittal, emissions from the FCCU Regenerator Vent were split and routed through two CO Boilers (CO Boiler 301-B-2A and CO Boiler 301-B-2B). In 2009, these two CO boiler vents were combined and routed through a new Wet Gas Scrubber (WGS) emissions control system (EQT 192 – EIQ 301-V-20). Also, Alliance recently received construction permit authorization for a new Selective Catalytic Reduction (SCR) unit for NO_x control of the FCCU Regenerator vent. The SCR unit will be placed upstream of the WGS. These current and planned emission control systems on the FCCU, which Alliance has implemented as a result of the Consent Decree (Civil Action No. H-05-0258), represent BART and control or will control emissions of the BART pollutants to the following levels:

- **SO_2**: $\leq$25 ppm_{vd} SO_2 on a 365-day rolling average basis @ 0% O_2; also, $\leq$50 ppm_{vd} SO_2 on a 7-day rolling average basis @ 0% O_2;
- **PM**: $\leq$0.5 lb PM/1000 lb of coke burn on a 3-hr average basis; and
- **NO_x**: $\leq$20 ppm_{vd} NO_x on a 365-day rolling average basis @ 0% O_2; also, $\leq$40 ppm_{vd} NO_x on a 7-day rolling average basis @ 0% O_2.

4.1 FCCU Baseline Emissions

In the Alliance data provided to LDEQ in June, 2007, as shown in Table 1, Alliance chose fairly high emission rates for baseline inputs into the CALPUFF model. These inputs were generally based on a scale-up (safety factor) applied to the permitted average hourly emission rates for the BART pollutants. In accordance with EPA and LDEQ guidance, these baseline model emission rate inputs for the FCCU Regenerator Vent reflected Alliance's best estimate of the maximum 24-hr actual emission rate during normal operating conditions in the time period from 2001 to 2003. Note that the post-BART-control modeling exercise only reduced SO_2 emissions by 50%. No credit for PM and NO_x emission reductions were included in the post-BART-control modeling. This approach to post-BART-control modeling was taken because SO_2 was the major contributor to visibility impairment.

Currently, the level of BART control actually achieved for the FCCU Regenerator Vent is substantially higher than what Alliance initially used for post-BART-control modeling. For the purpose of this demonstration of actual expected BART annual emission reductions, 2003 is used as the BART baseline year.

- **SO_2**: In 2003, SO_2 emissions from the FCCU Regenerator Vent were 2,678.6 tons/yr. In 2011, SO_2 emissions from the FCCU Regenerator Vent were 103.0 tons/yr. This represents an actual pre-BART-to-post-BART SO_2 annual emission reduction of 2,575.6 tons/yr. It also reflects a greater than 96% reduction in SO_2 emissions. Please note that this analysis represents two example years of data, and these results may not be indicative of emission reductions based on comparing other years of data;

- **PM**: In 2003, PM emissions from the FCCU Regenerator Vent were 333.4 tons/yr. In 2011, PM emissions from the FCCU Regenerator Vent were 148.6 tons/yr. This represents an actual pre-BART-to-post-BART PM annual emission reduction of 184.8 tons/yr. It also reflects a greater than 55% reduction in PM emissions. Please note that this analysis represents two example years of data, and these results may not be indicative of emission reductions based on comparing other years of data; and
- **NO_x**: The FCCU will not be operated without an SCR system after December 31, 2014. *See,* Paragraph 27 of Consent Decree, Civil Action No. H-05-258. Information provided in the Authorization to Construct (ATC) submittal for the SCR indicates an expected actual NO_x emission control efficiency of 83.6% based on a post-control NO_x flue gas concentration of 40 ppm_{vd} @ 0% O_2. In 2003, NO_x emissions from the FCCU Regenerator Vent were 757.7 tons/yr. Applying the estimated post-BART NO_x control efficiency to the 2003 actual annual NO_x emission rate from the FCCU results in an actual annual NO_x emissions reduction of 633.4 tons/yr, and an estimated annual NO_x emission rate of 124.3 tons/yr

4.2 FCCU Determination of Control Technologies

Alliance reviewed EPA's RACT/BACT/LAER Clearinghouse (RBLC) and other sources with respect to the use of SCR and WGS controls for NO_x, SO_2 and PM. Alliance agrees with the LDEQ that the emission controls documented above are among the most stringent or "top" level of available controls for FCCU Regeneration Vent. As a result, in accordance with 40 CFR 51, Appendix Y(IV)(D)(1)(9), no additional justification for these BART controls is required and no further BART analysis is required.

4.3 FCCU BART Emission Controls Enforceability

Finally, with respect to the requirement that the BART emission controls for FCCU Regenerator Vent at Alliance be federally enforceable, federal enforceability will be reflected in the AOC.

For the FCCU, the following specific requirements are BART:

- **SO_2**: a required SO_2 control level of $\leq$ 50 ppm_{vd} on a 7-day rolling average basis @ 0% O_2:
- **PM**: a required PM control level of $\leq$ 0.5 lb PM/1000 lb of coke burn on a 3-hr average basis: and
- **NO_x**: a required NO_x control level of $\leq$ 40 ppmvd NO_x on a 7-day rolling average basis @ 0% O_2.

SECTION 5
BART EMISSIONS UNIT: CRUDE CHARGE HEATER

The Crude Charge Heater (EQT 147 – EIQ 191-H-1) fires refinery fuel gas and has a maximum firing rate of 1080 MMBtu/hr.

The current emission control systems associated with the Crude Charge Heater, which Alliance has implemented as a result of their Consent Decree, represent BART, and controls emissions of the BART pollutants to the following levels:

- **SO_2**: ≤ 0.1 grains H_2S/dscf (or 162 ppm_{vd} H_2S) in refinery fuel on a 3-hr rolling average basis. This control level is achieved by amine scrubbing of the Alliance refinery fuel gas on a facility-wide basis for all process heaters;
- **PM**: 0.00745 lb PM/MMBtu of refinery fuel gas fired on an annual average basis using good combustion techniques based on AP-42 Table 1.4.2 (1998). Consistent with all other refinery fuel gas heaters in the U.S., there are no add-on controls for PM emissions; and
- **NO_x**: 0.0185 lb NOx/MMBtu of refinery fuel gas fired on a 365 day rolling average basis. This low NO_x emission limit is achieved by using a SCR control system.

5.1 Crude Charge Heater Baseline Emissions

In the Alliance data provided to LDEQ in June, 2007, Alliance chose emission rates for the baseline that were based on a scale-up (safety factor) applied to the permitted maximum hourly emission rates for the BART pollutants. In accordance with EPA and LDEQ guidance, these baseline model emission rate inputs for the Crude Charge Heater reflected Alliance's best estimate of the maximum 24-hr actual emission rate during normal operating conditions in the time period from 2001 to 2003.

5.2 Crude Charge Heater Determination of Control Technologies

In response to EPA's request for Alliance to address each of the factors specified in 40 CFR 51.308(e)(1)(ii)(A) for this emission unit, Alliance reviewed EPA's RBLC and other literature sources with respect to the use of SCR and amine scrubbing controls for NO_x and SO_2. With respect to PM emissions, no refinery heater in the U.S. was found to have add-on PM controls. The most stringent PM control specified is good combustion techniques, which the Crude Charge Heater employs and is BART. With respect to SO_2, the refinery is required by the consent decree to comply with fuel gas H_2S limits mandated by New Source Performance Standards Subpart J for Petroleum Refineries through the use of a fuel gas amine scrubbing system that applies to all heaters in the refinery, and represents among the most stringent available SO_2 control system. The specified NO_x control level is consistent with controls which are among the most stringent found in RBLC, Selective Catalytic Reduction.

Based on these findings, in accordance with 40 CFR 51, Appendix Y(IV)(D)(1)(9), Alliance contends that no additional justification for this emission unit's BART controls is required and no further BART analysis is required.

5.3 Crude Charge Heater BART Emission Controls Enforceability

As noted, federal enforceability will be reflected in the AOC. For the Crude Unit Heater the following specific requirements are BART:

- **SO_2:** a required SO_2 control level of ≤ 0.1 grains H_2S/dscf (or 162 ppm_{vd} H_2S) in refinery fuel on a 3-hr rolling average basis, and
- **NO_x:** a required NO_x control level of 0.0185 lb NO_x/MMBtu of refinery fuel gas fired on a 365 day rolling average basis:

SECTION 6
BART EMISSIONS UNIT: LOW PRESSURE AND HIGH PRESSURE FLARES

Because of their similarities, the Low Pressure Flare (EQT 151 – EIQ 308F-D-1) and the High Pressure Flare (EQT 152 – EIQ 308F-D-2) are discussed in parallel and will be referred to as "the flares" going forward.

6.1 Flare Baseline Emissions

The current required emission control systems associated with the flares represent BART and are as follows:

> Fuel gas: Hydrogen sulfide ≤ 0.1 gr/dscf (230 mg/dscm). Alliance Refinery shall comply with 40 CFR 60.104(a) by operating and maintaining, in accordance with good air pollution control practices, a Flare Gas Recovery System (FGRS) to control continuous or routine combustion in the flaring device

As shown in Table 1, Alliance chose fairly high emission rates for baseline inputs into the CALPUFF model. These inputs were generally based on a scale-up (safety factor) applied to the permitted maximum hourly emission rates for the BART pollutants. In accordance with EPA and LDEQ guidance, these baseline model emission rate inputs for the flares reflected Alliance's best estimate of the maximum 24-hr actual emission rate during normal operating conditions in the time period from 2001 to 2003. Note that the post-BART-control modeling exercise only showed reductions in SO_2 emissions. No credit for PM and NO_x emission reductions were included in the post-BART-control modeling. This approach to post-BART-control modeling was taken because SO_2 was the major contributor to visibility impairment.

With respect to actual emissions during the pre-BART years of 2001 – 2003, which were prior to Alliance's implementation of CD-required monitoring systems, the flares were not equipped with instrumentation that would allow accurate estimates of actual emissions from the flares. The FGRS did not commence operation until December 2011. Because Alliance was not sure about how the FGRS would perform, Alliance assumed a conservatively low FGRS capture and control efficiency of 50% in the permitting action which incorporated the FGRS. The best and most recent representation of post-BART-control actual emissions from the flares is estimated by applying a conservatively-low FGRS control efficiency of 50% to 2011 actual flare emissions as follows:

- **SO_2:** SO_2 emissions from the combined flares in 2011 were 696.7 tons/yr. Applying a 50% FGRS control efficiency indicates a future-year expected actual SO_2 emission rate of 349.3 tons/yr. Future actual SO_2 emission from the flares may exceed this estimated value depending on future-year specific operating conditions;
- **PM:** PM emissions from the combined flares in 2011 were 0.012 tons/yr. Applying a 50% FGRS control efficiency indicates a future-year expected actual PM emission rate of 0.006

tons/yr. Future actual PM emission from the flares may exceed this estimated value depending on future-year specific operating conditions; and

- **NO_x**: NO_x emissions from the combined flares in 2011 were 60.6 tons/yr. Applying a 50% FGRS control efficiency indicates a future-year expected actual NO_x emission rate of 30.3 tons/yr. Future actual NO_x emission from the flares may exceed this estimated value depending on future-year specific operating conditions.

6.2 Flare Determination of Control Technology

Presently there is not a technically feasible add-on air emission control systems for candle-type flares, such as those present at Alliance. Current control technology incorporates the following to reduce flare emissions, and represents BART: (1) provide a Flare Gas Recovery System (FGRS) to reduce the amount of flare gas combusted in the flare, and (2) provide amine scrubbing of the recovered flare gas to reduce the concentration of H_2S prior to the gas stream being routed to the refinery fuel gas system. Both Alliance flares are equipped with these systems. Therefore, Alliance employs controls which are among the most stringent available BART emission control systems on both of its flares.

Alliance maintains the position that the emission controls documented above are among the most stringent or "top" level of available controls for Alliance flares. As a result, in accordance with 40 CFR 51, Appendix Y(IV)(D)(1)(9), no additional justification for these BART controls is required and no further BART analysis is required.

6.3 Flares BART Emission Controls Enforceability

As noted, federal enforceability will be reflected in the AOC.

SECTION 7
CONCLUSION

In conclusion, Table 7-1 contains the selected control options based on the 5-Step BART Analysis as requested by EPA for the Alliance emission units using the factors specified in 40 CFR 51.308(e)(1)(ii)(A).

Table 7-1
Conclusions from BART 5-Step Analysis

Source ID	Pollutant	Selected BART Control	Emission Limitations reflected in AOC
Crude Charge Heater (191-H-1)	NO_x	-SCR - Good combustion practices	0.0185 lb/MMBTU on a 365-day rolling average basis [See CD (Civil Action H-05-0258) and AOC]
	SO_2	Amine scrubbing of refinery fuel gas	≤0.1 grains H_2S/dscf (or 162 ppm_{vd} H_2S) in refinery fuel on a 3-hr rolling average basis
	PM	Good combustion practices	0.00745 lb PM/MMBtu of refinery fuel gas fired on an annual average basis using good combustion techniques based on AP-42 Table 1.4.2 (1998)
Wet Gas Scrubber (301-V-20) [Formerly CO Boilers (301-B-2A and 301-B-2B)]	SO_2	WGS	≤ 25 ppm_{vd} SO_2 on a 365-day rolling average basis @ 0% O_2 and; ≤ 50 ppm_{vd} SO_2 on a 7-day rolling average basis @ 0% O_2 [See CD (Civil Action H-05-0258) and AOC]
	PM	WGS	≤ 0.5 lb PM/1000 lb of coke burn on a 3-hr average basis [See CD (Civil Action H-05-0258) and AOC]
	NO_x	SCR	≤ 20 ppm_{vd} NO_x on a 365-day rolling average basis @ 0% O_2 and; ≤ 40 ppm_{vd} NO_x on a 7-day rolling average basis @ 0% O_2 [See Consent Decree (Civil Action H-05-0258) and AOC]
Low Pressure Flare (308F-D-1)	NO_x	Flare Gas Recovery System	Operate and maintain Flare Gas Recovery System to control continuous or routine combustion in the Flaring Device [See Consent Decree (Civil Action H-05-0258), ¶139(a) and AOC]
	SO_2		
High Pressure Flare (308F-D-2)	NO_x	Flare Gas Recovery System	Operate and maintain Flare Gas Recovery System to control continuous or routine combustion in the Flaring Device Hydrogen sulfide ≤ 0.1 gr/dscf (230 mg/dscm) [See Consent Decree (Civil Action H-05-0258), ¶139(a) & 139(b) and AOC]
	SO_2		

Phillips 66 Company

Clarification to Best Available Retrofit Technology (BART) Demonstration

Alliance Refinery
Belle Chasse, Louisiana

April 2013

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SECTION 1
BACKGROUND AND PURPOSE

This document is prepared to clarify certain information provided by ConocoPhillips Company in June 2007 as a part of the Best Available Retrofit Technology (BART) demonstration for the Alliance Refinery. Phillips 66 Company now owns and operates the Alliance Refinery. In a final rule published in the Federal Register on July 3, 2012 (*See,* 77 Fed. Reg. 39425), the U.S. Environmental Protection Agency (EPA) issued a partial approval and partial disapproval of the Regional Haze (RH) State Implementation Plan (SIP) for Louisiana.

With respect to the RH SIP elements that concern the Phillips 66 Alliance Refinery (Alliance), the EPA requested additional justification for certain components of the Alliance BART demonstration submitted in June of 2007. While Alliance agrees with the comments submitted by the LDEQ in response to the proposal published by the EPA on February 28, 2012 (77 Fed. Reg. 11839), this document is nevertheless submitted to respond to EPA's final rule and specifically to Comments 9 and 10 set forth therein. Specifically, this document provides additional information on the following elements of the BART demonstration:

- Additional information on the baseline emissions used in the Alliance BART demonstration submitted in June 2007;
- Updates to emission control technologies applied to or planned for certain emissions units (which were in the preliminary stages of design at the time of Alliance's June 2007 BART submittal).
- Verification that the control technologies and emission limits for SO_2, NO_x, and PM selected for the emissions units are among the most stringent;
- A formal analysis of controls selected for the emission units using the factors specified in 40 CFR 51.308(e)(1)(ii)(A); and
- Confirmation of the enforceability of the emission limits for the BART-affected units operated at the Alliance Refinery.

In the proposed and final rules, EPA referenced five BART-affected units at the Alliance Refinery. However, two of the subject emissions units (carbon monoxide (CO) boilers) were combined into a single stream in 2009 and are now routed through one Wet Gas Scrubber (WGS) control device. Hence, there are now four BART emissions units at the Alliance Refinery:

- EQT 192 – EIQ 301-V-20: FCCU Regenerator Vent Wet Gas Scrubber (formerly EQT 69 and EQT 70 – EIQ 301-B-2A and 301-B-2B: CO Boilers);
- EQT 147 – EIQ 191-H-1: Crude Charge Heater;
- EQT 151 – EIQ 308F-D-1: Low Pressure Flare; and
- EQT 152 – EIQ 308F-D-2: High Pressure Flare.

SECTION 2
SUMMARY OF THE ORIGINAL ALLIANCE BART DEMONSTRATION DATA SUBMITTED IN JUNE 2007

Table 1 shows certain key data and modeling inputs and outputs from the original Alliance BART demonstration. As discussed in Section 1 above, the two CO Boiler emissions units listed in Table 1 are now combined into a single emissions unit. This single unit is now represented in the third row of Table 1 below (the Wet Gas Scrubber – WGS).

Table 1
Key Data and Modeling Inputs and Outputs from the Original Alliance BART Demonstration Submitted in June 2007

Emissions Unit	BART Pollutant	BART CALPUFF Baseline Modeling Input (lb/hr)	CALPUFF Baseline Modeling Visibility Impact (98th Percentile DV Value)	BART CALPUFF Post-Control Modeling Input (lb/hr)	CALPUFF Post-Control Modeling Visibility Impact (98th Percentile DV Value)
FCCU Regenerator Vent - EQT 069 (Was CO Boilers: 301-B-2A)	SO_2	550.24	0.53	275.12	0.34
	PM	48.33		48.33	
	NO_x	151.84		151.84	
FCCU Regenerator Vent - EQT 070 (Was CO Boilers: 301-B-2B)	SO_2	550.24	0.53	275.12	0.34
	PM	48.33		48.33	
	NO_x	151.57		151.57	
FCCU Regenerator Vent - EQT 192 (Now Wet Gas Scrubber: 301-V-20)	SO_2	1,100.47	0.53 & 0.53	550.24	0.34 & 0.34
	PM	96.67		96.67	
	NO_x	303.41		303.41	
Crude Charge Heater - EQT 147 (191-H-1)	SO_2	157.08	0.26	157.08	Not Remodeled
	PM	9.17		9.17	
	NO_x	324.26		324.26	
Low Pressure Flare - EQT 151 (308F-D-1)	SO_2	1,873.93	1.03	44.00	0.032
	PM	0.04		0.04	
	NO_x	26.64		26.64	
High Pressure Flare - EQT 152 (308F-D-2)	SO_2	500.63	0.36	43.92	0.037
	PM	0.04		0.04	
	NO_x	11.02		11.02	

SECTION 3
COMMENTS BY ALLIANCE ON BART REQUIREMENTS AND POLICIES

This section reviews the BART regulatory requirements and policies, and the overall basis for the BART determinations made for the Alliance Refinery. The following sections review the specific determinations for each BART-affected unit.

3.1 Baseline Emissions - Addressing EPA's Request for Basis for Selecting "Baseline Emissions"

The term "baseline emissions" used in the context of a BART analysis is not specifically defined in either 40 CFR 51.308 or 40 CFR 51 Appendix Y. Alliance interprets EPA's referral in the FRN to baseline emissions to be the emissions that were used in the facility's baseline CALPUFF modeling demonstration. The regulations and guidance give conflicting advice on the definition of "baseline emissions" for BART purposes. Consider the following references:

In 40 CFR 51.308, the term "baseline emissions" is not used in the regulation except in the following quotation at 51.308(d)(3)(iii):

> "The State must identify the baseline emissions inventory on which its strategies are based. The baseline emissions inventory year is presumed to be the most recent year of the consolidated periodic emissions inventory."

Alliance interprets this regulatory text to indicate that an inventory based on actual annual emissions from a source (facility) is used as the baseline. This approach of using an actual annual emissions inventory seems to be supported by the following text from 40 CFR 51 Appendix Y, Section IV.D.4.d:

> Appendix Y Section IV.D.4.d:
> "How do I calculate baseline emissions?
>
> 1. The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period.
> 2. When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.

3. For example, the baseline emissions calculation for an emergency standby generator may consider the fact that the source owner would not operate more than past practice of 2 weeks a year. On the other hand, baseline emissions associated with a base-loaded turbine should be based on its past practice which would indicate a large number of hours of operation. This produces a significantly higher level of baseline emissions than in the case of the emergency/standby unit and results in more cost-effective controls. As a consequence of the dissimilar baseline emissions, BART for the two cases could be very different.

EPA's interpretation of baseline modeling inputs appears to conflict with this description above of using actual annual emissions as BART baseline emissions. Specifically, in 40 CFR 51 Appendix Y, Section III, the following guidance is presented with respect to CALPUFF modeling inputs:

> "The emissions estimates used in the models are intended to reflect steady-state operating conditions during periods of high capacity utilization. We do not generally recommend that emissions reflecting periods of start-up, shutdown, and malfunction be used, as such emission rates could produce higher than normal effects than would be typical of most facilities. We recommend that States use the 24 hour average actual emission rate from the highest emitting day of the meteorological period modeled, unless this rate reflects periods start-up, shutdown, or malfunction."

The guidance above indicates a baseline emission level base on a 24-hr emissions rate. This is further supported in LDEQ guidance. In LDEQ's February 2007 Modeling Protocol to Determine Sources Subject to BART in the State of Louisiana, facilities are instructed

> "Emission rates for the BART analyses follow EPA's BART guidance. Specifically, the 24-hour average actual emission rate from the highest emitting day of the year under normal operations should be modeled. Identification of the maximum 24-hour actual emission rate should be made for each of the most recent three (3) years (2001-2003), according to the following prioritization:
>
> 1. Continuous Emissions Monitoring data;
> 2. Facility emissions tests;
> 3. Emissions factors;
> 4. Permit limits; or lastly; and
> 5. Potential to emit.

3.2 Determination of Control Technologies – Addressing EPA's Request for an Analysis of Controls Using the Factors Specified in 40 CFR 51.308(e)(1)(ii)(A)

The factors as required by 40 CFR 51.308(e)(1)(ii)(A) include:

- The control technology available;
- The costs of compliance;
- The energy and non-air quality environmental impacts of compliance,
- Any pollution control equipment in use at the source,
- The remaining useful life of the source, and
- The degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

As the LDEQ stated in its correspondence to EPA, dated March 29, 2012, when facilities use or plan to use the most stringent control technology available, then no further analysis of the BART factors specified in 40 CFR 51.308(e)(1)(ii)(A) is required. This BART procedural exemption is found in 40 CFR 51 Appendix Y(IV)(D)(1)(9):

> "9. If you find that a BART source has controls already in place which are the most stringent controls available (note that this means that all possible improvements to any control devices have been made), then it is not necessary to comprehensively complete each following step of the BART analysis in this section. As long these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source, you may skip the remaining analyses in this section, including the visibility analysis in step 5. Likewise, if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses in this section."

Alliance relied on this BART procedural exemption documented above to streamline the original BART demonstration. Nevertheless, Alliance is providing further information to definitively demonstrate that the emission controls required by the Alliance Refinery Consent Decree (Civil Action No. H-05-0258) do, in fact, represent the most stringent available controls. Alliance is also updating emission control efficiencies based on the latest available data.

3.3 BART Emission Controls Enforceability- Addressing EPA's Concerns on Federally Enforceability

Alliance agrees with the LDEQ's position that having Consent Decree requirements incorporated into a federally-enforceable Title V permit also makes the specified BART controls federally-enforceable. Federal enforceability can be reflected in the Emissions Rates Tables and/or the Specific Requirements section of the Title V permit for these units as mandated by the fully-delegated permitting authority (LDEQ).

SECTION 4
BART EMISSIONS UNIT: FCCU REGENERATOR VENT

As previously noted, at the time Alliance prepared its original BART demonstration submittal, emissions from the FCCU Regenerator Vent were split and routed through two CO Boilers (CO Boiler 301-B-2A and CO Boiler 301-B-2B). In 2009, these two CO boiler vents were combined and routed through a new Wet Gas Scrubber (WGS) emissions control system (EQT 192 – EIQ 301-V-20). As a result these two emission units in the original Alliance BART demonstration are now one emissions unit. Also, Alliance recently received construction permit authorization for a new Selective Catalytic Reduction (SCR) unit for NO_x control of the FCCU Regenerator vent. The SCR unit will be placed upstream of the WGS. These current and planned emission control systems on the FCCU, which Alliance has implemented as a result of the Consent Decree (Civil Action No. H-05-0258), control or will control emissions of the BART pollutants to the following levels:

- **SO_2**: $\leq$ 25 ppm_{vd} SO_2 on a 365-day rolling average basis @ 0% O_2, as documented in Specific Requirement 106 in the current FCCU Title V Permit No. 1810-V4AA; also, $\leq$ 50 ppm_{vd} SO_2 on a 7-day rolling average basis @ 0% O_2, as documented in Specific Requirement 107 in the current FCCU Title V Permit No. 1810-V4AA;
- **PM**: $\leq$ 0.5 lb PM/1000 lb of coke burn on a 3-hr average basis, as documented in Specific Requirement 105 in the current FCCU Title V Permit No. 1810-V4AA; and
- **NO_x**: $\leq$ 20 ppm_{vd} NO_x on a 365-day rolling average basis @ 0% O_2, as documented in the Alliance Authorization to Construct (ATC) submittal to LDEQ in March 2012; also, $\leq$ 40 ppm_{vd} NO_x on a 7-day rolling average basis @ 0% O_2, as documented in the Alliance Authorization to Construct (ATC) submittal to LDEQ in March 2012 – these requirements will soon be incorporated into the FCCU Title V Permit No. 1810-V4AA.

4.1 FCCU Baseline Emissions

To be conservative, as shown in Table 1, Alliance chose fairly high emission rates for baseline inputs into the CALPUFF model. These inputs were generally based on a scale-up (safety factor) applied to the permitted average hourly emission rates for the BART pollutants. In accordance with EPA and LDEQ guidance, these baseline model emission rate inputs for the FCCU Regenerator Vent reflected Alliance's best estimate of the maximum 24-hr actual emission rate during normal operating conditions in the time period from 2001 to 2003. Note that the post-BART-control modeling exercise only reduced SO_2 emissions by 50%. No credit for PM and NO_x emission reductions were included in the post-BART-control modeling. This conservative approach to post-BART-control modeling was taken because SO_2 was the major contributor to visibility impairment. Also, simply reducing the SO_2 emission input to the CALPUFF model generated visibility results well below the acceptable 0.5 DV guideline level. In accordance with 40 CFR 51, Appendix Y(IV)(D)(1)(9), a visibility analysis was not required for this analysis because the FCCU is employing the most stringent available BART controls.

In fact, the level of BART control actually achieved for the FCCU Regenerator Vent is substantially higher than what Alliance used for post-BART-control modeling. This leads to a

further discussion of what EPA means by the term "baseline emissions", which, as previously noted, is an undefined term in the BART regulations and guidance. Alliance believes that what EPA may be seeking in their comments in the July 9, 2012, *Federal Register* notice is an estimate of actual annual emission reductions achieved by employing BART controls. Estimates of these BART control emission reductions and control efficiencies for the FCCU Regenerator Vent are provided below. For the purpose of this demonstration of actual expected BART annual emission reductions, 2003 is used as the BART baseline year.

- **SO_2**: In 2003, SO_2 emissions from the FCCU Regenerator Vent were 2,678.6 tons/yr. In 2011, SO_2 emissions from the FCCU Regenerator Vent were 103.0 tons/yr. This represents an actual pre-BART-to-post-BART SO_2 annual emission reduction of 2,575.6 tons/yr. It also reflects a greater than 96% reduction in SO_2 emissions. Please note that this analysis represents two example years of data, and these results may not be indicative of emission reductions based on comparing other years of data;
- **PM**: In 2003, PM emissions from the FCCU Regenerator Vent were 333.4 tons/yr. In 2011, PM emissions from the FCCU Regenerator Vent were 148.6 tons/yr. This represents an actual pre-BART-to-post-BART PM annual emission reduction of 184.8 tons/yr. It also reflects a greater than 55% reduction in PM emissions. Please note that this analysis represents two example years of data, and these results may not be indicative of emission reductions based on comparing other years of data; and
- **NO_x**: The SCR system which controls NO_x emissions from the FCCU has not yet been installed. However, information provided in the ATC submittal for the SCR indicates an expected actual NO_x emission control efficiency of 83.6% based on a post-control NO_x flue gas concentration of 40 ppm_{vd} @ 0% O_2. In 2003, NO_x emissions from the FCCU Regenerator Vent were 757.7 tons/yr. Applying the estimated post-BART NO_x control efficiency to the 2003 actual annual NO_x emission rate from the FCCU results in an actual annual NO_x emissions reduction of 633.4 tons/yr, and an estimated annual NO_x emission rate of 124.3 tons/yr.

4.2 FCCU Determination of Control Technologies

Alliance reviewed EPA's RACT/BACT/LAER Clearinghouse (RBLC) and other sources with respect to the use of SCR and WGS controls for NO_x, SO_2 and PM. Alliance agrees with the LDEQ that the emission controls documented above are equivalent to the most stringent or "top" level of available controls for FCCU Regeneration Vent. As a result, in accordance with 40 CFR 51, Appendix Y(IV)(D)(1)(9), no additional justification for these BART controls is required and no further BART analysis of any kind is required. It is, therefore, unnecessary for Alliance to address each of the factors specified in 40 CFR 51.308(e)(1)(ii)(A). However, in response to the July 9, 2012 final rule, Alliance has provided additional information concerning how the original BART demonstration for the FCCU was performed and an updated effectiveness of the Alliance BART controls based on the latest available information.

4.3 FCCU BART Emission Controls Enforceability

Finally, with respect to whether the BART emission controls for FCCU Regenerator Vent at Alliance are federally enforceable, Alliance agrees with the LDEQ that having Consent Decree

requirements incorporated into a federally-enforceable Title V permit also makes the specified BART controls federally-enforceable. Alliance does not envision a circumstance where the LDEQ would allow relaxing any of the Consent Decree-required controls for the FCCU, as specified above. As noted, federal enforceability can be reflected in the Emissions Rates Tables and/or the Specific Requirements section of the Title V permit for these units at the discretion of the delegated permitting authority. For example, for the FCCU the following specific requirements could be added to the Title V permit:

- **SO_2**: For the SO_2 BART limit for the FCCU, add the following language to Specific Requirement 107 in the current FCCU Title V Permit No. 1810-V4AA, which specifies a CD-required SO_2 control level of ≤ 50 ppm_{vd} on a 7-day rolling average basis @ 0% O_2: "This SO_2 emission control level represents a Best Available Retrofit Technology (BART) determination for this emissions unit pursuant to the Louisiana Regional Haze (RH) State Implementation Plan (SIP)."
- **PM**: For PM BART limit for the FCCU, add the following language to Specific Requirement 105 in the current FCCU Title V Permit No. 1810-V4AA, which specifies a CD-required PM control level of ≤ 0.5 lb PM/1000 lb of coke burn on a 3-hr average basis: "This PM emission control level represents a Best Available Retrofit Technology (BART) determination for this emissions unit pursuant to the Louisiana Regional Haze (RH) State Implementation Plan (SIP). ;" and
- **NO_x:** For the NO_x BART limit for the FCCU, add the following language to the yet-to-be added Specific Requirement in the FCCU Title V Permit that will specify a CD-required NO_x control level of ≤ 40 ppmvd NO_x on a 7-day rolling average basis @ 0% O2: "This NO_x emission control level represents a Best Available Retrofit Technology (BART) determination for this emissions unit pursuant to the Louisiana Regional Haze (RH) State Implementation Plan (SIP). "

SECTION 5
BART EMISSIONS UNIT: CRUDE CHARGE HEATER

The Crude Charge Heater (EQT 147 – EIQ 191-H-1) fires refinery fuel gas and has a maximum firing rate of 1080 MMBtu/hr. The baseline CALPUFF modeling for the Crude Charge Heater resulted in a modeled visibility impairment of 0.26 DV, which is less than the guideline level of concern of 0.5 DV; therefore, no additional control technology or modeling evaluation for this emissions unit was required. Note that, Alliance's Consent Decree (Civil Action No. H-05-0258) required reductions in pollutant emissions from the Crude Charge Heater that will result in an even lower visibility impairment post control than the reported baseline visibility impairment of 0.26 DV.

The current emission control systems associated with the Crude Charge Heater, which Alliance has implemented as a result of their Consent Decree, control emissions of the BART pollutants to the following levels:

- **SO_2**: $\leq$ 0.1 grains H_2S/dscf (or 162 ppm_{vd} H_2S) in refinery fuel on a 3-hr rolling average basis, as documented in Specific Requirement 1in the current Crude Unit Title V Permit No. 2180-V3. This control level is achieved by amine scrubbing of the Alliance refinery fuel gas on a facility-wide basis for all process heaters;
- **PM**: 0.00745 lb PM/MMBtu of refinery fuel gas fired on an annual average basis using good combustion techniques based on AP-42 Table 1.4.2 (1998), as documented in the annual emission rate limit for the Crude Charge Heater in the current Crude Unit Title V Permit No. 2180-V3. Consistent with all other refinery fuel gas heaters in the U.S., there are no add-on controls for PM emissions; and
- **NO_x**: 0.0185 lb NOx/MMBtu of refinery fuel gas fired on a 365 day rolling average basis as documented in Specific Requirement 7 in the current Crude Unit Title V Permit No. 2180-V3. This low NO_x emission limit is achieved by using a SCR control system.

5.1 Crude Charge Heater Baseline Emissions

To be conservative Alliance chose emission rates for the baseline that were based on a scale-up (safety factor) applied to the permitted maximum hourly emission rates for the BART pollutants. In accordance with EPA and LDEQ guidance, these baseline model emission rate inputs for the Crude Charge Heater reflected Alliance's best estimate of the maximum 24-hr actual emission rate during normal operating conditions in the time period from 2001 to 2003.

5.2 Crude Charge Heater Determination of Control Technologies

In response to EPA's request for Alliance to address each of the factors specified in 40 CFR 51.308(e)(1)(ii)(A) for this emission unit, Alliance reviewed EPA's RBLC and other literature sources with respect to the use of SCR and amine scrubbing controls for NO_x and SO_2. With respect to PM emissions, no refinery heater in the U.S. was found to have add-on PM controls. The most stringent PM control specified is good combustion techniques, which the Crude Charge Heater employs. With respect to SO_2, the refinery is required by the consent decree to comply with fuel gas H_2S limits mandated by New Source Performance Standards Subpart J for Petroleum Refineries through the use of a fuel gas amine scrubbing system that applies to all heaters in the refinery, and represents the most stringent available SO_2 control system. The specified NO_x control level is consistent with the top level of control found in RBLC, Selective Catalytic Reduction.

Based on these findings, in accordance with 40 CFR 51, Appendix Y(IV)(D)(1)(9), Alliance contends that no additional justification for this emission unit's BART controls is required and no further BART analysis of any kind is required. However, in an attempt to address some of EPA's specific concerns, Alliance is providing a document to address that provides a formal evaluation of each of the factors specified in 40 CFR 51.308(e)(1)(ii)(A).

5.3 Crude Charge Heater BART Emission Controls Enforceability

As noted, federal enforceability can be reflected in the Emissions Rates Tables and/or the Specific Requirements section of the Title V permit for these units at the discretion of the delegated permitting authority. For example, for the Crude Unit Heater the following specific requirements could be added to the Title V permit:

- **SO_2**: For the SO_2 BART limit for the Crude Charge Heater, add the following language to Specific Requirement 1 in the current Crude Unit Title V Permit No. 2180-V3, which specifies a CD-required SO_2 control level of ≤ 0.1 grains H_2S/dscf (or 162 ppm_{vd} H_2S) in refinery fuel on a 3-hr rolling average basis,: "This SO_2 emission control level represents a Best Available Retrofit Technology (BART) determination for this emissions unit pursuant to the Louisiana Regional Haze (RH) State Implementation Plan (SIP)." and
- **NO_x:** For the NO_x BART limit for the Crude Charge Heater, add the following language to Specific Requirement 7 in the current Crude Unit Title V Permit No. 2180-V3, which specifies a CD-required NO_x control level of 0.0185 lb NO_x/MMBtu of refinery fuel gas fired on a 365 day rolling average basis: "This NO_x emission control level represents a Best Available Retrofit Technology (BART) determination for this emissions unit pursuant to the Louisiana Regional Haze (RH) State Implementation Plan (SIP)."

SECTION 6
BART EMISSIONS UNIT: LOW PRESSURE AND HIGH PRESSURE FLARES

Because of their similarities, the Low Pressure Flare (EQT 151 – EIQ 308F-D-1) and the High Pressure Flare (EQT 152 – EIQ 308F-D-2) are discussed in parallel and will be referred to as flares going forward.

6.1 Flare Baseline Emissions

The current CD-required emission control systems associated with the flares are specified in Specific Requirements 1 and 56 in the current Flares Unit Title V Permit No. 2779-V3 as follows:

> "...Fuel gas: Hydrogen sulfide ≤ 0.1 gr/dscf (230 mg/dscm). Alliance Refinery shall comply with 40 CFR 60.104(a) by operating and maintaining, in accordance with good air pollution control practices, a Flare Gas Recovery System (FGRS) to control continuous or routine combustion in the flaring device..."

To be conservative, as shown in Table 1, Alliance chose fairly high emission rates for baseline inputs into the CALPUFF model. These inputs were generally based on a scale-up (safety factor) applied to the permitted maximum hourly emission rates for the BART pollutants. In accordance with EPA and LDEQ guidance, these baseline model emission rate inputs for the flares reflected Alliance's best estimate of the maximum 24-hr actual emission rate during normal operating conditions in the time period from 2001 to 2003. Note that the post-BART-control modeling exercise only showed reductions in SO_2 emissions. No credit for PM and NO_x emission reductions were included in the post-BART-control modeling. This conservative approach to post-BART-control modeling was taken because SO_2 was the major contributor to visibility impairment. Also, simply reducing the SO_2 emission input to the CALPUFF model provided generated visibility results well below the acceptable 0.5 DV guideline level. Again, please keep in mind that, in accordance with 40 CFR 51, Appendix Y(IV)(D)(1)(9), no visibility analysis is required for this case because the flares are employing the most stringent available BART controls.

With respect to actual emissions during the pre-BART years of 2001 – 2003, which were prior to Alliance's implementation of CD-required monitoring systems, the flares were not equipped with instrumentation that would allow accurate estimates of actual emissions from the flares. The FGRS did not commence operation until December 2010. Because Alliance was not sure about how the FGRS would perform, Alliance assumed a conservatively low FGRS capture and control efficiency of 50% in the permitting action which incorporated the FGRS. The best and most recent representation of post-BART-control actual emissions from the flares is estimated by applying a conservatively-low FGRS control efficiency of 50% to 2011 actual flare emissions as follows:

- **SO_2**: SO_2 emissions from the combined flares in 2011 were 696.7 tons/yr. Applying a 50% FGRS control efficiency indicates a future-year expected actual SO_2 emission rate of 349.3 tons/yr. Future actual SO_2 emission from the flares may exceed this estimated value depending on future-year specific operating conditions;
- **PM**: PM emissions from the combined flares in 2011 were 0.012 tons/yr. Applying a 50% FGRS control efficiency indicates a future-year expected actual PM emission rate of 0.006 tons/yr. Future actual PM emission from the flares may exceed this estimated value depending on future-year specific operating conditions; and
- **NO_x**: NO_x emissions from the combined flares in 2011 were 60.6 tons/yr. Applying a 50% FGRS control efficiency indicates a future-year expected actual NO_x emission rate of 30.3 tons/yr. Future actual NO_x emission from the flares may exceed this estimated value depending on future-year specific operating conditions.

6.2 Flare Determination of Control Technology

Presently there is not a technically feasible add-on air emission control systems for candle-type flares, such as those present at Alliance. Current control technology incorporates the following to reduce flare emissions: (1) provide amine scrubbing of the flare gas to reduce the concentration of H_2S prior to the gas stream being routed to the flare, and (2) provide a Flare Gas Recovery System (FGRS) to reduce the amount of flare gas combusted in the flare. Both Alliance flares are equipped with these systems. Therefore, Alliance employs the "top" or most stringent available BART emission control systems on both of its flares.

Alliance and LDEQ still maintain the position that the emission controls documented above are equivalent to the most stringent or "top" level of available controls for Alliance flares. As a result, in accordance with 40 CFR 51, Appendix Y(IV)(D)(1)(9), no additional justification for these BART controls is required and no further BART analysis of any kind is required. It is therefore unnecessary for Alliance to address each of the factors specified in 40 CFR 51.308(e)(1)(ii)(A). However, in an attempt to address some of EPA's specific concerns, Alliance is providing some additional information concerning how the original BART demonstration for the flares was performed and the latest expected effectiveness of the Alliance BART controls based on the latest available information.

6.3 Flares BART Emission Controls Enforceability

As noted, federal enforceability can be reflected in the Emissions Rates Tables and/or the Specific Requirements section of the Title V permit for these units at the discretion of the delegated permitting authority. For example, for the flares subject to BART, the following specific requirements could be added to the Title V permit:

> "This emission control levels and systems specified here represent a Best Available Retrofit Technology (BART) determination for this emissions unit pursuant to the Louisiana Regional Haze (RH) State Implementation Plan (SIP)."

Phillips 66 Company

Supplemental Analysis for Best Available Retrofit Technology (BART) Demonstration

Alliance Refinery
Belle Chasse, Louisiana

April 2013

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SECTION 1
BACKGROUND AND PURPOSE

1.1 Background

This document is prepared to supplement the prior Best Available Retrofit Technology (BART) demonstration, submitted on behalf of the ConocoPhillips Alliance Refinery (now the Phillips 66 Alliance Refinery) in June 2007. In a final rule published in the Federal Register on July 3, 2012 (*See,* 77 Fed. Reg. 39425), the U.S. Environmental Protection Agency (EPA) issued a partial approval and partial disapproval of the Regional Haze (RH) State Implementation Plan (SIP) for Louisiana.

With respect to the Alliance Refinery, the EPA seeks additional information to support the Louisiana Department of Environmental Quality's (LDEQ's) conclusion "that the most stringent controls available have been installed or are scheduled to be installed on the [BART-affected] sources." *See,* 77 Fed. Reg. 39431. While the Alliance Refinery agrees with the comments submitted by the LDEQ in response to the proposal published by the EPA on February 28, 2012 (77 Fed. Reg. 11839), this document is nevertheless submitted to respond to EPA's final rule and specifically to Comment 9 set forth therein.

In its response, the EPA requested that the LDEQ provide additional information to support the above conclusion. The EPA specifically requested that an analysis be provided for the five BART-affected units subject to the federal consent decree for each pollutant to satisfy the requirement in 40 CFR 51.308(e)(1)(ii)(A). The EPA also stated that supplemental information such as the year or baseline emissions be provided to verify the emissions reduction information previously provided. This document provides the additional information referenced by the EPA in Comment 9 of the July 3, 2012 final rule. Documentation on the baseline emissions for the referenced units is addressed in the Clarification to BART Demonstration document.

In the proposed and final rules, EPA referenced five BART-affected units at the Alliance Refinery. However, two of the subject emissions units (carbon monoxide (CO) boilers) were combined into a single stream in 2009 and are now routed through a single Wet Gas Scrubber (WGS). Hence, there are now four BART emissions units at the Alliance Refinery:

- EQT 192 – EIQ 301-V-20: FCCU Regenerator Vent Wet Gas Scrubber (formerly the EQT 69 and EQT 70 – EIQ 301-B-2A and 301-B-2B: CO Boilers);
- EQT 147 – EIQ 191-H-1: Crude Charge Heater;
- EQT 151 – EIQ 308F-D-1: Low Pressure Flare; and
- EQT 152 – EIQ 308F-D-2: High Pressure Flare.

1.2 Purpose

In the final rule, the EPA referenced the BART evaluation requirements set forth in 40 CFR 51.308(e)(1)(ii)(A) which provides:

> The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

This BART Demonstration follows the guidelines and definitions set forth in 40 CFR 51, Appendix Y.IV.D 23, including the following five-step analysis:

Step 1: Commercially available control options are identified.

Step 2: Technically infeasible options are rejected.

Step 3: Remaining control options are ranked according to control effectiveness.

Step 4: The following items are evaluated: cost effectiveness, environmental effects, energy impacts, and site-specific factors. Generally, the cost effectiveness parameter is stated as either annualized cost (on a total or incremental basis) to control a single ton of pollutant.

