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Cc: Donaldson, Guy[Donaldson.Guy@epa.gov]; vivian.aucoin@la.gov[vivian.aucoin@la.gov]; kmcque1@entergy.com[kmcque1@entergy.com]; allison.mallick@bakerbotts.com[allison.mallick@bakerbotts.com]
From: debra.jezouit@bakerbotts.com
Sent: Tue 6/20/2017 1:24:30 AM
Subject: Comments of Entergy Louisiana, LLC on Proposed Louisiana BART SIP Approval
Entergy Comments on LA RH SIP.pdf

Mr. Coleman:

Attached please find comments submitted by Entergy Louisiana, LLC on EPA's proposed approval of Louisiana's state implementation plan to address best available retrofit technology for certain electric generating units. 82 Fed. Reg. 22,936 (May 19, 2017). A copy of these comments has been submitted electronically to the docket through regulations.gov.

If you have any questions about these comments, please do not hesitate to contact me or Kelly McQueen.

Regards,

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Ex. 6 - Personal Privacy

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Kelly McQueen
Assistant General Counsel

June 19, 2017

Mr. Samuel Coleman
Acting Regional Administrator
U.S. Environmental Protection Agency
Region 6
1445 Ross Avenue, Suite 700
Dallas, TX 75202-2733

Re: Proposed Approval and Promulgation of Implementation Plans; Louisiana; Regional Haze State Implementation Plan, EPA-R06-OAR-2017-0129

Dear Mr. Coleman:

Entergy Louisiana, LLC (Entergy) respectfully submits the following comments on EPA's Proposed Approval and Promulgation of Implementation Plans; Louisiana; Regional Haze State Implementation Plan, 82 Fed. Reg. 22,936 (May 19, 2017) (Proposed Rule).

Entergy urges EPA to incorporate these comments into its final action on the Proposed Rule. While Entergy agrees with EPA that Louisiana's participation in the Cross State Air Pollution Rule (CSAPR) satisfies Best Available Retrofit Technology (BART) obligations for emissions of nitrogen oxides (NOx) from Louisiana's electric generating units (EGUs), Entergy believes that EPA's analysis supporting other elements of the Proposed Rule are fundamentally flawed. Specifically, the CAMx and CALPUFF modeling that support the rulemaking contain significant defects, making the modeling far less reliable than the CAMx modeling Entergy submitted to the Agency in November 2015. The more reliable results from Entergy's modeling clearly indicate that Entergy's BART-eligible facilities in Louisiana should not be determined to be subject to BART. Nevertheless, Entergy agrees with the proposed BART limits for these units.

Thank you for considering these comments. We are happy to answer any follow up questions.

Sincerely,

Kelly M. McQueen
Assistant General Counsel – Environmental (Lead)
Entergy Services, Inc.

Attachment:

Comments of Entergy Louisiana, LLC

cc: Vivian Aucoin, Louisiana Department of Environmental Quality
Guy Donaldson, Chief, EPA Region 6 Air Planning Section

Entergy Louisiana LLC

Comments

On the Proposed Approval and Promulgation of Implementation Plans; Louisiana; Regional Haze State Implementation Plan

Docket No. EPA-R06-OAR-2017-0129

Submitted on:
June 19, 2017

To:

U.S. Environmental Protection Agency
1445 Ross Avenue, Suite 700
Dallas, Texas 75202-2733

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Introduction

On May 19, 2017, the U.S. Environmental Protection Agency (EPA) published a proposed rule in the *Federal Register*, at 82 Fed. Reg. 22,936 (Proposed Rule),[1] that would approve a majority of the revisions to the Louisiana State Implementation Plan (SIP) submitted by the Louisiana Department of Environmental Quality (LDEQ) on February 10, 2017, to address regional haze requirements for the first planning period.[2] The Proposed Rule would approve best available retrofit technology (BART) requirements for sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter (PM) for several electric generating units (EGUs) located at power plants owned and operated by Entergy Louisiana, LLC (Entergy): the Waterford Generating Plant (Waterford), the Willow Glen Electric Generating Plant (Willow Glen), the Ninemile Point Electric Generating Plant (Ninemile), and the Little Gypsy Generating Plant (Little Gypsy).

Entergy supports portions of EPA's proposed partial approval of LDEQ's SIP revision, but objects to a number of significant issues in EPA's evaluation of Entergy's previously submitted Comprehensive Air Quality Model with Extensions (CAMx) modeling and EPA's own CAMx assessment. Specifically, EPA should reconsider its evaluation of Entergy's CAMx modeling, as the Agency's concerns about the accuracy of these modeling results are unfounded. These comments address technical issues related to EPA's assessment of Entergy's CAMx modeling analyses, as well as problems with EPA's own CAMx modeling methodology and performance evaluation. The comments also address deficiencies with the CALPUFF modeling

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[1] Proposed Rule, Approval and Promulgation of Implementation Plans; Louisiana; Regional Haze State Implementation Plan, 82 Fed. Reg. 22,936-49 (May 19, 2017), Docket No. EPA-R06-OAR-2017-0129-0001 (Proposed Rule).

[2] Louisiana Department of Environmental Quality, Regional Haze State Implementation Plan: EGU BART Analysis, Final (Feb. 2017), Docket No. EPA-R06-OAR-2017-0129-0002 (SIP Revision Submittal).

system, as described in previous Entergy submittals to EPA and LDEQ. Although EPA has opted to defer its decision regarding Entergy's Roy S. Nelson Electric Generating Plant (Nelson) to a future rulemaking, EPA's CAMx modeling assessment included the Nelson facility. Therefore, in addition to problems with EPA's general CAMx modeling approach, Entergy has also identified specific problems related to EPA's modeling of Nelson. Importantly, Entergy's CAMx modeling remains the most reliable estimation of visibility impacts from Entergy's BART-eligible facilities, and demonstrates that these facilities should not be subject to BART.

Nonetheless, given that LDEQ has determined, based on CALPUFF modeling, that Waterford, Willow Glen, Ninemile and Little Gypsy are subject to BART, Entergy supports the BART limits LDEQ proposed for the units. These limits will fulfill the BART obligations for these units imposed by the statute. Although Entergy recognizes that LDEQ may need to evaluate controls for these units in the future to address reasonable progress requirements, that will be a separate analysis and will not affect the BART requirements for these units.

These comments also support EPA's conclusion that Louisiana's participation in the Cross State Air Pollution Rule (CSAPR) trading program for ozone-season NO_X satisfies BART obligations for NO_X emissions.

Comments

I. EPA Should Reconsider Its Evaluation of Entergy's Previously Submitted CAMx Modeling

Entergy submitted an initial CAMx modeling assessment as part of its BART screening analysis on November 9, 2015 (November 2015 Submittal).[3] This modeling utilized maximum annual emission rates from the original baseline period of 2000-2004, and evaluated impacts

[3] Trinity Consultants, Updated BART Applicability Screening Analysis, (Nov. 9, 2015). Submitted to Mr. Guy Donaldson (EPA) by Ms. Debra J. Jezouit (Counsel to Entergy) on Nov. 9, 2015 (November 2015 Submittal).

using the post-processing methodology for CAMx visibility assessments that was employed in the modeling performed for EPA as part of the Oklahoma and Texas Regional Haze Federal Implementation Plan (Texas Reasonable Progress FIP).[4] The results presented in the November 2015 Submittal demonstrate that Entergy's BART-eligible sources contribute only minimally to visibility impairment at Class I areas. At both the Breton Wilderness Area (Breton) and the Caney Creek Wilderness Area (Caney Creek), the maximum impacts from any facility during the worst 20% (W20%) visibility days was 0.025 deciviews (dv) at Breton from the Waterford Plant, supporting a conclusion that Entergy's sources should not be subject to BART.[5]

On March 16, 2016, EPA provided an initial response to the November 2015 Submittal, requesting the following:

- "Use of emissions representative of maximum 24-hr actual emissions from the baseline period
- Evaluation of the maximum modeled impact for all days, not just the subset of 20% Worst days
- Calculation of the deciview visibility impact based on a natural visibility background approach using the annual average natural background conditions for each Class I area."[6]

EPA's requested updates required Entergy to revise its CAMx modeling using technical assumptions that rendered the modeling results unreliable. Nevertheless, Entergy attempted to comply with EPA's requests and submitted a revised CAMx modeling report on June 30, 2016 (June 2016 Submittal).[7] Even using the unrealistic emission rates and overly conservative post-

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[4] EPA, Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans (Nov. 2014), Docket No. EPA-R06-OAR-2014-0754-0007 (Texas Reasonable Progress FIP TSD).

[5] Trinity Consultants & All4 Inc., CAMx Modeling Report, at 4-1, (Oct. 14, 2016). Submitted to Ms. Vivian Aucoin and Ms. Vennetta Hayes (LDEQ) by Ms. Kelly McQueen (Entergy) on Oct. 14, 2016 (2016 CAMx Modeling Report).

[6] Letter from Mr. Guy R. Donaldson to Ms. Kelly McQueen, "EPA Preliminary Review Response," (Mar. 16, 2016) (March 2016 Letter).

[7] Trinity Consultants, BART Applicability CAMx Modeling Report, (Jun. 30, 2016). Submitted to Mr. Guy Donaldson (EPA) by Ms. Kelly McQueen (Entergy) on Jun. 30, 2016 (June 2016 Submittal).

processing approach requested by EPA, this analysis showed that Entergy's units still only marginally contributed to visibility impairment at Breton and Caney Creek. During subsequent conversations with EPA regarding the CAMx modeling, EPA indicated that it would require Entergy to evaluate its CAMx modeling results using direct model output as opposed to the method EPA described in the Texas Reasonable Progress FIP TSD, which used relative response factors (RRFs) paired with monitor data.

Entergy submitted a thorough repudiation of EPA's technically unsound modeling requests to LDEQ on October 14, 2016 (2016 CAMx Modeling Report).[8] EPA responded to LDEQ with a preliminary review of Entergy's CAMx modeling on March 10, 2017.[9] This document critiqued the modeled emission rates and post-processing methodology utilized in Entergy's submittals and provided additional arguments against the use of RRFs. Entergy reviewed the information in this document and provided a response to LDEQ in an April 6, 2017 letter, which reiterated Entergy's positions regarding the proper application of the CAMx modeling system (April 2017 Letter).[10]

Although, as stated in its previous submittals, it is Entergy's position that the November 2015 Submittal presents the most technically reliable results for evaluating Entergy's BART-eligible units,[11] EPA's assessment of Entergy's CAMx modeling in its CAMx Modeling Technical Support Document (CAMx Modeling TSD) is similar to EPA's March 10, 2017,

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[8] 2016 CAMx Modeling Report, at 5-1 - 5-2.

[9] Feldman, Michael, EPA Region 6, Review of CAMx BART Modeling performed by Trinity Consultants for Louisiana Regional Haze, (Mar. 8, 2017) (March 2017 Review).

[10] Letter from Ms. Kelley McQueen to Ms. Vivian Aucoin, "Entergy's review of documents provided to LDEQ by U.S. EPA Region 6 on March 10, 2017: 'DRAFT BART Analysis for the Nelson Unit 6' and associated cost calculations spreadsheet; 'Review of CAMx BART Modeling performed by Trinity Consultants for Louisiana Regional Haze'" (Apr. 6, 2017) (April 2017 Letter).

[11] 2016 CAMx Modeling Report, at 1-1.

preliminary review document and primarily focuses on the revised modeling results presented in the June 2016 Submittal.[12] The following comments are intended to add to the discussion in Entergy's 2016 CAMx Modeling Report and the April 2017 Letter, and to respond to additional criticisms in EPA's CAMx Modeling TSD.

A. EPA's Request to Use Maximum 24-Hour Emission Rates Is Inappropriate in the Context of a CAMx Modeling Assessment

As discussed in the CAMx Modeling TSD, Entergy's June 2016 Submittal contained modeling that "utilized 2 times the 2002 actual annual emission rate as 'representative estimates of the maximum 24-hr emissions,'" instead of using continuous emission monitoring (CEM) data to identify actual maximum 24-hour emissions during the baseline period.[13] EPA maintains that use of maximum 24-hour emission rates is a required element of a BART assessment; however, as Entergy explained in the 2016 CAMx Modeling Report, the BART Guidelines "recommend," but do not require, use of maximum 24-hour steady-state emissions.[14]

Modeling capabilities for performing visibility assessments at the time the BART Guidelines were issued were limited primarily to CALPUFF, which was then the best long-range transport model available that was capable of performing single-source assessments.[15] The BART Guidelines were, therefore, not developed with consideration of photochemical grid models (e.g., CAMx) but were instead based on the overly-simplistic CALPUFF modeling system's abilities. Since the time that the BART Guidelines were developed, over 12 years ago,

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[12] EPA, Technical Support Document for Louisiana Regional Haze: CAMx Best Available Retrofit Technology Modeling, at 27-33 (April 2017), Docket No. EPA-R06-OAR-2017-0129-0010 (CAMx Modeling TSD).

[13] CAMx Modeling TSD, at 29.

[14] Guidelines for BART Determinations Under the Regional Haze Rule, 40 C.F.R. pt. 51, App. Y Section III.A.3.2

[15] Final Rule, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, 70 Fed. Reg. 39,104, 39,122 (July 6, 2005) (BART Guidelines).

CALPUFF has been removed as an EPA-preferred model for long-range transport assessments,[16] which indicates it is no longer the best single-source modeling application. Although EPA's removal of CALPUFF as a preferred model does not affect EPA's recommendation that states use CALPUFF to determine the applicability and level of BART,[17] this is an insufficient rationale for continuing to use a model that is outdated and has been demonstrated to overstate predicted impacts. The more rigorous chemistry mechanism and an ability to model complete emissions inventories make CAMx far better-suited to estimate a "maximum daily visibility value" as required by the BART Guidelines.[18] Arbitrarily applying the outdated BART procedures to CAMx modeling assessments is unreasonable and likely to result in mischaracterization of predicted visibility values.

Because representing sources at maximum emission rates during every modeled day is likely to skew the CAMx model's ability to accurately simulate impacts, Entergy's continued position is that the modeled impacts included in the November 2015 Submittal—based on actual annual emissions—best characterize visibility impacts from Entergy's BART-eligible sources in Louisiana.

However, because EPA's discussion in the CAMx Modeling TSD focuses on Entergy's June 2016 Submittal (rather than the November 2015 Submittal), EPA should be aware that the doubled annual emission rates used in the June 2016 Submittal for Entergy's Nelson Unit 6 are similar to the maximum 24-hour emission rates used in EPA's CAMx Modeling, as

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[16] Final Rule, Revisions to the Guideline on Air Quality Models: Enhancements to the AERMOD Dispersion Modeling System and Incorporation of Approaches To Address Ozone and Fine Particulate Matter, 82 Fed. Reg. 5,182, 5,194 (Jan. 17, 2017).

[17] *Id.* at 5,196.

[18] BART Guidelines, 70 Fed. Reg. at 39,121.

demonstrated in Table 1 below. Therefore, EPA should not disregard Entergy's modeling purely on the basis of its modeled emission rates.

Table 1. Comparison of EPA and Trinity's Modeled CAMx Emission Rates

Scenario and Emissions Basis	CAMx Modeled Emission Rates (tpy)					
	SO_2	NO_X	PM_{10}	VOC	CO	$PM_{2.5}$
Entergy's CAMx Modeling (2x Annual)	37,702.84	12,274.80	962.59	82.00	703.00	721.94
EPA's CAMx Modeling (Maximum 24-Hr)	32,601.80	25,520.80[A]	1,513.37	82.00	703.00	1,141.37

[A] The NO_X emission rate that EPA utilized in its modeling is an outlier value and should have been removed from consideration, as EPA did for other sources (*see* Section III.A.3). The NO_X emission rate that should have been used is 15,018.66 tons per year (tpy), representing the highest non-outlier daily NO_X emission rate.

B. EPA's Requested Post-Processing Methodology Is Unreliable and Criticisms of Entergy's Post-Processing Methodology Are Flawed

In the CAMx Modeling TSD, EPA critiques the post-processing methodologies used by Entergy. Entergy has provided comments on multiple occasions as to why its modeling is based on the most technically defensible methodologies: first, in the 2016 CAMx Modeling Report,[19] and again in Entergy's April 2017 letter to LDEQ.[20] The modeling analysis included in the November 2015 Submittal represents the most appropriate post-processing analysis of CAMx modeling results; however, EPA's focus in the CAMx Modeling TSD is on the post-processing approach included in Entergy's June 2016 Submittal. Responses to specific critiques made by EPA regarding this post-processing approach are provided below.

[19] 2016 CAMx Modeling Report, at 5-2.

[20] April 2017 Letter, at 7-9.

1. EPA's Determination that CAMx Outputs Should Be Evaluated Directly Defies Precedent and Prevents Amelioration of Modeling Bias

EPA's CAMx Modeling TSD states that Entergy's June 2016 CAMx modeling—which used RRFs paired with actual monitor data (gathered by the Interagency Monitoring of Protected Visual Environments (IMPROVE) workgroup) to assess visibility impacts—followed a post-processing methodology that is inconsistent with the previously approved Texas BART Screening CAMx Modeling Protocol (Texas BART Protocol) and the BART Guidelines.[21] The Texas BART Protocol is not a binding document and should not automatically be applied in every scenario without considering all relevant circumstances. Further, as described in Section I.A, because the BART Guidelines were originally developed assuming the use of the CALPUFF modeling system, the procedures described in the BART Guidelines may not automatically be appropriate for a CAMx analysis, even if they were appropriate for CALPUFF.

As described fully in Entergy's various responses to EPA's CAMx modeling reviews, the CAMx modeling system, although far superior to CALPUFF, still has potential for modeling bias. EPA stated as much in the Texas Reasonable Progress FIP Response to Comments (Texas Reasonable Progress FIP RTC): (1) CAMx modeling is subject to concerns of modeling bias, and (2) the use of RRFs can reduce the impacts of this modeling bias.[22]

In EPA's CAMx modeling for Louisiana and Texas, EPA ignores its own concerns about modeling bias. Given the relatively poor performance of the model, as demonstrated by the

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[21] Environ International Corporation, Revised Draft Final Modeling Protocol: Screening Analysis of Potentially BART-Eligible Sources in Texas (Sept. 27, 2006). Docket No. EPA-R06-OAR-2017-0129-0012-07.

[22] EPA, Response to Comments for the Federal Register Notice for the Texas and Oklahoma Regional Haze State Implementation Plans; Interstate Visibility Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze; and Federal Implementation Plan for Regional Haze, pp. 563-564, 566, 569, 585 (Dec. 9, 2015). Docket No. EPA-R06-OAR-2014-0754-0087 (Texas Reasonable Progress FIP RTC).

Model Performance Evaluation (MPE), EPA's disregard for potential modeling bias is suspect. And yet, EPA insists in this action that it is still appropriate to evaluate modeled sources based on the absolute maximum, direct-modeled impacts—a metric that provides the highest opportunity for modeling bias to influence regulatory decisions. For example, in the event that CAMx predicts source impacts well outside what might be expected in reality (i.e., an outlier), EPA's approach would select that over-predicted value to characterize visibility impacts from the source.

RRFs are of critical importance in properly evaluating CAMx modeling outputs so that modeling bias is ameliorated. EPA's proposed approach relies too heavily on direct CAMx output values, which are shown by the MPE to be at risk of being unrealistic and overstated. In light of the substantial potential costs to facilities associated with BART determinations, it is thoroughly inappropriate to depend on an approach that disregards known biases.

2. EPA's Assessment of the Averaged RRF Method Utilized in Entergy's June 2016 Submittal is Flawed

In the CAMx Modeling TSD, EPA claims that the averaged RRF method used in Entergy's modeling was not sufficient to represent the maximum estimated impacts from a source. According to EPA, because the best 20% monitored visibility days (B20%) are the days with the least impact from all sources, the maximum impacts from Louisiana's BART-eligible sources are less likely to be captured. Additionally, EPA suggests that visibility at Caney Creek is influenced significantly by sources in Northern Texas and/or the Eastern United States, so W20% monitored visibility days may not represent meteorological conditions that result in high

levels of visibility impacts from BART-eligible sources in Louisiana. Thus, EPA concluded that averaged B20% and W20% RRF values may not contain the modeled maximum impacts. [23]

EPA's analysis is flawed. When using RRFs, the various meteorological conditions and emissions scenarios that may occur throughout the modeled year must be considered, thus ensuring that modeled impacts are as representative of reality as possible. Entergy's June 2016 Submittal used averaged B20% and W20% RRF values to exemplify a wide range of conditions at each Class I area, and although Entergy's November 2015 Submittal contains the most technically defensible representation of CAMx modeled impacts, Entergy believes that this averaged RRF approach is appropriate and captures various meteorology and emissions circumstances necessary to estimate maximum visibility values.

EPA should seek to estimate impacts that are in line with monitored values from the IMPROVE workgroup; that goal is likely best served by use of these averaged RRFs. Given a relatively poor MPE (see Section III.B), using the averaged B20% and W20% RRF values is representative of the range of expected visibility conditions and reduces the potential for overestimation of modeled impacts.

3. EPA Should Not Disregard the Typical RRF Methodology Due to the IMPROVE Workgroup's Sampling Timeline

EPA also argues that, even if it agreed with the use of RRF values for BART assessments, there would not be enough observed data to represent the complete 365 days of modeled data. The IMPROVE Workgroup only records concentrations of visibility-impairing pollutants on every third day, which yields an approximate maximum of 120 days per year of IMPROVE visibility data. Out of 365 days in a year, that leaves approximately 240 days without observed concentrations.

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[23] CAMx Modeling TSD, at 31.

At the core of this argument is the assumption that EPA's direct-modeled, 365-day post-processing approach yields reliable modeled impacts, which Entergy contends is not the case. To comply with the BART Guidelines' goal of determining a maximum daily visibility value, the quality of modeled visibility estimates should be given greater weight than the sheer number of observations. In other words, quality should come before quantity.

Because the use of RRFs in conjunction with real monitoring data is an established procedure used to obtain the most realistic results possible with a minimum of model bias effects, Entergy believes that the RRF approach—although it is limited to only 120 days of monitor data—is a more appropriate method than absolute, direct-modeled impacts. Accordingly, EPA should not disregard Entergy's submitted modeling solely on the basis of the *number* of observations, but should evaluate post-processing methodologies based on the expected *quality* of observations.

II. EPA's Approval of Louisiana's CALPUFF Modeling Is Inappropriate Due to CALPUFF's Inherent Limitations and the Significant Distances between Sources and Class I Areas

On multiple occasions, Entergy has provided thorough explanations of the various limitations of the CALPUFF modeling system, including in the November 2015 Submittal,[24] the 2016 CAMx Modeling Report,[25] and the April 2017 Letter.[26] Entergy supplements the critiques described more fully in those documents with the following additional information.

[24] November 2015 Submittal, at 3-1 - 3-12.

[25] 2016 CAMx Modeling Report, at 2-1 - 3-2.

[26] April 2017 Letter, t 5-6.

A. The CALPUFF Modeling System Is Subject to a Number of Shortcomings that Result in Unreliable Visibility Estimates

One of the most critical flaws of the CALPUFF modeling system is its overly simplistic chemistry algorithms. EPA originally recommended CALPUFF in the BART Guidelines for its ability to simulate chemical transformations of NO_X and SO_2, but CALPUFF's less sophisticated chemistry mechanism (compared to CAMx) has been shown to cause significant modeling bias, which can inappropriately influence rulemaking decisions.

The Central Regional Air Planning Association (CENRAP) prepared a Modeling Protocol in 2005 (CENRAP Protocol) that noted CALPUFF's MESOPUFF-II chemistry algorithm "clearly neglects several environmental parameters and chemical processes that are important in simulating sulfate and nitrate formation in NO_X/SO_2 emissions source plumes."[27] These simplifications in CALPUFF's handling of chemical interactions can often "result in a systematic bias in the estimated concentrations and visibility impacts due to SO_2 and NO_X emissions sources"—often an "overestimation bias" for point sources emitting higher levels of NO_X and SO_2. The CENRAP protocol further states that this overestimation bias may lead to "unwarranted and excessive control of emissions from some sources,"[28] such that "a state or source operator may wish to apply full-science modeling methods to overcome CALPUFF's inherent limitations."[29]

Full-chemistry models like CAMx have significantly more sophisticated algorithms that outclass CALPUFF's oversimplified chemistry mechanism. CALPUFF modeling should therefore be used cautiously, and the tradeoffs between the conservative but simplistic

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[27] Alpine Geophysics, LLC, CENRAP BART Modeling Guidelines, at 3-8 (Dec. 15, 2005) (CENRAP Protocol).

[28] *Id.* at 3-9 - 3-10.

[29] *Id.* at 1-5.

CALPUFF and the more technically reliable CAMx must be considered carefully to avoid using CALPUFF results that bring about a costly mischaracterization of modeled pollutant concentrations.

B. EPA Should Not Rely on CALPUFF Modeling to Support BART Determinations if Sources Are Located Beyond CALPUFF's Allowable Distance Threshold

The Proposed Rule would arbitrarily extend the standard CALPUFF modeling distance threshold of 300 kilometers (km) to greater than 400 km.[30] In effect, EPA is proposing to allow the use of CALPUFF at distances more than 100 km farther than is recommended. This established 300-km threshold was originally determined by EPA's Interagency Workgroup on Air Quality Modeling (IWAQM), which noted that "there are serious conceptual concerns with the use of puff dispersion for very long-range transport (300 km and beyond)."[31] IWAQM ultimately concluded that the use of CALPUFF for transport distances "beyond 200 to 300 km should be done cautiously with an awareness of the likely problems involved." Moreover, Appendix W to 40 C.F.R. part 51 states that the "CALPUFF dispersion model…performed in a reasonable manner…so long as the transport distance was limited to less than 300km."[32]

EPA has consistently complied with this recommendation since its conception. There are numerous instances in which EPA appropriately set the CALPUFF distance limitation at 300 km, including a number of recent rulemaking actions. In the Final Arkansas Regional Haze FIP, for example, EPA noted that "there are concerns in using CALPUFF for modeling impacts at

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[30] Proposed Rule, 82 Fed. Reg. at 22,945.

[31] EPA, Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts at 18 (Dec. 1998), Publication No. EPA-454/R-98-019.

[32] Final Rule, Revision to the Guideline on Air Quality Models: Adoption of a Preferred Long Range Transport Model and Other Revisions, 68 Fed. Reg. 18,440, 18,458 (Apr. 15, 2003).

distances much greater than 300 km from the source."[33] Similarly, in the New Mexico Regional Haze SIP, EPA supported the decision to exclude receptors from Class I areas that were located more than 300 km away from modeled sources on the basis that "CALPUFF results are less reliable at distances greater than 300 km."[34] And in the Texas Reasonable Progress FIP RTC, EPA notes that use of CALPUFF beyond the distance for which it was originally promulgated—300 km—"raises concerns."[35]

CALPUFF has consistently been limited in EPA rulemaking actions to distances of less than 300 km due to modeling performance concerns, so it is unclear why EPA is proposing to extend the allowable use of CALPUFF to beyond 300 km without any technical justification. Many of Entergy's Louisiana BART-eligible sources are located more than 300 km from at least one Class I area, and one facility—the Nelson plant—is located more than 300 km from both Breton and Caney Creek (427 km from Breton and 460 km from Caney Creek).[36] EPA has deferred proposing a BART determination for Nelson until a future rulemaking, and Entergy would oppose EPA's use of CALPUFF modeling in its determination proposal. Although the significant distances alone should prevent the use of CALPUFF in making a Nelson BART

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[33] Final Rule, Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan, 81 Fed. Reg. 66,332, 66,394 (Sept. 27, 2016).

[34] Final Rule, Approval and Promulgation of Implementation Plans; New Mexico; Regional Haze and Interstate Transport Affecting Visibility State Implementation Plan Revisions; Withdrawal of Federal Implementation Plan for the San Juan Generating Station, 79 Fed. Reg. 60,978, 60,983 (Oct. 9, 2014).

[35] Texas Reasonable Progress FIP RTC at 562.

[36] EPA, Technical Support Document for Louisiana Regional Haze: CALPUFF Best Available Retrofit Technology Modeling Review, at 8 (April 2017), Docket No. EPA-R06-OAR-2017-0129-0009 (CALPUFF Modeling TSD).

determination, when taken with CALPUFF's numerous technical shortcomings (see Section II.A), use of CALPUFF in this instance cannot be justified. [37]

III. EPA's CAMx Modeling Methodology Is Technically Unreliable

In response to concerns about the application of CALPUFF at distances greater than the typical distance threshold and the general unreliability of CALPUFF due to its simplified chemistry mechanism, the University of North Carolina at Chapel Hill (UNC-IE) assisted EPA in performing CAMx modeling of several coal-fired EGUs in Louisiana that are BART-eligible. In the Proposed Rule, EPA notes that CAMx "provides a scientifically validated platform for assessment of visibility impacts over a wide range of source-to-receptor distances."[38] Further, the CAMx Modeling TSD states that CAMx "has a more robust chemistry mechanism than CALPUFF" making it "more suited than some other modeling approaches for evaluating the impacts of SO_2, NO_X, VOC and PM emissions."[39] EPA intended this CAMx modeling "to provide additional information on visibility impacts and impairment and address possible concerns with utilizing CALPUFF to assess visibility impacts at Class I areas located far from these[s] emission sources."[40]

Entergy agrees that CAMx modeling is necessary to assess the impairment (or lack thereof) caused by units located beyond CALPUFF's acceptable distance threshold, but EPA's CAMx modeling analysis is rendered unreliable by EPA's flawed modeling approach, as the MPE results indicate. Entergy continues to believe that the CAMx modeling presented in the

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[37] Entergy submitted CALPUFF modeling alongside its CAMx modeling in the expectation that CALPUFF results would be required by LDEQ and EPA. Nonetheless, Entergy has consistently explained its disagreement with the use of CALPUFF in BART determinations.

[38] Proposed Rule at 22,945.

[39] CAMx Modeling TSD, at 5.

[40] *Id.* at 6.

November 2015 Submittal, which modeled annual actual emission rates and calculated estimated visibility impacts on the W20% visibility days, represents the most technically reliable analysis and indicates insignificant visibility impairment attributable to Entergy's BART-eligible units in Louisiana. Entergy's June 2016 Submittal also demonstrated that minimal impacts are expected from Entergy's BART-eligible units, even though a more conservative approach was used.

Entergy has the following concerns with EPA's CAMx modeling assessment, which include issues with the selected modeling methodology and the results of the MPE.

A. EPA Employed a Technically Unreliable CAMx Modeling Methodology that Rendered its Results Invalid for Making BART Determinations

1. EPA's Blanket Application of Maximum 24-hour Emission Rates Inappropriately Skews Modeling Results

CAMx is a full-chemistry, multi-source modeling system that is better able to characterize visibility than CALPUFF. As such, use of a steady-state maximum 24-hour emission rate to evaluate BART-eligible sources on the basis that such emissions were used with CALPUFF is inappropriate, as explained in Section I.A and Entergy's past submittals.[41]

2. EPA Utilized a Post-Processing Methodology that Likely Overstates Visibility Impairment Attributable to Individual Sources

EPA has noted in other rulemakings that, regardless of CAMx's technical superiority, there remain concerns that modeling bias can inappropriately influence estimated visibility impacts (a concern with all models).[42] Therefore, RRFs should be used in conjunction with IMPROVE monitor data to "help remove potential bias concerns."[43] EPA's modeling conclusions are unreliable in this rulemaking, however, due to the Agency's reliance on absolute maximum modeled concentrations directly output by the model. The lack of evaluation of the

[41] 2016 CAMx Modeling Report, at 5-1; and April 2017 Letter, at 6.

[42] Texas and Oklahoma FIP RTC, at 585.

[43] *Id.*

potential effects of modeling bias is suspect, and until EPA remedies its post-processing methodology, the results of EPA's CAMx modeling cannot be used to finalize BART determinations that will impose significant costs on sources.

EPA should refer to Section I.B and Entergy's previous submittals for additional discussion regarding flaws with EPA's post-processing approach and the improvements offered through the use of RRFs.[44]

3. EPA Failed to Account for Outlier Emission Rates Consistently and Modeled Nelson Unit 6 with Incorrect NO_X Emission Rates

The CAMx modeling on which EPA relied in evaluating the selected Louisiana BART-eligible EGUs was the same modeling utilized to support the Proposed Texas BART FIP.[45] However, EPA's proposed action here is inexplicably inconsistent with its action in Texas. In determining modeled emission rates for one of the Texas EGUs—Harrington Station Unit 062B—EPA acknowledged that the modeled NO_X emission rate was selected "after ignoring outliers that appear to be due to abnormal operations such as SSM."[46] Specifically, EPA opted to disregard the absolute maximum 24-hour NO_X rate of 28.454 tons per day occurring on January 11, 2004, in favor of the second-highest value of 19.231 tons per day.[47] Without explanation, EPA failed to disregard similarly anomalous data for Entergy's Nelson Unit 6.

The maximum daily NO_X emission rate at Entergy's Nelson Unit 6 occurred on May 8, 2000, with a value of 69.925 tons per day. The next-highest value is 41.147 tons per day—

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[44] 2016 CAMx Modeling Report, at 5-2; and April 2017 Letter, at 7-9.

[45] CAMx Modeling TSD, at 8.

[46] EPA, TX187-0013-0025 – Modeling – CALPUFF_inputs, Posted Jan. 6, 2017, Docket No. EPA-R06-OAR-2016-0611-0013.

[47] EPA, TX187-0013-0040 - Modeling - coal fired daily ei 2000-2004, Posted Jan. 6, 2017, Docket No. EPA-R06-OAR-2016-0611-0013.

approximately 40% lower.[48] Compared with the Harrington Station Unit 062B, where the second-highest value is closer to 30% lower than the outlier, Nelson Unit 6's May 8, 2000 maximum is even more of an outlier.

EPA failed to recognize that the maximum NO_X emission rate at Nelson Unit 6 was an outlier and proceeded to model Nelson Unit 6 with excessively high NO_X emissions. EPA must be consistent in how it treats outliers when determining modeled emission rates. Choosing to ignore an outlier emissions value for one unit while subjectively failing to do so for another is arbitrary and capricious, invalidating the results of EPA's CAMx modeling with regard to Entergy's Nelson Unit 6.

4. EPA Should Not Have Included Modeled Nitrogen Dioxide in its Assessment of Visibility Impacts

The IMPROVE algorithm is an empirical equation that is used to estimate levels of visibility impairment in Class I areas. Monitored or modeled concentrations of visibility-impairing pollutants are input to the algorithm in conjunction with Class I area-specific parameters (e.g., relative humidity factors) to estimate light extinction. The IMPROVE algorithm version currently in use was adopted by the IMPROVE Steering Committee in 2005,[49] and includes several revisions to the original version that were anticipated to better align the

[48] EPA, Clean Air Markets Program Data, Continuous Daily Emission Rates for Entergy's Nelson Facility, https://ampd.epa.gov/ampd/#?bookmark=18881.

[49] IMPROVE Technical Subcommittee for Algorithm Review, Revised IMPROVE Algorithm for Estimating Light Extinction from Particle Speciation Data, http://vista.cira.colostate.edu/Improve/gray literature/ (Jan. 2006), Docket No. EPA-R06-OAR-2017-0129-0012-43 (Revised IMPROVE Algorithm Report).

estimated visibility values with observed values.[50] One specific addition to the algorithm was a new term for estimation of light extinction due to concentrations of nitrogen dioxide (NO_2).

In describing this revised algorithm, the IMPROVE Technical Subcommittee for Algorithm Review noted that the "addition of a NO_2 light absorption term…would only be used at sites with available NO_2 concentration data."[51] Thus, use of the NO_2 absorption term was intended to be dependent on the availability of NO_2 data at the receptor.

The revised IMPROVE algorithm has been used in countless visibility analyses since its release, but inclusion of a modeled NO_2 extinction term in CAMx-based BART analyses is fairly recent, owing to the fact that CAMx's Particulate Matter Source Apportionment Technology (PSAT) was only given the ability to track individual NO_2 concentrations in 2016 in version 6.30 (the version used in EPA's assessment).[52] EPA attempts to take advantage of this new capability in its Louisiana modeling by evaluating NO_2 impacts at Breton and Caney Creek. However, neither of these Class I areas observe ambient NO_2 concentrations. Thus, because inclusion of NO_2 is unverifiable with monitor data, EPA should not have included modeled impacts from this pollutant in evaluating BART-eligible sources.

B. The Results of EPA's Model Performance Evaluation Raise Concerns, Especially with Regard to EPA's Reliance on Absolute Maximum, Direct-Modeled Impacts

The intended purpose of an MPE is to assess whether a model can adequately simulate the various conditions that influence pollutant concentrations. In the case of visibility analyses, these conditions may include meteorological effects, emissions transport, and the chemical

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[50] Marc Pitchford, et al., Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data, Journal of the Air & Waste Management Association, JAWMA, 57.11, at 1,326-1,336 (2007)

[51] Revised IMPROVE Algorithm Report, at 13.

[52] Ramboll Environ, CAMx Version 6.30 Release Notes (April 2016).

interaction of pollutants in the atmosphere. Additionally, MPEs can often identify causes of poor model performance, such as errors in emissions inputs or problems with meteorological data. UNC-IE and EPA performed an MPE to evaluate the quality of the baseline CAMx modeling scenario (CAMx Run 1) relative to observed IMPROVE data.

Figure 1. UNC-IE's Total PM2.5 Model Performance Evaluation (EPA's CAMx Run 1)[53]

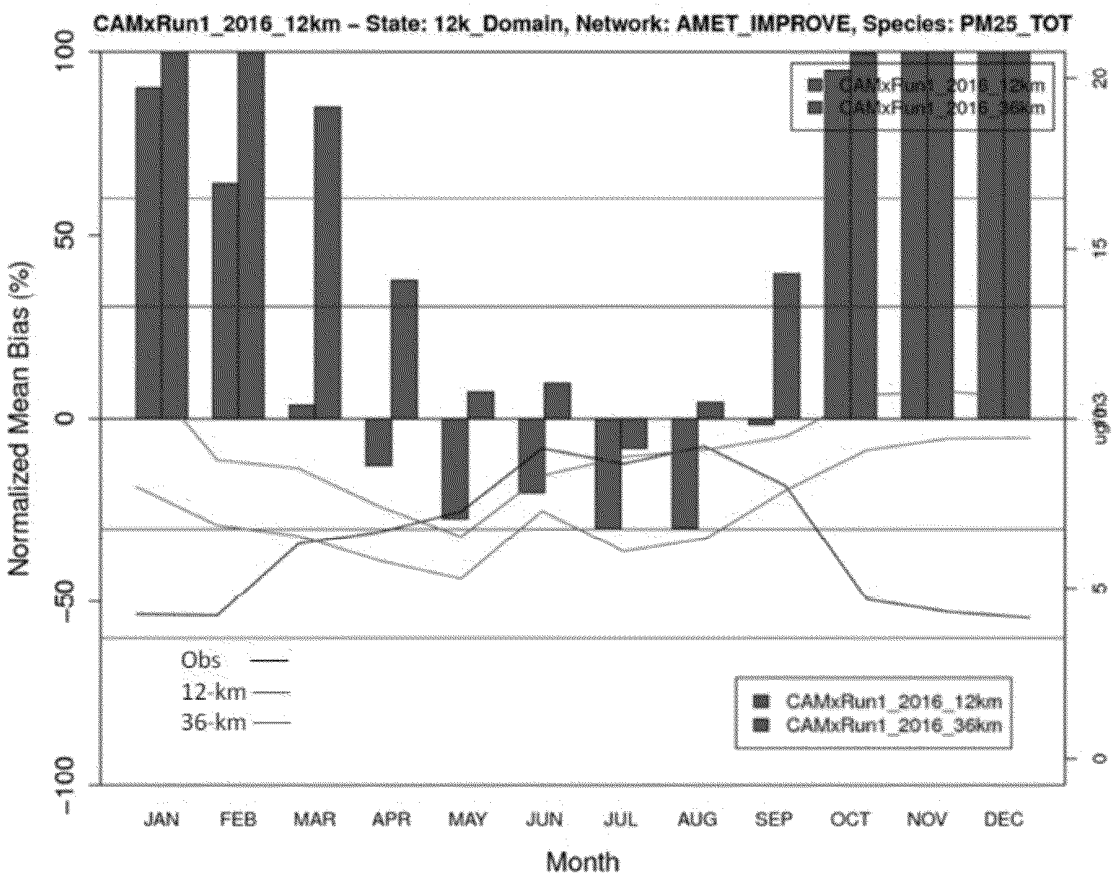


Figure 1 displays UNC-IE's evaluation of the modeled total $PM_{2.5}$ concentrations. This graph demonstrates a variable modeling performance, with a severe over-prediction bias during

[53] UNC Institute for the Environment, Regional Haze Evaluation Under Contract EP-D-11-084 Work Assignment No. 4-17: TASK 5, Subtask 2: Conducting CAMx PiG with PSAT Source Apportionment for BART screening (CAMx Run #1) (Dec. 7, 2016), Docket No. EPA-R06-OAR-2017-0129-0013-05 (UNC-IE Task 2 Memo).

cooler months of the modeled year and a slight under-prediction bias during warmer months. Notably, the simulation on the 12 km grid failed to meet model performance goals for total $PM_{2.5}$ from October through February (five months of the year), during which time normalized mean bias values exceeded 60%. The normalized mean bias values in November and December are *100% or higher.*[54]

EPA and UNC-IE ultimately concluded that this CAMx modeling assessment meets EPA's performance guidelines. However, the relatively poor performance indicated by this MPE warrants greater concern than EPA acknowledges. There is a severe overestimation bias during the cooler months and, despite the slight underestimation bias during the remaining months of the year, this MPE illustrates why EPA should not use the absolute maximum, direct-modeled impacts to make BART determinations.

EPA attempts to defend its conclusion that the modeling assessment generally meets EPA's performance guidelines by providing possible explanations as to why certain elements of the MPE do not comply with the performance guidelines (e.g., nitrate over-predictions). As part of these explanations, EPA compared the results of its CAMx modeling with a 2006/7 Community Multi-Scale Air Quality model (CMAQ) analysis performed for CENRAP by Environ.[55] As discussed below, however, EPA's explanations do not include passable supporting evidence, and the overall modeling performance remains subject to concern.

1. EPA's Implied Argument that Nitrate Over-Predictions Will Not Affect Individual Source Impacts Lacks Supporting Evidence

EPA argues that the cause of the observed nitrate overestimation bias is the use of maximum 24-hour emission rates for the BART-eligible sources, but does not provide any

[54] CAMx Modeling TSD, at 18.

[55] *Id.* at 18-24.

solution to counteract the potential effects this bias may have on individual source predictions. EPA is implying that, regardless of how much overall nitrate concentrations are overestimated, modeled nitrate concentrations from individual sources are still acceptable. However, this argument is not supported by adequate evidence.

EPA's own analysis indicates that modeling with maximum 24-hour emission rates is not the only cause of the observed nitrate over-predictions. In the soccer goal plot presented in Figure 2, the comparison of model performance metrics from EPA's CAMx modeling (with BART-eligible sources at maximum 24-hour emission rates) and the previous CENRAP CMAQ modeling (without elevated emissions) indicates that the overestimation of nitrates may be related more to time of year (i.e., cooler months) and modeling capabilities than to the use of maximum 24-hour emission rates. In fact, EPA's CAMx modeling exhibits higher fractional bias in only two of the four months considered in the comparison, which supports the theory that nitrate overestimation is not necessarily caused by the artificially heightened BART emission rates.[56] It is logical to assume, then, that predictions of individual source concentrations are affected by the same model tendencies affecting overall concentration predictions. Therefore, if overall nitrates are significantly overestimated during the cooler months of the year, it is possible—maybe even likely—that nitrate concentrations attributable to an individual source are likewise overestimated.