Step 5: Selection of appropriate BART option as the most effective control technology that is not rejected based on adverse economic, environmental, and/or energy impacts. To satisfy the above steps, this document will analyze controls for the Alliance Refinery emission units of concern using the following guidelines:

- The control technology available;
- The costs of compliance;
- The energy and non-air quality environmental impacts of compliance,
- Any pollution control equipment in use at the source,
- The remaining useful life of the source, and
- The degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

SECTION 2
BART FOR NITROGEN OXIDES (NO_X) FOR CRUDE CHARGE HEATER (191-H-1)

2.1 Step 1 - Identify Available Retrofit Emissions Control Technologies

The BART-eligible source, 191-H-1, fires refinery fuel gas and has a maximum heater duty of 1080 MMBtu/hr. A search for heaters and boilers firing gaseous fuels in the range of heater duties greater than 250 MMBtu/hr was conducted, and the control technologies identified in the search include the following:

- Low NO_x burners;
- Ultra-low NO_x burners;
- Flue gas recirculation;
- Water/steam injection;
- Selective non-catalytic reduction; and
- Selective catalytic reduction.

2.2 Step 2 - Eliminate Technically Infeasible Options

Low NO_x Burners and Ultra-low NO_x Burners – *Technically Infeasible*
Low NO_x Burners (LNBs) typically use staged air or staged fuel combustion principles to minimize the amount of thermal NO_x formation. Staged combustion limits the amount of oxygen available to react with nitrogen at the combustion zones in the heater/firebox where temperature profiles favor thermal NO_x formation. However, current industry practice is to install Ultra-low NO_x Burners (ULNBs) on process heaters (discussed below). Thus, based on current industry practices and availability of burner designs, LNBs were not included in the cost effectiveness evaluation for the subject process heater as UNLB technology is a more effective option.

Ultra-low NO_x Burners (ULNBs) use staged combustion principles similar to LNBs, and have special designs which facilitate internal flue gas recirculation (FGR). However, ULNBs are infeasible as this technology would restrict Alliance's ability to obtain the required heat transfer in process operations.

Flue Gas Recirculation – *Technically Infeasible*
FGR is a NO_x control technology that recycles 15% to 30% of the flue gas to the primary combustion zone. The recirculation dilutes the combustion reactants, reduces the peak temperature, and reduces the local oxygen concentrations. Thus, thermal NO_x formation is inhibited. FGR can only be used for a few select direct-fired heaters and typically is not cost effective due to increased energy costs; therefore, FGR was not included in cost effectiveness evaluation for the subject process heater.

Water/Steam Injection – *Technically Infeasible*
Water/steam injection involves the introduction of water/steam into the combustion zone of the burner. The water/steam acts as a thermal ballast which causes the peak flame temperature to be reduced, thereby limiting the thermal NO_x formation. Drawbacks of water/steam injection include increased equipment corrosion and reduced thermal and fuel efficiencies; therefore, water/steam injection was not included in cost effectiveness evaluation for the subject process heater.

Selective Non-Catalytic Reduction – *Technically Infeasible*
A potential post-combustion control includes selective non-catalytic reduction (SNCR). SNCR requires a flue gas exit temperature in the range of 1200 to 2000°F, with an optimum operating exit temperature between 1600 and 2000°F. Process heaters typically have exhaust temperatures ranging from 300 to 600°F. Therefore, additional fuel combustion or a similar energy supply would be needed to achieve exhaust temperatures compatible with SNCR operation. Due to this temperature restriction and the lack of information demonstrating that SNCR is an effective control technology for process heaters, SNCR was not included in cost effectiveness evaluation for the subject process heater.

Selective Catalytic Reduction – *Technically Feasible*
Selective catalytic reduction (SCR) is a proven NO_x post combustion control technology that usually offers the greatest potential for NO_x reductions. Vendors will typically guarantee 70% to 90% reduction of inlet NO_x levels, but this is a function of inlet NO_x loading, as shown below:

$$4\ NO + 4\ NH_3 + 3\ O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Operating temperature is highly important in SCR technology. The reactor must be operated at a temperature between 600 and 800°F. If the operating temperature is below this range, the catalyst activity is reduced allowing unreacted NH_3 to be emitted. If the operating temperature is higher than this range, NH_3 may be oxidized forming additional NO_x and may cause the catalyst to become thermally stressed.

2.3 Step 3 – Ranking Remaining Control Options Based on Effectiveness

The NO_x control technology alternatives that are considered technically feasible for the process heaters in this project are ranked in the order of most stringent to least stringent to form a control technology hierarchy. See Table 2-1 below.

Table 2-1
NO_x Control Hierarchy

Type of NO_x Control	NO_x Emission Factor (lb/MMBtu)	Control Ranking
SCR	0.0185	1
Good Combustion Practices (base case)	Variable Emission Factors (EFs)	2

2.4 Step 4 – Evaluate Most Cost Effective Controls

Alliance achieves 0.0185 lb NO_x /MMBtu of refinery fuel gas fired on a 365 day rolling average basis with the use of a SCR. As the SCR is demonstrated in Table 2-1 to be the most effective control alternative, no cost evaluation is necessary.

2.5 Step 5 - Selection of BART for NO_x Control

As a requirement of the consent decree, SCR was installed as the control device for 191-H-1 to achieve the emission rate of 0.0185 lb/MMBTU on a 365-day rolling average basis. Alliance asserts that this is the top level of control as the specified NO_x control level is consistent with the top level of control found in RBLC.

SECTION 3
BART FOR PARTICULATE MATTER (PM) AND SULFUR DIOXIDE (SO_2) FOR CRUDE CHARGE HEATER (191-H-1)

Based upon a review of EPA's RBLC and other literature sources, Alliance maintains that the emission controls documented for SO_2 and PM from the Crude Charge Heater are equivalent to the most stringent or "top" level of available controls. With respect to PM emissions, no refinery heater in the United States was found to have add-on PM controls. The most stringent PM control specified is good combustion techniques, which the Crude Charge Heater employs.

With respect to SO_2, the refinery is required by the consent decree to comply with fuel gas H_2S limits mandated by New Source Performance Standards Subpart J for Petroleum Refineries through the use of a fuel gas amine scrubbing system that applies to all heaters in the refinery, and represents the most stringent available SO_2 control system.

In conclusion, the current emission control systems for SO_2, which Alliance has implemented as a result of the consent decree, and PM associated with the Crude Charge Heater are the top level of control and a detailed BART analysis is not necessary. The Crude Charge Heater SO_2 and PM pollutants are controlled to the following levels:

- **SO_2**: ≤ 0.1 grains H_2S/dscf (or 162 ppm_{vd} H_2S) in refinery fuel on a 3-hr rolling average basis. This control level is achieved by amine scrubbing of the Alliance refinery fuel gas on a facility-wide basis for all process heaters.
- **PM**: 0.00745 lb PM/MMBtu of refinery fuel gas fired on an annual average basis using good combustion techniques based on AP-42 Table 1.4.2 (1998). Consistent with all other refinery fuel gas heaters operated in the U.S., there are no add-on controls for PM emissions.

SECTION 4
BART FOR SO_2 AND PM FOR FCCU REGENERATOR VENT (EMISSION POINTS 301-B-2A AND 301-B-2B)

As discussed in Section 1.1, at the time Alliance prepared its original BART demonstration submittal, emissions from the FCCU Regenerator Vent were split and routed through two CO Boilers (CO Boiler 301-B-2A and CO Boiler 301-B-2B). In 2009, these two CO boiler vents were combined and routed through a new WGS emissions control system (EQT 192 – EIQ 301-V-20). As a result, these two emission units identified in the original Alliance BART demonstration are now considered one emissions unit for BART demonstration purposes.

4.1 Step 1 - Identify Available Retrofit Emission Control Technologies

The following control technologies were identified in a search conducted by Alliance:

- Electrostatic Precipitators
- Wet Gas Scrubbers

4.2 Step 2 – Eliminate Technically Infeasible Options

Electrostatic Precipitator – *Technically feasible*

Electrostatic Precipitators (ESPs) use an electrostatic field to charge particulate matter (PM) contained in the gas stream. These charged particles then migrate to a grounded collecting surface. The surface is vibrated or rapped periodically to dislodge the particles, and the particles are then collected in a hopper in the bottom of the unit. The control efficiency for ESPs can range from at least 70% to 93 % removal efficiency.

Wet Gas Scrubber – *Technically feasible*

There are several different types of wet scrubbing apparatuses available. In each case, a water spray is introduced into the exhaust stream, resulting in the cooling and condensing of organic material. The water vapor condenses onto the organic aerosol which then becomes large enough to settle or be removed by cyclonic collectors, filters, or mist eliminators. Wet scrubbers typically obtain an efficiency rate higher than ESPs, 95% or greater.

4.3 Step 3 – Ranking Remaining Control Options Based on Effectiveness

The PM and SO_2 control technology alternatives that are considered technically feasible are ranked in the order of most stringent to least stringent to form a control technology hierarchy. See Table 4-1 below.

Table 4-1
PM/SO_2 Control Hierarchy

Available Control Alternatives	Control Efficiency	Control Ranking
Wet gas scrubber	>95%	1
Electrostatic precipitator	70-90%	2

4.4 Step 4 – Evaluate Most Cost Effective Controls

To achieve the needed SO_2 and PM emissions reductions, Alliance employs a WGS, which as demonstrated in Table 4-1, is the most effective control alternative. Therefore, no further cost evaluation is necessary.

Moreover, Alliance's emission limits are consistent with other approved BART limits for the refining industry. Specifically, SO_2 and PM BART control levels for Alliance are compared to Best Available Control Technology (BACT) limits as follows:

SO_2:

- Alliance: $\leq$ 25 ppm_{vd} SO_2 on a 365-day rolling average basis @ 0% $O_2$and $\leq$ 50 ppm_{vd} SO_2 on a 7-day rolling average basis @ 0% O_2,
- Other approved BACT limits: 25 ppm_{vd} (0% O_2, 365-day rolling average) is the typical approved BACT emission limit.

PM

- Alliance: $\leq$ 0.5 lb PM/1000 lb of coke burn on a 3-hr average basis
- Other approved BACT limits: Achieve an emission limit of 0.5 to 1.0 lb/1000 lb coke burn for particulate matter which is consistent with New Source Performance Standards (NSPS) and has been recognized as an approved BACT emission limit.

4.5 Step 5 - Selection of BART for SO_2/PM_{10} Control

The current SO_2 and PM control alternative, the WGS, is deemed the most effective control option. Further, the above emission limitations are stipulated by the Alliance Refinery consent decree; therefore, Alliance asserts that WGS qualifies as BART control.

SECTION 5
BART FOR NO_X
FOR FCCU REGENERATOR VENT
(EMISSION POINTS 301-B-2A AND 301-B-2B)

5.1 Step 1 - Identify Available Retrofit Emissions Control Technologies

Control options for NO_x emissions include the following listed below. The available options are based on general NO_x control knowledge and recent engineering evaluations.

- Feedstock Hydrotreatment;
- SNCR
- LoTOx™ technology;
- SCR

5.2 Step 2 - Eliminate Technically Infeasible Options

Feedstock Hydrotreatment– *Technically infeasible*
Hydrotreatment lowers FCCU NO_x emissions by reducing the total and basic nitrogen content of the feed. The FCCU unit does not have the capability to process feedstock through the hydrocracking unit and gas oil desulfurization prior to being sent to the FCCU. Thus, feedstock hydrotreatment is not a technically feasible option for Alliance Refinery.

LoTOx™ Technology – *Technically feasible*
The LoTOx™ system, a scrubber based control technology, injects ozone into the flue gas stream to oxidize insoluble NO_x to soluble oxidized compounds. Ozone is produced in situ in response to the amount of NO_x present in the flue gas. The ozone rapidly reacts with insoluble NO and NO_2 to form soluble N_2O_5, which then rapidly reacts with moisture in the gas stream to form nitric acid (HNO_3). The nitric acid is removed in an aqueous scrubber and neutralized.

Selective Catalytic Reduction – *Technically feasible*
SCR is a post-combustion, flue gas treatment technology (as described in Section 2.2). Due to advances in catalyst design, commercial applications of this technology can now operate over an extended temperature range. Precious metal catalysts, such as platinum, can promote oxidation at temperatures as low as 350°F, and zeolite catalysts can operate up to 1,000°F. Due to these catalyst design advancements, SCR systems can achieve reliable NO_x emission levels of about 20 ppm_v on FCCU regenerator vent systems.

To implement SCR control, ammonia (NH_3) storage and handling systems must be installed. Careful control of the ammonia injection and operating parameters must be maintained to limit emissions of unreacted ammonia and maintain desired NO_x reduction.

Selective Non-Catalytic Reduction – *Technically feasible*

A potential post-combustion control includes selective non-catalytic reduction (SNCR). SNCR requires a flue gas exit temperature in the range of 1200 to 2000°F, with an optimum operating exit temperature between 1600 and 2000°F. Engineering control practices generally dictate that this technology is not technically feasible as a standalone control due to the temperature requirements; however, typically, this technology is combined with other control options to achieve desirable NO_x outlet levels.

5.3 Step 3 – Ranking Remaining Control Options Based on Effectiveness

In Table 5-1 below, the technology alternatives that are considered technically feasible and justifications for BART selection are summarized.

Table 5-1
Summary of FCCU NO_x Feasible Control Options

Available Control Alternatives	NO_x ppm_{vd} @ 0% O_2	Control Ranking	BART Option?	Justification of BART Selection
SCR	20 ppm_{vd}	1	Yes	Achieved lowest NO_x limits at the most reasonable cost and reliability
LoTOx™	20 ppm_{vd}	1	No	Rejected as control levels not better than SCR Achieve 20 ppm_{vd} only with significant scrubber modifications, pre-treatment modifications, and significant capital/operating costs.
SNCR + LoTOx™	50 ppm_{vd}	2	No	Option has higher operating and capital costs than SCR although provides higher NO_x outlet levels
SNCR	90 ppm_{vd}	3	No	Typically used in the presence of high nitrogen levels in the CO gas and therefore, not an ideal application for Alliance Refinery

5.4 Step 4 – Evaluate Most Cost Effective Controls

As required by the consent decree, Alliance will install the top control alternative for NO_x control, SCR. As LoTOx™ is an equivalent control to SCR then no further analysis is necessary. NO_x control levels are stipulated in the consent decree as follows:

- $\leq$ 20 ppm_{vd} NO_x on a 365-day rolling average basis @ 0% O_2 and
- $\leq$ 40 ppm_{vd} NO_x on a 7-day rolling average basis @ 0% O_2.

These levels of controls are the highest levels of NO_x controls documented in the RBLC.

5.5 Step 5 - Selection of BART for NO_x Control

Alliance plans to achieve NO_x reductions from the FCCU Regenerator vent by installing SCR technology. In accordance with the consent decree compliance schedule, SCR will be installed before December 31, 2014. In 2012, the LDEQ Air Permits Division granted approval to construct SCR on the FCCU at the Alliance Refinery.

SECTION 6
BART FOR FLARES
(EMISSION POINTS 308F-D-1 AND 308F-D-2)

6.1 Step 1 - Identify Available Retrofit Emissions Control Technologies

Control options for flares include:

- Good Design and Monitoring (PM)
- Quality Fuels at Flare Tip (for SO_2 control)
- Amine Scrubbing for Flare Gas (for SO_2 control)
- Flare Gas Recovery System (for SO_2, PM, and NO_x control via reduction of flared gases)

6.2 Step 2 - Eliminate Technically Infeasible Options

Good Design and Monitoring - *Technically Feasible*

The practice to ensure the presence of a flame at the flare tip is to guarantee the complete combustion of streams. The purpose of this technology is to reduce the particulate matter of the exiting flue from the flare due to incomplete combustion of the gaseous stream.

Quality Fuels at Flare Tip - *Technically Feasible*

The use of quality fuels for pipeline quality natural gas or refinery fuel gases with an H_2S concentration less than 100 ppm_v (annual average) as fuels at flare tip. The purpose of this technology is to reduce the concentration of H_2S in the flare tip as not to introduce any additional pollutants into the gaseous stream.

Amine Scrubbing For Flare Gas- *Technically Feasible*

Amine scrubbing for flare gas uses aqueous solutions of various amines to remove H_2S and carbon dioxide (CO_2) from gases. The purpose of this technology is to reduce the concentration of H_2S before the flare gas is routed to the flare thus the control minimizes the formation of SO_2 emissions.

Flare Gas Recovery System – *Technically Feasible*

Flare Gas Recovery (FGRS) is the process of recovering the waste gases that would normally be flared, so they can be used as fuel gas elsewhere in the facility. This results in cost savings and reduced emissions of flare combustion emissions, such as NO_x, SO_2, and PM. The FGRS process is as follows:

- Isolate flare header with a proprietary-design liquid seal or staging valve;
- Recover normally flared gases;
- Remove liquids;
- Compress gases up to a defined pressure level;
- Cool recovered gases (if required); and
- Deliver recovered gases into the facility, so they can be processed and re-used as fuel gas.

6.3 Step 3 – Ranking Remaining Control Options Based on Effectiveness

The technology alternatives that are considered technically feasible are summarized in Table 6-1 below.

Table 6-1
Summary of Flare Feasible Control Options

Available Control Alternatives	Control Efficiency	Control Ranking
Good Design and Monitoring	Non specified	3
Quality Fuels at Flare Tip	Non specified	2
Amine Scrubbing for Flare Gas	>95%	1
FGRS	>95%	1

6.4 Step 4 – Evaluate Most Cost Effective Controls

Alliance designed flares to meet good engineering design and has installed flame presence monitoring equipment on both flares. Additionally, the pilot gas to the flares is natural gas supplied via pipeline. In accordance with the consent decree, Alliance installed the top control alternative for NO_x control, FGRS, and utilizes amine scrubbing on the refinery fuel gas and on the return streams from the FGRS to the fuel gas system. Since Alliance utilizes FGRS control technologies on the flares, the refinery employs the most stringent emissions control systems on both flares, and thus, a cost effective analysis is not required. Additionally, the 2007 CALPUFF modeling demonstration documents that post-control flare emissions have no adverse impacts to visibility.

Specifically, the post-BART-control modeling exercise only showed reductions in SO_2 emissions. No credit for PM and NO_x emission reductions were included in the post-BART-control modeling. This conservative approach to post-BART-control modeling was taken because SO_2 was the major contributor to visibility impairment. Also, simply reducing the SO_2 emission input to the CALPUFF model provided generated visibility results well below the acceptable 0.5 DV guideline level.

6.5 Step 5 - Selection of BART for Flare Control

The Alliance Refinery certified the Low Pressure Flare pursuant to the requirements of Paragraph 139(a) of the Consent Decree. The facility shall comply with Paragraph 139(a) by operating and maintaining a flare gas recovery system to control continuous or routine combustion in the Flaring Device. The Alliance Refinery certified the High Pressure Flare pursuant to the requirements of Paragraph 139(a) and 139(b) of the Consent Decree. The facility shall comply with Paragraph 139(a) by operating and maintaining a flare gas recovery system to control continuous or routine combustion in the Flaring Device. The facility shall comply with Paragraph 139(b) during those periods when gases from the Hydrofluoric (HF) Acid Alkylation

Unit and gases routed to the Alkylation Unit's flare header are sent directly to the High Pressure flare's tip for destruction.

Alliance maintains the position that the emission controls documented above are equivalent to the most stringent or "top" level of available controls for Alliance flares and meet BART level of control.

SECTION 7
CONCLUSION

In conclusion, Table 7-1 contains the selected control options based on the 5-Step BART Analysis as requested by EPA for the Alliance emission units using the factors specified in 40 CFR 51.308(e)(1)(ii)(A).

Table 7-1
Conclusions from BART 5-Step Analysis

Source ID	Pollutant	Selected BART Control	Post CD Emission Limitation
Crude Charge Heater (191-H-1)	NO_x	-SCR - Good combustion practices	0.0185 lb/MMBTU on a 365-day rolling average basis [See CD (Civil Action H-05-0258)]
	SO_2	Amine scrubbing of refinery fuel gas	$\leq$0.1 grains H_2S/dscf (or 162 ppm_{vd} H_2S) in refinery fuel on a 3-hr rolling average basis
	PM	Good combustion practices	0.00745 lb PM/MMBtu of refinery fuel gas fired on an annual average basis using good combustion techniques based on AP-42 Table 1.4.2 (1998)
Wet Gas Scrubber (301-V-20) [Formerly CO Boilers (301-B-2A and 301-B-2B)]	SO_2	WGS	$\leq$ 25 ppm_{vd} SO_2 on a 365-day rolling average basis @ 0% O_2 and; $\leq$ 50 ppm_{vd} SO_2 on a 7-day rolling average basis @ 0% O_2 [See CD (Civil Action H-05-0258)]
	PM	WGS	$\leq$ 0.5 lb PM/1000 lb of coke burn on a 3-hr average basis [See CD (Civil Action H-05-0258)]
	NO_x	SCR	$\leq$ 20 ppm_{vd} NO_x on a 365-day rolling average basis @ 0% O_2 and; $\leq$ 40 ppm_{vd} NO_x on a 7-day rolling average basis @ 0% O_2 [See Consent Decree (Civil Action H-05-0258)]
Low Pressure Flare (308F-D-1)	NO_x	Flare Gas Recovery System	Operate and maintain Flare Gas Recovery System to control continuous or routine combustion in the Flaring Device [See Consent Decree (Civil Action H-05-0258), ¶139(a)]
	SO_2		
High Pressure Flare (308F-D-2)	NO_x	Flare Gas Recovery System	Operate and maintain Flare Gas Recovery System to control continuous or routine combustion in the Flaring Device Hydrogen sulfide $\leq$ 0.1 gr/dscf (230 mg/dscm) [See Consent Decree (Civil Action H-05-0258), ¶139(a) & 139(b)]
	SO_2		

LDEQ RECEIPT

ConocoPhillips JUN 29 PM 4 21

ConocoPhillips Company
Alliance Refinery Agency Interest
No. 2418
P. O. Box 176
Belle Chasse, LA 70037
(504) 656-7711

June 28, 2007

RECEIVED
JUN 29 2007
LDEQ

Dr. Chuck Carr Brown, Assistant Secretary
Office of Environmental Services
Louisiana Department of Environmental Quality
P.O. Box 4313
Baton Rouge, LA 70821-4313

HAND DELIVERED

RECEIVED
JUL 03 2007
LDEQ Air Quality
Engineering Support

RE: ConocoPhillips Company – Alliance Refinery, AI# 2418
BART Engineering Analysis and Modeling Report

Dear Dr. Brown:

Pursuant to the requirements of 40 CFR 51.301 and in accordance with the discussions between Louisiana Department of Environmental Quality (LDEQ) and ConocoPhillips Company-Alliance Refinery (ConocoPhillips) in the May 11, 2007 meeting, ConocoPhillips is submitting the referenced report for review. Additionally, ConocoPhillips has combined both the refined modeling results report and the required BART Engineering Analysis into one submittal per LDEQ's request. This submittal has been revised to incorporate the changes requested by LDEQ from the agency's review of the draft document submitted for review to LDEQ on May 29, 2007.

On July 1, 1999, EPA promulgated rules to address visibility impairment, or regional haze, at national parks and wilderness areas designated as federal Class I areas. Guidelines issued by the EPA in July 2005 provided direction to the states for implementing the Regional Haze rules. Affected states, including Louisiana, are required to develop plans for addressing visibility impairment. The regulation specifies that any BART-eligible source that had not been screened out by the LDEQ must perform refined

modeling. The Alliance Refinery received notice from LDEQ on January 23, 2007, that the refinery had not passed the BART screening modeling process and would be subject to performing refined modeling.

The Alliance Refinery performed refined modeling for the years 2001-2003, as required by Central Regional Air Planning Association (CENRAP) guidance. The result of the refined modeling was a measure of visibility conditions at the Breton Wilderness Class I area. The 98th percentile modeled value was compared to the natural visibility conditions for the area. The modeling performed for Alliance Refinery resulted in a difference between the modeled and natural visibility of greater than 0.5 deciviews (dv). This difference of greater than 0.5 dv, indicates the Alliance Refinery is a contributor to visibility impairment at the Breton Wilderness Class I area. Refined modeling was performed for individual BART-eligible sources to evaluate the contribution of each source to the visibility impairment. The culpability analysis allowed separating emission sources subject to BART engineering analysis from sources that do not significantly contribute to visibility impairment. The emission sources subject to BART engineering analysis are the Fluidized Catalytic Cracker and the Process Refinery Flares. However, LDEQ has also requested that the Alliance Refinery include the Crude Unit Heater in the analysis.

Facilities with BART sources are directed to make a determination in accordance with 40 CFR 51, Appendix Y. They are also required to include information documenting the projected hourly and annual emission limits for the selected BART control strategies. The refinery believes the attached information meets the above requirements.

On December 5, 2005 ConocoPhillips and the EPA entered into a Consent Decree (Civil Action No. H-05-0285). The BART engineering analysis utilized emission reductions that are mandated per the Consent Decree for the Fluidized Catalytic Cracker, the Process Refinery Flares and the Crude Unit Heater. Implementing these control projects per the Consent Decree emissions reductions will result in reducing the overall site visibility impacts for the eighth highest delta dv from the baseline case ranging from 2.34 dv to 3.61 to 1.30 to 1.66 dv. Additionally, the Consent Decree created many other federally enforceable emission reductions for NO_x, SO_2 and PM that have either been implemented since 2003 or will be implemented in the future, thus significantly reducing the refinery's impact on the Breton Wilderness Class I area.

If you, or your staff, have any questions concerning this submittal, please call Steve Johnson of my staff at (504) 656-3669.

Sincerely,

Laurence R. Poché

Laurence R. Poché
Environmental Service Superintendent

Attachments
LRP/swj

A10-07

cc: Kelly J. Bradberry – Sage Environmental Consulting
John Dyer – LDEQ Permits
James Orgeron – LDEQ Engineering

SAGE
ENVIRONMENTAL CONSULTING

BART Engineering Analysis For

ConocoPhillips

Alliance Refinery (AI No. 2418)

Prepared by:

SAGE
ENVIRONMENTAL CONSULTING

Reviewed by:

Laurence R. Poché
Kelly Jean Bradberry

June 2007

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ConocoPhillips Company
BART Engineering Analysis
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1.0 Introduction

1.1 Objectives

The Regional Haze Rule regulations require Best Available Retrofit Technology (BART) for any BART-eligible source that "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility" in any mandatory Class I federal area. Louisiana Department of Environmental Quality (LDEQ) has identified the Alliance Refinery, located near Belle Chasse, Louisiana, owned and operated by ConocoPhillips Company (ConocoPhillips), as being a source that is eligible for consideration of BART controls. The purpose of this document is to summarize the procedures used to conduct the modeling analysis to quantify the visibility impact of BART control options at the Alliance Refinery and the engineering analysis of the various control options for defining BART.

1.2 Organization of Document

Section 1.3 provides a brief background about the Alliance Refinery and a summary of the refined modeling results. The Modeling Report in Attachment I summarizes the procedures used to determine baseline actual emissions for the 2001 to 2003 period and presents the baseline emission rates. Additionally, the CALPUFF modeling procedures, the visibility results for the baseline modeling case and the plan for post controls are presented. BART determinations based on the costs and the improvements in visibility associated with each emission control project are presented in Section 2.0. Finally, in response to discussions with LDEQ on the draft report submitted on May 29, 2007, information on BART eligible sources that do not have planned controlled projects at this time due to the level of effectiveness on reducing the impact of visibility at the designated Class I area are included in Section 3.0.

1.3 Facility Information and Background Summary

The Alliance Refinery produces a wide range of petroleum products from crude oil, such as LPG, motor gasoline, jet fuel, diesel, carbon black feedstock, propane, and coke. The Alliance Refinery also produces petrochemicals such as benzene, toluene, xylenes, and by-product elemental sulfur. Emission sources at the Alliance Refinery include process heaters, boilers, storage vessels, loading facilities, fugitive emissions from equipment, process vents, and flares. A Facility Map Location and a Plot Plan are included in this submittal (see Figure 1-1 and 1-2, respectively).

As stated in the cover letter, the Alliance Refinery received notice from LDEQ on January 23, 2007, that the Alliance Refinery had not passed the BART screening modeling performed by LDEQ and the Alliance Refinery would be required to perform refined modeling. Attachment II is a copy of the written notification from LDEQ to the Alliance Refinery. The visibility impacts were evaluated for the Breton Wilderness Class I area, which is located approximately 94 kilometers from Belle Chasse, LA. The result of the modeling was a measure of visibility conditions at the Breton Wilderness Class I area with a difference greater than 0.5 deciview (dv); therefore, the Alliance Refinery is considered to contribute to the visibility impairment at the Breton Wilderness Class I area and is required to perform an engineering analysis.

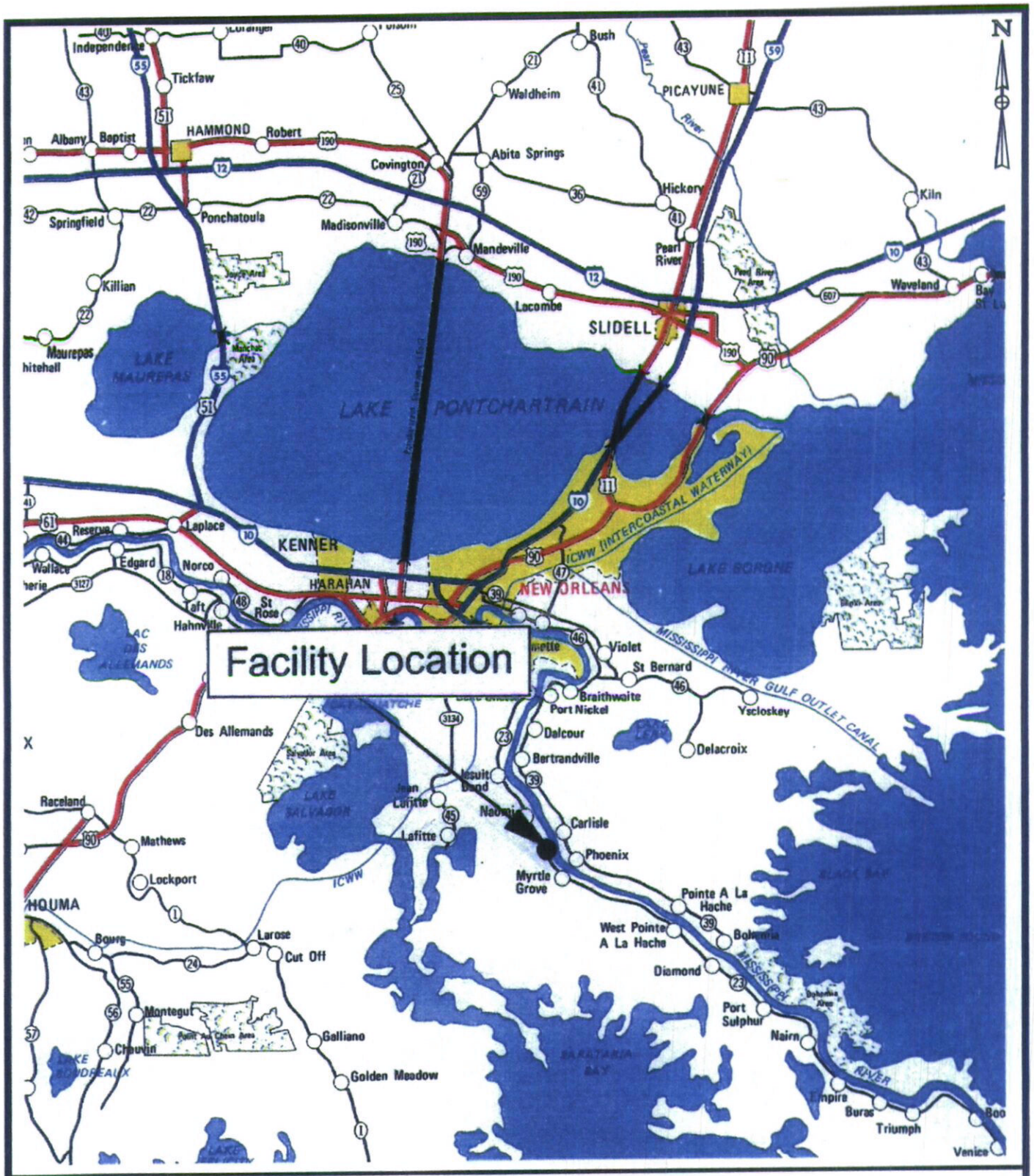

FIGURE 1-1

FACILITY LOCATION MAP

Alliance Refinery
Belle Chasse, Louisiana

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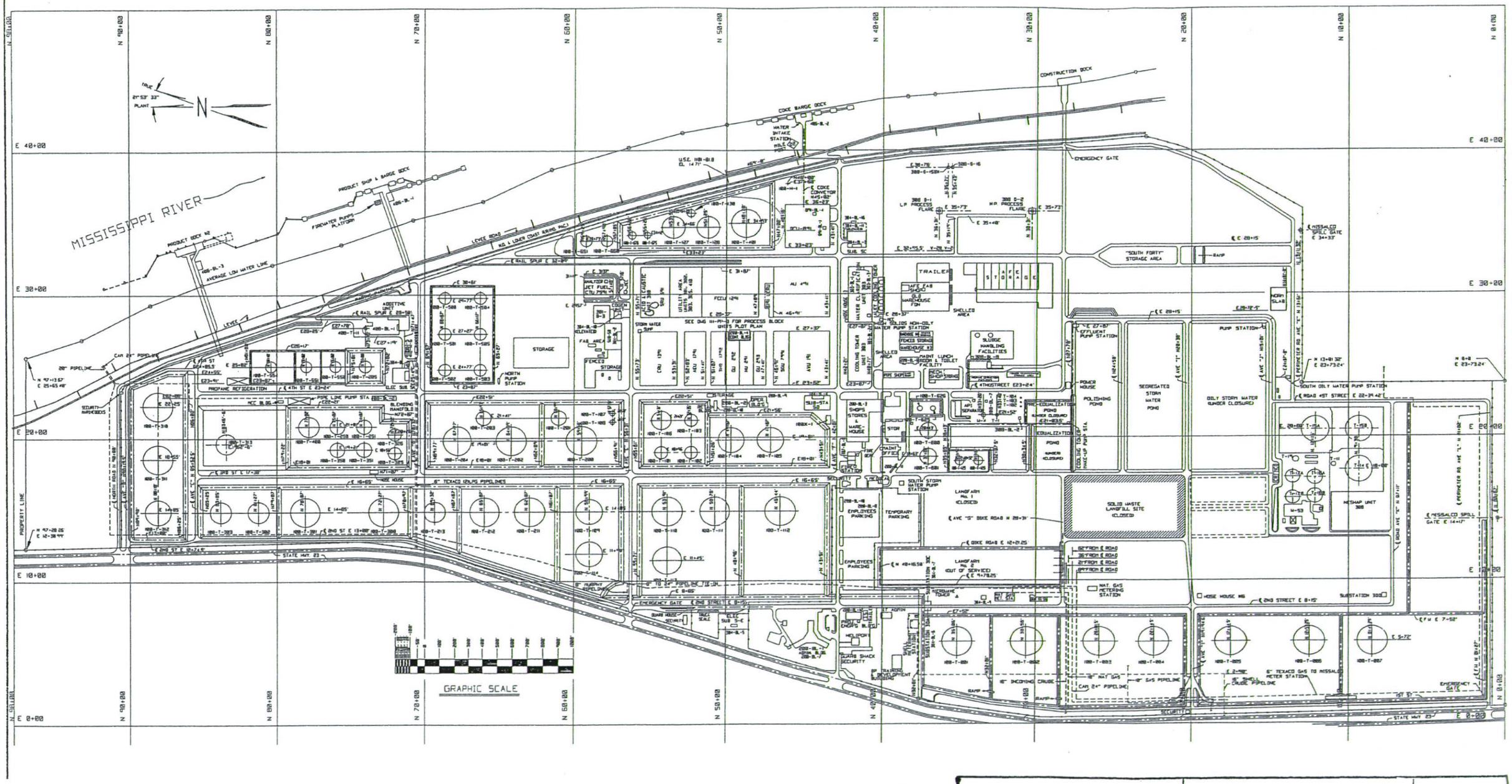

ConocoPhillips Company Belle Chasse, Louisiana	Plot Plan	Figure Number 1-2

2.0 Emission Reduction Projects

The Alliance Refinery is reducing emissions as required by the Consent Decree (Civil Action No. H-05-0285) that was entered into on December 5, 2005 between ConocoPhillips and the U.S. Environmental Protection Agency (EPA). The future planned emission reductions after completion of these projects are discussed in Section 2.1.

2.1 Currently Planned Emission Controls

The Alliance Refinery has reduced emissions since the 2001 to 2003 baseline period as part of the Consent Decree emission reductions. Additional emissions reductions will be achieved in the next few years as part of planned Alliance Refinery improvement projects and as required by the Consent Decree. Major planned emission reductions for the sources subject to BART engineering controls, the Fluidized Catalytic Cracker (FCC) and the Process Refinery Flares, are discussed below. A discussion in this section has been included to address LDEQ's request for information pertaining to additional planned emission reduction projects specifically for the Crude Unit Heater, (Point Source 191-H-1). Attachment III contains the LDEQ email correspondence requesting this additional information.

2.1.1 Currently Planned Emission Controls for the FCC

The Consent Decree requires the Alliance Refinery to reduce emissions of SO_2 from the Alliance Refinery's FCC. This emission reduction will be accomplished by the installation of a Wet Gas Scrubber on the FCC by December 31, 2009 as dictated in the Consent Decree. The FCC regenerator vents to the Alliance Refinery's two CO Boilers; therefore, the emission point sources for the FCC are the atmospheric stacks from the CO Boilers (Point Source 301-B-2A, & 301-B-2B). The CO Boilers burn both the FCC Regenerator flue gas and supplemental refinery fuel gas. Baseline SO_2 emissions were estimated as 550.24 lb/hr for each CO Boiler. It is estimated that future SO_2 emissions will be reduced to less than 275.12 lb/hr for each CO Boiler. It is expected that future average SO_2 emissions may be significantly lower than 275.12 lb/hr, but the exact emission rate cannot be defined until the Wet Gas Scrubber is commissioned.

2.1.2 Currently Planned Emission Controls for the Process Refinery Flares

The Consent Decree requires that by no later than December 31, 2011, the Alliance Refinery will accept NSPS Subpart J applicability for both flares and certify that the flares' emissions and operations comply with this standard. By compliance with this requirement, the Alliance Refinery

will reduce emissions of SO_2 from the Alliance Refinery's Low Pressure and High Pressure Process Flares (Point Source 308F-D-1, & 308F-D-2). The control methods that the Alliance Refinery will implement on the flares are still under consideration; however, post control modeling results were based on reducing the flare emission rates from 2,374.56 lbs/hr to 87.91 lbs/hr. Per LDEQ's request, an excerpt from the Consent Decree is included in Attachment IV that lists the acceptable emissions control options in the Consent Decree that are allowed in order to meet the above emission reductions.

2.1.3 Currently Planned Emission Controls for the Crude Unit Heater

The Consent Decree requires the Alliance Refinery to reduce emissions of NO_x from the Alliance Refinery's combustion devices sources. To meet this emission reduction requirement the Alliance Refinery will install Selective Catalytic Reduction (SCR) on the Crude Unit Heater by December 31, 2008. It is estimated that future Crude Unit Heater NO_x emissions will be reduced from the baseline emissions of 294.17 lb/hr to 27.55 lb/hr.

2.1.4 Summary of Currently Planned Emission Controls Projects on Visibility

As a result of the installation of the emission control projects on the FCC and the process flares, SO_2 from these BART eligible sources will be reduced from an estimated 3,475.04 lb/hr to 638.15 lb/hr. This reduced SO_2 emission rate will result in the FCC and the Low Pressure Process Refinery Flares having less than a delta difference of 0.5 dv per each source. The High Pressure Process Flare and the Crude Unit Heater have less than a delta difference of 0.5 dv prior to controls being installed. The result of the installation of the emission control projects on the Crude Unit Heater as stated previously will reduce the NO_x emissions an estimated 90%.

All of these control requirements are considered more stringent than BART and are therefore considered to satisfy the regulatory requirements of the BART analysis.

2.2 Emission Reduction Costs of Planned Projects

ConocoPhillips is in the process of performing the engineering and design of the proposed projects; therefore, the costs below are estimates of anticipated capital expenditures and operating costs based on literature sources including John Zinc Presentations, EPA Air Pollution Control Cost Manual, and internal budgetary estimates. The estimated capital costs and operational costs are listed in Table 2-1.

Table 2-1 - Emission Reduction Costs of Planned Control Projects

Emission Reduction Project	Capital Cost Estimate	Annual Operating Cost
FCC Wet Gas Scrubber	$155,000,000.00	$4,500,000.00
Refinery Flare Gas Recovery*	$20,000,000.00	$182,000.00
Crude Unit Heater SCR	$35,000,000.00	$820,000.00
Total Estimated Cost	**$197,425,000.00**	**$5,502,000.00**

*The Flare Gas Recovery Control Option Cost was included for the process flares; however, the refinery has not chosen a control option.

2.3 Visibility Impacts

Visibility impacts for the baseline emission case and post controls are presented in Attachment I in the modeling report. Please note that the post control visibility impacts results do not include reductions associated with the installation of the SCR on the Crude Unit Heater. This emissions control project was not evaluated in the draft submittal to LDEQ; however, in subsequent conversations with Mr. James Orgeron of LDEQ, he expressed that it was not necessary to revise the visibility impacts analysis to include this project.

The above planned control projects target the most significant contributor to visibility impairment SO_2. According to a report to Congress titled Visibility in Mandatory Federal Class I Areas (1994-1998), EPA participated in the IMPROVE visibility monitoring program (Interagency Monitoring of Protected Visual Environments). During this program five major types of aerosols were measured at 30 monitoring sites. These sites are considered to be representative of all mandatory Federal Class I areas except the isolated Bering Sea Wilderness. The five aerosols measured were sulfates, nitrates, organic carbon, elemental carbon and crystal metal. The tests results showed that on an annual basis between 1994 and 1998, sulfate particles accounted for 23-78%; nitrate particles accounted for 3-39%, organic carbon for 9-28%, elemental carbon for 2-16% and crystal material accounted for 3-31 percent of the calculated light extinction. Therefore, as stated in the report, sulfate aerosols are generally formed in the atmosphere from sulfur dioxide. Thus by installing the emission controls on the FCC and Process Flares, Alliance Refinery is targeting the largest contributor to visibility impairment resulting in the highest impact on improving the visibility quality at the effected Class I area. Additional controls of the other BART eligible sources to reduce other pollutants would result in a significant impact on the visibility quality at the Class I area. For the baseline case, the number of days with impacts greater than 1.0 dv ranges from 30 days to 47 days, depending upon the year being modeled. Future emission controls already planned will reduce the number of days greater than 1.0 dv from 30 to 47 days to only 11 to 29 days, depending upon the year modeled. Similar results for the

eighth highest delta dv show a reduction from a range of 2.34 dv to 3.61 for the baseline case to only 1.30 to 1.66 dv for the future planned case. Therefore, the currently planned emission reductions will provide a very large improvement in visibility, provide for reasonable further progress, and qualify for BART.

3.0 Analysis for Controls on Other BART Eligible Sources

The Alliance Refinery is reducing emissions as required by the Consent Decree (Civil Action No. H-05-0285) that was entered into on December 5, 2005 between ConocoPhillips and the U.S. Environmental Protection Agency (EPA). The potential controls and cost analyses for all other BART eligible sources not covered in the Consent Decree are discussed in this section.

For the purpose of analyzing the other BART Eligible sources, a linear relationship was assumed between emissions reductions and delta-deciview since post modeling was not performed for control options on these eligible sources. This assumption errs on the conservative side (i.e. over states the actual effect of the control option on the visibility) due to the fact that the 98th Percentile Delta-deciview value for these BART eligible sources is much lower than the BART eligible sources that the Alliance Refinery is proposing to install controls projects on. The FCC, Process Flares and Crude Unit Heater are the BART eligible sources with the highest Delta-deciview value per the Visibility Impact Chart Table below. Reducing the emissions on the other BART eligible sources will most likely not have a significant impact on decreasing the visibility impact on the Class I area.

Table 3-1 - 98th Percentile Delta-deciview Value

EPN	98th Percentile Delta-DV Value
308F-D-1	**2.067**
301-B-2A	**0.760**
301-B2-B	**0.759**
308F-D-2	**0.540**
191-H-1	**0.485**
303 -R-1	0.174
1391-H-4	0.096
191-H-2	0.094
491-H-2	0.066
891-H-1	0.061
491-H-1	0.056
1791-H-1	0.038
291-H-1	0.038

EPN	98th Percentile Delta-DV Value
1391-H-1	0.035
1391-H-2/3	0.033
291-H-2	0.030
1792-H-1	0.026
1291-H-2/3	0.025
293-H-2	0.014
293-H-1	0.011
406-D-15	0.010
406-D-16	0.010
292-H-2	0.009
292-H-1	0.005
891-CP	0.005
100-H-1	0.002
1391-H-5	0.002

3.1 Cooling Water Tower (Point Source 301-R-1) BACT for Particulate Matter (PM) and Particulate Matter Less Than Ten Microns (PM10)

3.1.1 Step 1 - Identify Available Control Technologies

The EPA's RACT/BACT/LAER Clearinghouse database, commonly known as the RBLC database includes determinations of the reasonably achievable control technology (RACT), best available control technology (BACT) and the lowest achievable emission rate technology (LAER). Based on research on the RBLC database, control technologies available for PM/PM_{10} emissions from cooling towers are identified as follows.

- High Efficiency Drift Eliminator (and high-end);
- Drift Eliminator; and
- Good Operating Practices.

High Efficiency Drift Eliminator (HEDE)

HEDEs are eliminators that are incorporated in a cooling tower design to provide a drift rate lower than the industrial standard of 0.005%. Results from the EPA RBLC research indicate that

HEDE can achieve drift rates range from 0.001% to 0.0001% on an annual basis. In general, higher efficiency drift eliminators will have high pressure drop which leads to higher energy requirements.

Drift Eliminator

Research indicates that drift eliminators are typically designed with drift eliminators having an efficiency of 0.005%.

Good Operating Practices

Good operating practices on cooling towers include maintaining equipment in good working order, and limiting solids buildup in the cooling water.

3.1.2 Step 2 – Eliminate Technically Infeasible Options

None of the available options identified above to control PM/PM_{10} emissions from cooling towers are deemed technically infeasible.

3.1.3 Step 3 – Ranking Technically Feasible Control Options Based on Effectiveness

The control effectiveness of the remaining control technologies is ranked from the most efficient to the least efficient in table below.

Table 3-2 - PM/PM_{10} Control Effectiveness Ranking

Type of Drift Eliminator	Drift Rate %	Drift Rate lb/Mgal	TDS ppm	PM Emissions TPY	PM Emission Reduction TPY	Control Effective-ness %	Ranking of Effective-ness
High Efficiency (high-end)	0.0001	-	1000	0.41	83.36	99.51%	1
High Efficiency	0.001	-	1000	4.11	79.66	95.09%	2
Drift Eliminator (industry standard)	0.005	-	1000	20.55	63.22	75.47%	3
Good Operating Practices (base case)	-	1.7	1000	83.77	-	-	4

3.1.4 Step 4 – Evaluate Most Cost Effective Controls

Economic analyses were performed for high-end HEDEs and HEDEs. Summaries for the cost effectiveness' are presented below. The cost analysis for both high-end HEDEs and HEDEs was obtained from the EPA Air Pollution Control Cost Manual, Sixth Edition, 2002 (EPA/452/B-02-001), Chapter 3, Electrostatic Precipitators (ESP). For the purposes of this analysis, it is assumed that HEDEs are operating on the similar principle as ESPs. The capital cost for the 0.001% HEDE was based upon an estimate of HEDEs for a comparable cooling tower. The capital cost for the 0.0001% HEDE was assumed to be twice as much as the estimate of the 0.001% HEDEs.

The cost analysis for high-end HEDEs and HEDEs are presented in following tables of this section. A summary of cost effectiveness for control equipment on PM/PM_{10} emissions from cooling tower is presented below.

Table 3-3 - Cost Analysis for HEDEs

	High-End HEDE	**HEDE**
Total Annualized cost	$76,373	$38,187
Expected PM/PM_{10} Visibility Reduction (dv)	0.173	0.165
Cost Effectiveness ($/dv)	**$441,462**	**$231,436**

As shown above, the levels of cost-effectiveness using high-end HEDEs and HEDEs to control PM/PM_{10} from the cooling tower are not an effective control to reduce overall visibility impact. Therefore, they are not considered cost-effective for retrofitting the cooling tower at the site.

3.1.5 Step 5 - Selection of BACT for PM_{10} Control

As previously demonstrated, retrofitting with HEDEs is technically feasible, but not economically feasible to control PM/PM_{10} emissions from the cooling tower at the site.

3.2 BACT for Nitrogen Oxides (NO_x) for Heaters

3.2.1 Step 1 - Identify Available Control Technologies and Step 2 - Eliminate Technically Infeasible Options

A search of the EPA's RBLC database and available state BACT links was conducted to identify recent permitting actions and BACT determinations.

The BART eligible sources heaters will fire refinery fuel gas and have maximum heat duties ranging from 45 MMBtu/hr to 267 MMBtu/hr. A search for heaters and boilers firing gaseous fuels in the range of heater duties between 100 to 250 MMBtu/hr was conducted. Control technologies identified in the search include the following:

- Selective catalytic reduction (SCR);
- Ultra-low NO_x burners (ULNB);
- Low NO_x burners (LNB);
- Flue gas recirculation (FGR);
- Selective non-catalytic reduction (SNCR); and
- Water injection.

Ultra-low NOx Burners and Low NOx Burners

Some common methods of combustion control for process heaters are staged combustion and flue gas recirculation. Low NO_x Burners (LNBs) typically use staged air or staged fuel combustion principles to minimize the amount of thermal NO_x formation. Staged combustion limits the amount of oxygen available to react with nitrogen at the combustion zones in the heater/firebox where temperature profiles favor thermal NO_x formation. Partial combustion occurs in the first stage and is then completed in subsequent stages. However, current industry practice is to install ULNBs on process heaters. Based on current practice and availability of burner designs LNB were not included in cost effectiveness evaluation for the subject process heaters in favor of UNLB.

Ultra Low NO_x Burners (ULNBs) use staged combustion principles similar to LNBs, but also have special designs which facilitate internal flue gas recirculation (FGR). FGR introduces a relatively cool, inert stream into the combustion zones where thermal NO_x formation is favored. This inert stream also contains less oxygen than primary combustion air which helps to limit the amount of oxygen available for thermal NO_x formation. ULNBs are potentially applicable NO_x controls for the process heaters in this BACT analysis.

Selective catalytic reduction (SCR) and Selective non-catalytic reduction (SNCR)

Common post-combustion controls that could be applicable to the process heaters and supplemental boiler in this BACT analysis include SCR and SNCR. SCR is a proven NO_x control technology that usually offers the greatest potential for NO_x reductions. Vendors will typically guarantee 70% to 90% reduction of inlet NO_x levels, but this is a function of inlet NOx loading. SCR is usually the highest cost post-combustion control, primarily because of the cost of the catalyst.

In SCR technology ammonia (NH_3) diluted with air or steam is injected into the flue gas upstream of a catalytic reactor. NH_3 reacts with NO_x in the presence of the catalyst to form nitrogen and water according to the following reactions:

$$4\ NO + 4\ NH_3 + 3\ O_2 \rightarrow 4\ N_2 + 6\ H_2O$$
$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Operating temperature is highly important in SCR technology. The reactor must be operated at a temperature between 600 and 800°F. If the operating temperature is below this range, the catalyst activity is reduced allowing unreacted NH_3 to slip through. If the operating temperature is higher than this range, NH_3 may be oxidized forming additional NO_x and may cause the catalyst to become thermally stressed.

SNCR or the combination of SNCR with LNB/ULNB was not identified as a control technology from the RBLC search. SNCR requires a flue gas exit temperature in the range of 1200 to 2000°F, with an optimum operating exit temperature between 1600 and 2000°F. Process heaters typically have exhaust temperatures of ranging from 300 to 600°F. Therefore, additional fuel combustion or a similar energy supply would be needed to achieve exhaust temperatures compatible with SNCR operation. Additionally, with the lack of information demonstrating that SNCR can be used on process heaters, it is uncertain of the performance of SNCR on process heaters and the temperature restriction; therefore, SNCR was not included in cost effectiveness evaluation for the subject process heaters.

Flue gas recirculation

Flue gas recirculation (FGR) is a NO_x control technology that recycles 15% to 30% of the flue gas to the primary combustion zone. The recirculation dilutes the combustion reactants, reduces the peak temperature, and reduces the local oxygen concentrations. Thus, thermal NO_x formation is inhibited. FGR can only be used for a few select direct-fired heaters and typically is not cost

effective due to increased energy costs; therefore, FGR was not included in cost effectiveness evaluation for the subject process heaters.

Water/Steam Injection

Water/steam injection involves the introduction of water/steam into the combustion zone of the burner. The water/steam acts as a thermal ballast which causes the peak flame temperature to be reduced, thereby limiting the thermal NO_x formation. Drawbacks of water/steam injection include increased equipment corrosion and reduced thermal and fuel efficiencies; therefore, water/steam injection was not included in cost effectiveness evaluation for the subject process heaters.

The technologies that are considered to be potentially applicable BACT options for NO_x control for the process heaters which are subject to BART are ULNB, ULNB and SCR and SCR. Use of these technologies will be evaluated further in the next step of the NO_x BACT analysis.

3.2.2 Step 3 – Ranking Remaining Control Options Based on Effectiveness

The NOx control technology alternatives that are considered technically feasible for the process heaters in this project are ranked in the order of most stringent to least stringent to form a control technology hierarchy.

Table 3-4 - NO_x Control Hierarchy

Type of NO_x Control	NOx Emission Factor (Lb/MMbtu)	Ranking of Effectiveness
Ultra Low NO_x Burners and SCR	0.0125	1
ULNB Low	0.03	2
SCR	0.036	3
Good Combustion Practices (base case)	Variable EFs	4

3.2.3 Step 4 – Evaluate Most Cost Effective Controls

Table 4 shows the resulting control technology hierarchy for the existing heaters that require a BACT analysis as a result of this BART Engineering Study.

Table 3-5 - NO_x Control Hierarchy for Existing Heaters

Source	Current Control (if any)	BACT Analysis Controls Reviewed	Selected Control	Estimated Delta-deciview Reduction	Estimated Cost Per Delta-deciview Reduction
1291-H-2/3(1)	ULNB	UNLB with SCR	UNLB with SCR	0.001784	$910,509,147.26
292-H-1	Good Combustion	UNLB and UNLB with SCR	UNLB with SCR	0.001837	$557,941,799.83
292-H-2	Good Combustion	UNLB and UNLB with SCR	UNLB with SCR	0.003306	$331,860,637.44
191-H-2	Good Combustion	UNLB and UNLB with SCR	UNLB with SCR	0.02115	$116,745,393.95
891-H-1	Good Combustion	UNLB and UNLB with SCR	UNLB with SCR	0.012994	$130,404,469.84
491-H-1	Good Combustion	UNLB and UNLB with SCR	UNLB with SCR	0.00972	$154,659,337.53
491-H-2	Good Combustion	UNLB and UNLB with SCR	UNLB with SCR	0.012375	$133,219,460.22
100-H-1	Good Combustion	UNLB and UNLB with SCR	UNLB with SCR	0.000735	$1,321,121,598.34
293-H-1	Good Combustion	UNLB and UNLB with SCR	UNLB with SCR	0.004041	$285,144,661.02
293-H-2	Good Combustion	UNLB and UNLB with SCR	UNLB with SCR	0.005143	$235,644,544.88
1391-H-1(1)	UNLB	UNLB with SCR	UNLB with SCR	0.010938	$204,557,189.12
1391-H-2/3(1)	UNLB	UNLB with SCR	UNLB with SCR	0.010313	$215,285,533.97
1391-H-4	Good Combustion	UNLB and UNLB with SCR	UNLB with SCR	0.010225	$162,727,215.04
1391-H-5	Good	UNLB and	UNLB with	0.00072	$1,347,051,740.63

Source	Current Control (if any)	BACT Analysis Controls Reviewed	Selected Control	Estimated Delta-deciview Reduction	Estimated Cost Per Delta-deciview Reduction
	Combustion	UNLB with SCR	SCR		
1791-H-1	Good Combustion	UNLB and UNLB with SCR	UNLB with SCR	0.007316	**$191,367,936.56**
1792-H-1(1)	UNLB	UNLB with SCR	UNLB with SCR	0.008125	**$192,785,285.47**
291-H-1	Good Combustion	UNLB and UNLB with SCR	UNLB with SCR	0.013959	**$101,529,812.07**
291-H-2	Good Combustion	UNLB and UNLB with SCR	UNLB with SCR	0.01102	**$119,238,993.62**

Economic impacts of installing Ultra Low NO_x burners were evaluated based on cost and performance information provided by John Zink Company. The total estimated cost effectiveness for installing new ULNB on all the above sources is $23,183,470.44 per dv of visibility improved. This value is clearly not cost effective. The total estimated cost effectiveness for installing SCR is $186,590,931.76 per dv of visibility improved. This value is clearly not cost effective.

3.2.4 Step 5 - Selection of BACT for NO_x Control

As previously demonstrated, retrofitting with ULNB or SCR is technically feasible, but not economically feasible to control NO_x emissions from the BART eligible process heaters. The proposed emission control projects, once installed, significantly reduced the effect of the Alliance Refinery on the visibility of the Class I area which satisfy the requirements of Regional Haze Rule Best Available Retrofit Technology.

ATTACHMENT I

SAGE
ENVIRONMENTAL CONSULTING

BART Refined Modeling For Baseline Emissions

Prepared for ConocoPhillips

ConocoPhillips

Alliance Refinery
Belle Chasse, LA

Sage Environmental Consulting, L.P.
May 2007

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SECTION 1
INTRODUCTION

1.1 Objectives

The objective of the refined Best Available Retrofit Technology (BART) modeling was to determine the potential visibility impairment impact of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and inhalable particulate matter (PM_{10}) emissions from the Alliance Refinery operated by ConocoPhillips in Belle Chasse, LA on the Breton Wilderness Class I area. The purpose of refined modeling was to compare the predicted visibility impact of the Alliance Refinery BART-eligible units on the Breton Wilderness Class I area with the BART exemption threshold. If the modeled impact exceeds the threshold, the refined modeling was to be used in a BART engineering analysis to establish the pre-control baseline basis.

1.2 Facility Information and Relevant Class I Areas

ConocoPhillips owns and operates a petroleum refinery in Belle Chasse, Louisiana. The refinery will be further addressed as Alliance Refinery throughout this report. The refinery is located in Plaquemines Parish. The Louisiana Department of Environmental Quality (LDEQ) agency interest number for this facility is 2418.

The visibility impacts were evaluated for the Breton Wilderness Class I area per the pre-modeling protocol. This Class I area is located approximately 94 kilometers from Belle Chase, LA. The other three nearest Class I Areas (Caney Creek in Arkansas, Sipsey Wilderness in Alabama, and St. Marks Wilderness in Florida) are located well beyond 500 km from the refinery. The Alliance Refinery BART-eligible units have a greater probability of impacting visibility impairment at the Breton Wilderness Class I area than contributing to visibility impairment at other areas. Therefore, as agreed to by LDEQ in the modeling protocol discussed in Section 1.6 of this report, the only Breton Wilderness Class I area was evaluated.

1.3 Source Impact Evaluation Criteria

Refined modeling was performed for the years 2001-2003, as required by Central Regional Air Planning Association (CENRAP). The result of modeling was a measure of visibility conditions at the Breton Wilderness Class I area. The 98th percentile modeled value[1] was compared to the natural visibility conditions for the area. The impact depended on the difference between the modeled and natural visibility, measured in deciviews (dv). If the difference was less than 0.5 dv, the Alliance Refinery did not impact visibility at the Breton

[1] The *CENRAP BART Modeling Guidelines* document defines the 98th percentile modeled value as the "8th highest day annually at a receptor or 22nd highest [value] over 3 years" (p. 2-5).

Wilderness Class I area. Thus the refinery would then be exempt from further stages in the BART process. If however, the difference was greater than or equal to 0.5 dv, the Alliance Refinery would be considered a contributor to visibility impairment at the Breton Wilderness Class I area. The latter was the case; therefore, modeling was performed for individual BART-eligible units to evaluate the contribution of each unit to the visibility impairment. The contribution analysis allowed separating units subject to BART engineering analysis from units that do not significantly contribute to visibility impairment.

1.4 Relevant Air Quality Guidelines and Standards

Several guidance documents were used when performing BART modeling. The *CENRAP BART Modeling Guidelines*[2] specified the requirements of a refined modeling protocol and the years to model. The receptors for the Breton Wilderness Class I area were obtained from the National Park Service website. Tables 5 and 6 of the *BART Modeling Protocol* published by the LDEQ in February 2007 list relative humidity correction factors and annual natural levels of aerosol used to compute visibility. Two other guidance documents from the LDEQ were used to determine modeling requirements for Louisiana. The "Regional Haze Preliminary Plan" document identifies 0.5 deciviews as the visibility threshold, and the "BART Determination Process" document specifies Louisiana's requirements for a source to be subject to BART.

1.5 Qualifications and Experience of Sage Environmental

Sage Environmental Consulting, L.P. (Sage Environmental) provided the modeling for this project. Sage Environmental has comprehensive experience in various air dispersion modeling applications in the United States of America and world-wide. Sage Environmental provides full-service engineering and management consulting services in the areas of air permitting and compliance program development, atmospheric studies, infrastructure development, hazardous waste site investigation and remediation, air quality management, environmental assessment, permitting and compliance, pollution prevention, and environmental management systems.

Sage Environmental's air dispersion modeling team provides consulting services in the atmospheric sciences. The team specializes in non-steady-state modeling, photochemical modeling, dispersion model development, air quality permitting and licensing, modeling for accidental release, analysis of aerometric and emissions data, and regulatory consulting. The Sage Environmental's technical staff employs highly qualified scientists and consultants with exceptional depth and breadth of professional experience.

1.6 Modeling Protocol

A modeling protocol was submitted to the LDEQ, EPA Region VI, and Federal Land Managers (FLM) in February 2007 and is included in Attachment F. Mr. Patrick

[2] Dennis McNally, T. W. Tesche, and George Schewe, Alpine Geophysics, LLC. *CENRAP BART Modeling Guidelines*. Ft. Wright, Kentucky: December 15, 2005.

Pakunpanya of the Air Quality Assessment Division at LDEQ reviewed the protocol and sent comments to Sage Environmental on March 19, 2007. Sage Environmental revised the protocol to address the comments and resubmitted it in April 2007. The revised protocol was subsequently approved. Sage Environmental followed the revised protocol when performing the modeling.

On May 8, 2007, Ms. Jill Webster of the U.S. Fish and Wildlife Service provided additional comments to the previously approved modeling protocol. In her letter, Ms. Webster requested that Sage Environmental utilize meteorological data from overwater stations in the modeling and assure that all visibility impairing pollutants (i.e., sulfates, nitrates, and particulate matter) are included in computing total light extinction.

At the time the comments were received, the modeling analyses that used meteorological stations listed in the modeling protocol approved by the LDEQ were complete. These analyses demonstrated that the source was not exempt from BART compliance based on the modeling results. Since ConocoPhillips accepted a responsibility to conduct a BART engineering analysis and otherwise achieve compliance with the BART rule, inclusion of overwater stations in the modeling did not seem to be necessary. LDEQ personnel concurred with ConocoPhillips that the modeling that includes land stations would be sufficient to establish that the source is not exempt from BART engineering analysis and compliance.

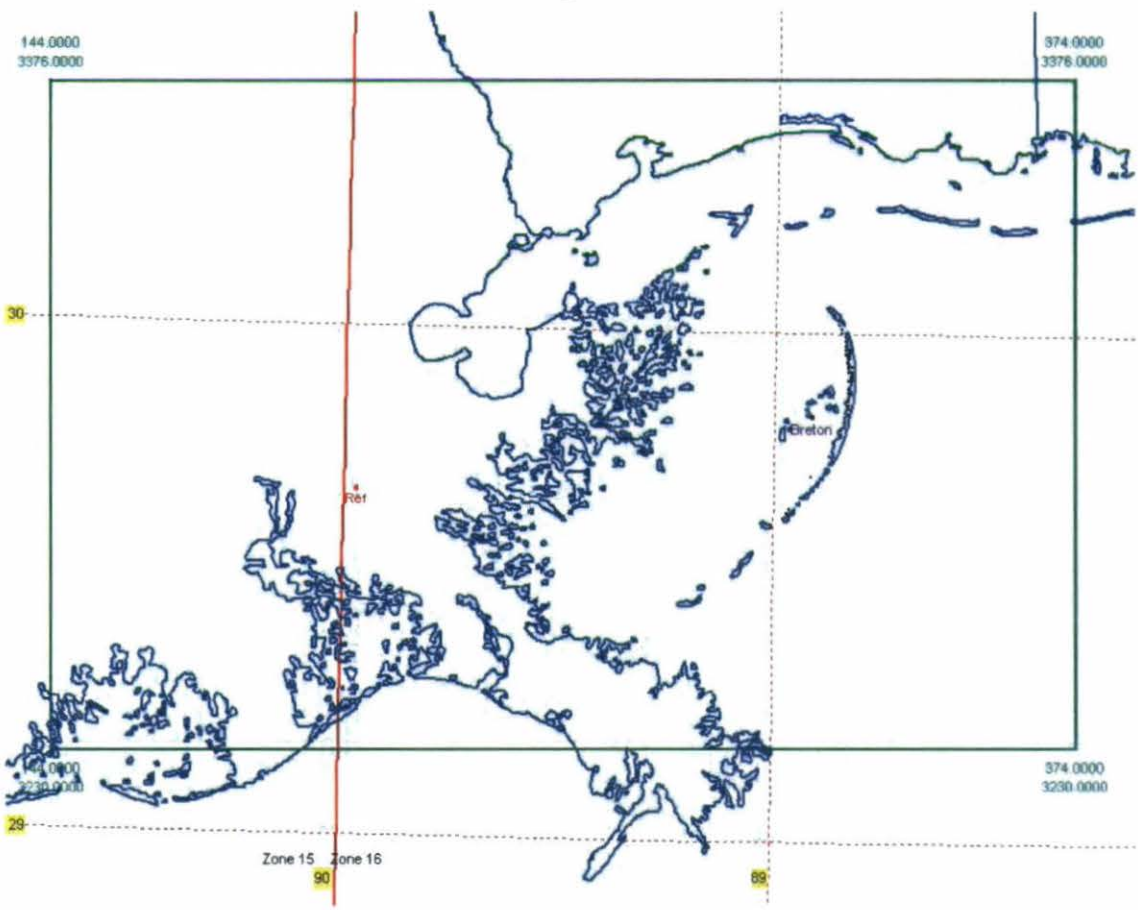
Additionally, Ms. Webster requested that in addition to sulfates and nitrates, contributions from particulate matter be included in the evaluation. Per this request, the completed modeling was revised to include three additional species in the modeling results presented in Section 6 and Appendix F of this report. However, it should be noted that all PM species combined contribute only slightly more than one (1) percent to the overall 98th percentile visibility impacts created by the Alliance Refinery BART-eligible units. Therefore, the engineering analysis is focused on SO_2 and NOx emissions.

SECTION 2
MODEL INPUT DATA

2.1 Modeling Domain

The modeling domain is depicted in Figure 2-1. Each grid cell has the size 2 km by 2 km. The domain is a rectangle that includes all BART-eligible emission units, the Breton Wilderness Class I area, and a buffer extending at least 50 km in all directions from the boundaries of the Alliance Refinery and Class I area. The coordinates in the figure for the corners of the domain are UTM coordinates. The UTM coordinate system was used in the modeling. Lambert Conformal Conic and other system coordinates were converted into UTM coordinates as necessary.

Figure 2-1
Modeling Domain



The CALPUFF model has two domains: the meteorological domain and the computational domain. The meteorological domain determines the extent of meteorological data processed by CALMET. The computational domain determines how far CALPUFF tracks puffs and their concentrations. The computational domain can be a subset of the meteorological domain. For the refined BART modeling, the two domains were the same.

2.2 Terrain and Land Use

CALMET requires land use and terrain data in addition to weather observations. Sage Environmental obtained both sets of data for the modeling domain depicted in Figure 2-1. For terrain, Sage Environmental used the 3-arc-second data included in the Professional CALPUFF interface developed by BEE-Line Software. The data was originally obtained from the US Geological Survey (USGS). For land use, Sage Environmental obtained the 250K LULC data in CTG format from USGS. The USGS data set was supplemented with land use data for the continent of North America (available from the CALPUFF website[3]) to account for the lack of USGS data for the Gulf of Mexico.

2.3 Emissions Data

2.3.1 Species Modeled

Six species were modeled together in every CALPUFF simulation. The species are SO_2, SO_4, NO_X, HNO_3, NO_3, and PM_{10}. VOC and ammonia were not modeled per the LDEQ flowchart in the "BART Determination Process" document.[4] Emissions of inhalable particulate matter (with an effective diameter less than 10 micrometers) were speciated as recommended by the National Park Service[5] and as provided in Table 2-1.

Table 2-1
PM_{10} Speciation

PM_{10} Total	Filterable				
	Total	EC		Soil	
100.00%	46.00%	6.70%	of Filterable	93.30%	of Filterable
		3.08%	of Total	42.92%	of Total
	Condensable				
	Total	SO_4		SOA (OC)	
	54.00%	66.00%	of Condensable	34.00%	of Condensable
		35.64%	of Total	18.36%	of Total

[3] Atmospheric Studies Group. "Land Use/Land Cover (LULC) data." ASG at TRC: Air Quality Modeling Data Sets. July 10, 2006. http://www.src.com/datasets/datasets_lulc.html

[4] Louisiana Department of Environmental Quality. "BART Determination Process." Current Issues. No Date. http://www.deq.louisiana.gov/portal/Portals/0/AirQualityAssessment/bart.doc.

[5] National Park Service. "Particulate Matter Speciation." Explore Air. March 28, 2006. http://www2.nature.nps.gov/air/Permits/ect/index.cfm

2.3.2 BART-Eligible Units Modeled

In early 2006, ConocoPhillips submitted an emissions inventory to the LDEQ for BART-eligible unit emissions in 2001-2003 in response to the BART survey conducted by the LDEQ. The emission units and rates from this inventory were used in the refined BART modeling. Only BART-eligible units were included in the modeling. Twenty-seven (27) units were modeled, and 24-hour maximum potential emissions were used in lieu of the highest actual daily emissions for the 2001-2003 period. Appendix A lists the units modeled, along with the corresponding stack parameters and emission rates. Per the Louisiana modeling guidelines, potential visibility impacts at the Breton Wilderness Class I Area were initially determined for all BART-eligible units as a group. Since the predictions for the group exceeded 0.5 delta-dv, visibility impacts were obtained for each individual unit. Only units with impacts exceeding 0.5 delta-dv on the Breton Wilderness Class I Area will be considered for BART engineering analysis.

2.4 Meteorological Data

The meteorological preprocessor for CALPUFF is called CALMET. Sage Environmental developed CALMET data files for the years 2001-2003. Prognostic data for 2001 (36 km EPA), 2002 (12 km WRAP) and 2003 (36 km MRPO) were used for developing the Initial Guess Wind Fields in the CALMET model. The CALMM5 extraction from the prognostic data was supplied by BEE-Line Software. The 2001 and 2003 data cover the contiguous United States at a spacing of 36 km. The 2002 data cover the western portion of the contiguous United States at a spacing of 12 km. In addition to the CALMM5 data, observations were used to develop the Step 2 Wind Fields, including surface, upper air, and precipitation weather observations. The stations from which observations were obtained are listed in Section 3.8.

2.5 Air Quality Data

Ammonia concentrations were held constant per the LDEQ *BART Modeling Protocol*.[6] The value of 3 ppb was always used for ammonia concentrations. When calculating light extinction, relative humidity correction factors (*f*(RH)s) provided by CENRAP and listed in Table 2-2 were entered into CALPOST.

Table 2-2
Monthly Averaged *f*(RH)

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Breton Wilderness	3.7	3.5	3.7	3.6	3.8	4.0	4.3	4.3	4.2	3.7	3.7	3.7

[6] Louisiana Department of Environmental Quality (February 2007). *Best Available Retrofit Technology (BART) Modeling Protocol to Determine Sources Subject to BART in the State of Louisiana*, p. 11.

Sage Environmental used ozone concentration files provided by LDEQ.[7] Three files have been provided, each containing ozone concentration data for one year. A default value of 40 ppb was used for hours in which ozone data were missing.

Sage Environmental pre-processed the ozone files in two ways. The version of CALPUFF used in the modeling required ozone station coordinates within the ozone concentration files to be UTM coordinates. The files provided had Lambert Conformal Conic (LCC) coordinates, so the coordinates were converted to UTM. In the ozone concentration file for 2002, ozone observations included stations for the entire CENRAP South domain. The number of stations was too large for CALPUFF to process, so the file was modified to only contain data for a 50-km region surrounding the modeling domain.

2.6 Natural Conditions at Class I Areas

CALPOST uses monthly concentrations of aerosol components to compute background extinction coefficients. Sage Environmental used the levels provided by CENRAP and listed in Table 2-3 when performing BART refined modeling.

Table 2-3
Average Annual Natural Levels of Aerosol Components ($\mu g/m^3$)

Class I Area	SO4	NO3	OC	EC	Soil	Coarse Mass
Breton Wilderness	0.23	0.10	1.40	0.02	0.50	3.00

[7] Louisiana Department of Environmental Quality. *Ozone Data.* March 1, 2007. ftp://ftp-cenrap.ldeq.org/ozonedata.zip

SECTION 3
CALMET MODELING METHODOLOGY

This section of the report describes the configuration settings for CALMET, the meteorological pre-processor for the CALPUFF model. Default CALMET settings were used, with the exceptions described in this section. Sage Environmental ran CALMET for each of the three years modeled (with the settings specified below) and produced output files in the CALMET.DAT format. Twelve files were produced for each year, one meteorological data file for each month. The same set of CALMET output files was then used for all CALPUFF model runs.

3.1 Meteorological Domain

The meteorological domain is a system of regular-spaced grid points at which meteorological parameters (wind components, mixing heights, etc.) are defined. The meteorological domain is determined by the grid formed in the meteorological preprocessor CALMET. The origin of the meteorological domain is the basic reference frame for all spatial input data to both CALMET and CALPUFF (e.g., coordinates of meteorological stations, sources, and receptors).

The domain depicted in Figure 2-1 is the meteorological domain used for all CALMET runs. Table 3-1 contains the CALMET variable values defining the domain.

Table 3-1
Meteorological Domain Settings

Variable	Value	Definition
PMAP	UTM	Map projection
IUTMZN	16	UTM zone
UTMHEM	N	Hemisphere
DATUM	WGS-G	National Imagery and Mapping Agency (NIMA) datum-region
NX	115	Number of x grid cells
NY	73	Number of y grid cells
DGRIDKM	2	Grid spacing in kilometers
XORIGKM	144	X coordinate of the southwest corner of the domain
YORIGKM	3230	Y coordinate of the southwest corner of the domain

3.2 Terrain

TERREL is the pre-processor for terrain data. This program accepts terrain surface elevation data from a number of digital data bases and forms grid-cell averages or point-values for use in CALMET and CALPUFF. TERREL produces a gridded terrain file for the MAKEGEO pre-processor, which then creates the geophysical data file GEO.DAT used by CALMET.

A single run of TERREL was necessary to process the terrain data. The map projection variables in TERREL were set to the appropriate values in Table 3-1. The IMODEL variable was set to 1 so that the output file format would be compatible with CALMET.

3.3 Land Use

CTGPROC is the pre-processor for land use data. The program reads a Land Use and Land Cover (LULC) data file and determines fractional land use for each grid cell in the meteorological domain. The domain required multiple land use files, so CTGPROC was applied iteratively (run several times) to build the land use grid incrementally. The land use file for the continent of North America was processed last, so that it filled the gaps in USGS land use data. The map projection variables in CTGPROC were set to match the variables in Table 3-1. The LULC variable, which indicates the type of file processed, was set to 1 (USGS CTG files) when processing USGS data and to 2 (USGS Global files) when processing the North American continent data.

3.4 Vertical Layer Structure

The vertical layer structure is defined by two variables in CALMET, NZ and ZFACE. NZ is the number of vertical layers, and ZFACE is an array containing cell face heights in meters. The value of the NZ variable was set to 12. The values for the ZFACE option were set to 0 m, 20 m, 40 m, 80 m, 160 m, 320 m, 640 m, 1000 m, 1200 m, 1500 m, 2000 m, 3000 m, and 4000 m per the pre-modeling protocol.

3.5 Diagnostic Model Settings

When developing CALMET data files, Sage Environmental changed the following default settings that determine processing of wind fields. The variable IWFCOD was set to 1 to use CALMET's diagnostic wind module. The variable IPROG was set to 14 to utilize CALMM5 data files in developing the initial guess field.

3.6 BIAS, RMIN2, IXTERP Settings

The BIAS variable affects how the initial winds are interpolated to each grid cell in each vertical layer, based on surface and upper air observations. This variable was set to an array of twelve zeroes, corresponding to the number of vertical layers. The result is that surface and upper air observations were given equal weight. The RMIN2 variable was set to -1 and the IEXTRP variable was set to -4 to extrapolate surface wind observations to upper layers.

3.7 TERRAD, R1, R2, RMAX1, RMAX2, RMAX3 Settings

CALMET uses the listed variables to construct the Step 2 wind field. Table 3-2 lists the values to which the variables were set in the CALMET input files per the pre-modeling protocol. The values all represent distances in kilometers.

Table 3-2
Wind Field Settings

Variable	Value	Definition
TERRAD	25	Radius of influence of terrain features
R1	20	Distance from a surface station at which the observation and the first guess field are equally weighted
R2	50	Distance from an upper air station at which the observation and the first guess field are equally weighted
RMAX1	100	Maximum radius of influence over land in the surface layer
RMAX2	200	Maximum radius of influence over land aloft
RMAX3	300	Maximum radius of influence over water

3.8 Weather Stations

Sage Environmental obtained observational data from one upper air station (Slidell, LA, WBAN number 53813), fourteen surface stations, and ten precipitation stations.[8] The stations are listed in Table 3-3. Anemometer heights were set to 10 meters for all surface stations. No overwater station observations were used.

Some of the data for the upper air station were missing and were replaced as follows. Each year was treated independently of the other years. If a day of data was missing, it was filled with data from the previous day. Data missing on January 1 was filled with data from January 2 for each year. If two days were missing, data from the day before the first missing day was used to fill the first missing day and data from the day after the second missing day was used to fill the second missing day. There were no periods in the modeled years when more than two consecutive days were missing.

If CALMET indicated that there were errors in the data, the modeler corrected them. If the errors could not be easily corrected, the data was replaced with data from the previous day. The corrections and replacements of data are listed in Appendix E.

[8] Observations from eight precipitation stations were used for the years 2001 and 2002. Observations from all ten precipitation stations were used in 2003.

Table 3-3
WBAN Stations Used for CALMET Processing

WBAN ID	Station Name	State	Type of Data
12884	Boothville	LA	Surface
12916	New Orleans International Airport	LA	Surface, Precipitation
12936	Patterson	LA	Surface
12968	Salt Point	LA	Surface
13820	Keesler	MS	Surface
13838	Mobile	AL	Surface
13894	Mobile Airport	AL	Surface, Precipitation
13943	New Orleans	LA	Surface
13970	Baton Rouge Ryan Airport	LA	Surface
53813	Slidell	LA	Surface, Upper Air
53858	Pascagoula	MS	Surface
93874	Gulfport-Biloxi	MS	Surface
Not available	Dauphin Island #2	AL	Surface, Precipitation
Not available	Southwest Pass	LA	Surface
Not available	LSU Citrus Research Station	LA	Precipitation
Not available	New Orleans Audubon	LA	Precipitation
Not available	Hammond	LA	Precipitation
Not available	Slidell WSFO	LA	Precipitation
Not available	Biloxi	MS	Precipitation
Not available	Pascagoula	MS	Precipitation
Not available	Saucier Exp Forest	MS	Precipitation

SECTION 4
CALPUFF MODELING METHODOLOGY

4.1 Model Selection

The California Puff (CALPUFF) air dispersion modeling system used in this modeling analysis is a multi-layer, multi-species, non-steady state puff dispersion model which can simulate the effects of time- and space-varying meteorological conditions on pollutant transport, transformation, and removal. CALPUFF uses three-dimensional meteorological fields computed by the CALMET meteorological preprocessor. CALPUFF contains algorithms for taking into account near-source effects such as building downwash, transitional plume rise, partial plume penetration, and sub-grid scale terrain interactions as well as longer range effects such as pollutant removal (wet scavenging or dry deposition), chemical transformation, vertical wind shear, and over-water transport.

By its puff-based formulation and through the use of three-dimensional meteorological data developed by the CALMET meteorological preprocessor, CALPUFF can simulate the effects of time- and space-varying meteorological conditions on pollutant transport from point, volume, area, and line sources in complex terrain.

Table 4-1
Versions of the Modeling Software

Program Name	Version	Level
CTGPROC	2.4	030402
TERREL	3.3	030402
MAKEGEO	2.2	030402
READ62	5.5	030402
PMERGE	5.3	030402
PXTRACT	4.2	030402
SMERGE	5.56	050324
CALMET	5.53a	040716
CALPUFF	5.711a	040716
POSTUTIL	1.3	030402
CALPOST	5.51	030709

Sage Environmental used EPA-approved versions of the CALPUFF, CALPOST, and POSTUTIL programs listed in Table 4-1. These programs and their pre-processors were obtained from the CALPUFF website[9] and were then recompiled as recommended by

[9] Atmospheric Studies Group. "Codes and Related Processors: EPA-Approved Version." January 16, 2007. http://www.src.com/calpuff/download/p2.htm

LDEQ[10]. The parameter files for all three programs were modified; the modified file printouts are provided in Appendix C. Sage Environmental used version 2.34.1 of the Professional CalPuff graphical user interface developed by BEE-Line Software to create model input files. Three annual simulations were performed for the years 2001-2003.

4.2 Computational Domain and Receptor Grid

As discussed in Section 2.1, the computational domain is the same as the meteorological domain. It is defined by the CALPUFF variables in Table 4-2, and has the same 2 km by 2 km spacing as the meteorological domain.

Table 4-2
Computational Domain Settings

Variable	Value	Definition
IBCOMP	1	X index of lower left corner
JBCOMP	1	Y index of lower left corner
IECOMP	115	X index of upper right corner
JECOMP	73	Y index of upper right corner

The receptors were the set of Class I area receptors developed by the National Park Service. There were 40 receptors covering the Breton Wilderness Class I area, spaced approximately 1 km from each other. When running CALPUFF, only the receptors for this Class I area were included.

4.3 CALPUFF Configuration

4.3.1 Subgrid-scale complex terrain

An optional module in CALPUFF, Complex Terrain Sub-grid (CTSG), treats terrain features that are not resolved by the gridded terrain field. This module utilizes calculation routines that are based on the Complex Terrain Dispersion Model (CTDMPlus). Sage Environmental did to not use this option as dictated in the pre-modeling protocol by setting the CALPUFF variable MCTSG to 0.

4.3.2 Chemical Mechanism

CALPUFF includes options for assessing chemical transformation effects using the five species scheme (SO_2, SO_4, NO_x, HNO_3, and NO_3) employed in the MESOPUFF II model; the six species RIVAD scheme (SO_2, SO_4, NO, NO_2, HNO_3, and NO_3); or a set of user-specified, diurnally-varying transformation rates. Sage Environmental set the CALPUFF variable MCHEM to 1 to use the MESOPUFF II chemical transformation scheme.

[10] Louisiana Department of Environmental Quality (February 2007). *Best Available Retrofit Technology (BART) Modeling Protocol to Determine Sources Subject to BART in the State of Louisiana*, p. 8.

4.3.3 Building Downwash

The Huber-Snyder and Schulman-Scire (ISC3) downwash models and the PRIME building downwash algorithm are both incorporated into CALPUFF computation routines. Both algorithms have been implemented in such a way as to allow the use of wind direction-specific building dimensions. The use of downwash algorithms is optional. Since buildings and other solid structures only affect plume dispersion out to approximately 10 building/structure heights downwind of the structure and the Breton Wilderness Class I area is approximately 94 km away from the Alliance Refinery, Sage Environmental did not include building downwash effects in the modeling analysis.

4.3.4 Puff Splitting

CALPUFF contains an optional puff splitting algorithm that allows vertical wind sheer effects across individual puffs to be simulated. Differential rates of dispersion and transport occur on the puffs generated from the original puff, which under some conditions can substantially increase the effective rate of horizontal growth of the plume. Sage Environmental did to not use this option by setting the CALPUFF variable MSPLIT to 0.

4.3.5 Sampling Grid

CALPUFF contains an option to place additional receptors within the computational domain. Since only the Breton Wilderness Class I area is being modeled, Sage Environmental did to not use this option by setting the CALPUFF variable LSAMP to F.

4.3.6 Dispersion Coefficients

Several options are provided in CALPUFF for the computation of dispersion coefficients, including the use of turbulence measurements (σ_v and σ_w), the use of similarity theory to estimate σ_v and σ_w from modeled surface heat and momentum fluxes, or the use of Pasquill-Gifford (PG) or McElroy-Pooler (MP) dispersion coefficients, or dispersion equations based on the Complex Terrain Dispersion Model (CTDMPlus). Options are provided to apply an averaging time correction or surface roughness length adjustments to the PG coefficients. Sage Environmental utilized PG dispersion coefficients as the CALPUFF default option for rural type of dispersion by setting the variable MDISP to 3.

4.3.7 Dry Deposition

A full resistance model is provided in CALPUFF for the computation of dry deposition rates of gases and particulate matter as a function of geophysical parameters, meteorological conditions, and pollutant species. Options are provided to allow user-specified, diurnally varying deposition velocities to be used for one or more pollutants instead of the resistance model (e.g., for sensitivity testing) or to by-pass the dry deposition model completely. For particles, source-specific mass distributions may be provided for use in the resistance model. Sage Environmental included dry deposition effect calculations by setting the CALPUFF variable MDRY to 1.

4.3.8 Wet Removal

An empirical scavenging coefficient approach is used in CALPUFF to compute the depletion and wet removal fluxes due to precipitation scavenging. The scavenging coefficients are specified as a function of the pollutant and precipitation type (i.e., frozen vs. liquid precipitation). Sage Environmental included wet removal effect calculations by setting the CALPUFF variable MWET to 1.

SECTION 5
POST PROCESSING METHODOLOGY

5.1 POSTUTIL Configuration

Following each CALPUFF run, the POSTUTIL post-processor program was run to compute the HNO_3/NO_3 partition of concentrations. This computation used the ammonia limiting method, with the background ammonia concentration set to 3 ppb, as discussed in Section 2.5. The MNITRATE variable was set to 1 to compute the partition and the BCKNH3 variable was set to 3.

5.2 CALPOST Configuration

The CALPOST post-processor program was run after POSTUTIL to obtain the daily delta-deciview values indicating the visibility impact of the Alliance Refinery on the Breton Wilderness Class I area. CALPOST produced both light extinction values and delta-deciview values. The settings in Table 5-1 were used for visibility processing of the concentrations computed by POSTUTIL.

Table 5-1
CALPOST Settings

Variable	Value	Definition
METRUN	1	Run for all dates in POSTUTIL output file
ASPEC	VISIB	Visibility processing
LD	T	Process discrete receptors
LVSO4	T	Process sulfate
LVNO3	T	Process nitrate
LVOC	T	Process organic carbon
LVPMC	F	Do not process coarse particles
LVPMF	T	Process fine particles
LVEC	T	Process elemental carbon
SPECPMF	SOIL	Species name used for fine particles
MVISBK	6	Method used for background light extinction
IPRTU	3	Output units are $\mu g/m^3$
L24HR	T	Output 24-hour averages

After running CALPOST for each year, the yearly results were combined to obtain the 98th percentile delta-deciview value for all BART-eligible units combined and for each individual BART-eligible unit. The delta-deciview values for each year were sorted in descending order, and the first eight values were extracted. After obtaining twenty-four values from three years of results, the 22nd highest value was computed. This value was then compared with the 0.5 delta-deciview threshold.

SECTION 6
MODELING RESULTS

This section contains a summary of the modeling results. See Appendix F for the details.

6.1 Visibility Impacts

When the BART-eligible units at the Alliance Refinery are considered together as a group, their combined impact on the Breton Wilderness Class I area is 2.689 delta-deciviews. This is the 98th percentile value for the years 2001-2003. Since the value is above the 0.5 delta-deciview threshold, the Alliance Refinery BART-eligible units were determined to contribute to visibility impairment at the Breton Wilderness Class I area.

6.2 Contribution Analysis

After determining that the Alliance Refinery contributes to visibility impairment, Sage Environmental ran CALPUFF again for each BART-eligible unit within the refinery. It was determined that three units have impacts greater than 0.5 delta-deciview. The units are: EPN 301-B-2A (CO boiler), with an impact of 0.530 delta-deciview; EPN 301-B-2B (CO Boiler), with an impact of 0.529 delta-deciview; and EPN 308F-D-1 (low-pressure flare), with an impact of 1.033 delta-deciview. The other units all have impacts not exceeding the 0.5 delta-deciview threshold.

Additional modeling runs were conducted to determine the contribution of different species (i.e, sulfates, nitrates, and particulate matter) to the overall visibility impairment impact created by the BART-eligible units. The runs demonstrated that approximately 77% of visibility impairment in 2001-2003 can be attributed to sulfur dioxide, 22% can be attributed to nitrogen oxides emissions, and all particulate species contributed approximately 1% to the overall impacts. Based on this analysis, ConocoPhillips proposes to focus their BART engineering analysis to address emissions reductions for sulfur dioxide.

SECTION 7
POST CONTROL MODELING RESULTS

This section contains a summary of the post-control modeling results. See Appendix F for the details.