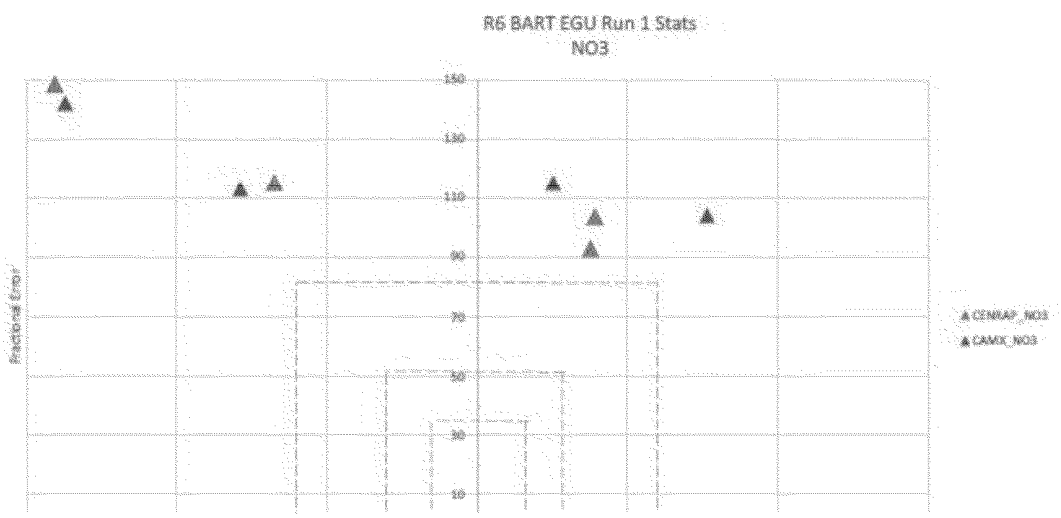
Thus, it is possible that modeled concentrations attributable to individual sources may be affected by the general nitrate over-prediction bias revealed by the MPE, thereby resulting in overstated individual source impacts. EPA must account for the potential effects of modeling bias, or the impacts from individual sources are likely to be exaggerated. The observed

[56] Although these two assessments are not directly comparable, they provide useful general model performance information—CAMx Modeling TSD, at 19, 23.

overestimation of nitrates demonstrates why the absolute maximum direct-modeled impact is an inappropriate metric, and EPA should reconsider other post-processing methodologies that utilize RRFs.

Figure 2. Nitrate Model Fractional Model Bias Comparison between CENRAP CMAQ and EPA's CAMx Run 1[57]

	CENRAP		R6 CAMX	
Month	Frac Bias	Frac Error	Frac Bias	Frac Error
January	37.8	92.9	76.6	104
April	-67.4	115.2	-78.7	113
July	-140.5	148.4	-137	142
October	39.3	103.6	25.4	115



2. Overall Sulfate Under-Predictions Do Not Necessarily Indicate Individual Source Under-Predictions

Modeled sulfate concentrations in EPA's CAMx Run 1 scenario were typically more likely to suffer from underestimation bias than overestimation bias. Based on this observation,

[57] CAMx Modeling TSD, at 22.

EPA determined that "the impacts of the BART-eligible sources are likely underestimated and the actual impacts would be greater."[58]

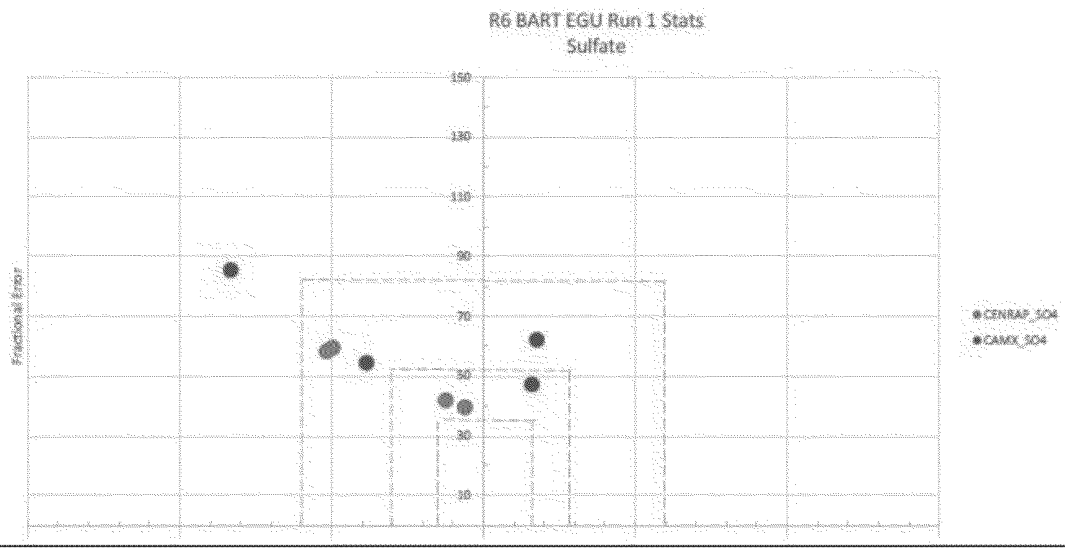
Contrary to its statements regarding nitrates, EPA is claiming that, because the overall sulfate concentrations are typically under-predicted, individual source impacts also are likely under-predicted. EPA then assumes that actual sulfate concentrations from individual sources are likely higher than the model predicts. In a complete reversal from its conclusion that overall nitrate overestimations should not affect how individual source nitrate concentrations are perceived, EPA concludes that overall sulfate under-predictions likely apply to individual source sulfate concentrations as well. EPA's inconsistency in evaluating nitrates versus sulfates is arbitrary and capricious. EPA cannot suggest that individual source sulfate concentrations are likely under-predicted without also admitting that individual source nitrate concentrations likely are over-predicted.

Moreover, EPA has no basis for its conclusion that impacts from BART-eligible sources are likely greater in reality than the model predicts. Since the level of over- or under-prediction bias is dependent on time of year, EPA should expected that the date under consideration will be a significant factor in whether actual impacts are likely greater or less than the modeled impacts. For example, an individual source's modeled sulfate concentrations are more likely underestimated by the model during January rather than overestimated as EPA suggests, because the average fractional bias of sulfates is identified as 16% in January (see Figure 3).

[58] CAMx Modeling TSD, pp. 23-24.

Figure 3. Sulfate Model Fractional Model Bias Comparison between CENRAP CMAQ and EPA's CAMx Run 1[59]

	CENRAP CMAQ		R6 CAMX Run1	
Month	Frac Bias	Frac Error	Frac Bias	Frac Error
January	-12.4	41.9	16	47.2
April	-51.6	58.2	-38.5	54.4
July	-49.6	59.4	-83.2	85.3
October	-6.1	39.6	17.6	62.0



3. EPA's Conclusion that Visibility Benefits Are Underestimated Is Flawed

As part of its evaluation of sulfates, EPA proposed that, given the typical sulfate underestimation bias, potential visibility benefits from controls also are likely underestimated relative to what is expected to be observed in reality. This conclusion lacks adequate supporting evidence. Potential visibility improvement values are dependent on the date under consideration, just as are the effects of bias on modeled sulfate concentrations. The distribution of species

[59] *Id*. at 21.

contributions also plays a significant role in the potential effects of sulfate bias on predicted improvement values. For example, if baseline impacts attributable to a source are primarily due to nitrates, sulfate modeling bias is not likely to substantially influence potential improvement values one way or the other.

Furthermore, it is equally likely that sulfate concentrations will be underestimated during a baseline scenario as it is during modeled control scenarios (CAMx Run 3 and Run 4), which means any potential underestimation in the baseline scenario would be offset by similar underestimation in the control scenarios, resulting in insignificant net underestimation of visibility improvement values. Therefore, EPA's suggestion that visibility benefits are *likely* underestimated is baseless, and the insinuation that CAMx-predicted impacts are lower than what would be expected in reality should be withdrawn.

IV. Entergy's Sources Should Not Be Subject to BART

Entergy disagrees with EPA's proposal to approve LDEQ's conclusion that Entergy's Waterford, Willow Glen, Ninemile Point, and Little Gypsy plants are subject to BART.[60] For the reasons explained in these comments, the CAMx modeling submitted by Entergy in the November 2015 Submittal represents the most reliable estimation of baseline visibility impacts from Entergy's BART-eligible facilities. Based on this CAMx modeling, Entergy's sources should not be determined to be subject to BART. Nonetheless, assuming EPA finalizes BART determinations for these facilities, Entergy agrees with the proposed BART limits.

Entergy's CAMx modeling utilized realistic actual emission rates and evaluated visibility impacts relative to IMPROVE monitor data through the use of RRFs to obtain the most realistic possible assessment of potential visibility impacts from Entergy's facilities on Class I areas.

[60] Proposed Rule, 82 Fed. Reg. at 22,942.

Table 2 below presents the facility-wide impacts for Entergy's Waterford, Willow Glen, Ninemile Point, and Little Gypsy plants at the Breton Wilderness Area. The modeled impacts during the 20% worst visibility days are minuscule – all less than 0.025 dv – indicating that the BART-eligible units at these facilities contribute only minimally to visibility impairment at Breton. Because these sources are "not reasonably anticipated to cause or contribute to any visibility impairment in a Class I area,"[61] Entergy's sources should not be found subject to BART.

Table 2. Maximum Contribution to Visibility Impairment at the Breton Wilderness Area During the Worst 20% Visibility Days[62]

Entergy Facility	Visibility Impacts (dv)
Waterford	0.025
Willow Glen	0.0093
Ninemile Point	0.0055
Little Gypsy	0.0036

Nonetheless, assuming that EPA's final rulemaking continues to find that the Waterford, Willow Glen, Ninemile Point and Little Gypsy plant are subject to BART, Entergy supports the BART limits that LDEQ adopted into its SIP. The limits represent appropriate BART determinations for these sources.

V. Entergy Agrees That CSAPR Constitutes BART for NO_X Emissions

Entergy agrees with EPA's proposal that Louisiana's participation in CSAPR's ozone season NO_X trading program satisfies BART obligations for NO_X emissions.[63] Louisiana is

[61] BART Guidelines, 70 Fed. Reg. at 39,161

[62] 2016 CAMx Modeling Report, at 4-3.

subject to the CSAPR trading program for ozone season NO_X, which qualifies it to forgo unit-specific BART for NO_X emissions pursuant to the Regional Haze Rule.[64] Under the Regional Haze Rule, a "[s]tate ... subject to a [Transport Rule] trading program [i.e., CSAPR] ... need not require BART-eligible [EGUs] … to install, operate, and maintain BART" for the pollutant covered by the trading program.[65] The Regional Haze Rule specifically authorizes compliance through the Clean Air Interstate Rule (CAIR) trading programs, but EPA has determined that participation in CSAPR, the rule that replaced CAIR, provides greater reasonable progress towards the national visibility goal than BART with respect to emissions from EGUs in states subject to CSAPR.[66]

EPA need not wait to finalize this element of the Proposed Rule until the Agency finalizes its proposed finding that CSAPR continues to be better than BART despite the removal of Texas from the annual NO_X and SO_2 trading programs.[67] EPA has performed technical analyses supporting its conclusion that the ozone season NO_X trading program remains "better than" BART despite the removal of Texas from the annual programs, which supports a final action in this rulemaking.[68] Further, this Proposed Rule provides sufficient public notice and opportunity to comment on whether CSAPR participation appropriately satisfies NO_X BART

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[63] Proposed Rule, at 22,943.

[64] 40 C.F.R. § 51.308(e)(4).

[65] *Id.*

[66] Final Rule, Regional Haze: Revisions to Provisions Governing Alternatives to Source Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans, 77 Fed. Reg. 33,642 (June 7, 2012).

[67] Proposed Rule, at 22,938 (citing Proposed Rule, Interstate Transport of Fine Particulate Matter: Revision of Federal Implementation Plan Requirements for Texas, 81 Fed. Reg. 78,954 (Nov. 10, 2016) (Proposed Texas Interstate Transport FIP)).

[68] Proposed Rule, Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan, 82 Fed. Reg. 912, 946 (Jan. 4, 2017) ("EPA's actions in response to the D.C. Circuit's remand would not adversely impact our 2012 demonstration that CSAPR is better than BART"); Proposed Texas Interstate Transport FIP at 78,954.

requirements for Louisiana EGUs. In light of this, EPA should determine in this rulemaking that participation in CSAPR satisfies BART for NO_X emissions from Louisiana's EGUs. At the very least, EPA should finalize its proposal that CSAPR remains better than BART[69] in an expeditious manner, so that it can finalize this portion of the Proposed Rule.

Conclusion

Entergy appreciates the opportunity to comment on the Proposed Rule. While Entergy supports EPA's determination that CSAPR satisfies NO_X BART obligations for Louisiana EGUs, Entergy has serious concerns about the flaws in the CAMx and CALPUFF modeling that EPA used to support this rule. Entergy continues to believe that the CAMx modeling it submitted in the November 2015 Submittal represents the most reliable estimation of baseline visibility impacts from Entergy's BART-eligible facilities. This CAMx modeling demonstrates that Entergy's sources should not be determined to be subject to BART. Nonetheless, assuming EPA finalizes BART determinations for these facilities, Entergy agrees with the proposed BART limits. Entergy urges EPA to take these comments into account when taking final action in this rulemaking, which would result in a final SIP approval that relies on a more technically robust modeling analysis.

[69] Proposed Texas Interstate Transport FIP, 81 Fed. Reg. 78,954.

To: Coleman, Sam[Coleman.Sam@epa.gov]
From: Chuck Brown
Sent: Thur 6/15/2017 9:31:23 PM
Subject: Fwd: Louisiana Draft Reg Haze SIP
Proposed SIP EGU Transmittal Letter Entergy Addendum June 2017.doc
RH Nelson Louisiana June 2017 Proposal.docx

Fyi.

Chuck Carr Brown, Ph.D.
Secretary
Louisiana Department of Environmental Quality
602 North 5th Street
Baton Rouge, Louisiana 70802
225.219.3950

-------- Original message --------
From: Vivian Aucoin <Vivian.Aucoin@LA.GOV>
Date: 6/15/17 3:59 PM (GMT-06:00)
To: Bijan Sharafkhani <Bijan.Sharafkhani@LA.GOV>
Cc: Chuck Brown <Chuck.Brown@LA.GOV>
Subject: RE: Louisiana Draft Reg Haze SIP

Greetings!

1.) The statement or phrase concerning the 3 years was in the AOC, not the SIP narrative. The SIP sets an emissions limit of 0.6lbs/MMBtu on a rolling 30-day average as BART; since this emission limit is not based solely on the use of lower sulfur coal, we have removed the phrase in the AOC which gave Entergy 3 years to comply. The phrase now reads "as expeditiously as practicable". Entergy is currently meeting this limit, so there should be no issue with meeting the limit once the SIP becomes final.

2.) Wren is correct; LDEQ must include the information in the SIP as it was used to determine the basis for BART. All information that was submitted will be placed in the proper appendix.

I have completed the revisions and have attached the narrative for your review. I have also asked Marian to print the transmittal letter for Dr. Brown's signature so that we can get the hard copies mailed and into EDMS prior to Tuesday, June 20.

Please let me know if you need anything else.

Vivian H. Aucoin

Environmental Scientist Manager

Office of Environmental Assessment, Air Planning Division

225-219-3482

vivian.aucoin@la.gov

From: Bijan Sharafkhani
Sent: Thursday, June 15, 2017 3:50 PM
To: Vivian Aucoin
Cc: Chuck Brown
Subject: FW: Louisiana Draft Reg Haze SIP

Vivian,

Please respond to Dr Brown and copy me.

Thanks

From: Stenger, Wren [mailto:stenger.wren@epa.gov]
Sent: Thursday, June 15, 2017 3:46 PM
To: Coleman, Sam; Chuck Brown
Cc: Stenger, Wren; Bijan Sharafkhani; Price, Lisa
Subject: Louisiana Draft Reg Haze SIP

Sam, Dr. Brown,

Based on our review of the latest draft LA Reg Haze SIP, my team discussed two follow-up items with Vivian.

1. Add some documentation/language explaining why the low sulfur coal would take 3 years to implement. We understand that the company has to complete its current coal purchasing contracts, but it would be best to have something in the record. Vivian agreed to add some language to the SIP explaining this.

2. We asked if any additional information would be added to the SIP beyond the draft we reviewed and edits provided. Vivian confirmed that the material that we sent would be included in the document as an appendix and that no new material was being added from Entergy.

With these things addressed, when we get the formal SIP submission, we are ready to process it. We anticipate receiving the formal submittal on June 20, the same date LDEQ will publish it in the Louisiana Register.

Thanks for the support and coordination to make this happen. Bijan has been a great partner!

June 19, 2017

Mr. Sam Coleman, Acting Administrator
US EPA Region 6, 6-RA
1445 Ross Avenue, Suite 1200
Dallas Texas 75202-2733

RE: Louisiana's State Implementation Plan (SIP) Revisions Addendum
Regional Haze Rule EGU Best Available Retrofit Technology (BART)

Dear Mr. Coleman:

Please find enclosed 2 bound copies of the draft revision to the SIP for the Regional Haze Rule. An electronic copy will be forwarded via electronic mail presently to the Region 6 staff.

Written comments regarding the proposed SIP revision are due no later than July 26, 2017 and should be mailed to Vivian H. Aucoin, Office of Environmental Services, P. O. Box 4314, Baton Rouge, La., 70821-4314 or emailed to vivian.aucoin@la.gov.

If you have any questions concerning this matter, please feel free to contact Donald Trahan, Air Permits Administrator at 225-219-3408 or at donald.trahan@la.gov.

Sincerely,

Chuck Carr Brown, Ph.D.
Secretary

Enclosures

Cc: Wren Stenger, EPA Region 6
Guy Donaldson, EPA Region 6

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

Regional Haze State Implementation Plan

EGU BART Analysis

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

Revision Proposed June 2017

I. Background on the Regional Haze Rule

A. Plan Submission

[No Change]

B. Legal Authority

[No Change]

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 June 20, 2017 in the *Louisiana Register*. Public comments on the proposal should be submitted no later than July 26, 2017. A public hearing will be held if requested. A copy of the potpourri notice is included in Appendix A

D. Commitment to Plan Revision

[No Change]

E. History of Regional Haze

[No Change]

F. Breton National Wilderness Area (Class I)

[No Change]

G. Louisiana's Visibility History

[No Change]]

H. Class I Areas outside the State Boundaries

[No Change]

II. BART Analysis

[No Change]

A. CLECO

[No Change]

B. Louisiana Generating, LLC, a subsidiary of NRG

[No Change]

C. Entergy Louisiana LLC

Entergy submitted to LDEQ CALPUFF modeling for $S0_2$ and PM for the various units that were found to be BART-eligible; all reports are included in Appendix D. In the course of this exercise, Entergy has submitted not only CALPUFF modeling and a five-factor analysis to satisfy the RH and BART requirements, but has also submitted CAMx modeling to support their findings. While LDEQ has not used the CAMx modeling to ascertain that the units have satisfied the BART requirements, the model results have been included for consideration. Following Louisiana's final revision submittal, a discussion between EPA, LDEQ and Entergy took place and based upon the results of that discussion, EPA provided additional information on Entergy's proposed BART five-factor analysis and EPA's draft analyses for LDEQ's review. Therefore this SIP is being revised to include the EPA information. The additional information submitted by EPA is included in Appendix F.

•**Entergy Ninemile Point Units:**

[No Change]

•**Entergy Little Gypsy Units:**

[No Change]

•**Entergy Willow Glen Units:**

[No Change]

•**Entergy Sterlington Units:**

[No Change]

•**Entergy Michoud Units:**

[No Change]

•**Roy S. Nelson Generating Plant (Nelson):** The facility is located in Westlake, Calcasieu Parish, Louisiana and is located 264 miles west of the Breton National Wilderness Area and 286 miles south of the Caney Creek Wilderness Area in Arkansas. The facility is a fossil-fuel steam electric power generating facility and operates three BART-eligible steam generating units: Unit 4, Unit 4 Auxiliary Boiler and Unit 6.

The Unit 4 Boiler is permitted to combust natural gas, No. 2, No. 4 and No. 6 fuel oils And refinery fuel gas. Unit 4 has a maximum heat rated capacity of 5400 MMBtu/hour and exhausts out of one stack. It has flue gas recirculation equipment installed for control of NOx emissions. The Auxiliary Boiler for Unit 4 is permitted to burn natural gas and fuel oil.

The Unit 6 Boiler is permitted to burn coal as its primary fuel, with No. 2 and No. 4 fuel oils as its secondary fuels which are mainly used for start-up. Unit 6 has maximum heat rated capacity of 6216 MMBtu/hour and exhausts out of one stack. It has an electrostatic precipitator (ESP) with flue gas condition for control of particulate matter (PM) emissions. Unit 6 has installed Separated Overfire Air Technology (SOFA) and a Low NOx Concentric Firing System (LNCFS) for NOx control. Steam from these boilers is used to drive steam turbines which in turn generate rotary motion that is used to drive electric generators. The electric generators then produce electricity.

Entergy has performed the traditional CALPUFF analysis as well as CAMx based upon EPA modeling guidance. The guidance, Appendix Y of the BART rule (July 6, 2005), states that CALPUFF shall be used for single-source modeling where the distance between the BART source and the Class I area is less than 300 kilometers (km). Since CALPUFF may significantly over predict impacts at greater distances, CAMx is approved for situations where the distance is greater than 300km. The facility is 425 km from Breton and 460km from Caney Creek.

Unit 4 and the auxiliary boiler are permitted to burn fuel oil. However, fuel oil has not been burned at either unit in several years and there are no current operational plans to burn fuel oil. Entergy and LDEQ have executed an Administrative Order on Consent (AOC) that states before fuel oil firing is allowed to take place at Unit 4 and/or the auxiliary boiler, a revised BART determination must be promulgated for SO_2 and PM for the fuel oil firing scenario through a SIP revision, which will then have to be approved by EPA and such action will become federally enforceable.

In the Entergy BART five-factor SO_2 analysis for the Unit 6 Boiler, a number of emission reduction controls were reviewed. Those controls included lower sulfur coal, DSI, enhanced DSI, dry flue-gas desulfurization (FGD) and wet FGD. LDEQ has weighed the five factors and after a review of both Entergy's and EPA's information has concluded that BART is the emission limit of 0.6 lbs./MMBtu based on at 30 day rolling average as defined in the AOC. While additional visibility benefits may be available through the use of FGD, the lower sulfur coal option results in visibility benefits at a lower annual cost. In addition, FGD use results in additional waste due to spent reagent and has some power demands to run the equipment. LDEQ believes, at present, that the use of lower sulfur coal presents the appropriate SO_2 control based on consideration of economics, energy impacts, non-air quality environmental impacts, and impacts to visibility.

Regarding PM, Unit 6 is currently equipped with an ESP to control PM emissions. Impacts from PM emissions are small and any additional controls beyond the ESP would have

minimal visibility benefits and would not be cost–effective. Therefore, the existing controls are sufficient to meet BART for PM.

Based upon this decision and the inclusion of the emission limits in the AOC, LDEQ has determined that the conditions are sufficient to meet BART. As the energy industry evolves, LDEQ continues to work with EGUs throughout Louisiana to evaluate the operation of utilities. As such, LDEQ will engage in discussions with Entergy about any potential changes in usage or emission rates at the Nelson facility. Any such changes will be considered for reasonable progress for future planning periods as appropriate.

•Waterford 1 & 2 Electric Generating Plant (Waterford):

[No Change]

D. Municipal Facility Units

[No Change]

Appendix A

Public Notice and Participation

Appendix B

CLECO

BART Determination and Evaluation

[No Change]

Appendix C

NRG
BART Determination and Evaluation

[No Change]

Appendix D

Entergy Louisiana LLC
BART Determination and Evaluation

[no change]

Appendix E

Municipal Facilities

[No Change]

Appendix F

EPA DRAFT BART Modeling and Costs Information

To: Coleman, Sam[Coleman.Sam@epa.gov]
From: william.bumpers@bakerbotts.com
Sent: Thur 4/13/2017 2:03:10 PM
Subject: Louisiana Regional Haze SIP
Response to EPA review of modeling and cost analyses 2017-0406_FINAL.PDF

Sam,

I appreciated your candor during our call yesterday. I followed up on your comments about the sufficiency of the cost information on calls at Nelson 5. I am attaching a letter that Entergy sent to LDEQ that addresses the concerns you expressed yesterday and, I think, dispel some of the misconceptions that EPA has about the costs of controls. I encourage you to review the letter prior to our call this afternoon.

Best,

Bill

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Kelly McQueen
Assistant General Counsel

VIA ELECTRONIC MAIL; WITH HARD COPY TO FOLLOW BY U.S. MAIL

April 6, 2017

Ms. Vivian Aucoin
Senior Scientist, Air Permits Division
Louisiana Department of Environmental Quality (LDEQ)
P.O. Box 4313
Baton Rouge, LA 70821-4313
vivian.aucoin@la.gov

RE: Entergy's review of documents provided to LDEQ by U.S. EPA Region 6 on March 10, 2017: "DRAFT BART Analysis for the Nelson Unit 6" and associated cost calculations spreadsheet "Review of CAMx BART Modeling performed by Trinity Consultants for Louisiana Regional Haze"

Dear Ms. Aucoin:

Entergy Services, Inc. on behalf of Entergy Louisiana, Inc. (Entergy) has reviewed the above-referenced documents provided by U.S. EPA Region 6 (EPA) and provides the following comments to assist the Louisiana Department of Environmental Quality (LDEQ) in finalizing its regional haze state implementation plan (SIP). In general, EPA's March 10th critiques are not novel and have been addressed in previous reports and correspondence between Entergy, EPA, and LDEQ, most recently in the response to comments letter provided by Entergy on January 20, 2017, and the Comprehensive Air Quality Model with Extensions (CAMx) Modeling Report submitted on October 14, 2016 (2016 CAMx Modeling Report).

Entergy's continued position is that the Roy S. Nelson Electric Generating Plant (Nelson) Unit 6 should not be subject to any best available retrofit technology (BART) limits. Entergy's submitted CAMx modeling, which is discussed in the latter sections of this letter, demonstrates that Nelson Unit 6 does not contribute towards visibility impairment at either of the nearest Class I areas in any meaningful way, indicating that it should not be subject to BART. However, even if Nelson Unit 6 were found to be subject to BART, the actual costs of compliance for all control technologies evaluated are prohibitive, especially in light of the minimal potential visibility improvements.

The below sections provide responses to EPA's March 10th comments regarding controls costs and the use of CAMx.

"DRAFT BART Analysis for the Nelson Unit 6" and associated cost calculations spreadsheet

As part of the Louisiana Regional Haze SIP development process, Entergy prepared and submitted to LDEQ, on April 14, 2016, a BART five-factor analysis for the Nelson facility (the "2016 BART Analysis"). The project and site-specific costs included in this assessment addressed unit-specific operating parameters that impact the design of each control technology, as well as site-specific constraints that impact constructability and balance-of-plant scope. Therefore, in its "DRAFT BART Analysis for the Nelson Unit 6," EPA should have relied on the site-specific costs provided in the 2016 BART Analysis rather than the generic control system costs generated by the IPM cost algorithms. Moving forward, proper consideration should be given to the actual cost estimates provided by Entergy.

Sargent & Lundy's Site-Specific Control Technology Evaluation

The 2016 BART Analysis included a comprehensive evaluation of control technologies available to reduce sulfur dioxide (SO_2) emissions from Nelson Unit 6. Control technologies assessed in the analysis included dry sorbent injection (DSI), dry spray dryer absorber flue gas desulfurization (SDA), and wet flue gas desulfurization (WFGD).[1] The 2016 BART Analysis was submitted to EPA for review and comment as part of the Louisiana Regional Haze SIP review process.

To support the preparation of its 2016 BART Analysis, Entergy engaged Sargent & Lundy, LLC (S&L) to evaluate the technical feasibility, effectiveness, and costs of various SO_2 control technologies for Nelson Unit 6. S&L performed a site-specific evaluation and prepared a comprehensive technical report for each SO_2 control technology. As part of its evaluation, S&L determined the achievable control efficiency, identified site-specific design considerations, and estimated the total capital investment and annual operating costs of each technology. S&L followed procedures described in 40 CFR Part 51 Appendix Y (the "BART Guidelines") to develop its control system cost estimates for Nelson Unit 6. The BART Guidelines describe the following approach to the development of control system cost estimates:

1) Identify the emission units being controlled;
2) Identify design parameters for the emission controls; and
3) Develop cost estimates based upon those design parameters.

The BART Guidelines note that it is important to specify the control system design parameters and to ensure that the design parameter values will achieve the level of emission control being

[1] Fuel switching to low sulfur coal was also evaluated in the 2016 BART Analysis but was not considered by the EPA.

evaluated. The BART Guidelines require the analyst to document any assumptions regarding the design parameters, and to provide a summary list of equipment and the associated control costs included in the cost estimate. The basis for equipment cost estimates should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source such as the EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (the "Control Cost Manual"). To maintain consistency in BART determinations, the BART Guidelines suggest that cost estimates should be based on the Control Cost Manual, where possible.

The cost estimating methodology described by the Control Cost Manual is directed toward developing a "study" level cost estimate with a nominal accuracy of ±30%.[2] The Manual identifies the following factors that should be provided to develop a study level cost estimate:

- Location of the source within the plant;
- Rough sketch of the process flow sheet (i.e., the relative locations of the equipment in the system);
- Preliminary sizes of, and material specifications for, the system equipment items;
- Approximate sizes and types of construction of any buildings required to house the control system;
- Rough estimates of utility requirements (e.g., electricity);
- Preliminary flow sheet and specifications for ducts and piping;
- Approximate sizes of motors.

The Control Cost Manual includes specific chapters for a number of air pollution control technologies; however, the manual does not include chapters specific to SO_2 emissions controls for coal-fired power plants, including DSI, SDA or WFGD control systems.

The approach S&L used to develop its cost estimates for the Nelson facility is described in each SO_2 control technology report provided as part of the 2016 BART Analysis. In general, S&L identified the emission unit being controlled, established the boundary limits of the air pollution control system, developed the design basis for the control system, and identified the major subsystems and balance-of-plant scope required to install the system. The design basis for each control system is described in each report. Major control system equipment lists, subsystem lists, and balance-of-plant scope is provided in each report. Capital costs for large equipment were derived from S&L's database of control system costs and recent vendor or manufacturer's quotes for similar items, scaled as required for Nelson Unit 6. Annual O&M costs were developed based on site-specific utility and reactant consumption costs. The methodology used by S&L to develop cost estimates for the 2016 BART Analysis followed the approach described in the BART Guidelines and was consistent with the methodology described in the Control Cost Manual.

[2] Control Cost Manual, Section 1, Chapter 2, pg. 2-3.

EPA's Draft BART Analysis

EPA has now provided to LDEQ a draft BART analysis evaluating the same control technologies included in Entergy's 2016 BART Analysis. However, rather than relying on the unit-specific costs provided in Entergy's 2016 BART Analysis, EPA used IPM cost algorithms to calculate costs for its "DRAFT BART Analysis for the Nelson Unit 6." EPA relied on the IPM cost algorithms to calculate total capital costs, annual control system costs (annualized capital recovery costs plus annual fixed and variable O&M costs), and the cost-effectiveness of each control system on a dollar per ton ($/ton) of SO_2 removed basis. EPA's reliance on the IPM cost algorithms to develop control system costs does not meet the requirements described in the BART Guidelines and is not consistent with the cost estimating approach described in the Control Cost Manual.

The IPM cost algorithms, which were developed by S&L, were based on a statistical evaluation of cost data available from various industry publications. The primary purpose of the IPM cost algorithms is to provide generic order-of-magnitude costs for various air pollution control technologies that can be applied to the electric power generating industry on a system-wide basis to inform an economic impact evaluation of proposed regulatory initiatives, such as the Cross State Air Pollution Rule. The IPM cost algorithms were not intended to substitute for plant-specific costs estimates as they do not take into consideration site-specific costs or constructability issues, are not designed to accurately estimate costs for any specific unit, and do not provide study-level cost estimates.

By necessity, the IPM cost algorithms are designed to require minimal information that can be obtained from publicly available sources. Inputs to the IPM DSI, SDA, and WFGD capital cost algorithms are limited to gross unit size (MW), fuel type, unit heat input or heat rate, and an SO_2 removal efficiency. The IPM cost algorithms are not designed to take into consideration site-specific constructability or balance-of-plant issues, beyond applying a subjective retrofit factor. Therefore, using the IPM cost algorithms to determine project-specific costs is inherently unreliable and unreasonable as it is inconsistent with the Control Cost Manual methodology and does not meet the requirements of the BART Guidelines.

Entergy provided project-specific costs in its 2016 BART Analysis, which addressed unit-specific operating parameters that impact the design of each control technology, as well as site-specific constraints that impact constructability and balance-of-plant scope. EPA should have relied on the site-specific costs provided in the 2016 BART Analysis rather than the generic control system costs generated by the IPM cost algorithms as the basis for its "DRAFT BART Analysis for the Nelson Unit 6." LDEQ should do the same.

"Review of CAMx BART Modeling performed by Trinity Consultants for Louisiana Regional Haze"

On November 9, 2015, Entergy submitted a report to LDEQ for a modeling analysis conducted using CAMx (the "2015 CAMx Analysis"),[3] which is a more advanced model than CALPUFF. This revised analysis demonstrated minimal modeled impacts from Entergy's BART-eligible sources and concluded that none of the Entergy BART-eligible sources are subject to BART. In response, on March 16, 2016, EPA provided comments that called for revisions to the CAMx modeling analysis. Entergy disagreed with these requests, but nevertheless submitted revised modeling results on June 30, 2016. EPA subsequently requested additional revisions to the CAMx modeling methodology that appeared to be technically unsound and would render the CAMx results materially less reliable. The 2016 CAMx Modeling Report prepared by Trinity Consultants, Inc. and All4 Inc. (together: Entergy's consultants) provided a discussion of these additional requested revisions and explained why the methods used in the 2015 CAMx Analysis were more technically defensible than the adjustments requested by EPA.[4]

The modeling comments provided by EPA on March 10th have already been largely addressed by Entergy in the 2016 CAMx Modeling Report, which describes the merits of using CAMx instead of CALPUFF and explains why EPA's requested adjustments would cause the results from CAMx to be unreliable. For a more in-depth discussion of Entergy's CAMx modeling, this 2016 report should be referenced. The below sections reiterate the points made in this report and provide additional clarification as applicable.

Superiority of CAMx over CALPUFF for Nelson's BART Analysis

First, with regard to EPA's revised CALPUFF modeling referenced in the March 10th document, it is Entergy's position that CALPUFF modeling of Nelson Unit 6 should not be given *any* consideration due to its inability to accurately characterize visibility at the distances at issue with respect to the Nelson facility. Both the Caney Creek Wilderness Area (Caney Creek) and the Breton Wilderness Area (Breton) are over 400 km away from the facility, which are distances well beyond the recommended distance threshold for CALPUFF use.[5]

The CAMx modeling system, on the other hand, is significantly more robust than the CALPUFF modeling system and alleviates many of the concerns about CALPUFF's accuracy. CAMx includes full chemistry, which allows for more accurate characterization of reactions taking place in the

---

[3] "Updated BART Applicability Screening Analysis." Prepared for Entergy by Trinity Consultants, November 9, 2015.
[4] "CAMx Modeling Report." Prepared for Entergy by Trinity Consultants and All4, October 14, 2016, attached as part of Appendix D to the LDEQ SIP proposal dated October 20, 2016.
[5] *"IWAQM recommends use of CALPUFF for transport distances of order 200 km and less. Use of CALPUFF for characterizing transport beyond 200 to 300 km should be done cautiously with an awareness of the likely problems involved."* Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts, EPA-454/R-98-019, December 1998.

atmosphere. The use of nested grids, the Particulate Matter Source Apportionment Tool (PSAT), and full chemistry Plume-in-Grid (PIG) allows for finer resolution and better characterization of plume transport, dispersion, and chemistry for individual point sources. CALPUFF analyses conducted in support of BART do not consider the full inventory of sources and, thus, do not account for other pollutants challenging and consuming precursor emissions. As such, ammonia and other precursor pollutants are more fully available to react with a facility's emissions and generate haze in a modeled simulation using CALPUFF, which contributes to over-predictions of impacts. Because CALPUFF does not accurately reflect the interaction of pollutants in the atmosphere, and because of the distance involved for modeling the Nelson plant, CALPUFF modeling should not be considered in determining whether Entergy's BART-eligible sources are subject to BART.

Modeling Maximum 24-hour Emission Rates

The first item raised by EPA in regard to Entergy's CAMx modeling is related to modeled emission rates. EPA insists that maximum 24-hour emission rates must be utilized with CAMx in accordance with the BART guidelines. EPA's argument is based on the application of these guidelines (including the recommendation to use maximum 24-hour emissions), which were issued in 2005 and limited by the then-available modeling capabilities, being designed for a single-source, simplified-chemistry model as compared to the current modeling capabilities available with a multi-source, advanced-chemistry photochemical model, such as CAMx, and its ability to better characterize visibility.

The conservatism built into the BART protocol (e.g., maximum 24-hour emission rates, annual average ammonia concentrations, etc.), in part in response to the then-model-capabilities of CALPUFF, does not allow for accurate representation of temporal considerations. Likewise, CALPUFF's inherent limitations prevent it from providing modeled impacts with meaningful relationships to modeled dates. If CALPUFF BART modeling undertaken according to the BART protocol is neither capable of nor intended to differentiate modeled impacts from one hour to the next or provide any indication of when impacts occur (but instead to estimate an overall maximum impact for the modeled meteorological period), it would perhaps be appropriate to model worst-case emissions for every modeled day. However, given CAMx's superior ability to characterize temporal, hour-to-hour conditions, utilizing a worst-case emission rate is unnecessary and further, unreasonable in part because such a modeled rate likely overstates an individual source's actual visibility impacts. According to Entergy's consultants, the CAMx model's capability to provide a complete representation of emissions, chemistry, transport, deposition, and temporal considerations is skewed if the emissions from a select few sources are inflated. In other words, *the use of maximum 24-hour emissions creates an implicit bias against the BART sources, which causes the CAMx predictions (as altered by EPA's requested adjustments) to be an unrealistic representation of the impact or contribution from those sources – and inherently unreliable.*

Post-Processing CAMx Model Output for BART Assessments

The remaining comments regarding Trinity's CAMx modeling pertain to the post-processing methodology. Although CAMx is a more robust modeling system than CALPUFF, CAMx is still subject to the concerns about potential model performance issues upon which all air quality models are contingent. In its Response to Comments regarding the Texas and Oklahoma FIP for Regional Haze, EPA admits that "any bias issues in CAMx are ameliorated by tethering the model to real monitoring data, through the use of relative response factors generated by modeling of base and future cases to predict future monitored values."[6] This use of relative response factors (RRFs) combined with actual monitor data gathered by the Interagency Monitoring of Protected Visual Environments (IMPROVE) program is the methodology utilized in Entergy's 2015 CAMx Analysis modeling. Entergy's consultants have determined that EPA's proposed methodology, which is based on applying CALPUFF modeling principles to CAMx processing, is technically unsound and should not be used for CAMx modeling analyses.

In its March 10th comments, EPA states that the use of the RRF methodology—an accepted method to account for model bias—is *not* acceptable for BART analyses using CAMx. EPA insists that a limited, CALPUFF-based methodology must be utilized without offering any alternate paths for ameliorating model bias. Therefore, EPA is recommending that the direct-modeled absolute maximum impacts output from CAMx should be utilized as the metric of choice for visibility impairment, despite the likelihood that this method overstates impacts because it fails to account for model bias. Entergy believes that the post-processing methodology used in the 2015 CAMx Analysis (RRFs combined with IMPROVE monitor data) represents the most appropriate and technically defensible evaluation of CAMx modeling outputs for visibility purposes. Additional details regarding EPA's requested adjustments to both the modeled emission rates and post-processing methodology can be found in the 2016 CAMx Modeling Report.

Clean Versus Dirty Background Evaluations

EPA's modeled anticipated visibility baseline impacts and benefits due to proposed controls on Nelson Unit 6 are based on a clean background approach, which evaluates the impact of Nelson Unit 6 against a natural background (i.e., the conditions under which no man-made sources are impacting a Class I area). This methodology assumes that the source of interest is the only source contributing to the overall visibility at the Class I area and no other sources will be influencing the visibility conditions. Therefore, visibility impacts calculated using the clean background methodology are an artificial visibility metric that does not necessarily correspond to the actual visibility conditions in a Class I area.

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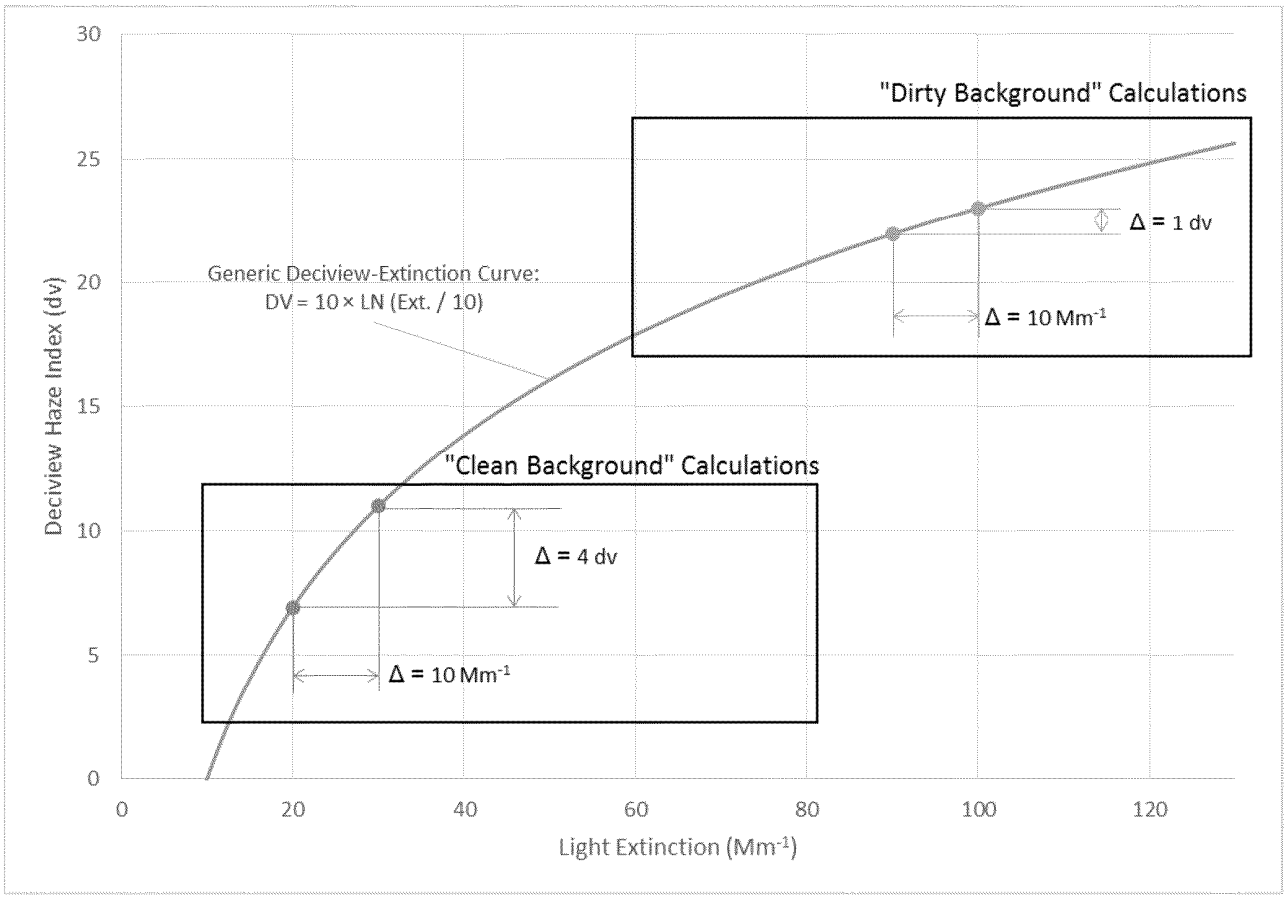
[6] "Response to Comments for the Federal Register Notice for the Texas and Oklahoma Regional Haze State Implementation Plans; Interstate Visibility Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze; and Federal Implementation Plan for Regional Haze." December 9, 2015.

Depending on the background condition at which potential control technology visibility improvements are evaluated (i.e., where on the deciview visibility curve the benefits are applied), the logarithmic nature of the deciview metric can result in widely varying deciview improvements for identical extinction changes. For example, hypothetically, a clean background approach might translate a 10 Mm^{-1} change in light extinction into a 4 dv improvement, while the same 10 Mm^{-1} change might equate to only 1 dv relative to dirty background conditions. Figure 1 below illustrates this general example of logarithmic variation.

Figure 1. Deciview-Extinction Curve – Generic Comparison of Clean and Dirty Background Calculations



The CAMx modeling system is capable of incorporating the influence and contribution of all emissions inventory sources (including both biogenic and anthropogenic sources) into its visibility projections (giving one of several reasons for its better predictive value over CALPUFF). This allows CAMx to estimate the visibility baseline impacts and control technology benefits based on the dirty background methodology, resulting in more realistic visibility predictions relative to the actual visibility conditions during a given time period. Therefore, the baseline visibility

impacts and benefits from controls estimated by CAMx using the dirty background methodology will be closer to the actual visibility improvement expected at a given Class I area in the near term than values estimated based on the clean background methodology. See Figures below (CAMx v. CALPUFF v. Actual IMPROVE data). EPA's clean background projected visibility impacts and control technology benefits for Nelson Unit 6 are unreliable indicators of actual conditions, especially when combined with EPA's other reliability-impairing modeling adjustments (e.g., maximum 24-hour emissions, post-processing without RRFs, etc.).

Figure 2. Observed (IMPROVE) Percent of Total Extinction by Species for 20% Worst Days at Breton Wilderness Area

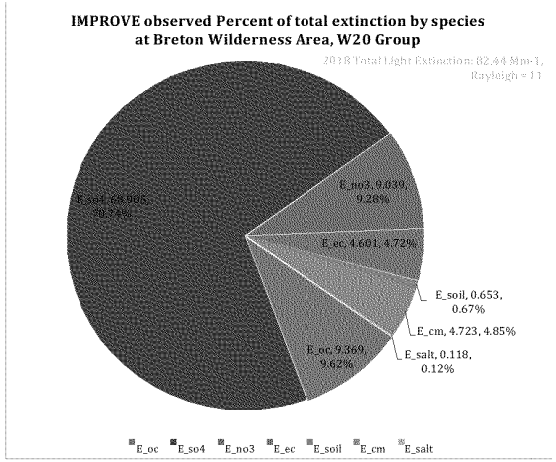


Figure 3. CALPUFF Predicted Percent of Total Extinction by Species for 20% Worst Days at Breton Wilderness Area

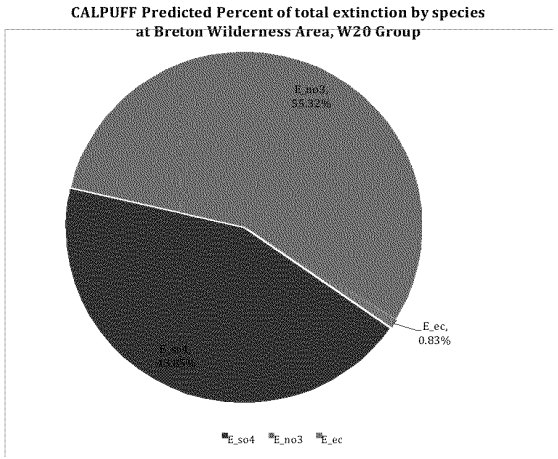
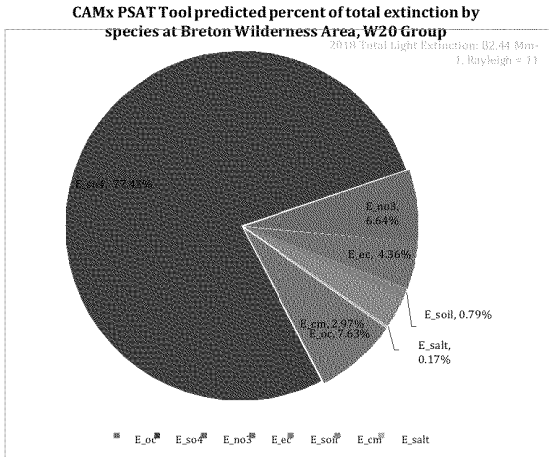


Figure 4. CENRAP CAMx PSAT Tool Predicted Percent of Total Extinction by Species for 20% Worst Days at Breton Wilderness Area



Conclusion

As presented in the 2016 BART Analysis, based on the dirty background post-processing methodology described in the 2016 CAMx Modeling Report, the baseline impact of Nelson Unit 6 is 0.019 dv at Caney Creek and 0.012 dv at Breton. The subsequent visibility benefits due to any of the add-on control options evaluated are therefore *at most* 0.019 dv and 0.012 dv at Caney Creek and Breton, respectively. This equates to a cost of $3 billion or more per dv improvement.

Thus, Entergy continues to believe that Nelson Unit 6 should not be subject to BART. Entergy's CAMx modeling, which utilizes a more technically defensible modeling approach, demonstrates that Nelson Unit 6 does not meaningfully contribute to visibility impairment at either of the nearest Class I areas. If Nelson Unit 6 were nonetheless found to be subject to BART, SO_2 controls are not warranted for Nelson in light of the prohibitive actual costs of all control technologies evaluated and the minimal visibility benefits that potentially could be achieved from such controls.

Thank you for your consideration of this information. Please contact me with any questions or concerns.

Sincerely,

ENTERGY SERVICES, INC.

Kelly McQueen
Assistant General Counsel – Environmental (Lead)

To: Mccarthy, Gina[McCarthy.Gina@epa.gov]; McCabe, Janet[McCabe.Janet@epa.gov]; Gray, David[gray.david@epa.gov]; strenger.wren@epa.gov[strenger.wren@epa.gov]; Hansen, Mark[Hansen.Mark@epa.gov]; Donaldson, Guy[Donaldson.Guy@epa.gov]; Medina, Dayana[Medina.Dayana@epa.gov]; Nann, Barbara[nann.barbara@epa.gov]; Curry, Ron[Curry.Ron@epa.gov]; Coleman, Sam[Coleman.Sam@epa.gov]
Cc: Stephen Cain[Stephen.Cain@aecc.com]
From: Jennifer Loiacano
Sent: Thur 11/24/2016 3:09:30 PM
Subject: Petition for Reconsideration and Administrative Stay - Arkansas Regional Haze FIP - EPA-R06-OAR-2015-0189
2016-11-23 AECC Petition for Reconsideration and Administrative Stay (2) 2.pdf

?Dear Administrator McCarthy,

The email we sent yesterday did not go through to all intended recipients, so please accept this email and attachment as Arkansas Electric Cooperative Corporation's (AECC) Petition for Reconsideration and Request for Administrative Stay. AECC will also be filing a Petition for Review challenging the final rule. Paper copies of this request will follow by mail. If you have any questions about the Petition for Reconsideration and Administrative Stay, please contact me (contact information below) or Stephen Cain at (501) 570-2420 or Stephen.Cain@aecc.com<mailto:Stephen.Cain@aecc.com>.

Thank you in advance for your consideration of this request.
?
Thank you,

Jennifer L. Loiacano
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BEFORE THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In re:	)	
	)	
Promulgation of Air Quality	)	
Implementation Plans; State of	)	Docket No. EPA-R06-OAR-2015-0189
Arkansas; Regional Haze and	)	
Interstate Visibility Transport Federal	)	
Implementation Plan; Final Rule	)	
	)	

Arkansas Electric Cooperative Corporation's
Petition for Reconsideration and Request for Administrative Stay

In accordance with Section 307 of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B), Arkansas Electric Cooperative Corporation (AECC) respectfully requests that the U.S. Environmental Protection Agency (EPA) reconsider and grant an immediate administrative stay of the compliance deadline, and toll the effective date of certain requirements in the final rule entitled "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule" (Final FIP), published at 81 Fed. Reg. 66332 on September 27, 2016. AECC understands that Entergy Arkansas, Inc. and Entergy Mississippi Inc. submitted a comprehensive petition for reconsideration and administrative stay of the Final FIP (Entergy Petition), and AECC incorporates by reference the Entergy Petition into this petition. In this petition, AECC specifically highlights the unique impact EPA's Final FIP would have on AECC's operation and ability to supply affordable power to its members.

I. Introduction

AECC is an Arkansas not-for-profit electric utility owned by 17 distribution cooperatives across the state of Arkansas (members), which in turn are owned by the utility customers they serve. AECC's mission is to provide reliable, affordable, responsible electric service to its members. As a result, AECC is a consumer advocate representing more than 38 percent of the residential consumers in Arkansas, i.e. approximately 520,000 end-use consumers. AECC's service territory extends into 74 of Arkansas's 75 counties, and covers more than 60 percent of the state's geographic area.

AECC owns more than 3500 megawatts (MW) of diverse generation resources including coal, natural gas, gas/oil, and hydropower. AECC also has access to 500 MW of wind, hydropower and biomass pursuant to purchased power agreements. AECC's Board has purposefully invested in a diverse array of generation resources in order to provide the most reliable and affordable electricity for its cooperative members across the state.

The wisdom of this resource diversification is evident in the fact that AECC's wholesale cost to its members is one of the lowest in the country at approximately 4.9 cents/kilowatt hour (kwh).[1] This affordability is absolutely necessary for the large proportion of AECC's low income households: Arkansas has the 9th lowest per capita income in the United States,[2] and 19.1 percent of its citizens[3] and 26 percent of the state's children live below the poverty level .[4] Since AECC serves the rural communities in the state and most of the areas in the Delta, the percentage of electric cooperative households and children in poverty is much higher than the state average served by investor-owned utilities.

The EPA published the Final FIP for Regional Haze for Arkansas on Tuesday, September 27, 2016. The Final FIP requires, among other things, installation of SO2 controls (scrubbers) on the units located at the Flint Creek Power Plant – which AECC owns jointly with American Electric Power's Southwestern Electric Power Company (AEP) – as well as the White Bluff S team Electric Station Units I and II in Redfield, Arkansas (White Bluff) and the Independence Steam Electric Station Units I and II in Newark, Arkansas (Independence) –all of which AECC co -owns with Entergy Corporation, including its operating company Entergy Arkansas, Inc. (EAI or Entergy).

White Bluff I and II and Independence I and II represent a total of approximately 1168 MW of generating capacity for AECC , out of a total of 3500 MW . These four units entered commercial operation between 1980 and 1984 , and could potentially operate indefinitely into the future absent economic or regulatory constraints. As a 35% owner of White Bluff and Independence, AECC will be forced to spend approximately $700 million dollars to prepare to install the required controls. Collectively, EAI, AECC, and other co-owners of the units will be forced to spend approximately $2 billion. Because of the extreme financial hardship AECC will face if the Final FIP is not stayed,AECC has already begun discussion about the possible retirement of both White Bluff and Independence in order to meet the imminent compliance deadline of October 27, 2021 , rather than add scrubbers to those units.

Regarding White Bluff, a recent economic impact study of this plant's contribution to the regional economy demonstrates that this plant provides hundreds of millions in annual revenues to businesses, schools, and the communities in some of the most impoverished counties in the country.[5] The removal of these revenues from some of the poorest communities in the nation is unconscionable. These families, farms, schools and

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[1] *See* Arkansas Electric Cooperative Corporation Annual Report 2015 (received by the Arkansas PSC on April 29, 2016), available at http://www.apscservices.info/RcvdDocs/3_1_05022016_1_1.pdf (calculated by dividing the net revenue by the number of kilowatt hours).

[2] Michael Pakko, Personal Income – 2015Q4, ARKANSASECONOMIST.COM (March 24, 2016) (citing U.S. Bureau of Economic Analysis).

[3] 2015 American Community Survey 1-Year Profiles, Individuals Below Poverty Level by State, WWW.CENSUS.GOV. (ranking Arkansas as the second state, after Louisiana, with the highest number of citizens living below the poverty level).

[4] Arkansas Demographics of Poor Children, National Center for Children in Poverty, WWW.NCCP.ORG (last updated April 6, 2016) (state data calculated using the 2010-2014 American Community Survey, representing information from 2014).

[5] Willlie Lee Brooks, Jr., *What is the Economic Impact of the White Bluff Electric Power Plant?* (May 30, 2014), available at www.arkleg.state.ar.us (accessible via google searching "Economic Impact Study of White Bluff").

businesses have nowhere to turn for replacement income. The loss of the White Bluff plant more than two decades early would have devastating impacts on this region and a large portion of Arkansas, particularly the members AECC serves.

AECC respectfully requests that EPA reconsider and grant an immediate administrative stay of a number of the requirements imposed on White Bluff and Independence. Specifically, AECC requests EPA reconsider and administratively stay the (1) best available retrofit technology (BART) requirements related to sulfur dioxide (SO_2) emission control equipment at White Bluff, (2) 18-month compliance deadline for installation of oxides of nitrogen (NOx) controls at these units, (3) NOx limit that applies at low loads and the three-hour averaging period for NOx compliance, and (4) imposition of reasonable progress controls on Independence.

With respect to the request for stay, any costs of compliance for AECC are passed directly to AECC's members, who in turn pass them along to their members—many of whom are already struggling financially. These expenditures would be wholly unnecessary if AECC's legal challenges to the FIP are successful. Not only does justice require a stay of the FIP, but these legal challenges are based on sound legal principles and are likely to succeed on the merits, and making a stay in the public interest and necessary to prevent irreparable harm to AECC and its members. In contrast, no significant harm will result to either EPA or the public from a stay of the FIP, given that the emission reductions and resulting visibility improvements contemplated under the Final FIP will be incremental at best.[6]

II. Request for Reconsideration

The Clean Air Act requires the Administrator of EPA to grant reconsideration of a proceeding if a petitioner "can demonstrate . . . it was impracticable to raise [an] objection" to a final action within the time for public comment or if "the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." 42 U.S.C. § 7607(d)(7)(B). As demonstrated below, EPA must grant reconsideration of the Final FIP, because EPA failed to provide adequate notice and opportunity to comment on requirements that are of central relevance to the Final FIP.

A. The 18-month compliance deadline for installation of low-NOx burners and separated overfire air (LNB/SOFA) was decided without due process and is arbitrary and capricious.

The Final FIP changed the timeframe for NOx burners' installation on five units from 3 years to 18 months without allowing the interested parties any opportunity to comment.[7] This requirement is not a logical outgrowth[8] of the proposed FIP, and such a tight compliance timeframe is both extremely difficult—if not impossible—to meet and

[6] 81 Fed. Reg. at 66386.

[7] 81 Fed. Reg. at 66344, 66358. In the proposed FIP, EPA invited public comment on the appropriateness of the proposed compliance dates for emission limits of Domtar Ashdown Power Boiler No. 2. only. 80 Fed. Reg. 18988 ("We are proposing to require compliance with the emission limit no later than 3 years from the effective date of the final rule, and are inviting public comment on the appropriateness of this compliance date.") EPA did not invite comments on other proposed compliance dates for any other units.

[8] *See Envtl. Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005).

unprecedented. In fact, upon review of other Regional Haze Rule FIPs issued by EPA, AECC believes that the Arkansas Final FIP is the first time EPA has ever issued a FIP requiring a compliance date of less than 3 years to install LNB/SOFA.

In the 2015 Proposed FIP, published at 80 Fed. Reg. 18944, EPA proposed to require installation and operation of LNB/SOFA on the White Bluff and Independence units "no later than 3 years from the effective date of the final rule, consistent with [its] regional haze regulations."[9] EPA justified this proposal, stating "as is generally the case for installation of NOx controls on EGUs, we expect that 3 years from the date of our final action would be sufficient time for Independence to install and operate LNB/SOFA controls at Units 1 and 2 and to comply with the associated emission limits."[10] Moreover, in the Final FIP, EPA stated that to determine what is "as expeditiously as practicable" for installation and operation of a control technology, "the states and EPA usually consider the amount of time it generally takes to install and operate that type of technology at similar sources and the compliance dates that have been required for the installation and operation of the same type of control technology at similar sources in other regional haze actions."[11]

Directly contrary to EPA's own statements in the Proposed FIP and the Final FIP, EPA finalized an 18-month compliance deadline for White Bluff and Independence to install LNB/SOFA on five units based on comments from environmental groups stating that LNB/SOFA could be installed in six to eight months.[12] EPA agreed with the environmental groups with no further explanation and imposed the 18-month deadline, as opposed to its own proposed 3-year compliance period.

For LNB/SOFA, three years is generally considered the time required for installation. For Arkansas specifically, AECC agrees the three-year time frame is "as expeditious as practicable," especially considering there are four units at White Bluff and Independence within the same regional transmission organization system that would be affected by outages during the period.

In any case, EPA's newly-imposed 18-month requirement is not feasible. Accelerated construction schedules would be required at additional expense to AECC's members. Outages to install the controls could not be optimally scheduled to minimize the cost of replacement energy and could also compromise system reliability. In short, the lack of due process in EPA's requested comment on 3 years, to an imposition of an 18-month deadline requires EPA to reconsider its unprecedented and impracticable compliance deadline.

[9] 80 Fed. Reg. at 18975.
[10] 80 Fed. Reg. at 18996.
[11] 81 Fed. Reg. at 66376-77.
[12] 81 Fed. Reg. at 66342.

B. The NOx emission limits for White Bluff and Independence are not a logical outgrowth of the proposed rule and parties did not have a meaningful opportunity to comment.

In addition to EPA's failure to provide an opportunity to comment on the compliance date, EPA also failed to allow an opportunity to comment on the rolling 3-hour average limit when the units operate below 50 percent capacity.

In its proposed FIP, EPA proposed a NOx BART emission limit of 0.15 lb/MMBtu on a 30-boiler-operating day rolling average based on the installation and operation of LNB/SOFA with a 3-year compliance deadline.[13] Although EPA did not specifically sdicit comments on this proposal, Entergy proposed a rolling 30-boiler-operating day average emission rate of 1,342.5 lb NOx/hr at each coal-fired unit at White Bluff and Independence to address the potential for a higher NOx emission rate at operating rates of less than 50% of unit capacity.[14] And, in the alternative, Entergy suggested a bifurcated emission limit a limit of 1,342.5 lb NOx/hr, based on a rolling 30-boiler operating day average for all unit operation (0-100% of capacity), and a limit of 0.15 lb NOx/MMBtu, based on a rolling 30-boiler operating day average, to include only those hours for which the unit was dispatched at 50% or greater of maximum capacity.[15]

The Final FIP requires the units at White Bluff and Independence to each meet NOx emission limits of 0.15 lb/MMBtu on a rolling 30-boiler operating day basis at loads of 50-100 percent of maximum heat input rating and a rolling 3-hour average limit of 671 lb/hr at loads of less than 50 percent of maximum heat input rating.[16] These emission limits, which must be met beginning April 27, 2018, are based on the installation of LNB/SOFA on each unit.[17] It cannot be said that the Final FIP's averaging period and emission limits are a logical outgrowth of the proposed rule, as EPA suggests.[18] For the reasons explained in Entergy's Petition, these limits and averaging periods are unworkable for low-load operation and will result in exceedances of the limit.[19]

The Final FIP's averaging period and limits are arbitrary and capricious, unprecedented, and exceed the bounds of a "logical outgrowth" of the proposed FIP. As it stands, the Final FIP is "in violation of the procedures mandated by the notice and comment provisions of the APA." *Am. Fed'n of Labor & Cong. of Indus. Organizations v. Donovan,* 757 F.2d 330, 340 (D.C. Cir. 1985). Thus, EPA must revise the averaging time to a 30-boiler-operating day period and the limit to the achievable value specified in the Entergy Petition to allow the unavoidable NOxspikes that occur during start-ups and load

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[13] 80 Fed. Reg. at 18970, 18997.
[14] Entergy Arkansas, Inc. Comments on the Proposed Regional Haze and Interstate Visibility Report Federal Implementation Plan for Arkansas, Docket No. EPA-R06-OAR-2015-0189 (Aug. 7, 2015), at 51-52.
[15] *Id.*
[16] 40 C.F.R. §§ 52.173(c)(6)-(8); 81 Fed. Reg. at 66344
[17] 81 Fed. Reg. at 66344.
[18] 81 Fed. Reg. at 66344.
[19] *See* Entergy Petition.

changes to level off over the averaging period, which results in a limit that is possible to achieve.

C. Independence should not have been included in the Final FIP.

AECC believes that the intent of the Regional Haze Rule is to place primary emphasis during the first planning period on BART-eligible units and the secondary emphasis on units that are not BART-eligible *only* if the state was not meeting its visibility goals.

Arkansas is meeting its visibility goals.[20] Further, EPA agrees that Independence is not a BART-eligible unit.[21] Therefore, Independence should be excluded from the first regional haze planning period as controls are not required at this time. EPA did not appropriately analyze which sources, if any, should be controlled for reasonable progress on visibility and did not follow the procedures it has regularly used in other regional haze FIPs. Further, emission limits on Independence during the first planning period are unnecessary to demonstrate reasonable progress as Arkansas already is below the glide path for the first planning period. In short, it is an impermissible overreach to include Independence in the Final FIP.

In its Final FIP, EPA claimed that it began its reasonable progress analysis by determining "whether additional controls on Arkansas sources are necessary to make reasonable progress in the first regional haze planning period." [22] The EPA's analysis is flawed and unprecedented, given that the proposed emission limits for Independence, as well as other sources in Arkansas, are not necessary to achieve reasonable progress for background visibility.[23] The CAA requires regional haze implementation plans to determine whether reductions in a source's emissions are *necessary* to achieve reasonable progress for the planning period under consideration. 42 U.S.C. § 7491(b)(2). Moreover, ""neither the Clean Air Act nor the Regional Haze Rule requires source-specific analysis in the determination of reasonable progress goals." *Texas v. EPA*, 829 F.3d 405, 428 (5th Cir. 2016) (quoting *Wildearth Guardians v. EPA*, 770 F.3d 919, 944 (10th Cir. 2014)).

According to the IMPROVE monitoring data submitted by EAI,[24] Caney Creek and Upper Buffalo already are meeting the EPA's proposed RPGs and Arkansas' RPGs and that visibility impairment continues to trend downward. Because Arkansas' Class I areas already surpassed the RPGs and the URP goals, reasonable progress controls during the

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[20] Entergy Arkansas Inc., Supplemental Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, Docket No. EPA-R06-OAR-2015-0189 (submitted on Aug. 8 2016). ADEQ also submitted data showing that Caney Creek and Upper Buffalo will be below the glide path in 2018. State of Arkansas, State Implementation Plan Review for the Five-Year Regional Haze Progress Report, at 55-56 (May 2015)

[21] 81 Fed Reg. at 66336, 66350.

[22] 81 Fed. Reg. at 66350.

23 *See* Entergy Petition.

[24] Entergy Arkansas Inc., Supplemental Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, Docket No. EPA-R06-OAR-2015-0189 (submitted on Aug. 8 2016).

first planning period are not necessary to ensure reasonable progress towards the natural visibility goals, as stated in 42 U.S.C. § 7941(b)(2).

Essentially, it appears that, for certain regional haze SIPs and FIPs, EPA deemed a control to be "reasonable" if it is "cost-effective."[25] This is concerning because it does not consider the costs in relation to visibility improvement or lack thereof. The Final FIP requires controls on Independence because it alleges the plant is "a significant source of SO2 and NOx" and controls would be cost-effective. Whether or not a plant is a significant source of visibility impairing pollutants is not a statutory factor that states must consider in evaluating reasonable progress controls and neither is cost-effectiveness a statutory standard that allows EPA to exceed its jurisdiction.

Specifically, EPA's assertion that Independence warrants additional controls relies entirely on the Agen cy's claim that the controls would be cost -effective, on a dollar per ton basis.[26] EPA gave no consideration to whether the controls and resulting emissions reductions would actually improve visibility in any Class I areas and, in fact, recognized that controls would not be necessary for Arkansas Class I areas to meet their URPs.[27] The absurd result is that EPA is proposing that a public utility and its customers be required to invest more than $1 billion in power plant controls that would have negligible, if any, impacts on visibility in any Class I areas when such measures are unnecessary for Arkansas to achieve its reasonable progress goals. Such a jurisdictional overstep is not legally permissible and should be reconsidered.

III. Request for Administrative Stay

The legal standard for an administrative stay is broader than the standard for a judicial stay. The Clean Air Act provides that EPA may grant a stay if the agency has decided to reconsider the rule. 42 U.S.C. § 7607(d)(7)(B). Under the Administrative Procedures Act, EPA has authority to stay the requirements of a FIP when "justice so requires . . . pending judicial review." 5 U.S.C. § 705. No other conditions are imposed on the Agency's authority to issue a stay. AECC respectfully requests that EPA stay the Final FIP, specifically §§ 52.173(c)(6) -(8) and §§ 52.173(c)(24) -(26). A s this section demonstrates, a stay of the FIP would prevent harms to AECC and its member-owners and will not negatively affect visibility. In addition, a stay will permitwell-justified further consideration of the Final FIP.

Absent an administrative stay AECC and other petitioners will suffer various forms of irreparable injury, harming AECC members and impairing Arkansas' economy. Moreover, t he costs imposed by the Final FI P on electric generation capacity within Arkansas are substantial. The Final FIP will impose approximately $2 billion in costs, and no discernible benefit will accrue during the relevant implementation period covered by the SIP submittal under review, whi ch ends in 2018. Owner/operators of five coal-fired units within Arkansas are required to install scrubbers by October 2021 and LNB/SOFA by April 2018. These costs will likely challenge the economic viability of these units, and it is possible that some of the units will shut down rather than incur the costs

[25] 81 Fed. Reg. at 66353.
[26] *Id.*
[27] 80 Fed. Reg. at 18,992.

of installing the required controls causing additional costs in the form of replacement power.

Installing dry scrubbers on all four units would be a massive undertaking and an extreme financial and technological hardship for AECC. This work would have to begin immediately, as the process requires the entirety of the five years allotted in the Final FIP. Of the $2.1 billion that Entergy estimates it would spend for scrubbers on White Bluff and Independence AECC is financially responsible for 35% of the total cost – or approximately $700 million. Based on Entergy's estimates, AECC would need to spend $9 million within the first six months, and $31 million within first 12 months, $84 million within 18 months, and $156 million within 24 months. These estimates do not include the costs for LNB/SOFA which are required to be installed by April 2018.

If Entergy decides to deactivate the units, then AECC must procure replacement power. This would consist of designing, gaining regulatory approval for, constructing, and making operational a new alternative generating unit. Depending on the site that is selected for the new units, rights-of-way will likely need to be obtained. Transmission – both electrical and gas – would need to be planned and built to connect the new units to the grid. Specifically, to construct replacement generation as quickly as possible, AECC must select a location, prepare and submit environmental permit applications, prepare requests for proposals, select vendors, and received Arkansas Public Service Commission approval.

Accordingly, in order to meet the October 2021 deadline, planning must begin immediately to limit, as much as possible, the duration of member exposure to market prices. In the meantime, even maintaining reliability through the purchase of power would require AECC to accelerate planned transmission projects which would only drive up the costs of those projects.

If all four units are shut down in October of 2021, AECC would need to add an estimated 500 megawatts of firm generation capacity. Estimates of the cost of this new replacement generation would be approximately $490 million. The levelized investment recovery costs of this generation capacity to AECC's member cooperatives would be approximately $34 million annually. AECC would also need to add an estimated additional 250 megawatts of replacement generation capacity by year 2026. This would require a further investment of approximately $245 million – or a further increase of approximately $17 million annually to AECC's members.

The Supreme Court has declared that "[o]ne would not say that it is even rational. . . to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits." *Michigan v. EPA*, 135 S. Ct. 2699, 2707 (2015). Moreover, courts have often issued stays to similarly situated petitioners challenging other FIPs. *See, e.g., Texas v. United States EPA*, 829 F.3d 405, 424 (5th Cir. 2016) (staying implementation of Texas FIP imposing over $2 billion in costs); *Oklahoma v. EPA*, 723 F.3d at 1206-07 (staying implementation of rule imposing $1.2 billion in costs).

In addition to the harm that will result absent a stay, AECC has a strong likelihood of success in establishing that EPA exceeded its statutory authority by imposing emission controls that will not affect the reasonable progress goals covered by the first round of implementation plans. State implementation plans must be designed to achieve the

reasonable progress goals for the period covered by the plan, *i.e.* the December 2007 to July 31, 2018 period. *Texas v. United States EPA*, 829 F.3d at 429. When Arkansas submitted its plan in 2008, the regulations in effect required states "to set the emissions controls necessary to achieve the reasonable progress goal for 2018." *Id.* (stating that courts assess agency actions according to the effective statutes and regulations at the time of the relevant activity) (citing *Caring Hearts Personal Home Servs., Inc. v. Burwell*, 824 F.3d 968, 971 (10th Cir. 2016)).

In its Final FIP, EPA stated:

> In this instance, we are taking final action on the Arkansas Regional Haze FIP 9 years after the state's initial SIP submission was due. As a result, only some of the control measures that we have determined are necessary to satisfy the BART and reasonable progress requirements will be installed by the end of 2018. Some controls will not be installed until 2021.[28]

Measures that would be implemented at the end of or after the 2018 period are not appropriate for inclusion in a FIP that is purportedly filling a gap in the 2008 SIP revision covering a period to end in 2018. The regional haze planning process requires "control strategies to cover an initial implementation period extending to the year, 2018, with a reassessment and revision of those strategies, as appropriate, every 10 years."[29] Thus, it is improper for EPA to prescribe controls that are not required until the end of the first planning period, or thereafter, given that such controls will not affect the reasonable progress goal for the first implementation period. Even if such controls were determined appropriate for this planning period, the 18-month compliance date is unjustifiable, was implemented without allowing interested parties an opportunity to comment in contravention of due process, and materially deviates from other FIP compliance dates.

As demonstrated above, a stay is in the public interest and necessary to prevent irreparable harm to AECC and its members. In contrast, no significant harm will result to either EPA or the public from a stay of the Final FIP, given that Arkansas already is below the glide path and many of the emission reductions and resulting visibility improvements contemplated under the Final FIP will be incremental at best.[30] Thus, EPA should grant AECC's stay request.

IV. Conclusion

For the foregoing reasons, and the reasons set forth in Entergy's Petition, EPA should grant AECC's petition for reconsideration and administrative stay of the Final FIP.

November 23, 2016

[28] 81 Fed. Reg. at 66410.
[29] 64 Fed. Reg. at 35,734.
[30] 81 Fed. Reg. at 66386.

Respectfully submitted,

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Cc: Stephen Cain[Stephen.Cain@aecc.com]
From: Jennifer Loiacano
Sent: Wed 11/23/2016 8:14:07 PM
Subject: Petition for Reconsideration and Administrative Stay - Arkansas Regional Haze FIP - EPA-R06-OAR-2015-0189
2016-11-23 AECC Petition for Reconsideration and Administrative Stay.pdf

Dear Administrator McCarthy,

Please find attached a Petition for Reconsideration and Administrative Stay filed on behalf of Arkansas Electric Cooperative Corporation (AECC). AECC will also be filing a Petition for Review today challenging the final rule. Paper copies of this request will follow by mail. If you have any questions about the Petition for Reconsideration and Administrative Stay, please contact me (contact information below) or Stephen Cain at (501) 570-2420 or Stephen.Cain@aecc.com.

Thank you in advance for your consideration of this request.

Thank you,

Jennifer L. Loiacano

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BEFORE THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In re:	)	
	)	
Promulgation of Air Quality	)	
Implementation Plans; State of	)	Docket No. EPA-R06-OAR-2015-0189
Arkansas; Regional Haze and	)	
Interstate Visibility Transport Federal	)	
Implementation Plan; Final Rule	)	
	)	

Arkansas Electric Cooperative Corporation's
Petition for Reconsideration and Request for Administrative Stay

In accordance with Section 307 of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B), Arkansas Electric Cooperative Corporation (AECC) respectfully requests that the U.S. Environmental Protection Agency (EPA) reconsider and grant an immediate administrative stay of the compliance deadline and toll the effective date of certain requirements in the final rule entitled "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule" (Final FIP), published at 81 Fed. Reg. 66332 on September 27, 2016. AECC understands that Entergy Arkansas, Inc. and Entergy Mississippi Inc. submitted a comprehensive petition for reconsideration and administrative stay of the Final FIP (Entergy Petition), and AECC incorporates by reference the Entergy Petition into this petition. In this petition, AECC specifically highlights the unique impact EPA's Final FIP would have on AECC's operation and ability to supply affordable power to its members.

I. Introduction

AECC is an Arkansas not-for-profit electric utility owned by 17 distribution cooperatives across the state of Arkansas (members), which in turn are owned by the utility customers they serve. AECC's mission is to provide reliable, affordable, responsible electric service to its members. As a result, AECC is a consumer advocate representing more than 38 percent of the residential consumers in Arkansas, i.e. approximately 520,000 end-use consumers. AECC's service territory extends into 74 of Arkansas's 75 counties, and covers more than 60 percent of the state's geographic area.

AECC owns more than 3500 megawatts (MW) of diverse generation resources including coal, natural gas, gas/oil, and hydropower. AECC also has access to 500 MW of wind, hydropower and biomass pursuant to purchased power agreements. AECC's Board has purposefully invested in a diverse array of generation resources in order to provide the most reliable and affordable electricity for its cooperative members across the state.

The wisdom of this resource diversification is evident in the fact that AECC's wholesale cost to its members is one of the lowest in the country at approximately 4.9

cents/kilowatt hour (kwh).[1] This affordability is absolutely necessary for the large proportion of AECC's low income households: Arkansas has the 9th lowest per capita income in the United States,[2] and 19.1 percent of its citizens[3] and 26 percent of the state's children live below the poverty level .[4] Since AECC serves the rural communities in the state and most of the areas in the Delta, the percentage of electric cooperative households and children in poverty is much higher than the state average served by investor-owned utilities.

The EPA published the Final FIP for Regional Haze for Arkansas on Tuesday, September 27, 2016. The Final FIP requires, among other things, installation of SO2 controls (scrubbers) on th e units located at the Flint Creek Power Plant – which AECC owns jointly with American Electric Power's Southwestern Electric Power Company (AEP) – as well as the White Bluff Steam Electric Station Units I and II in Redfield, Arkansas (White Bluff) and the Independence Steam Electric Station Units I and II in Newark, Arkansas (Independence) –all of which AECC co -owns with Entergy Corporation, including its operating company Entergy Arkansas, Inc. (EAI or Entergy).

White Bluff I and II and Independence I and II represent a total of approximately 1168 MW of generating capacity for AECC , out of a total of 3500 MW . These four units entered commercial operation between 1980 and 1984, and could potentially operate indefinitely into the future absent economic or regulatory constraints. As a 35% owner of White Bluff and Independence, AECC will be forced to spend approximately $700 million dollars to prepare to install the required controls. Collectively, EAI, AECC, and other co-owners of the units will be force d to spend approximately $2 billion. Because of the extreme financial hardship AECC will face if the Final FIP is not stayed,AECC has already begun discussion about possible retirement of both White Bluff and Independence in order to meet the imminent compliance deadline of October 27, 2021 , rather than add scrubbers to those units.

Regarding White Bluff, a recent economic impact study of this plant's contribution to the regional economy demonstrates that this plant provides hundreds of millions in annual revenues to businesses, schools, and the communities in some of the most impoverished counties in the country.[5] The removal of these revenues from some of the poorest communities in the nation is unconscionable. These families, farms, schools and businesses have nowhere to turn for replacement income. The loss of the White Bluff

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[1] *See* Arkansas Electric Cooperative Corporation Annual Report 2015 (received by the Arkansas PSC on April 29, 2016), available at http://www.apscservices.info/RcvdDocs/3_1_05022016_1_1.pdf (calculated by dividing the net revenue by the number of kilowatt hours).

[2] Michael Pakko, Personal Income – 2015Q4, ARKANSASECONOMIST.COM (March 24, 2016) (citing U.S. Bureau of Economic Analysis).

[3] 2015 American Community Survey 1-Year Profiles, Individuals Below Poverty Level by State, WWW.CENSUS.GOV. (ranking Arkansas as the second state, after Louisiana, with the highest number of citizens living below the poverty level).

[4] Arkansas Demographics of Poor Children, National Center for Children in Poverty, WWW.NCCP.ORG (last updated April 6, 2016) (state data calculated using the 2010-2014 American Community Survey, representing information from 2014).

[5] Willlie Lee Brooks, Jr., *What is the Economic Impact of the White Bluff Electric Power Plant?* (May 30, 2014), available at www.arkleg.state.ar.us (accessible via google searching "Economic Impact Study of White Bluff").

plant more than two decades early would have devastating impacts on this region and a large portion of Arkansas, particularly the members AECC serves.

AECC respectfully requests that EPA reconsider and grant an immediate administrative stay of a number of the requirements imposed on White Bluff and Independence. Specifically, AECC requests EPA reconsider and administratively stay the (1) best available retrofit technology (BART) requirements related to sulfur dioxide (SO_2) emission control equipment at White Bluff, (2) 18-month compliance deadline for installation of oxides of nitrogen (NOx) controls at these units, (3) NOx limit that applies at low loads and the three-hour averaging period for NOx compliance, and (4) imposition of reasonable progress controls on Independence.

With respect to the request for stay, any costs of compliance for AECC are passed directly to AECC's members, who in turn pass them along to their members—many of whom are already struggling financially. These expenditures would be wholly unnecessary if AECC's legal challenges to the FIP are successful. Not only does justice require a stay of the FIP, but these legal challenges are based on sound legal principles and are likely to succeed on the merits, and making a stay is in the public interest and necessary to prevent irreparable harm to AECC and its members. In contrast, no significant harm will result to either EPA or the public from a stay of the FIP, given that the emission reductions and resulting visibility improvements contemplated under the Final FIP will be incremental at best.[6]

II. Request for Reconsideration

The Clean Air Act requires the Administrator of EPA to grant reconsideration of a proceeding if a petitioner "can demonstrate . . . it was impracticable to raise [an] objection" to a final action within the time for public comment or if "the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." 42 U.S.C. § 7607(d)(7)(B). As demonstrated below, EPA must grant reconsideration of the Final FIP, because the FIP is riddled with clear errors and EPA failed to provide adequate notice and opportunity to comment on requirements that are of central relevance to the Final FIP.

A. The 18-month compliance deadline for installation of low-NOx burners and separated overfire air (LNB/SOFA) was decided without due process and is arbitrary and capricious.

The Final FIP changed the timeframe for NOx burners' installation on five units from 3 years to 18 months without allowing the interested parties any opportunity to comment.[7] This requirement is not a logical outgrowth of the proposed FIP, and such a tight compliance timeframe is both extremely difficult—if not impossible—to meet and

[6] 81 Fed. Reg. at 66386.

[7] 81 Fed. Reg. at 66344, 66358. In the proposed FIP, EPA invited public comment on the appropriateness of the proposed compliance dates for emission limits of Domtar Ashdown Power Boiler No. 2. only. 80 Fed. Reg. 18988 ("We are proposing to require compliance with the emission limit no later than 3 years from the effective date of the final rule, and are inviting public comment on the appropriateness of this compliance date.") EPA did not invite comments on other proposed compliance dates for any other units.

unprecedented. In fact, u pon review of other Regional Haze Rule FIPs issued by EPA, AECC believes that t he Arkansas Final FIP is the first time EPA has ever issued a FIP requiring a compliance date of less than 3 years to install LNB/SOFA.

In the 2015 Proposed FIP, published at 80 Fed. Reg. 18944, EPA proposed to require installation and operation of LNB/SOFA on the W hite Bluff and Independence units "no later than 3 years from the effective date of the final rule, consistent with [its] regional haze regulations."[8] EPA justified this proposal, stat ing "as is generally the case for installation of NOx controls on EGUs, we expect that 3 years from the date of our final action would be sufficient time for Independence to install and operate LNB/SOFA controls at Units 1 and 2 and to comply with the asso ciated emission limits."[9] Moreover, in the Final FIP, EPA stated thatto determine what is "as expeditiously as practicable" for installation and operation of a control technology, "the states and EPA usually consider the amount of time it generally takes to install and operate that type of technology at similar sources and the compliance dates that have been required for the installation and operation of the same type of control technology at similar sources in other regional haze actions."[10]

Directly contrary to EPA's own statements in the Proposed FIP and the Final FIP, EPA finalized an 18 -month compliance deadline for White Bluff and Independence to install LNB/SOFA on five units based on comments from environmental groups stating that LNB/SOFA could be installed in six to eight months.[11] EPA agreed with the environmental groups with no further explanation and imposed the 18 -month deadline, as opposed to its own proposed 3-year compliance period.

For LNB/SOFA, three years is generally considered the time required for installation. For Arkansas specifically, AECC agrees the three -year time frame is "as expeditious as practicable," especially considering there are four units at White Bluff and Independence within the same regional transmission organization system that would be affected by outages during the period.

In any case, EPA's newly-imposed 18-month requirement is not feasible. Accelerated construction schedules would be required at additional expense to AECC's members. Outages to install the controls could not be optimally scheduled to minimize the cost of replacement energy and could also compromise system reliability . In short, the lack of due process in EPA's requested comment on 3 years, to an imposition of an 18 month deadline requires EPA to re consider its unprecedented and impracticable compliance deadline.

[8] 80 Fed. Reg. at 18975.
[9] 80 Fed. Reg. at 18996.
[10] 81 Fed. Reg. at 66376-77.
[11] 81 Fed. Reg. at 66342.

B. The NOx emission limits for White Bluff and Independence are not a logical outgrowth of the proposed rule and parties did not have a meaningful opportunity to comment.

In addition to EPA's failure to provide an opportunity to comment on the compliance date, EPA also failed to allow an opportunity to comment on the rolling 3-hour average limit when the units operate below 50 percent capacity.

In its proposed FIP, EPA proposed a NOx BART emission limit of 0.15 lb/MMBtu on a 30-boiler-operating day rolling average based on the installation and operation of LNB/SOFA with a 3-year compliance deadline.[12] Although EPA did not specifically solicit comments on this proposal, Entergy proposed a rolling 30-boiler-operating day average emission rate of 1,342.5 lb NOx/hr at each coal-fired unit at White Bluff and Independence to address the potential for a higher NOx emission rate at operating rates of less than 50% of unit capacity.[13] And, in the alternative, Entergy suggested a bifurcated emission limit a limit of 1,342.5 lb NOx/hr, based on a rolling 30-boiler operating day average for all unit operation (0-100% of capacity), and a limit of 0.15 lb NOx/MMBtu, based on a rolling 30-boiler operating day average, to include only those hours for which the unit was dispatched at 50% or greater of maximum capacity.[14]

The Final FIP requires the units at White Bluff and Independence to each meet NOx emission limits of 0.15 lb/MMBtu on a rolling 30-boiler operating day basis at loads of 50-100 percent of maximum heat input rating and a rolling 3-hour average limit of 671 lb/hr at loads of less than 50 percent of maximum heat input rating.[15] These emission limits, which must be met beginning April 27, 2018, are based on the installation of LNB/SOFA on each unit.[16] It cannot be said that the Final FIP's averaging period and emission limits are a logical outgrowth of the proposed rule, as EPA suggests.[17] For the reasons explained in Entergy's Petition, these limits and averaging periods are unworkable for low-load operation and will result in exceedances of the limit.[18]

The Final FIP's averaging period and limits are arbitrary and capricious, unprecedented, and exceed the bounds of a "logical outgrowth" of the proposed FIP. As it stands, the Final FIP is "in violation of the procedures mandated by the notice and comment provisions of the APA." *Am. Fed'n of Labor & Cong. of Indus. Organizations v. Donovan,* 757 F.2d 330, 340 (D.C. Cir. 1985). Thus, EPA must revise the averaging time to a 30-boiler-operating day period and the limit to the achievable value specified in the Entergy Petition to allow the unavoidable NOx spikes that occur during start-ups and load changes to level off over the averaging period, which results in a limit that is possible to achieve.