7.1 Visibility Impacts

When the BART-eligible units at the Alliance Refinery are considered together as a group, their combined post-control impact on the Breton Wilderness Class I area is 1.444 delta-deciviews. This is the 98th percentile value for the years 2001-2003. The value is above the 0.5 delta-deciview threshold.

7.2 Contribution Analysis

Sage Environmental analyzed the contributions of the BART-eligible units for which emission rates were reduced as a control mechanism. The units are: EPN 301-B-2A (CO boiler); EPN 301-B-2B (CO Boiler); and EPN 308F-D-1 (low-pressure flare); and EPN 308F-D-2 (high-pressure flare). These units all have impacts not exceeding the 0.5 delta-deciview threshold after controls are applied.

SECTION 8
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APPENDIX A
EMISSIONS DATA

ConocoPhillips Company
Alliance Refinery
Belle Chasse, Louisiana
List of BART- Eligible Units Included in BART Modeling

EPN	Description	Source ID	UTM Easting (X) (km)	UTM Northing (Y) (km)	Zone	Stack Height (m)	Base Elevation (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp. (K)	Init. Sigma-y (m)	Init. Sigma-z (m)	Momentum Flux
1291-H-2/3	FCCU Light/Heavy Feed Heater	1291H23	212.246	3287.375	16	56.7	1.22	2.59	4.08	552	0	0	1
301-B-2A	CO Boiler	301B2A	212.232	3287.396	16	23.8	1.22	3.51	20.49	609.3	0	0	1
301-B-2B	CO Boiler	301B2B	212.21	3287.389	16	23.8	1.22	3.51	20.99	582	0	0	1
292-H-1	Light Distillate Gulfiner Reactor Heater	292H1	212.037	3287.241	16	28	0.61	1.22	2.44	595.9	0	0	1
292-H-2	Light Distillate Gulfiner Stabilizer Heater	292H2	212.032	3287.254	16	36.9	0.66	1.6	2	597	0	0	1
191-H-1	Crude Charge Heater	191H1	212.092	3287.117	16	63.7	0.61	4.69	8.05	465.9	0	0	1
191-H-2	Vacuum Charge Heater	191H2	212.103	3287.09	16	63.7	0.61	2.74	4.4	449.3	0	0	1
406-D-15	Product Dock No.1 MVR Loading	406D15	212.61	3286.993	16	7.6	1.52	0.79	20	1273.2	0	0	1
406-D-16	Product Dock No.2 MVR Loading	406D16	212.612	3286.984	16	7.6	1.52	0.79	20	1273.2	0	0	1
891-H-1	Delayed Coker Charge Heater	891H1	212.395	3287.189	16	50.3	1.22	2.29	6.01	605.4	0	0	1
891-CP	Coke Transfer and Storage	891CP	212.397	3287.217	16	1.00	1.22	1.00	0.001	298.15	0	0	1
491-H-1	Alkylation Isostripper Reboiler	491H1	212.252	3287.133	16	51.2	0.91	3.12	2.5	615.9	0	0	1
491-H-2	Alkylation Depropanizer Reboiler	491H2	212.269	3287.139	16	43	0.91	3.05	4.48	574.3	0	0	1
100-H-1	Coker Charge Storage Heater	100H1	212.47	3287.281	16	15.2	1.94	0.61	6.07	594.3	0	0	1
293-H-1	Heavy Distillate Gulfiner Reactor Feed Heater	293H1	212.051	3287.2	16	39.6	0.61	2.03	2.68	577.6	0	0	1
293-H-2	Heavy Distillate Gulfiner Stabilizer Reboiler	293H2	212.055	3287.187	16	34.4	0.61	1.92	4.42	603.7	0	0	1
1391-H-1	Catalytic Reformer Feed Heater No. 1	1391H1	212.015	3287.43	16	62.8	0.91	3.51	4.76	490.4	0	0	1
1391-H-2/3	Catalytic Reformer Feed Heater No. 2 & 3	1391H23	212.051	3287.443	16	65	0.91	3.93	3.75	763.1	0	0	1
1391-H-4	Depentanizer Reboiler	1391H4	212.025	3287.433	16	44.2	0.91	2.18	6.34	550.4	0	0	1
1391-H-5	Dry Reactivation Heater	1391H5	212.07	3287.45	16	42.2	0.91	2.2	1.49	550.4	0	0	1
1791-H-1	Reformate Splitter Reboiler	1791H1	212.056	3287.319	16	38.1	0.91	1.96	3.5	552	0	0	1
1792-H-1	Hydrodealkylation Charge Heater	1792H1	212.027	3287.269	16	45.1	0.7	2.29	4.24	552	0	0	1
291-H-1	Naphiner Reactor Feed Heater	291H1	212.042	3287.227	16	39.6	0.64	1.92	2.99	599.3	0	0	1
291-H-2	Naphiner Deisohexanizer Reboiler	291H2	212.045	3287.214	16	38.7	0.61	1.93	3.66	541.5	0	0	1
303-R-1	Cooling Water Tower No. 1	303R1P	212.177	3287.033	16	18.288	0.61	8.5344	8.534	303.15	0	0	1
308F-D-1	Low Pressure Flare	308FD1	212.51	3286.983	16	65	1.22	3.07	20	1273.2	0	0	1
308F-D-2	High Pressure Flare	308FD2	212.569	3286.81	16	65	1.09	2.15	20	1273.2	0	0	1

ConocoPhillips Company
Alliance Refinery
Belle Chasse, Louisiana
List of BART- Eligible Units Included in BART Modeling

EPN	Description	Source ID	SO_2	SO_2	SO_4	SO_4	NO_X	NO_X	EC	EC	Soil	Soil	OC	OC
			(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)
1291-H-2/3	FCCU Light/Heavy Feed Heater	1291H23	0.6792	5.3903	0.0668	0.5304	1.0097	8.0138	0.0058	0.0458	0.0805	0.6387	0.0344	0.2732
301-B-2A	CO Boiler	301B2A	69.3287	550.2371	2.3925	18.9884	19.1319	151.8434	0.2068	1.6410	2.8812	22.8671	1.2325	9.7819
301-B-2B	CO Boiler	301B2B	69.3287	550.2371	2.3925	18.9884	19.0972	151.5678	0.2068	1.6410	2.8812	22.8671	1.2325	9.7819
292-H-1	Light Distillate Gulfiner Reactor Heater	292H1	0.0930	0.7383	0.0094	0.0746	0.3389	2.6896	0.0008	0.0065	0.0113	0.0899	0.0048	0.0385
292-H-2	Light Distillate Gulfiner Stabilizer Heater	292H2	0.1636	1.2982	0.0163	0.1296	0.5958	4.7289	0.0014	0.0112	0.0197	0.1561	0.0084	0.0668
191-H-1	Crude Charge Heater	191H1	19.7917	157.0794	0.4538	3.6013	40.8565	324.2632	0.0392	0.3112	0.5464	4.3369	0.2338	1.8552
191-H-2	Vacuum Charge Heater	191H2	1.5042	11.9380	0.1485	1.1786	8.9472	71.0109	0.0128	0.1019	0.1788	1.4193	0.0765	0.6072
406-D-15	Product Dock No.1 MVR Loading	406D15	0.0056	0.0441	0.0238	0.1886	0.8819	6.9997	0.0021	0.0163	0.0286	0.2271	0.0122	0.0971
406-D-16	Product Dock No.2 MVR Loading	406D16	0.0056	0.0441	0.0238	0.1886	0.8819	6.9997	0.0021	0.0163	0.0286	0.2271	0.0122	0.0971
891-H-1	Delayed Coker Charge Heater	891H1	0.8967	7.1165	0.0886	0.7032	5.6333	44.7097	0.0077	0.0608	0.1067	0.8469	0.0456	0.3623
891-CP	Coke Transfer and Storage	891CP	0.0000	0.0000	0.0262	0.2082	0.0000	0.0000	0.0023	0.0180	0.0316	0.2507	0.0135	0.1073
491-H-1	Alkylation Isostripper Reboiler	491H1	0.8069	6.4044	0.0663	0.5264	5.1847	41.1493	0.0057	0.0455	0.0799	0.6340	0.0342	0.2712
491-H-2	Alkylation Depropanizer Reboiler	491H2	1.0111	8.0248	0.0832	0.6600	6.0167	47.7521	0.0072	0.0570	0.1001	0.7948	0.0428	0.3400
100-H-1	Coker Charge Storage Heater	100H1	0.0403	0.3197	0.0040	0.0314	0.1472	1.1684	0.0003	0.0027	0.0048	0.0378	0.0020	0.0162
293-H-1	Heavy Distillate Gulfiner Reactor Feed Heater	293H1	0.1812	1.4381	0.0238	0.1886	0.7917	6.2832	0.0021	0.0163	0.0286	0.2271	0.0122	0.0971
293-H-2	Heavy Distillate Gulfiner Stabilizer Reboiler	293H2	0.2298	1.8236	0.0272	0.2161	1.0042	7.9697	0.0024	0.0187	0.0328	0.2602	0.0140	0.1113
1391-H-1	Catalytic Reformer Feed Heater No 1	1391H1	1.2778	10.1413	0.1262	1.0018	1.9000	15.0796	0.0109	0.0866	0.1520	1.2064	0.0650	0.5161
1391-H-2/3	Catalytic Reformer Feed Heater No 2 & 3	1391H23	1.2611	10.0090	0.1242	0.9861	1.8750	14.8812	0.0107	0.0852	0.1496	1.1875	0.0640	0.5080
1391-H-4	Depentanizer Reboiler	1391H4	0.7167	5.6879	0.0708	0.5618	9.0139	71.5400	0.0061	0.0486	0.0852	0.6766	0.0365	0.2894
1391-H-5	Dry Reactivation Heater	1391H5	0.0389	0.3086	0.0040	0.0314	0.1431	1.1354	0.0003	0.0027	0.0048	0.0378	0.0020	0.0162
1791-H-1	Reformate Splitter Reboiler	1791H1	0.4597	3.6487	0.0455	0.3614	3.1944	25.3532	0.0039	0.0312	0.0548	0.4353	0.0235	0.1862
1792-H-1	Hydrodealkylation Charge Heater	1792H1	0.6222	4.9384	0.0614	0.4872	0.9250	7.3414	0.0053	0.0421	0.0739	0.5867	0.0316	0.2510
291-H-1	Naphiner Reactor Feed Heater	291H1	0.4764	3.7809	0.0470	0.3732	3.2986	26.1799	0.0041	0.0323	0.0566	0.4495	0.0242	0.1923
291-H-2	Naphiner Deisohexanizer Reboiler	291H2	0.3750	2.9762	0.0371	0.2946	2.6000	20.6353	0.0032	0.0255	0.0447	0.3548	0.0191	0.1518
303-R-1	Cooling Water Tower No. 1	303R1P	0.0000	0.0000	0.9870	7.8337	0.0000	0.0000	0.0853	0.6770	1.1886	9.4339	0.5085	4.0355
308F-D-1	Low Pressure Flare	308FD1	236.1111	1873.9292	0.0020	0.0157	3.3565	26.6392	0.0002	0.0014	0.0024	0.0189	0.0010	0.0081
308F-D-2	High Pressure Flare	308FD2	63.0787	500.6331	0.0020	0.0157	1.3889	11.0231	0.0002	0.0014	0.0024	0.0189	0.0010	0.0081

APPENDIX B
CALPUFF SPECIES DEFINITION FILE

ConocoPhillips Company
Alliance Refinery
Belle Chasse, Louisiana
CALPUFF Species Parameters for Refined BART Modeling

	Dry (Gas)					Dry (Particle)		Wet	
Species	Diffusivity	Alpha Star	Reactivity	Meso. Resist.	Henry's Law	Geo. Mass Mean Diameter	Geometric Standard Deviation	Scavenging Coef. Liquid Precip.	Scavenging Coef. Frozen Precip.
	(cm^2/s)			(s/cm)		(microns)	(microns)	(1/s)	(1/s)
SO2	0.1509	1000	8	0	0.04	0	0	3.00E-05	0
SO4	0	0	0	0	0	0.48	2	1.00E-04	3.00E-05
NOX	0.1656	1	8	5	3.5	0	0	0	0
HNO3	0.1628	1	18	0	8.00E-08	0	0	6.00E-05	0
NO3	0	0	0	0	0	0.48	2	1.00E-04	3.00E-05
EC	0	0	0	0	0	0.48	2	1.00E-04	3.00E-05
SOIL	0	0	0	0	0	0.48	2	1.00E-04	3.00E-05
SOA	0	0	0	0	0	0.48	2	1.00E-04	3.00E-05

APPENDIX C
PARAMETER FILES FOR CALPUFF, POSTUTIL, AND CALPOST

```
c-----------------------------------------------------------------------
c     CALPUFF PARAMETERS
c-----------------------------------------------------------------------

c --- Specify model version
      character*12 mver, mlevel, mmodel
      parameter(mver='5.711a',mlevel='040716')
      parameter(mmodel='CALPUFF')

c --- Specify parameters
      parameter(mxpuff=100000)
      parameter(mxspec=20)
      parameter(mxnx=388,mxny=265,mxnz=16)
      parameter(mxnxg=265,mxnyg=265,mxrec=10000)
      parameter(mxrfog=40)
      parameter(mxss=350,mxus=99,mxps=700)
      parameter(mxpt1=200,mxpt2=200,mxarea=200,mxvert=5)
      parameter(mxlines=24,mxlngrp=1,mxvol=200)
      parameter(mxrise=50)
      parameter(mxpdep=9,mxint=9)
      parameter(mxoz=725,mxaq=1)
      parameter(mxhill=20,mxtpts=25,mxrect=1000,mxcntr=21)
      parameter(mxprfz=50)
      parameter(mxent=10,mxntr=50,mxnw=5000)
      parameter(mxvalz=10)
      parameter(mxcoast=10,mxptcst=5000)
      parameter(mxbndry=10,mxptbdy=5000)
      parameter(mxmetdat=366, mxemdat=12)
      parameter(mxmetsav=2)
      parameter(mxsg=30)
      parameter(io3=3,io4=4,io5=1,io6=2,io7=7,io8=8,io9=9)
      parameter(io10=10,io11=11,io12=12,io15=15,io19=19)
      parameter(io20=20,io22=22,io23=23,io24=24)
      parameter(io25=25,io28=28,io29=29,io30=30,io31=31,io32=32)
      parameter(io35=35,io36=36,io37=37)
      parameter(iomesg=0)
      parameter(iox=99)
      parameter(iopt2=100)
      parameter(ioar2=iopt2+mxemdat)
      parameter(iovol=ioar2+mxemdat)

c --- Compute derived parameters
      parameter(mxbc=2*mxnx+2*mxny)
      parameter(mxnzp1=mxnz+1)
      parameter(mxvertp1=mxvert+1)
      parameter(mxnxy=mxnx*mxny)
      parameter(mxnxyg=mxnxg*mxnyg)
      parameter(mxgsp=mxnxg*mxnyg*mxspec)
      parameter(mxrsp=mxrec*mxspec)
      parameter(mxcsp=mxrect*mxspec)
      parameter(mx2=2*mxspec,mx5=5*mxspec,mx7=7*mxspec)
      parameter(mxp2=2+mxspec,mxp3=3+mxspec)
      parameter(mxp4=4+mxspec,mxp6=6+mxspec)
      parameter(mxp7=7+mxspec,mxp8=8+mxspec,mxp14=mxspec+14)
      parameter(mxpuf6=6*mxpuff)
      parameter(mxlev=mxprfz)
      parameter(mxprfp1=mxprfz+1)
      parameter(mxentp1=mxent+1)
      parameter(mxgrup=mxspec)
      parameter(mxq12=mxspec*(mxpt1+mxarea)*2)
      parameter(mxspar=mxspec*mxarea,mxspln=mxspec*mxlines)
      parameter(mxsppt1=mxspec*mxpt1,mxspvl=mxspec*mxvol)
      parameter(mxspbc=mxspec*mxbc)
```

```
c --- Specify parameters for sizing GUI
      parameter(mxavar=1)
      parameter(mxlvar=1)
      parameter(mxpvar=1)
      parameter(mxvvar=1)

c --- GENERAL PARAMETER definitions:
c        MXPUFF - Maximum number of active puffs allowed on the
c                 computational grid at one time
c        MXSLUG - Maximum number of active slugs allowed on the
c                 computational grid at one time (can be set to
c                 one if the slug option is not used)
c        MXSPEC - Maximum number of chemical species.  N.B.: Changes
c                 to MXSPEC may also require code changes to BLOCK DATA
c                 and READCF.
c        MXGRUP - Maximum number of Species-Groups.  Results for grouped
c                 species are added together and reported using the
c                 name of the group, rather than the name of one of the
c                 species in the group. (MXGRUP = MXSPEC since specie
c                 names are used as group names whenever group names are
c                 not provided)
c          MXNX - Maximum number of METEOROLOGICAL grid cells in
c                 the X direction
c          MXNY - Maximum number of METEOROLOGICAL grid cells in
c                 the Y direction
c          MXNZ - Maximum number of vertical layers in
c                 the METEOROLOGICAL grid
c         MXNXG - Maximum number of SAMPLING grid cells in
c                 the X direction
c         MXNYG - Maximum number of SAMPLING grid cells in
c                 the Y direction
c         MXREC - Maximum number of non-gridded receptors
c        MXRFOG - Maximum number of distances used when MFOG=1
c                 NOTE:  There are NPT1+NPT2 receptor 'trails', with
c                        MXRFOG receptors on each, so
c                        MXREC >= (NPT1+NPT2)*MXRFOG
c          MXSS - Maximum number of surface meteorological stations
c                 in the CALMET data
c          MXUS - Maximum number of upper air stations in the CALMET
c                 data
c          MXPS - Maximum number of precipitation stations in the
c                 CALMET data
c          MXBC - Maximum number of sources used to represent boundary
c                 conditions (inlux of background mass);  source
c                 segments span the computational domain perimeter
c         MXPT1 - Maximum number of point sources with constant
c                 emission parameters
c         MXPT2 - Maximum number of point sources with time-varying
c                 emission parameters
c        MXAREA - Maximum number of polygon area sources with constant
c                 emission parameters (i.e., non-gridded area sources)
c        MXVERT - Maximum number of vertices in polygon area source
c        MXLINES- Maximum number of line sources
c        MXLNGRP- Maximum number of groups of line sources
c         MXVOL - Maximum number of volume sources
c        MXRISE - Maximum number of points in computed plume rise
c                 tabulation for buoyant area and line sources
c        MXPDEP - Maximum number of particle species dry deposited
c         MXINT - Maximum number of particle size intervals used
c                 in defining mass-weighted deposition velocities
c          MXOZ - Maximum number of ozone data stations (for use in the
c                 chemistry module)
```

```
c          MXAQ - Maximum number of Air Quality data stations (e.g.
c                 H2O2 data stations for aqueous chemistry module)
c        MXHILL - Maximum number of subgrid-scale (CTSG) terrain
c                 features
c        MXTPTS - Maximum number of points used to obtain flow
c                 factors along the trajectory of a puff over the hill
c        MXRECT - Maximum number of complex terrain (CTSG) receptors
c        MXCNTR - Maximum number of hill height contours (CTDM ellipses)
c        MXPRFZ - Maximum number of vertical levels of met. data in
c                 CTDM PROFILE file
c         MXLEV - Maximum number of vertical levels of met. data
c                 allowed in the CTSG module (set to MXPRFZ in the
c                 current implementation of CALPUFF)
c         MXENT - Maximum number of perturbed entrainment coefficients
c                 entered
c         MXNTR - Maximum number of downwind distances for which
c                 numerical plume rise will be reported
c          MXNW - Maximum number of downwind distances for numerical
c                 plume rise integration (should be set equal to
c                 SLAST/DS)
c        MXVALZ - Maximum number of heights above ground at which valley
c                 widths are found for each grid cell
c       MXCOAST - Maximum number of coasts provided in COASTLN.DAT file
c       MXPTCST - Maximum number of points used to store all coastlines
c       MXBNDRY - Maximum number of boundaries provided in FLUXBDY.DAT
c       MXPTBDY - Maximum number of points used to store all boundaries
c      MXMETDAT - Maximum number of CALMET.DAT files used in run
c       MXEMDAT - Maximum number of variable emissions files (each type)
c      MXMETSAV - Maximum number of met periods for which source tables
c                 (e.g. numerical rise) are saved
c         MXQ12 - Maximum number of groups of 12 emission rate scaling
c                 factors.  Factors come in groups of 12,24,36, or 96.
c                 These are specified for source-species combinations,
c                 but not all combinations will be filled.  Default
c                 value of MXQ12 assumes that no more than 24 factors
c                 are provided for each source-species combination for
c                 point and area sources.

c --- CONTROL FILE READER definitions:
c           MXSG - Maximum number of input groups in control file

c --- FORTRAN I/O unit numbers:
c            IO3 - Restart file (RESTARTB.DAT)    - input  - unformatted
c            IO4 - Restart file (RESTARTE.DAT)    - output - unformatted
c            IO5 - Control file (CALPUFF.INP)     - input  - formatted
c            IO6 - List file (CALPUFF.LST)        - output - formatted
c            IO7 - Meteorological data file       - input  - unformatted
c                  (CALMET.DAT)
c            IO8 - Concentration output file      - output - unformatted
c                  (CONC.DAT)
c            IO9 - Dry flux output file           - output - unformatted
c                  (DFLX.DAT)
c           IO10 - Wet flux output file           - output - unformatted
c                  (WFLX.DAT)
c           IO11 - Visibility output file         - output - unformatted
c                  (VISB.DAT)
c           IO12 - Fog plume data output file     - output - unformatted
c                  (FOG.DAT)
c           IO15 - Boundary Condition file        - input  - unformatted
c                  (BCON.DAT)
c           IO19 - Buoyant line sources file      - input  - free format
c                  (LNEMARB.DAT) with arbitrarily
c                  varying location & emissions
```

```
c          IO20 - User-specified deposition     - input  - formatted
c                 velocities (VD.DAT)
c          IO22 - Hourly ozone monitoring data  - input  - formatted
c                 (OZONE.DAT)
c          IO23 - Hourly H2O2 monitoring data   - input  - formatted
c                 (H2O2.DAT)
c          IO24 - User-specified chemical       - input  - formatted
c                 transformation rates
c                 (CHEM.DAT)
c          IO25 - User-specified coast line(s)  - input  - free format
c                 for sub-grid TIBL module
c                 (COASTLN.DAT)
c          IO28 - CTSG hill specifications from - input  - formatted
c                 CTDM terrain processor
c                 (HILL.DAT)
c          IO29 - CTSG receptor specifications  - input  - formatted
c                 from CTDM receptor generator
c                 (RECS.DAT)
c          IO30 - Tracking puff/slug data       - output - formatted
c                 (DEBUG.DAT)
c          IO31 - CTDM "tower" data             - input  - formatted
c                 (PROFILE.DAT)
c          IO32 - CTDM surface layer parameters - input  - formatted
c                 (SURFACE.DAT)
c          IO35 - User-specified boundary lines(s)- input- free format
c                 for mass flux calculations
c                 (FLUXBDY.DAT)
c          IO36 - Mass flux data                - output - formatted
c                 (MASSFLX.DAT)
c          IO37 - Mass balance data             - output - formatted
c                 (MASSBAL.DAT)
c         IOPT2 - 1st Pt. source emissions file - input  - unformatted
c                 (PTEMARB.DAT) with arbitrarily          or free fmt
c                 varying point source emissions
c         IOAR2 - 1st Buoyant area sources file - input  - free format
c                 (BAEMARB.DAT) with arbitrarily
c                 varying location & emissions
c         IOVOL - 1st Volume source file        - input  - unformatted
c                 (VOLEMARB.DAT) with arbitrarily          of free fmt
c                 varying location & emissions
c        IOMESG - Fortran unit number for screen- output - formatted
c                 output (NOTE: This unit is
c                 NOT opened -- it must be a
c                 preconnected unit to the screen
c                 -- Screen output can be suppressed
c                 by the input "IMESG" in the
c                 control file)
c           IOX - Fortran unit number for      - scratch - formatted
c                 temporary file of "doc" records
c                 written to header of output files

c --- GUI memory control parameters:  variable emissions scaling factors
c     for areas, lines, points, and volumes require much memory in GUI.
c     To reduce GUI memory requirement, set one or more of the
c     following parameters to ZERO when such scaling is not required.
c     These parameters have no effect on CALPUFF, but are read by the
c     GUI at execution time.
c        MXAVAR - Using scaled area sources?   (1:yes, 0:no)
c        MXLVAR - Using scaled line sources?   (1:yes, 0:no)
c        MXPVAR - Using scaled point sources?  (1:yes, 0:no)
c        MXVVAR - Using scaled volume sources? (1:yes, 0:no)
```

```
c-----------------------------------------------------------------------
c     POSTUTIL PARAMETERS
c-----------------------------------------------------------------------

c --- Specify model version
      character*12 mver, mlevel
      parameter(mver='1.3',mlevel='030402')

c --- Specify application size
      PARAMETER(mxtpd=24)
      PARAMETER(mxssg=10)
      PARAMETER(mxgx=388)
      PARAMETER(mxgy=265)
      PARAMETER(mxgrec=mxgx*mxgy)
      PARAMETER(mxnx=mxgx,mxny=mxgy,mxnxy=mxgrec)
      PARAMETER(mxdrec=10000)
      PARAMETER(mxctrec=1000)
      PARAMETER(mxnz=16,mxspec=20)
      PARAMETER(mxsplv=mxspec)
      PARAMETER(mxnzp1=mxnz+1)
      PARAMETER(mxss=350,mxus=99,mxps=700,mxprfz=50)
      PARAMETER(mxfile=366)
      PARAMETER(icols=25)
      PARAMETER(in1=10,in2=5,in3=9,in4=4)
      PARAMETER(io7=in4)
      PARAMETER(io1=7,io2=8,io6=6)
      PARAMETER(iox=99)
      parameter(mxsg=3)

c-----------------------------------------------------------------------
c     DEFINITIONS       [i]=integer     [r]=real        [a]=array
c-----------------------------------------------------------------------
c mxtpd          maximum number of time periods (CALPUFF files)      [i]
c                (NOT ACTIVE)
c mxssg          maximum number of source-species groups             [i]
c                in CALPUFF output files
c                (NOT ACTIVE)
c mxgx           maximum number gridded receptors along "x"          [i]
c mxgy           maximum number gridded receptors along "y"          [i]
c mxgrec         product mxgx*mxgy                                   [i]
c mxnx           maximum number of met grid cells along "x"          [i]
c mxny           maximum number of met grid cells along "y"          [i]
c mxnxy          product mxnx*mxny                                   [i]
c mxdrec         maximum number of discrete receptors                [i]
c mxctrec        maximum number of complex terrain (CTSG) receptors  [i]
c mxnz           maximum number of levels                            [i]
c mxnzp1         maximum number of levels + 1                        [i]
c mxspec         maximum number of species                           [i]
c mxsplv         max number of chemical species * max number levels  [i]
c mxss           maximum number of surface met stations              [i]
c mxus           maximum number of upper air met stations            [i]
c mxps           maximum number of precipitation stations            [i]
c mxprfz         maximum number of levels in vertical profile        [i]
c mxfile         max number of CALPUFF data files processed          [i]
c icols          number of columns in gridded integer output         [i]
c in1            unit number for input data file (CALPUFF.DAT)       [i]
c                - this is for the first file in the list, the
c                - subsequent files are incremented from in1
c                - MAKE CERTAIN NO OTHER UNIT #s EXCEED in1
c in2            unit number for control file input (POSTUTIL.INP)   [i]
c in3            unit number for input file of RH data (CALPUFF.VIS) [i]
c in4 (io7)      unit number for complete met. input file (MET.DAT)  [i]
c io1            unit number for output list file (POSTUTIL.LST)     [i]
```

```
c io2            unit number for output data file (MODEL.DAT)        [i]
c io6            unit number for screen output (error messages)      [i]
c iox            unit number for control file images (scratch)       [i]
c-----------------------------------------------------------------------

c --- CONTROL FILE READER definitions:
c          MXSG - Maximum number of input groups in control file
```

```
c-----------------------------------------------------------------------
c     CALPOST PARAMETERS
c-----------------------------------------------------------------------

c --- Specify model version
      character*12 mver, mlevel
      parameter(mver='5.51',mlevel='030709')

c --- Specify application size
      PARAMETER(mxgx=388)
      PARAMETER(mxgy=265)
      PARAMETER(mxgrec=mxgx*mxgy)
      PARAMETER(mxdrec=10000, mxring=40)
      PARAMETER(mxctrec=1000)
      PARAMETER(mxtser=30)
      PARAMETER(mxnz=1,mxspec=20)
      PARAMETER(mxsplv=mxnz*mxspec)
      PARAMETER(mxss=350)
      PARAMETER(mxwsta=30)
      PARAMETER(mxday=366)
      PARAMETER(mxwin=10)
      PARAMETER(mxrnk=10,mxtop=4)
      PARAMETER(icols=25)
      PARAMETER(in1=4,in2=5,in3=9,in4=18,in5=19)
      PARAMETER(io1=8,io6=6)
      PARAMETER(iot1=21,iot3=22,iot24=23,iotn=24)
      PARAMETER(mapu=11)
      PARAMETER(iox1=12,iox2=13,iox3=14,iox4=15)
      PARAMETER(iowx1=31,iowx2=32,iohrv=33)
      parameter(mxsg=4)

c-----------------------------------------------------------------------
c     DEFINITIONS       [i]=integer     [r]=real        [a]=array
c-----------------------------------------------------------------------
c mxgx          maximum number gridded receptors along "x"          [i]
c mxgy          maximum number gridded receptors along "y"          [i]
c mxgrec        product mxgx*mxgy                                   [i]
c mxdrec        maximum number of discrete receptors                [i]
c mxring        maximum number of discrete receptor "rings"         [i]
c mxctrec       maximum number of complex terrain (CTSG) receptors  [i]
c mxtser        maximum number of receptors in timeseries output    [i]
c mxnz          maximum number of levels                            [i]
c mxspec        maximum number of species                           [i]
c mxsplv        max number of chemical species * max number levels  [i]
c mxss          max number of surface stations in CALMET/CALPUFF    [i]
c mxwsta        max number of weather stations in VSRN.DAT (DATSAV3)[i]
c mxday         max number of days in run for violation option      [i]
c mxwin         max number of days in window (for violation search) [i]
c mxrnk         max rank of top-ranked concentrations               [i]
c mxtop         max number of top-ranked concentrations             [i]
c icols         number of columns in gridded integer output         [i]
c in1           unit number for "concentration" input file          [i]
c in2           unit number for control file input                  [i]
c in3           unit number for input file of RH data               [i]
c in4           unit number for input file of background data       [i]
c in5           unit number for input file of visual range data     [i]
c io1           unit number for output list file                    [i]
c io6           unit number for standard output (error messages)    [i]
c iot1          unit number for timeseries file (1hr avg)           [i]
c iot3          unit number for timeseries file (3hr avg)           [i]
c iot24         unit number for timeseries file (24hr avg)          [i]
c iotn          unit number for timeseries file (Nhr avg)           [i]
c mapu          unit number for current plot-file                   [i]
```

```
c iox1           unit number for scratch file (extinction summary)   [i]
c iox2           unit number for scratch file (deciview summary)     [i]
c iox3           unit number for scratch file (run length extinction)[i]
c iox4           unit number for scratch file (run length deciview)  [i]
c iowx1          unit number for scratch file (weather data image 1) [i]
c                (saved as DEBUG.WX1 when LDEBUG=T)
c iowx2          unit number for scratch file (weather data image 2) [i]
c                (saved as DEBUG.WX2 when LDEBUG=T)
c iohrv          unit number for hourly visibility calculation       [i]
c                details (saved as DEBUG.HRV when LDEBUG=T)
c-----------------------------------------------------------------------

c --- CONTROL FILE READER definitions:
c          MXSG - Maximum number of input groups in control file
```

APPENDIX D
LDEQ SUBMITTALS

The files submitted electronically with this report are organized into the directories listed in Table D-1. The files are listed in Tables D-2 through D-4 and include input and output files from all models and pre-processors. The submissions do not include CALMM5 files, files containing observations from the weather stations listed in Table 3-3, CALMET.DAT files output by CALMET, or VISB.DAT files output by CALPUFF, since these files together would require over 70 GB of storage space. In Tables D-1 through D-4, *yyyy* or *yy* stand for one of the years 2001-2003 and numbers in square brackets ([*1-3*]) stand for a sequence of numbers (*1, 2, 3*).

Table D-1
Directory Structure

Directory	Contents
GeoData	Files for geophysical data pre-processors (see Table D-2)
MetData	Files for meteorological data pre-processors (see Table D-3)
yyyy\	CALMET files for year *yyyy*
yyyy\bret	CALPUFF and POSTUTIL files for modeling all units for year *yyyy*
yyyy\bret\fullyear	CALPOST files for modeling all units for year *yyyy*
yyyy\contrib	CALPUFF and POSTUTIL files for contribution analysis for year *yyyy*
yyyy\contrib\results	CALPOST files for contribution analysis for year *yyyy*
yyyy\post	CALPUFF and POSTUTIL files for post-control modeling for year *yyyy*
yyyy\post\results	CALPOST files for post-control modeling for year *yyyy*

Table D-2
Files in GeoData Directory

Filename	Contents
Ctgproc[*0-4*].inp	Land use pre-processor input file
CTGPROC[*0-4*].LST	Land use pre-processor runtime information file
LANDUSE[*0-3*].DAT	Land use pre-processor intermediate output files
LANDUSE.DAT	Land use pre-processor output file from final run
TERREL.INP	Terrain pre-processor input file
terrel.lst	Terrain pre-processor runtime information file
terrel.dat	Terrain pre-processor output file
MAKEGEO.INP	Geophysical data pre-processor input file
MAKEGEO.LST	Geophysical data pre-processor runtime information file
MAKEGEO.DAT	Geophysical data pre-processor output file

For the meteorological data pre-processors, a single input file has been included. The files for other years have the same processing options, but different starting and ending dates.

Table D-3
Files in MetData Directory

Filename	Contents
ozone*yyyy*.dat	Ozone concentration files for year *yyyy*
SMERGE.INP	Surface data pre-processor input file
smerge*.lst	Surface data pre-processor runtime information files for various surface stations
surf*yy*.dat	Surface data pre-processor output file for year *yy*
READ62.INP	Upper air data pre-processor input file
Original 53813_*yy*.UA	Upper air output file before substitutions for year *yy*
53813_*yy*.UA	Upper air output file after substitutions for year *yy*
53813_*yy*.LST	Upper air data pre-processor runtime information file for year *yy*
PMERGE.INP	Precipitation data pre-processor input file
PMERGE*YY*.LST	Precipitation data pre-processor runtime information file for year *yy*
PRECIP*YY*.DAT	Precipitation data pre-processor output file for year *yy*

When performing contribution analysis, the CALPUFF input file for each year was split into 27 different files (i.e., one file for each BART-eligible unit). The unit was assigned a number corresponding to its order within the original input file. POSTUTIL and CALPOST input files were then created to process and evaluate visibility impacts for individual units.

Table D-4
Files Generated by Models

Filename	Directory	Contents
calmet*yyyy*[*01-12*].inp	*yyyy*	CALMET input file for a single month in year *yyyy*
calmet*yyyy*[*01-12*].lst	*yyyy*	CALMET runtime information file for a single month in year *yyyy*
CALPUFF.INP	*yyyy*\bret	CALPUFF input file for modeling all units for year *yyyy*
CALPUFF.LST	*yyyy*\bret	CALPUFF runtime information file for modeling all units for year *yyyy*
CONC.DAT	*yyyy*\bret	CALPUFF concentration output file for year *yyyy*
DFLX.DAT	*yyyy*\bret	CALPUFF dry flux output file for year *yyyy*
WFLX.DAT	*yyyy*\bret	CALPUFF wet flux output file for year *yyyy*
POSTUTIL.INP	*yyyy*\bret	POSTUTIL input file for modeling all units for year *yyyy*

Table D-4
(continued)

postutil.lst	*yyyy*\bret	POSTUTIL runtime information file for modeling all units for year *yyyy*
postutilconcout.dat	*yyyy*\bret	POSTUTIL output file for year *yyyy*
CALPOST.INP	*yyyy*\bret\fullyear	CALPOST input file for modeling all units for year *yyyy*
calpost.lst	*yyyy*\bret\fullyear	CALPOST runtime information file for modeling all units for year *yyyy*
v24v*yyyy*.dat	*yyyy*\bret\fullyear	CALPOST visibility output file for year *yyyy*
CALPUFF[*1-27*].INP	*yyyy*\contrib	CALPUFF input file for year *yyyy* for a single unit
CALPUFF[*1-27*].LST	*yyyy*\contrib	CALPUFF runtime information file for year *yyyy* for a single unit
CONC[*1-27*].DAT	*yyyy*\contrib	CALPUFF concentration output file for year *yyyy* for a single unit
DFLX[*1-27*].DAT	*yyyy*\contrib	CALPUFF dry flux output file for year *yyyy* for a single unit
WFLX[*1-27*].DAT	*yyyy*\contrib	CALPUFF wet flux output file for year *yyyy* for a single unit
POSTUTIL[*1-27*].INP	*yyyy*\contrib	POSTUTIL input file for year *yyyy* for a single unit
postutil[*1-27*].lst	*yyyy*\contrib	POSTUTIL runtime information file for year *yyyy* for a single unit
postutilconcout[*1-27*].dat	*yyyy*\contrib	POSTUTIL output file for year *yyyy* for a single unit
CALPOST[*1-27*].INP	*yyyy*\contrib\results	CALPOST input file for year *yyyy* for a single unit
calpost[*1-27*].lst	*yyyy*\contrib\results	CALPOST runtime information file for year *yyyy* for a single unit
v24v*yy*[*1-27*].dat	*yyyy*\contrib\results	CALPOST visibility output file for year *yyyy* for a single unit

The **post** directory contains modeling files for both all-unit and contribution analyses. The files are named similarly to those in the **bret** and **contrib** directories, except that the POSTUTIL input file for modeling all units is named POSTUTIL_ALL.INP.

The files are submitted on three compact disks (CDs). The first CD contains the GeoData, MetData, and 2001 directories. The second CD contains the 2002 directory with all files pertinent to 2002 impacts modeling. The third CD contains the 2003 directory.

APPENDIX E
UPPER AIR DATA SUBSTITUTIONS

ConocoPhillips Company
Alliance Refinery
Belle Chasse, Louisiana

Upper Air Data Substitutions
Slidell, LA
WBAN Station 53813

Date	Error	Substitution
January 1, 2001, hour 0	Missing sounding	Filled with data for January 2, 2001, hour 0
January 17, 2001, hour 0	Missing sounding	Filled with data for January 16, 2001, hour 0
January 25, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 283.6 Kelvin at bottom of sounding
January 30, 2001, hour 0	Missing sounding	Filled with data for January 29, 2001, hour 0
February 5, 2001, hour 0	Data at bottom of sounding is missing	Replaced with data for February 4, 2001, hour 0
February 26, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 291.5 Kelvin at bottom of sounding
March 14, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 294.9 Kelvin at bottom of sounding
March 30, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 293.1 Kelvin at bottom of sounding
April 13, 2001, hour 0	Missing sounding	Filled with data for April 12, 2001, hour 0
April 17, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 297.2 Kelvin at bottom of sounding
April 19, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 289.6 Kelvin at bottom of sounding
April 22, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 295.9 Kelvin at bottom of sounding
April 23, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 296.6 Kelvin at bottom of sounding
April 26, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 294.4 Kelvin at bottom of sounding
April 27, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 297.2 Kelvin at bottom of sounding
May 9, 2001, hour 0	Missing sounding	Filled with data for May 8, 2001, hour 0
May 16, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 302.2 Kelvin at bottom of sounding
May 25, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 302.2 Kelvin at bottom of sounding
June 2, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 302.8 Kelvin at bottom of sounding
June 17, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 302.9 Kelvin at bottom of sounding
June 19, 2001, hour 12	Top of sounding is below 500.0 mb	Replaced with data for June 18, 2001, hour 12
June 20, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 298.6 Kelvin at bottom of sounding
July 9, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 303.4 Kelvin at bottom of sounding
July 14, 2001, hour 0	Data at bottom of sounding is missing	Temperature set to 296.6 Kelvin at bottom of sounding
August 10, 2001, hour 12	Top of sounding is below 500.0 mb	Replaced with data for August 9, 2001, hour 12
September 1, 2001, hour 0	Missing sounding	Filled with data for August 31, 2001, hour 0
October 14, 2001, hour 0	Top of sounding is below 500.0 mb	Replaced with data for October 13, 2001, hour 0

ConocoPhillips Company
Alliance Refinery
Belle Chasse, Louisiana

Upper Air Data Substitutions
Slidell, LA
WBAN Station 53813

Date	Error	Substitution
March 5, 2002, hour 0	Data at bottom of sounding is missing	Replaced with data for March 4, 2002, hour 0
March 10, 2002, hour 0	Missing sounding	Filled with data for March 9, 2002, hour 0
April 3, 2002, hour 12	Missing sounding	Filled with data for April 2, 2002, hour 12
June 28, 2002, hour 0	Missing sounding	Filled with data for June 27, 2002, hour 0
July 22, 2002, hour 0	Missing sounding	Filled with data for July 21, 2002, hour 0
July 23, 2002, hour 12	Data at bottom of sounding is missing	Replaced with data for July 22, 2002, hour 12
August 3, 2002, hour 0	Missing sounding	Filled with data for August 2, 2002, hour 0
September 26, 2002, hour 12	Data at bottom of sounding is missing	Replaced with data for September 25, 2002, hour 12
November 11, 2002, hour 0	Data at bottom of sounding is missing	Replaced with data for November 10, 2002, hour 0
February 10, 2003, hour 12	Elevation is decreasing with height	Replaced with data for February 9, 2003, hour 12
February 21, 2003, hour 0	Missing sounding	Filled with data for February 20, 2003, hour 0

APPENDIX F
VISIBILITY IMPACTS

ConocoPhillips Company
Alliance Refinery
Belle Chasse, Louisiana
Visibility Impact Analysis

Breton Class I Area		
2001 delta-dv	2002 delta-dv	2003 delta-dv
4.234	6.278	4.926
3.650	5.355	4.543
3.396	4.962	4.488
3.324	4.650	4.119
2.995	4.543	4.042
2.689	3.610	4.021
2.358	3.437	3.791
2.344	3.116	3.610

The 22nd highest value over the three-year period is 2.689 delta-dv, which is above the 0.5 delta-dv threshold.

ConocoPhillips Company
Alliance Refinery
Belle Chasse, Louisiana
Visibility Impact Summary

EPN	Description	98th Percentile Delta-DV Value
1291-H-2/3	FCCU Light/Heavy Feed Heater	0.013
301-B-2A	CO Boiler	**0.530**
301-B-2B	CO Boiler	**0.529**
292-H-1	Light Distillate Gulfiner Reactor Heater	0.003
292-H-2	Light Distillate Gulfiner Stabilizer Heater	0.005
191-H-1	Crude Charge Heater	0.264
191-H-2	Vacuum Charge Heater	0.062
406-D-15	Product Dock No.1 MVR Loading	0.006
406-D-16	Product Dock No.2 MVR Loading	0.006
891-H-1	Delayed Coker Charge Heater	0.039
891-CP	Coke Transfer and Storage	0.002
491-H-1	Alkylation Isostripper Reboiler	0.034
491-H-2	Alkylation Depropanizer Reboiler	0.040
100-H-1	Coker Charge Storage Heater	0.001
293-H-1	Heavy Distillate Gulfiner Reactor Feed Heater	0.007
293-H-2	Heavy Distillate Gulfiner Stabilizer Reboiler	0.009
1391-H-1	Catalytic Reformer Feed Heater No. 1	0.024
1391-H-2/3	Catalytic Reformer Feed Heater No. 2 & 3	0.022
1391-H-4	Depentanizer Reboiler	0.055
1391-H-5	Dry Reactivation Heater	0.001
1791-H-1	Reformate Splitter Reboiler	0.021
1792-H-1	Hydrodealkylation Charge Heater	0.012
291-H-1	Naphiner Reactor Feed Heater	0.021
291-H-2	Naphiner Deisohexanizer Reboiler	0.017
303-R-1	Cooling Water Tower No. 1	0.076
308F-D-1	Low Pressure Flare	**1.033**
308F-D-2	High Pressure Flare	0.359

ConocoPhillips Company
Alliance Refinery
Belle Chasse, Louisiana
Post Control Visibility Impact Analysis

Breton Class I Area		
2001 delta-dv	2002 delta-dv	2003 delta-dv
2.162	3.107	2.975
2.106	3.034	2.178
1.833	2.296	2.081
1.805	2.268	2.071
1.483	1.942	1.827
1.468	1.676	1.748
1.451	**1.444**	1.684
1.301	1.326	1.664

The 22nd highest value over the three-year period is 1.444 delta-dv, which is above the 0.5 delta-dv threshold.