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[12] 80 Fed. Reg. at 18970, 18997.
[13] Entergy Arkansas, Inc. Comments on the Proposed Regional Haze and Interstate Visibility Report Federal Implementation Plan for Arkansas, Docket No. EPA-R06-OAR-2015-0189 (Aug. 7, 2015), at 51-52.
[14] *Id.*
[15] 40 C.F.R. §§ 52.173(c)(6)-(8); 81 Fed. Reg. at 66344
[16] 81 Fed. Reg. at 66344.
[17] 81 Fed. Reg. at 66344.
[18] *See* Entergy Petition.

C. Independence should not have been included in the Final FIP.

AECC believes that the intent of the Regional Haze Rule is to place primary emphasis during the first planning period on BART-eligible units and the secondary emphasis on units that are not BART-eligible *only* if the state was not meeting its visibility goals. Arkansas is meeting its visibility goals and, therefore, units that are not BART-eligible should not be addressed during the first planning period.

Arkansas is meeting its visibility goals. Plus, EPA agrees that Independence is not a BART-eligible unit.[19] Therefore, Independence should be excluded from the first regional haze planning period as controls are not required at this time. EPA did not appropriately analyze which sources, if any, should be controlled for reasonable progress on visibility and did not follow the procedures it has regularly used in other regional haze FIPs. Further, emission limits on Independence during the first planning period are unnecessary to demonstrate reasonable progress as Arkansas already is below the glide path for the first planning period. In short, it is an impermissible overreach to include Independence.

In its Final FIP, EPA claimed that it began its reasonable progress analysis by determining "whether additional controls on Arkansas sources are necessary to make reasonable progress in the first regional haze planning period."[20] The EPA's analysis is flawed and unprecedented, given that the proposed emission limits for Independence, as well as other sources in Arkansas, are not necessary to achieve reasonable progress for background visibility.[21] The CAA requires regional haze implementation plans to determine whether reductions in a source's emissions are *necessary* to achieve reasonable progress for the planning period under consideration. 42 U.S.C. § 7491(b)(2). Moreover, ""neither the Clean Air Act nor the Regional Haze Rule requires source-specific analysis in the determination of reasonable progress goals." *Texas v. EPA*, 829 F.3d 405, 428 (5th Cir. 2016) (quoting *Wildearth Guardians v. EPA*, 770 F.3d 919, 944 (10th Cir. 2014)).

According to the IMPROVE monitoring data submitted by EAI,[22] Caney Creek and Upper Buffalo already are meeting the EPA's proposed RPGs and Arkansas' RPGs and that visibility impairment continues to trend downward. Because Arkansas' Class I areas already surpassed the RPGs and the URP goals, reasonable progress controls during the first planning period are not necessary to ensure reasonable progress towards the natural visibility goals, as stated in 42 U.S.C. § 7941(b)(2).

Essentially, it appears that, for certain regional haze SIPs and FIPs, EPA deemed a control to be "reasonable" if it is "cost-effective."[23] This is concerning because it does not

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[19] 81 Fed Reg. at 66336, 66350.
[20] 81 Fed. Reg. at 66350.
21 Entergy submitted IMPROVE data that further confirms that visibility in the two Arkansas Class I areas are already better than the RPGs that EPA finalized for the areas. *See* Entergy Petition.
[22] Entergy Arkansas Inc., Supplemental Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, Docket No. EPA-R06-OAR-2015-0189 (submitted on Aug. 8 2016). ADEQ also submitted data showing that Caney Creek and Upper Buffalo will be below the glide path in 2018. State of Arkansas, State Implementation Plan Review for the Five-Year Regional Haze Progress Report, at 55-56 (May 2015).
[23] 81 Fed. Reg. at 66353.

consider the costs in relation to visibility improvement or lack thereof. The Final FIP requires controls on Independence because it alleges the plant is "a significant source of SO2 and NOx" and controls would be cost-effective. Whether or not a plant is a significant source of visibility impairing pollutants is not a statutory factor that states must consider in evaluating reasonable progress controls and neither is cost-effectiveness a statutory standard that allows EPA to exceed its jurisdiction.

Specifically, EPA's assertion that Independence warrants additional controls relies entirely on the Ag ency's claim that the controls would be cost -effective, on a dollar per ton basis.[24] EPA gave no consideration to whether the controls and resulting emissions reductions would actually improve visibility in any Class I areas and, in fact, recognized that controls would not be necessary for Arkansas Class I areas to meet their URPs.[25] The absurd result is that EPA is proposing that a public utility and its customers be required to invest more than $1 billion in power plant controls that would have negligible, if any, impacts on visibility in any Class I areas when such measures are unnecessary for Arkansas to achieve its reasonable progress goals. Such a jurisdictional overstep is not legally permissible and should be reconsidered.

III. Request for Administrative Stay

The legal standard for an administrative stay is broader than the standard for a judicial stay. The Clean Air Act provides that EPA may grant a stay if the agency has decided to reconsider the rule. 42 U.S.C. § 7607(d)(7)(B). Under the Administrative Procedures Act, EPA has authority to stay the requirements of a FIP when "justice so requires . . . pending judicial review." 5 U.S.C. § 705. No other conditions are imposed on the Agency's authority to issue a stay. AECC respectfully requests that EPA stay the Final FIP, specifically §§ 52.173(c)(6) -(8) and §§ 52.173(c)(24) -(26). A s this section demonstrates, a stay of the FIP would prevent harms to AECC and its member-owners and will not negatively affect visibility. In addition, a stay will permitwell-justified further consideration of the Final FIP.

Absent an administrative stay AECC and other petitioners will suffer various forms of irreparable injury, harming AECC members and impairing Arkansas' economy. Moreover, t he costs imposed by the Final FI P on electric generation capacity within Arkansas are substantial. The Final FIP will impose approximately $2 billion in costs, and no discernible benefit will accrue during the relevant implementation period covered by the SIP submittal under review, whi ch ends in 2018. Owner/operators of five coal-fired units within Arkansas are required to install scrubbers by October 2021 and LNB/SOFA by April 2018. These costs will likely challenge the economic viability of these units, and it is possible that some of the units will shut down rather than incur the costs of installing the required controls causing additional costs in the form of replacement power.

Installing dry scrubbers on all four units would be a massive undertaking and an extreme financial and technological hardship for AECC. This work would have to begin immediately, as the process requires the entirety of the five years allotted in the Final FIP.

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[24] *Id.*
[25] 80 Fed. Reg. at 18,992.

Of the $2.1 billion that Entergy estimates it would spend for scrubbers on White Bluff and Independence AECC is financially responsible for 35% of the total cost – or approximately $700 million. Based on Entergy's estimates, AECC would need to spend $9 million within the first six months, and $31 million within first 12 months, $84 million within 18 months, and $156 million within 24 months. These estimates do not include the costs for LNB/SOFA which are required to be installed by April 2018.

If Entergy decides to deactivate the units, then AECC must procure replacement power. This would consist of designing, gaining regulatory approval for, constructing, and making operational a new alternative generating unit. Depending on the site that is selected for the new units, rights-of-way will likely need to be obtained. Transmission – both electrical and gas – would need to be planned and built to connect the new units to the grid. Specifically, to construct replacement generation as quickly as possible, AECC must select a location, prepare and submit environmental permit applications, prepare requests for proposals, select vendors, and received Arkansas Public Service Commission approval.

Accordingly, in order to meet the October 2021 deadline, planning must begin immediately to limit, as much as possible, the duration of member exposure to market prices. In the meantime, even maintaining reliability through the purchase of power would require AECC to accelerate planned transmission projects which would only drive up the costs of those projects.

If all four units are shut down in October of 2021, AECC would need to add an estimated 500 megawatts of firm generation capacity. Estimates of the cost of this new replacement generation would be approximately $490 million. The levelized investment recovery costs of this generation capacity to AECC's member cooperatives would be approximately $34 million annually. AECC would also need to add an estimated additional 250 megawatts of replacement generation capacity by year 2026. This would require a further investment of approximately $245 million – or a further increase of approximately $17 million annually to AECC's members.

The Supreme Court has declared that "[o]ne would not say that it is even rational. . . to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits." *Michigan v. EPA*, 135 S. Ct. 2699, 2707 (2015). Moreover, courts have often issued stays to similarly situated petitioners challenging other FIPs. *See, e.g., Texas v. United States EPA*, 829 F.3d 405, 424 (5th Cir. 2016) (staying implementation of Texas FIP imposing over $2 billion in costs); *Oklahoma v. EPA*, 723 F.3d at 1206-07 (staying implementation of rule imposing $1.2 billion in costs).

In addition to the harm that will result absent a stay, AECC has a strong likelihood of success in establishing that EPA exceeded its statutory authority by imposing emission controls that will not affect the reasonable progress goals covered by the first round of implementation plans. State implementation plans must be designed to achieve the reasonable progress goals for the period covered by the plan, *i.e.* the December 2007 to July 31, 2018 period. *Texas v. United States EPA*, 829 F.3d at 429. When Arkansas submitted its plan in 2008, the regulations in effect required states "to set the emissions controls necessary to achieve the reasonable progress goal for 2018." *Id.* (stating that courts assess agency actions according to the effective statutes and regulations at the time

of the relevant activity) (citing *Caring Hearts Personal Home Servs., Inc. v. Burwell*, 824 F.3d 968, 971 (10th Cir. 2016)).

In its Final FIP, EPA stated:

> In this instance, we are taking final action on the Arkansas Regional Haze FIP 9 years after the state's initial SIP submission was due. As a result, only some of the control measures that we have determined are necessary to satisfy the BART and reasonable progress requirements will be installed by the end of 2018. Some controls will not be installed until 2021.[26]

Measures that would be implemente d at the end of or after the 2018 period are not appropriate for inclusion in a FIP that is purportedly filling a gap in the 2008 SIP revision covering a period to end in 2018. The regional haze planning process requires "control strategies to cover an initial implementation period extending to the year, 2018, with a reassessment and revision of those strategies, as appropriate, every 10 years." [27] Thus, it is improper for EPA to prescribe controls that are not required until the end of the first planning period, or thereafter, given that such con trols will not affect the reasonable progress goal for the first implementation period. Even if such controls were determined appropriate for this planning period, the 18-month compliance date is unjustifiable, was implemented without allowing interested p arties an opportunity to comment in contravention of due process, and materially deviates from other FIP compliance dates.

As demonstrated above, a stay is in the public interest and necessar y to prev ent irreparable harm to AECC and its members. In contrast, no significant harm will result to either EPA or the public from a stay of the Final FIP, given that Arkansas already is below the glide path and many of the emission reductions and resulting visibility improvements contemplated under the Final FIP will be incremental at best. [28] Thus, EPA should grant AECC's stay request.

IV. Conclusion

For the foregoing reasons, and the reasons set forth in Entergy's Petition, EPA should grant AECC's petition for reconsideration and administrative stay of the Final FIP.

Respectfully submitted,

[26] 81 Fed. Reg. at 66410.
[27] 64 Fed. Reg. at 35,734.
[28] 81 Fed. Reg. at 66386.

To: Feldman, Michael[Feldman.Michael@epa.gov]; Thomas, Carrie[Thomas.Carrie@epa.gov]
Cc: Donaldson, Guy[Donaldson.Guy@epa.gov]; Tomasovic, Brian[Tomasovic.Brian@epa.gov]
From: Terry Salem
Sent: Thur 6/22/2017 6:49:17 PM
Subject: Re: RH BART June 20, 2017 SIP Proposal

Thanks!

Terry G. Salem, Staff Attorney
512.239.0469
Confidential Attorney Work Product / Client Communication

From: Feldman, Michael <Feldman.Michael@epa.gov>
Sent: Thursday, June 22, 2017 12:42:52 PM
To: Terry Salem; Thomas, Carrie
Cc: Donaldson, Guy; Tomasovic, Brian
Subject: FW: RH BART June 20, 2017 SIP Proposal

Terry – I believe this is the language that Sam was referring to. Please see Carrie's email below.

Thanks,

Michael Feldman, PhD
Environmental Engineer
Air Planning Section
U.S. EPA Region 6, 6PD-L
Phone: 214-665-9793
feldman.michael@epa.gov

From: Thomas, Carrie
Sent: Thursday, June 22, 2017 11:39 AM
To: Feldman, Michael <Feldman.Michael@epa.gov>
Cc: Donaldson, Guy <Donaldson.Guy@epa.gov>; Wiley, Adina <Wiley.Adina@epa.gov>; Tomasovic, Brian <Tomasovic.Brian@epa.gov>
Subject: FW: RH BART June 20, 2017 SIP Proposal
Importance: High

Hi Michael,

Is this the language that TCEQ is looking for? It's on the 7th page of LDEQ's proposed submittal in the attached pdf.

"As the energy industry evolves, LDEQ continues to work with EGUs throughout Louisiana to evaluate the operation of utilities. As such, LDEQ will engage in discussions with Entergy about any potential changes in

usage or emission rates at the Nelson facility. Any such changes will be considered for reasonable progress for future planning periods as appropriate."

Please forward to anyone else. I'm not sure who all was on the call.

Thanks,

Carrie K. Thomas
Office of Regional Counsel
U.S. Environmental Protection Agency, Region 6
1445 Ross Ave. (6-RC-M)
Dallas, TX 75202
Tel: (214) 665-7121
Fax: (214) 665-2182

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To: Donaldson, Guy[Donaldson.Guy@epa.gov]; Huser, Jennifer[Huser.Jennifer@epa.gov]; Todd, Robert[Todd.Robert@epa.gov]
Cc: Bijan Sharafkhani[Bijan.Sharafkhani@LA.GOV]; Stenger, Wren[stenger.wren@epa.gov]; Donald Trahan[Donald.Trahan@LA.GOV]; vennetta.hayes@la.gov[vennetta.hayes@la.gov]
From: Vivian Aucoin
Sent: Mon 6/19/2017 5:21:15 PM
Subject: RH BART June 20, 2017 SIP Proposal (2 of 3)
DRAFT LA CALPUFF BART modeling report draft with Nelson.pdf
DRAFT LA CAMx BART Modeling TSD draft with Nelson.pdf
LA_RH_Nelson_TSD.pdf
Nelson CAMx LSC for SIP.xlsx
LA_CALPOST_Nelson for SIP.xlsx
LA_summary CAMx vis daily for SIP.xlsx
Nelson CALPUFF inputs for SIP.xlsx
Nelson CAMx DFGD WFGD for SIP.xlsx
Nelson control costs with Entergy corrections.xlsx

Greetings,

This is the second of three emails that you will receive which constitutes the electronic version of the Louisiana Regional Haze State Implementation Plan as it relates to the re-proposal of the final SIP submitted to EPA Region 6 on February 10, 2017.

This email contains the those items submitted by EPA Region 6 that will be contained in Appendix F.

Should you have any questions, please do not hesitate to contact me.

Vivian H. Aucoin

Environmental Scientist Manager

Office of Environmental Assessment, Air Planning Division

225-219-3482

vivian.aucoin@la.gov

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To: Curry, Ron[Curry.Ron@epa.gov]; Donaldson, Guy[Donaldson.Guy@epa.gov]
Cc: kmcque1@entergy.com[kmcque1@entergy.com]; William Bumpers[william.bumpers@bakerbotts.com]; allison.mallick@bakerbotts.com[allison.mallick@bakerbotts.com]; twebster@sidley.com[twebster@sidley.com]; rmartella@sidley.com[rmartella@sidley.com]; jvisser@sidley.com[jvisser@sidley.com]
From: debra.jezouit@bakerbotts.com
Sent: Wed 11/23/2016 11:45:25 PM
Subject: Petition for Reconsideration and Request for Stay or Arkansas Regional Haze Federal Implementation Pl
removed.txt
Cover Letter for Entergy Petition for Reconsideration.pdf
Entergy Petition for Reconsideration and Request for Stay.pdf
Exhibits to Entergy Petition - no Confidential Business Information.pdf

Gentlemen:

Enclosed please find a cover letter, Petition for Reconsideration and Request for Stay of Entergy Arkansas Inc., Entergy Mississippi Inc. and Entergy Power LLC of the final Arkansas Regional Haze FIP, and exhibits to the Petition. Two of the exhibits to the Petition contain confidential business information and have not been included with this email. They will be provided separately, as addressed in the cover letter.

If you have any questions about the attached documents, please do not hesitate to contact me.

Debra J. Jezouit

Partner

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Ex. 6 - Personal Privacy

The Warner

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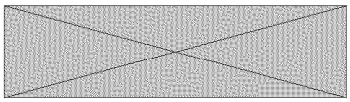
Washington, DC 20004



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November 23, 2016

VIA EMAIL AND FEDEX

Debra J. Jezouit
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debra.jezouit@bakerbotts.com

Mr. Ron Curry
Regional Administrator
U.S. Environmental Protection Agency
Fountain Place 12th Fl., Ste. 1200
1445 Ross Avenue
Dallas, TX 75202-2733

Re: Petition for Reconsideration and Request for Stay of Entergy Arkansas Inc. et al. of the Arkansas Regional Haze and Interstate Visibility Transport Federal Implementation Plan, EPA Docket No. EPA-R06-OAR-2015-0189

Dear Administrator Curry:

Entergy Arkansas Inc., Entergy Mississippi Inc., and Entergy Power, LLC (collectively "Entergy") respectfully submit the enclosed Petition for Reconsideration and Request for Stay ("Petition") of the U.S. Environmental Protection Agency's ("EPA" or "Agency") final "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan" ("Final FIP"). 81 Fed. Reg. 66,332 (Sept. 27, 2016).

The Petition includes exhibits that contain Confidential Business Information for Entergy and for a third party. The exhibits have been partially redacted to remove non-pertinent information and are clearly marked as "Redacted and Confidential Business Information." Entergy also is providing a copy of the exhibits without the aforementioned confidential exhibits. Due to their length, both versions of the exhibits to the Petition are being provided on the enclosed CDs. An additional copy of the Petition is enclosed to be time-stamped and returned in the attached envelope.

Thank you for your consideration of the enclosed Petition for Reconsideration and Request for Stay. If you have any questions, please contact me at (202) 639-7728.

Sincerely,

Debra J. Jezouit
Counsel to Entergy Services Inc.

Enclosures

cc: The Honorable Gina McCarthy, Administrator
U.S. Environmental Protection Agency

BEFORE THE UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY

In re:	)	EPA Docket No.
	)	
Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan	)	EPA-R06-OAR-2015-0189

Petition for Reconsideration and Request for Stay of Entergy Arkansas Inc., et al., of the Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan

---

Entergy Arkansas Inc. ("EAI"), Entergy Mississippi Inc. ("EMI"), and Entergy Power, LLC (collectively "Entergy") respectfully submit this petition for reconsideration and request for stay ("Petition") of the U.S. Environmental Protection Agency's ("EPA" or "Agency") final "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan" ("Final FIP").[1] As discussed below, Entergy requests that EPA reconsider and stay elements of the Final FIP that relate to Entergy's White Bluff and Independence plants. To avoid the significant, irreparable harms that already have begun to occur, Entergy respectfully requests that EPA take action on this Petition by February 1, 2017. The administrative stay requested by Entergy would not cause adverse visibility impacts in Arkansas' Class I areas.

I. INTRODUCTION AND SUMMARY

The Final FIP affects four coal-fired electric generating units owned by Entergy: two at the White Bluff Electric Power Plant ("White Bluff") and two at the Independence Steam Electric Station ("Independence"), which will impose costs on Entergy, its co-owners and its customers of approximately $2 billion for minimal visibility benefits. Specifically, the Final FIP requires each coal-fired unit at White Bluff and Independence to meet a sulfur dioxide ("SO_2") emission limit of 0.06 lb/MMBtu by October 27, 2021.[2] This emission limit is based on the installation of a dry scrubber (flue gas desulfurization ("FGD") technology) on each unit. The Final FIP also will require each coal-fired unit to meet a nitrogen oxides ("NOx") emission limit of 0.15 lb/MMBtu on a rolling 30-boiler operating day basis at loads of 50-100 percent of maximum heat input rating, and a rolling 3-hour average limit of 671 lb/hr at loads of less than 50 percent of maximum heat input rating.[3] These emission limits, which must be met beginning

[1] 81 Fed. Reg. 66,332 (Sept. 27, 2016).
[2] *Id.* at 66,339, 66,416, 66,420.
[3] *Id.* at 66,416-17.

April 27, 2018, are based on the installation of low-NOx burners and separated overfire air ("LNB/SOFA") on each unit.

The Petition must be granted because EPA failed to provide adequate notice and opportunity to comment on significant, burdensome requirements in the Final FIP that affect the requirements imposed on Entergy's units, are of central relevance to the outcome of the Final FIP, and are not logical outgrowths of the proposed rule ("Proposed FIP").[4] Additionally, the Final FIP contains clear errors that must be corrected. These administrative shortcomings demand reconsideration and a stay of key elements of the Final FIP. Specifically, Entergy requests that EPA reconsider the following:

- the imposition of reasonable progress controls on Independence;
- EPA's determination that dry FGD technology constitutes best available retrofit technology ("BART") for White Bluff for SO_2 emissions;
- the 18-month deadline for installation of NOx controls at White Bluff and Independence;
- the adoption of source-specific NOx BART in lieu of reliance on the emissions reductions resulting from implementation of the Cross-State Air Pollution Rule ("CSAPR");[5] and
- the NOx limit and three-hour averaging period for NOx compliance that applies when units at White Bluff and Independence operate at low loads.

A stay of certain requirements in the Final FIP is necessary because justice so requires and to avoid irreparable harm to Entergy and its co-owners, customers, and communities while EPA reconsiders the Final FIP, and while the U.S. Court of Appeals for the Eighth Circuit ("Eighth Circuit") considers Entergy's petition for review of those requirements.[6] The pollution controls at White Bluff and Independence required by the Final FIP would cost approximately *$2 billion* to design, permit, purchase, and install. Absent a stay, Entergy will be forced to make a costly Hobson's choice: (1) commence designing, permitting, purchasing, and installing the required controls immediately; or (2) commence planning to decommission White Bluff and Independence by the Final FIP compliance deadline in 2021. Either course of action causes irreparable harm. The first option would require Entergy to expend $150 million or more just within the next 18 months that could be rendered entirely unnecessary by a grant of reconsideration. The second option would require an array of costly steps planning for decommissioning the units and would ultimately lead to a host of significant harms to Entergy and its co-owners, customers, and local economies. Furthermore, Entergy could not avoid these harms by changing course at a later date, because it will either already have expended multiple millions of dollars on equipment that will serve no purpose (if it initially selected the first option), or it will be too late to install the controls in time to meet the deadline (if it initially selected the second option).

[4] 80 Fed. Reg. 18,944 (Apr. 8, 2015).

[5] *See* Petition for Reconsideration and Request for Administrative Stay of Arkansas Department of Environmental Quality, at 5-8 (Nov. 22, 2016) (hereinafter "ADEQ Petition").

[6] Specifically, Entergy seeks a stay of 40 C.F.R. §§ 52.173(c)(6)-(8) with respect to White Bluff and §§ 52.173(c)(24)-(26) with respect to Independence.

A stay would avoid irreparable harm yet would have no adverse impact on visibility in either Arkansas Class I area, as monitoring data show that current visibility already is better than the reasonable progress goals ("RPGs") established by EPA for this implementation period and that visibility in the Class I areas continues to improve.

Immediate action on this Petition is urgently needed to avoid the harms described herein. Therefore, Entergy respectfully requests that EPA take action in response to this Petition by February 1, 2017. In the absence of a grant of reconsideration and stay by that time, Entergy will consider the Petition to be denied, unless the parties have jointly agreed to a longer period of time for EPA to take action on the Petition.

II. DESCRIPTION OF PETITIONERS

EAI is an electric utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in portions of Arkansas. EAI provides electrical utility service to approximately 712,000 electric customers, deriving 81 percent of its operating revenues from electric customers in 2015. EAI owns portions of White Bluff and Independence and operates both plants. EAI is a regulated utility company subject to the rate and general operating jurisdiction of the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). All of the common stock of EAI is owned by Entergy Corporation.

EMI is an electric utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in portions of Mississippi, and is a co-owner of Independence. EMI provides electrical utility service to approximately 447,000 electric customers, deriving 89 percent of its operating revenues from electric customers in 2015. EMI is a regulated utility company subject to the rate and general operating jurisdiction of the Mississippi Public Service Commission and FERC. All of the common stock of EMI is owned by Entergy Corporation.

Entergy Power, LLC is an electric utility company that sells electric energy at wholesale and is a co-owner of Independence. Its principal business office is located in Little Rock, Arkansas. Entergy Power, LLC is an indirect wholly owned subsidiary of Entergy Corporation.

III. REQUEST FOR RECONSIDERATION

A. Reconsideration Is Required Under Clean Air Act Section 307(d)(7)(B).

EPA *must* grant reconsideration of a final action when a petitioner "can demonstrate to the Administrator that it was impracticable to raise [an] objection [during the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule."[7] In such a situation, reconsideration is mandatory, as the Clean Air Act ("CAA") commands that EPA "*shall* convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed."[8] EPA must grant this Petition because

[7] 42 U.S.C. § 7607(d)(7)(B).
[8] *Id.* (emphasis added).

(1) Entergy's objections are to actions EPA took in the Final FIP, or developments since the comment period closed, and thus could not have been raised during the comment period on the Proposed FIP; (2) the objections arose during the period for judicial review; and (3) the objections are of central relevance to the outcome of this rulemaking.

Reconsideration also is appropriate to correct clear errors, as the CAA provides for judicial invalidation of rules if errors are "so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been significantly changed if such errors had not been made."[9] EPA should grant this Petition to address serious errors that are of central relevance to the Final FIP.

B. EPA Should Reassess its Imposition of Reasonable Progress Controls on Independence in Light of More Recent Air Quality Data and Corrected Contribution Data.

Data that became available after the close of the public comment period on the Proposed FIP confirm that reasonable progress controls on Independence for the first planning period are wholly unnecessary. Additionally, EPA's reasonable progress analysis relies on a false characterization of Independence's contribution to visibility impairment in Class I areas. EPA should reconsider the Final FIP and the controls on Independence in light of more recent air quality data, as well as corrected data regarding Independence's contribution to visibility impairment.

According to Interagency Monitoring of Protected Visual Environments ("IMPROVE") monitoring data for 2015, which became available subsequent to the close of the comment period, visibility continues to improve at a greater rate than the uniform rate of progress ("URP") in the Caney Creek Wilderness Area ("Caney Creek") and the Upper Buffalo Wilderness Area ("Upper Buffalo").[10] In addition, the recent IMPROVE data further confirm that visibility in the two Arkansas Class I areas already is better than the RPGs that EPA finalized for the areas. EPA set the RPGs for the 20 percent worst days at 22.47 deciviews ("dv") for Caney Creek and at 22.51 dv for Upper Buffalo.[11] The recent IMPROVE data for both Class I areas demonstrate that monitored visibility impairment in the areas already is well below EPA's RPGs, as well as Arkansas' RPGs, and that visibility impairment is continuing to trend downward.[12] Given that Caney Creek and Upper Buffalo already have surpassed the URP goals, Arkansas' RPGs, and EPA's final RPGs for the first planning period, reasonable progress controls during the first planning period are not "*necessary*" to ensure reasonable progress towards the natural visibility goal.[13] There is simply no standard of reasonable progress that necessitates controls on

[9] 42 U.S.C. § 7607(d)(8).
[10] Assessment of Recent Class I Area IMPROVE Monitoring Data prepared by Trinity Consultants, Inc., at 3 (Aug. 8, 2016, updated Nov. 15, 2016) (hereinafter "Trinity Report") (attached as Exhibit A).
[11] 81 Fed. Reg. at 66,354.
[12] Trinity Report at 3. Actual visibility impairment at Caney Creek in 2015 was 20.41 dv, below Arkansas' RPG of 22.48 dv and EPA's final RPG of 22.47. Actual visibility impairment at Upper Buffalo in 2015 was 19.96 dv, below Arkansas' RPG of 22.52 and EPA's final RPG of 22.51. *Id.*
[13] *See* 42 U.S.C. § 7491(b)(2) (requiring regional haze implementation plans to contain measures "necessary to make reasonable progress toward meeting the national goal").

Independence for this planning period, especially in light of the fact that the Regional Haze Program is designed to achieve its goals over a long horizon – by 2064.

EPA also should reconsider the need for NOx controls on Independence based on a corrected understanding of the plant's contribution to visibility impairment. In the Final FIP, EPA justified the need for NOx controls on Independence based on a false characterization of the plant's contribution to visibility impairment. EPA stated that, "Entergy's CAMx modeling shows that nitrate from Independence is responsible for 30 – 40% of the visibility impairment in Arkansas' Class I areas on 2 of the 20% worst days."[14] This statement is false and must be corrected. EPA's statement indicates that on two of the 20 percent worst days, *30-40 percent of all impairment* at Arkansas' Class I areas is due to nitrates derived from NOx emissions from Independence. In reality, *30-40 percent of the impairment on these days that is due to nitrates* is attributable to Independence. But nitrates are a minute portion of visibility impairment at Arkansas' two Class I areas. The average total nitrate contribution from Independence to visibility impairment on these days is only 0.02 percent at Upper Buffalo and 0.03 percent at Caney Creek. Thus, the actual contribution is over three orders of magnitude less than EPA stated.

Entergy had no opportunity to comment on this mischaracterization of Independence's nitrate contribution to visibility impairment, which is of central relevance to the outcome of the rule. EPA should correct this mischaracterization and clearly acknowledge that the contribution of Independence to visibility impairment in Arkansas' Class I areas is almost meaningless.

In sum, EPA should reconsider the necessity of reasonable progress controls for Independence in light of the recent IMPROVE monitoring data as well as a corrected assessment of Independence's contribution to visibility impairment in Arkansas' Class I areas.

C. The SO_2 BART Determination in the Final FIP for White Bluff Failed to Consider Critical Information.

1. EPA materially misunderstood Entergy's comments regarding EPA's proposed SO_2 BART determination for White Bluff.

The Final FIP imposes SO_2 limits on White Bluff Units 1 and 2 premised on the installation of dry FGD, which EPA found to be cost-effective based on a 30-year amortization period.[15] EPA failed to consider Entergy's proposal to cease combusting coal in 2027 and 2028, which would limit the remaining useful coal-fired lives of the units and significantly alter the cost-effectiveness of SO_2 controls.[16] Entergy had no notice of or opportunity to timely comment

[14] 81 Fed. Reg. at 66,359.
[15] *Id.* at 66,335, 66,360.
[16] Entergy Arkansas Inc. Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, at 5 (Aug. 7, 2015) (Docket ID No. EPA-R06-OAR-2015-0189-0153) (hereinafter "EAI Comments") (attached as Exhibit B).

on EPA's failure, which was only evident in the Final FIP and EPA's associated Response to Comments.[17]

In the Final FIP, EPA unreasonably mischaracterized Entergy's White Bluff proposal, resulting in the Agency's failure to properly determine BART for White Bluff Units 1 and 2. EPA acknowledged that a binding requirement to cease combustion of coal at White Bluff would limit the remaining useful lives of Units 1 and 2 for the purpose of evaluating SO_2 controls, but mistakenly assumed that Entergy had not offered such a proposal. EPA explained, "If Entergy's alternative proposal had included accepting a binding requirement to burn only natural gas at White Bluff Units 1 and 2 after coal combustion ceases, or a binding requirement to completely shut down the units, *then we would agree that it would be appropriate to assume that SO_2 emissions from White Bluff will be zero beginning in 2027/2028*."[18] However, contrary to EPA's assertion, Entergy explicitly made such a commitment in its comments on the Proposed FIP:

> As part of a multi-unit plan to improve visibility and to better manage its generation assets for reliability and costs, Entergy proposes to cease burning coal at White Bluff Units 1 and 2 by 2027 and 2028, one unit per year, *and is prepared to take an enforceable commitment to that effect*.[19]

EPA's conclusion that Entergy "does not propose…adopting a binding requirement to burn only natural gas or completely shut down the units"[20] is inexplicable in light of the plain language of Entergy's proposal. Because EPA determined that a binding requirement to cease burning coal would allow the Agency to assume that SO_2 emissions would be zero subsequent to the cessation of coal combustion, EPA must reconsider the SO_2 BART determination for White Bluff. Failure to do so is unreasonable and arbitrary and capricious.

EPA also asserted that Entergy's proposal to cease using coal at White Bluff appeared tied to EPA's acceptance of Entergy's separately proposed emission limits for Independence.[21] That assertion is incorrect. Nowhere in its comments did Entergy claim that its acceptance of a binding requirement to cease burning coal at White Bluff Units 1 and 2 was contingent on EPA's agreement to the emission limits that Entergy was proposing for Independence. Although Entergy proposed an approach addressing all four coal-fired units at White Bluff and Independence and provided modeling of its proposal demonstrating that its approach would achieve virtually the same visibility benefits as EPA's Proposed FIP for significantly less cost,[22] Entergy did not indicate that its proposed emission limits for Independence were a necessary element of its White Bluff proposal. In fact, in its comments, Entergy explicitly stated that the

[17] 81 Fed. Reg. at 66,335, 66,360; Response to Comments for the Federal Register Notice for the State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan, at 52-54 (Aug. 31, 2016) (Docket ID No. EPA-R06-OAR-2015-0189-0187).
[18] 81 Fed. Reg. at 66,356-57 (emphasis added).
[19] EAI Comments at 5 (emphasis added).
[20] 81 Fed. Reg. at 66,356.
[21] *Id.* at 66,358 ("Entergy's comments provide no indication that it is willing to accept a binding requirement to cease coal combustion at White Bluff by 2027/2028, unless we also accept the elements of its alternative proposal that are applicable to Independence as satisfying the reasonable progress requirements.").
[22] EAI Comments at 45-46.

interim emissions reductions it offered, which included the emission limits for Independence, were a *complement* to its proposal for White Bluff.[23]

2. EPA did not account for Entergy's proposal regarding the remaining useful life of White Bluff in analyzing SO_2 controls.

Had EPA appropriately characterized Entergy's proposal for White Bluff, EPA would have used a shorter remaining useful life for White Bluff in its BART analysis. Proper accounting of remaining useful life is critical because, as EPA acknowledged in the Final FIP, "a shorter remaining useful life [at White Bluff Units 1 and 2] might result in a conclusion that dry scrubbers are not cost-effective…."[24] Indeed, as explained in Entergy's comments, Entergy's proposal for White Bluff rendered EPA's proposed BART determination inapplicable, requiring EPA to undertake a new BART analysis to address the remaining useful coal-fired life of the units.[25] Because EPA's FGD cost-effectiveness analysis failed to take into account Entergy's proposed binding commitment to cease combusting coal at White Bluff, a failure on which Entergy could not previously have provided comment, EPA must reconsider this issue. In doing so, EPA also should reconsider the cost-effectiveness of dry scrubbers in light of the correct control cost information, as explained in the following section.

3. Dry FGD is not cost-effective at White Bluff.

EPA calculates that installing and operating dry FGD at White Bluff would cost $2,565 per ton of SO_2 removed for Unit 1 and $2,421 per ton of SO_2 removed for Unit 2.[26] However, these cost estimates fail to account for Entergy's proposal, discussed above, regarding the remaining useful life of the units as well as data regarding the actual cost of controls. Had this information been properly considered, EPA should have estimated that the costs per ton of SO_2 removed would range from approximately $7,100 to $8,000 per ton of SO_2 removed, which is patently *not* cost-effective.[27]

EPA's cost estimate *failed to include over $495 million* that Entergy will be required to incur to install dry FGD on the White Bluff units.[28] EPA rejected certain costs in the analysis prepared for Entergy by Sargent & Lundy because Entergy did not provide to EPA the underlying 2009 and 2013 Alstom quotes on which Sargent & Lundy's cost analysis relied.[29] Because Entergy had no notice that EPA would require submission of these quotes, which contain non-public, highly confidential and proprietary information, to validate Entergy's cost analysis, Entergy is providing redacted versions of these quotes now.[30] The Alstom quotes

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[23] *Id.* at 4 ("Entergy is prepared to offer meaningful interim emission reductions to complement its proposed commitment to cease coal-fired operations at White Bluff and assure that Arkansas remains on a path that is below the URP for the long term.").
[24] 81 Fed. Reg. at 66,356.
[25] EAI Comments at 5.
[26] 81 Fed. Reg. at 66,386.
[27] Memorandum from Sargent & Lundy (Nov. 18, 2016) (hereinafter "Sargent & Lundy Memo") (attached as Exhibit C).
[28] *See* Sargent & Lundy Memo at 2.
[29] 81 Fed. Reg. at 66,383.
[30] 2009 Alstom Report (attached as Exhibit D) and 2013 Alstom Report (attached as Exhibit E). These reports contain confidential business information. Non-pertinent information has been redacted.

demonstrate that EPA improperly excluded extensive costs associated with "Balance of Plant" items, which are items not included in the FGD supplier's scope, but which are necessary to integrate the FGD system into the plant.[31] The quotes also demonstrate that EPA underestimated escalation by using the Chemical Engineering Plant Cost Indices ("CEPCI") instead of relying on more accurate information from the vendor.

The more detailed and accurate cost analysis prepared by Sargent & Lundy, which includes costs improperly excluded by EPA and correctly predicts tons removed, estimates that dry FGD cost-effectiveness will range from approximately $7,100 to $8,000 per ton if the units cease combusting coal in 2027-2028.[32] Even if certain costs rejected by EPA were excluded in Sargent & Lundy's cost estimate (i.e., allowance for funds used during construction ("AFUDC"), escalation, and owner's costs), the cost-effectiveness of dry FGD at White Bluff would range from approximately $5,400 to $6,100 per ton.[33] Regardless of which estimate is used, these costs exceed those that EPA has previously rejected in other BART analyses and thus are too high to represent BART for the White Bluff units.[34] As a result, dry FGD cannot constitute SO_2 BART for White Bluff Units 1 and 2. Accordingly, EPA should reconsider the White Bluff SO_2 BART.

4. EPA must reconsider SO_2 BART for White Bluff even in the absence of a DSI analysis.

In the Final FIP, EPA argues, for the first time, that it would be necessary to assess dry sorbent injection ("DSI") as an interim control if the White Bluff units cease to combust coal, and indicates that this lack of DSI analysis somehow negates EPA's obligation to conduct a reasonable BART analysis of dry FGD at the White Bluff units. Entergy did not have notice of or an opportunity to comment on this assertion, which is of central relevance to the Final FIP. The lack of a DSI analysis, which EPA had not previously requested, does not absolve EPA of its obligation to properly assess the cost-effectiveness of dry FGD.

EPA explains in the Final FIP that "[b]ecause Entergy has provided no analysis to demonstrate that there is no more effective interim SO_2 control that would constitute BART, the company's proposed strategy is not adequate to ensure that the BART requirements for White Bluff Units 1 and 2 will be met."[35] EPA ties the lack of a DSI analysis to its determination that it

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[31] Upon further review, Sargent & Lundy determined that costs associated with ductwork downstream of the booster fans were included in the Alstom quote. The updated cost estimates in this Petition remove these costs. Sargent & Lundy Memo at 2.
[32] *Id.* at 3.
[33] *Id.*
[34] EPA declined to impose dry FGD as BART in Arizona, where the average cost effectiveness was estimated to be $5,090/ton. Proposed Arizona Regional Haze FIP, 79 Fed. Reg. 9,317, 9,331-33 (Feb. 18, 2014); Final Arizona Regional Haze FIP, 79 Fed. Reg. 52,420, 52,436 (Sept. 3, 2014). In North Dakota, EPA approved the state's determination that a cost effectiveness of $6,525 per ton was excessive for NOx controls and did not constitute BART. Proposed North Dakota FIP, 76 Fed. Reg. 58,570, 58,630 (Sept. 21, 2011); Final North Dakota Regional Haze FIP, 77 Fed. Reg. 20,894, 20,896 (Apr. 6, 2012). And, in Montana, EPA concluded that certain SO_2 controls with a cost effectiveness of $5,442/ton and $6,365/ton were not cost effective. Proposed Montana Regional Haze FIP, 77 Fed. Reg. 23,988, 24,047 (Apr. 20, 2012); Final Montana Regional Haze FIP; 77 Fed. Reg. 57,864, 57,866 (Sept. 18, 2012).
[35] 81 Fed. Reg. at 66,356.

need not even consider Entergy's finding that FGD is not cost-effective in light of its proposal for White Bluff. This is a false premise; the appropriateness of DSI as an interim control measure is irrelevant to the assessment of whether dry FGD is cost-effective. As outlined above, EPA failed to account for the proposed remaining useful life of Units 1 and 2 when assessing dry FGD as a control technology, as well as certain costs associated with such controls, and must do so now on reconsideration. To the extent that EPA *also* believes that an assessment of DSI as a potential control technology is warranted, such assessment is wholly independent of the FGD assessment.

Despite the fact that EPA's request for a DSI analysis arose for the first time in the Final FIP, Entergy is willing to develop and provide the analysis if EPA grants reconsideration on SO_2 BART for White Bluff. Additionally, Entergy understands that the Arkansas Department of Environmental Quality ("ADEQ") will develop a state implementation plan ("SIP") to replace portions of the Final FIP, including the BART controls for White Bluff, and Entergy will submit a DSI analysis to ADEQ, if required, as part of the SIP development process.

D. EPA's LNB/SOFA Assumptions Are Unsupported and Unreasonable, and Must Be Revised.

EPA should reconsider whether NOx controls should be required for either White Bluff or Independence. As addressed in Section III.A above, NOx controls on Independence to address reasonable progress are unnecessary for this first planning period. Further, EPA should reconsider its imposition of source-specific NOx BART controls in the Final FIP and instead determine that compliance with CSAPR is acceptable for compliance with the NOx BART requirements in Arkansas, including for White Bluff, as addressed more fully in ADEQ's Petition for Reconsideration and Request for Administrative Stay.[36]

However, if EPA denies reconsideration on these threshold issues, EPA must grant reconsideration on the compliance deadline and NOx emission limits applicable to both White Bluff and Independence. The compliance deadline and NOx limits are not logical outgrowths of the Proposed FIP, are not reasonable and fraught with errors, and are of central relevance to EPA's determination of NOx BART in the rulemaking.

1. EPA must extend the 18-month timeline for the installation of LNB/SOFA to Three Years.

a. The 18-month deadline is not a logical outgrowth of the proposed rule and was promulgated in error.

The Final FIP unlawfully shortens the compliance deadline for the NOx emission limits for White Bluff and Independence from three years to 18 months.[37] EPA proposed a three-year NOx compliance deadline for these plants and did not indicate in the Proposed FIP that it was considering a shorter deadline. The 18-month deadline is not a logical outgrowth of the proposed compliance deadline. While Entergy stated in its comments that it was prepared to

[36] ADEQ Petition at 5-8.
[37] 81 Fed. Reg. at 66,338, 66,354.

meet the proposed three-year deadline,[38] it lacked notice and had no opportunity to comment on its ability to comply with a shortened compliance deadline.