ConocoPhillips Company
Alliance Refinery
Belle Chasse, Louisiana
Visibility Impact Summary

EPN	Description	98th Percentile Delta-DV Value
1291-H-2/3	FCCU Light/Heavy Feed Heater	0.013
301-B-2A	CO Boiler	**0.530**
301-B-2B	CO Boiler	**0.529**
292-H-1	Light Distillate Gulfiner Reactor Heater	0.003
292-H-2	Light Distillate Gulfiner Stabilizer Heater	0.005
191-H-1	Crude Charge Heater	0.264
191-H-2	Vacuum Charge Heater	0.062
406-D-15	Product Dock No.1 MVR Loading	0.006
406-D-16	Product Dock No.2 MVR Loading	0.006
891-H-1	Delayed Coker Charge Heater	0.039
891-CP	Coke Transfer and Storage	0.002
491-H-1	Alkylation Isostripper Reboiler	0.034
491-H-2	Alkylation Depropanizer Reboiler	0.040
100-H-1	Coker Charge Storage Heater	0.001
293-H-1	Heavy Distillate Gulfiner Reactor Feed Heater	0.007
293-H-2	Heavy Distillate Gulfiner Stabilizer Reboiler	0.009
1391-H-1	Catalytic Reformer Feed Heater No. 1	0.024
1391-H-2/3	Catalytic Reformer Feed Heater No. 2 & 3	0.022
1391-H-4	Depentanizer Reboiler	0.055
1391-H-5	Dry Reactivation Heater	0.001
1791-H-1	Reformate Splitter Reboiler	0.021
1792-H-1	Hydrodealkylation Charge Heater	0.012
291-H-1	Naphiner Reactor Feed Heater	0.021
291-H-2	Naphiner Deisohexanizer Reboiler	0.017
303-R-1	Cooling Water Tower No. 1	0.076
308F-D-1	Low Pressure Flare	**1.033**
308F-D-2	High Pressure Flare	0.359

ConocoPhillips Company
Alliance Refinery
Belle Chasse, Louisiana
Post Control Visibility Impact Summary

EPN	Description	98th Percentile Delta-DV Value
301-B-2A	CO Boiler	0.338
301-B-2B	CO Boiler	0.342
308F-D-1	Low Pressure Flare	0.032
308F-D-2	High Pressure Flare	0.037

APPENDIX G
MODELING PROTOCOL AND APPROVAL

ATTACHMENT II

SAGE
ENVIRONMENTAL CONSULTING

ConocoPhillips

Revised BART Refined Modeling Protocol

Alliance Refinery
Belle Chasse, LA

April 2007

1100 CENTENNIAL BLVD., SUITE 160 • RICHARDSON, TEXAS • 75081 • 972/480-9800 • FAX 972/480-9865

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SECTION 1
INTRODUCTION

1.1 Objectives

The objective of the refined Best Available Retrofit Technology (BART) modeling is to determine the potential visibility impairment impact of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and inhalable particulate matter (PM_{10}) emissions from the Alliance Refinery operated by ConocoPhillips in Belle Chasse, LA on the Breton Wilderness Class I area. The purpose of refined modeling is to show that the visibility impact of the Alliance Refinery on the Breton Wilderness Class I area is below the BART threshold. If this cannot be demonstrated, then refined modeling will be used in a BART engineering analysis.

1.2 Guidances Used

Several guidances were used to develop this protocol. The Central Regional Air Planning Association's *CENRAP BART Modeling Guidelines*[1] specified the requirements of a refined modeling protocol and the years to model. The receptors for the Breton Wilderness area were obtained from the National Park Service website. Tables 5 and 6 of the *BART Modeling Protocol* published by the Louisiana Department of Environmental Quality (LDEQ) in February 2007 list relative humidity correction factors and annual natural levels of aerosol used to compute visibility. Two other guidances from the LDEQ were used to determine modeling requirements for Louisiana. The "Regional Haze Preliminary Plan" document identifies 0.5 deciviews as the visibility threshold, and the "BART Determination Process" document specifies Louisiana's requirements for a source to be subject to BART.

1.3 Source Impact Evaluation Criteria

Refined modeling will be performed for the years 2001-2003, as required by Central Regional Air Planning Association (CENRAP). The result of modeling will be a measure of visibility conditions at the Breton Wilderness Class I area. The 98th percentile modeled value[2] will be compared to the natural visibility conditions for the area. The impact will depend on the difference between the modeled and natural visibility, measured in deciviews (dv). If the difference is less than 0.5 dv, the Alliance Refinery does not impact visibility at the Breton Wilderness Class I area. It is then exempt from further stages in the BART process. If the difference is greater than or equal to 0.5 dv, the Alliance Refinery is considered to contribute to visibility impairment. In this case, additional modeling will be

[1] Dennis McNally, T. W. Tesche, and George Schewe, Alpine Geophysics, LLC. *CENRAP BART Modeling Guidelines*. Ft. Wright, Kentucky: December 15, 2005.
[2] The *CENRAP BART Modeling Guidelines* document defines the 98th percentile modeled value as the "8th highest day annually at a receptor or 22nd highest over 3 years" (p. 2-5).

completed for individual BART-eligible units to evaluate the contribution of each unit to the visibility impairment. The culpability analysis will allow separating units subject to BART engineering analysis from units that do not significantly contribute to visibility impairment.

1.4 Class I Areas Evaluated

The visibility impacts will be evaluated for the Breton Wilderness Class I area. This area is located approximately 94 kilometers from Belle Chase, LA. The other three Class I Areas (Caney Creek in Arkansas, Sipsey Wilderness in Alabama, and St. Marks Wilderness in Florida) are located well beyond 500-km from the refinery. Results of screening modeling conducted by the LDEQ for Louisiana BART-eligible sources[3] demonstrated that the Alliance Refinery and other facilities in southeast Louisiana, as a group, do not adversely impact the Caney Creek Class I Area. Back tracking analysis conducted by Visibility Improvement State and Tribal Association of the Southeast (VISTAS) for the 20% worst days for all areas located within the VISTAS domain[4] indicates that during only one day puffs traveling from southeast Louisiana can impact either Sipsey or St. Marks wilderness areas. If impacts on the Breton Wilderness from the Alliance Refinery exceed the visibility impairment contribution level, the source will be subject to BART Engineering Analyses. If, however, Alliance Refinery BART-eligible units do not contribute to visibility impairment at the Breton Class I Area located less than 100 kilometers from the source, it is not likely that the source may contribute to visibility impairments at areas located at puff travel distances exceeding 500 km.

1.5 Modeling Team

Sage Environmental Consulting, L.P. (Sage Environmental) will provide the modeling for this project. Sage Environmental has comprehensive experience in various air dispersion modeling applications in the United States of America and world-wide. Sage Environmental provides full-service engineering and management consulting services in the areas of air permitting and compliance program development, atmospheric studies, infrastructure development, hazardous waste site investigation and remediation, air quality management, environmental assessment, permitting and compliance, pollution prevention, and environmental management systems.

Sage Environmental's air dispersion modeling team provides consulting services in the atmospheric sciences. The team specializes in non-steady-state modeling, photochemical modeling, dispersion model development, air quality permitting and licensing, modeling for accidental release, analysis of aerometric and emissions data, and regulatory consulting. The Sage Environmental's technical staff employs highly qualified scientists and consultants with exceptional depth and breadth of professional experience.

---

[3] Louisiana Department of Environmental Quality (February 2007). *Best Available Retrofit Technology (BART) Modeling Protocol to Determine Sources Subject to BART in the State of Louisiana*, pp. 34-36.

[4] Brewer, Pat. *Weight of Evidence: Residence Time Analyses.* September 22, 2005. http://www.vistas-sesarm.org/documents/VISTASJointWorkGroupMeeting09052005/7_Brewer_Residence%20time_20050922.ppt

1.6 Submittals

The modeling results will be summarized in a modeling report to be submitted to the LDEQ. This report will include a textual description of all phases of the modeling analysis and tables containing the modeling results. The report will also include all input, output, and supplemental electronic files pertinent to the modeling analysis, as required by the LDEQ *BART Modeling Protocol.*[5]

[5] Louisiana Department of Environmental Quality (February 2007). *Best Available Retrofit Technology (BART) Modeling Protocol to Determine Sources Subject to BART in the State of Louisiana*, p. 15.

SECTION 2
MODELING METHODOLOGY

2.1 Model Selection

The model recommended by the LDEQ for BART refined modeling is CALPUFF, developed by Atmospheric Studies Group. Sage will use the EPA-approved versions of CALPUFF, CALMET and CALPOST in Table 2-1. Sage will also use version 2.34.1 of the Professional CALPUFF graphical user interface developed by BEE-Line Software. Three annual simulations will be done for the years 2001-2003.

Table 2-1
Proposed Versions of the Modeling Software

Program Name	Version	Released
CALMET	5.53a	July 16, 2004
CALPUFF	5.711a	July 16, 2004
CALPOST	5.51	July 9, 2003

2.2 CALMET Configuration and Specific Settings

When performing refined modeling for BART, Sage will use the following CALMET options. Default settings will be used unless noted in Section 3.2.

- No data will be used from overwater stations.
- Anemometer heights for surface stations will be set to 10 m.
- The values for the ZFACE option (cell face heights) will be set to 0 m, 20 m, 40 m, 80 m, 160 m, 320 m, 640 m, 1000 m, 1200 m, 1500 m, 2000 m, 3000 m, and 4000 m.
- The value for the NZ option (number of vertical layers) will be set to 12.
- The value for the TERRAD option will be set to 25 km.
- The value for the R1 option will be set to 20 km.
- The value for the R2 option will be set to 50 km.
- The value for the RMAX1 option will be set to 100 km.
- The value for the RMAX2 option will be set to 200 km.
- The value for the RMAX3 option will be set to 300 km.

The CALMET processor contains overwater and overland boundary layer parameterizations allowing certain of the effects of water bodies on plume transport, dispersion, and deposition to be estimated. These effects include the abrupt changes that occur at a coastline of a major body of water.

Additional details are provided in Section 3.2.

2.3 CALPUFF Configuration and Specific Settings

When performing refined modeling for BART, Sage will use the following CALPUFF options. Default settings will be used unless noted in Sections 3.3 and 3.4.

- No puff splitting.
- No building downwash.
- No sub-grid scale complex terrain.
- Wet removal will be modeled.
- Dry deposition will be modeled.

The emission sources will be the BART-eligible units at the Alliance Refinery. A list of the sources and their release parameters is provided in Appendix A. See Section 3.4 for additional details.

2.4 CALPOST Configuration and Specific Settings

When performing refined modeling for BART, Sage will use the following CALPOST options. Default settings will be used unless noted in Section 3.5.

- Visibility processing.
- Method 6 for background light extinction.
- Sulfate and nitrate species included in computing total light extinction.
- Create file of daily delta-deciview.
- 24-hour averaging period.
- 98th percentile (22nd high value for the 3-year period) will be compared to the natural visibility conditions.

2.5 Domain Configuration and Receptors

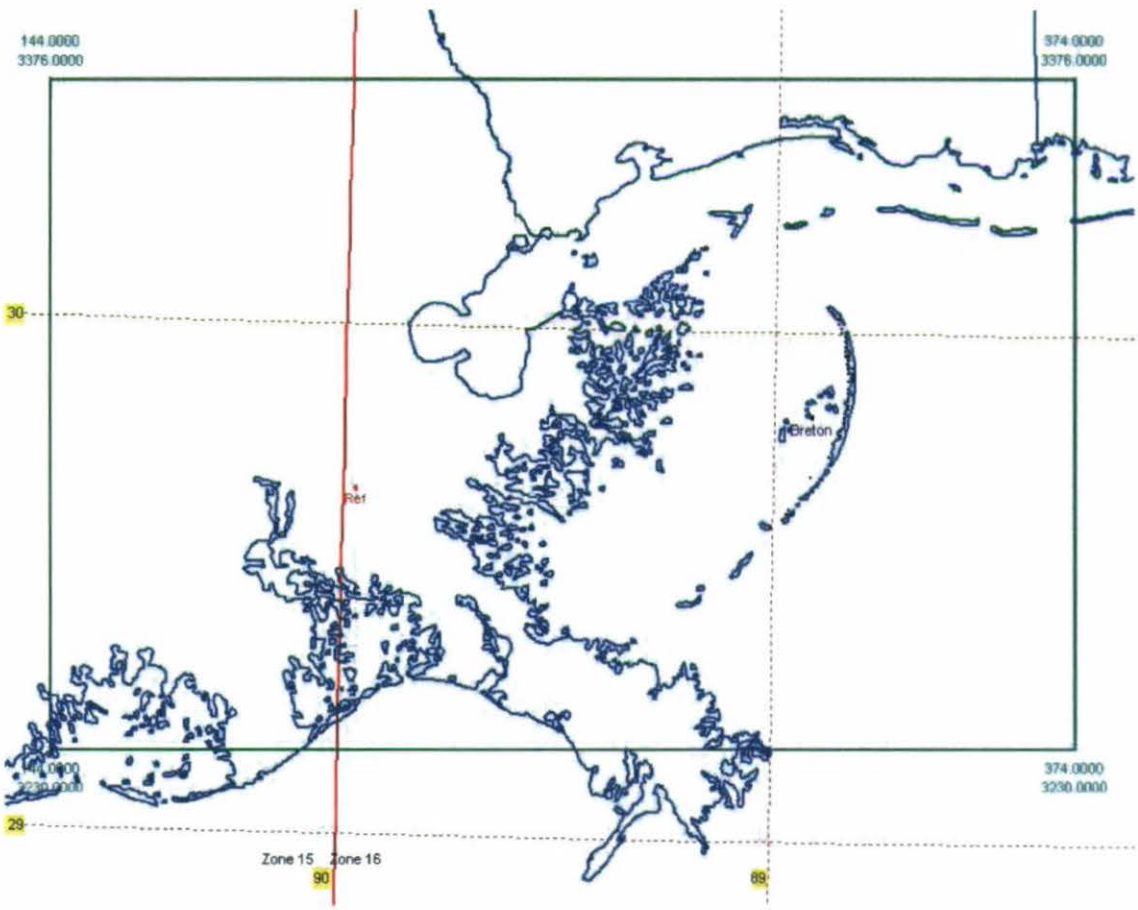
The modeling domain is depicted in Section 3.1. The receptors will be the set of Class I area receptors developed by the National Park Service. There will be 40 receptors covering the Breton Wilderness Class I area, spaced approximately 1 km from each other. When running CALPUFF, only the receptors for this Class I area will be included.

SECTION 3
MODEL INPUT DATA

3.1 Modeling Domain

The proposed modeling domain is depicted on Figure 3-1. Each grid cell will have the size 2 km by 2 km. The domain will be a rectangle that will include all emission sources, the Breton Wilderness Class I area, and a buffer extending at least 50 km in all directions from the boundaries of the Alliance Refinery and Class I area.

Figure 3-1
Modeling Domain



CALPUFF has two domains, the meteorological domain and the computational domain. The meteorological domain determines the extent of meteorological data processed by CALMET.

The computational domain determines how far CALPUFF tracks puffs and their concentrations. The computational domain can be a subset of the meteorological domain. For the refined BART modeling, the two domains will be the same.

3.2 Meteorological Data

The meteorological preprocessor for CALPUFF is called CALMET. Sage will develop CALMET data files for the years 2001-2003. Prognostic data for 2001 (36 km EPA), 2002 (12 km WRAP) and 2003 (36 km MRPO) will be used for developing the Initial Guess Wind Fields in the CALMET model. The CALMM5 extraction from the prognostic data was supplied by BEE-Line Software. The 2001 and 2003 data cover the conterminous United States at a spacing of 36 kilometers. The 2002 data cover the western portion of the conterminous United States at a spacing of 12 kilometers. In addition to the CALMM5 data, observations will be used to develop the Step 2 Wind Fields, including surface, upper air, and precipitation weather observations from the stations listed in Table 3-1.

Table 3-1
WBAN Stations Proposed for CALMET Processing

WBAN ID	Station Name	State	Type of Data
12884	Boothville	LA	Surface
12916	New Orleans International Airport	LA	Surface, Precipitation
12936	Patterson	LA	Surface
12968	Salt Point	LA	Surface
13820	Keesler	MS	Surface
13838	Mobile	AL	Surface
13894	Mobile Airport	AL	Surface, Precipitation
13943	New Orleans	LA	Surface
13970	Baton Rouge Ryan Airport	LA	Surface
53813	Slidell	LA	Surface, Upper Air
53858	Pascagoula	MS	Surface
93874	Gulfport-Biloxi	MS	Surface
Not available	Dauphin Island #2	AL	Surface, Precipitation
Not available	Southwest Pass	LA	Surface
Not available	LSU Citrus Research Station	LA	Precipitation
Not available	New Orleans Audubon	LA	Precipitation
Not available	Hammond	LA	Precipitation
Not available	Slidell WSFO	LA	Precipitation
Not available	Biloxi	MS	Precipitation
Not available	Pascagoula	MS	Precipitation
Not available	Saucier Exp Forest	MS	Precipitation

When developing CALMET data files, Sage will change the following default options that determine processing of wind fields. The option IWFCOD will be set to 1 (one) to use

CALMET's diagnostic wind module. The option IPROG will be set to 14 to utilize CALMM5 data files in developing the initial guess field. The BIAS option will be an array of twelve zeroes, corresponding to the number of vertical layers. The CALMM5 files which will be used in the modeling will be prepared by BEE-Line Software.

3.2.1 Land Use and Terrain Data

CALMET requires land use and terrain data in addition to weather observations. Sage will obtain both sets of data for the modeling domain addressed in Section 3.1. For terrain, Sage will use the 3-arc-second data included in the Professional CALPUFF interface, originally obtained from the US Geological Survey (USGS). For land use, Sage will obtain the 250K LULC data in CTG format from USGS. The USGS data set will be supplemented with land use data for the continent of North America (available from the CALPUFF website[6]) to account for the lack of USGS data for the Gulf of Mexico.

3.2.2 Procedures for Missing Meteorological Data

Missing upper air data will be replaced as follows. Each year will be treated independently of the other years. If a day of data is missing, it will be filled with data from the day before. Data missing on January 1 will be filled with data from January 2 for each year. If two days are missing, data from the day before the first missing day will be used to fill the first missing day and data from the day after the second missing day will be used to fill the second missing day. A preliminary review indicated that there are no periods in the modeled years when more than two consecutive days are missing.

If CALMET indicates that there are errors in the data, the modeler will attempt to correct them. If the errors cannot be easily corrected, the data will be replaced with data from the previous day. The modeler will document the corrections and replacements of data in an appendix to the final modeling report.

3.3 Species Modeled

Six species will be modeled together in every CALPUFF simulation. The species are SO_2, SO_4, NO_X, HNO_3, NO_3, and PM_{10}. VOC and ammonia will not be modeled per the LDEQ flowchart in the "BART Determination Process" document.[7] Emissions of inhalable particulate matter (with an effective diameter less than 10 micrometers) will be speciated as recommended by the National Park Service[8] and as provided in Table 3-2.

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[6] Atmospheric Studies Group. "Land Use/Land Cover (LULC) data." ASG at TRC: Air Quality Modeling Data Sets. July 10, 2006. http://www.src.com/datasets/datasets_lulc.html

[7] Louisiana Department of Environmental Quality. "BART Determination Process." Current Issues. No Date. http://www.deq.louisiana.gov/portal/Portals/0/AirQualityAssessment/bart.doc.

[8] National Park Service. "Particulate Matter Speciation." Explore Air. March 28, 2006. http://www2.nature.nps.gov/air/Permits/ect/index.cfm

Table 3-2
PM_{10} Speciation

PM_{10} Total	Filterable				
	Total	EC		Soil	
100.00%	46.00%	6.70%	of Filterable	93.30%	of Filterable
		3.08%	of Total	42.92%	of Total
	Condensable				
	Total	SO_4		SOA (OC)	
	54.00%	66.00%	of Condensable	34.00%	of Condensable
		35.64%	of Total	18.36%	of Total

3.4 Sources Modeled

In early 2006, ConocoPhillips submitted an emissions inventory to the LDEQ in response to the BART survey conducted by the LDEQ. The emission units and rates from this inventory will be used in the refined BART modeling. Twenty-seven (27) units will be modeled, and 24-hour maximum potential emissions will be used in lieu of the highest actual daily emissions for the 2001-2003 period. Appendix A lists the units to be modeled, along with the corresponding stack parameters and emission rates. Only BART-eligible units will be included in the modeling. Per the Louisiana modeling guidelines, potential visibility impacts in the Breton Wilderness Area will be determined for all BART-eligible units as a group and, if the predictions for the group exceed 0.5 delta-dv, for each individual unit. Only units with impacts exceeding 0.5 delta-dv on the Breton Class I Area will be considered for BART engineering analysis.

3.5 Air Quality Database

Ammonia concentrations will be held constant per the LDEQ *BART Modeling Protocol.*[9] The value of 3 ppb will be used for ammonia. When calculating light extinction, relative humidity correction factors (*f*(RH)s) provided by CENRAP and listed in Table 3-3 will be entered into CALPOST. Please note that the values in Table 3-3 exceed the U.S. EPA Recommended Monthly Site-Specific f(RH) Values for Breton[10]; therefore, the modeling predictions are expected to be conservative.

Table 3-3
Monthly Averaged f(RH)

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Breton Wilderness	3.7	3.5	3.7	3.6	3.8	4.0	4.3	4.3	4.2	3.7	3.7	3.7

[9] Louisiana Department of Environmental Quality (February 2007). *Best Available Retrofit Technology (BART) Modeling Protocol to Determine Sources Subject to BART in the State of Louisiana*, p. 11.
[10] U.S. EPA. "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program." EPA-454/B-03-005, September 2003. Table A-2, p. A-6.

Sage Environmental will use ozone concentration files provided by LDEQ.[11] Three files have been provided, each containing ozone concentration data for one year. A default value of 40 ppb will be used for hours in which ozone data are missing.

3.6 Natural Conditions at Class I areas

CALPOST uses monthly concentrations of aerosol components to compute background extinction coefficients. Sage Environmental will use the levels provided by CENRAP and listed in Table 3-4 when performing BART refined modeling.

Table 3-4
Average Annual Natural Levels of Aerosol Components ($\mu g/m^3$)

Class I Area	SO4	NO3	OC	EC	Soil	Coarse Mass
Breton Wilderness	0.23	0.10	1.40	0.02	0.50	3.00

[11] Louisiana Department of Environmental Quality. *Ozone Data.* March 1, 2007. ftp://ftp-cenrap.ldeq.org/ozonedata.zip

SECTION 4
REFERENCES

Atmospheric Studies Group. *Land Use/Land Cover (LULC) data.* ASG at TRC: Air Quality Modeling Data Sets. July 10, 2006. http://www.src.com/datasets/datasets_lulc.html

Brewer, Pat. *Weight of Evidence: Residence Time Analyses.* September 22, 2005. http://www.vistas-sesarm.org/documents/VISTASJointWorkGroupMeeting09052005/7_Brewer_Residence%20time_20050922.ppt

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Louisiana Department of Environmental Quality. *Louisiana's Regional Haze Preliminary Plan.* Current Issues. November 2, 2006. http://www.deq.louisiana.gov/portal/LinkClick.aspx?link=AirQualityAssessment%2fPlanning%2fSIP%2fLouisiana+RH+Plan+(7).pdf

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Dennis McNally, T. W. Tesche, and George Schewe. *CENRAP BART Modeling Guidelines.* Alpine Geophysics, LLC. Ft. Wright, Kentucky: December 15, 2005.

National Park Service. *Particulate Matter Speciation.* Explore Air. March 28, 2006. http://www2.nature.nps.gov/air/Permits/ect/index.cfm

U.S. Department of the Interior. *Class I Receptors.* National Park Service Nature & Science. November 18, 2005. http://www2.nature.nps.gov/air/maps/receptors/index.cfm

U.S. EPA. *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations.* Federal Register, **70 (128)**, Wednesday, July 6, 2005.

U.S. EPA. *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program.* EPA-454/B-03-005, September 2003.

APPENDIX A
EMISSIONS DATABASE

ConocoPhillips Company
Alliance Refinery
Belle Chasse, Louisiana

List of BART- Eligible Sources for Inclusion in BART Modeling

EPN	Description	Source ID	UTM Easting (X) (km)	UTM Northing (Y) (km)	Zone	Stack Height (m)	Base Elevation (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Temp. (K)	Init. Sigma-y (m)	Init. Sigma-z (m)	Momentum Flux
1291-H-2/3	FCCU Light/Heavy Feed Heater	1291H23	212.246	3287.375	16	56.7	1.22	2.59	4.08	552	0	0	1
301-B-2A	CO Boiler	301B2A	212.232	3287.396	16	23.8	1.22	3.51	20.49	609.3	0	0	1
301-B-2B	CO Boiler	301B2B	212.21	3287.389	16	23.8	1.22	3.51	20.99	582	0	0	1
292-H-1	Light Distillate Gulfiner Reactor Heater	292H1	212.037	3287.241	16	28	0.61	1.22	2.44	595.9	0	0	1
292-H-2	Light Distillate Gulfiner Stabilizer Heater	292H2	212.032	3287.254	16	36.9	0.66	1.6	2	597	0	0	1
191-H-1	Crude Charge Heater	191H1	212.092	3287.117	16	63.7	0.61	4.69	8.05	465.9	0	0	1
191-H-2	Vacuum Charge Heater	191H2	212.103	3287.09	16	63.7	0.61	2.74	4.4	449.3	0	0	1
406-D-15	Product Dock No.1 MVR Loading	406D15	212.61	3286.993	16	7.6	1.52	0.79	20	1273.2	0	0	1
406-D-16	Product Dock No.2 MVR Loading	406D16	212.612	3286.984	16	7.6	1.52	0.79	20	1273.2	0	0	1
891-H-1	Delayed Coker Charge Heater	891H1	212.395	3287.189	16	50.3	1.22	2.29	6.01	605.4	0	0	1
891-CP	Coke Transfer and Storage	891CP	212.397	3287.217	16	1.00	1.22	1.00	0.001	298.15	0	0	1
491-H-1	Alkylation Isostripper Reboiler	491H1	212.252	3287.133	16	51.2	0.91	3.12	2.5	615.9	0	0	1
491-H-2	Alkylation Depropanizer Reboiler	491H2	212.269	3287.139	16	43	0.91	3.05	4.48	574.3	0	0	1
100-H-1	Coker Charge Storage Heater	100H1	212.47	3287.281	16	15.2	1.94	0.61	6.07	594.3	0	0	1
293-H-1	Heavy Distillate Gulfiner Reactor Feed Heater	293H1	212.051	3287.2	16	39.6	0.61	2.03	2.68	577.6	0	0	1
293-H-2	Heavy Distillate Gulfiner Stabilizer Reboiler	293H2	212.055	3287.187	16	34.4	0.61	1.92	4.42	603.7	0	0	1
1391-H-1	Catalytic Reformer Feed Heater No. 1	1391H1	212.015	3287.43	16	62.8	0.91	3.51	4.76	490.4	0	0	1
1391-H-2/3	Catalytic Reformer Feed Heater No. 2 & 3	1391H23	212.051	3287.443	16	65	0.91	3.93	3.75	763.1	0	0	1
1391-H-4	Depentanizer Reboiler	1391H4	212.025	3287.433	16	44.2	0.91	2.18	6.34	550.4	0	0	1
1391-H-5	Dry Reactivation Heater	1391H5	212.07	3287.45	16	42.2	0.91	2.2	1.49	550.4	0	0	1
1791-H-1	Reformate Splitter Reboiler	1791H1	212.056	3287.319	16	38.1	0.91	1.96	3.5	552	0	0	1
1792-H-1	Hydrodealkylation Charge Heater	1792H1	212.027	3287.269	16	45.1	0.7	2.29	4.24	552	0	0	1
291-H-1	Naphiner Reactor Feed Heater	291H1	212.042	3287.227	16	39.6	0.64	1.92	2.99	599.3	0	0	1
291-H-2	Naphiner Deisohexanizer Reboiler	291H2	212.045	3287.214	16	38.7	0.61	1.93	3.66	541.5	0	0	1
303-R-1	Cooling Water Tower No. 1	303R1P	212.177	3287.033	16	18.288	0.61	8.5344	8.534	303.15	0	0	1
308F-D-1	Low Pressure Flare	308FD1	212.51	3286.983	16	65	1.22	3.07	20	1273.2	0	0	1
308F-D-2	High Pressure Flare	308FD2	212.569	3286.81	16	65	1.09	2.15	20	1273.2	0	0	1

ConocoPhillips Company
Alliance Refinery
Belle Chasse, Louisiana

List of BART- Eligible Sources for Inclusion in BART Modeling

EPN	Description	Source ID	SO_2	SO_2	SO_4	SO_4	NO_X	NO_X	EC	EC	Soil	Soil	OC	OC
			(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)
1291-H-2/3	FCCU Light/Heavy Feed Heater	1291H23	0.6792	5.3903	0.0668	0.5304	1.0097	8.0138	0.0058	0.0458	0.0805	0.6387	0.0344	0.2732
301-B-2A	CO Boiler	301B2A	69.3287	550.2371	2.3925	18.9884	19.1319	151.8434	0.2068	1.6410	2.8812	22.8671	1.2325	9.7819
301-B-2B	CO Boiler	301B2B	69.3287	550.2371	2.3925	18.9884	19.0972	151.5678	0.2068	1.6410	2.8812	22.8671	1.2325	9.7819
292-H-1	Light Distillate Gulfiner Reactor Heater	292H1	0.0930	0.7383	0.0094	0.0746	0.3389	2.6896	0.0008	0.0065	0.0113	0.0899	0.0048	0.0385
292-H-2	Light Distillate Gulfiner Stabilizer Heater	292H2	0.1636	1.2982	0.0163	0.1296	0.5958	4.7289	0.0014	0.0112	0.0197	0.1561	0.0084	0.0668
191-H-1	Crude Charge Heater	191H1	19.7917	157.0794	0.4538	3.6013	40.8565	324.2632	0.0392	0.3112	0.5464	4.3369	0.2338	1.8552
191-H-2	Vacuum Charge Heater	191H2	1.5042	11.9380	0.1485	1.1786	8.9472	71.0109	0.0128	0.1019	0.1788	1.4193	0.0765	0.6072
406-D-15	Product Dock No.1 MVR Loading	406D15	0.0056	0.0441	0.0238	0.1886	0.8819	6.9997	0.0021	0.0163	0.0286	0.2271	0.0122	0.0971
406-D-16	Product Dock No.2 MVR Loading	406D16	0.0056	0.0441	0.0238	0.1886	0.8819	6.9997	0.0021	0.0163	0.0286	0.2271	0.0122	0.0971
891-H-1	Delayed Coker Charge Heater	891H1	0.8967	7.1165	0.0886	0.7032	5.6333	44.7097	0.0077	0.0608	0.1067	0.8469	0.0456	0.3623
891-CP	Coke Transfer and Storage	891CP	0.0000	0.0000	0.0262	0.2082	0.0000	0.0000	0.0023	0.0180	0.0316	0.2507	0.0135	0.1073
491-H-1	Alkylation Isostripper Reboiler	491H1	0.8069	6.4044	0.0663	0.5264	5.1847	41.1493	0.0057	0.0455	0.0799	0.6340	0.0342	0.2712
491-H-2	Alkylation Depropanizer Reboiler	491H2	1.0111	8.0248	0.0832	0.6600	6.0167	47.7521	0.0072	0.0570	0.1001	0.7948	0.0428	0.3400
100-H-1	Coker Charge Storage Heater	100H1	0.0403	0.3197	0.0040	0.0314	0.1472	1.1684	0.0003	0.0027	0.0048	0.0378	0.0020	0.0162
293-H-1	Heavy Distillate Gulfiner Reactor Feed Heater	293H1	0.1812	1.4381	0.0238	0.1886	0.7917	6.2832	0.0021	0.0163	0.0286	0.2271	0.0122	0.0971
293-H-2	Heavy Distillate Gulfiner Stabilizer Reboiler	293H2	0.2298	1.8236	0.0272	0.2161	1.0042	7.9697	0.0024	0.0187	0.0328	0.2602	0.0140	0.1113
1391-H-1	Catalytic Reformer Feed Heater No. 1	1391H1	1.2778	10.1413	0.1262	1.0018	1.9000	15.0796	0.0109	0.0866	0.1520	1.2064	0.0650	0.5161
1391-H-2/3	Catalytic Reformer Feed Heater No. 2 & 3	1391H23	1.2611	10.0090	0.1242	0.9861	1.8750	14.8812	0.0107	0.0852	0.1496	1.1875	0.0640	0.5080
1391-H-4	Depentanizer Reboiler	1391H4	0.7167	5.6879	0.0708	0.5618	9.0139	71.5400	0.0061	0.0486	0.0852	0.6766	0.0365	0.2894
1391-H-5	Dry Reactivation Heater	1391H5	0.0389	0.3086	0.0040	0.0314	0.1431	1.1354	0.0003	0.0027	0.0048	0.0378	0.0020	0.0162
1791-H-1	Reformate Splitter Reboiler	1791H1	0.4597	3.6487	0.0455	0.3614	3.1944	25.3532	0.0039	0.0312	0.0548	0.4353	0.0235	0.1862
1792-H-1	Hydrodealkylation Charge Heater	1792H1	0.6222	4.9384	0.0614	0.4872	0.9250	7.3414	0.0053	0.0421	0.0739	0.5867	0.0316	0.2510
291-H-1	Naphiner Reactor Feed Heater	291H1	0.4764	3.7809	0.0470	0.3732	3.2986	26.1799	0.0041	0.0323	0.0566	0.4495	0.0242	0.1923
291-H-2	Naphiner Deisohexanizer Reboiler	291H2	0.3750	2.9762	0.0371	0.2946	2.6000	20.6353	0.0032	0.0255	0.0447	0.3548	0.0191	0.1518
303-R-1	Cooling Water Tower No. 1	303R1P	0.0000	0.0000	0.9870	7.8337	0.0000	0.0000	0.0853	0.6770	1.1886	9.4339	0.5085	4.0355
308F-D-1	Low Pressure Flare	308FD1	236.1111	1873.9292	0.0020	0.0157	3.3565	26.6392	0.0002	0.0014	0.0024	0.0189	0.0010	0.0081
308F-D-2	High Pressure Flare	308FD2	63.0787	500.6331	0.0020	0.0157	1.3889	11.0231	0.0002	0.0014	0.0024	0.0189	0.0010	0.0081

APPENDIX B
CALPUFF SPECIES

ConocoPhillips Company
Alliance Refinery
Belle Chasse, Louisiana

CALPUFF Species Parameters for Refined BART Modeling

	Dry (Gas)					Dry (Particle)		Wet	
Species	Diffusivity	Alpha Star	Reactivity	Meso. Resist.	Henry's Law	Geo. Mass Mean Diameter	Geometric Standard Deviation	Scavenging Coef. Liquid Precip.	Scavenging Coef. Frozen Precip.
	(cm^2/s)			(s/cm)		(microns)	(microns)	(1/s)	(1/s)
SO2	0.1509	1000	8	0	0.04	0	0	3.00E-05	0
SO4	0	0	0	0	0	0.48	2	1.00E-04	3.00E-05
NOX	0.1656	1	8	5	3.5	0	0	0	0
HNO3	0.1628	1	18	0	8.00E-08	0	0	6.00E-05	0
NO3	0	0	0	0	0	0.48	2	1.00E-04	3.00E-05
EC	0	0	0	0	0	0.48	2	1.00E-04	3.00E-05
SOIL	0	0	0	0	0	0.48	2	1.00E-04	3.00E-05
SOA	0	0	0	0	0	0.48	2	1.00E-04	3.00E-05

DEPARTMENT OF ENVIRONMENTAL QUALITY

KATHLEEN BABINEAUX BLANCO
GOVERNOR

MIKE D. McDANIEL, Ph.D.
SECRETARY

RECEIVED
APR 25 2007
L.R. POCHE'

April 12, 2007

Mr. Laurence R. Poche'
Environmental Superintendent
ConocoPhillips
P. O. Box 176
Belle Chasse, LA 70037

RE: Modeling protocol for ConocoPhillip Best Available Retrofit Technology (BART) Determination, ConocoPhillip, Alliance Refinery, Belle Chasse, Plaquemines Parish, Louisiana.

Dear Mr. Poche':

The Office of Environmental Assessment, Air Quality Assessment Division, Engineering Group I have no objection to the methodology proposed in the April 4, 2007 modeling protocol from Mr. Igor Shnayder of Sage Environmental Consulting, L.P.. for the subject facility. Any deviation from this protocol requires the submittal of an amended protocol and subsequent approval by this Office.

The modeling results should be submitted to our office no later than May 31, 2007.

Please contact me at (225)219-3490 if you have any questions.

Sincerely,

Sirisak Patrick Pakunpanya
Air Quality Dispersion
Modeling Coordinator

CC: Jennifer Mouton, Office of Air Quality Assessment Engineering Group I
Erik Snyder, EPA Region 6
Tim Allen, Federal Wild Life and Fishery

ENVIRONMENTAL **ASSESSMENT**
: PO BOX 4314, BATON ROUGE, LA 70821-4314
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ATTACHMENT III

DEPARTMENT OF ENVIRONMENTAL QUALITY

KATHLEEN BABINEAUX BLANCO
GOVERNOR

MIKE D. McDANIEL, Ph.D.
SECRETARY

January 23, 2007

CERTIFIED MAIL
RETURN RECEIPT REQUESTED #7004 1160 0000 3796 1247

Mr. Laurence R. Poche'
Environmental Superintendent
ConocoPhillips Company
P.O. Box 176
Belle Chasse, LA 70037

RE: Best Available Retrofit Technology (BART) Determination
ConocoPhillips, Alliance Refinery, AI # 2418
Belle Chasse, Plaquemines Parish, Louisiana.

Dear Mr. Poche':

The Louisiana Department of Environmental Quality is in the process of conducting preliminary screening modeling to determine which sources in Louisiana may be subject to the Best Available Retrofit Technology portion of the Regional Haze Rules. The screening model results indicate that the BART-eligible source emissions at the ConocoPhillips Alliance Refinery may have the potential to exceed acceptable overall Regional Haze Rule (RHR) visibility improvement goals in the Breton Wildlife Refuge class I area.

Since the preliminary screening run indicates potential visibility impacts at Breton Wildlife Refuge, we are recommending that a refined air dispersion modeling study be performed. Please contact Mr. Patrick Pakunpanya, Environmental Chemical Specialist, at (225) 219-3490 to arrange a meeting to discuss the modeling protocol and guidance.

Sincerely,

Jennifer J. Mouton

Jennifer J. Mouton
Environmental Scientist Manager
Air Quality Assessment Division

JJM/spp

c: Chris Roberie, Administrator, AQAD
Teri Lanoue, Environmental Scientist Manager, AQAD SIP Planning

ENVIRONMENTAL **ASSESSMENT**
: PO BOX 4314, BATON ROUGE, LA 70821-4314
P:225-219-3236 F:225-219-3239
WWW.DEQ.LOUISIANA.GOV

ATTACHMENT IV

Kelly Bradberry

From: Yvette McGehee [Yvette.McGehee@LA.GOV]
Sent: Wednesday, June 06, 2007 4:36 PM
To: Kelly Bradberry
Cc: Vivian Aucoin; James Orgeron
Subject: Draft ConocoPhillips Alliance BART Engineering Analysis

Ms. Bradberry,

We have reviewed your Draft BART Engineering Analysis for ConocoPhilips and we have a few comments.

For the flare with NSPS controls we need you to include a discussion of whether any new technologies have subsequently become available.

Also the charge heater is also a large source and we think that you should include a BACT analysis of this piece of equipment explaining why no controls have been applied to it and do the BART 5 factor analysis under 51.308 (e)(1)(ii)(A).

Yvette McGehee
LDEQ

ATTACHMENT V

Consent Decree Allowable Control Options

J. NSPS Applicability of Flaring Devices

138. NSPS Applicability of Flaring Devices. COPC owns and operates the Flaring Devices that are identified in Appendix A. These Flaring Devices are or will become affected facilities as that term is used in the NSPS at such time as COPC certifies compliance and accepts NSPS applicability under Paragraphs 142 - 143.

139. Compliance Methods for Flaring Devices. For each Flaring Device, COPC will elect to use one or any combination of following compliance methods:

(a) Operate and maintain a flare gas recovery system to control continuous or routine combustion in the Flaring Device. Use of a flare gas recovery system on a flare obviates the need to continuously monitor and maintain records of hydrogen sulfide in the gas as otherwise required by 40 C.F.R. §§ 60.105(a)(4) and 60.7;

(b) Operate the Flaring Device as a fuel gas combustion device and comply with NSPS monitoring requirements by use of a CEMS pursuant to 40 C.F.R. § 60.105(a)(4) or with a predictive monitoring system approved by EPA as an alternative monitoring system pursuant to 40 C.F.R. § 60.13(i);

(c) Eliminate the routes of continuous or intermittent, routinely-generated fuel gases to a Flaring Device and operate the Flaring Device such that it receives only process upset gases, fuel gas released as a result of relief valve leakage or gases released due to other emergency malfunctions; or

(d) Eliminate to the extent practicable routes of continuous or intermittent, routinely-generated fuel gases to a Flaring Device and monitor the Flaring Device by use of a CEMS and a flow meter; provided however, that this compliance method may not be used unless COPC: (i) demonstrates to EPA that the Flaring Device in question emits less than 500 pounds per day of SO_2 under normal conditions; (ii)

secures EPA approval for use of this method as the selected compliance method; and (iii) uses this compliance method for five or fewer of the Flaring Devices listed in Appendix A.

140. For the compliance method described in Paragraph 139(b), to the extent that COPC seeks to use an alternative monitoring method at a particular Flaring Device to demonstrate compliance with the limits at 40 C.F.R. § 60.104(a)(1), COPC may begin to use the method immediately upon submitting the application for approval to use the method, provided that the alternative method for which approval is being sought is the same as or is substantially similar to the method identified as the "Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gas" attached to EPA's December 2, 1999, letter to Koch Refining Company LP.

141. Compliance Plan for Flaring Devices (Paragraphs 141 - 142). For each Covered Refinery, COPC will submit a Compliance Plan for Flaring Devices to EPA and the Applicable Co-Plaintiff by no later than December 31, 2007. The Plan will have the objective of reducing to the extent practicable: (i) the routing of continuous or intermittent, routinely-generated fuel gas streams that contain hydrogen sulfide of greater than 230 mg/dscm (0.10 gr/dscf) to Flaring Devices; and (ii) the characterization of streams that COPC considers to be the result of alleged malfunctions, process upsets, and/or relief valve leakage by taking into consideration the source and frequency of the stream.

142. In each Refinery's Compliance Plan for Flaring Devices, COPC will:

(a) Certify compliance with one of the four compliance methods set forth in Paragraph 139 and accept NSPS applicability for at least (i) 50% of the system-wide Flaring Devices identified in Appendix A; and (ii) one Flaring Device per Refinery where such Refinery has three or more Flaring Devices;

(b) Identify the Paragraph 139 compliance method used for each Flaring Device that COPC identifies under Subparagraph 142(a);

(c) Describe the activities that COPC has taken or anticipates taking, together with a schedule, to meet the objectives of Paragraph 141 at each Refinery; and

(d) Describe the anticipated compliance method and schedule that COPC will undertake for the remaining Flaring Devices identified in Appendix A.

143. By no later than December 31, 2011, COPC will certify compliance to EPA and the Applicable Co-Plaintiff with one of the four compliance methods in Paragraph 139 and will accept NSPS applicability for all of the Flaring Devices in Appendix A.

144. Performance Tests. By no later than ninety (90) days after bringing a Flaring Device into compliance by using one or more of the methods in Paragraph 139, COPC will conduct a flare performance test pursuant to 40 C.F.R. §§ 60.8 and 60.18, or an EPA-approved equivalent method. In lieu of conducting the velocity test required in 40 C.F.R. § 60.18, COPC may submit velocity calculations that demonstrate that the Flaring Device meets the performance specification required by 40 C.F.R. § 60.18.

145. The combustion in a Flaring Device of process upset gases or fuel gas that is released to the Flaring Device as a result of relief valve leakage or other emergency malfunctions is exempt from the requirement to comply with 40 C.F.R. § 60.104(a)(1).

146. Good Air Pollution Control Practices. On and after the Date of Entry of this Decree, COPC, at all times, including during periods of startup, shutdown, and or Malfunction, will, to the extent practicable, maintain and operate the Flaring Devices in Appendix A, and associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions pursuant to 40 C.F.R. § 60.11(d).

147. Compliance with Consent Decree Constitutes Compliance with Certain NSPS Subpart A Requirements. For Flaring Devices that become affected facilities under NSPS Subpart J pursuant to Paragraphs 142 and 143, entry of this Consent Decree and compliance with the relevant monitoring requirements of this Consent Decree for Flaring Devices will satisfy the notice requirements of 40 C.F.R. § 60.7(a) and the initial performance test requirement of 40 C.F.R. § 60.8(a).

148. Periodic Maintenance of Flare Gas Recovery Systems. The Parties recognize that periodic maintenance may be required for properly designed and operated flare gas recovery systems. To the extent that COPC currently operates or will operate flare gas recovery systems, COPC will take all reasonable measures to minimize emissions while such periodic maintenance is being performed.