EPA erred in relying on comments from environmental organizations when contracting the compliance timeline.[39] First, the environmental organizations requested a shorter compliance deadline only for White Bluff, not for Independence.[40] Indeed, while the organizations asserted that LNB/SOFA could be installed on Independence in under a year, the comment concluded that "three years is more than reasonable."[41] Even if the environmental organizations had requested a shortened compliance deadline for both plants, it is well-established that EPA "cannot bootstrap notice from a comment." *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 549 (D.C. Cir. 1983); *Am. Fed'n of Labor v. Donovan*, 757 F.2d 330, 340 (D.C. Cir. 1985).

Further, the environmental organizations' comments on installation of LNB/SOFA fail to provide a reasonable justification for the shorter compliance timeline. The comments were based on an expert report, which, in turn, relied on a 10-year-old vendor association report that did not consider permitting considerations, a company's internal project development and approval process, site-specific factors, or reliability concerns.[42] The vendor association report explicitly recognized that "[v]ariations in the schedule may occur due to site specific conditions that may increase or decrease the typical deployment time."[43] The vendor report also does not appear to allow sufficient time for testing and optimization of equipment, providing only one week for commissioning and startup.[44] Because the environmental organization comments relied on outdated, generic information about timing, they do not provide a proper basis for the shortened deadline for these specific units. Notably, EPA has not even attempted to provide any explanation of how this shorter deadline is reasonable for White Bluff and Independence in light of site-specific and company-specific considerations. Nor does EPA appear to have required such a short timeframe for the installation of controls in other regional haze plans. Even for AEP's Flint Creek plant, where SO_2 control equipment *is installed and functioning already*, EPA granted the company 18 months to make any modifications necessary to ensure the controls can meet the BART limit.[45]

b. The 18-month deadline is unreasonable.

The 18-month deadline to install LNB/SOFA at White Bluff and Independence is infeasible, as it does not guarantee sufficient time to develop, plan, permit, install, tune, and test the equipment. Specifically, a project of this scope requires Entergy to develop a prevention of significant deterioration ("PSD") permit application, obtain a PSD permit, comply with the

[38] EAI Comments at 13-14.
[39] 81 Fed. Reg. at 66,378.
[40] Comments of Earthjustice, National Parks Conservation Association, and Sierra Club at 25 (Aug. 7, 2015) (Docket ID No. EPA-R06-OAR-2015-0189-0153) (hereinafter "Sierra Club Comments").
[41] *Id.* at 39.
[42] *Id.* at 25; Technical Support Document to Comments of Conservation Organizations, Prepared by Victoria R. Stamper, at 46 (Aug. 5, 2015) (Docket ID No. EPA-R06-OAR-2015-0189-0171) (hereinafter "Stamper Report").
[43] Typical Installation Timelines for NOx Emission Control Technologies on Industrial Sources, Institute of Clean Air Companies, at 4 (Dec. 4, 2006), available at https://c.ymcdn.com/sites/icac.site-ym.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.
[44] *Id.*
[45] 81 Fed. Reg. at 66,338.

company's internal planning and prudence review procedures, complete a request for proposal ("RFP") process, select a vendor, procure equipment, schedule outages, install equipment, and then tune and test the equipment. Completion of all of these steps will require more than 18 months, even though Entergy already has obtained the necessary PSD permit for White Bluff, and is in the process of developing the PSD permit application for Independence.[46] Entergy would only be able to complete installation and tuning of LNB/SOFA on all four units by the final deadline if it circumvented its internal planning and prudence review procedures and completed the tuning and testing process *after* the compliance deadline.

The internal process that must be completed before the performance of any equipment work is robust, with preparation for this work just getting underway with respect to Independence. First, projects over $20 million, like the installation of LNB/SOFA, are subject to an internal company approval process that includes risk review and investment procedures. This process takes approximately two months and requires approval from several levels of Entergy management. Once the review process has been completed, Entergy can undertake project-specific planning. An engineer will draft project specifications based on the Final FIP requirements and design characteristics, a process that takes approximately two months. These specifications will be included in an RFP, which will be put out for a four- to six-week bidding process. Once a vendor is selected, negotiation of the final contract will take an additional four to six weeks.

Simultaneous to this internal process, Entergy must prepare a PSD permit application for the installation of LNB/SOFA at Independence.[47] Despite the fact that work already is proceeding, the earliest the application will be ready for submittal to ADEQ will be mid-December. ADEQ approval is expected to take, at a minimum, between six and eight months, resulting in permit issuance between mid-June and mid-August 2017, but this process could take longer for a variety of reasons outside of Entergy's control. For example, the permitting process could be extended if significant public comments are received on the draft permit that must be addressed by the ADEQ before a final permit can be issued, due to agency resource constraints, or due to an appeal of the final permit to the Arkansas Pollution Control and Ecology Commission, which, absent additional regulatory proceedings, would result in an automatic stay of the permit pending final resolution of the appeal.

Once the permit is issued and the final contract has been signed, the selected vendor must design and fabricate the equipment, which takes approximately eight months. Outages must be scheduled for all four units, each lasting between six and seven weeks. Once installation is complete, each unit will need to undergo four weeks of boiler tuning and two weeks of performance verification testing to demonstrate that the controls are achieving the anticipated NOx reductions. After this, Entergy will have to perform a final phase of fine-tuning and training. During the final phase, which lasts approximately five months, each unit will undergo a three-month procedure review during which the system description is re-written to include the new equipment and components, and the operating procedures are updated. This process cannot

[46] Although Entergy already has acquired control equipment for one unit at White Bluff, equipment still must be obtained for the second White Bluff unit and both Independence units to comply with the requirements in the Final FIP.

[47] As noted above, Entergy already has obtained a permit to install LNB/SOFA on White Bluff but does not yet have all the equipment needed to do so.

be truncated as it requires the operators to observe performance during all operating scenarios, including startup, shutdown, and periods of load transition. The staff must then be trained on both the system description and the operating procedures, which typically takes a month. An additional month is needed to validate operating configurations to determine which combinations result in the best load profile. It would be imprudent not to complete the entire training and fine-tuning process prior to the compliance deadline.

Even with a truncated schedule, Entergy cannot reasonably expect to meet the 18-month deadline. At best, Entergy could take the following steps, which increase risk and cost without any guarantee of compliance. It could circumvent its normal internal procedures, including its risk and prudence reviews and its process for obtaining competitive bids from multiple vendors. Entergy would be required to perform a more limited risk and prudence review, would have to forgo a complete bidding process in favor of using a pre-selected vendor that can fabricate and install the equipment as quickly as possible, and may even need to engage this vendor prior to having all regulatory approvals in hand. These internal procedures are in place to attempt to ensure cost recovery, and failure to comply with them puts the company at risk of making investments that the APSC later determines are not in the public interest and therefore not eligible for cost recovery. The schedule also does not allow for any delays associated with the PSD permitting process.

Finally, even with these truncated procedures, and assuming final PSD permit issuance in mid-June to mid-August 2017, the timeframe allowed in the Final FIP is insufficient for Entergy to conduct thorough testing and tuning of the NOx control equipment, where unforeseen issues frequently arise and must be addressed to ensure compliance. For example, it is common during the installation process to discover previously unknown equipment issues that complicate installation or hinder the expected performance of the installed equipment. Installation of controls involves many variables and each unit has unique characteristics, resulting in unpredictable challenges. As an example, small, unforeseen differences in mill performance or coal pulverization could result in problems that must be addressed to ensure the LNB/SOFA equipment performs as expected.

In light of these site-specific considerations, including the mandatory regulatory approval process, EPA should grant reconsideration and revise the 18-month deadline to provide the full three years provided in the Proposed FIP for installation of LNB/SOFA at White Bluff and Independence. This will allow time for Entergy to comply with its internal planning and prudence review procedures, to obtain all required approvals, and ensure that the controls are properly tuned prior to the compliance deadline. At a minimum, EPA should grant reconsideration and provide at least 30 months for the installation of LNB/SOFA at White Bluff and Independence as this is the minimum amount of time Entergy anticipates that the NOx compliance deadline could be met even by truncating its internal procedures and barring any unforeseen issues.

2. EPA must revise the NOx limit and averaging period that apply during periods of low load.

In the Final FIP, EPA unlawfully introduced, for the first time, a NOx emission limit of 671 lb/hr on a rolling 3-hour average that applies when the White Bluff and Independence units are operating at less than 50 percent of their maximum heat input capacity.[48] In contrast, EPA had proposed an emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average that would apply regardless of the capacity at which the units were operating.[49] Entergy did not have notice of or an opportunity to comment on the significant change in the Final FIP to the limit and averaging period that apply when the units are operating at low loads. Entergy explained in its comments on the Proposed FIP that a higher limit is necessary during periods of low load operation because the LNB/SOFA system is designed to operate primarily in the range of 50-100 percent of unit load, and the vendor would not guarantee that LNB/SOFA could meet a limit of 0.15 lb/MMBtu for operating loads below 50 percent.[50] While Entergy appreciates EPA's apparent attempt to account for periods of low load in the Final FIP, EPA must reconsider the emission rate and averaging period that apply when the units are operating at less than 50 percent of the maximum heat input capacity.

First, Entergy did not have an opportunity to comment on the new emission limit and averaging period that apply during low load operation. EPA has not explained why either the limit that it established or the shorter averaging period are appropriate for either White Bluff or Independence, given that they were not raised or considered in the Proposed FIP or in Entergy's comments. The final limit and averaging period are not logical outgrowths of the Proposed FIP and they are plainly unlawful, arbitrary and capricious. EPA must grant reconsideration of these elements of the Final FIP.

Second, the new averaging period is unworkable for low load operation and will result in exceedances of the limit. During periods of load transition and, in particular, periods of reduced load, NOx is very sensitive to changing conditions such as air flow, fuel flow, and burner tilt position. When load is being ramped up or down, and mills are put in or out of service, NOx can spike to levels well above typical levels for short periods of time. Within minutes of the excursion, NOx typically will return to and stabilize at the steady state level. With the short 3-hour averaging period, a single 15-minute spike in NOx could result in NOx exceeding the low-load NOx emission limit for a 3-hour period, even if the remaining 165 minutes were below compliance levels.[51] A 30-boiler-operating-day period is necessary to moderate the variations in NOx due to load transition and low load.

Finally, the low-load NOx emission limit, which EPA set at one half the limit proposed by Entergy, also is problematic. It offers no compliance margin, which is necessary to account for increased NOx levels that occur as a function of low load operation, and the unavailability of SOFA when the unit is operated at less than 30 percent of capacity. When load falls below 50 percent, NOx levels increase as a percentage of heat input, trending upwards as load is reduced. This phenomenon is due to the increased levels of excess air that are used to ensure safe boiler

[48] 81 Fed. Reg. at 66,344, 66,354.
[49] 80 Fed. Reg. at 18,974, 18,997.
[50] EAI Comments at 50.
[51] *See* Memorandum from Foster Wheeler (hereinafter "Foster Wheeler Memo") (attached as Exhibit F).

operation during low loads. During load swings, control systems lead load increases with increases in air flow and follow load decreases with reductions in air flow. This excess air leads to NOx formation from nitrogen-laden air. Not only are NOx emissions generated at a higher rate at low load, but NOx control options are limited during these periods. SOFA is unavailable when the boiler operates below 30 percent capacity, including during startup, because there is insufficient air to support both good combustion and maintain overfire air flow to the boiler. As a result, the SOFA system cannot provide any NOx reduction during these operational periods.

Accordingly, EPA should reconsider the NOx limit and averaging time that applies to periods of low load operation and adopt the limit requested by Entergy in its comments: a rolling 30-boiler operating day average emission rate of 1,342.5 lb NOx/hr at each coal-fired unit at White Bluff and Independence.[52] At the least, EPA should revise the NOx averaging time to a 30-boiler-operating day period, and the limit to 895 lb/hr.[53] This will allow the inevitable NOx variations to be smoothed out over the averaging period, resulting in a limit that is possible to achieve.

IV. REQUEST FOR STAY

A. EPA Should Grant a Stay Pursuant to the CAA and the APA.

Section 307(d)(7)(B) of the CAA authorizes EPA to stay the effectiveness of a rule for up to three months during reconsideration,[54] which can be extended for additional three-month periods. Additionally, the Administrative Procedure Act ("APA") authorizes EPA to stay the effectiveness of a rule indefinitely. Under the APA, "[w]hen an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review."[55] EPA has applied this standard to CAA actions.[56]

Unlike a judicial stay, an administrative stay does not require a demonstration of irreparable harm. The APA states:

> When an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review. On such conditions as may be required and to the extent necessary to prevent irreparable injury, the reviewing court . . . may issue all necessary and appropriate process to postpone the effective date of an agency action or to preserve status or rights pending conclusion of the review proceedings.[57]

The APA deliberately contrasts what is required for an administrative stay—"justice so requires"—and a judicial stay—"conditions as may be required" and "irreparable harm." Similarly, CAA Section 307(d)(7)(B) authorizes an administrative stay, but does not premise that

[52] EAI Comments at 49.
[53] Foster Wheeler Memo at 4.
[54] *See* 42 U.S.C. § 7607(d)(7)(B).
[55] 5 U.S.C. § 705.
[56] *See, e.g.,* Prevention of Significant Deterioration ("PSD") and Nonattainment New Source Review ("NSR"): Aggregation, 75 Fed. Reg. 27,643 (May 18, 2010).
[57] 5 U.S.C. § 705. EPA has stayed a rule pursuant to Section 705 even after the rule's effective date has passed. *See Stay of Federal Water Quality Criteria for Metals*, 60 Fed. Reg. 22,228 (May 4, 1995).

stay on a finding of irreparable injury, noting simply that "[t]he effectiveness of the rule may be stayed during such reconsideration…for a period not to exceed three months."[58]

EPA should administratively stay the Final FIP's emission limitations for White Bluff and Independence while it addresses the issues identified above in Entergy's Petition, and while the Eighth Circuit considers Entergy's petition for review of the Final FIP. Specifically, Entergy requests that EPA stay 40 C.F.R. §§ 52.173(c)(6)-(8) with respect to White Bluff and §§ 52.173(c)(24)-(26) with respect to Independence. As explained below, a delay in implementation of the FIP would prevent harms to Entergy, with negligible visibility impact, while the Final FIP is reviewed. An administrative stay also would allow ADEQ time to develop its replacement SIP.

B. Justice Requires that EPA Grant a Stay.

1. Compliance with the SO_2 limits would immediately and irreparably harm Entergy, its co-owners, employees, customers, and communities.

To meet the Final FIP's SO_2 emission limits at White Bluff and Independence, Entergy must make plans for compliance now. Implementation of the Final FIP requires Entergy to make a Hobson's choice as soon as possible to either (1) permit, design, gain regulatory approval for, construct, install, and tune dry scrubbers on all four units by October 27, 2021, or (2) deactivate the units by that date, eliminate 230 Entergy jobs in rural Arkansas,[59] dramatically reduce the local tax revenues, and commit to new resources to replace a significant portion of its generating capacity. Either path for compliance with the SO_2 emission limits at White Bluff and Independence is a complex undertaking that must be pursued independently for each unit, and will result in immediate and irreparable harm to Entergy, its co-owners,[60] and local economies.

To ensure compliance, either path would require Entergy to begin making commitments and significant financial investments in the immediate future and without state agency review of the proposed path. Entergy must pursue both potential paths for as long as there is regulatory uncertainty.[61] Entergy would suffer irreparable harm if it is forced to proceed before EPA acts

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[58] 42 U.S.C. § 7607(d)(7)(B).

[59] Entergy also directly employs several hundred contractors over the course of the year, for both seasonal outage work and ongoing plant support.

[60] As described in petitions for reconsideration of the Final FIP filed by co-owners of the White Bluff and Independence plants, the harms to these co-owners would be significant. For example, deactivation of both plants in October of 2021 would create the immediate need to add an estimated 500 megawatts ("MW") of firm generation capacity to the Midcontinent Independent System Operator ("MISO") side of the Arkansas Electric Cooperative Corporation ("AECC") system. This replacement capacity is estimated to require the investment of $490,000,000. The levelized investment recovery cost of this generation capacity to AECC's member cooperatives would be approximately $34,000,000 annually. Jonesboro City Water and Light estimates that replacement of its share of ownership of the generation capacity of the White Bluff and Independence units in 2021 would result in increased costs between $16.3 million and $25 million, *in 2021 alone*, which translates to a 17-27 percent increase in customer rates. *See* Petition for Reconsideration and Request for Administrative Stay of AECC and Petition for Reconsideration and Request for Administrative Stay of Energy & Environmental Alliance of Arkansas ("EEAA").

[61] Either choice would cause irreparable harm in so far as significant financial investments would need to be made that could not be reversed if the Final FIP were later revised or vacated. Additionally, due to the lead time needed to install FGD technology or to prepare for permanent retirement, more time is needed to select one of these two options than the Final FIP allows. As described in this section, regulatory reviews are required for both paths, so the

on the Petition and before the Eighth Circuit determines the merits of Entergy's petition for review of the Final FIP. And yet, to meet the compliance deadline, it will be compelled to do so or risk noncompliance with the Final FIP. The first path, installing dry scrubbers on all four units, would be a massive undertaking costing approximately $2 billion. The first phase of this multi-phase project would have to begin as soon as the decision to proceed was made, as the process would require the entirety of the five years allotted in the Final FIP, as explained in further detail below, including spending over $150 million in the first 18 months alone. The second path, deactivating the units, is complicated and costly in different ways, as explained below. Both paths cause Entergy irreparable harm.

Given the lead times for either path, Entergy must start immediately to conduct analyses and reviews to support its internal decision-making process, which will take several months. Entergy's internal review process would assess both approaches, particularly analyzing and comparing the economics of each approach, and would be coordinated with the co-owners of White Bluff and Independence. Assessing the costs of the two approaches is extremely complicated. For example, for EAI to retire an existing generating unit, EAI must provide at least six months' notice to MISO, the regional transmission operator that dispatches White Bluff and Independence, of its intent to retire the unit. Because of the interconnected nature of the electric grid, a decision to retire a unit can have implications for the remainder of the grid, some of which may require upgrades to the transmission system to ensure that the grid can be operated reliably after the generating unit is retired. Accordingly, owners/operators of a generating unit typically would request that MISO perform an "Attachment Y-2 study," which would determine, on a non-binding basis, whether the retirement of the generating unit (i.e., White Bluff or Independence) would impact transmission system reliability, or whether the plant would need to continue to operate until transmission upgrades or other system changes to maintain reliability can be completed. In Entergy's experience, an Attachment Y-2 study takes approximately three to four months for a standard request. However, this situation is far from standard; assessing the retirement of four units totaling nearly 3400 MW of capacity may take much longer. Entergy would incorporate the Attachment Y-2 results into its internal economic analysis. Depending on the time needed to perform the economic analysis, coordinate with co-owners, and obtain the results of MISO's Attachment Y-2 study, this decision-making process would take between six and nine months.

Compliance with the FIP also requires EAI, the operator of all four units, along with the other co-owners of White Bluff and Independence to adhere to other regulatory processes, each unique to each co-owner.[62] In similar cases involving significant capital investments at existing generating units, EAI has sought a declaratory order from the APSC confirming that the selected path is in the public interest.[63] Because EAI is a rate-regulated entity, costs prudently incurred in the provision of electrical service typically are recoverable from customers, but cost recovery can occur only after the costs are reviewed by the APSC and a regulatory rate adjustment is made. In

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compressed timeline mandated by the Final FIP requires Entergy to simultaneously prepare for both paths in the event that the selected path does not earn regulatory approval.

[62] For example, EMI also has regulatory reviews and approvals before the Mississippi Public Service Commission that it must pursue. *See also* Petition for Reconsideration and Request for Stay of Energy and Environmental Alliance of Arkansas.

[63] *See. e.g.,* APSC Docket No. 09-024-U (Seeking public interest finding for installation of environmental controls at White Bluff Units 1 and 2).

other words, a public interest finding addresses the prudence of the investment; it does not address the prudence of the management of the incurrence of the costs nor does it modify base rates or effect other charges to include those costs (which would be the result of a separate review by the APSC in a later proceeding). If cost recovery is not approved or if recovery is significantly delayed, EAI could be deprived of a reasonable opportunity to receive adequate recovery of costs incurred.[64] In either case, the preparation of the application and supporting testimony could take up to six months. Additionally, completion of discovery, an APSC-determined procedural schedule with multiple rounds of testimony from the APSC General Staff, Attorney General, and other intervenors, a public hearing, and the issuance of a final order, could take an additional 14 months to complete. Accordingly, the state regulatory process may take as long as 20 months, and that is prior to any potential challenge by EAI to the APSC's final order, which could include a petition for rehearing and subsequent appeal.

Should Entergy choose to install dry scrubbers on all four units, Entergy would be forced to make considerable expenditures within the next few years, effectively prohibiting any alternative approach. Of the approximately $2 billion that Entergy estimates it would spend for scrubbers on White Bluff and Independence, Entergy would need to spend well in excess of $38 million within the first year, $150 million within 18 months, and $305 million within 24 months.[65]

The work to install the dry scrubbers also would need to begin immediately to comply with the FIP's five-year deadline. During the preliminary engineering phase of the project, which is expected to take between six and 12 months, an engineer would need to develop detailed specification requirements for the engineering, procurement, and construction of the FGD systems. Contractors would need at least three months to develop proposals, and then several weeks would be required to evaluate the proposals and award the contract. Because White Bluff and Independence have different co-owners, two separate FGD contracts would need to be developed. Afterward, the FGD contractor at each plant would proceed with the detailed engineering phase, during which every component required for a complete and operable FGD system would be designed and fabricated. Next, the engineered components would be delivered to the sites and the FGD contractor at each site would erect them and integrate them into the existing plants. A tie-in outage must be taken for each unit so that physical connections to existing systems can be made. Because Entergy would not take simultaneous outages at all four units for reliability reasons, and because there would be two FGD contracts awarded at different times, the construction phase likely would be staggered by approximately one year across all four units. Once constructed, equipment startup and commissioning would occur, followed by operational tuning and performance optimization. Performance testing would then

[64] EAI has elected to be regulated pursuant to Ark. Code Ann. § 23-4-1201 et seq., which provides that a public utility may choose to be regulated under a formula rate review mechanism that provides for an annual streamlined review of a public utility's rates and designation of a test period based on a projected test year. EAI's APSC-approved Rate Schedule No. 44, Formula Rate Plan Rider ("Rider FRP") provides for annual adjustment of customers' rates based on a comparison of EAI's earned return on common equity and its target return rate approved by the APSC. However, pursuant to Ark. Code Ann. § 23-4-1207 and Rider FRP, the annual Rider FRP revenue increase or decrease for each rate class shall not exceed four percent of each rate class' revenue. Accordingly, in complying with the FIP, EAI may pursue cost recovery for those costs pursuant to Rider FRP or other potential cost recovery mechanisms.

[65] These estimates were developed by Sargent & Lundy but do not include the significant costs for AFUDC, escalation and owner's costs that Entergy also will incur. Sargent & Lundy Memo at 5.

be conducted to confirm compliance with emission limits. The FGD contractor would need approximately three years to complete engineering and construction of one unit, followed by up to six months of commissioning, startup, performance optimization, and performance testing.

Alternatively, were Entergy to choose deactivation, the company would have to secure additional regulatory approvals as quickly as possible to provide for a smooth transition to replacement power by the 2021 deadline. The company must provide six months' notice to MISO before a generator can be retired (the "Attachment Y" process described above). .

Entergy next would need to procure and build replacement power because White Bluff and Independence currently are needed for Entergy to provide reliable electricity generation to its customers and meet its obligations to MISO. Entergy's resource planning process would consist of designing, gaining regulatory approval for, constructing, and making operational a new alternative generating unit. Entergy anticipates that the replacement generation would be a combined cycle gas turbine ("CCGT"),[66] which may require construction of a new gas pipeline to the selected site. Depending on the site that is selected for the CCGT, rights-of-way may need to be obtained. Transmission would need to be planned and built to connect the new CCGT with the grid. To construct replacement generation as quickly as possible, Entergy must prepare an environmental permit application, prepare RFPs for the construction, select a vendor, and submit a permit application. The time required for this process means that replacement power would not be available for five years at the earliest, thus exposing customers to market capacity prices in the interim. Accordingly, planning must begin immediately to limit, as much as possible, the duration of customer exposure to market prices. In the meantime, even maintaining reliability through the purchase of power would require Entergy to accelerate planned transmission projects. A project that currently is planned to be completed in 2024 would have to be accelerated to be completed in 2020, at an additional cost of $8 million and with a start date in 2017.

Ceasing operations at White Bluff and/or Independence would cause irreparable harm to Entergy employees and the communities in which they work. The total number of jobs created and supported by the White Bluff plant alone is estimated to be 1,237.[67] Entergy itself employs 105 full-time employees at White Bluff, along with 10 Entergy Service Company employees that support White Bluff full time. White Bluff also employs approximately 300 contractors for at least six weeks in the spring and fall each year for planned outage support. Additionally, there are about 20 contractors that work full time in security, coal dust management, janitorial, lawn maintenance, ash management and scaffolding support. At Independence, Entergy employs 108

[66] White Bluff cannot be replaced by renewable energy. White Bluff provides approximately 1,600 MW of reliable capacity to the MISO system and there are no practical or reasonable renewable generation options to meet the MISO resource adequacy requirements currently satisfied by White Bluff. Replacement of White Bluff would require 3,200 MW of solar power (necessitating 22,000 acres of panels), or 10,000 MW of wind generation (necessitating 7,000 windmills that would have to be located in the plains states hundreds of miles away from Entergy's load). Additionally, there is insufficient biomass fuel available to supply a 1,600 MW replacement biomass plant, and even if sufficient fuel were available, it would take an impracticable amount of trucks to deliver the necessary fuel. None of these options is feasible.

[67] Willie Lee Brooks, Jr., Senior Analyst, Economic & Financial Risk, *What is the Economic Impact of the White Bluff Electric Power Plant?*, at 2, Arkansas Electric Cooperative Corporation (May 30, 2014), available at http://www.arkleg.state.ar.us/assembly/2015/Meeting%20Attachments/890/I12666/HANDOUT%202%20-%20HIGHLEY%20%20Economic%20Impact%20of%20White%20Bluff%20Electric%20Pwr%20Plant.pdf

full-time employees, along with seven Entergy Service Company employees that support Independence full time. Independence also employs 83 contractors, who provide janitorial services, maintenance support, ash disposal services, and work on insulation and scaffolding during outages. If White Bluff and Independence were to cease operations, the company would have to lay off or reassign its employees, and the contractors would be out of work. These shutdowns would have significant impacts on the rural Arkansas communities where the plants are located. For example, the estimated the value of White Bluff to the local economy is $173 million.[68]

2. Compliance with the NOx limits would immediately and irreparably harm Entergy, its co-owners, employees, customers, and communities.

As explained above in Section III.D, the 18-month deadline to install LNB/SOFA at White Bluff and Independence is infeasible, as it does not provide sufficient time to develop, plan, permit, install, and appropriately tune the equipment. Entergy could complete installation of LNB/SOFA at all four units by the final deadline only by circumventing its normal internal procedures and the tuning and training process. Entergy would be forced to perform a more limited risk and prudence review, would have to forgo a competitive bidding process in favor of using a pre-selected vendor for fabrication and installation, and may even need to engage this vendor prior to having all regulatory approvals in hand. These procedures are in place to attempt to ensure cost recovery, and failure to comply with them puts the company at risk of making investments that the APSC later determines are not in the public interest and therefore ineligible for cost recovery. Additionally, Entergy would be forced to comply with the emission limits prior to the conclusion of its tuning and training procedures. Even with these truncated procedures, the schedule does not allow for any unforeseen issues in the installation and tuning process, which frequently arise and complicate installation or hinder the expected performance of the installed equipment.

Implementation of the Final FIP forces Entergy to choose between two untenable options each resulting in irreparable harm and unnecessary risk: (1) increasing costs and risk through rushed work and non-compliance with company prudence procedures, with no guarantee of FIP compliance once the work is completed, and (2) taking more time than the Final FIP permits, resulting in cessation of operation of the White Bluff and Independence units until LNB/SOFA can be installed. Beyond the fact that cessation of operations would necessitate Entergy to obtain costly replacement power on the open market, critically, it also could cause reliability issues, as generation from White Bluff and Independence is necessary for Entergy to provide reliable electricity generation to its customers and meet its obligations to MISO. In light of this, EPA must issue a stay of the deadline for compliance with the NOx limits until a more appropriate deadline can be set.

[68] *Id.*

3. A stay would prevent harm to Entergy and its co-owners, customers, and communities but would still allow Arkansas to meet its regional haze goals.

Arkansas already is below the URP and EPA's RPGs, and thus a delay in the implementation of the FIP would not contribute to unacceptable visibility impairment. As discussed previously, the IMPROVE data for January 2014 through December 2015 show that visibility continues to improve at a greater rate than the URP in Caney Creek and Upper Buffalo.[69] The recent IMPROVE data also confirm that visibility in the two Arkansas Class I areas already is better than EPA's final RPGs for the areas.[70] Accordingly, a stay would not interfere with attainment of the URP or the RPGs.

D. Entergy Also Meets the Four Factors that Courts Consider When Assessing Judicial Stay Requests.

Although the judicial test for analyzing a request for a stay does not apply here, Entergy's request for stay nonetheless satisfies this test. First, as described above, Entergy has made a strong showing of likelihood of success on the merits. For the reasons explained in this Petition, the Final FIP contains significant errors and unreasonable requirements upon which Entergy was unable to comment during the period for public review, and that are not logical outgrowths of the Proposed FIP. The CAA *requires* that EPA reconsider these elements of the Final FIP. Second, Entergy would be irreparably harmed if the Final FIP is not stayed. As explained above, implementation of the FIP would force Entergy to make expensive choices about the installation of controls and possible deactivation of units in very short order. Entergy would be forced to spend significant amounts of money once these choices are made. Third, a stay of the rule would not cause harm. Visibility in Arkansas' Class I areas already is improving at a rate greater than the URP for each area, and the areas already have surpassed EPA's final RPGs for the first planning period. Implementation of SO_2 and NOx controls at White Bluff and Independence is not needed to achieve either the URP or the RPGs. Fourth, the balance of harms and the public interest favor a stay. A stay would prevent significant, irreparable harm to Entergy with little visibility impact, as Arkansas already has met the goals that the installation of FGD and LNB/SOFA are designed to achieve. It also would prevent the harm to employees and local communities that would ensue from the deactivation of any of the units. In light of this, a stay is appropriate and just, and should be granted.

V. CONCLUSION

For the reasons discussed above, Entergy urges EPA, by February 1, 2017, to reconsider and stay certain provisions of the Final FIP to avoid the harms to Entergy, its employees, co-owners, customers and local communities, as described herein.

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[69] Trinity Report at 3.
[70] See *supra* at 4.

Dated: November 23, 2016

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From: Vivian Aucoin
Sent: Mon 6/12/2017 10:57:48 AM
Subject: Regional Haze documents
DRAFT Nelson AOC - djt.docx
RH Nelson Louisiana Final redline_vha-djt edits.docx

Greetings,

Here are the regional haze documents on Entergy's R. S. Nelson facility that you have requested. As you already know, the public comment period will begin on June 20, 2017. Let me know if you wish to discuss and we will set up a conference call.

Thanks!

Vivian H. Aucoin

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STATE OF LOUISIANA
DEPARTMENT OF ENVIRONMENTAL QUALITY

OFFICE OF ENVIRONMENTAL ASSESSMENT

IN THE MATTER OF	*	
	*	
ENTERGY LOUISIANA, LLC	*	**REGIONAL HAZE**
R.S. NELSON GENERATING PLANT	*	**STATE IMPLEMENTATION PLAN**
CALCASIEU PARISH, LOUISIANA	*	**EGU BART ANALYSIS**
	*	
	*	**AGENCY INTEREST NO. 19588**
	*	
PROCEEDINGS UNDER THE LOUISIANA	*	
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 **ENTERGY LOUISIANA, LLC (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 the R. S. Nelson Generating Plant located at 3500 Houston River Road, Westlake, Calcasieu Parish, Louisiana (Facility). The Facility currently operates pursuant to Title V and PAL Permit Number 6250-00014-V4 issued on April 11, 2017.

II.

Under Clean Air Act (CAA) section 110, each state must prepare and submit for the EPA approval, a 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 is concurrently submitting a proposed SIP on behalf of the State of Louisiana to EPA Region VI that addresses Best Available Retrofit Technology (BART) for the Facility. The BART analysis is based in part on submittals made by RESPONDENT to the Department on August 31, 2015, November 9, 2015 and April 15, 2016.

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:

> Before fuel oil firing is allowed to take place at Unit 4 and the auxiliary boiler at the Facility, a revised BART determination must be promulgated for SO_2 and PM for the fuel oil firing scenario through a FIP or an action by the LDEQ as a SIP revision and approved by EPA such that the action is federally enforceable.

II.

The Respondent shall comply with the sulfur dioxide (SO_2) emission limitations set forth below as expeditiously as practicable, but no later than three years of the effective date of a final SIP pursuant to 40 CFR PART 51, Appendix Y:

Unit	**Pollutant**	**Emission Limit lb./ MMBtu (30-day rolling average, conventional rounding)**
6	**SO_2**	**0.6**

III.

The Respondent shall comply with the particulate matter less than 10 microns (PM_{10}) emissions limit set forth below no later than the effective date of a final SIP pursuant to 40 CFR PART 51, Appendix Y:

Unit 6

Unit	**Pollutant**	**Emission Limit lb/hr (30-day rolling average)**
6	**PM_{10}**	**317.61**

IV.

The Respondent shall continue to comply with all reporting and record keeping requirements contained within all applicable permits.

V.

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*.

VI.

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.

VII.

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.

VIII.

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.

IX.

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 State 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** 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 **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**.

X.

A.)"This **ADMINISTRATIVE ORDER ON CONSENT** shall be final and effective upon final approval of a SIP by EPA and signature by an authorized representative of the Department

and signature by the authorized representative of the Respondent, provided that the federally enforceable limits set forth herein shall not become effective until the final approval by EPA of the SIP as it relates to the BART Five Factor Analysis for the Facility based upon those federally-enforceable limits".

Baton Rouge, Louisiana, this _____ day of June, 2017.

_____
Chuck Carr Brown, Ph.D.
Secretary

Entergy Louisiana LLC

By:_____ Date:_____

Name:

Title: President

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

Regional Haze State Implementation Plan

EGU BART Analysis

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

Revision Proposed June 2017

I. Background on the Regional Haze Rule

A. Plan Submission

[No Change]

B. Legal Authority

[No Change]

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 June 20, 2017 in the *Louisiana Register*. Public comments on the proposal should be submitted no later than July 26, 2017. A public hearing will be held if requested. A copy of the potpourri notice is included in Appendix A

D. Commitment to Plan Revision

[No Change]

E. History of Regional Haze

[No Change]

F. Breton National Wilderness Area (Class I)

[No Change]

G. Louisiana's Visibility History

[No Change]]

H. Class I Areas outside the State Boundaries

[No Change]

II. BART Analysis

[No Change]

A. CLECO

[No Change]

B. Louisiana Generating, LLC, a subsidiary of NRG

[No Change]

C. Entergy Louisiana LLC

Entergy submitted to LDEQ CALPUFF modeling for $S0_2$ and PM for the various units that were found to be BART-eligible; all reports are included in Appendix D. In the course of this exercise, Entergy has submitted not only CALPUFF modeling and a five-factor analysis to satisfy the RH and BART requirements, but has also submitted CAMx modeling to support their findings. While LDEQ has not used the CAMx modeling to ascertain that the units have satisfied the BART requirements, the model results have been included for consideration. Following Louisiana's final revision submittal, a discussion between EPA, LDEQ and Entergy took place and based upon the results of that discussion, EPA provided additional information on Entergy's proposed BART five-factor analysis and EPA's draft analyses for LDEQ's review all additional information submitted by EPA is included in Appendix F. Therefore this SIP is being revised to include the EPA information.

•**Entergy Ninemile Point Units:**

[No Change]

•**Entergy Little Gypsy Units:**

[No Change]

•**Entergy Willow Glen Units:**

[No Change]

•**Entergy Sterlington Units:**

[No Change]

•**Entergy Michoud Units:**

[No Change]

•**Roy S. Nelson Generating Plant (Nelson):** The facility is located in Westlake, Calcasieu Parish, Louisiana and is located 264 miles west of the Breton National Wilderness Area and 286 miles south of the Caney Creek Wilderness Area in Arkansas. The facility is a fossil-fuel steam electric power generating facility and operates three BART-eligible steam generating units: Unit 4, Unit 4 Auxiliary Boiler and Unit 6.

The Unit 4 Boiler is permitted to combust natural gas, No. 2, No. 4 and No. 6 fuel oils And refinery fuel gas. Unit 4 has a maximum heat rated capacity of 5400 MMBtu/hour and exhausts out of one stack. It has flue gas recirculation equipment installed for control of NOx emissions. The Auxiliary Boiler for Unit 4 is permitted to burn natural gas and fuel oil.

The Unit 6 Boiler is permitted to burn coal as its primary fuel, with No. 2 and No. 4 fuel oils as its secondary fuels. Unit 6 has maximum heat rated capacity of 6216 MMBtu/hour and exhausts out of one stack. It has an electrostatic precipitator (ESP) with flue gas condition for control of particulate matter (PM) emissions. Unit 6 has installed Separated Overfire Air Technology (SOFA) and a Low NOx Concentric Firing System (LNCFS) for NOx control. Steam from these boilers is used to drive steam turbines which in turn generate rotary motion that is used to drive electric generators. The electric generators then produce electricity.

Entergy has performed the traditional CALPUFF analysis as well as CAMx based upon EPA modeling guidance. The guidance, Appendix Y of the BART rule (July 6, 2005), states that CALPUFF shall be used for single-source modeling where the distance between the BART source and the Class I area is less than 300 kilometers (km). Since CALPUFF may significantly over predict impacts at greater distances, CAMx is approved for situations where the distance is greater than 300km. The facility is 425 km from Breton and 460km from Caney Creek.

Unit 4 and the auxiliary boiler are permitted to burn fuel oil. However, fuel oil has not been burned at either unit in several years and there are no current operational plans to burn fuel oil. Entergy and LDEQ have executed an Administrative Order on Consent (AOC) that states before fuel oil firing is allowed to take place at Unit 4 and/or the auxiliary boiler, a revised BART determination must be promulgated for SO_2 and PM for the fuel oil firing scenario through a SIP revision, which will then have to be approved by EPA and such action will become federally enforceable.

In the Entergy BART five-factor analysis for SO_2 for the Unit 6 Boiler, a number of emission reduction controls were reviewed. Those controls included lower sulfur coal, DSI, enhanced DSI, dry flue-gas desulfurization (FGD) and wet FGD. LDEQ has weighed the five factors and after a review of both Entergy's and EPA's information has concluded that BART is the emission limit of 0.6 lbs./MMBtu based on at 30 day rolling average as defined in the AOC. While additional visibility benefits may be available through the use of FGD, the lower sulfur coal option results in visibility benefits at a lower annual cost. In addition, FGD use results in additional waste due to spent reagent and has some power demands to run the equipment. LDEQ believes, at present, that the use of lower sulfur coal presents the appropriate SO_2 control based on consideration of economics, energy impacts, non-air quality environmental impacts, and impacts to visibility.

Regarding PM, Unit 6 is currently equipped with an ESP to control PM emissions. Impacts from PM emissions are small and any additional controls beyond the ESP would have minimal visibility benefits and would not be cost–effective. Therefore, the existing controls are

sufficient to meet BART for PM. Based upon this decision and the inclusion of the emission limits in the AOC, LDEQ has determined that the conditions are sufficient to meet BART.

As the energy industry evolves, LDEQ continues to work with EGUs throughout Louisiana to evaluate the operation of utilities. As such, LDEQ will engage in discussions with Entergy about any potential changes in usage or emission rates at the Nelson facility. Any such changes will be considered for reasonable progress for future planning periods as appropriate.

•Waterford 1 & 2 Electric Generating Plant (Waterford):

[No Change]

D. Municipal Facility Units

[No Change]

Appendix A

Public Notice and Participation

Appendix B

CLECO

BART Determination and Evaluation

[No Change]

Appendix C

NRG

BART Determination and Evaluation

[No Change]

Appendix D Entergy Louisiana LLC BART Determination and Evaluation

Appendix E

Municipal Facilities

[No Change]

Appendix F

EPA DRAFT BART Modeling and Costs Information

To: Vivian Aucoin[Vivian.Aucoin@LA.GOV]; Donald Trahan[Donald.Trahan@LA.GOV]; Charlotte Goudeau[Charlotte.Goudeau@LA.GOV]; vennetta.hayes@la.gov[vennetta.hayes@la.gov]
Cc: Donaldson, Guy[Donaldson.Guy@epa.gov]; Stenger, Wren[stenger.wren@epa.gov]; Kordzi, Joe[Kordzi.Joe@epa.gov]; Feldman, Michael[Feldman.Michael@epa.gov]; Thomas, Carrie[Thomas.Carrie@epa.gov]
From: Huser, Jennifer
Sent: Wed 5/31/2017 8:03:41 PM
Subject: Revised SIP Narrative and supporting documents (1 of 2)
LA_RH_Nelson_TSD.pdf
DRAFT Nelson AOC.docx
DRAFT LA CAMx BART Modeling TSD draft with Nelson.pdf
DRAFT LA CALPUFF BART modeling report draft with Nelson.pdf

[redacted]

RH Nelson Louisiana Final redline _clean 5_26_2017.docx

Good afternoon,

Thank you again for making time this afternoon to discuss the LA RH SIP revision for Entergy Nelson. Please find attached the following documents:

- Draft CAMx Modeling Report
- Draft CALPUFF Modeling Report
- Draft Nelson Technical Assistance Document
- Draft revised SIP narrative
- Draft AOC
- Supporting files for CAMx/CALPUFF/TAD

Please note that we have revised the SIP narrative to reflect discussions we had this afternoon. All supporting documents or those referenced in the TAD will be transmitted in a separate email.

Please feel free to contact me if you have any additional questions. We look forward to seeing

your draft by the 12th.

Thanks!

Jennifer Huser

Environmental Scientist

Air Planning Section (6MM-AA)
USEPA Region 6
1445 Ross Ave. Suite 1200
Dallas, TX 75202-2733
214-665-7347

DRAFT
Technical Support Document for Louisiana Regional Haze: CALPUFF Best Available Retrofit Technology Modeling Review

(DRAFT CALPUFF Modeling TSD)

Prepared by:

Michael Feldman
Erik Snyder
April 2017
(revised May 2017 to include Entergy Nelson)

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I. Introduction

To address the first implementation period, the State of Louisiana submitted a RH SIP on June 13, 2008 (hereafter referred to as the 2008 Louisiana Regional Haze SIP). EPA acted on that submittal in two separate actions: a limited disapproval (77 FR 33642; June 7, 2012) because the SIP relied on the Clean Air Interstate Rule (CAIR) to address the impact of emissions from the State's electric generating units (EGUs); and a partial limited approval/partial disapproval (77 FR 39425; July 3, 2012) noting deficiencies in the SIP revision that did not meet the applicable requirements of the CAA and EPA's regulations as set forth in sections 169A and 169B of the CAA and in 40 CFR 51.300-308. In our final action on June 7, 2012, we found that the requirements of section 169A of the CAA were not met because the 2008 Louisiana Regional Haze SIP did not include fully approvable measures for meeting the requirements of 40 CFR 51.308(d)(3) and 51.308(e) with respect to emissions of NOx and SO2 from electric generating units. We also determined that the Cross State Air Pollution Rule (CSAPR or the Transport Rule)[1], a rule issued in 2011 to address the interstate transport of NOx and SO2 in the eastern United States would, like CAIR, provide for greater reasonable progress towards the national goal than would BART for states in which CSAPR applies. 76 FR 82219. EPA finalized that rule on May 30, 2012 (77 FR 33642). Based on this finding, the EPA also revised the Regional Haze Rule (RHR) to allow CSAPR states to substitute participation in the trading programs under CSAPR for source-specific BART. States such as Louisiana that are subject to the requirements of the CSAPR trading program only for ozone season nitrogen oxides (NOx) can still substitute CSAPR for BART for NOx, but must address BART for EGUs for SO2 and other visibility impairing pollutants. 76 FR 82224.

States are required to identify all BART-eligible sources within their boundaries by utilizing the three eligibility criteria in the BART Guidelines (70 FR 39158) and the Regional Haze regulations (40 CFR 51.301): (1) One or more emission units at the facility fit within one of the 26 categories listed in the BART Guidelines; (2) the emission unit(s) began operation on or after August 6, 1962, and the unit was in existence on August 6, 1977; and (3) the potential emissions of any visibility-impairing pollutant from subject units are 250 tons or more per year. Sources that meet these three criteria are considered BART-eligible. In our proposed partial disapproval and partial limited approval (77 FR 11839) of the 2008 Louisiana Regional Haze SIP, we approved LDEQ's identification of 76 BART-eligible sources.

Once a list of BART-eligible sources within a state has been compiled, states must determine whether to make BART determinations for all of them or to consider exempting some of them from BART because they may not reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. The BART Guidelines present several options that rely on modeling analyses and/or emissions analysis

[1] 76 FR 48207, 48208 (August 8, 2011).

approaches to determine if a source may reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. A source that may not be reasonably anticipated to cause or contribute to any visibility impairment in a Class I area is not "subject to BART," and for such sources, a state need not apply the five statutory factors to make a BART determination.

Louisiana's 2008 Regional Haze SIP submittal did not include a determination of which BART eligible EGUs were subject to BART, and Louisiana cannot rely on CSAPR as a substitute for BART for SO2. On May 19, 2015, EPA Region 6 sent CAA Section 114 letters to several BART-eligible sources in Louisiana. In those letters we noted our understanding that the sources were actively working with LDEQ to develop a SIP. However, in order to be in a position to develop a FIP, should that be necessary, EPA requested information regarding the BART-eligible sources. The Section 114 letters required sources to conduct modeling to determine if the sources were subject to BART, and included a modeling protocol. The letters also requested that a BART analysis in accordance with the BART Guidelines be performed for those sources determined to be subject to BART. The LDEQ worked closely with the BART facilities and with EPA Region 6. On February 10, 2017, Louisiana submitted a SIP revision (2017 Louisiana Regional Haze SIP) intended to cure the deficiencies noted in our partial limited approval/partial disapproval. On behalf of each BART facility, Trinity Consultants (or CB&I on behalf of NRG Big Cajun I and Big Cajun II), performed BART screening modeling for BART-eligible sources and five-factor analyses for subject-to-BART sources to address the BART requirements for EGU sources in the state. These modeling analyses were included as part of the 2017 Louisiana Regional Haze SIP. As part of our proposed action, we have reviewed the BART analyses performed by Trinity Consultants and CB&I that have been provided to us via the SIP submittal. The CALPUFF visibility modeling protocol reviewed here was followed in the technical work performed by Trinity Consultants and CB&I[2] for each facility and is described in detail in this document along with a summary of model results. Modeled emission rates and additional details of CALPUFF visibility modeling for specific BART sources are available in the modeling reports included in the appendices of the 2017 Louisiana Regional Haze SIP.

As discussed in the TSD and proposed rule, the 2017 Louisiana Regional Haze SIP submittal identifies a number of BART-eligible sources that have since retired from operation, and LDEQ rescinded their permits making the retirements permanent and enforceable, rendering them no longer subject to the requirements of the Regional Haze Rule. The following table identifies the remaining EGU sources in Louisiana that were identified in the 2008 Louisiana Regional Haze SIP submittal as BART-eligible. These sources are subject to the requirements of the Regional Haze Rule, including a determination of whether or not those sources are subject to BART.

[2] A copy of each BART analysis performed by Trinity Consultants on behalf of the BART sources can be found in the docket for this proposed rulemaking as part of the 2017 Louisiana Regional Haze SIP.

Table 1-1. BART-eligible sources requiring screening modeling

Facility Name	Units	Parish
Terrebonne Parish Consolidated Government Houma Generating Station	Units 15 and 16	Terrebonne
Louisiana Energy and Power Authority Plaquemine Steam Plant	Boilers 1 and 2	Iberville
Lafayette Utilities System Louis "Doc" Bonin Station	Units 1, 2, and 3	Lafayette
Cleco Rodemacher/Brame	Nesbitt I (Unit 1) Rodemacher II (Unit 2)	Rapides
Cleco Teche	Unit 3	St. Mary
Entergy Sterlington	Unit 7 (7AB and 7C)	Ouachita
Entergy Waterford	Units 1, 2, and auxiliary boiler	St. Charles
Entergy Willow Glen	Units 2, 3, 4, 5, auxiliary boiler	Iberville
Entergy Ninemile Point	Units 4 and 5	Jefferson
Entergy Nelson	Units 4, 6, and auxiliary boiler	Calcasieu
Entergy Little Gypsy	Units 2, 3 and auxiliary boiler	St. Charles
Louisiana Generating (NRG) Big Cajun I	Units 1 and 2	Point Coupee
Louisiana Generating (NRG) Big Cajun II	Units 1 and 2	Point Coupee

Throughout this document, we may use language such as, "we find" or other similar phrases that on the surface would suggest a final determination has been made. However, all aspects of our TSDs should be considered to be part of our proposal and are subject to change based on comments and other information we may receive during our public comment period

DRAFT

II. BART Guidelines and Modeling Protocol

A. Background and Introduction to BART Modeling

Once the list of BART-eligible sources is compiled, an examination is required to determine whether a particular BART-eligible source causes or contributes to visibility impairment in nearby Class I areas.[3] For those sources that are not reasonably anticipated to cause or contribute to any visibility impairment in a Class I area, a BART determination is not required.[4] Those sources are determined to be not subject-to-BART. Sources determined to be reasonably anticipated to cause or contribute to any visibility impairment in a Class I area are determined to be subject-to-BART.[5] For each source subject to BART, 40 CFR 51.308(e)(1)(ii)(A) requires that States identify the level of control representing BART after considering the factors set out in CAA section 169A(g).

The BART guidelines discuss several approaches available to exempt sources from the BART determination process, including modeling individual sources and the use of model plants. To determine which sources are anticipated to contribute to visibility impairment, the BART guidelines state you can use CALPUFF or other appropriate model to estimate the visibility impacts from a single source at a Class I area.[6] For those units outside of the CALPUFF model's typical range, CAMx modeling can also be performed to inform the determination of whether sources' visibility impacts are large enough to identify them as being subject to BART. CAMx modeling for BART screening and for evaluation of visibility benefits of potential controls is discussed in the CAMx Modeling TSD.

Following the protocol described and reviewed below, BART screening modeling using CALPUFF was performed to screen the sources identified in table 1. These modeling analyses were included as part of the 2017 Louisiana Regional Haze SIP. See Section III of this TSD for a discussion of results of this screening modeling for each BART-eligible source. There are two Class I Areas within approximately 300-400 km of the facilities that were included in the CALPUFF modeling analyses to assess visibility impacts at nearby Class I areas. These Class I areas are listed in Table 2-1.

For those units determined to be subject-to-BART, an analysis of BART must be performed. The BART analysis for those units determined to be subject-to-BART includes engineering and modeling methods and procedures used to determine the appropriate controls for the subject-to-BART units to address the source's contribution to pollutant concentrations that result in visibility impairment in the surrounding Class I areas. The final factor to consider in identifying a level of control as BART under EPA's

[3] See 40 C.F.R. Part 51, Appendix Y, III, How to Identify Sources "Subject to BART"
[4] *Id.*
[5] *Id.*
[6] *Id.*

BART Guidelines is the degree of visibility improvement from the BART control options.[7] The BART guidelines again recommend use of the CALPUFF air quality dispersion model to estimate the visibility improvements at each Class I area, and to compare these to each other and to the impact of the baseline, or current, source configuration. Following the protocol described and reviewed below, BART modeling using CALPUFF was also performed to assess visibility benefits of controls for the sources identified as subject-to-BART. See Section IV of this TSD for a discussion of CALPUFF modeling for visibility benefits of controls for the sources identified as subject-to-BART.

Table 2-1. Class I Areas

Class I Area	**State**	**Agency**	**IMPROVE monitor**
Caney Creek Wilderness Area	AR	USFS	CACR
Breton Wilderness Area	LA	FWS	BRET

Table 2-2. Approximate distances to Class I areas (km)

Facility Name	**Breton Island**	**Caney Creek**
Cleco Rodemacher/Brame	422	352
Cleco Teche	245	569
Entergy Sterlington	440	230
Entergy Waterford	150	592
Entergy Willow Glen	217	530
Entergy Ninemile Point	117	615
Entergy Nelson	427	460
Entergy Little Gypsy	150	592
Louisiana Generating (NRG) Big Cajun I	263	476
Louisiana Generating (NRG) Big Cajun II	263	476

Under the BART guidelines[8], the measure of the visibility impact and improvement to be used in screening and comparisons between various control scenarios is the 98th percentile of impacts expressed as 24-hour averages of delta deciviews relative to natural background, as estimated using the CALPUFF air quality modeling system. The meaning of this is described next, followed by particulars of the application of CALPUFF to the individual BART determinations.

[7] 59 FR 39104, 39170 (July 6, 2005), [40 C.F.R. Part 51, Appendix Y].
[8] 40 C.F.R. Part 51, Appendix Y.

Table 2-3. CALPUFF system modeling components utilized by Trinity and CB&I

Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8.4	130731
POSTUTIL	1.56	070627
CALPOST	6.221	080724

B. Calculation of Visibility Impact

Under the RHR, visibility is measured in deciviews.[9] Visibility is traditionally described in terms of visual range in kilometers or miles. However, the visual range scale does not correspond to how people perceive visibility: a given increase in visual range is perceived differently depending on how good the original visibility was (that is, it is not on a linear scale). The deciview scale is designed to address this problem. It is linear with respect to perceived visual changes over its entire range, analogous to the decibel scale for sound: a given change in deciviews will be perceived as the same amount of visibility change, whatever the original visibility was. The defining equation is:

$$deciviews = 10*ln(b_{ext} / 10)$$

where ln is the natural logarithm, and extinction b_{ext} is the fraction of light scattered out of a viewing path. Extinction increases with the amount of pollution (b_{ext} is in units of 1/Mm, "inverse megameters"). Lower deciview values represent better visibility, more pristine atmospheres, and greater visual range, while increasing deciview values represent increasingly poor visibility. An increase of 1 deciview corresponds to about a 10% increase in extinction. (Deciviews are related to the more traditional visual range according to dv = 10*ln(391 / visual range)). An eligible BART source with a predicted impact of 0.5 dv or more of impairment in a Class I area "contributes" to visibility impairment and is subject to BART.[10]

Under the BART guidelines, deciviews are estimated using the CALPUFF air quality model. CALPUFF predicts 24-hour average pollutant concentrations based on source emissions and how they disperse in the atmosphere. The CALPUFF modeling includes source emissions of the following visibility-impairing pollutants: SO_2, SO_4, NO_x, secondary organic aerosol (SOA), fine particulate matter (PMF), coarse particulate matter (PMC), and elemental carbon (EC). CALPUFF incorporates a semi-empirical chemical module that simulates the conversion of SO_2 to particulate sulfate and NO_x to particulate

[9] 40 C.F.R. 51.301.
[10] 70 FR 39104, 39121 (July 6, 2005), [40 C.F.R. Part 51, Appendix Y].

nitrate, at a rate dependent on meteorological conditions and background ozone concentration. These concentrations are converted to deciviews by the CALPOST post-processor in two steps.

1. IMPROVE Equation

Under the original IMPROVE[11] equation, extinction (b_{ext}) is estimated from the predicted concentrations of various pollutants:

$$
\begin{aligned}
b_{ext} &= 3 * f(RH) * [\text{sulfate}] \\
&+ 3 * f(RH) * [\text{nitrate}] \\
&+ 4 * [\text{organic mass}] \\
&+ 10 * [\text{elemental carbon}] \\
&+ 1 * [\text{fine soil}] \\
&+ 0.6 * [\text{coarse mass}] \\
&+ 10
\end{aligned}
$$

The 10 is for Rayleigh scattering, which is due to the interaction of light with molecules of air itself with no pollutants. The f(RH) is a water growth factor for sulfate and nitrate; its value depends on relative humidity (RH), ranging from 1 at low humidity to 18 at 98% humidity.

2. Revised IMPROVE Equation

The Trinity revised modeling used the "revised" IMPROVE equation[12] to calculate light extinction. Sometimes the revised IMPROVE equation is called the "New" IMPROVE equation. The revised IMPROVE equation is used to convert measured or modeled concentrations into extinction for each pollutant chemical species, and then total them up, accounting for the effect of relative humidity.

Revised IMPROVE equation:

$$
\begin{aligned}
b_{ext} &= 2.2 * f_s(RH) * [\text{small sulfate}] + 4.8 * f_L(RH) * [\text{large sulfate}] \\
&+ 2.4 * f_s(RH) * [\text{small nitrate}] + 5.1 * f_L(RH) * [\text{large nitrate}] \\
&+ 2.8 * [\text{small organic mass}] + 6.1 * [\text{large organic mass}] \\
&+ 10 * [\text{elemental carbon}] \\
&+ 1 * [\text{fine soil}] \\
&+ 1.7 * f_{ss}(RH) * [\text{sea salt}]
\end{aligned}
$$

[11] Interagency Monitoring of Protected Visual Environments (IMPROVE) is a network of monitors in various Class I Areas, established to assess visibility impairment and its causes. The IMPROVE equation is used to convert monitored concentrations into extinction, a measure of visibility. See: http://vista.cira.colostate.edu/improve/

[12] Pitchford, M. L., W. C. Malm, B. A. Schichtel, N. Kumar, D. Lowenthal and J. L. Hand, Revised algorithm for estimating light extinction from IMPROVE particle speciation data, *Journal of the Air & Waste Management Association, 57*, 1326-1336, 2007.

+ 0.6 * [coarse mass]
+ Rayleigh scattering (site-specific)
+ 0.33 * [NO_2(ppb)]

Sulfate is assumed to be all "large sulfate" if total sulfate is over 20 μg/m^3, otherwise its fraction of the total is assumed to increase uniformly between 0 and 1 when the total is in the range between 0 and 20 (i.e. large sulfate = (total sulfate/20)*total). A similar definition applies for nitrate and for organic mass. The organic mass is assumed to be 1.8 times the organic carbon mass that is measured by IMPROVE monitors, an increase over the old 1.4. Sea salt is estimated as 1.8* [chloride] (or chlorine if chloride not available). The f_s, f_L, f_{ss} are water growth factors for small ("S") and large ("L") fractions of sulfate and nitrate, and for sea salt ("SS"). Their values depend on relative humidity, ranging from 1 at low humidity to over 5 at 95% humidity. Rayleigh scattering is due to the interaction of light with molecules of air itself with no pollutants.

The IMPROVE program revised the IMPROVE equation after a scientific assessment of its implications for regional haze planning to reduce biases in light extinction estimates compared to the old algorithm.[13] In particular, when compared to nephelometer direct measurements of visibility extinction, the original IMPROVE equation over-predicts for low extinction conditions and under-predicts for high extinction. These biases have direct relevance for estimates for the worst 20% visibility days that are used to assess visibility impact. The new equation shows broader scatter overall, but less bias in matching visibility measurements under high and low visibility conditions. The split between small and large particles was the main factor in reducing the biases. The revised IMPROVE equation has less bias, is more refined, accounts for more pollutants and pollutant sizes, incorporates more recent data, and is based on considerations of relevance for the calculations needed for assessing progress under the Regional Haze Rule.

EPA 2007 guidance[14] states that the use of either the IMPROVE or the revised IMPROVE equation is acceptable provided that the same algorithm is utilized for both the base and future extinction calculations. EPA believes it is appropriate to use the revised IMPROVE equation and that this is the preferred method.

3. Deciview Impact Calculation

In the second CALPOST step this extinction is converted to deciviews, using the defining equation above for deciviews. The delta deciviews (Δdv) represents the impact on

[13] *Revised IMPROVE algorithm for Estimating Light Extinction from Particle Speciation Data*, IMPROVE, January 2006 (http://vista.cira.colostate.edu/improve/Publications/GrayLit/gray_literature.htm); Hand, J.L., Douglas, S.G., 2006, Review of the IMPROVE Equation for Estimating Ambient Light Extinction Coefficients – Final Report (http://vista.cira.colostate.edu/improve/Publications/GrayLit/016_IMPROVEEeqReview/IMPROVEeqReview.htm).

[14] *Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze*, EPA-454/B-07-002, April 2007, EPA OAQPS; (http://www.epa.gov/ttn/scram/guidance/guide/final-03-pm-rh-guidance.pdf).

visibility in deciviews of the source being evaluated, and is also provided by CALPUFF. It is the change, or "delta", between deciviews with and without the source. Under the BART guidelines, delta deciviews is the difference between deciviews including the impact of the source and natural background, and deciviews of the natural background alone. Each modeled day and location in the Class I area will have an associated delta deciview. For each day, the model finds the maximum visibility impact of all locations (receptors) in the Class I area. From among these daily values, the BART guidelines recommend use of the 98th percentile, roughly equivalent to the 8th highest day, visibility impacts expressed as 24-hour averages of delta deciviews relative to natural background, as estimated using the CALPUFF air quality modeling system for comparing the base case and the effects of various controls. In the BART guidelines, we made the decision to consider the less conservative 98th percentile primarily because the chemistry modules in the CALPUFF model are simplified and likely to provide conservative (higher) results for peak impacts.[15]

The BART guidelines recommend that impacts of sources be estimated in deciviews relative to natural background. The CALPUFF BART evaluations used average background concentrations (Table 2-3) and relative humidity adjustment factors (Tables 2-5, 2-6, and 2-7) from the Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report[16] for use with the revised IMPROVE equation ("Method 8").

Table 2-4. Natural Background Concentrations used for "Method 8"

Class I Area	**CALPOST control input parameters (μg/m^3)**						
	BKSO4	BKNO3	BKOC	BKEC	BKSOIL	BKCM	BKSALT
	Ammonium sulfate	Ammonium nitrate	Organic carbon	Elemental carbon	Soil	Coarse mass	Sea salt
Caney Creek	0.23	0.10	1.80	0.02	0.50	3.00	0.03
Breton Island	0.23	0.10	1.78	0.02	0.48	3.01	0.19

Table 2-5. $f_L(RH)$ Large RH Adjustment Factors

Class I Area	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Caney Creek	2.77	2.53	2.37	2.43	2.68	2.71	2.59	2.6	2.71	2.69	2.67	2.79
Breton Island	2.91	2.76	2.74	2.72	2.83	2.94	3.10	3.07	2.97	2.82	2.83	2.90

[15] "Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source. Because of these features and the uncertainties associated with the model, we believe it is appropriate to use the 98th percentile—a more robust approach that does not give undue weight to the extreme tail of the distribution." 70 FR 39104, 39121 (July 6, 2005), [40 C.F.R. Part 51, Appendix Y].
[16] Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report—Revised (2010) Natural Resource Report NPS/NRPC/NRR—2010/232 (http://www.nature.nps.gov/air/Pubs/pdf/flag/FLAG_2010.pdf)

Table 2-6. fs(RH) Small RH Adjustment Factors

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek	3.85	3.44	3.14	3.24	3.66	3.71	3.49	3.51	3.73	3.72	3.68	3.88
Breton Island	4.08	3.82	3.79	3.74	3.94	4.12	4.41	4.37	4.18	3.92	3.93	4.06

Table 2-7. fss(RH) Sea Salt RH Adjustment Factors

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek	3.9	3.52	3.31	3.41	3.83	3.88	3.69	3.68	3.82	3.76	3.77	3.93
Breton Island	4.1	3.89	3.87	3.85	4.02	4.21	4.44	4.38	4.23	3.99	4.01	4.11

C. CALMET/CALPUFF modeling protocol

On May 19, 2015, EPA Region 6 sent CAA Section 114 letters to several BART-eligible sources in Louisiana. In those letters we noted our understanding that the sources were actively working with LDEQ to develop a SIP. However, in order to be in a position to develop a FIP, should that be necessary, EPA requested information regarding the BART-eligible sources. The Section 114 letters required sources to conduct modeling to determine if the sources were subject to BART, and included a modeling protocol. The letters also requested that a BART analysis in accordance with the BART Guidelines be performed for those sources determined to be subject to BART. The EPA Region 6 worked closely with the BART facilities and with LDEQ. As a result, the LDEQ submitted a revised SIP submittal on February 10, 2017, (the 2017 Louisiana Regional Haze SIP) intended to address EGU BART for Louisiana. The 2017 Louisiana Regional Haze SIP includes modeling analyses conducted by Trinity Consultants and CB&I for each of the facilities of interest consistent with the protocol provided by us in the Section 114 letters.[17] These modeling analyses generally followed the BART protocol developed by CENRAP.[18] However, unlike previous modeling conducted for many sources in Louisiana, surface and upper air observations were utilized (NO OBS = 0) for the refined source-specific modeling, consistent with EPA and FLM recommendations. The CALPUFF modeling used an existing CALMET data set supplied by EPA that utilized CALMET v5.53a, which is a slightly earlier regulatory version and compatible with the regulatory version of CALPUFF (v5.8). EPA previously evaluated the differences in the

[17] A copy of each BART analysis performed by Trinity Consultants or CB&I on behalf of the BART sources is included in the 2017 Louisiana Regional Haze SIP.

[18] CENRAP BART Modeling Guidelines, T. W. Tesche, D. E. McNally, and G. J. Schewe (Alpine Geophysics LLC), December 15, 2005

CALMET model versions. Based on the changes between CALMET versions, we do not expect the newer version would yield different impact estimates and would not affect any of our decisions in this proposal. The Section 114 letters identified the availability of this existing dataset. This dataset was generated by Trinity Consultants for use in BART analyses of sources in Oklahoma.[19] The modeling protocol for this CALMET data set is available in the docket for this action and describes in full the modeling domain and input data utilized in developing the meteorological dataset. We note that because this CALMET data was prepared using both surface and upper air observations (NO OBS = 0), consistent with our guidance, we recommend the use of the 98th percentile or 8th highest value in analyzing the visibility benefits anticipated due to the use of controls, rather than the maximum value utilized in the previous CENRAP modeling analyses and screening analyses included in the 2008 Louisiana Regional Haze SIP. The 2017 Louisiana Regional Haze SIP submittal includes appendices with descriptions of the modeling protocol followed for each modeled source.

Table 2-8 shows selected CALMET settings used for modeling visibility impacts from these facilities as reflected in the 2017 Louisiana Regional Haze SIP submittal. R1MAX and R2MAX represent the radius of influence of surface and upper air observations, respectively. R1 (R2) defines the distance from an observation at which the surface (upper air) observation and the initial wind field are equally weighted and is typically set to half the value of R1MAX (R2MAX). EPA and FLMs recommend the use of higher values for R1MAX (100 km) and R2MAX (200 km) based on tracer evaluations and testing.[20] EPA is aware of these deviations and weighed the potential differences that may occur due to these deviations with the additional work and computing resources that would be required to redo the analyses. Given the time and resource constraints, EPA concludes that these deviations are acceptable and shared this dataset with LDEQ and BART sources for the purpose of evaluating visibility impacts for BART screening and benefits due to the use of controls as part of a full five-factor BART analysis for subject-to-BART sources in Louisiana.

Table 2-8. Selected CALMET Settings Used

Option	Description	EPA default	Trinity/CB&I
Version	CALMET version	5.8.4, level 130731	5.53a, level 040716
NOOBS	No Observation Mode	0	0
ICLOUD	gridded cloud fields	0	0
IWFCOD	diagnostic winds	1	1
IFRADJ	Froude wind adj.	1	1
IKINE	kinematic effects	0	0
IOBR	O'Brien vertical wind adj.	0	0
ISLOPE	slope flows	1	1

[19] The modeling protocol for this CALMET dataset can be found as: CALMET DATA Processing Protocol BART Determination Oklahoma Gas and Electric, Prepared by Trinity Consultants, January 23, 2008.
[20] Memorandum from Tyler Fox (EPA OAQPS) "Clarification on EPA-FLM Recommended Settings for CALMET," August 31, 2009.

IEXTRP	extrapolate wind to upper air	-4	-4
ICALM	extrapolate calm to upper air	0	0
BIAS	layer biases sfc vs. UA	NZ*0	NZ*0
IPROG	gridded initial prognostic	0	14
RMAX1	max surface radius of influence	NA	20
RMAX2	max aloft radius of influence	NA	50
RMAX3	max over-water radius of influence.	NA	100
RMIN	min wind radius of influence.	0.1	0.1
RMIN2	min dist sfc winds extrap	4	4
TERRAD	terrain radius of in influence	NA	10
R1	weight surface Step 1 vs. obs	NA	10
R2	weight aloft Step 1 vs. obs	NA	25
ITPROG	3D T from obs or prognostic	0	0
TRADKM	radius of influ. for T interp.	500	500
IAVET	spatial T averaging	1	1
JWAT1	starting land use for T interp. over water	999	55
JWAT2	ending land use for T interp. over water	999	55

The BART modeling submitted as part of the 2017 Louisiana Regional Haze SIP used the regulatory version of CALPUFF (v5.8.4) at the time the analyses were initiated[21] and CALPOST (v6.221). We note that the current regulatory version of CALPUFF was recently updated to v5.8.5.[22] Based on the changes between 5.8.4 and 5.8.5 and the types of sources we modeled with CALPUFF, we do not expect the newer version would yield different impact estimates and would not affect any of our decisions in this proposal. For visibility calculations, the pollution concentration predictions of CALPUFF are used in post-processing. First, POSTUTIL considers ammonia background concentrations, temperature, and humidity to determine how much nitrate ends up as particulate ammonium nitrate; this is to reflect the competition between sulfate and nitrate for available ammonia and is referred to as "Nitrate Repartitioning." CALPOST then converts the predicted pollutant concentrations into extinction using the revised IMPROVE equation followed by converting the estimated total extinction into deciviews.

The refined source-specific modeling used a constant value of 3 ppb background concentration of ammonia for the domain during the modeling period consistent with previously agreed values in Louisiana's CALPUFF modeling protocol. Hourly ozone

[21] On December 4, 2013, EPA approved an update to v5.8.4 that contained bug fixes to the previous version. See December 3, 2013 CALPUFF Update Memo for a discussion of model changes.
[22] On July 26, 2016, EPA approved an update to v5.8.5 that contains fixes to bugs in the implementation of PRIME downwash, along with updates to eliminate specific compilation and list file errors. See Model Change Bulletin H dated December 14, 2015 for a discussion of model changes.

observational data over the 2001-2003 timeframe were used to define background ozone concentrations.

Trinity utilized a CALPUFF modeling domain that extends at least 50 km in all directions beyond all Entergy units and the Class I areas of interest.[23] In general this approach seemed reasonable. However, model results for some sources or Class I areas may be sensitive to this assumption depending on their locations relative to the domain boundary, and the use of a larger modeling domain could result in higher impacts on certain days. This is due to the model's inability to track puffs that exit the smaller domain and then re-enter the modeling domain before impacting the Class I area. Using a larger modeling domain prevents puffs from being lost by exiting the domain. For those sources that required additional modeling to be performed by EPA to evaluate visibility benefits of potential controls, we did see some difference in some initial results using a larger modeling domain, so a larger modeling domain was utilized for all of EPA's additional modeling.

D. EPA Conclusion

In general, we find the CALPUFF modeling submitted in the 2017 SIP submittal to be consistent with EPA and FLM guidance and acceptable for the purposes of evaluating the anticipated visibility impacts for BART screening and the visibility benefits that can be achieved with the use of controls at the subject-to-BART facilities in Louisiana.

We note that included in the 2017 SIP submittal's BART analysis for the Cleco and Entergy sources prepared by Trinity Consultants is an evaluation of the CALPUFF model.[24] This analysis claims that due to limitations in the CALPUFF model, reliance on the CALPUFF results for determining if units are subject-to-BART is inappropriate. The model limitations identified in the analysis include reliance on an outdated version of the model, using the model at distances beyond 200 km, not using the puff-splitting option in the model, and over-prediction of nitrates. The analysis also includes an evaluation that purports to estimate the margin of error of the CALPUFF model for estimating impacts from specific Entergy sources and presents several case studies comparing CALPUFF modeled impacts to measured visibility conditions. We disagree with this assessment and have addressed these specific comments concerning the CALPUFF model in our past actions. [25] We also note that all Entergy BART sources with the exception of Entergy

[23] See Figure D-1 in appendix D of the Updated BART Applicability Screening Analysis Prepared by Trinity Consultants, November 9, 2015. Available in Appendix D of the 2017 Louisiana regional Haze SIP.

[24] See "Updated BART Applicability Screening Analysis" Prepared by Trinity Consultants, November 9, 2015. Available in appendix D of the 2017 Louisiana Regional Haze SIP

[25] For example, see Section 7.c "Model Selection" and Section 7.d "Margin of Error CALPUFF Modeling" of our Response to Comments (AR RTC) on the Arkansas Regional Haze FIP (81 FR 66332, Sept. 27,

R.S. Nelson are located approximately 200 km or less from the nearest Class I area, well within the recommended range for CALPUFF[26]. We agree with LDEQ that the CALPUFF model following the reviewed protocol is an appropriate tool to evaluate visibility impacts and benefits to inform a BART determination.

In addition to the CALPUFF modeling included in the 2017 Louisiana Regional Haze SIP submittal, the results of CAMx modeling performed by Trinity consultants was included in the submittal as additional screening analyses[27] that purport to demonstrate that the baseline visibility impacts from Cleco Brame and a number of the Entergy sources[28] are significantly less than the 0.5 dv threshold established by Louisiana. However, this modeling was not conducted in accordance with the BART Guidelines and a previous modeling protocol developed for the use of CAMx modeling for BART screening (EPA, Texas, and FLM representatives approved)[29,30], and does not properly assess the maximum baseline impacts. Therefore, we consider the submitted CAMx modeling to be invalid for supporting any determination of visibility impacts below 0.5 dv. We agree with LDEQ's decision to not rely on this CAMx modeling, but rather rely on the CALPUFF modeling for BART determinations.[31] We provide a detailed discussion of our review of this CAMx modeling in the CAMx Modeling TSD.

As discussed above, Louisiana relied on CALPUFF modeling to inform BART determinations consistent with the BART Guidelines. However, the use of CALPUFF is typically used for distances less than 300-400 km. The Cleco Brame source is located 352 km from Caney Creek and 422 km from Breton. For the largest emission sources, NRG Big Cajun II, and Cleco Brame Energy, we performed our own CAMx modeling

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2016) available in the docket for this action. EPA does not recommend using puff splitting and as discussed in the AR RTC, concerns with nitrate performance was a primary reason we used 98th percentile values instead of the maximum impact value.

[26] CALPUFF max range was typically recommended for distances of 300 km – 400km during the BART process.

[27] See October 10, 2016 Letter from Cleco Corporation to Vivian Aucoin and Vennetta Hayes, LDEQ, RE: Cleco Corporation Louisiana BART CAMx Modeling, included in Appendix B of the 2017 Louisiana Regional Haze SIP submittal; CAMx Modeling Report, prepared for Entergy Services by Trinity Consultants, Inc. and All 4 Inc, October 14, 2016, included in Appendix D of the 2017 Louisiana Regional Haze SIP submittal

[28] Entergy's CAMx modeling included model results for Michoud, Little Gypsy, R.S. Nelson, Ninemile Point, Willow Glen, and Waterford.

[29] Texas had over 120 BART eligible facilities located at a wide range of distances to the nearest class I areas in their original Regional Haze SIP. Due to the distances between sources and Class I areas and the number of sources, Texas worked with EPA and FLM representatives to develop a modeling protocol to conduct BART screening of sources using CAMx photochemical modeling. Texas was the only state that screened sources using CAMx and had a protocol developed for how the modeling was to be performed and what metrics had to be evaluated for determining if a source screened out. See Guidance for the Application of the CAMx Hybrid Photochemical Grid Model to Assess Visibility Impacts of Texas BART Sources at Class I Areas, ENVIRON International, December 13, 2007, available in the docket for this action.

[30] EPA, TCEQ, and FLM representatives verbally approved the approach in 2006 and in email exchange with TCEQ representatives in February 2007 (see email from Erik Snyder (EPA) to Greg Nudd of TCEQ Feb. 13, 2007 and response email from Greg Nudd to Erik Snyder Feb. 15, 2007, available in the docket for this action).

[31] See Response to Comments in Appendix A of the 2017 Louisiana Regional Haze SIP submittal

following the BART Guidelines and consistent with previously agreed techniques and metrics of the Texas CAMx BART screening protocol to provide additional information on visibility impacts and impairment and address possible concerns with utilizing CALPUFF to assess visibility impacts at Class I areas located far from these emission sources. See the CAMx Modeling TSD for additional information on EPA's CAMx modeling protocol, inputs, and model results.

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III. BART Screening Modeling

A. Visibility Impairment Threshold

The preamble to the BART Guidelines advises that, "for purposes of determining which sources are subject to BART, States should consider a 1.0 deciview change or more from an individual source to 'cause' visibility impairment, and a change of 0.5 deciviews to 'contribute' to impairment."[32] It further advises that "States should have discretion to set an appropriate threshold depending on the facts of the situation," and describes situations in which states may wish to exercise that discretion, mainly in situations in which a number of sources in an area were all contributing fairly equally to the visibility impairment of a Class I area In Louisiana's 2008 Regional Haze SIP submittal, the LDEQ used a contribution threshold of 0.5 dv for determining which sources are subject to BART, and we approved this threshold in our previous action.[33] We find that the use of the same threshold is appropriate for these EGU sources.

B. Baseline Emissions

The BART Guidelines in 40 CFR 51 Appendix Y 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 maximum 24-hour emission rate (lb/hr) for NOx and the maximum 24-hour emission rate (lb/hr) for SO_2 (not paired in time) from the 2000-2004 baseline period for each source was identified by each source through a review of the daily emission data for each BART-eligible unit from EPA's Air Markets Program Data.[34] Because daily emissions are not available for PM, maximum 24-hr PM emissions were estimated based on permit limits, maximum heat input and AP-42 factors, and/or stack testing.[35]

Speciated PM emissions were calculated using the National Park Service (NPS) speciation worksheets corresponding to unit type and the emission control equipment present in each modeling scenario.[36] PM speciation in the NPS worksheets is based on AP-42 emission factors and depends on the type of emission control equipment and the properties of the fuel used. PM coarse, PM fine, soil, elemental carbon and SOA

[32] 70 FR 39104, 39120 (July 6, 2005), [40 C.F.R. Part 51, Appendix Y].
[33] See, 77 FR 11839, 11849 (February 28, 2012).
[34] http://ampd.epa.gov/ampd
[35] A copy of the final version of each BART analysis performed by Trinity Consultants or CB&I on behalf of the BART sources can be found in the appendices of the submitted 2017 LA Regional Haze SIP.
[36] Original PM Speciation worksheets available at http://www.nature.nps.gov/air/permits/ect/ectCoalFiredBoiler.cfm

emissions were input into CALPUFF. See the BART analyses for additional information on PM speciation.[37]

Estimates of H_2SO_4 emissions from the coal-fired units are based on the best current information available from the Electric Power Research Institute (EPRI) and coal properties. Sulfuric acid emissions from the coal-fired power plants are calculated by estimating the amount of H_2SO_4 produced and the amount of H_2SO_4 removed by control equipment using information from EPRI.[38] These calculations rely on assumed values for the amount of fuel sulfur converted to SO_2, the amount of SO_2 oxidized to SO_3, and the amount of H_2SO_4 lost to (or mitigated by) the air pre-heater and applicable control equipment, such as baghouses, and FGDs.

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[37] A copy of the final version of each BART analysis performed by Trinity Consultants or CB&I on behalf of the BART sources can be found in the appendices to the 2017 Louisiana RH SIP submittal.
[38] Estimating Total Sulfuric Acid Emissions from Stationary Power Plants. EPRI, Palo Alto, CA: March, 2012. 1023790.

C. *Results of CALPUFF Modeling Screening Analyses*

1. "Doc" Bonin, Houma, and Plaquemine

As part of our development of the BART Guidelines, we developed analyses of model plants with representative plume and stack characteristics for both EGU and non-EGU sources using the CALPUFF model.[39] As we discuss in the BART Guidelines,[40] based on those analyses, we believe that sources that emit less than 1,000 tons per year of NO_X and SO_2 and that are located more than 100 km from any Class I area can be exempted from the BART determination. The BART Guidelines note that the model plant concept can be extended using additional modeling analyses to ratios of emission levels and distances other than 1,000 tons/100 km. The BART Guidelines explain that: "you may find based on representative plant analyses that certain types of sources are not reasonably anticipated to cause or contribute to visibility impairment. To do this, you may conduct your own modeling to establish emission levels and distances from Class I areas on which you can rely to exempt sources with those characteristics."[41] Modeling analyses of representative plants are used to reflect groupings of specific sources with important common characteristics.

Louisiana unintentionally omitted discussion of two BART eligible facilities in its 2017 Louisiana Regional Haze SIP: Terrebonne Parish Consolidated Government Houma Generating Station (Houma) and Louisiana Energy and Power Authority Plaquemine Steam Plant (Plaquemine). However, Louisiana's 2008 Regional Haze SIP submittal identified these two sources as BART eligible, and EPA approved the inclusion of these two sources on that list in 2012.[42] The LDEQ has indicated that it inadvertently failed to address whether these two sources are subject to BART in the 2017 Regional Haze SIP. These two sources were included in its 2008 Regional Haze SIP, but Louisiana relied on CAIR better than BART coverage for these sources when they adopted their 2008 SIP. Therefore, we have evaluated these two sources based on available information to determine whether they are subject to BART. We are not relying on the more general 1000 tpy/100 km model plant approach but are instead relying on existing modeling included in the 2008 Louisiana Regional Haze SIP as being a representative plant for the model plant analysis for the purpose of establishing emission levels and distances to exempt BART-eligible sources. Specifically, the 2008 Louisiana Regional Haze SIP included review of CALPUFF modeling of a source, Valero, which demonstrated that Valero's BART- eligible sources do not cause or contribute to visibility impairment at the nearby Class I area, Breton.

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[39] CALPUFF Analysis in Support of the June 2005 Changes to the Regional Haze Rule, U.S. Environmental Protection Agency, June 15, 2005, Docket No. OAR–2002–0076.
[40] 70 FR 39119 (July 6, 2005),
[41] 70 FR 39163 (July 6, 2005).
[42] See Appendix E of the 2008 Louisiana RH SIP contained in the docket for this rulemaking; 77 FR 11839, 11848.

For Valero, the 2008 SIP submittal included BART Screening Modeling using the CALMET files developed by the Central Regional Air Planning Association (CENRAP). This CALPUFF Model Screening approach utilized the highest emission values and No-Observations (No-Obs) CALMET data No-Obs is a model run that does not include meteorological observations in the CALMET modeling. EPA's guidelines were to include observations but CENRAP processed the meteorological data with CALMET without including surface, upper air, and overwater observations. Louisiana, CENRAP, EPA and the FLM representatives agreed that this CALMET data with no observations could still be used for screening of sources but the metric to compare with the established visibility threshold would be the maximum delta deciview impact, not the 98th percentile delta deciview. Other than the No-Obs issue, the CALPUFF modeling for Valero was determined to conform with EPA modeling guidelines/practices and the modeling protocol between LDEQ and EPA/FLM representatives, and determined to be acceptable for the purposes of screening the BART-eligible units at Valero. Therefore, we are finding that this Valero modeling is also acceptable for us to use in screening out Houma and Plaquemine, as a more specific model plant analysis. Louisiana previously used modeling of specific facilities to screen out other facilities for some of their BART eligible non-EGU sources, and we approved that analysis.

Houma and Plaquemine are both further from Breton than Valero and oriented such that transport winds are similar for all three facilities towards Breton. Plaquemine is upwind of Valero when transport patterns would carry emissions to Breton. Houma is located in the same general direction from Breton with similar transport conditions (winds from the west) transporting pollutants from Houma and Valero towards Breton. See the figure below for a map showing the location of the sources and the model plant. The Valero plant has higher emissions of SO2, NOx and PM than the Houma and Plaquemine sources. The Valero plant is also representative (similar stack height and parameters)[43] of the Houma and Plaquemine sources and can therefore be relied on in a more specific model plant analysis to demonstrate that, based on baseline emissions and distance to the Class I area, the Houma and Plaquemine sources are not anticipated to cause or contribute to visibility impairment at Breton and are therefore not subject to BART.[44] We analyzed the ratio of visibility impairing pollutants, denoted as 'Q' (NOx, SO_2, and PM-10 in tons/year)[45] to the distance, denoted as 'D' (distance of source to Breton in km). For example, if two sources were similar but one has a lower Q/D value, the lower ratio value (either due to lower emissions and/or greater distance) would be expected to have smaller visibility impacts at Breton. The Q/D ratio for Houma and Plaquemine are significantly lower compared to Valero's ratio (See Table 3 below). The Q/D ratios of Houma are approximately 20% of Valero's, and Plaquemine's ratio is less than 10% of Valero's Q/D ratio, and modeled impacts of the Valero source were less than the 0.5 dv

[43] See MPStackComp.xlsx in the Docket.
[44] See 40 CFR Part 51 Appendix Y.
[45] To calculate Q, the maximum 24-hr emissions for NOx, SO2 and PM from the 2000-2004 baseline were identified for each BART-eligible unit at a source (See Table 9.3 of the 2008 Louisiana RH SIP). Emissions are not paired in time (i.e. max 24- hour NOx emissions value would not usually be on the same day as max 24-hour SO_2 emissions). The sum of these daily max NOx, PM and SO_2 emissions were summed and then multiplied by 365 days.

threshold. Therefore, the data demonstrates that visibility impacts from the BART-eligible units at Houma and Plaquemine are reasonably anticipated to be less than the modeled impacts from Valero and less than the 0.5 dv threshold to screen out.

We also note that on December 11, 2015, the Lafayette Utilities System Louis "Doc" Bonin Generating Station advised our Clean Air Markets Division that: Unit 1 last operated on June 22, 2011, and was put into cold storage on June 1, 2013; Unit 2 last operated on July 5, 2013, and was put into cold storage on June 29, 2014; and Unit 3 last operated on August 27, 2013, and was put into cold storage on June 24, 2014. The Midcontinent Independent System Operator (MISO) is currently conducting a study to predict the future use of these unit(s) for peaking purposes. If it is determined that these units are no longer necessary to facilitate electrical power generation, they will be retired.[46] However, at this time Lafayette Utilities System has not yet submitted a request to rescind the permit for the Louis "Doc" Bonin Electric Generating Station. Because placing the units in cold storage is not a permanent and enforceable closure under the Regional Haze requirements, we applied our specific model plant analysis utilizing the Valero source as a representative source to assess the anticipated visibility impacts of the Louis "Doc" Bonin source.