149. Safe Operation of Refining Processes. The Parties recognize that under certain conditions, a flare gas recovery system may need to be bypassed in the event of an emergency or in order to ensure safe operation of refinery processes. Nothing in this Consent Decree precludes COPC from temporarily bypassing a flare gas recovery system under such circumstances.

Attention EDMS User: Additional Content Available

There is an item associated with this facility or record which cannot be entered into the Electronic Document Management System (EDMS) because it is in a format which cannot be scanned. Below you will find a description of the item.

- *To request a copy of the item, please complete a Public Records Request form at www.deq.louisiana.gov/prr and include the box number and reference number of the item in your request.*
- *To review the item, please print a copy of this page and visit the DEQ Public Records Center, 602 N. Fifth Street, Baton Rouge, LA, 70802.*
- *DEQ employees may review the item by contacting the Public Records Center.*

For more information, please contact the Public Records Center at (225)219-3172.

Box number: 040102

Reference Number: NP36318

Description:: 3 CDs

Detailed description:

AI#2418

ConocoPhillips Co-Alliance Refinery
15551 Hwy 23, 12 Mi S of
Belle Chasse, LA 70037

BART Refined Modeling
May 2007

Appendix D

Eco-Services Operations, LLC

(Formerly known as Solvay/Rhodia)

Administrative Order on Consent,

BART Determination

And Evaluation

JOHN BEL EDWARDS
GOVERNOR

CHUCK CARR BROWN, PH.D.
SECRETARY

State of Louisiana

DEPARTMENT OF ENVIRONMENTAL QUALITY
OFFICE OF ENVIRONMENTAL COMPLIANCE

July 29, 2016

FedEx
FedEx Tracking Number 8081 9022 5780

ECO SERVICES OPERATIONS CORP. -DE
c/o Elaine Simpson
300 Lindenwood Drive
Valleybrooke Corporate Center
Malvern, PA 19355

RE: ADMINISTRATIVE ORDER ON CONSENT
ENFORCEMENT TRACKING NO. AE-AOC-16-00682
AGENCY INTEREST NO. 1314

Dear Madam:

Pursuant to the Louisiana Environmental Quality Act (La. R.S. 30:2001, *et seq.*), the attached **ADMINISTRATIVE ORDER ON CONSENT** is hereby served on **ECO SERVICES OPERATIONS CORP. -DE (RESPONDENT).**

Any questions concerning this action should be directed to Pascal Ojong at 225.219.4468 or pascal.ojong@la.gov.

Sincerely,

Celena J. Cage
Administrator
Enforcement Division

CJC/PON/pon
Alt ID No. 0840-00033
Attachment

c: Eco Services Operations Corp. -DE
1301 Airline Highway
Baton Rouge, LA 70807

STATE OF LOUISIANA
DEPARTMENT OF ENVIRONMENTAL QUALITY

OFFICE OF ENVIRONMENTAL COMPLIANCE

IN THE MATTER OF	*	
	*	
ECO SERVICES OPERATIONS CORP. -DE	*	**ENFORCEMENT TRACKING NO.**
EAST BATON ROUGE PARISH	*	
ALT ID NO. 0840-00033	*	**AE-AOC-16-00682**
	*	
	*	**AGENCY INTEREST NO.**
	*	
PROCEEDINGS UNDER THE LOUISIANA	*	**1314**
ENVIRONMENTAL QUALITY ACT,	*	
La. R.S. 30:2001, ET SEQ.	*	

ADMINISTRATIVE ORDER ON CONSENT

The following **ADMINISTRATIVE ORDER ON CONSENT** is issued this day to **ECO SERVICES OPERATIONS CORP.-DE (RESPONDENT)** by the Louisiana Department of Environmental Quality (the Department), under the authority granted by the Louisiana Environmental Quality Act (the Act), La. R.S. 30:2001, *et seq.*, and particularly by La. R.S. 30:2011(D)(6) and (D)(14). The Respondent consents to the requirements set forth below.

FINDINGS OF FACT

I.

The Respondent owns and/or operates a sulfuric acid manufacturing facility (the Facility) located at 1301 Airline Highway in Baton Rouge, East Baton Rouge Parish, Louisiana. The Facility currently operates pursuant to Title V Permit 0840-00033-V6 issued on June 3, 2015.

II.

Under Clean Air Act (CAA) section 110, each state must prepare and submit for the U.S. Environmental Protection Agency (EPA) approval, a State Implementation Plan (SIP) that provides for the implementation, maintenance and enforcement of the National Ambient Air Quality Standards (NAAQS) in each air quality control region within the state.

III.

In addition to the general SIP requirements, in CAA section 169A, 42 U.S.C. §7491, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This

section establishes as a national goal the "prevention of any future, and the remedying of any existing, impairment of visibility" in those national parks and wilderness areas identified as "Class I" areas under CAA section 161, 42 U.S.C. §7472(a), 42 U.S.C. §7491.

IV.

Under CAA section 169A and its associated implementing regulations, states must assure the reasonable progress toward the goal of achieving natural visibility conditions in Class I areas by preparing, and submitting for EPA approval, a Regional Haze SIP. *See generally,* 42 U.S.C. §7491; 40 C.F.R. §51.308.

V.

To comply with the requirements set forth in CAA section 169A and the implementing regulations, the Department submitted a proposed SIP on behalf of the State of Louisiana to EPA Region VI on June 13, 2008. The SIP included a Best Available Retrofit Technology (BART) analysis for the Facility at the time owned and operated by Rhodia Inc.[1] The BART analysis was based on a submittal made by Rhodia Inc. to the Department in June 2007.

VI.

On February 28, 2012, the EPA promulgated a proposed partial limited approval and partial disapproval of Louisiana's SIP revision to address regional haze. *See,* 77 Fed. Reg. 11,839.

VII.

On July 3, 2012, the EPA promulgated a final rule, entitled "Approval and Promulgation of Implementation Plans; Louisiana; Regional Haze State Implementation Plan" pursuant to its statutory authority under the CAA, 42 U.S.C. §7401 *et seq.* *See,* 77 Fed. Reg. 39,425 (July 3, 2012). In the final rule, the EPA finalized under CAA section 110(k), 42 U.S.C. §7410(k), a partial limited approval and partial disapproval of the Regional Haze SIP submitted to EPA by the State of Louisiana, through the Department on June 13, 2008. In this final rule, the EPA requested, among other things, that the Department provide additional information to support the Department's conclusion concerning the BART determination for the Facility.

---

[1]Effective October 1, 2013, Rhodia Inc. changed its company name and the name of the Facility from Rhodia Inc. to Solvay USA Inc. The LDEQ Office of Environmental Services acknowledged the name change in correspondence, dated November 1, 2013. On December 1, 2014, Solvay USA Inc. transferred ownership and operation of the Facility to Eco Services Operations LLC. On May 4, 2016, Eco Services Operations LLC transferred ownership and operation of the Facility to Eco Services Operations Corp. Pursuant to the agreement between the companies and the Department's approval of the permit transfer, responsibility for compliance with the terms and conditions of Title V Permit No. 0840-00033-V6 now resides with Eco Services Operations Corp.

ADMINISTRATIVE ORDER

Based on the foregoing, the Department **hereby orders**, and the Respondent hereby **agrees** that:

I.

The Respondent shall comply with the emissions limitations set forth below:

Source ID	Source Description	Sulfur Dioxide (SO_2)	
		Limit	Citation
RLP 0014	Sulfuric Acid Unit No. 1	1.9 lbs of SO_2 emitted per ton of 100% sulfuric acid produced, averaged over all operating hours in a rolling 365-day period	Consent Decree (CA No. 2:07CV134 WL), eff. July 23, 2007 and Title V Permit No. 0840-00033-V6 Specific Requirement No.225
RLP 0013	Sulfuric Acid Unit No. 2	2.2 lbs of SO_2 emitted per ton of 100% sulfuric acid produced, averaged over all operating hours in a rolling 365-day period	Consent Decree (CA No. 2:07CV134 WL), eff. July 23, 2007 and Title V Permit No. 0840-00033-V6 Specific Requirement No.218

II.

The Respondent shall continue to comply with all reporting and record keeping requirements contained within all applicable permits.

III.

To the extent required by law, further proceedings relating to this **ADMINSTRATIVE ORDER** will be governed by the Administrative Procedure Act, La. R.S. 49.950, *et seq*.

IV.

Under CAA section 504(a), permits issued under this section shall include enforceable emission limitations and standards. In accordance with CAA section 504(a), the Department has issued to the Respondent Title V Permit No. 0840-00033-V6, which contains the federally enforceable limitations listed herein.

V.

This **ADMINISTRATIVE ORDER ON CONSENT** may be executed in counterparts, each of which may be executed by one (1) or more of the signatory parties hereto. Signature pages may be detached from the counterparts and attached to one or more copies of this Agreement to form multiple legally effective documents. Facsimile signatures shall be sufficient in lieu of original signatures.

VI.

For each action or event described herein, the Department reserves the right to seek compliance with its rules and regulations in any manner allowed by law, and nothing herein shall be construed to preclude the right to seek such compliance.

VII.

This **ADMINISTRATIVE ORDER ON CONSENT** may be amended by mutual consent of the Department and Respondent. Such amendments shall be in writing, shall follow proper SIP procedures and be submitted to EPA as a SIP revision, and shall be final and effective upon signature by an authorized representative of the Department and signature by the authorized representative of the Respondent.

VIII.

The following paragraph addresses transfers of the obligations of this **ADMINISTRATIVE ORDER ON CONSENT** and the Facility:

A) The obligations of this **ADMINISTRATIVE ORDER ON CONSENT** apply to and are binding upon the United States and the State Parties and upon the Respondent and its officers, employees, Agents, subsidiaries, successors, assigns, or other entities or persons otherwise bound by law.

B) Prior to the execution of any agreement for the transfer of ownership or operation of the Facility, the Respondent shall provide notice of and a copy of this **ADMINISTRATIVE ORDER ON CONSENT** to the proposed transferee. No transfer of ownership or operation of any portion of the Facility shall relieve the Respondent of its obligation to ensure that the terms of this **ADMINISTRATIVE ORDER ON CONSENT** are implemented unless at least 30 days prior to such transfer, the Respondent provides written notice of the prospective transfer to the EPA Region 6 and the Department and the prospective transferee executes an **ADMINISTRATIVE ORDER ON CONSENT** with the Department prior to the effective date of the transfer providing for continued compliance with these standards. The Notice of Transfer shall clearly identify the parties responsible for any existing violations of this **ADMINISTRATIVE ORDER ON CONSENT** and otherwise

comply with LAC 33:I.1907. Any attempt to transfer ownership or operation of the Facility without complying with this Paragraph constitutes a violation of this **ADMINISTRATIVE ORDER ON CONSENT**.

IX.

This **ADMINISTRATIVE ORDER ON CONSENT** shall be final and effective upon signature by an authorized representative of the Department and signature by the authorized representative of the Respondent.

Baton Rouge, Louisiana, this 29th day of July, 2016.

Lourdes Iturralde
Assistant Secretary
Office of Environmental Compliance

ECO SERVICES BATON ROUGE SULFURIC ACID PLANT

By: Claire Simpson **Date:** 8/8/16

Name: Elaine Simpson

Title: VP, Health, Safety & Environment

Rhodia

Baton Rouge Plant

June 14, 2007

Certified Mail Return Receipt Requested (7003 1010 0005 5151 9464)

Dr. Chuck Carr Brown, Assistant Secretary
Office of Environmental Services
Louisiana Department of Environmental Quality
P.O. Box 4314
Baton Rouge, LA 70821-4314

RE: Summary of CALPUFF BART Screening Modeling Analysis for Rhodia Sulfuric Acid Plant

Dear Dr. Brown::

Providence Engineering & Environmental Group LLC (Providence) has completed a CALPUFF screening modeling analysis for the Rhodia Sulfuric Acid plant located in Baton Rouge, Louisiana for purposes of recently promulgated regulations associated with Best Available Retrofit Technology (BART). This letter summarizes the results of the base case scenario and an abated scenario. This base case scenario is formulated using the emission data and stack parameters provided by Rhodia. The abated scenario is formulated using estimated emission data and stack parameters from Rhodia's proposal to use caustic scrubbing to reduce SO_2 emissions by 94%.

BACKGROUND

The 1990 Clean Air Act Amendments required the United States Environmental Protection Agency (USEPA) to promulgate regulations to protect against visibility impairment (regional haze) in 156 scenic areas (also referred to as Class I areas) across the United States. Regional haze regulations in 40 CFR 51.300 through 51.309 and guidelines found in Appendix Y to 40 CFR Part 51, help states identify sources that are BART eligible and determine the level of control that represents BART. Based on the Regional Haze rule, various state agencies are in the process of performing screening analyses to determine a list of potential sources that may cause visibility impairment at Class I areas. These screening analyses have been performed using screening models or emissions and distance thresholds. It is expected that the sources that are not screened out by the state agencies will be required to either perform comprehensive long-range transport modeling using the USEPA-promulgated CALPUFF model (in a screening analysis or a refined analysis) and/or submit an engineering analysis.

The Louisiana Department of Environmental Quality (LDEQ) has established screening criteria. Facilities that could not reasonably be eliminated from BART consideration by the criteria are asked to perform site-specific CALPUFF modeling analyses to evaluate if they impact Breton and Caney Creek Class 1 areas by 0.5 deciviews or more. Rhodia has received a request from the LDEQ to perform the modeling analysis. Rhodia has requested that Providence perform a screening analysis for their Baton Rouge sulfuric acid plant. This report provides the summary for the screening analysis.

MODEL SETUP

A CALPUFF model is set up for the Rhodia sulfuric acid plant in accordance with the Central Regional Air Planning Association (CENRAP) protocol and the LDEQ protocol for BART analyses. This section summarizes the model setup for the CALPUFF screening analysis.

Site Location, Receptor Location And Model Range

The modeling domain is shown in the Lambert Conformal Conic (LCC) coordinate system in Figure 1. The grid cell size used in the models is 6 km. All the domain range, coordinate system, and spatial resolution are same to the south meteorological domain prepared by CENRAP. The blue crosses indicate the receptors at Breton Wilderness Area and Caney Creek Wilderness, and the red circle represents the Rhodia sulfuric acid facility. Figure 2 shows a more detailed map of the receptor and sources.

Figure 1 – Rhodia facility on Whole LCC Modeling Domain

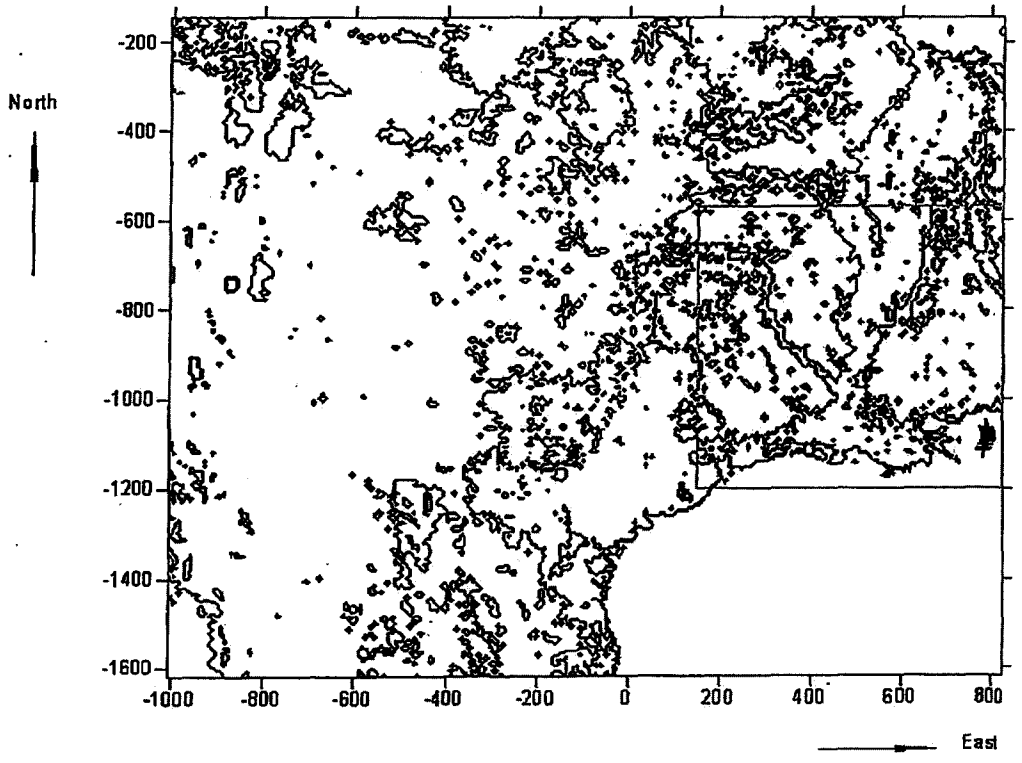
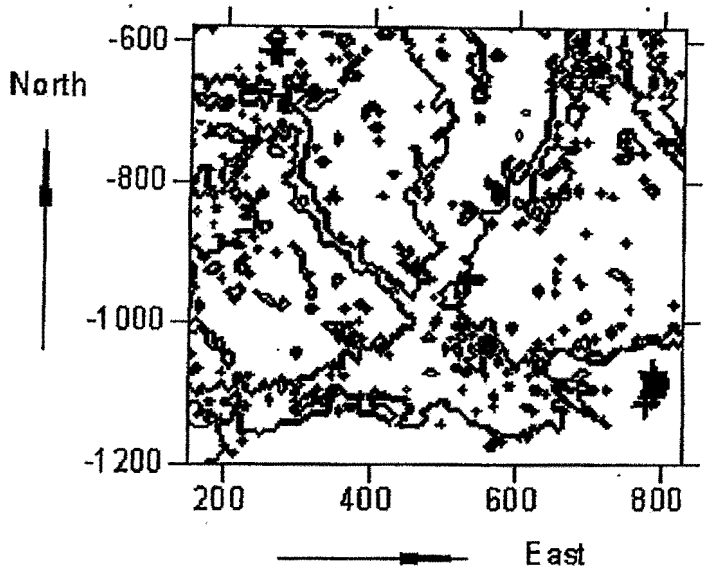


Figure 2 – Rhodia facility and Class I Areas



Meteorological data

The CALPUFF-ready meteorological data prepared by CENRAP is used directly for this screening analysis.

Emission rates and stack parameters

The emission rate and stack parameters used for the base case scenario and the abated scenario are provided in Table 1 below. A site elevation of 15.2 meters is used in the model.

Table 1 - Emission Rate and Stack Parameters

	Package Boiler	Base Case Sulfuric Acid Unit 2	Base Case Sulfuric Acid Unit 1	Abated Sulfuric Acid Unit 2	Abated Sulfuric Acid Unit 1
LCC Easting (km)	560.646	560.809	560.521	560.809	560.521
LCC Northing (km)	-1032.650	-1032.578	-1032.629	-1032.578	-1032.629
Stack Height (m)	18.288	76.2	76.2	39.0	39.0
Exit temperature (K)	517.04	338.71	335.37	305.4	305.4
Exit Velocity (m/s)	23.04	8.11	10.42	35.475	34.377
Diameter (m)	1.07	3.05	1.83	1.37	0.91
SO2 24 h max emission (g/s)	0.03	244.18	113.90	29.93	14.18
NOx 24 h max emission (g/s)	3.07	13.38	6.20	13.38	6.20
PM10 24 h max emission (g/s)	0.16	0.09	0.05	0.09	0.05

Model options

The model is set up following CENRAP's guidance on CALPUFF screening modeling. Key model options are listed below:

CALPUFF:
Dispersion: Pasquill-Gifford (PG) coefficient.
Chemical species modeled include: SO_2, SO_4, NO_x, HNO_3, NO_3, PM.

Chemistry: Mesopuff.
Aqueous phase chemistry: Use relative humidity (RH) instead of real water content.
Ozone: Ozone data is provided by LDEQ.
Ammonia: Constant ammonia concentration is assumed as 3 ppb.
Wet and dry deposition: Both gaseous and particle phase are modeled.

POSTUTIL:
Species input: SO_2, SO_4, NO_x, HNO_3, NO_3, PM.
Species output: SO_2, SO_4, NO_x, HNO_3, NO_3, PM.
Background NH_3: 3 ppb.

CALPOST:
Visibility is calculated using Mehtod 6 based on IMPROVE's equation:

$$b_{ext}=3f(RH)[(NH_4)_2SO_4]+3f(RH)[NH_4NO_3]+10[PM]+b_{Ray}$$

where b_{ext} is the calculated light extinction, f(RH) is the humidity effect, b_{Ray} is the Rayleigh scattering of air. A light extinction efficiency of 10 is used for PM.
The change of haze index in deciviews is calculated by:

$$\Delta dv = 10 \ln (\{b_{background}+ b_{source}\}/ b_{background})$$

where b_{source} is the light extinction caused by the source and the $b_{background}$ is the natural background light extinction.

The natural background light extinction is provided in CENRAP's guidance. For eastern states, background extinctions are EC=0.02, SO_4=0.23, NO_3=0.1, PMC=3, SOC=1.4, Soil=0.5, Raleight scattering=10.

Monthly f(RH) values at Breton and Caney Creek are obtained from EPA's Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule. As suggested in LDEQ's model protocol, the RH factors at the centroid receptor of each Class I area are used for the 12 months.

Recompilation

The CALPUFF, CALPOST and POSTUTIL programs were recompiled with the FORTRAN source code provided in the CALPUFF BART version. The compiler used is Lahey/Fujitsu Fortran Express v7.1. The changes for the recompilation are described below:

CALPUFF: In params.puf, mxnx=320,mxny=265, mxoz=2725. The source code is in calpuff.for and the executable file is calpuffc.exe.

POSTUTIL

In params.utl, PARAMETER(mxgx=320), PARAMETER(mxgy=265). The source code is in postutilc.for and the executable file is postutilc.exe

CALPOST
In params.pst, PARAMETER(mxgx=320) , PARAMETER(mxgy=265) . The source code is in the calpost.for. The executable file is calpost.exe.

To recompile, the parameters in the parameter files are changed first as indicated in the above paragraphs. The source files are recompiled by Lahey's command. The newly generated .exe files are used for the model runs in this work.

MODEL RESULTS

This section describes the modeling results for the CALPUFF screening analysis of the base case scenario and the abated scenario.

Model runs

For 2001, 36 met files are used in three groups of CALPUFF and POSTUTIL runs. The results are then merged by APPEND, a tool of CALPUFF BART version. For 2002 and 2003, 12 met files of each year are directly used in CALPUFF and POSTUTIL.

Model results of 2001, 2002, 2003

Modeling runs were executed for 2001, 2002, and 2003. Based on these runs, the tables below provide the results for the respective years under the base case scenario and the abated scenario. CALPOST was run separately for Breton and Caney Creek receptors since different RH factors were used for the two Class I areas.

Table 2 - CALPUFF Screening Analysis Results for Rhodia Base Case Scenario

2001 Breton Base Case Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	%_SO4	%_NO3	%_PMF	Rank
2001	191	5	2.003	4.3	99.53	0.44	0.02	1
2001	229	40	1.822	4.3	99.62	0.37	0.01	2
2001	231	40	1.315	4.3	99.72	0.26	0.02	3
2001	192	40	1.275	4.3	99.36	0.6	0.03	4
2001	202	40	1.18	4.3	99.67	0.31	0.02	5
2001	163	1	1.162	4	99.5	0.49	0.02	6
2001	190	1	1.102	4.3	99.27	0.7	0.03	7
2001	89	40	1.043	3.7	94.16	5.81	0.02	8
2001	226	1	1.034	4.3	99.77	0.22	0.02	9
2001	260	40	1.023	4.2	99.72	0.26	0.02	10
2001	53	40	0.962	3.5	93.9	6.07	0.03	11
2001	90	1	0.911	3.7	98.05	1.93	0.02	12
2001	230	40	0.897	4.3	99.16	0.81	0.02	13
2001	91	1	0.851	3.604	97.69	2.29	0.02	14
2001	187	40	0.747	4.3	99.79	0.19	0.01	15
2001	261	40	0.721	4.2	99.79	0.2	0.01	16
2001	212	40	0.571	4.3	99.8	0.18	0.02	17
2001	225	40	0.515	4.3	99.42	0.56	0.02	18
2001	232	1	0.508	4.3	99.72	0.26	0.02	19
2001	162	16	0.489	4	99.73	0.25	0.01	20

2001 Caney Creek Base Case Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	%_SO4	%_NO3	%_PMF	Rank
2001	44	43	0.726	3.1	94.33	5.65	0.02	1
2001	186	58	0.549	3.4	99.92	0.07	0.01	2
2001	350	58	0.477	3.5	91.36	8.61	0.03	3
2001	207	58	0.472	3.4	99.69	0.3	0.01	4
2001	235	49	0.472	3.4	99.77	0.22	0.01	5
2001	178	107	0.441	3.6	99.66	0.33	0.01	6
2001	318	76	0.431	3.4	94.29	5.68	0.03	7
2001	14	49	0.408	3.4	93.66	6.32	0.02	8
2001	295	75	0.379	3.5	97.72	2.26	0.02	9
2001	187	75	0.369	3.4	99.95	0.05	0.01	10

2002 Breton Base Case Scenario

YEAR	DAY	RECEPTOR	DELTA	F(RH)	% SO4	% NO3	% PMF	Rank

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			DV					
2002	194	40	1.389	4.3	99.79	0.2	0.01	1
2002	206	40	1.075	4.3	99.8	0.19	0.01	2
2002	203	40	1.048	4.3	99.91	0.08	0.01	3
2002	186	1	0.989	4.3	99.88	0.11	0.01	4
2002	238	1	0.917	4.3	99.8	0.19	0.01	5
2002	213	40	0.844	4.3	99.74	0.24	0.02	6
2002	237	40	0.787	4.3	99.76	0.22	0.02	7
2002	204	1	0.691	4.3	99.92	0.07	0.01	8
2002	334	1	0.656	3.7	96.62	3.35	0.02	9
2002	202	40	0.578	4.3	99.9	0.09	0.01	10
2002	325	1	0.555	3.7	95.67	4.31	0.02	11
2002	363	40	0.533	3.7	95.51	4.47	0.02	12
2002	25	1	0.522	3.7	94.62	5.36	0.02	13
2002	299	40	0.51	3.7	97.19	2.79	0.01	14
2002	258	40	0.488	4.2	99.42	0.56	0.02	15

2002 Caney Creek Base Case Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	% PMF	Rank
2002	234	76	1.102	3.4	99.6	0.39	0.01	1
2002	177	43	0.903	3.6	98.86	1.13	0.01	2
2002	222	76	0.82	3.4	99.45	0.53	0.02	3
2002	103	75	0.81	3	99.35	0.63	0.01	4
2002	298	43	0.772	3.5	97.13	2.86	0.01	5
2002	302	43	0.772	3.5	97.94	2.06	0.01	6
2002	23	75	0.63	3.4	94.87	5.11	0.02	7
2002	178	75	0.624	3.6	99.3	0.69	0.01	8
2002	22	41	0.544	3.4	93.24	6.73	0.02	9
2002	301	58	0.478	3.5	98.02	1.97	0.01	10

2003 Breton Base Case Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	% PMF	Rank
2003	74	40	1.626	3.7	96.17	3.82	0.01	1
2003	310	1	1.486	3.7	99.22	0.75	0.03	2
2003	199	40	1.241	4.3	99.91	0.08	0.01	3
2003	75	40	0.987	3.7	96.42	3.57	0.01	4
2003	364	9	0.979	3.7	95.98	4	0.02	5
2003	22	1	0.851	3.7	92.7	7.28	0.03	6
2003	295	1	0.755	3.7	98.91	1.01	0.08	7
2003	81	16	0.713	3.7	97.89	2.07	0.03	8
2003	220	1	0.647	4.3	99.81	0.18	0.02	9
2003	160	1	0.643	4	99.8	0.19	0.01	10
2003	77	1	0.636	3.7	95.84	4.14	0.02	11
2003	32	40	0.59	3.508	96.35	3.63	0.01	12
2003	339	1	0.57	3.7	96.86	3.13	0.02	13
2003	147	40	0.567	3.8	99.57	0.41	0.01	14
2003	103	1	0.546	3.6	97.72	2.25	0.03	15
2003	132	40	0.537	3.8	98.79	1.19	0.02	16
2003	41	40	0.522	3.5	94.82	5.16	0.02	17
2003	161	40	0.501	4	99.8	0.19	0.01	18
2003	202	40	0.477	4.3	99.63	0.35	0.02	19

2003 Caney Creek Base Case Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	% PMF	Rank
2003	281	41	1.219	3.5	98.4	1.59	0.01	1
2003	76	43	1.137	2.9	96.81	3.17	0.02	2
2003	52	43	1.097	3.1	95.85	4.14	0.01	3
2003	283	107	1.092	3.5	98.37	1.61	0.01	4
2003	284	41	0.978	3.5	98.79	1.2	0.01	5
2003	282	119	0.858	3.5	98.08	1.91	0.01	6
2003	29	58	0.742	3.4	95.75	4.24	0.01	7
2003	227	107	0.696	3.4	99.7	0.29	0.01	8
2003	242	43	0.587	3.4	99.03	0.96	0.02	9
2003	228	119	0.581	3.4	99.92	0.07	0.01	10
2003	71	49	0.536	2.9	98.38	1.61	0.01	11
2003	285	41	0.515	3.5	99.67	0.32	0.01	12
2003	239	58	0.481	3.4	99.86	0.13	0.01	13

Table 3 - CALPUFF Screening Analysis Results for Rhodia Abated Scenario

2001 Breton Abated Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	% PMF	Rank
2001	191	5	0.288	4.3	97.05	2.79	0.17	1
2001	229	40	0.207	4.3	97.08	2.8	0.12	2
2001	231	40	0.2	4.3	97.73	2.14	0.14	3
2001	53	39	0.184	3.5	66.47	33.34	0.19	4
2001	89	40	0.171	3.7	66.95	32.92	0.13	5
2001	192	40	0.164	4.3	96	3.73	0.27	6
2001	163	1	0.148	4	95.73	4.14	0.13	7
2001	190	1	0.147	4.3	94.38	5.39	0.23	8
2001	226	1	0.134	4.3	98.05	1.82	0.13	9
2001	260	40	0.134	4.2	97.74	2.13	0.13	10

2001 Caney Creek Abated Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	% PMF	Rank
2001	44	43	0.13	3.1	67.15	32.74	0.11	1
2001	350	58	0.092	3.5	56.9	42.95	0.14	2
2001	14	49	0.074	3.4	64.33	35.57	0.1	3
2001	318	76	0.072	3.4	66.86	32.97	0.16	4
2001	186	58	0.07	3.4	99.36	0.56	0.07	5
2001	207	58	0.059	3.4	97.56	2.36	0.09	6
2001	235	49	0.059	3.4	98.12	1.78	0.1	7
2001	338	75	0.055	3.5	69.11	30.68	0.21	8
2001	45	75	0.054	3.1	70.84	29.05	0.11	9
2001	295	75	0.053	3.5	83.73	16.11	0.16	10

2002 Breton Abated Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	% PMF	Rank
2002	194	40	0.17	4.3	98.18	1.73	0.09	1
2002	206	40	0.14	4.3	98.28	1.65	0.07	2
2002	203	40	0.12	4.3	99.24	0.67	0.1	3
2002	238	1	0.116	4.3	98.47	1.42	0.11	4
2002	186	1	0.108	4.3	98.93	0.96	0.1	5
2002	237	40	0.096	4.3	98.18	1.68	0.13	6
2002	25	1	0.088	3.7	68.15	31.73	0.12	7
2002	72	1	0.086	3.7	71.27	28.63	0.1	8
2002	363	40	0.086	3.7	72.09	27.78	0.13	9
2002	325	1	0.079	3.7	70.75	29.13	0.13	10

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2002 Caney Creek Abated Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	% PMF	Rank
2002	234	76	0.144	3.4	96.64	3.28	0.08	1
2002	177	43	0.12	3.6	91.22	8.71	0.08	2
2002	298	43	0.113	3.5	80.17	19.76	0.07	3
2002	302	43	0.109	3.5	85.53	14.41	0.06	4
2002	22	41	0.107	3.4	63.98	35.89	0.12	5
2002	103	75	0.106	3	94.88	5.02	0.1	6
2002	222	76	0.101	3.4	95.28	4.58	0.14	7
2002	23	75	0.09	3.4	69.18	30.72	0.1	8
2002	178	75	0.078	3.6	94.55	5.38	0.07	9
2002	5	41	0.069	3.4	50.37	49.5	0.13	10

2003 Breton Abated Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	% PMF	Rank
2003	74	40	0.286	3.7	75.56	24.36	0.08	1
2003	310	4	0.201	3.7	93.06	6.7	0.25	2
2003	199	40	0.166	4.3	99.22	0.69	0.09	3
2003	364	9	0.161	3.7	74.63	25.26	0.11	4
2003	75	40	0.16	3.7	76.76	23.17	0.07	5
2003	32	40	0.107	3.508	76.67	23.24	0.09	6
2003	81	17	0.106	3.7	84.86	14.91	0.23	7
2003	77	1	0.104	3.7	73.75	26.11	0.13	8
2003	295	1	0.1	3.7	92.06	7.32	0.62	9
2003	22	1	0.093	3.7	56.9	42.91	0.19	10

2003 Caney Creek Abated Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	% PMF	Rank
2003	52	43	0.173	3.1	74.09	25.82	0.09	1
2003	76	43	0.165	2.9	79.22	20.65	0.13	2
2003	281	41	0.163	3.5	88.29	11.62	0.09	3
2003	283	118	0.147	3.5	87.85	12.07	0.08	4
2003	284	58	0.13	3.5	90.72	9.2	0.08	5
2003	29	76	0.122	3.4	73.59	26.34	0.07	6
2003	282	119	0.116	3.5	86.23	13.68	0.09	7
2003	227	92	0.092	3.4	97.55	2.37	0.07	8
2003	242	43	0.08	3.4	92.55	7.32	0.13	9
2003	71	49	0.074	2.9	88.14	11.77	0.09	10

Sources with modeled maximum impacts below the 0.5 deciview threshold are exempt from the remainder of the BART process. As shown in the tables above, the visibility impacts from the base case scenario exceed the 0.5 deciview threshold for several days each year. In the abated scenario, impacts from the sources at the Rhodia facility do not exceed the 0.5 deciview threshold.

If you have any questions please call me at (225) 359-3768.

Sincerely,

John D. Richardson
Environmental Manager

cc: Yousheng Zeng, Ph D., P.E., Providence - Certified Mail Return Receipt Requested (7003 1010 0005 5151 9297)
Tim Allen, U.S. Fish and Wildlife Service- Certified Mail Return Receipt Requested (7003 1010 0005 5151 9280)
Eric Snyder, EPA Region VI - Certified Mail Return Receipt Requested (7003 1010 0005 5151 9273)

File 404.1.8

Rhodia

Baton Rouge Plant

June 14, 2007

Certified Mail Return Receipt Requested (7003 1010 0005 5151 9464)

Dr. Chuck Carr Brown, Assistant Secretary
Office of Environmental Services
Louisiana Department of Environmental Quality
P.O. Box 4314
Baton Rouge, LA 70821-4314

RE: BART Engineering Analysis for Rhodia Sulfuric Acid Plant

Dear Dr. Brown:

In 1999, EPA promulgated regulations to improve visibility in 156 national parks and wilderness areas (known as Class I Areas) across the country. The regulations are referred to as the Regional Haze rule. These regulations, included in 40 CFR 51 Subpart P, direct states to revise their State Implementation Plan (SIP) to address Class I area visibility. A major component of the regional haze program is Best Available Retrofit Technology (BART), which requires emission controls for existing stationary sources[1]. The pollutants to which BART applies are fine particulate matter (PM2.5) that cause light scattering, and compounds that contribute to PM2.5 formation, such as nitrogen oxides, sulfur dioxides, certain volatile organic compounds, and ammonia.

Once a state determines that a facility is BART-eligible, an air quality modeling analysis (such as CALPUFF) is performed. Screening and refined modeling are conducted to determine whether the facility is contributing to visibility impairment in a Class I Area; if so, the facility must then implement BART.

BART is established on a case-by-case basis, taking into consideration the technology available. Once technically infeasible options are eliminated, the facility may then consider

- the costs of compliance,
- the energy and non-air quality environmental impacts of compliance,
- any pollution control equipment in use or in existence at the source,
- the remaining useful life of the source, and
- the degree of improvement in visibility which may reasonably be anticipated

to select a best alternative which will represent BART.

The Rhodia Process and BART Eligibility

[1] An existing stationary source is defined as one that is (1) located at one of 26 specific types of facilities listed in 40 CFR 51.301, (2) began operation after August 7, 1962 and was in existence on August 7, 1977, and (3) has potential emissions of 250 tons per year or more for any visibility-impairing pollutant.

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The Rhodia Baton Rouge Sulfuric Acid Plant produces sulfuric acid by using two sulfuric acid production trains, Unit No.1 and Unit No. 2. Unit No.1 was constructed in 1953, and is a 700 ton/day unit. Unit No. 2 was constructed in 1968, and is a 1500 ton/day unit. Rhodia receives spent sulfuric acid and hazardous waste fuels from off-site sources and recovers the sulfur and energy values in its industrial furnaces, forming fresh sulfuric acid.

In March 2007, the state of Louisiana identified Rhodia as a BART-eligible source and requested that it assess its contribution to regional haze. Rhodia performed a CALPUFF screening analysis, assessing impacts in the nearby Class I areas of Breton Wilderness and Caney Creek Wilderness. The following emission rates and stack parameters were used:

Table 1 – Current Emission Rates and Stack Parameters

	Sulfuric Acid Unit No. 2	Sulfuric Acid Unit No. 1	Package Boiler
LCC Easting (km)	560.809	560.521	560.646
LCC Northing (km)	-1032.578	-1032.629	-1032.650
Stack Height (m)	76.2	76.2	18.288
Exit temperature (K)	338.71	335.37	517.04
Exit Velocity (m/s)	8.11	10.42	23.04
Diameter (m)	3.05	1.83	1.07
SO_2 24 h max emission (g/s)	244.18	113.90	0.03
NO_x 24 h max emission (g/s)	13.38	6.20	3.07
PM10 24 h max emission (g/s)	0.09	0.05	0.16

Complete information on the modeling inputs, setup, and results are provided in the accompanying letter report dated June 14, 2007.

The screening modeling results indicate that the Rhodia facility does impact visibility in both the Breton and Caney Creek areas. Rhodia may choose to conduct a refined modeling analysis to confirm the impact; however, Rhodia has recently entered into a consent decree with USEPA to reduce SO_2 emissions. Therefore, it is more expeditious for Rhodia to forego the refined analysis, and proceed with an emissions abatement strategy which will satisfy both the consent decree and BART.

Analysis of Available Control Technologies

Rhodia has considered the following SO_2 control technologies that may potentially be applicable to these units:

Alkali Scrubbing. The alkali scrubbing process uses ammonia (NH_3), caustic (sodium hydroxide, NaOH), or soda ash (sodium carbonate, Na_2CO_3) to remove inorganic sulfur compounds from the sulfuric acid unit tail gas. The system removes the compounds as chemically fixed salts. This technology has been used successfully at several U.S. plants.

Amine Processes (ASARCO, UCAP, and Cansolv). Removal of SO_2 by amines has been used since the 1960's. The amine absorbs the acidic components (SO_2, sulfur trioxide, sulfuric acid mist, and carbon dioxide) from the gas. Amines differ in their selectivity for SO_2 over carbon dioxide, SO_2 loading, amount of steam required for regeneration, and the amount of amine degradation in the regeneration system. Problems with amine systems include degradation from heat in the regeneration process, degradation from sulfur trioxide and sulfuric acid (vapor, particles, and mist), corrosion of materials and equipment, high steam usage, and high capital costs. Amine processes are suitable applications in petroleum refining processes. There are no amine-based systems treating sulfuric acid plant tail gas in the Unites States.

Add-On Double Absorption Process. Conversion to integral double absorption requires access to the existing converter, or the addition of a second converter with one catalyst bed, and plot space near the existing converter area. In a few plants, the existing plant design makes conversion to integral double absorption difficult, expensive and/or not possible. In some rare cases, the conversion to double absorption equipment can be installed remote to the existing converter area. The double absorption process can be either fuel fired or not. The double absorption system includes an absorption tower system (tower, pump tank, acid cooler, and mist eliminator); a fuel-fired system also includes fuel-fired indirect gas heater with gas heat exchanger, a process gas heat exchanger, and a final converter stage before the absorption tower. The additional capital costs and higher operating cost for heater fuel has limited use of the fuel-fired process to a few special cases.

Of the alternatives listed above, amine processes are suitable for petroleum refining processes, not for the processes at the Rhodia facility.

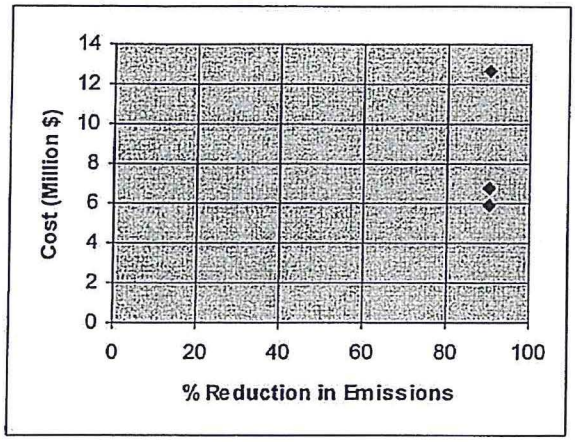
Double absorption is difficult to implement as a retrofit technology due to space constraints in the units; the physical positioning of equipment at Rhodia is such that the necessary equipment cannot easily be installed. The capital cost for double absorption for the No. 2 Unit is approximately $12.63 million.

For ammonia scrubbing, the non-air quality environmental impacts make this option prohibitive. First, ammonia storage is hazardous and undesirable. Second, the effluent cannot be disposed of due to bio-toxicity; therefore, it would have to be sold (a business undertaking the facility is not currently positioned for) or burned (requiring extra fuel and diminishing plant capacity). Third, there will be emissions of residual ammonia, a toxic air pollutant. The capital cost for ammonia scrubbing is approximately $6.73 million.

Caustic scrubbing is technically feasible and can achieve a high SO_2 control efficiency. Also, the non-air quality environmental impacts are much more favorable: first, the sodium is used twice—once for scrubbing, then again for neutralization of weak acid effluent. Second, the sodium sulfate effluent is considered safe for discharge. The capital cost for caustic scrubbing is approximately $5.94 million.

All three of these technologies (double absorption, ammonia scrubbing, and caustic scrubbing) have similar destruction efficiencies (approximately 94%), but the costs are notably dissimilar. A least-cost envelope for the three options is presented as Figure 1; however, it is obvious an incremental cost analysis is not necessary since destruction efficiencies do not vary.

Figure 1 -- Least-Cost Envelope



Selection of Proposed Technology

Based on these considerations, Rhodia proposes to use caustic scrubbing to reduce SO_2 emissions. The scrubbing will reduce emissions by ≥94% which corresponds to long-term (annual average) emission limits of 1.9 pounds of SO_2 emitted per ton of sulfuric acid produced (lb/ton) for Unit 1 and 2.2 lbs/ton for Unit 2. The short-term (3-hour average) limits for both units will be set at 3.0 lbs/ton. This compares favorably to other emission standards available, specifically:

- 40 CFR 60, Subpart H—this New Source Performance Standard limits emissions to 4 lb/ton.
- RACT/BACT/LAER Clearinghouse (RBLC)--A search of all permitted control technologies within the last 10 years for sulfuric acid plants yielded the following results:
  - 3.5 lb/ton (double absorption scrubber, Farmland Hydro, L.P., Florida)
  - 4.0 lb/ton (dual absorption catalyst, PCS Phosphate Company, North Carolina)
  - 4.0 lb/ton (Lucite, Texas)
  - 3.5 lb/ton (double absorption, Piney Point Phosphates, Florida)

The proposed control not only meets the best available retrofit technology, it surpasses the control for new facilities under NSPS and recently permitted new facilities.

Although not required by LDEQ, Rhodia has conducted CALPUFF screening modeling with the abated SO_2 emissions. The emission rates and stack parameters used are summarized in Table 2. Details of the modeling analysis are provided in the accompanying letter report.

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Table 2 – Proposed Emission Rates and Stack Parameters

	Sulfuric Acid Unit No. 2	Sulfuric Acid Unit No. 1	Package Boiler
LCC Easting (km)	560.809	560.521	560.646
LCC Northing (km)	-1032.578	-1032.629	-1032.650
Stack Height (m)	39.0	39.0	18.288
Exit temperature (K)	305.4	305.4	517.04
Exit Velocity (m/s)	35.475	34.377	23.04
Diameter (m)	1.37	0.91	1.07
SO_2 24 h max emission (g/s)	29.93	14.18	0.03
NO_x 24 h max emission (g/s)	13.38	6.20	3.07
PM10 24 h max emission (g/s)	0.09	0.05	0.16

As demonstrated in the accompanying letter report, with the SO_2 abatement system, all impacts of the Rhodia facility to the Breton and the Caney Creek Wilderness Area are below 0.5 deciview.