For our model plant comparison, Doc Bonin is further away from Breton than Valero but located in an area that sees similar wind transport to Breton. Doc Bonin has similar stacks and parameters[47] compared to the Valero sources. Overall emissions are similar, but Valero has more SO2 and slightly less NOx than Doc Bonin. We consider Valero to be conservative in terms of emissions of SO2 and NOx since SO2 yields much more visibility impairment in this region than NOx. With these factors being similar or conservative we analyze the Q/D ratios for the two facilities. The Q/D ratio for Louis "Doc" Bonin is significantly lower compared to Valero's Q/D ratio (See Table 3 below). The ratio is less than 40% of Valero's ratio and modeled impacts of the Valero source were less than the 0.5 dv threshold, which demonstrates that visibility impairment from the BART-eligible units at Louis "Doc" Bonin are reasonably anticipated to be less than the modeled impacts from Valero and below the 0.5 dv threshold to screen out. The model plant analysis demonstrates that, based on baseline emissions, the source is not anticipated to cause or contribute to visibility impairment of any Class I area, and is therefore not subject to BART. See the CALPUFF Modeling TSD for additional discussion of the model plant analysis. Because the modeling results demonstrate that Louis "Doc" Bonin is not subject to BART, we propose to approve this portion of the 2017 Louisiana Regional Haze SIP.

[46] See Appendix E of the 2017 Louisiana Regional Haze SIP
[47] See MPStackComp.xlsx in the Docket.

Figure 3-1. Map of BART-eligible EGUs for Model Plant analysis

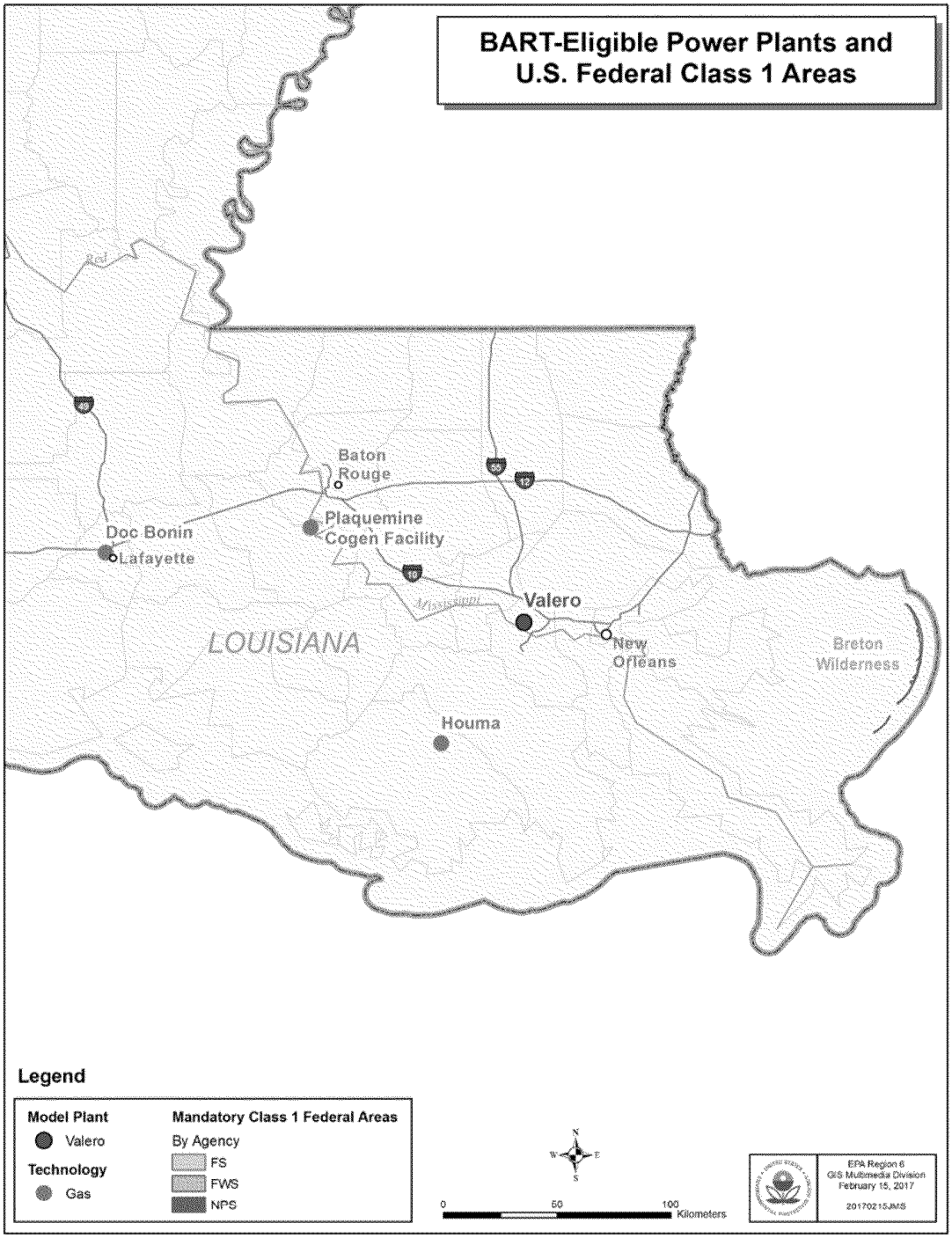

Table 3-1. Model Plant Analysis: Q/D Ratios

Facility	NOx (TPY)	SOx (TPY)	PM (TPY)	Facility Emissions (TPY)	Distance to Breton (km)	Q/D (TPY/km)	Max Percentile Delta DV
Houma	909.8	3.65	7.3	930.75	165	5.64	---
Plaquemine	492.75	0	0	492.75	227.1	2.17	---
Louis "Doc" Bonin	2993	7.3	109.5	3109.8	298.9	10.04	
Valero	1876	1091	401.5	3368.5	139.3	24.18	0.484

2. Cleco Teche Unit 3

Cleco Corporation (Cleco) owns and operates a 359 MW EGU boiler located at the Teche Power Station (Teche Unit 3) in Baldwin, St. Mary Parish, Louisiana. This unit burns natural gas, No. 2 fuel oil, and No. 4 fuel oil. This unit is not equipped with any air pollution control devices. Pursuant to a Section 114 CAA Information Request issued by EPA Region 6, Trinity Consultants conducted CALPUFF modeling on behalf of Cleco to determine if the visibility impacts from Teche Unit 3 exceeded the established visibility impact threshold of 0.5 dv. The "CALPUFF Modeling Report BART Applicability Screening Analysis" provided by Trinity Consultants is provided in Appendix B of LDEQ's 2017 Regional Haze SIP submittal.[48] The results of this screening modeling are summarized in the table below.

Table 3-2. Teche: 98th Percentile of daily maximum baseline visibility impact

Class I area	2001	2002	2003	Maximum
Caney Creek	0.106	0.064	0.099	0.106
Breton Island	0.243	0.179	0.299	0.299

Because the results of the modeling demonstrate that Teche Unit 3 has a visibility impact of less than 0.5 dv, we agree with the finding in the 2017 Louisiana Regional Haze SIP submittal that the unit is not subject to BART.

3. Entergy Sterlington Units 7AB and 7C

Entergy Louisiana LLC (Entergy) owns and operates the Sterlington Generating Plant (Sterlington) in Ouachita Parish, Louisiana. Sterlington is a fossil fueled steam and electric generation facility. Two units (7AB and 7C) were identified as BART-eligible emission units by LDEQ in their 2008 Regional Haze SIP submittal (2008 LA RH SIP).

[48] CALPUFF Modeling Report BART Applicability Screening Analysis: Cleco Corporation, Brame Energy Center, Teche Power Station, Prepared by Trinity Consultants, July 30, 2015.

Unit 7AB is a combined-cycle combustion turbine with a maximum heat input capacity of 923 million British thermal units/hr (MMBtu/hr) that primarily burns natural gas, and is equipped with a heat recovery steam generator (HRSG). The HRSG has a duct burner which uses natural gas as its primary fuel and has a heat input capacity of 221.6 MMBtu/hr. Unit 7C is a combined cycle combustion turbine with a maximum heat input capacity of 923 MMBtu/hr that primarily burns natural gas as its primary fuel and has a heat input capacity of 221.6 MMBtu/hr. Pursuant to a Section 114 CAA Information Request issued by EPA Region 6, Trinity Consultants conducted CALPUFF modeling on behalf of Entergy to determine if the visibility impacts from Sterlington exceeded the BART threshold of 0.5 dv. The "Entergy Louisiana, LLC, Sterlington Generating Plant, CALPUFF Modeling Report Initial BART Applicability Screening Analysis" provided by Trinity Consultants is provided in Appendix D of LDEQ's 2017 Regional Haze SIP submittal.[49] The results of this screening modeling are summarized in the table below.

Table 3-3. Sterlington: 98th Percentile of daily maximum baseline visibility impact

Class I area	2001	2002	2003	Maximum
Caney Creek	0.094	0.066	0.113	0.113
Breton Island	0.065	0.036	0.043	0.065

Because the results of the modeling demonstrate that Sterlington units 7AB and 7C have a visibility impact of less than 0.5 dv, we agree with the finding in the 2017 Louisiana Regional Haze SIP submittal that the units are not subject to BART.

4. NRG Big Cajun I

Louisiana Generating, LLC a subsidiary of NRG Energy owns and operates the Big Cajun I facility in Jarreau, Pointe Coupee Parish, Louisiana. Pursuant to a Section 114 CAA Information Request issued by EPA Region 6, CB&I conducted CALPUFF modeling on behalf of NRG to determine if the visibility impacts from Big Cajun I exceeded the BART threshold of 0.5 dv. The "Source-Specific Refined Screening assessment for BART-eligible Sources for Big Cajun I Facility" provided by CB&I is provided in Appendix C of LDEQ's 2017 Regional Haze SIP submittal.[50] The results of this screening modeling are summarized in the table below.

Table 3-4. Big Cajun I: 98th Percentile of daily maximum baseline visibility impact

Class I area	2001	2002	2003	Maximum
Caney Creek	0.069	0.046	0.056	0.069

[49] Entergy Louisiana, LLC, Sterlington Generating Plant, CALPUFF Modeling Report Initial BART Applicability Screening Analysis, Prepared by Trinity Consultants, August 31, 2015.
[50] Source-Specific Refined Screening assessment for BART-eligible Sources for Big Cajun I Facility, Prepared by CB&I, July 29, 2015.

Breton Island	0.120	0.097	0.139	0.139

Because the results of the modeling demonstrate that Big Cajun I units 1 and 2 have a visibility impact of less than 0.5 dv, we agree with the finding in the 2017 Louisiana Regional Haze SIP submittal that the units are not subject to BART.

5. NRG Big Cajun II

Louisiana Generating, LLC a subsidiary of NRG Energy owns and operates the Big Cajun II facility in New Roads, Pointe Coupee Parish, Louisiana. Unit 1 and Unit 2 were identified as BART-eligible. Pursuant to a Section 114 CAA Information Request issued by EPA Region 6, CB&I conducted initial CALPUFF modeling on behalf of NRG to determine if the visibility impacts from Big Cajun II exceeded the BART threshold of 0.5 dv. The "Source-Specific Refined Screening assessment for BART-eligible Sources for Big Cajun II Facility" provided by CB&I is provided in Appendix C of LDEQ's 2017 Regional Haze SIP submittal.[51] The results of this initial screening modeling utilizing the maximum 24-hr emissions rates from the 2000-2004 baseline period are summarized in the table below.

Table 3-5. Big Cajun II: 98th Percentile of daily maximum baseline (2000 -2004) visibility impact

Class I area	2001	2002	2003	Maximum
Caney Creek	0.927	0.781	1.048	1.048
Breton Island	1.897	2.166	1.486	2.166

As discussed in the 2017 Louisiana Regional Haze SIP revision, on March 6, 2013, Louisiana Generating entered a consent decree (CD) with EPA, the LDEQ, and others to resolve a complaint filed against Louisiana Generating for several violations of the CAA at Big Cajun II. *U.S. et al v. Louisiana Generating, LLC*, Civil Action No. 09-100-JJB-RLB (M.D. La.). Among other things, the CD requires Louisiana Generating to refuel Big Cajun II Unit 2 to natural gas, and install and continuously operate dry sorbent injection (DSI) at Big Cajun II Unit 1 while maintaining a 30-day rolling average emission rate of no greater than 0.380 lb/MMBtu by no later than April 15, 2015.[52] Prior to the submittal of the 2017 Regional Haze SIP, the LDEQ and Louisiana Generating entered into an Agreed Order on Consent (AOC) that made these existing control requirements and maximum daily emission limits permanent and enforceable for BART. The AOC is included in Louisiana's 2017 Regional Haze SIP revision. Thus, if the EPA finalizes its proposed approval of this portion of the SIP submittal, the control requirements and emission limits will become permanent and federally enforceable for

[51] Source-Specific Refined Screening assessment for BART-eligible Sources for Big Cajun II Facility, Prepared by CB&I, July 28, 2015.
[52] CD paragraph 62 in the docket for this rulemaking.

purposes of regional haze. As these controls were not installed to meet BART requirements, and existing enforceable emission limits for Units 1 and 2 prevent the source from emitting at levels seen during the 2000-2004 baseline, LDEQ's screening modeling in the 2017 Regional Haze SIP submittal utilizes the current daily emission limits for these units in the AOC as representative of the anticipated 24-hr maximum emissions for screening modeling purposes. Revised CALPUFF screening modeling prepared by CB&I utilizing these emission limits is summarized below and demonstrate that the source has an impact less than the 0.5 dv threshold.[53]

It should be noted that in addition to requiring DSI, the applicable enforcement CD requires Louisiana Generating to retire, refuel, repower, or retrofit Big Cajun II Unit 1 by no later than April 1, 2025. Louisiana Generating must notify us of which option it will select to comply with this condition no later than December 31, 2022.[54]

Table 3-6. Big Cajun II: Modeled emission rates

Facility/ Unit	NOx (lbs/hr)	SO_2 (lbs/hr)	SO_4 (lbs/hr)	PM coarse (lbs/hr)	PM fine (lbs/hr)	EC (lbs/hr)	SOA (lbs/hr)
Big Cajun II Unit 1	963.00	2439.60	0.00	109.2	83.4	3.09	0.97
Big Cajun II Unit 2	963.00	10.79	0.00	0.00	11.96	0.00	0.00

Table 3-7. Big Cajun II: 98th Percentile of daily maximum visibility impact, current emission limits.

Class I area	2001	2002	2003	Maximum
Caney Creek	0.239	0.179	0.282	0.282
Breton Island	0.449	0.488	0.361	0.488

Because the results of the revised screening modeling demonstrate that Big Cajun II units 1 and 2 have a visibility impact of less than 0.5 dv utilizing current emission limits, we agree with the finding in the 2017 Louisiana Regional Haze SIP submittal that the units are not subject to BART. We are proposing to approve the AOC which establishes enforceable emissions limits consistent with this revised screening analysis.

6. Cleco Brame Rodemacher and Nesbitt

Cleco Corporation (Cleco) owns and operates the Brame Energy Center in Lena, Rapides Parish, Louisiana. Brame Energy Center is a fossil fueled steam and electric generation facility. Two units Nesbitt I (Unit 1) and Rodemacher II (Unit 2) were identified as BART-eligible. Nesbitt I is a 440-MW boiler that primarily burns natural gas and is not equipped with any air pollution devices. Rodemacher II is a 523-MW wall-fired boiler

[53] Revised Baseline Modeling for Big Cajun II for BART Analysis, Prepared by CB&I, July 13, 2016. Available in Appendix C of the 2017 Louisiana Regional Haze SIP submittal

[54] CD paragraph 63 in the docket for this rulemaking.

that burns Powder River Basin (PRB) coal. It is currently equipped with Low-NOx Burners, Selective Non-Catalytic Reduction, and Dry Sorbent Injection. Pursuant to a Section 114 CAA Information Request issued by EPA Region 6, Trinity Consultants conducted CALPUFF modeling on behalf of Cleco to determine if the visibility impacts from Brame Energy Center exceeded the BART threshold of 0.5 dv. The "CALPUFF Modeling Report BART Applicability Screening Analysis" provided by Trinity Consultants is provided in Appendix B of LDEQ's 2017 Regional Haze SIP submittal.[55] The results of this CALPUFF screening modeling are summarized in the table below.

Table 3-8. Brame Energy Center: 98th Percentile of daily maximum baseline visibility impact

Class I area	2001	2002	2003	Maximum
Caney Creek	1.170	1.045	1.215	1.215
Breton Island	1.060	0.474	1.044	1.060

Because the results of the modeling demonstrate that Brame Energy Center has a visibility impact greater than 0.5 dv, we agree with the finding in the 2017 Regional Haze SIP submittal the units are subject to BART and must undergo a five-factor analysis. We note that the estimated sulfuric acid emissions for Rodemacher II in the screening modeling include removal of SO_3 in the form of ammonia bisulfate due to ammonia slip from the SNCR. Because the SNCR was not in operation during the 2000-2004 baseline period, the sulfuric acid emissions modeled for the baseline screening should have been higher. This would result in 2000-2004 baseline visibility impacts greater than those modeled by Trinity. Additional CALPUFF modeling performed by Trinity as part of the BART five factor analysis shows that modeled impacts from Rodemacher II alone exceeds the 0.5 dv threshold, even when considering more recent emissions based on current operation of DSI.[56] We also note that Cleco also had CAMx modeling performed as an additional screening analysis. However, this modeling was not conducted in accordance with the BART guidelines and we consider the CAMx modeling provided by Cleco to be invalid for supporting any determination of minimal visibility impacts. We discuss this CAMx modeling and the results of our own CAMx modeling for this source in more detail in the CAMx Modeling TSD.

7. Entergy Little Gypsy

Entergy operates three BART-eligible units at Little Gypsy Generating Plant (Little Gypsy). Unit 2 is an EGU boiler with a maximum heat input capacity of 4,550 MMBtu/hr that is permitted to burn natural gas as its primary fuel, and No. 2 and No. 4 fuel oil as

[55] CALPUFF Modeling Report BART Applicability Screening Analysis: Cleco Corporation, Brame Energy Center, Teche Power Station, Prepared by Trinity Consultants, July 30, 2015. Available in Appendix B of the 2017 Louisiana Regional Haze SIP submittal

[56] Impacts for DSI and FF control scenario are 0.521 dv at Breton and 0.589 dv at Caney Creek. See Table 5-5, CLECO Brame Energy Center BART Five-Factor Analysis, prepared by Trinity Consultants, October 31, 2015. Available in Appendix B of the 2017 2017 Louisiana Regional Haze SIP submittal.

secondary fuels. Unit 3 is an EGU boiler with a maximum heat input capacity of 5,578 MMBtu/hr that burns natural gas, but is also permitted to burn fuel oil. The auxiliary boiler for Unit 3 has a maximum heat input capacity of 252 MMBtu/hr and is permitted to burn only natural gas. Pursuant to a Section 114 CAA Information Request issued by EPA Region 6, Trinity conducted CALPUFF modeling on behalf of Entergy to determine if the visibility impacts from Little Gypsy exceeded the BART threshold of 0.5 dv. The "Updated BART Applicability Screening Analysis" provided by Trinity is provided in Appendix D of LDEQ's 2017 Regional Haze SIP submittal.[57] The results of this CALPUFF screening modeling are summarized in the table below.

Table 3-9. Little Gypsy: 98th Percentile of daily maximum baseline visibility impact

Class I area	2001	2002	2003	Maximum
Breton Island	1.294	1.402	1.954	1.954

Because the results of the modeling demonstrate that Entergy Little Gypsy has a visibility impact greater than 0.5 dv, we agree with the finding in the 2017 Regional Haze SIP submittal the units are subject to BART. We note that Entergy also had CAMx modeling performed as an additional screening analysis. However, this modeling was not conducted in accordance with the BART guidelines and we consider the CAMx modeling provided by Entergy to be invalid for supporting any determination of minimal visibility impacts. We discuss this CAMx modeling in more detail in the CAMx Modeling TSD.

8. Entergy Ninemile Point

Entergy operates two BART-eligible units at Ninemile Point Electric Generating Plant (Ninemile Point). Unit 4 is an EGU boiler with a maximum heat input capacity of 7,146 MMBtu/hr that burns primarily natural gas and No. 2 and No. 4 fuel oil. Unit 5 is an EGU boiler with a maximum heat input capacity of 7,152 MMBtu/hr that burns primarily natural gas and No. 2 and No. 4 fuel oil. Pursuant to a Section 114 CAA Information Request issued by EPA Region 6, Trinity conducted CALPUFF modeling on behalf of Entergy to determine if the visibility impacts from Ninemile Point exceeded the BART threshold of 0.5 dv. The "Updated BART Applicability Screening Analysis" provided by Trinity is provided in Appendix D of LDEQ's 2017 Regional Haze SIP submittal.[58] The results of this CALPUFF screening modeling are summarized in the table below.

Table 3-10. Ninemile Point: 98th Percentile of daily maximum baseline visibility impact

Class I area	2001	2002	2003	Maximum
Breton Island	2.518	2.393	3.348	3.348

[57] See Appendix J of the Updated BART Applicability Screening Analysis Prepared by Trinity Consultants, November 9, 2015.
[58] See Appendix E of the Updated BART Applicability Screening Analysis Prepared by Trinity Consultants, November 9, 2015.

Because the results of the screening modeling demonstrate that Entergy Ninemile Point has a visibility impact greater than 0.5 dv, we agree with the finding in the 2017 Regional Haze SIP submittal the units are subject to BART. We note that Entergy also had CAMx modeling performed as an additional screening analysis. However, this modeling was not conducted in accordance with the BART guidelines and we consider the CAMx modeling provided by Entergy to be invalid for supporting any determination of minimal visibility impacts. We discuss this CAMx modeling in more detail in the CAMx Modeling TSD.

9. Entergy Willow Glen

Entergy operates five BART-eligible units at the Willow Glen Electric Generating Plant (Willow Glen) in Iberville Parish, Louisiana. Unit 2 is an EGU boiler with a maximum heat input capacity of 2,188 MMBtu/hr that burns natural gas. Unit 2 is permitted to burn fuel oil, but has not done so in several years, and has no current operational plans to burn oil at this unit in the future. Unit 3 is an EGU boiler with a maximum heat input capacity of 5,900 MMBtu/hr that burns natural gas. Unit 3 is permitted to burn fuel oil, but has not done so in several years and Entergy has no operational plans to burn oil at this unit in the future. Unit 4 is an EGU boiler with a maximum heat input capacity of 5,400 MMBtu/hr that burns natural gas. Unit 4 is permitted to burn fuel oil, but it has not done so in several years and Entergy has no current operational plans to burn oil at this unit in the future. Unit 5 is an EGU boiler with a maximum heat input capacity of 5,544 MMBtu/hr that burns natural gas. Unit 5 is permitted to burn fuel oil, but has not done so in several years, and Entergy has no operational plans to burn oil at this unit in the future. The auxiliary boiler (206 MMBtu/hr) for Unit 3 burns natural gas. The auxiliary boiler is permitted to burn fuel oil, but it has not done so in several years, and Entergy has no operational plans to burn oil at this unit in the future.[59] Pursuant to a Section 114 CAA Information Request issued by EPA Region 6, Trinity conducted CALPUFF modeling on behalf of Entergy to determine if the visibility impacts from Willow Glen exceeded the BART threshold of 0.5 dv. The "Updated BART Applicability Screening Analysis" provided by Trinity is provided in Appendix D of LDEQ's 2017 Regional Haze SIP submittal.[60] The results of this CALPUFF screening modeling are summarized in the table below.

Table 3-11. Willow Glen: 98th Percentile of daily maximum baseline visibility impact

Class I area	2001	2002	2003	Maximum

[59] As explained in the proposed rulemaking associated with this TSD, if any of the five units at Willow Glen decides to burn fuel oil, Entergy will complete a BART analysis for each pollutant for the fuel oil firing scenario and submit the analysis to the State. Upon receiving Entergy's submission indicating that the units intend to switch to fuel oil, the State will submit a SIP revision with BART determinations for the fuel oil firing scenario for the units intending to switch to fuel oil. The sources will not begin to burn fuel oil until we have approved the submitted SIP revision containing the BART determinations.

[60] See Appendix G of the Updated BART Applicability Screening Analysis Prepared by Trinity Consultants, November 9, 2015.

Breton Island	1.603	1.818	2.169	2.169

Because the results of the screening modeling demonstrate that Entergy Willow Glen has a visibility impact greater than 0.5 dv, we agree with the finding in the 2017 Regional Haze SIP submittal the units are subject to BART. We note that Entergy also had CAMx modeling performed as an additional screening analysis. However, this modeling was not conducted in accordance with the BART guidelines and we consider the CAMx modeling provided by Entergy to be invalid for supporting any determination of minimal visibility impacts. We discuss this CAMx modeling in more detail in the CAMx Modeling TSD.

10. Entergy Waterford

Entergy operates three BART-eligible units at the Waterford 1 & 2 Generating Plant (Waterford) in St. Charles Parish, Louisiana. Unit 1 is an EGU boiler with a maximum heat input capacity of 4,440 MMBtu/hr that burns primarily natural gas and No. 6 fuel oil as its secondary fuel. Unit 2 is an EGU boiler with a maximum heat input capacity of 4,440 MMBtu/hr that burns primarily natural gas and No. 6 fuel oil as its secondary fuel. Unit 3 auxiliary boiler (77 MMBtu/hr) burns only natural gas. Pursuant to a Section 114 CAA Information Request issued by EPA Region 6, Trinity conducted CALPUFF modeling on behalf of Entergy to determine if the visibility impacts from Waterford exceeded the BART threshold of 0.5 dv. The "Updated BART Applicability Screening Analysis" provided by Trinity is provided in Appendix D of LDEQ's 2017 Regional Haze SIP submittal.[61] The results of this screening modeling are summarized in the table below.

Table 3-12. Waterford: 98th Percentile of daily maximum baseline visibility impact

Class I area	2001	2002	2003	Maximum
Breton Island	3.087	3.485	3.966	3.966

Because the results of the modeling demonstrate that Entergy Waterford has a visibility impact greater than 0.5 dv, we agree with the finding in the 2017 Regional Haze SIP submittal the units are subject to BART. We note that Entergy also had CAMx modeling performed as an additional screening analysis. However, this modeling was not conducted in accordance with the BART guidelines and we consider the CAMx modeling provided by Entergy to be invalid for supporting any determination of minimal visibility impacts. We discuss this CAMx modeling in more detail in the CAMx Modeling TSD.

[61] See Appendix F of the Updated BART Applicability Screening Analysis Prepared by Trinity Consultants, November 9, 2015.

As discussed later in this document in section IV.D where we discuss the control scenario CALPUFF modeling performed for Waterford, we discovered errors in the estimates of PM emissions. We remodeled the baseline impacts, correcting for this error.[62] Our visibility impact modeling results are summarized below.

Table 3-13. Waterford: 98th Percentile of daily maximum baseline visibility impact (EPA modeling)

Class I area	2001	2002	2003	Maximum
Breton Island	3.319	4.363	4.591	4.591

11. Entergy Nelson

Entergy operates three BART-eligible units at the Roy S. Nelson Electric Generating Plant. Unit 4 is an EGU boiler with a heat input capacity of 5,400 MMBtu/hr that burns primarily natural gas and is equipped with flue gas recirculation equipment installed for control of NOX emissions. Unit 6 is an EGU boiler with a heat input capacity of 6,216 MMBtu/hr that burns primarily coal and is equipped with Electrostatic precipitator (ESP) with flue gas conditioning for PM control and Separated Overfire Air (SOFA) Technology and a Low NOX Concentric Firing System (LNCFS) for NOX control. Auxiliary boiler (206 MMBtu/hr) for Unit 4 burns natural gas and fuel oil.

Pursuant to a Section 114 CAA Information Request issued by EPA Region 6, Trinity Consultants conducted CALPUFF modeling on behalf of Entergy to determine if the visibility impacts from Nelson exceeded the BART threshold of 0.5 dv. The "Updated BART Applicability Screening Analysis" provided by Trinity Consultants is provided in Appendix D of LDEQ's 2017 Regional Haze SIP submittal.[63] The results of this screening modeling are summarized in the table below.

Table 3-14. Nelson: 98th Percentile of daily maximum baseline visibility impact

Class I area	2001	2002	2003	Maximum
Caney Creek	0.743	0.679	0.748	0.748
Breton Island	0.65	0.396	0.798	0.798

Because the results of the modeling demonstrate that Entergy Nelson has a visibility impact greater than 0.5 dv, we agree with the finding in the 2017 Regional Haze SIP submittal the units are subject to BART. We note that Entergy also had CAMx modeling performed as an additional screening analysis. However, this modeling was not conducted in accordance with the BART guidelines and we consider the CAMx modeling

[62] We also utilized a larger CALPUFF modeling domain to address concerns that the source plume was being transported out of the modeling grid and estimates of impacts and benefits of controls might be underestimated with the smaller grid.

provided by Entergy to be invalid for supporting any determination of minimal visibility impacts. We discuss this CAMx modeling and the results of our own CAMx modeling for this source in more detail in the CAMx Modeling TSD. We also note that additional CALPUFF modeling provided by Trinity Consultants using 2012-2014 emissions also showed visibility impacts over the 0.5 dv threshold at Breton.

As discussed later in this document in Section IV.E where we discuss the control scenario modeling performed for Nelson unit 6, we discovered errors in the estimates of sulfuric acid emissions. We remodeled the baseline impacts, correcting for this error.[64] Our visibility impact modeling results are summarized below.

Table 3-15. Nelson: 98th Percentile of daily maximum 2000-2004 baseline visibility impact (EPA modeling)

Class I area	2001	2002	2003	Maximum
Caney Creek	1.251	0.99	1.225	1.251
Breton Island	1.022	0.471	1.189	1.189

D. Summary of CALPUFF BART Screening

With the use of CALPUFF modeling results as discussed above, Louisiana concluded, and we are proposing to agree, that the facilities listed in Table 3-16 have visibility impacts greater than 0.5 dv. These facilities are therefore subject to BART and must undergo a five-factor analysis.

Table 3-16. Subject to BART Sources

Facility Name	Units	Parish
Cleco Rodemacher/Brame	Nesbitt I (Unit 1) Rodemacher II (Unit 2)	Rapides
Entergy Waterford	Units 1, 2, and auxiliary boiler	St. Charles
Entergy Willow Glen	Units 2, 3, 4, 5, and auxiliary boiler	Iberville
Entergy Ninemile Point	Units 4 and 5	Jefferson
Entergy Little Gypsy	Units 2 and 3 and auxiliary boiler	St. Charles
Entergy R.S. Nelson	Units 4 and 6 and auxiliary boiler	Calcasieu

We note that we performed additional modeling using CAMx to evaluate the visibility impacts and benefits of controls for the Nelson, Cleco Rodemacher, and Big Cajun II sources to address possible concerns with utilizing CALPUFF to assess visibility impacts

at Class I areas located far from this large emission source. See the CAMx Modeling TSD for additional information and results.

IV. CALPUFF modeling for BART five factor analysis

For those units determined to be subject-to-BART, an analysis of BART must be performed. The BART analysis for those units determined to be subject-to-BART includes engineering and modeling methods and procedures used to determine the appropriate controls for the subject-to-BART units to reduce the source's contribution to pollutant concentrations that result in visibility impairment in the surrounding Class I areas. The final factor to consider under EPA's BART Guidelines is the degree of visibility improvement from the BART control options.[65] The BART guidelines again recommend use of the CALPUFF air quality dispersion model to estimate the visibility improvements at each Class I area, and to compare these to each other and to the impact of the baseline, or current, source configuration.

A. Cleco Brame Rodemacher and Nesbitt

For Rodemacher II, visibility benefits of wet flue gas desulfurization (WFGD), dry flue gas desulfurization (DFGD), enhanced dry sorbent injection (DSI), and DSI were evaluated and compared to the baseline visibility impacts following the CALPUFF protocol discussed above.[66] NOx emissions were held constant at the baseline rate for all control scenarios modeled. SO2 emissions modeled were based on assumed emission rates of 0.41 lb/MMBtu for DSI, 0.30 lb/MMBtu for enhanced DSI, 0.06 lb/MMBtu for DFGD, and 0.04 lb/MMBtu for WFGD. The table below summarizes the model results for these control scenarios.

Table 4-1. Anticipated visibility benefit due to controls on Cleco Rodemacher Unit 2 (CALPUFF, 98th percentile)

Class I area	Baseline Impact (dv)	Visibility benefit of controls over baseline (dv)			
		DSI[67]	Enhanced DSI	SDA	WFGD
Breton	0.724	0.134	0.226	0.436	0.445
Caney Creek	0.734	0.085	0.122	0.311	0.322

[65] 59 FR 39104, 39170 (July 6, 2005).
[66] CLECO Brame Energy Center BART Five-Factor Analysis, prepared by Trinity Consultants, October 31, 2015 revised on April 14, 2016 and April 18, 2016. Available in Appendix B of the 2017 Louisiana Regional Haze SIP.
[67] DSI modeled at 0.41 lb/MMBtu, DSI and fabric filter are already installed and operational.

Enhanced DSI achieves benefits of approximately 0.092 dv at Breton and 0.037 dv at Caney Creek Wilderness (Caney Creek) over DSI and benefits of 0.226 dv at Breton and 0.122 dv at Caney Creek over the baseline impairment. The visibility benefits of SDA and wet FGD exceed the benefits from enhanced DSI by approximately 0.2 dv at Caney Creek and Breton. We performed additional modeling using CAMx to evaluate the visibility impacts and benefits of controls for this unit to address possible concerns with utilizing CALPUFF to assess visibility impacts at Class I areas located far from this large emission source. See the CAMx Modeling TSD for additional information and results.

For Nesbitt I, the BART determination is based on the use of natural gas only and an emission limit for SO2 of 3.0 lb/hr.[68] Therefore, no modeling evaluation of benefits of additional SO2 controls needed to be performed.

B. Entergy Little Gypsy and Entergy Ninemile Point

LDEQ and Entergy entered into an AOC limiting fuel oil to ULSD with a sulfur content of 0.0015% for Little Gypsy Units 2 and 3 and Ninemile Point Units 4 and 5. As the BART Guidelines state "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."[69] Entergy states that during the baseline period, Little Gypsy Units 2 and 3 burned fuel oil[70] with an average sulfur content of 0.5% and Ninemile Point units 4 and 5 burned fuel oil with an average sulfur content of 0.3%. Switching to ULSD will result in a reduction of SO_2 emissions of over 99%. We propose to find that ULSD is the most stringent control available for addressing SO_2 emissions from fuel oil burning. Thus no modeling evaluation of benefits of additional SO2 controls is needed.

We note that visibility benefits of switching to a lower sulfur fuel oil, ULSD at 0.0015% S was modeled using the CALPUFF protocol reviewed above for both Little Gypsy and Ninemile Point.[71],[72] These visibility benefit analyses are available in Appendix D of the 2017 Louisiana Regional Haze SIP.

Visibility benefits of add-on PM controls were also evaluated. CALPUFF modeling was performed for control scenarios including fuel switching to ULSD, cyclone (40% reduction in PM emissions), wet scrubber (55%), and wet ESP (90%). NOx emissions were held constant at the baseline rate for all control scenarios modeled. SO2 emissions were also held constant except for the fuel switching scenario. The modeled visibility benefits of add-on controls are very small and range from 0.0 dv to 0.08 dv for each unit

[68] See AOC in Appendix B of the 2017 Louisiana Regional Haze SIP submittal.
[69] See 40 C.F.R. Part 51, Appendix Y, IV, D
[70] The primary fuel burned has historically been pipeline quality natural gas.
[71] Entergy Louisiana, LLC, Little Gypsy Generating Plant, BART Five-Factor Analysis, Prepared by Trinity Consultants, November 9, 2015, Revised April 14, 2016. Available in appendix D of the LA RH SIP.
[72] Entergy Louisiana, LLC, Ninemile Point Generating Plant, BART Five-Factor Analysis, Prepared by Trinity Consultants, November 9, 2015, revised April 14, 2016. Available in appendix D of the LA RH SIP.

for cyclone, wet scrubber, and wet ESP. See the visibility benefit analyses available in Appendix D of the 2017 Louisiana Regional Haze SIP for more information.

For Little Gypsy auxiliary boiler that is subject to BART, this unit only burns natural gas. Thus, no modeling evaluation of benefits of additional SO2 or PM controls was needed.

C. Entergy Willow Glen

Entergy Willow Glen considered two firing scenarios, natural gas firing and fuel oil firing for the subject to BART units. For natural gas firing, no modeling evaluation of benefits of additional SO2 or PM controls was needed. Louisiana has committed to submit a SIP revision with a BART five factor analysis for fuel oil firing should the facility decided to burn fuel oil in the future.

D. Entergy Waterford

Waterford Units 1 and 2 burn natural gas and fuel oil. The sulfur content of the fuel oil burned during the baseline period was 1.0%. Visibility benefits of switching to a lower sulfur fuel oil, 0.5% S No. 6 fuel oil was modeled using the CALPUFF protocol reviewed above.[73] NOx emissions were held constant at the baseline rate for all control scenarios modeled. Modeled PM emissions were based on stack test data from one day. The table below summarizes the results.

Table 4-2. Waterford Unit 1: Visibility Benefits of Fuel Switching (dv, 98th percentile)

Class I area	Baseline Impact (dv)	Visibility Impact with 0.5% S	Visibility benefit of 0.5% S
Breton	2.263	1.591	0.672

Table 4-3. Waterford Unit 2: Visibility Benefits of Fuel Switching (dv, 98th percentile)

Class I area	Baseline Impact (dv)	Visibility Impact with 0.5% S	Visibility benefit of 0.5% S
Breton	2.054	1.509	0.545

The BART analysis included in the 2017 SIP submission provided no discussion or demonstration that the identified and modeled PM emission rate based on stack test data is representative of maximum actual emissions. In addition, in assessing the visibility

[73] Entergy Louisiana, LLC, Little Gypsy Generating Plant, BART Five-Factor Analysis, Prepared by Trinity Consultants, November 9, 2015. Available in appendix D of the LA RH SIP.

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benefits of fuel switching, Louisiana submitted CALPUFF modeling for only 1% sulfur and 0.5% sulfur fuel oil. We believe the units could be modified to burn distillate fuel oils, with even lower sulfur content, at low cost. Therefore, in addition to our consideration of 0.5% No. 6 fuel oil, we also considered No. 2 fuel oils with 0.3% sulfur and ultra-low sulfur diesel, which has a sulfur content of 0.0015%. We performed additional CALPUFF modeling to adjust the PM emissions used in modeling and to evaluate the visibility benefits of additional fuel types (0.0015% and 0.3% sulfur fuel oils). PM and SO2 emission rates for control cases were based on AP-42 factors and the maximum heat input for each unit.[74] Table 4-4 below summarizes the results of that modeling.[75] See Appendix A for emission inputs used.

Table 4-4. Waterford: Visibility Benefits of Fuel Switching (dv, 98th percentile, EPA modeling)

	Class I area	Baseline Impact (dv)	Visibility benefit 0.5% S	Visibility benefit of 0.3% S	Visibility benefit of 0.0015% S
Unit 1	Breton	2.704	0.883	1.348	1.744
Unit 2	Breton	2.378	0.798	1.207	1.601

Visibility benefits of PM controls were also evaluated.[76] CALPUFF modeling was performed for control scenarios including, cyclone (40% reduction in PM emissions), fuel switching to 0.5% S fuel oil (50%), wet scrubber (55%), and wet ESP (90%). NOx emissions were held constant at the baseline rate for all control scenarios modeled. SO2 emissions were also held constant with the exception of the fuel switching scenario. The modeled benefits are summarized below (fuel switching benefits are summarized in the table above).

Table 4-5. Waterford Unit 1: Visibility Benefits of PM controls (dv, 98th percentile)

Class I area	Baseline Impact (dv)	Visibility benefit of controls over baseline (dv)		
		Cyclone	Wet Scrubber	Wet ESP
Breton	2.263	-0.002	-0.013	0.028

Table 4-6. Waterford Unit 2: Visibility Benefits of PM controls (dv)

Class I area	Baseline Impact (dv)	Visibility benefit of controls over baseline (dv)		
		Cyclone	Wet Scrubber	Wet ESP
Breton	2.054	-0.004	-0.028	0.060

[74] See "Waterford CALPUFF inputs and monthly ei and 767 data.xlsx" for emission inputs and calculations.
[75] See " LA_CALPOST_Waterford.xlsx" for additional model results.
[76] Entergy Louisiana, LLC, Little Gypsy Generating Plant, BART Five-Factor Analysis, Prepared by Trinity Consultants, November 9, 2015 revised April 14, 2016. Available in appendix D of the LA RH SIP.

For the Waterford auxiliary boiler that is subject to BART, this unit only burns natural gas. Thus, no modeling evaluation of benefits of additional SO2 or PM controls was needed.

E. Entergy Nelson

For Entergy Nelson Unit 6, visibility benefits of WFGD, DFGD, enhanced DSI, DSI, and lower sulfur coal were evaluated and compared to the revised baseline visibility impacts (using 2012-2014 emissions) following the CALPUFF protocol discussed above.[77] NOx emissions were held constant at the rate identified from the 2012-2014 period for all control scenarios modeled. SO2 emissions modeled were based on assumed emission rates of 0.60 lb/MMBtu for lower sulfur coal, 0.47 lb/MMBtu for DSI, 0.19 lb/MMBtu for enhanced DSI, 0.06 lb/MMBtu for DFGD, and 0.04 lb/MMBtu for WFGD. We note that the baseline emission rates are based on 24-hr actual emissions during the baseline periods while the control scenario emission rates are based on anticipated 30-day boiler operating day rolling emission rates. At a maximum heat input of 6126 MMBtu/hr for the boiler, the baseline short term emission rates are approximately 1.2 lb/MMbtu for the 2000-2004 baseline and 1.0 lb/MMBtu for Entergy's alternative 2012-2014 baseline. The table below summarizes the model results prepared by Trinity Consultants for Entergy Nelson and included in the 2017 Louisiana Regional Haze SIP submittal for these control scenarios.

Table 4-7. Visibility Impact and benefits of controls, Nelson Unit 6.

Class I area	"Refined Baseline" Impact (dv)[1]	Visibility benefit of controls over refined baseline (dv)				
		Lower sulfur coal	DSI	Enhanced DSI	DFGD	WFGD
Breton	0.493	0.157	0.384	0.333	0.391	0.399
Caney Creek	0.463	0.164	0.302	0.304	0.355	0.365

[1] "Refined baseline" impacts based on 2012-2014 emissions.

We identified errors in the calculation of emissions modeled for RS Nelson unit 6 for the baseline and control scenarios. The calculation of sulfuric acid emissions using the EPRI method contained errors in the input of uncontrolled emissions and the application of factors to account for removal of sulfuric acid by downstream equipment. Estimates developed by Trinity Consultants for Entergy Nelson utilized the controlled SO2 emission rate rather than the uncontrolled rate when estimating the amount of sulfuric acid generated during combustion. The input for sulfur dioxide emissions (E2) must be

[77] Entergy Services, Roy S. Nelson Generating Plant, BART Five-Factor Analysis, Prepared by Trinity Consultants, November 9, 2015, revised April 15, 2016. Available in Appendix D of the 2017 LA Regional Haze SIP.

the uncontrolled SO2 emissions rate rather than a controlled rate based on removal equipment. As explained in the EPRI report:

> When any source uses FGD equipment or another technology to control SO2 emissions, either the fuel basis must be used for the manufacturing and release calculations, or CEMS data can be used, but only when the CEMS precedes the FGD or SO2 control equipment. Data from a CEMS located after a flue gas desulfurization system cannot be used, because the measured SO2 has already been decreased by the control equipment, and therefore is not an accurate predictor of the SO3 emissions rate.