Rhodia believes that this report demonstrates BART for its facility. Per proposed federal consent decree (D.J. Ref. 90-5-2-1-08500) to which LDEQ is a signatory, the facility will be operating under its abated scenario in mid-2012 for Unit 1, and early 2011 for Unit 2. These dates are well in advance of the expected deadline for BART controls.

Since Rhodia is already conducting preliminary engineering on the project, we would like your concurrence on our selection of the proposed technology and reduction efficiency at your earliest convenience. Please contact me at (225) 359-3768 with any questions or to schedule a meeting to discuss further.

Sincerely,

John D. Richardson
Environmental Manager

cc: Yousheng Zeng, Ph D., P.E., Providence - Certified Mail Return Receipt Requested (7003 1010 0005 5151 9297)
Tim Allen, U.S. Fish and Wildlife Service- Certified Mail Return Receipt Requested (7003 1010 0005 5151 9280)
Eric Snyder, EPA Region VI - Certified Mail Return Receipt Requested (7003 1010 0005 5151 9273)

File 404.1.8

Rhodia

Baton Rouge Plant

June 14, 2007

Certified Mail Return Receipt Requested (7003 1010 0005 5151 9464)

Dr. Chuck Carr Brown, Assistant Secretary
Office of Environmental Services
Louisiana Department of Environmental Quality
P.O. Box 4314
Baton Rouge, LA 70821-4314

RE: Summary of CALPUFF BART Screening Modeling Analysis for Rhodia Sulfuric Acid Plant

Dear Dr. Brown::

Providence Engineering & Environmental Group LLC (Providence) has completed a CALPUFF screening modeling analysis for the Rhodia Sulfuric Acid plant located in Baton Rouge, Louisiana for purposes of recently promulgated regulations associated with Best Available Retrofit Technology (BART). This letter summarizes the results of the base case scenario and an abated scenario. This base case scenario is formulated using the emission data and stack parameters provided by Rhodia. The abated scenario is formulated using estimated emission data and stack parameters from Rhodia's proposal to use caustic scrubbing to reduce SO_2 emissions by 94%.

BACKGROUND

The 1990 Clean Air Act Amendments required the United States Environmental Protection Agency (USEPA) to promulgate regulations to protect against visibility impairment (regional haze) in 156 scenic areas (also referred to as Class I areas) across the United States. Regional haze regulations in 40 CFR 51.300 through 51.309 and guidelines found in Appendix Y to 40 CFR Part 51, help states identify sources that are BART eligible and determine the level of control that represents BART. Based on the Regional Haze rule, various state agencies are in the process of performing screening analyses to determine a list of potential sources that may cause visibility impairment at Class I areas. These screening analyses have been performed using screening models or emissions and distance thresholds. It is expected that the sources that are not screened out by the state agencies will be required to either perform comprehensive long-range transport modeling using the USEPA-promulgated CALPUFF model (in a screening analysis or a refined analysis) and/or submit an engineering analysis.

The Louisiana Department of Environmental Quality (LDEQ) has established screening criteria. Facilities that could not reasonably be eliminated from BART consideration by the criteria are asked to perform site-specific CALPUFF modeling analyses to evaluate if they impact Breton and Caney Creek Class 1 areas by 0.5 deciviews or more. Rhodia has received a request from the LDEQ to perform the modeling analysis. Rhodia has requested that Providence perform a screening analysis for their Baton Rouge sulfuric acid plant. This report provides the summary for the screening analysis.

MODEL SETUP

A CALPUFF model is set up for the Rhodia sulfuric acid plant in accordance with the Central Regional Air Planning Association (CENRAP) protocol and the LDEQ protocol for BART analyses. This section summarizes the model setup for the CALPUFF screening analysis.

Site Location, Receptor Location And Model Range

The modeling domain is shown in the Lambert Conformal Conic (LCC) coordinate system in Figure 1. The grid cell size used in the models is 6 km. All the domain range, coordinate system, and spatial resolution are same to the south meteorological domain prepared by CENRAP. The blue crosses indicate the receptors at Breton Wilderness Area and Caney Creek Wilderness, and the red circle represents the Rhodia sulfuric acid facility. Figure 2 shows a more detailed map of the receptor and sources.

Figure 1 – Rhodia facility on Whole LCC Modeling Domain

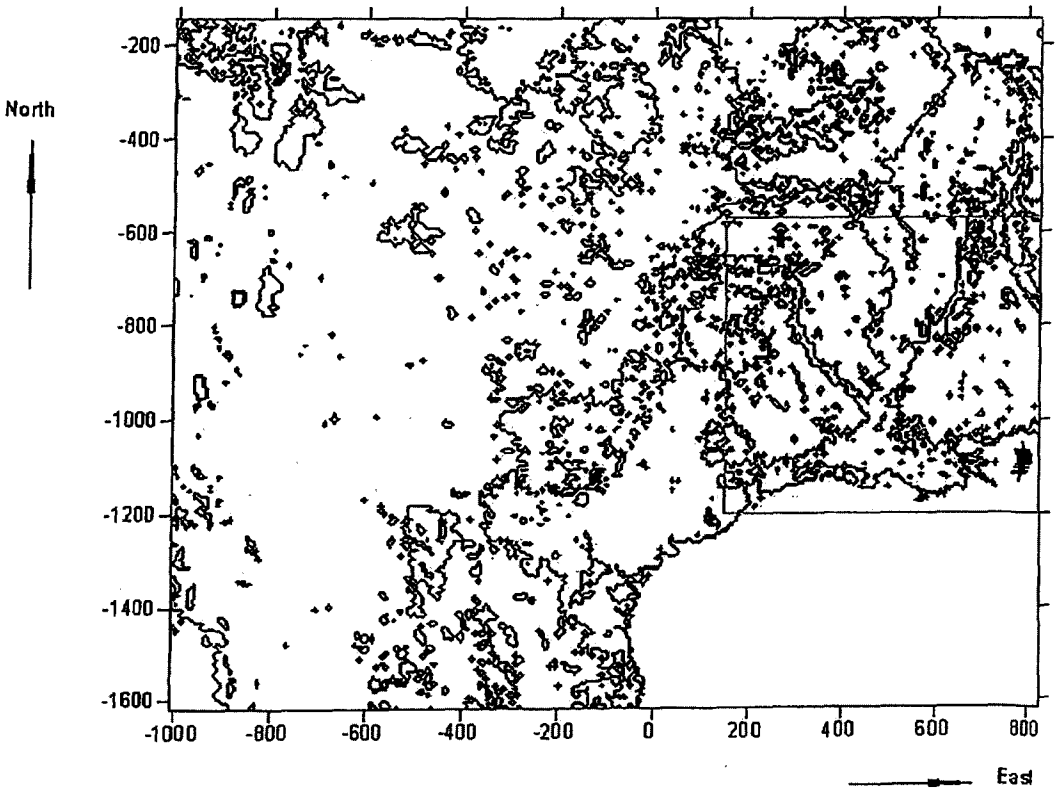
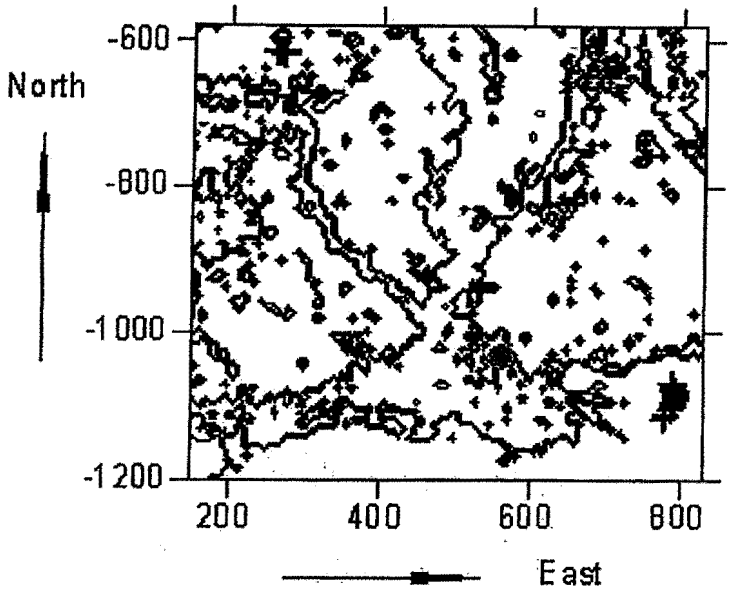


Figure 2 – Rhodia facility and Class I Areas



Meteorological data

The CALPUFF-ready meteorological data prepared by CENRAP is used directly for this screening analysis.

Emission rates and stack parameters

The emission rate and stack parameters used for the base case scenario and the abated scenario are provided in Table 1 below. A site elevation of 15.2 meters is used in the model.

Table 1 - Emission Rate and Stack Parameters

	Package Boiler	Base Case Sulfuric Acid Unit 2	Base Case Sulfuric Acid Unit 1	Abated Sulfuric Acid Unit 2	Abated Sulfuric Acid Unit 1
LCC Easting (km)	560.646	560.809	560.521	560.809	560.521
LCC Northing (km)	-1032.650	-1032.578	-1032.629	-1032.578	-1032.629
Stack Height (m)	18.288	76.2	76.2	39.0	39.0
Exit temperature (K)	517.04	338.71	335.37	305.4	305.4
Exit Velocity (m/s)	23.04	8.11	10.42	35.475	34.377
Diameter (m)	1.07	3.05	1.83	1.37	0.91
SO2 24 h max emission (g/s)	0.03	244.18	113.90	29.93	14.18
NOx 24 h max emission (g/s)	3.07	13.38	6.20	13.38	6.20
PM10 24 h max emission (g/s)	0.16	0.09	0.05	0.09	0.05

Model options

The model is set up following CENRAP's guidance on CALPUFF screening modeling. Key model options are listed below:

CALPUFF:
Dispersion: Pasquill-Gifford (PG) coefficient.
Chemical species modeled include: SO_2, SO_4, NO_x, HNO_3, NO_3, PM.

Chemistry: Mesopuff.
Aqueous phase chemistry: Use relative humidity (RH) instead of real water content.
Ozone: Ozone data is provided by LDEQ.
Ammonia: Constant ammonia concentration is assumed as 3 ppb.
Wet and dry deposition: Both gaseous and particle phase are modeled.

POSTUTIL:
Species input: SO_2, SO_4, NO_x, HNO_3, NO_3, PM.
Species output: SO_2, SO_4, NO_x, HNO_3, NO_3, PM.
Background NH_3: 3 ppb.

CALPOST:
Visibility is calculated using Mehtod 6 based on IMPROVE's equation:

$$b_{ext}=3f(RH)[(NH_4)_2SO_4]+3f(RH)[NH_4NO_3]+ 10[PM] + b_{Ray}$$

where b_{ext} is the calculated light extinction, f(RH) is the humidity effect, b_{Ray} is the Rayleigh scattering of air. A light extinction efficiency of 10 is used for PM.
The change of haze index in deciviews is calculated by:

$$\Delta dv = 10 \ln (\{b_{background}+ b_{source}\}/ b_{background})$$

where b_{source} is the light extinction caused by the source and the $b_{background}$ is the natural background light extinction.

The natural background light extinction is provided in CENRAP's guidance. For eastern states, background extinctions are EC=0.02, SO_4=0.23, NO_3=0.1, PMC=3, SOC=1.4, Soil=0.5, Raleight scattering=10.

Monthly f(RH) values at Breton and Caney Creek are obtained from EPA's Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule. As suggested in LDEQ's model protocol, the RH factors at the centroid receptor of each Class I area are used for the 12 months.

Recompilation

The CALPUFF, CALPOST and POSTUTIL programs were recompiled with the FORTRAN source code provided in the CALPUFF BART version. The compiler used is Lahey/Fujitsu Fortran Express v7.1. The changes for the recompilation are described below:

CALPUFF: In params.puf, mxnx=320,mxny=265, mxoz=2725. The source code is in calpuff.for and the executable file is calpuffc.exe.

POSTUTIL
In params.utl, PARAMETER(mxgx=320), PARAMETER(mxgy=265). The source code is in postutilc.for and the executable file is postutilc.exe

CALPOST
In params.pst, PARAMETER(mxgx=320) , PARAMETER(mxgy=265) . The source code is in the calpost.for. The executable file is calpost.exe.

To recompile, the parameters in the parameter files are changed first as indicated in the above paragraphs. The source files are recompiled by Lahey's command. The newly generated .exe files are used for the model runs in this work.

MODEL RESULTS

This section describes the modeling results for the CALPUFF screening analysis of the base case scenario and the abated scenario.

Model runs

For 2001, 36 met files are used in three groups of CALPUFF and POSTUTIL runs. The results are then merged by APPEND, a tool of CALPUFF BART version. For 2002 and 2003, 12 met files of each year are directly used in CALPUFF and POSTUTIL.

Model results of 2001, 2002, 2003

Modeling runs were executed for 2001, 2002, and 2003. Based on these runs, the tables below provide the results for the respective years under the base case scenario and the abated scenario. CALPOST was run separately for Breton and Caney Creek receptors since different RH factors were used for the two Class I areas.

Table 2 - CALPUFF Screening Analysis Results for Rhodia Base Case Scenario

2001 Breton Base Case Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	%_SO4	%_NO3	%_PM F	Rank
2001	191	5	2.003	4.3	99.53	0.44	0.02	1
2001	229	40	1.822	4.3	99.62	0.37	0.01	2
2001	231	40	1.315	4.3	99.72	0.26	0.02	3
2001	192	40	1.275	4.3	99.36	0.6	0.03	4
2001	202	40	1.18	4.3	99.67	0.31	0.02	5
2001	163	1	1.162	4	99.5	0.49	0.02	6
2001	190	1	1.102	4.3	99.27	0.7	0.03	7
2001	89	40	1.043	3.7	94.16	5.81	0.02	8
2001	226	1	1.034	4.3	99.77	0.22	0.02	9
2001	260	40	1.023	4.2	99.72	0.26	0.02	10
2001	53	40	0.962	3.5	93.9	6.07	0.03	11
2001	90	1	0.911	3.7	98.05	1.93	0.02	12
2001	230	40	0.897	4.3	99.16	0.81	0.02	13
2001	91	1	0.851	3.604	97.69	2.29	0.02	14
2001	187	40	0.747	4.3	99.79	0.19	0.01	15
2001	261	40	0.721	4.2	99.79	0.2	0.01	16
2001	212	40	0.571	4.3	99.8	0.18	0.02	17
2001	225	40	0.515	4.3	99.42	0.56	0.02	18
2001	232	1	0.508	4.3	99.72	0.26	0.02	19
2001	162	16	0.489	4	99.73	0.25	0.01	20

2001 Caney Creek Base Case Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	%_SO4	%_NO3	%_PM F	Rank
2001	44	43	0.726	3.1	94.33	5.65	0.02	1
2001	186	58	0.549	3.4	99.92	0.07	0.01	2
2001	350	58	0.477	3.5	91.36	8.61	0.03	3
2001	207	58	0.472	3.4	99.69	0.3	0.01	4
2001	235	49	0.472	3.4	99.77	0.22	0.01	5
2001	178	107	0.441	3.6	99.66	0.33	0.01	6
2001	318	76	0.431	3.4	94.29	5.68	0.03	7
2001	14	49	0.408	3.4	93.66	6.32	0.02	8
2001	295	75	0.379	3.5	97.72	2.26	0.02	9
2001	187	75	0.369	3.4	99.95	0.05	0.01	10

2002 Breton Base Case Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	%_PM F	Rank
2002	194	40	1.389	4.3	99.79	0.2	0.01	1
2002	206	40	1.075	4.3	99.8	0.19	0.01	2
2002	203	40	1.048	4.3	99.91	0.08	0.01	3
2002	186	1	0.989	4.3	99.88	0.11	0.01	4
2002	238	1	0.917	4.3	99.8	0.19	0.01	5
2002	213	40	0.844	4.3	99.74	0.24	0.02	6
2002	237	40	0.787	4.3	99.76	0.22	0.02	7
2002	204	1	0.691	4.3	99.92	0.07	0.01	8
2002	334	1	0.656	3.7	96.62	3.35	0.02	9
2002	202	40	0.578	4.3	99.9	0.09	0.01	10
2002	325	1	0.555	3.7	95.67	4.31	0.02	11
2002	363	40	0.533	3.7	95.51	4.47	0.02	12
2002	25	1	0.522	3.7	94.62	5.36	0.02	13
2002	299	40	0.51	3.7	97.19	2.79	0.01	14
2002	258	40	0.488	4.2	99.42	0.56	0.02	15

2002 Caney Creek Base Case Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	%_PM F	Rank
2002	234	76	1.102	3.4	99.6	0.39	0.01	1
2002	177	43	0.903	3.6	98.86	1.13	0.01	2
2002	222	76	0.82	3.4	99.45	0.53	0.02	3
2002	103	75	0.81	3	99.35	0.63	0.01	4
2002	298	43	0.772	3.5	97.13	2.86	0.01	5
2002	302	43	0.772	3.5	97.94	2.06	0.01	6
2002	23	75	0.63	3.4	94.87	5.11	0.02	7
2002	178	75	0.624	3.6	99.3	0.69	0.01	8
2002	22	41	0.544	3.4	93.24	6.73	0.02	9
2002	301	58	0.478	3.5	98.02	1.97	0.01	10

2003 Breton Base Case Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	%_PM F	Rank
2003	74	40	1.626	3.7	96.17	3.82	0.01	1
2003	310	1	1.486	3.7	99.22	0.75	0.03	2
2003	199	40	1.241	4.3	99.91	0.08	0.01	3
2003	75	40	0.987	3.7	96.42	3.57	0.01	4
2003	364	9	0.979	3.7	95.98	4	0.02	5
2003	22	1	0.851	3.7	92.7	7.28	0.03	6
2003	295	1	0.755	3.7	98.91	1.01	0.08	7
2003	81	16	0.713	3.7	97.89	2.07	0.03	8
2003	220	1	0.647	4.3	99.81	0.18	0.02	9
2003	160	1	0.643	4	99.8	0.19	0.01	10
2003	77	1	0.636	3.7	95.84	4.14	0.02	11
2003	32	40	0.59	3.508	96.35	3.63	0.01	12
2003	339	1	0.57	3.7	96.86	3.13	0.02	13
2003	147	40	0.567	3.8	99.57	0.41	0.01	14
2003	103	1	0.546	3.6	97.72	2.25	0.03	15
2003	132	40	0.537	3.8	98.79	1.19	0.02	16
2003	41	40	0.522	3.5	94.82	5.16	0.02	17
2003	161	40	0.501	4	99.8	0.19	0.01	18
2003	202	40	0.477	4.3	99.63	0.35	0.02	19

2003 Caney Creek Base Case Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	%_PM F	Rank
2003	281	41	1.219	3.5	98.4	1.59	0.01	1
2003	76	43	1.137	2.9	96.81	3.17	0.02	2
2003	52	43	1.097	3.1	95.85	4.14	0.01	3
2003	283	107	1.092	3.5	98.37	1.61	0.01	4
2003	284	41	0.978	3.5	98.79	1.2	0.01	5
2003	282	119	0.858	3.5	98.08	1.91	0.01	6
2003	29	58	0.742	3.4	95.75	4.24	0.01	7
2003	227	107	0.696	3.4	99.7	0.29	0.01	8
2003	242	43	0.587	3.4	99.03	0.96	0.02	9
2003	228	119	0.581	3.4	99.92	0.07	0.01	10
2003	71	49	0.536	2.9	98.38	1.61	0.01	11
2003	285	41	0.515	3.5	99.67	0.32	0.01	12
2003	239	58	0.481	3.4	99.86	0.13	0.01	13

Table 3 - CALPUFF Screening Analysis Results for Rhodia Abated Scenario

2001 Breton Abated Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	%_PM F	Rank
2001	191	5	0.288	4.3	97.05	2.79	0.17	1
2001	229	40	0.207	4.3	97.08	2.8	0.12	2
2001	231	40	0.2	4.3	97.73	2.14	0.14	3
2001	53	39	0.184	3.5	66.47	33.34	0.19	4
2001	89	40	0.171	3.7	66.95	32.92	0.13	5
2001	192	40	0.164	4.3	96	3.73	0.27	6
2001	163	1	0.148	4	95.73	4.14	0.13	7
2001	190	1	0.147	4.3	94.38	5.39	0.23	8
2001	226	1	0.134	4.3	98.05	1.82	0.13	9
2001	260	40	0.134	4.2	97.74	2.13	0.13	10

2001 Caney Creek Abated Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	%_PM F	Rank
2001	44	43	0.13	3.1	67.15	32.74	0.11	1
2001	350	58	0.092	3.5	56.9	42.95	0.14	2
2001	14	49	0.074	3.4	64.33	35.57	0.1	3
2001	318	76	0.072	3.4	66.86	32.97	0.16	4
2001	186	58	0.07	3.4	99.36	0.56	0.07	5
2001	207	58	0.059	3.4	97.56	2.36	0.09	6
2001	235	49	0.059	3.4	98.12	1.78	0.1	7
2001	338	75	0.055	3.5	69.11	30.68	0.21	8
2001	45	75	0.054	3.1	70.84	29.05	0.11	9
2001	295	75	0.053	3.5	83.73	16.11	0.16	10

2002 Breton Abated Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	%_PM F	Rank
2002	194	40	0.17	4.3	98.18	1.73	0.09	1
2002	206	40	0.14	4.3	98.28	1.65	0.07	2
2002	203	40	0.12	4.3	99.24	0.67	0.1	3
2002	238	1	0.116	4.3	98.47	1.42	0.11	4
2002	186	1	0.108	4.3	98.93	0.96	0.1	5
2002	237	40	0.096	4.3	98.18	1.68	0.13	6
2002	25	1	0.088	3.7	68.15	31.73	0.12	7
2002	72	1	0.086	3.7	71.27	28.63	0.1	8
2002	363	40	0.086	3.7	72.09	27.78	0.13	9
2002	325	1	0.079	3.7	70.75	29.13	0.13	10

2002 Caney Creek Abated Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	%_PM F	Rank
2002	234	76	0.144	3.4	96.64	3.28	0.08	1
2002	177	43	0.12	3.6	91.22	8.71	0.08	2
2002	298	43	0.113	3.5	80.17	19.76	0.07	3
2002	302	43	0.109	3.5	85.53	14.41	0.06	4
2002	22	41	0.107	3.4	63.98	35.89	0.12	5
2002	103	75	0.106	3	94.88	5.02	0.1	6
2002	222	76	0.101	3.4	95.28	4.58	0.14	7
2002	23	75	0.09	3.4	69.18	30.72	0.1	8
2002	178	75	0.078	3.6	94.55	5.38	0.07	9
2002	5	41	0.069	3.4	50.37	49.5	0.13	10

2003 Breton Abated Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	%_PM F	Rank
2003	74	40	0.286	3.7	75.56	24.36	0.08	1
2003	310	4	0.201	3.7	93.06	6.7	0.25	2
2003	199	40	0.166	4.3	99.22	0.69	0.09	3
2003	364	9	0.161	3.7	74.63	25.26	0.11	4
2003	75	40	0.16	3.7	76.76	23.17	0.07	5
2003	32	40	0.107	3.508	76.67	23.24	0.09	6
2003	81	17	0.106	3.7	84.86	14.91	0.23	7
2003	77	1	0.104	3.7	73.75	26.11	0.13	8
2003	295	1	0.1	3.7	92.06	7.32	0.62	9
2003	22	1	0.093	3.7	56.9	42.91	0.19	10

2003 Caney Creek Abated Scenario

YEAR	DAY	RECEPTOR	DELTA DV	F(RH)	% SO4	% NO3	%_PM F	Rank
2003	52	43	0.173	3.1	74.09	25.82	0.09	1
2003	76	43	0.165	2.9	79.22	20.65	0.13	2
2003	281	41	0.163	3.5	88.29	11.62	0.09	3
2003	283	118	0.147	3.5	87.85	12.07	0.08	4
2003	284	58	0.13	3.5	90.72	9.2	0.08	5
2003	29	76	0.122	3.4	73.59	26.34	0.07	6
2003	282	119	0.116	3.5	86.23	13.68	0.09	7
2003	227	92	0.092	3.4	97.55	2.37	0.07	8
2003	242	43	0.08	3.4	92.55	7.32	0.13	9
2003	71	49	0.074	2.9	88.14	11.77	0.09	10

Sources with modeled maximum impacts below the 0.5 deciview threshold are exempt from the remainder of the BART process. As shown in the tables above, the visibility impacts from the base case scenario exceed the 0.5 deciview threshold for several days each year. In the abated scenario, impacts from the sources at the Rhodia facility do not exceed the 0.5 deciview threshold.

If you have any questions please call me at (225) 359-3768.

Sincerely,

John D. Richardson
Environmental Manager

cc: Yousheng Zeng, Ph D., P.E., Providence - Certified Mail Return Receipt Requested (7003 1010 0005 5151 9297)
Tim Allen, U.S. Fish and Wildlife Service- Certified Mail Return Receipt Requested (7003 1010 0005 5151 9280)
Eric Snyder, EPA Region VI - Certified Mail Return Receipt Requested (7003 1010 0005 5151 9273)

File 404.1.8

Appendix E

Sid Richardson Carbon and Energy

Addis Plant

BART Modeling Analyses

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LONG B. NGUYEN, P.E.
Environmental, Health & Safety Manager

January 23, 2014

Ms. Vivian Aucoin
Department of Environmental Quality
Office of Environmental Services
Air Permits Division
P.O. Box 4313
Baton Rouge, LA 70821-4313

DEQ - OES
2014 JAN 27 AM 9:28

Re: Sid Richardson Carbon & Energy
Addis Plant – Agency Interest No. 4174
BART Modeling

Dear Ms. Aucoin:

Per your request, this letter details the differences between the Best Available Retrofit Technology (BART) modeling analyses that were performed in 2013 and 2007.

The 2013 analysis (Bowman) used the methods and guidance of FLAG 2010 and the 8/31/2009 Memorandum "Clarification on EPA-FLM Recommended Settings for CALMET", along with the most recent versions of the CALPUFF system of programs. The 2007 analysis (Environ) modeling used methods and guidance of FLAG 2000, along with older versions of the CALPUFF system of programs that were current in 2007.

FLAG 2010/IMPROVE Equations - The FLAG 2010 guidance document includes new IMPROVE equations to calculate visibility impacts. The FLAG 2010/IMPROVE equations include new higher background concentrations and relative humidity adjustment factors for the hygroscopic effects for each of the major species that account for most of the visibility effects. Higher natural background concentrations and higher relative humidity adjustment factors for the 2013 analysis gives higher background visibility than the previous data and methods used the 2007 analysis. The visibility impacts from the Addis plant when included with the natural background visibility gives a lower delta-deciview impact because of the higher natural background visibility.

CALMET Parameters – There were major differences in the 2013 analysis and the 2007 analysis in the CALMET parameters. The 2013 analysis followed the 8/31/2009 Memorandum for CALMET settings. According to this Memorandum, "These recommendations are based in large part upon the understanding we have developed from the numerous tracer evaluations we have conducted in addition to the collective experience of the national Park Service, Forest Service, and US Fish and Wildlife from the BART process." The 2007 analysis used values determined by the modeler and approved in their protocol. The CALMET parameters and values for the 2013 analysis and 2007 analysis are shown below.

CALMET – Six of the important CALMET parameters were "User Defined" values under FLAG 2000 and were defined by EPA/FLM in 8/31/2009 Memorandum.

	2007 Environ	2013 Bowman	EPA/FLM
TERRAD	10	15	15
RMAX1	30	100	100
RMAX2	60	200	200
RMAX3	60	200	200
R1	6*, 18**	50	50
R2	12*, 36**	100	100

*2001, **2002 & 2003

For example, the parameter RMAX1 sets the distance that surface observations (surface met stations) modify Step 1 Wind Fields to develop the Step 2 Wind Fields of the three-dimensional Meteorological Grid. The 2013 analysis used the guideline value of 100 km for RMAX1. The 2007 analysis used 30 km. The smaller value used in the 2007 analysis means that the surface observations did not influence the wind fields beyond 30 km, whereas the 2013 analysis that used the Memorandum value of 100 km influenced the wind fields out to a much greater distance. The change in the CALMET three-dimensional Meteorological Grid is expected to change the overall visibility impact. Never the less, the 2013 analysis used the current guidance.

CALPUFF Modeling System of Programs – The 2013 analysis used the versions of the CALPUFF system of programs that were current at the time of the protocol submittal (June 2013). The 2007 analysis used the versions of the programs that were current at the time of their modeling analysis. The version numbers of the programs used in the 2013 analysis and 2007 analysis are shown below.

CALMET	5.53A	5.8
CALPUFF	5.711A	5.8
CALPOST	5.51	6.221
POSTUTIL	1.3	1.56
TERREL	3.311	3.684
CTGPROC	2.42	2.682
MAKEGEO	2.22	2.29

Emission Rates Used in Modeling Analysis– The emission rates used in the 2007 modeling analysis were based on the highest annual emission rates from the period of 2001-2003, which occurred in 2002. The daily emission rates were back-calculated from these annual emission rates. These daily emission rates (rates used in the modeling) did not necessarily represent the worst-case scenario emission rates because they were based on annual averages. The emission rates used in the 2013 modeling analysis, on the other hand, represented the worst-case scenario emission rates because they were derived from the permitted lbs/hr limits. The emission rates used in the 2013 modeling analysis were greater than those that were used in the 2007 modeling analysis.

Please call me at (817) 390-8604 if you have any questions.

Sincerely,

Long B. Nguyen

BART Visibility Impact Analysis

Sid Richardson Carbon Company, Ltd.
Addis, Louisiana, Plant

Prepared for:
Sid Richardson Carbon Company, Ltd.
Fort Worth, Texas

Prepared by:
J. Thomas Bowman, Ph.D., P.E.

October 2013

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1. Executive Summary

Overview. The Sid Richardson Carbon & Energy Company (Sid Richardson) retained J. Thomas Bowman (Bowman) to perform a source-specific Best Available Retrofit Technology (BART) modeling analysis using the CALPUFF model for the Sid Richardson Addis, Louisiana, Plant. Sid Richardson submitted a BART analysis in 2007 prepared by Environ.

The 2007 analysis showed a maximum 98th percentile of 0.619 delta-deciviews at the Breton NWR and 0.147 delta-deciviews at the Caney Creek Wilderness Area.

Bowman has been asked to remodel the facility's impact at the Breton NWR using the current versions of the models and current guidelines. This document is the result of this request. The impact of the Addis plant at the Caney Creek Wilderness Area was well below 0.50 delta-deciviews and was not remodeled as part of this study.

Summary of Results. The highest 98th percentile for the 2001-2003 period was 0.344 delta-deciviews and the highest 98th percentile for the highest year was 0.397 delta-deciviews for the year 2002. These impacts are well below the 0.50 delta-deciview requirement.

Table 1.1
Results (delta-deciviews)

Value	Year of Meteorological Data			
	Breton NWR, LA			
	2001	2002	2003	2001-2003
98th Percentile	0.316	0.397	0.340	0.344

2. Facility Description

The Sid Richardson Addis Plant is a carbon black manufacturing facility (SIC code 2895, NAICS code 325182) located in Addis, Louisiana. The Plant is located west of Louisiana Highway 1 on Sid Richardson Road about 3 kilometers south-southwest of the town of Addis. Figure 2.1 shows the location of the plant in relation to the town of Addis, Highway 1, and the Mississippi River. Figure 2.2 shows an enlarged image of the Addis Plant. Both images were created using Google Earth.

Figure 2.1 Addis Site Location

Figure 2.2 Addis Plant

3. Source Parameters and Emission Rates

The source information below and source parameters in Table 3.1, Table 3.2 and Table 3.3 and were supplied by Sid Richardson. To be consistent with the 2007 Environ analysis, the speciated emission rates shown in Table 3.4 were calculated using the same ration of SOA(OC) to PM and PMF to PM as used in the 2007 analysis.

The worst-case scenario emissions (i.e., permitted emission rates) were used in this analysis. Just like the 2007 analysis, the emissions from certain pieces of equipment that were built outside of the BART eligible period of 1962-1977 were not included in the analysis. The excluded equipment in the current analysis is the identical to the excluded equipment in the 2007 analysis. The details of these exclusions are outlined below.

Unit 1 (Reactors A, 1, 2, 3) => Reactor A was built outside of 1962-1977 time frame, therefore it was excluded. All reactors are identical in terms of capacity, therefore the emission rates have been reduced by 25% for the exclusion of reactor A.

Unit 3 (Reactors 8, 9, 10, 11) => Reactor 11 was built outside of 1962-1977 time frame, therefore it was excluded. Reactors 8 and 9 are slightly smaller (45" tunnel) than Reactors 10 and 11 (60" tunnel). The percentage of reactor 11 when compared to the unit's overall capacity is 29%. Therefore, the emission rates have been reduced by 29% for the exclusion of reactor 11.

West Dryer Stack (Dryer 6) => Dryer 6 was built outside of 1962-1977 timeframe. Therefore, it was excluded.

East Dryer Stack (Dryers A, 1, 2, 3, 5) => Dryers A and 5 were built outside of 1962-1977 time frame, therefore they were excluded. All dryers are identical in terms of capacity. Therefore, the emission rates have been reduced by 40% for the exclusion of Dryers A and 5.

The emissions from Units' 1and 2 dryer exhaust bagfilters are routed to a common stack (DF1). The emission rate used in the modeling is the summation of the emission rates from these two bagfilters.

The emission rates in Table 3.3 reflect the permitted emission rates with the exclusion of the equipment stated above.

Table 3.1

Source Locations

Source ID	Geographic Location		LCC		UTM Coordinates		
	Longitude	Latitude	Easterly	Northerly	Easterly	Northerly	Zone
	(deg)	(deg)	(km)	(km)	(km)	(km)	
B1	91.2791	30.3292	551.8023	-1055.5936	665.4378	3356.5160	15
B2	91.2792	30.3291	551.7906	-1055.6019	665.4257	3356.5084	15
B3	91.2796	30.3290	551.7573	-1055.6189	665.3918	3356.4931	15
D5	91.2794	30.3292	551.7741	-1055.5935	665.4097	3356.5175	15
SF1	91.2793	30.3292	551.7808	-1055.5948	665.4163	3356.5159	15
SF2	91.2795	30.3291	551.7636	-1055.6061	665.3987	3356.5055	15
SF3A	91.2800	30.3289	551.7233	-1055.6319	665.3573	3356.4819	15
DF1	91.2797	30.3290	551.7493	-1055.6110	665.3842	3356.5013	15

Table 3.2

Stack Parameters

Source ID	Stack Height	Base Elevation	Stack Diameter	Exit Velocity	Exit Temp.
	(m)	(m)	(m)	(m/s)	(K)
B1	32.50	5.49	1.64	20.00	1273.20
B2	32.50	5.49	1.72	20.00	1273.20
B3	32.50	5.49	1.68	20.00	1273.20
D5	60.40	5.49	1.52	32.30	699.80
SF1	27.30	5.49	0.46	40.20	366.50
SF2	27.30	5.49	0.46	40.20	366.50
SF3A	26.20	5.49	0.61	37.20	366.50
DF1	36.60	5.49	0.91	16.18	477.60

Table 3.3

Permit Emission Rates

Source ID	Permit Limits					
	NOX		SO2		PM10	
	(lb/hr)	(g/s)	(lb/hr)	(g/s)	(lb/hr)	(g/s)
B1	4.6575	0.5868	392.3625	49.4377	46.2000	5.8212
B2	6.1400	0.7736	485.1700	61.1314	51.2400	6.4562
B3	4.8351	0.6092	483.1621	60.8784	67.9612	8.5631
D5	40.4520	5.0970	346.7760	43.6938	73.9440	9.3169
SF1	0.0000	0.0000	0.0000	0.0000	22.8000	2.8728
SF2	0.0000	0.0000	0.0000	0.0000	18.9600	2.3890
SF3A	0.0000	0.0000	0.0000	0.0000	35.4400	4.4654
DF1	0.0000	0.0000	0.0000	0.0000	6.2000	0.7812

Table 3.4

Speciated Emission Rates as Modeled

Source ID	Modeled Emission Rates								
	SO2	SO4	NOX	HNO3	NO3	EC	SOA	PM10	PMF
	(g/s)	(g/s)	(g/s)	(g/s)	(g/s)	(g/s)	(g/s)	(g/s)	(g/s)
B1	49.4377	0.0000	0.5868	0.0000	0.0000	0.0000	5.7937	0.0000	0.0231
B2	61.1314	0.0000	0.7736	0.0000	0.0000	0.0000	6.4307	0.0000	0.0260
B3	60.8784	0.0000	0.6092	0.0000	0.0000	0.0000	8.5213	0.0000	0.0341
D5	43.6938	0.0000	5.0970	0.0000	0.0000	0.0000	9.2827	0.0000	0.0371
SF1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	3.8107	0.0000	0.0154
SF2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	2.3810	0.0000	0.0096
SF3A	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	5.9397	0.0000	0.0238
DF1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.8241	0.0000	0.0031

4. Model Selection

The current guideline versions of the CALPUFF system of programs was used. The programs and program versions that were used in this analysis are as follows:

Main Programs
- CALMET 5.8
- CALPUFF 5.8

Postprocessors
- CALPOST 6.221
- PRTMET 4.34
- POSTUTIL 1.56

Geophysical Data Preprocessors
- TERREL 3.684
- CTGPROC 2.682
- MAKEGEO 2.29

Meteorological Preprocessors
- SMERGE 5.57
- PXTRACT 4.25
- PMERGE 5.32
- READ62 5.54

5. Modeling Domain

The Modeling Domain is set large enough to ensure that puffs are not eliminated from the computational grid prematurely. The Modeling Domain extends more than 150 kilometers beyond all sources and receptors. This Domain is cast on a Lambert Conformal Conic (LCC) coordinate system. The Modeling Domain is shown in Figure 5.1. The projection parameters and Meteorological Domain coordinates are listed in Table 5.1 and Table 5.2.

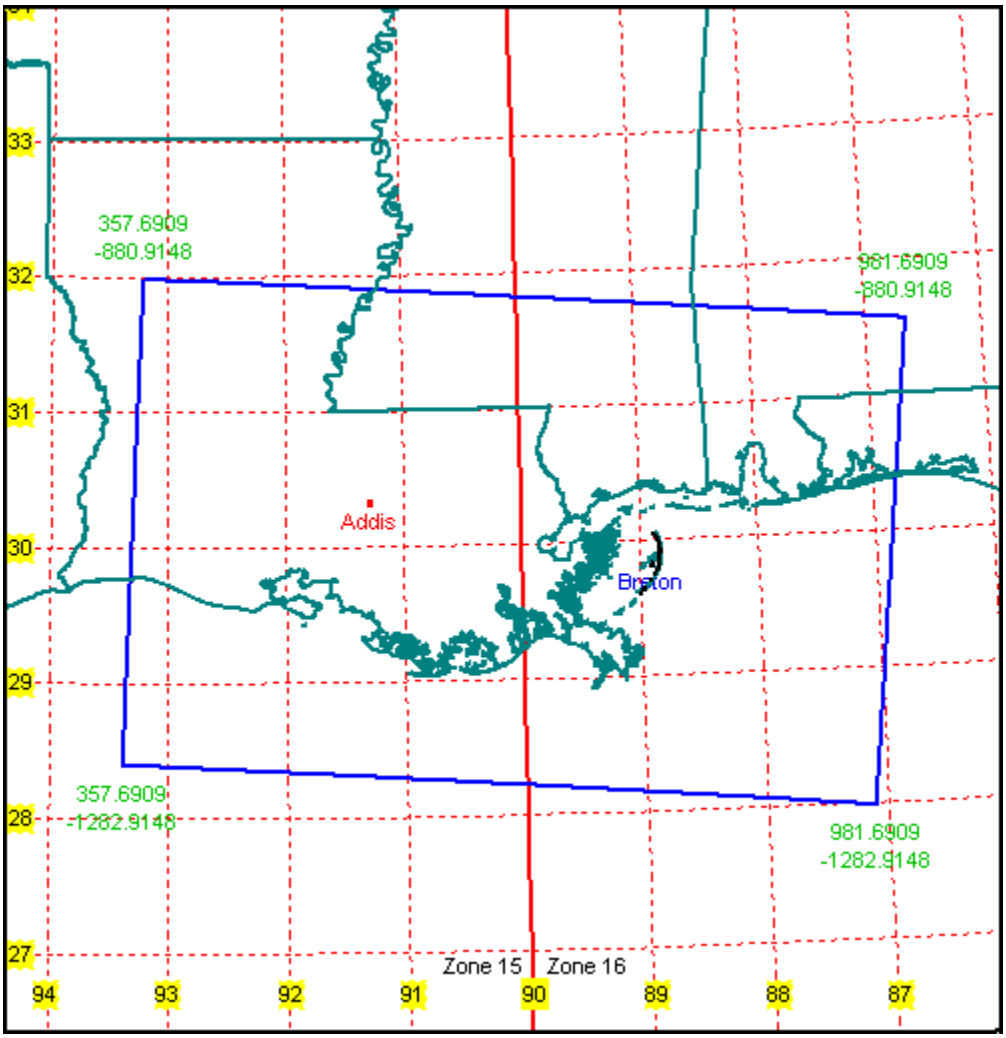

Figure 5.1 Meteorological Domain

Table 5.1

LCC Projection Parameters

Projection Origin		
	RLAT0	40.0N
	RLON0	97.0W
False Origin		
	FEAST	0
	FNORTH	0
Matching Parallels		
	XLAT1	33.0N
	XLAT2	45.0N

Table 5.2

Meteorological Domain

Datum		WGS-84
Southwest Corner (KM)		
	XORIGKM	357.691
	YORIGKM	-1282.915
Number of Grid Cells		
	NX	104
	NY	67
Horizontal Grid Spacing (KM)		6
Vertical Grid Spacing (KM)*		
	1	20
	2	40
	3	80
	4	160
	5	320
	6	640
	7	1200
	8	2000
	9	3000
	10	4000

*Top of each cell

6. CALMET Analysis

The CALMET analysis was conducted in accordance with August 31, 2009, Memorandum *Clarification on EPA-FLM Recommended Settings for CALMET.* The CALMET model was used to develop the parameters for the three-dimensional Meteorological Grid. The Meteorological Grid includes meteorological parameters, surface parameters, and terrain elevations for each hour. This three-dimensional Meteorological Grid was calculated by CALMET in three steps, as discussed in the following subsections. The technical options that were used in CALMET are listed in Appendix A, which is a CALMET input file for January 2001.

Initial Guess Wind Fields. The 36-km prognostic data for 2002 and 2003 and the 12-km data for 2001 from the CALMM5 CENRAP data were used by CALMET for developing the Initial Guess Wind Fields of the 6-km, three-dimensional Meteorological Grid.

Step 1 Wind Fields. The terrain and surface parameters were used by CALMET to modify the Initial Guess Wind Fields to develop the Step 1 Wind Fields of the 6-km, three-dimensional Meteorological Grid. The terrain character of this area is, in general, gently sloping to flat. The terrain varies from sea level to about 160 meters amsl.

Step 2 Wind Fields. Meteorological observations (surface data, upper air data, precipitation data, and buoy data) are used by CALMET to modify the Step 1 Wind Fields to develop the Step 2 Wind Fields of the 6-km, three-dimensional Meteorological Grid.

6.1 Meteorological Data

CALMM5 Data. The CENRAP CALMM5 data were acquired from Erik Snyder, US EPA Region VI. Extractions of the data were make for each year for an area that included the Modeling Domain and all meteorological stations. Upper air substitution files were created using the nearest CALMM5 node for each upper air station. The substitution files are used as input to the READ62 program. Figure 6.1 shows the location of the 2001 nodes and Figure 6.2 shows the location of the 2002 and 2003 nodes.

Surface Data. Surface data for 2001, 2002 and 2003 were used as observations in developing the Step 2 Wind Fields in the CALMET model. The surface data were obtained from the National Climatic Data Center (NCDC) in Asheville, North Carolina. The data included all stations having sufficient data for modeling that are located within 100 kilometers of the meteorological modeling domain. Data from a total of 45 surface stations were used for 2001, 42 for 2002 and 43 for 2003. Table 6.1 is a listing of these surface stations and associated site information. Figure 6.3 depicts the surface station locations.

Upper Air Data. Upper air data for 2001, 2002 and 2003 were used as observations in developing the Step 2 Wind Fields in the CALMET model. The upper air data were downloaded from the National Oceanic and Atmospheric Administration (NOAA) Forecast Systems Laboratory web site. Four upper air stations are located within 200 kilometers of the meteorological modeling domain and were used in this analysis. Table

6.2 lists the upper air data stations and locations, and the station locations are depicted in Figure 6.3.

Precipitation Data. .Precipitation data for 2001, 2002 and 2003 were used as observations in developing the Step 2 Wind Fields in the CALMET model. The precipitation data were obtained from the NCDC. The precipitation data stations consisted of all stations having sufficient data for modeling that are also located within the meteorological modeling domain. Totals of 34, 35, and 38 stations were used for the precipitation analyses conducted for 2001, 2002, and 2003, respectively. Table 6.3 lists these stations and locations, and Figure 6.4 depicts the station locations.

Buoy Data. .Buoy data for 2001, 2002 and 2003 were used as observations in developing the Step 2 Wind Fields in the CALMET model. The buoy data were obtained from the National Oceanographic Data Center. The buoy data consisted of two stations. Table 6.4 lists these stations and locations, and Figure 6.4 depicts the station locations.

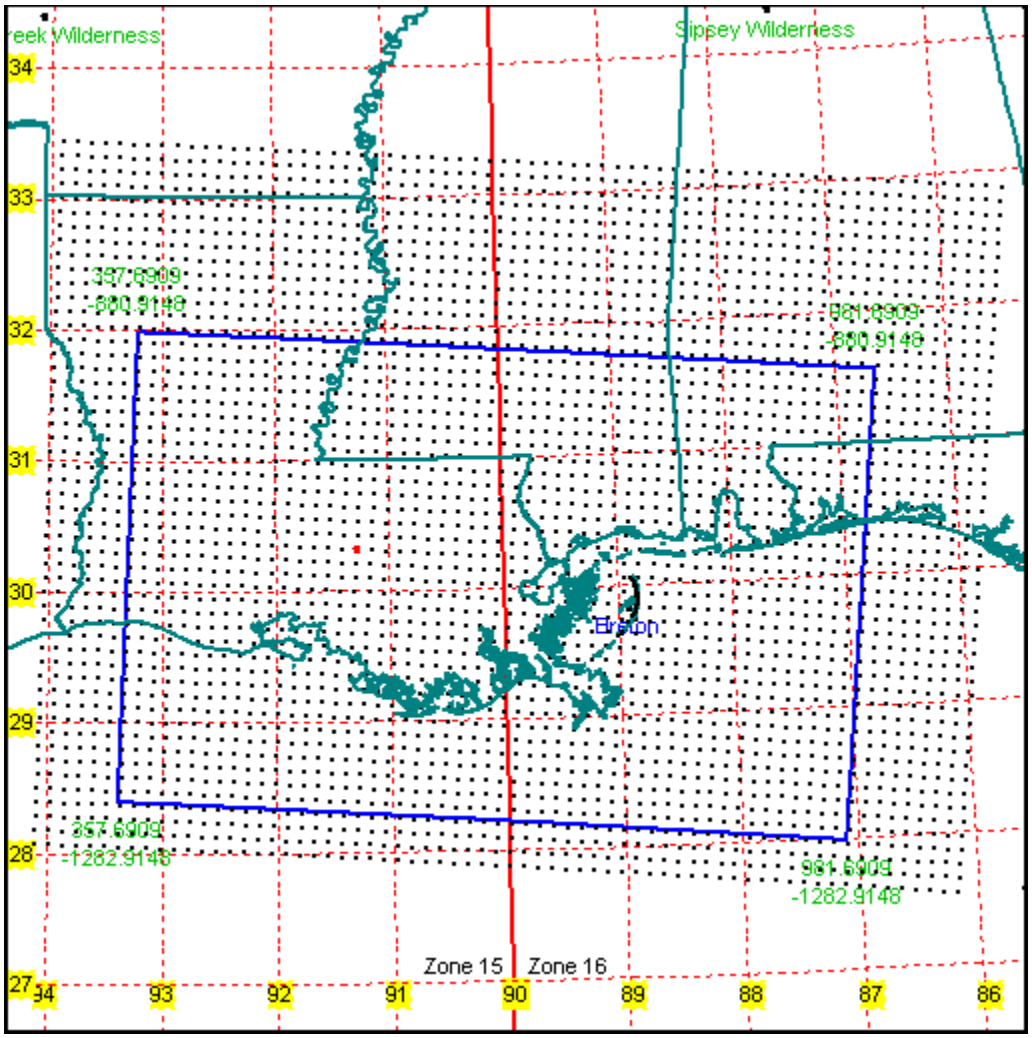

Figure 6.1 Location of Nodes From the 2001 CALMM5 Extraction From CENRAP Data

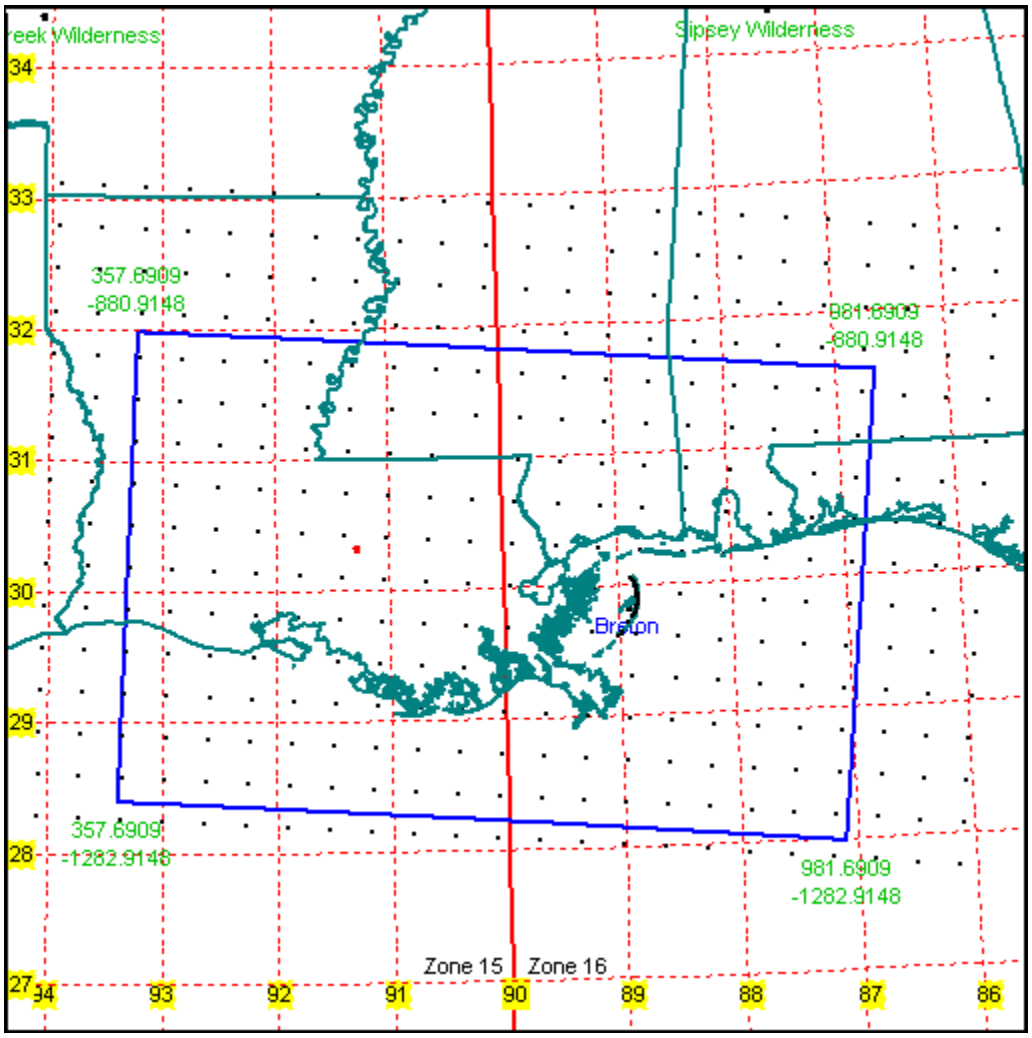

Figure 6.2 Location of Nodes From the 2002 and 2003 CALMM5 Extraction From CENRAP Data

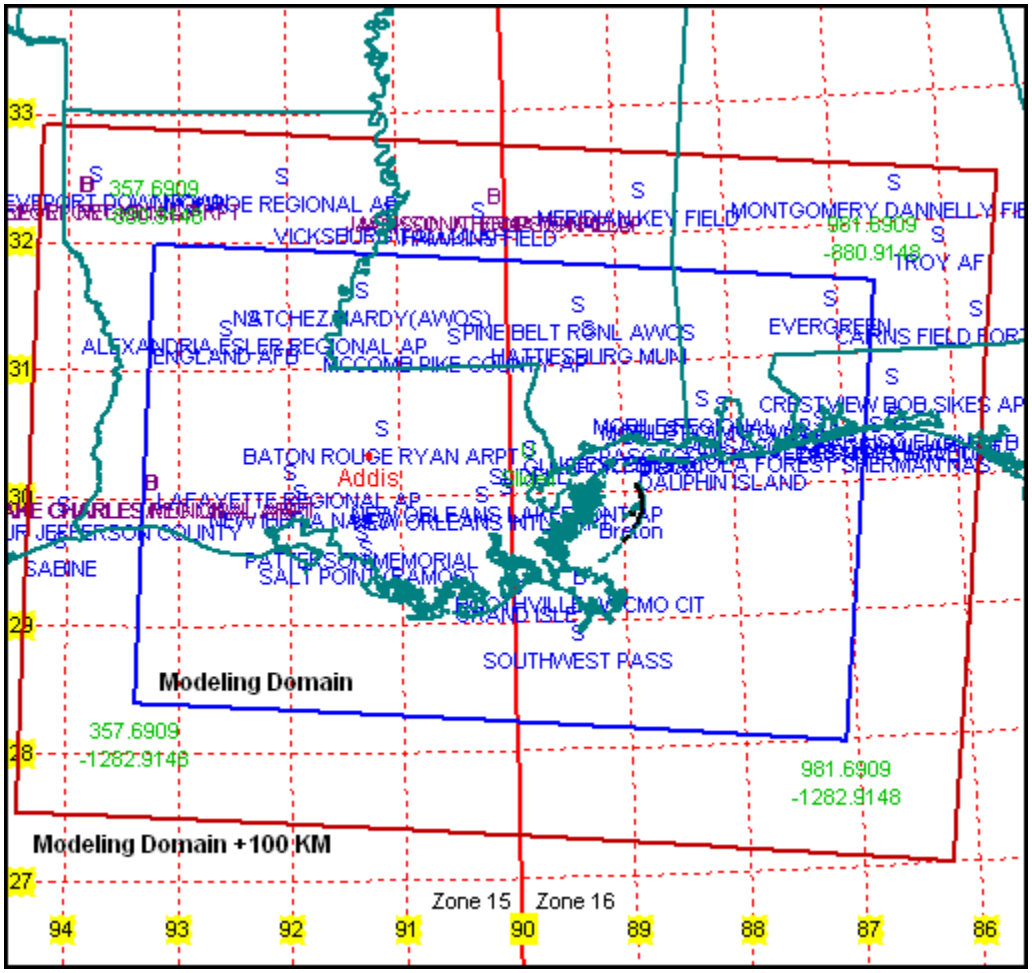

Figure 6.3 Surface and Upper Air Stations

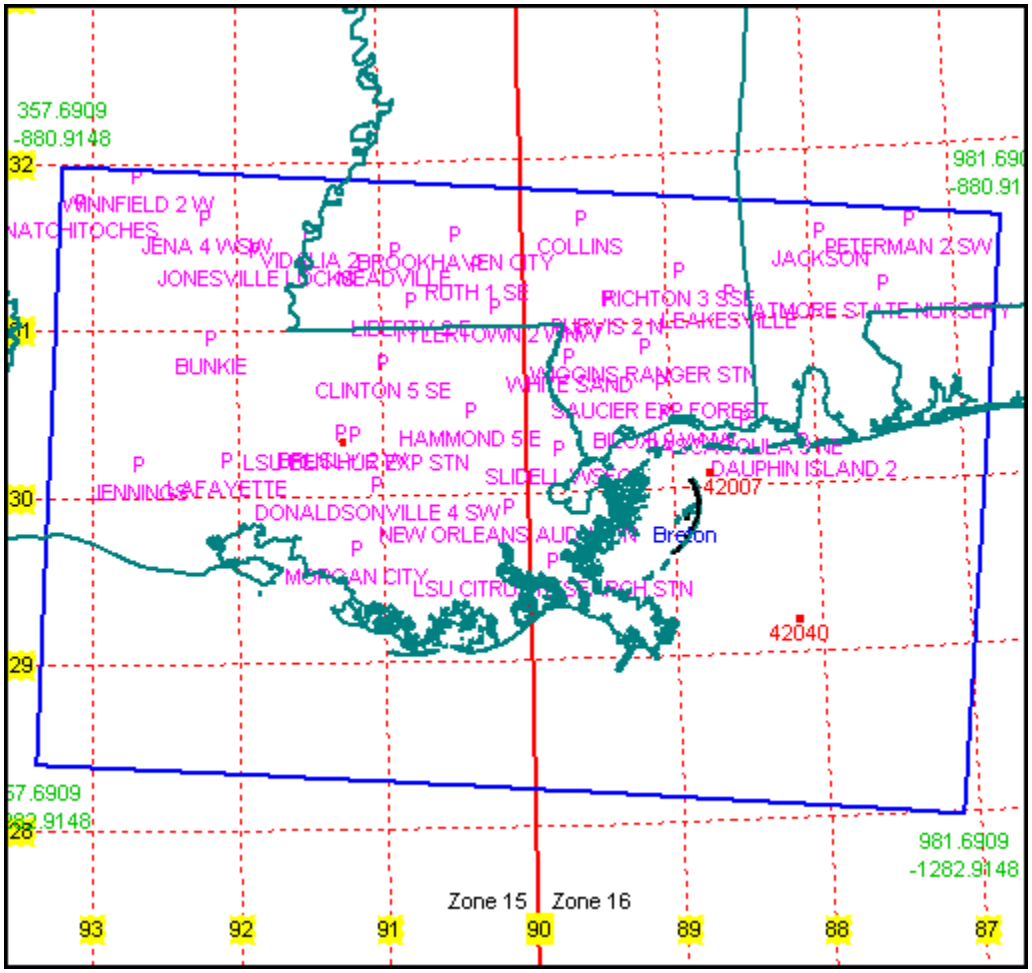

Figure 6.4 Precipitation and Buoy Stations

Table 6.1

Surface Stations

WBAN	USAF	Name	State	Geographic Location		LCC		UTM Coordinates		Zone
				Longitude (deg)	Latitude (deg)	Easterly (km)	Northerly (km)	Easterly (km)	Northerly (km)	
3850	722269	CAIRNS FIELD FORT RUCKER	AL	87.3170	30.3500	932.5653	-1020.9092	1194.2010	3482.1700	15
3852	747770	VALPARAISO HURLBURT	FL	86.6830	30.4170	992.5226	-1006.7479	1107.3000	3381.9870	15
3855	722225	PENSACOLA FOREST SHERMAN NAS	FL	87.3170	30.3500	932.5653	-1020.9092	1046.6200	3371.2950	15
3878	722267	TROY AF	AL	86.0170	31.8670	1036.7804	-838.5950	1161.2600	3547.0330	15
3934	722314	NEW IBERIA NAAS	LA	91.8830	30.0330	495.4845	-1092.1452	607.7000	3322.9680	15
3937	722400	LAKE CHARLES REGIONAL ARPT	LA	93.2330	30.1170	364.4612	-1089.1449	477.5540	3331.7730	15
3940	722350	JACKSON INTERNATIONAL AP	MS	90.0830	32.3170	650.1048	-826.4515	774.6250	3579.3130	15
12884	722320	BOOTHVILLE WSCMO CIT	LA	89.4000	29.3330	741.9960	-1153.4636	849.6300	3250.2650	15
12916	722310	NEW ORLEANS INTL ARPT	LA	90.2500	30.0000	653.6274	-1085.5065	765.2820	3321.9700	15
12917	722410	PORT ARTHUR JEFFERSON COUNTY	TX	94.0170	29.9500	289.2526	-1110.6404	401.8610	3313.6800	15
13820	747686	KEESLER AFB	MS	88.9170	30.4170	778.2516	-1028.5148	892.3020	3372.0780	15
13838	722235	MOBILE DOWNTOWN AP	AL	88.0670	30.6330	857.4715	-996.8283	973.0110	3399.3220	15
13858	722210	VALPARAISO ELGIN AFB	FL	86.5170	30.4830	1007.5725	-997.5914	1122.8690	3390.2320	15
13865	722340	MERIDIAN KEY FIELD	MS	88.7500	32.3330	774.9116	-814.2255	900.1360	3585.2930	15
13884	722215	CRESTVIEW BOB SIKES AP	FL	86.5170	30.7830	1003.7143	-964.2936	1120.9380	3423.5800	15
13894	722230	MOBILE REGIONAL AP	AL	88.2500	30.6830	839.4226	-992.9767	955.2080	3404.1140	15
13895	722260	MONTGOMERY DANNELLY FIELD	AL	86.4000	32.3000	995.1807	-794.9915	1121.9600	3592.8830	15
13899	722223	PENSACOLA REGIONAL AP	FL	87.1830	30.4830	943.8175	-1004.7419	1058.7680	3386.7280	15
13934	747540	ENGLAND AFB	LA	92.5500	31.3170	423.9314	-952.2589	542.8170	3464.8220	15
13935	722487	ALEXANDRIA ESLER REGIONAL AP	LA	92.3000	31.4000	447.2483	-941.8144	566.5460	3474.1450	15
13942	722486	MONROE REGIONAL AP	LA	92.0330	32.5170	465.8337	-816.2109	590.8240	3598.1560	15
13957	722480	SHREVEPORT REGIONAL ARPT	LA	93.8170	32.4500	298.8685	-831.1667	423.2080	3590.6100	15
13970	722317	BATON ROUGE RYAN ARPT	LA	91.1500	30.5330	562.7725	-1032.0620	677.4820	3379.3040	15
13976	722405	LAFAYETTE REGIONAL AP	LA	91.9830	30.2000	484.7807	-1074.0300	597.8930	3341.3840	15
53905	722484	SHREVEPORT DOWNTOWN	LA	93.7500	32.5330	304.8272	-821.7132	429.5710	3599.7650	15
53917	722315	NEW ORLEANS LAKEFRONT AP	LA	90.0330	30.0500	674.1718	-1078.3416	786.0810	3328.0370	15
93919	722358	MCCOMB PIKE COUNTY AP	MS	90.4670	31.2330	622.7553	-949.6183	741.2620	3458.1910	15
722069	722069	DESTIN FT. WALTON	GA	86.4670	30.4000	1013.4295	-1006.2527	1128.2180	3381.2830	15
722276	722276	EVERGREEN	AL	87.0500	31.4170	945.1591	-899.6924	1066.0040	3491.1710	15
722312*	722312	HAMMOND	LA	90.4170	30.5170	633.3004	-1029.0216	747.8640	3378.9140	15

Table 6.1 (cont.)

Surface Stations

WBAN	USAF	Name	State	Geographic Location		LCC		UTM Coordinates		Zone
				Longitude (deg)	Latitude (deg)	Easterly (km)	Northerly (km)	Easterly (km)	Northerly (km)	
722319*	722319	NATCHITOCHES	LA	93.1000	31.7330	369.5797	-908.3226	490.5270	3510.8460	15
722329*	722329	PATTERSON MEMORIAL	LA	91.3330	29.7170	550.8803	-1124.2950	661.2440	3288.5900	15
722347*	722347	HATTIESBURG MUNI	MS	89.2500	31.2670	738.1833	-936.7234	857.1150	3465.2640	15
722348*	722348	PINE BELT RGNL AWOS	MS	89.3330	31.4670	728.4160	-915.1646	848.4650	3487.1850	15
722354*	722354	HAWKINS FIELD	MS	90.2170	32.2130	638.3983	-838.9472	762.3050	3567.4430	15
722357*	722357	NATCHEZ/HARDY(AWOS)	MS	91.3000	31.6170	540.7777	-912.2194	661.2490	3499.2390	15
722366*	722366	SLIDELL	LA	89.8170	30.3500	692.3811	-1043.2610	805.9880	3361.8670	15
722403*	722403	SALT POINT (RAMOS)	LA	91.3000	29.6000	554.9055	-1137.1746	664.6270	3275.6700	15
722488*	722488	VICKSBURG\TALLULAH	LA	91.0330	32.2500	561.4463	-840.2241	685.3040	3569.8450	15
747685*	747685	GULFPORT BILOXI INT	MS	89.0670	30.4000	764.0119	-1031.6801	877.9440	3369.6810	15
747688*	747688	PASCAGOULA	MS	88.5330	30.4670	814.5995	-1019.5829	929.0130	3379.0250	15
994010*	994010	SOUTHWEST PASS	LA	89.4330	28.9000	742.8224	-1202.1420	847.8800	3202.1440	15
994260*	994260	SABINE	TX	94.0500	29.6670	287.0827	-1142.4170	398.3910	3282.3480	15
994290*	994290	GRAND ISLE	LA	89.9670	29.2670	687.3269	-1165.2992	794.7240	3241.3830	15
994420*	994420	DAUPHIN ISLAND	AL	88.0830	30.2500	860.1348	-1039.5895	973.3280	3356.7350	15

*A pseudo-WBAN number was assigned for the missing WBAN number.

Note: 722312 and 722319 data for 2003, only. 994290 data for 2002 and 2003.

Table 6.2

Upper Air Stations

WBAN	Name	State	Geographic Location		LCC		UTM Coordinates			Time Zone
			Longitude	Latitude	Easterly	Northerly	Easterly	Northerly	Zone	
			(deg)	(deg)	(km)	(km)	(km)	(km)		
3937	LAKE CHARLES/MUNICIPAL ARPT	LA	93.2170	30.1170	366.0080	-1089.0806	479.0950	3331.7700	15	6
3940	JACKSON/THOMPSON FIELD	MS	90.0830	32.3170	650.1048	-826.4515	774.6250	3579.3130	15	6
13957	SHREVEPORT REGIONAL ARPT	LA	93.8170	32.4500	298.8685	-831.1667	423.2080	3590.6100	15	6
53813	Slidell	LA	89.8200	30.3330	692.2422	-1045.1795	805.7520	3359.9730	15	6

Table 6.3

Precipitation Stations

WBAN	Name	State	Geographic Location		LCC		UTM Coordinates		Zone
			Longitude (deg)	Latitude (deg)	Easterly (km)	Northerly (km)	Easterly (km)	Northerly (km)	
10402	ATMORE ST NURSERY	AL	87.4800	31.1700	907.3470	-931.4728	1026.4160	3461.5930	15
12172	DAUPHIN ISLAND 2	AL	88.0800	30.2500	860.4231	-1039.5606	973.6170	3356.7480	15
14193	JACKSON	AL	87.9000	31.5000	863.7734	-898.9469	984.6100	3496.3040	15
15478	MOBILE WSO ARPT	AL	88.2500	30.6800	839.4557	-993.3103	955.2230	3403.7810	15
16370	PETERMAN 2 SW	AL	87.2800	31.5500	921.8113	-887.3103	1043.3170	3504.7780	15
160549	BATON ROUGE WSO AP	LA	91.1300	30.5300	564.7158	-1032.2716	679.4070	3379.0040	15
161246	BRUSLY 2 W	LA	91.2700	30.3800	552.3220	-1049.8663	666.2280	3362.1630	15
161287	BUNKIE	LA	92.1700	30.9500	462.2752	-991.3118	579.2790	3424.3560	15
161899	CLINTON 5 SE	LA	90.9700	30.8000	578.0857	-1001.1644	694.2190	3409.1990	15
162534	DONALDSONVILLE 4 SW	LA	91.0300	30.0700	577.6989	-1082.9764	689.8870	3328.1780	15
164030	HAMMOND 5 E	LA	90.3700	30.5000	637.9519	-1030.5884	752.4190	3377.1330	15
164696	JENA 4 WSW	LA	92.2000	31.6700	455.1667	-911.2527	575.8350	3504.1370	15
164700	JENNINGS	LA	92.6700	30.2000	418.4516	-1077.4440	531.7640	3340.9930	15
164739	JONESVILLE LOCKS	LA	91.8500	31.4800	489.5216	-930.5864	609.2360	3483.3720	15
165021	LAFAYETTE	LA	92.0700	30.2200	476.2609	-1072.2560	589.5000	3343.5290	15
165078	LK CHARLES WSO ARPT	LA	93.2200	30.1200	365.7043	-1088.7573	478.8070	3332.1030	15
165620	LSU BEN-HUR EXP STN	LA	91.1700	30.3700	562.0197	-1050.3686	675.8560	3361.2060	15
165624	LSU CITRUS RESEARCH	LA	89.8300	29.5800	697.9226	-1129.2767	807.0990	3276.4440	15
166394	MORGAN CITY	LA	91.1800	29.6800	565.9980	-1127.4904	676.1100	3284.7130	15
166582	NATCHITOCHES	LA	93.0800	31.7700	371.2965	-904.1217	492.4250	3514.9450	15
166660	NEW ORLEANS WSMO A	LA	90.2500	29.9800	653.7943	-1087.7382	765.3360	3319.7530	15
166664	NEW ORLEANS AUDUBON	LA	90.1300	29.9200	665.9020	-1093.5644	777.0850	3313.3840	15
168539	SLIDELL WSFO	LA	89.7700	30.2500	697.7904	-1054.0494	810.8240	3350.9050	15
169357	VIDALIA 2	LA	91.4700	31.5800	524.9196	-917.3335	645.1790	3494.8990	15
169803	WINNFIELD 2 W	LA	92.6800	31.9300	408.3095	-884.5962	530.2490	3532.7210	15
220797	BILOXI 9 WNW	MS	89.0300	30.4500	767.0762	-1025.8008	881.3070	3375.3520	15
221094	BROOKHAVEN CITY	MS	90.4500	31.5500	621.8265	-914.2358	742.0660	3493.3780	15

Table 6.3 (cont.)

Precipitation Stations

WBAN	Name	State	Geographic Location		LCC		UTM Coordinates		Zone
			Longitude	Latitude	Easterly	Northerly	Easterly	Northerly	
			(deg)	(deg)	(km)	(km)	(km)	(km)	
221852	COLLINS	MS	89.5700	31.6300	704.4664	-898.9216	825.3640	3504.5360	15
224966	LEAKESVILLE	MS	88.5500	31.1500	805.8855	-943.7804	924.3570	3454.7610	15
225074	LIBERTY 2 E	MS	90.7700	31.1700	594.4002	-958.6598	712.5360	3450.5840	15
225704	MEADVILLE	MS	90.8800	31.4700	581.6693	-925.9825	701.4100	3483.6370	15
226718	PASCAGOULA 3 NE	MS	88.4800	30.4000	820.3849	-1026.5636	934.4060	3371.7920	15
227220	PURVIS 2 N	MS	89.4000	31.1500	725.0195	-950.9404	843.2440	3451.8080	15
227444	RICHTON 3 SSE	MS	88.9000	31.3000	771.1068	-930.1499	890.3350	3470.1130	15
227714	RUTH 1 SE	MS	90.3000	31.3700	637.5207	-933.2165	756.8020	3473.7600	15
227840	SAUCIER EXP FOREST	MS	89.0500	30.6300	763.3987	-1005.9288	878.6840	3395.2550	15
229048	TYLERTOWN 2 WNW	MS	90.1800	31.1200	651.0093	-960.1830	768.9280	3446.3230	15
229617	WHITE SAND	MS	89.6800	30.8000	701.5116	-992.0814	817.6920	3412.1540	15
229648	WIGGINS RANGER STN	MS	89.1500	30.8500	751.7006	-982.2792	868.2510	3419.3290	15

Note: 2001 missing 164700, 166394, 166664, 220797 AND 229617

Note: 2002 missing 15478, 160549, 165078 and 166660

Note: 2003 missing 227714

Table 6.4
Buoy Stations

NODC	Name	State	Geographic Location		LCC		UTM Coordinates		Zone
			Longitude (deg)	Latitude (deg)	Easterly (km)	Northerly (km)	Easterly (km)	Northerly (km)	
42040	MOBILE SOUTH 64 NM SOUTH OF DAUPHIN ISLAND	AL	88.2000	29.2080	860.1680	-1156.8460	966.8688	3240.5876	15
42007	BILOXI 22 NM SOUTH-SOUTHEAST OF BILOXI	MS	88.7690	30.0900	795.7710	-1063.6580	907.8873	3336.3177	15

6.2 Geophysical Data

Land Use Data. Land Use Data are used to develop the surface characteristic for input to the CALMET model. The best large-scale land use data sets are the USGS National Land Cover Datasets (NLCD 92), which have a 30-meter resolution. Data extracted from these data sets are used as raw data input to the CTGPROC program to calculate surface characteristics for input to the CALMET program. Figure 6.5 shows land use for each grid cell (output from ctgproc.exe and makegeo.exe).

Terrain Data. Terrain data is used by the CALMET model to modify the Initial Guess Wind Fields in developing the Step 1 Wind Fields. USGS 1:250,000 scale Digital Elevation Model (DEM) data are used as the raw data input to the TERREL program to calculate elevations for input to the CALMET program. Figure 6.5 shows contours based on the elevation of the center of each grid cell (output from terrel.exe).

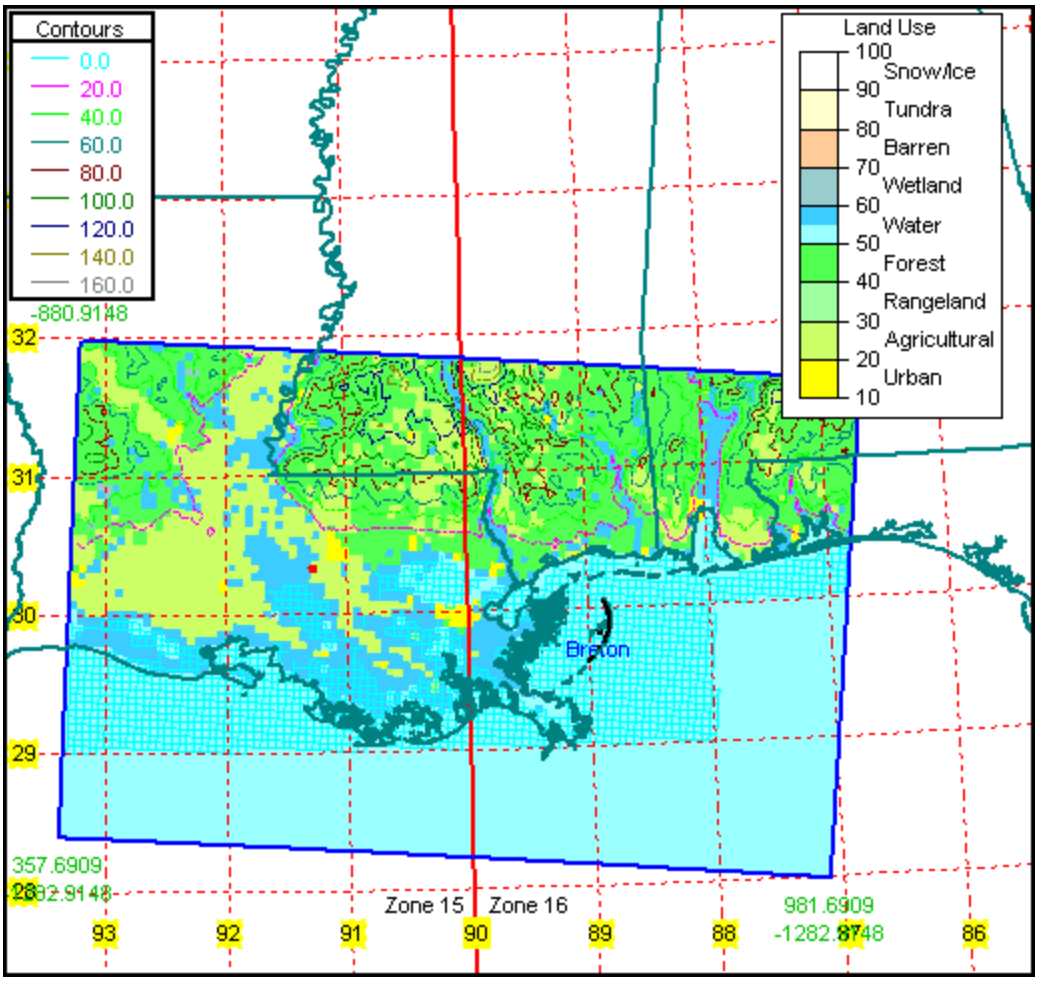

Figure 6.5 Land Use and Terrain

6.3 Preparing Data for CALMET

SMERGE. The SMERGE program reads multiple surface data files that may be in several different formats, makes any needed units conversion, and writes the combined data to a single file (surf.dat). The surf.dat file is read by CALMET as observations and is used in the modification of the Step 1 Wind Fields in developing the Step 2 Wind Fields.

READ62. The READ62 program reads an upper air data file and a substitution file, extracts soundings, makes any needed units conversion, substitutes for missing or bad data from the substitution file, and writes the data to a processed data file (*.ua) for each upper air station. The substitution file is an extraction of the nearest CALMM5 node. READ62 is repeated for each upper air file. Any data errors flagged in the READ62 output files are corrected and documented in the upper air list (.lst) files for each station. The processed data files are read by CALMET as observations and are used in the modification of the Step 1 Wind Fields in developing the Step 2 Wind Fields.

PXTRACT and PMERGE. PXTRACT and PMERGE extract data for specific stations and combine the data into a single processed data file (PRECIP.DAT). The processed data file is read by CALMET as observations and is used in the modification of the Step 1 Wind Fields in developing the Step 2 Wind Fields.

CTGPROC. CTGPROC reads land use data and calculates weighted land use for each grid cell in the modeling domain and writes a processed data file.

TERREL. TERREL reads terrain data, calculates the elevation of the center of each grid cell in the modeling domain, and writes a processed data file.

MAKEGEO. MAKEGEO reads the processed data files from CTGPROC and TERREL. MAKEGEO calculates weighted surface characteristics and writes these characteristics along with the terrain elevations to a processed data file (MAKEGEO.DAT). The processed data file is used by the CALMET model to modify the Initial Guess Wind Fields in developing the Step 1 Wind Fields. Figure 6.3 shows the land use for each grid cell and topographic lines based on the terrain elevation at the center of each grid cell.

6.4 CALMET Options

MREG. The regulatory default option, MREG, was set to one (1 = required).

NoObs. The NoObs option was set to zero so that surface and upper air stations were required. Overwater (buoy) data and precipitation data were also used.

EPA-FLM Recommended Settings. The major CALMET EPA/FLM Recommended Settings are shown in Table 6.5. All settings are as required by the Clarification Memorandum of August 31, 2009.

Table 6.5
EPA-FLM CALMET Settings

Parameter	Description	CALMET Default	EPA/FLM Value
TERRAD	Radius of Influence of Terrain	None	15
RMAX1	Max. radius of influence over land in surface layer	None	100
RMAX2	Max. radius of influence over land in layers aloft	None	200
RMAX3	Max. radius of influence over water	None	200
R1	Relative weighting in surface layer	None	50
R2	Relative weighting in the aloft layer	None	100

7. CALPUFF Analysis

The CALPUFF model calculates transport and dispersion using the three-dimensional Meteorological Grid created by CALMET. The technical options that were used in CALPUFF are listed in Appendix B, which is a CALPUFF input file for 2001.

The CALPUFF default values for particle size parameters and scavenging coefficients for sulfate and nitrate particles are used.

Ammonia. As in the 2007 analysis, a constant background ammonia concentration of 3.0 parts per billion (ppb) was used as input to CALPUFF for calculating chemical transformation using the MESOPUFF II chemical transformation procedure.

Ozone. The hourly ozone files from the 2007 analysis were used. Monthly average values were calculated for each month to be used for missing data. Table 7.1 lists the average ozone values for each month.

Table 7.1
Average Monthly Ozone Background Concentrations (ppb)

Month	2001	2002	2003
January	20.87535	23.12891	24.92080
February	25.09028	29.52795	24.28612
March	34.87327	31.38484	33.93057
April	36.24034	33.80058	37.85152
May	38.01718	35.46679	39.30647
June	34.46120	32.98103	33.02329
July	35.22554	29.20031	28.53507
August	33.63565	37.03028	33.90635
September	27.97368	35.61813	33.09259
October	28.62675	20.19771	30.40248
November	24.67059	24.26124	22.96470
December	21.96526	21.46122	24.35795

Receptors. In accordance with EPA-FLM guidance, the required discrete receptor locations contained in the NPS database for Class I areas are used in the CALPUFF analysis. Each receptor provided by this database has an associated terrain height. Table 7.2 shows the receptors for the Breton NWR.

Table 7.2

NPS Receptors for Breton NWR Class I Area

Geographic Location		LCC		UTM Coordinates			Ground Elevation
Longitude	Latitude	Easterly	Northerly	Easterly	Northerly	Zone	
(deg)	(deg)	(km)	(km)	(km)	(km)		(m)
89.0042	29.6208	777.7102	-1118.0130	887.0070	3283.4487	15	0
88.9792	29.6375	779.9709	-1115.9389	889.3661	3285.3817	15	0
88.9708	29.6458	780.6968	-1114.9374	890.1416	3286.3343	15	0
88.9625	29.6542	781.4225	-1113.9359	890.9169	3287.2870	15	0
88.9125	29.7208	785.6071	-1106.0668	895.5004	3294.8538	15	0
88.8708	29.7625	789.2269	-1101.0580	899.3700	3299.6204	15	0
88.8625	29.7875	789.7834	-1098.1972	900.0770	3302.4232	15	0
88.8458	29.8042	791.2295	-1096.1934	901.6233	3304.3305	15	1
88.8458	29.8125	791.1458	-1095.2640	901.5899	3305.2551	15	1
88.8375	29.8292	791.7848	-1093.3328	902.3293	3307.1335	15	1
88.8375	29.8375	791.7011	-1092.4035	902.2959	3308.0581	15	1
88.8292	29.8542	792.3396	-1090.4724	903.0349	3309.9365	15	1
88.8292	29.8625	792.2559	-1089.5431	903.0013	3310.8612	15	1
88.8292	29.8708	792.1721	-1088.6139	902.9677	3311.7858	15	1
88.8292	29.8792	792.0883	-1087.6848	902.9341	3312.7104	15	1
88.8292	29.8875	792.0046	-1086.7556	902.9005	3313.6350	15	0
88.8292	29.8958	791.9208	-1085.8265	902.8669	3314.5597	15	0
88.8292	29.9125	791.7533	-1083.9682	902.7997	3316.4089	15	0
88.8208	29.9125	792.5586	-1083.8956	903.6052	3316.4382	15	1
88.8208	29.9208	792.4747	-1082.9665	903.5715	3317.3629	15	1
88.8292	29.9292	791.5858	-1082.1101	902.7324	3318.2582	15	0
88.8208	29.9292	792.3909	-1082.0375	903.5378	3318.2875	15	1
88.8292	29.9375	791.5020	-1081.1811	902.6988	3319.1828	15	0
88.8208	29.9375	792.3071	-1081.1085	903.5041	3319.2121	15	1
88.8292	29.9458	791.4182	-1080.2521	902.6651	3320.1074	15	1
88.8292	29.9542	791.3345	-1079.3231	902.6315	3321.0321	15	1
88.8375	29.9625	790.4459	-1078.4666	901.7927	3321.9274	15	0
88.8292	29.9625	791.2507	-1078.3941	902.5978	3321.9567	15	1
88.8375	29.9708	790.3623	-1077.5376	901.7591	3322.8520	15	0
88.8292	29.9708	791.1670	-1077.4651	902.5641	3322.8813	15	1
88.8375	29.9792	790.2786	-1076.6087	901.7254	3323.7766	15	0
88.8375	29.9875	790.1949	-1075.6798	901.6918	3324.7013	15	0
88.8375	29.9958	790.1113	-1074.7509	901.6582	3325.6259	15	1
88.8458	30.0042	789.2232	-1073.8944	900.8198	3326.5213	15	0
88.8458	30.0125	789.1397	-1072.9655	900.7862	3327.4459	15	0
88.8542	30.0208	788.2519	-1072.1090	899.9480	3328.3413	15	0
88.8542	30.0292	788.1684	-1071.1802	899.9144	3329.2659	15	1
88.8625	30.0375	787.2808	-1070.3236	899.0764	3330.1614	15	0
88.8708	30.0458	786.3934	-1069.4669	898.2385	3331.0569	15	0
88.8792	30.0542	785.5062	-1068.6102	897.4007	3331.9525	15	0

8. POSTUTIL and CALPOST Analysis

CALPOST is the CALPUFF modeling system post-processor that computes the final modeling results. CALPOST performs averaging and ranking of the concentration or deposition files derived from CALPUFF or POSTUTIL. CALPOST is processed individually for each impact-of-interest (e.g., concentrations, visibility impacts, and total deposition of sulfur and nitrogen). The technical options that were used in POSTUTIL are listed in Appendix C, which is a POSTUTIL input file for 2001. The technical options that were used in CALPOST are listed in Appendix D, which is a CALPOST input file for 2001.

POSTUTIL. POSTUTIL was used to re-compute the HNO_3/NO_3 concentration partition for the TOTAL (all sources) concentration fields (SO_4, NO_3, HNO_3; NH_3) (MNITRATE = 1). A monthly average of 3.0 parts per billion (ppb) was used for ammonia.

Visibility. The CALPUFF modeling system is used to predict the impacts that the Project emissions will have at the Breton NWR Class I Area. The CALPOST postprocessor uses the POSTUTIL concentrations to calculate the change in light extinction due to the project emissions. CALPOST includes several methods to calculate visibility. Following the EPA-FLM guidance, the IMPROVE (2006) formulation (MFRH = 4) was used along with Method 8 (MVISBK = 8), Mode 5 (M8_MODE = 5). Values from the FLAG2010 guidance document were used for the relative humidity adjustment factors and for the background concentrations for average conditions.

The background conditions and relative humidity factors for Method 8 for the Breton NWR are from the *Federal Land Managers' Air Quality Related Values Workgroup (FLAG), Phase I Report – Revised (2010).* Table 8.1 shows the relative humidity adjustment factors for Breton NWR and Table 8.2 shows the monthly background concentrations for average conditions for Breton NWR.

Table 8.1

Monthly Average Relative Humidity Adjustment Factors for the Breton NWR Class I Area

Month	Large SO4 and NO3	Small SO4 and NO3	Sea Salt
January	2.91	4.08	4.10
February	2.76	3.82	3.89
March	2.74	3.79	3.87
April	2.72	3.74	3.85
May	2.83	3.94	4.02
June	2.94	4.12	4.21
July	3.10	4.41	4.44
August	3.07	4.37	4.38
September	2.97	4.18	4.23
October	2.82	3.92	3.99
November	2.83	3.93	4.01
December	2.90	4.06	4.11

Table 8.2

Monthly Background Concentrations for the Breton NWR Class I Area

Month	Ammonium Sulfate	Ammonium Nitrate	Organic Mass	Elemental Carbon	Soil	Coarse Mass	Sea Salt
	($\mu g/m^3$)	($\mu g/m^3$)	($\mu g/m^3$)	($\mu g/m^3$)	($\mu g/m^3$)	($\mu g/m^3$)	($\mu g/m^3$)
January	0.23	0.1	1.78	0.02	0.48	3.01	0.19
February	0.23	0.1	1.78	0.02	0.48	3.01	0.19
March	0.23	0.1	1.78	0.02	0.48	3.01	0.19
April	0.23	0.1	1.78	0.02	0.48	3.01	0.19
May	0.23	0.1	1.78	0.02	0.48	3.01	0.19
June	0.23	0.1	1.78	0.02	0.48	3.01	0.19
July	0.23	0.1	1.78	0.02	0.48	3.01	0.19
August	0.23	0.1	1.78	0.02	0.48	3.01	0.19
September	0.23	0.1	1.78	0.02	0.48	3.01	0.19
October	0.23	0.1	1.78	0.02	0.48	3.01	0.19
November	0.23	0.1	1.78	0.02	0.48	3.01	0.19
December	0.23	0.1	1.78	0.02	0.48	3.01	0.19

9. Results

The highest 98th percentile impact of the Addis plant at the Breton NWR Class I Area was 0.397 delta-deciviews for 2002 for the individual years and 0.344 delta-deciviews for the combined period. This is well below the standard of 0.5 delta-deciviews

Table 9.1

Visibility Impacts at Breton NWR

For Each Year (delta-dv)

Day	Year of Meteorological Data		
	Breton NWR		
	2001	2002	2003
1st Highest	0.631	0.766	0.735
2nd Highest	0.594	0.659	0.691
3rd Highest	0.534	0.600	0.475
4th Highest	0.469	0.568	0.385
5th Highest	0.418	0.527	0.373
6th Highest	0.391	0.479	0.355
7th Highest	0.370	0.426	0.344
8th Highest (98th Percentile)	0.316	0.397	0.340

Table 9.2

Visibility Impacts at Breton NWR

For the Period 2001-2003 (delta-dv)

High Ranking	Impact (delta-dv)	Year	Day
1	0.766	2002	285
2	0.735	2003	210
3	0.691	2003	309
4	0.659	2002	363
5	0.631	2001	5
6	0.600	2002	202
7	0.594	2001	353
8	0.568	2002	258
9	0.534	2001	229
10	0.527	2002	201
11	0.479	2002	237
12	0.475	2003	310
13	0.469	2001	226
14	0.426	2002	205
15	0.418	2001	190
16	0.397	2002	213
17	0.391	2001	191
18	0.385	2003	150
19	0.373	2003	294
20	0.370	2001	202
21	0.355	2003	104
22 (8th Percentile)	0.344	2003	31