In addition, Trinity's estimates noted that the flue gas conditioning was moved to be downstream of the air preheater, however this was not reflected in the control scenario estimates. The anticipated removal of sulfuric acid in the air preheater should not be applied to the amount of sulfuric acid introduced by flue gas conditioning because the flue gas conditioning now occurs after the preheater. We also noted an error in the application of technology impact factors ($F2_x$) that describe sulfate removal observed over the air heater, the ESP or other particulate control device, and FGD process equipment. All of the factors that apply must be multiplied together to estimate the removal of a combination of downstream equipment. Estimates developed by Trinity Consultants for Entergy Nelson summed these factors rather than multiplying them, resulting in a failure to properly account for the anticipated removal of sulfuric acid. We have corrected for these errors and recalculated the sulfuric acid emissions for each modeled scenario.[78] See Appendix B for a summary of emission inputs.

We also adjusted PM emissions for control scenarios that included a fabric filter to account for the increased removal of PM. PM10 emissions were reduced by 50% to estimate an anticipated additional removal of PM. While this is not a refined estimate of the additional PM reduction anticipated for the control scenarios, PM emissions are already reduced significantly due to the existing ESP (estimated 99.5% removal for PM filterable) and the visibility impact from direct PM emissions are a very small portion of the overall visibility impact due to the facilities emissions. Therefore, we do not anticipate a more refined approach to estimate PM emissions for these scenarios would significantly impact the modeling results.

Finally, we remodeled utilizing a larger modeling domain. In general, the approach Trinity utilized to establish the modeling domain (extending 50 km beyond the source and each class I area) seemed acceptable. However, our initial modeling demonstrated that the model results are sensitive to this assumption, and the use of a larger modeling domain resulted in higher impacts on certain days. This is due to the model's inability to track puffs that exit and then re-enter the modeling domain before impacting the Class I area. Using a larger modeling domain prevents puffs from being lost by exiting the domain.

[78] See "Nelson CALPUFF inputs.xlsx" for emission inputs and revised EPRI calculations.

The table below summarizes the CALPUFF model results prepared by EPA for Entergy Nelson.[79] We also provide modeled impact and benefits from the revised baseline developed by Entergy (using 2012-2014 emissions) to allow for direct comparison with Trinity's CALPUFF model results (See Table 4-9).

Table 4-8. Visibility Benefits of Controls on Nelson Unit 6 over baseline (98th percentile, EPA modeling)

Class I area	Baseline Impact (dv)	Visibility benefit of controls over baseline (dv)				
		Lower sulfur coal	DSI	Enhanced DSI	DFGD	WFGD
Breton	1.189	0.617	0.725	0.915	0.983	0.990
Caney Creek	1.251	0.668	0.756	0.958	1.035	1.035

Table 4-9. Visibility Benefits of Controls on Nelson Unit 6 over "refined baseline" (98th percentile, EPA modeling)

Class I area	"Refined Baseline" Impact (dv)[1]	Visibility benefit of controls over refined baseline (dv)				
		Lower sulfur coal	DSI	Enhanced DSI	DFGD	WFGD
Breton	0.865	0.295	0.401	0.612	0.678	0.691
Caney Creek	0.805	0.222	0.31	0.514	0.589	0.589

[1]"Refined baseline" impacts based on 2012-2014 emissions.

We performed additional modeling using CAMx to evaluate the visibility impacts and benefits of controls for this unit to address possible concerns with utilizing CALPUFF to assess visibility impacts at Class I areas located far from this large emission source. See the CAMx Modeling TSD for additional information and results.

[79] See "LA_CALPOST_Nelson.xlsx" for additional model results.

Note: Modeling files (CALPUFF and CAMx) are large and due to size and/or file type cannot be added to the electronic docket available at www.regulations.gov. Electronic files are available upon request. Contact Erik Snyder (Snyder.erik@epa.gov 214-665-7305) or Michael Feldman (Feldman.Michael@epa.gov 214-665-9793).

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Appendix A. EPA CALPUFF Emission inputs for Waterford Units

Unit 1	SO2 (lb/hr)	NOX (lb/hr)	SO4 (lb/hr)	PMc (lb/hr)	PMf (lb/hr)	SOA (lb/hr)	EC (lb/hr)
base	5,274.50	3,087.17	55.90	104.50	260.00	9.90	20.80
0.50%	2,544.97	3,087.17	55.10	64.30	160.10	9.70	12.80
0.30%	1,479.74	3,087.17	25.80	22.90	56.90	4.60	4.50
0.0015%	7.40	3,087.17	39.60	19	46	7.00	3.70

Unit 2	SO2 (lb/hr)	NOX (lb/hr)	SO4 (lb/hr)	PMc (lb/hr)	PMf (lb/hr)	SOA (lb/hr)	EC (lb/hr)
base	4,532.75	2,718.58	47.80	89.30	222.30	8.40	17.80
0.50%	2,176.54	2,718.58	47.1	55	136.9	8.3	10.9
0.30%	1,265.52	2,718.58	22.1	19.5	48.6	3.9	3.9
0.0015%	6.33	2,718.58	33.8	15.8	39.3	6	3.1

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Appendix B. EPA CALPUFF Emission inputs for Nelson (lb/hr)

Unit 6	SO2	SO4	NOx	PMc	PMf	EC	SOA
base	7443.5	14.564	5827.08	71.79	55.31	2.13	16.05
2012-2014 base	6178.42	26.011	1565.75	71.88	55.38	2.13	15.31
low sulfur	3729.6	24.164	1565.75	72.41	55.79	2.14	15.42
DSI w/ESP	2921.52	5.202	1565.75	16.62	16.01	0.62	105.38
Enhanced DSI	1181.04	0.520	1565.75	8.445	8.13	0.31	53.525
DFGD	372.96	0.361	1565.75	32.355	24.925	0.96	13.785
WFGD	248.64	10.405	1565.75	26.34	27.9	1.07	16.83

	SO2	SO4	NOx	PMc	PMf	EC	SOA
Unit 4	2.75	1.38	796.75			8.56	24.29
Auxiliary Boiler	106.76	0.63	56.55	0.74	1.83	0.15	0.11

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Technical Support Document for

Louisiana Regional Haze: CAMx Best Available Retrofit Technology Modeling

(DRAFT CAMx Modeling TSD)

Prepared and Reviewed by:

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April 2017
(Revised May 2017 to include Entergy Nelson)

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1. Introduction

To address the first implementation period, the State of Louisiana submitted a Regional Haze (RH) State Implementation Plan (SIP) on June 13, 2008 (hereafter referred to as the 2008 Louisiana Regional Haze SIP). EPA acted on that submittal in two separate actions: a limited disapproval (77 FR 33642 (June 7, 2012)) because the SIP relied on the Clean Air Interstate Rule (CAIR) to address the impact of emissions from the State's electric generating units (EGUs); and a partial limited approval/partial disapproval (77 FR 39425 (July 3, 2012)) noting deficiencies in the SIP revision that did not meet the applicable requirements of the CAA and EPA's regulations as set forth in sections 169A and 169B of the CAA and in 40 CFR 51.300-308. In our final action on June 7, 2012, we found that the requirements of section 169A of the CAA were not met because the 2008 Louisiana Regional Haze SIP did not include fully approvable measures for meeting the requirements of 40 CFR 51.308(d)(3) and 51.308(e) with respect to emissions of NOx and SO2 from electric generating units (EGUs). We also determined that the Cross State Air Pollution Rule (CSAPR or the Transport Rule)[1], a rule issued in 2011 to address the interstate transport of NOx and SO2 in the eastern United States would, like CAIR, provide for greater reasonable progress towards the national goal than would BART for states in which CSAPR applies. 76 FR 82219. EPA finalized that rule on May 30, 2012 (77 FR 33642). Based on this finding, the EPA also revised the Regional Haze Rule (RHR) to allow CSAPR states to substitute participation in the trading programs under CSAPR for source-specific BART. States such as Louisiana that are subject to the requirements of the CSAPR trading program only for ozone season nitrogen oxides (NOx) can still substitute CSAPR for BART for NOx, but must address BART for EGUs for SO2 and other visibility impairing pollutants. 76 FR 82224.

States are required to identify all BART-eligible sources within their boundaries by utilizing the three eligibility criteria in the BART Guidelines (70 FR 39158) and the Regional Haze regulations (40 CFR 51.301): (1) One or more emission units at the facility fit within one of the 26 categories listed in the BART Guidelines; (2) the emission unit(s) began operation on or after August 6, 1962, and the unit was in existence on August 6, 1977; and (3) the potential emissions of any visibility-impairing pollutant from subject units are 250 tons or more per year. Sources that meet these three criteria are considered BART-eligible. In our proposed partial disapproval and partial limited approval (77 FR 11839) of the 2008 Louisiana Regional Haze SIP, we approved LDEQ's identification of 76 BART-eligible sources.

Once a list of BART-eligible sources within a state has been compiled, states must determine whether to make BART determinations for all of them or to consider exempting some of them from BART because they may not reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. The BART guidelines discuss several approaches available to exempt sources from the BART determination process, including modeling individual sources and the use of model plants. To determine which sources are anticipated to contribute to visibility impairment the BART guidelines state you can use CALPUFF or other appropriate model to estimate the visibility impacts from a single source at a Class I area.

[1] 76 FR 48207, 48208 (August 8, 2011).

Louisiana's 2008 Regional Haze SIP submittal did not include a determination of which BART eligible EGUs were subject to BART, and Louisiana cannot rely on CSAPR as a substitute for BART for SO2. On May 19, 2015, EPA Region 6 sent CAA Section 114 letters to several BART-eligible sources in Louisiana. In those letters we noted our understanding that the sources were actively working with LDEQ to develop a SIP. However, in order to be in a position to develop a FIP, should that be necessary, EPA requested information regarding the BART-eligible sources. The Section 114 letters required sources to conduct modeling to determine if the sources were subject to BART, and included a CALPUFF modeling protocol. The letters also requested that a BART analysis in accordance with the BART Guidelines be performed for those sources determined to be subject to BART. The LDEQ worked closely with the BART facilities and with EPA Region 6. On February 10, 2017, Louisiana submitted a SIP revision (2017 Louisiana Regional Haze SIP) intended to cure the deficiencies noted in our partial limited approval/partial disapproval. On behalf of each BART facility, Trinity Consultants (or CB&I on behalf of NRG Big Cajun I and Big Cajun II), performed CALPUFF BART screening modeling for BART-eligible sources and five-factor analyses for subject-to-BART sources to address the BART requirements for EGU sources in the state. These modeling analyses were included as part of the 2017 Louisiana Regional Haze SIP. As part of our proposed action, we have reviewed the CALPUFF BART analyses performed by Trinity Consultants and CB&I that have been provided to us via the SIP submittal. CALPUFF modeling was also utilized to assess the anticipated visibility benefit of controls for those sources determined to be subject to BART. See the CALPUFF Modeling TSD for a review of the modeling protocol, model inputs, and results.

As discussed above, Louisiana relied on CALPUFF modeling to inform BART determinations consistent with the BART Guidelines. However, the use of CALPUFF is typically used for distances less than 300-400 km. Some of the BART-eligible sources in Louisiana are far away from a Class I area yet have high enough emissions that they may significantly impact visibility at Class I areas in Louisiana and surrounding states. For example, the Cleco Brame source is located 352 km from Caney Creek and 422 km from Breton. The table below shows the distances from these large coal-fired EGU sources in Louisiana to nearby Class I areas. CAMx provides a scientifically defendable platform for assessment of visibility impacts over a wide range of source to receptor distances. CAMx is also more suited than some other modeling approaches for evaluating the impacts of SO_2, NOx, VOC and PM emissions as it has a more robust chemistry mechanism than CALPUFF. The CAMx PM Source Apportionment Technology (PSAT) modeling was conducted for BART-eligible sources. A BART-eligible source that is shown not to contribute significantly to visibility impairment at any of the Class I areas using CAMx modeling may be excluded from further steps in the BART process. For the largest emission sources, NRG Big Cajun II, Entergy Nelson and Cleco Brame Energy, we performed our own CAMx modeling following the BART Guidelines and consistent with previously agreed techniques and metrics of the Texas CAMx BART screening protocol (EPA,

Texas, and FLM representatives approved)[2, 3], to provide additional information on visibility impacts and impairment and address possible concerns with utilizing CALPUFF to assess visibility impacts at Class I areas located far from theses emission sources. CAMx modeling was also performed to evaluate the anticipated visibility benefits of controls for subject-to-BART units, as described below and in the CALPUFF Modeling TSD. This TSD provides additional information on EPA's CAMx modeling protocol, inputs, and model results.

Table 1-1. Distances from BART-eligible coal-fired sources to Class I areas (km)

Facility Name	**Breton Island**	**Caney Creek**
Cleco Rodemacher/Brame	422	352
Entergy Nelson	427	460
Louisiana Generating (NRG) Big Cajun II	263	476

In addition to the CALPUFF modeling included in the 2017 Louisiana Regional Haze SIP submittal, the results of CAMx modeling performed by Trinity consultants[4] was included in the submittal as additional screening analyses[5] that purport to demonstrate that the baseline visibility impacts from Cleco Brame and a number of the Entergy sources[6] are significantly less than the 0.5 dv threshold established by Louisiana. However, this modeling was not conducted in accordance with the BART Guidelines and a previous modeling protocol developed for the use

[2] Texas had over 120 BART eligible facilities located at a wide range of distances to the nearest class I areas in their original Regional Haze SIP. Due to the distances between sources and Class I areas and the number of sources, Texas worked with EPA and FLM representatives to develop a modeling protocol to conduct BART screening of sources using CAMx photochemical modeling. Texas was the only state that screened sources using CAMx and had a protocol developed for how the modeling was to be performed and what metrics had to be evaluated for determining if a source screened out. See Guidance for the Application of the CAMx Hybrid Photochemical Grid Model to Assess Visibility Impacts of Texas BART Sources at Class I Areas, ENVIRON International, December 13, 2007, available in the docket for this action.

[3] EPA, TCEQ, and FLM representatives verbally approved the approach in 2006 and in email exchange with TCEQ representatives in February 2007 (see email from Erik Snyder (EPA) to Greg Nudd of TCEQ Feb. 13, 2007 and response email from Greg Nudd to Erik Snyder Feb. 15, 2007, available in the docket for this action).

[4] Where we reference CAMx modeling performed by Trinity Consultants, this also includes modeling and analysis performed by Trinity and All4 Inc.

[5] See October 10, 2016 Letter from Cleco Corporation to Vivian Aucoin and Vennetta Hayes, LDEQ, RE: Cleco Corporation Louisiana BART CAMx Modeling, included in Appendix B of the 2017 Louisiana Regional Haze SIP submittal; CAMx Modeling Report, prepared for Entergy Services by Trinity Consultants, Inc. and All 4 Inc, October 14, 2016, included in Appendix D of the 2017 Louisiana Regional Haze SIP submittal

[6] Entergy's CAMx modeling included model results for Michoud, Little Gypsy, R.S. Nelson, Ninemile Point, Willow Glen, and Waterford.

of CAMx modeling for BART screening (EPA, Texas, and FLM representatives approved)[7,8], and does not properly assess the maximum baseline impacts. Therefore, we consider the submitted CAMx modeling to be invalid for supporting any determination of visibility impacts below 0.5 dv. We agree with LDEQ's decision to not rely on this CAMx modeling, but rather rely on the CALPUFF modeling included in the 2017 Louisiana Regional Haze SIP for BART determinations.[9] We provide a detailed discussion of our review of this CAMx modeling in Section 4 of this document.

Throughout this document, we may use language such as, "we find" or other similar phrases that on the surface would suggest a final determination has been made. However, all aspects of our TSDs should be considered to be part of our proposal and are subject to change based on comments and other information we may receive during our public comment period

2. Visibility Impairment Threshold

The preamble to the BART Guidelines advises that, "for purposes of determining which sources are subject to BART, States should consider a 1.0 deciview change or more from an individual source to 'cause' visibility impairment, and a change of 0.5 deciviews to 'contribute' to impairment." It further advises that "States should have discretion to set an appropriate threshold depending on the facts of the situation," and describes situations in which states may wish to exercise that discretion, mainly in situations in which a number of sources in an area were all contributing fairly equally to the visibility impairment of a Class I area. In Louisiana's initial 2008 Regional Haze SIP submittal, the LDEQ used a contribution threshold of 0.5 dv for determining which sources are subject to BART, and we approved this threshold in our previous action.[10] We find that the use of the same threshold is appropriate for these EGU sources. The 2017 SIP revision includes a BART determination for each of the State's BART- eligible EGUs whose visibility impacts exceed the 0.5dv threshold.

3. CAMx Modeling Protocol

[7] Texas had over 120 BART eligible facilities located at a wide range of distances to the nearest class I areas in their original Regional Haze SIP. Due to the distances between sources and Class I areas and the number of sources, Texas worked with EPA and FLM representatives to develop a modeling protocol to conduct BART screening of sources using CAMx photochemical modeling. Texas was the only state that screened sources using CAMx and had a protocol developed for how the modeling was to be performed and what metrics had to be evaluated for determining if a source screened out. See Guidance for the Application of the CAMx Hybrid Photochemical Grid Model to Assess Visibility Impacts of Texas BART Sources at Class I Areas, ENVIRON International, December 13, 2007, available in the docket for this action.

[8] EPA, TCEQ, and FLM representatives verbally approved the approach in 2006 and in email exchange with TCEQ representatives in February 2007 (see email from Erik Snyder (EPA) to Greg Nudd of TCEQ Feb. 13, 2007 and response email from Greg Nudd to Erik Snyder Feb. 15, 2007, available in the docket for this action).

[9] See Response to Comments in Appendix A of the 2017 Louisiana Regional Haze SIP submittal

[10] See, 77 FR 11839, 11849 (February 28, 2012).

The Texas Commission on Environmental Quality (TCEQ) developed a modeling protocol in 2006/7 using CAMx to evaluate non-EGU BART sources, as well as evaluate VOC and PM impacts from all BART-eligible sources to inform their Texas Regional Haze SIP.[11] TCEQ requested to use CAMx due to the number of BART sources in Texas (over 120 facilities) and most of the facilities were on the edge or outside of the range CALPUFF is used for BART screening. The modeling protocol was reviewed by TCEQ, EPA and FLM representatives specialized in air quality analyses and BART. EPA and FLMs agreed with the use of CAMx for screening BART sources in 2006/7 and approved of the protocol using the maximum (not 98th percentile) daily visibility impacts.[12] The Texas protocol addressed modeling for sources that did not usually have CEM data for the pollutants, so as an approximation of maximum 24-hour emissions we indicated doubling annual was generally acceptable in the absence of better data. In our modeling we are evaluating NOx, SO_2 and PM emissions and have utilized CEM data for NOx and SO_2 (maximum 24-hour emissions from the 2000-2004 baseline period) and doubled the annual PM emission rate consistent with past practices and protocols. We approved Texas' subject-to-BART analysis for non-EGU sources which relied on this CAMx modeling in our January 5, 2016 rulemaking.[13] Our subject-to-BART screening modeling for EGU-sources in Louisiana using CAMx is consistent with the protocol developed and utilized by Texas and used by us in evaluating EGU BART sources in Texas.[14] The evaluation of Louisiana BART-eligible EGUs using CAMx relied on the same CAMx modeling utilized in our recent evaluation of BART-eligible EGU sources in Texas.

The EPA BART screening analysis was built upon the regional photochemical modeling utilized in our earlier action on Texas Reasonable Progress ("EPA R6 Texas RH study")[15]; which was built from the 2002 annual regional photochemical modeling database developed for CENRAP and utilized by Texas for their Regional Haze SIP and BART screening with CAMx.[16] CENRAP developed a 2002 annual modeling database for CAMx on the 36 km unified national Regional Planning Organization (RPO) grid that covers the continental United States. The CENRAP

[11] See TX RH SIP Appendix 9-5, "Screening Analysis of Potential BART-Eligible Sources in Texas"; Revised Draft Final Modeling Protocol Screening Analysis of Potentially BART-Eligible Sources in Texas, Environ Sept. 27, 2006; and Guidance for the Application of the CAMx Hybrid Photochemical Grid Model to Assess Visibility Impacts of Texas BART Sources at Class I Areas, Environ December 13, 2007 all available in the docket for this action.

[12] We note that in February 2007 EPA raised concern with using the 98th percentile for sources analyzed with CAMx, rather than the maximum or 1st high. TCEQ and EPA agreed that evaluation and screening would be done using the Maximum (1st High). See EPA-Snyder 2007, TCEQ-Knud 2007, TCEQ BART Screening Clarification 2007

[13] 81 FR 296

[14] *See* 82 FR 912 (January 4, 2017).

[15] ENVIRON. 2013. "Memorandum: 2002 Baseline CAMx Simulation, Texas Regional Haze Evaluation", prepared by ENVIRON International Corporation for EPA Region 6 (RTI Contract EP-W-011-029). February 21, 2013.

[16] ENVIRON and CERT. 2007. "Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans", prepared for the Central Regional Air Planning Association, prepared by ENVIRON International Corporation, and the University of California, Riverside. September 12.

modeling protocol[17], CENRAP modeling Quality Assurance Program Plan (QAPP)[18]; Morris and Tonnesen, 2004), and base model evaluation[19] reports provide details on the development of the CENRAP 2002 36-km annual modeling database. Emissions inputs for the CENRAP study were based on 2002 Base G Typical (Typ02G) annual emissions database. Numerous iterations of the emissions modeling were conducted using interim databases before arriving at the final Base G emission inventories[20]. For the EPA R6 Texas RH study, ENVIRON updated the CENRAP 36 km annual CAMx photochemical modeling database to include a 12 km nested-grid that covers Texas, Louisiana and other nearby states and Class I areas in and near Texas (see figure below for modeling domain).

ENVIRON made the following updates to the CENRAP emissions data for the EPA R6 Texas RH study:

- Updated from SMOKE version 2.3 to version 3.1, although some SMOKE modules came from an older version to maintain compatibility with the format of data from CENRAP.
- CB05 chemical speciation profiles for area and point sources
- Processed point source emissions in CAMx input format to preserve stack parameters and location
- Changed the earth sphere variable (IOAPI_ISPH) in SMOKE from 19 to 20. CENRAP SMOKE setup used IOAPI_ISPH=19 that could cause inconsistencies between point source locations and the meteorological points. IOAPI_ISPH=20 assumes a 6740 km earth radius consistent with MM5 and CAMx
- Tagged Plume-in-Grid (PiG) for large SO_2 and NOx sources
- Added organic aerosol precursor emissions from biogenic sources based on CENRAP BEIS CB4 emissions
- Adjusted primary organic aerosol mass from POC to POA mass

In the process of developing this modeling analysis for evaluating BART-eligible sources in Louisiana, we received assistance in conducting modeling runs from University of North Carolina at Chapel Hill, Institute for the Environment (UNC-IE), a consultant to RTI International under EP-D-11-084 Work Assignment No. 4-17. UNC-IE used the EPA R6 Texas RH study database as a starting point for the CAMx modeling performed for this study.[21] For

[17] Morris, R.E., G.E. Mansell, B. Koo, G. Tonnesen, M. Omary and Z. Wang. 2004. Modeling Protocol for the CENRAP 2002 Annual Emissions and Air Quality Modeling, Draft 2.0. (http://pah.cert.ucr.edu/aqm/cenrap/docs/CENRAP_Draft2.0_Modeling_Protocol_1208 4.pdf). December 8.

[18] Morris, R.E. and G. Tonnesen. 2004. Quality Assurance Project Plan (Draft) for Central Regional Air Planning Association (CENRAP) Emissions and Air Quality Modeling. (http://pah.cert.ucr.edu/aqm/cenrap/docs/CENRAP_QAPP_Nov_24_2004.pdf). December 23

[19] ENVIRON and CERT. 2007. "Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans", prepared for the Central Regional Air Planning Association, prepared by ENVIRON International Corporation, and the University of California, Riverside. September 12.

[20] e.g., Morris, R.E., A. Hoats, S. Lau, B. Koo, G. Tonnesen, C-J. Chien and M. Omary. 2005. Air Quality Modeling Analysis for CENRAP – Preliminary 2002 Base Case CMAQ and CAMx Modeling of the Continental US 36 km Domain and Model Performance Evaluation. ENVIRON International Corporation, Novato, California. April 30.

[21] The evaluation of Louisiana BART-eligible EGUs using CAMx relied on the same CAMx modeling utilized in our evaluation of BART-eligible EGU sources in Texas. See the BART Modeling TSD and BART Screening TSD

emissions processing, the only difference between this study and the EPA R6 Texas RH study is to integrate updates from EPA R6 to the emissions rates and stack parameters for some sources in Texas and Louisiana in the EGU BART point source emissions inventory See Appendix A for emission rates and stack parameters for sources in Louisiana. Additional information on emission inputs for sources in Texas is available in the BART Screening TSD and BART Modeling TSD that accompanied our proposed action on Texas BART.[22] UNC-IE used CAMx v6.30 for this study because it is the most recent version of the model and updated science available at the initiation of the project.

The December 7, 2016 UNC-IE memorandum documents the BART screening modeling setup and results.[23] From this point this memo will be referred to as "UNC Task 2 BART Screening Memo". Please see the UNC Task 2 BART Screening Memo for full details. We touch on some specific issues that we analyzed and made decisions in the discussion below.

We utilized PiG for all the selected BART-eligible sources in order to utilize the PSAT within the PiG. We also utilized PiG for other large point sources of NOx and SO_2 within the modeling domain as would typically be done in current day SIP modeling. Selection of sources and emissions thresholds for PiG treatment (for other than the selected BART-eligible sources) was based on balancing PiG treatment with model run time. The BART Guidelines in 40 CFR 51 Appendix Y recommends 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. For the selected BART-eligible sources we used the maximum actual 24-hr emission rates for NOx and SO_2 from the 2000-2004 baseline period for each source as identified through a review of the daily emission data for each BART-eligible unit from EPA's Air Markets Program Data and modeled these emission rates as constant emission rates for the entire modeled year, consistent with the emissions identified by the sources and utilized in the CALPUFF modeling performed by Trinity consultants (or CB&I) on behalf of the facilities.[24] To estimate maximum PM emissions the annual average emission rate in pounds per hour from the CENRAP 2002 modeling emission inventory was doubled to estimate the 24-hr maximum emission rate.[25]. Documentation of these emission rates, preprocessors and other model selection options is included in the UNC BART Screening Memo.[26] Additional

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that accompanied that action (identified by Docket No. EPA-R06-OAR-2016-0611, at http://www.regulations.gov) for additional information, including information on emissions for Texas sources included in the modeling

[22] *See* 82 FR 912 (January 4, 2017);

[23] "Regional Haze Evaluation Under Contract EP-D-11-084 Work Assignment No. 4-17: TASK 5, Subtask 2: Conducting CAMx PiG with PSAT Source Apportionment for BART screening (CAMx Run #1)", Memorandum from Zac Adelman and Uma Shankar, UNC Institute for the Environment to Erik Snyder, EPA Region 6, December 7, 2016. Available in the docket for this action as "EPA-R6_RH_Task2_Memo_UNC_07Dec2016.pdf"

[24] Emissions data available at https://ampd.epa.gov/ampd/

[25] Based on evaluation of some sources that had both annual and maximum 24-hour actual data, EPA recommended that sources could use an emission rate that was double the annual emission rate to approximate the maximum 24-hour actual emission rates for some sources for CALPUFF modeling when there was not enough data to generate a maximum 24-hr actual emission rate. For additional information on this approach see the Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans (TX RH FIP TSD, page A-36. Available at http://www.regulations.gov/#!documentDetail;D=EPA-R06-OAR-2014-0754-0007)

[26] "Regional Haze Evaluation Under Contract EP-D-11-084 Work Assignment No. 4-17: TASK 5, Subtask 2: Conducting CAMx PiG with PSAT Source Apportionment for BART screening (CAMx Run #1)", Memorandum

information on emission inputs for sources in Texas is available in the BART screening TSD and BART modeling TSDs that accompanied our proposed action on Texas BART.[27] See Appendix A for a summary of emissions and stack parameters used for the selected BART-eligible sources in Louisiana. In addition to the modeling results from the initial base case modeling (CAMx base case modeling is also referred to as BART Screening Modeling and Run 1), as discussed in more detail elsewhere, we also had additional control scenario modeling performed (low control is also referred to as "Run 4", high control is also referred to as "Run 3") to estimate the benefits of emission reductions from controls representing a high level and intermediate level of control.[28]

Below is a map of our CAMx 36/12 km modeling domain and the locations of the Class I area receptors:

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from Zac Adelman and Uma Shankar, UNC Institute for the Environment to Erik Snyder, EPA Region 6, December 7, 2016. Available in the docket for this action as "EPA-R6_RH_Task2_Memo_UNC_07Dec2016.pdf"

[27] *See* 82 FR 912; and TSDs (contained in Docket No. EPA-R06-OAR-2016-0611, at *http://www.regulations.gov*)

[28] These additional runs are documented by UNC in "Regional Haze Evaluation Under Contract EP-D-11-084 Work Assignment No. 4-17: TASK 5, Subtask 4: Conducting CAMx PiG with PSAT Source Apportionment for BART Control Evaluations (CAMx Run #3 and #4)", Memorandum from Zac Adelman and Uma Shankar, UNC Institute for the Environment to Erik Snyder, EPA Region 6, December 8, 2016. Available in the docket for this action as "EPA-R6_RH_Task4_Memo_UNC_08Dec2016.pdf"

Figure 3-1. CAMx Modeling 36/12 km modeling domain and locations of Class I area receptors.

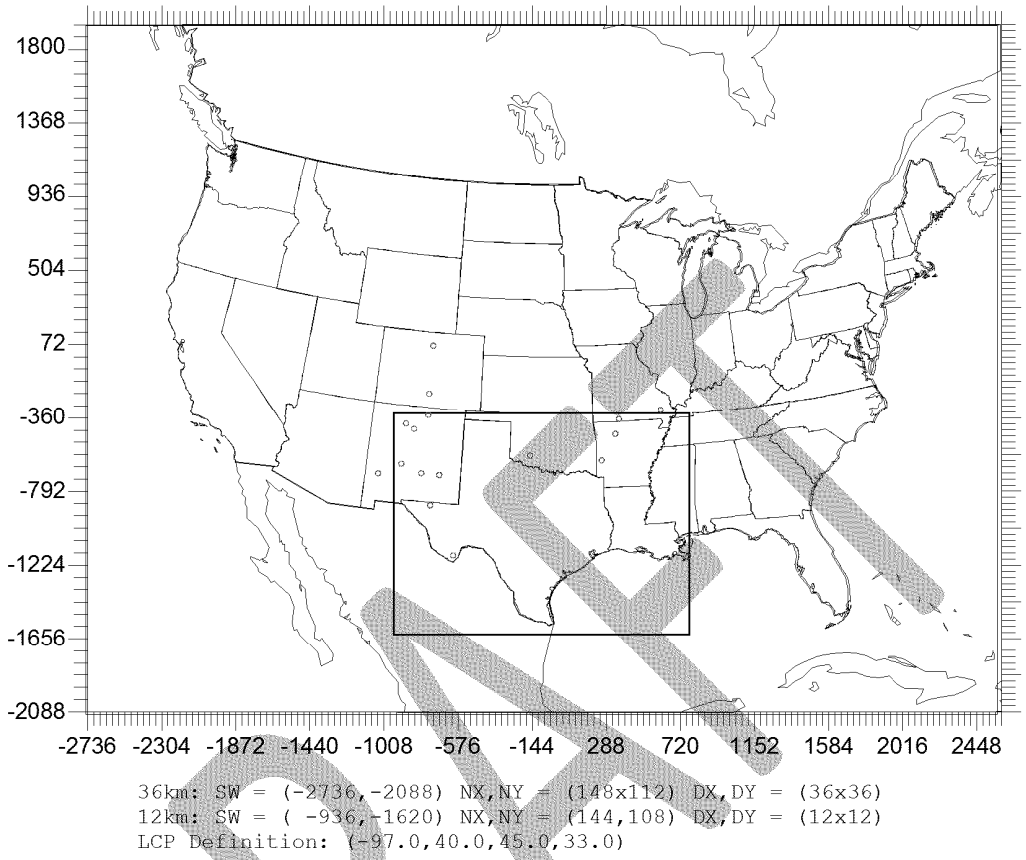

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Table 3-1. Class I area receptors for CAMx modeling

Site	State	Code	County	Lat	Lon	Grid	Annual Average Natural visibility conditions[1]
Breton Wilderness Area	LA	BRET1	St. Bernard Parish	29.1189	-89.2066	12km	8.275 dv
Big Bend National Park	TX	BIBE1	Brewster County	29.3027	-103.178	12km	4.015 dv
Guadalupe Mountains	TX	GUMO1	Culberson County	31.833	-104.809	12km	3.412 dv
Wichita Mountains Wilderness	OK	WIMO1	Comanche County	34.7323	-98.713	12km	5.082 dv
Caney Creek Wilderness Area	AR	CACR1	Polk County	34.4544	-94.1429	12km	7.619 dv
Upper Buffalo Wilderness Area	AR	UPBU1	Newton County	35.8258	-93.203	12km	7.534 dv
Bandelier Wilderness Area	NM	BAND1	Los Alamos County	35.7797	-106.266	12km	3.367 dv
Salt Creek Wilderness Area	NM	SACR1	Grant County	33.4598	-104.404	12km	4.156 dv
Wheeler Peak Wilderness Area	NM	WHPE1	Taos County	36.5854	-105.452	12km	2.337 dv
White Mountain Wilderness Area	NM	WHIT1	Lincoln County	33.4687	-105.535	12km	3.309 dv
Hercules-Glades Wilderness Area	MO	HEGL1	Taney County	36.6138	-92.9221	12km	7.572 dv
Mingo	MO	MING1	Stoddard County	36.9717	-90.1432	12km	7.894 dv
Great Sand Dunes	CO	GRSA1	Saguache County	37.7249	-105.519	36km	3.465 dv
Carlsbad Caverns National Park[2]	NM	GUMO1	Culberson County	31.833	-104.809	12km	3.412 dv
Pecos Wilderness Area[2]	NM	WHPE1	Taos County	36.5854	-105.452	12km	2.337 dv

[1] NC II, or new IMPROVE natural visibility conditions are available at: http://vista.cira.colostate.edu/Docs/IMPROVE/Aerosol/NaturalConditions/NaturalConditionsII_Format2_v2.xls, which is also available in our docket.
[2] Carlsbad Caverns shares a monitor with the Guadalupe Mountains. Pecos Wilderness shares a monitor with Wheeler Peak

The CAMx Particulate Matter Source Apportionment Tool (PSAT) is designed to track emissions of the following PM species from primary sources to defined receptor locations:

- Sulfate (SO_4)
- Particulate nitrate (NO_3)
- Ammonium (NH_4)
- Particulate mercury (Hg(p))
- Secondary organic aerosol (SOA)
- Six categories of primary particulate matter (PM):
    - Elemental carbon (EC)
    - Primary organic aerosol (POA)

- Fine crustal PM (FCRS)
- Fine other primary PM (FPRM)
- Coarse crustal PM (CCRS)
- Coarse other primary PM (CPRM)

PSAT performs PM source apportionment (also called source tagging) for selected source groups. A source group may consist of a combination of geographic regions and emissions source categories. For this study, we initially selected 29 units in Texas and Louisiana (see map and table below) to assign to unique PSAT source groups.

The PSAT uses "reactive tracers" that are added for each source category/region combination (i). In general, a single tracer can track primary PM species, whereas secondary PM species require several tracers to track the relationship between gaseous precursors and the resulting PM. Particulate nitrate and secondary organics are the most complex species to apportion because the emitted precursor gases (NOx and VOCs) are several steps removed from the resulting PM species (NO_3 and SOA). There is a PSAT convention that tracer names for particulate species begin with the letter "P."

One fundamental assumption in PSAT is that PM is apportioned back to the primary precursor for each type of PM. For example, SO_4 is apportioned to SO_x emissions, NO_3 is apportioned to NO_x emissions, NH_4 is apportioned to NH_3 emissions, etc.

The PSAT results from the BART Screening CAMx run are used directly to estimate the impacts of the BART sources on visibility at the Class I Area receptors. The PSAT tagged species concentrations are extracted for every day of the year from the grid cells that contain the Class I area receptors listed in the table above. The CAMx 12-km simulation results are used for all of the receptors but Great Sand Dunes National Monument (GRSA1), which uses the 36-km CAMx simulation. UNC-IE time-shifted the CAMx results from GMT to local time at each monitor and computed 24-hour average concentrations for each PSAT tracer species. The daily average tracer concentrations were then used to compute the visibility impacts of each source at the monitor using the revised IMPROVE equation discussed above. Daily average tracer concentrations from BART-eligible units at the same facility were summed to assess the impact from the BART-eligible source. UNC-IE and developed a new post-processing and analysis approach to extract variables from the CAMx output files and to calculate visibility impacts from the PSAT tracers for each model run.[29] We used these data to develop spreadsheets to analyze the modeled visibility impairment from each source and unit.[30]

[29] Data files from UNC-IE: Run 3: camx_v630.EPA-R6-2016.TX-BART.CAMxRun3.36-12.PiG-PSAT.2002001-2002365.data.template.bext_dv.xlsx; Run 4: camx_v630.EPA-R6-2016.TX-BART.CAMxRun4.36-12.PiG-PSAT.2002001-2002365.data.template.bext_dv.xlsx; Run 1: camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.2002001-2002365.no2mod.data.template.bext_dv.xlsx; and EPA R6 Texas RH 2002 base: camx.v5.41.txhaze.12FE.2002001-2002364.camv5bs.data.template.v3.bext_dv.txt

[30] EPA Worksheets: LA_summary CAMx vis daily.xlsx; LA summary CAMx vis daily_Brame_Big_CajunII.xlsx; Run 3: camx_v630.EPA-R6-2016.TX-BART.CAMxRun3.final.xlsx; Run4: camx_v630.EPA-R6-2016.TX-BART.CAMxRun4.final.xlsx, Run1: camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx; and EPA R6 Texas RH 2002 base: camx_v630.EPA-R6-2016.TX-BART.CAMxv5bs.xlsx

The Haze Index (HI) for each source is calculated in deciviews from the source's extinction plus natural background using the following formula:

HIsource = 10 ln[(bsource + bnatural)/10]

Here, bnatural is the Class I area specific clean natural visibility background (natural conditions); we rely on the adjusted default estimates for the new IMPROVE equation from the Natural Conditions II committee for the annual average natural conditions.[31] Natural conditions (bnatural) are listed by Class I areas and assume clean conditions with no man-made or weather interference.

The source's HI is compared against natural conditions to assess the significance of the source's visibility impact. The visibility significance metric for evaluating BART sources is the change in deciview (delta-dv) from the source's and natural conditions Haze Indices:

delta-dv = HIsource – HInatural =

10 ln[(bsource + bnatural)/10] - 10 ln[bnatural/10] = 10 ln[(bsource + bnatural)/bnatural]

The maximum delta-dv impact from each BART-eligible source is compared to the 0.5 dv threshold to determine if the source is reasonably anticipated to cause or contribute to visibility impairment at a Class I area and is therefore Subject-to-BART. The use of the maximum impact is consistent with the BART screening protocol developed by the TCEQ in consultation with EPA and the FLMs in 2006/7 and used in their Regional Haze SIP and our TX BART FIP. The BART Guidelines proposed to use the maximum impact from CALPUFF modeling (and other modeling).[32] The Final BART Guidelines took into account concerns raised about CALPUFF's simple chemistry and an overestimation concern in nitrates and likely to provide conservative (higher) results for peak impacts and EPA did not want to use these likely overestimated maximum impacts which would be on the tail end of the impact data, so EPA chose the less conservative 98th percentile to address the concerns with CALPUFF.[33] Since CAMx utilizes a more robust chemistry mechanism, the concerns that drove the selection of the 98th percentile value for CALPUFF based modeling are not applicable and we are using the maximum impacts. As previously discussed Texas agreed to use the maximum impacts with their CAMx modeling as we are now doing in our CAMx modeling. We approved the use of the maximum impact and the screening of non-EGU BART-eligible sources in our previous action on the TX RH SIP.[34]

[31] Regional Haze Rule Natural Level Estimates Using the Revised IMPROVE Aerosol Reconstructed Light Extinction Algorithm, Copeland, S. A., et al, Final Paper # 48, available in our docket.; NC II, or new IMPROVE natural visibility conditions are available at: http://vista.cira.colostate.edu/Docs/IMPROVE/Aerosol/NaturalConditions/NaturalConditionsII_Format2_v2.xls, which is also available in our docket.

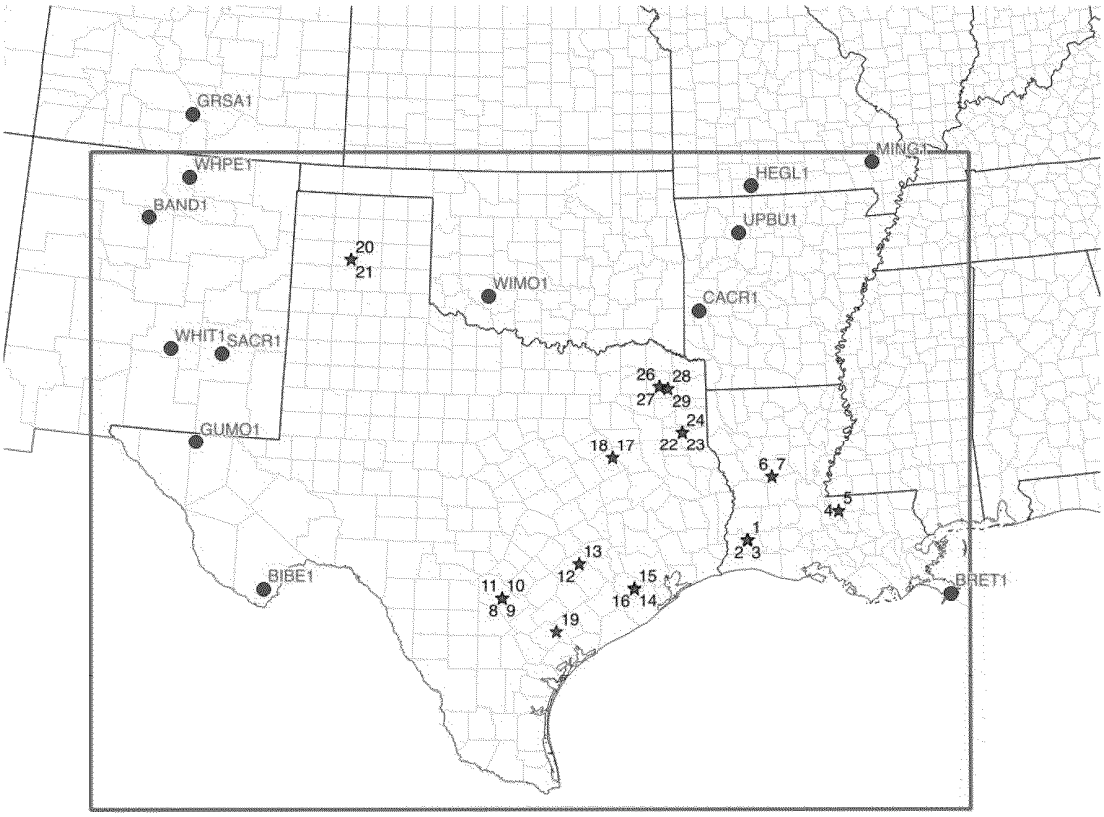
[32] FR Vol. 69, No. 87 pages 25193-25195, 25218 (Wednesday May 5, 2004)

[33] "Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source. Because of these features and the uncertainties associated with the model, we believe it is appropriate to use the 98th percentile—a more robust approach that does not give undue weight to the extreme tail of the distribution." 70 FR 39104, 39121.

[34] We note that in February 2007 EPA raised concern with using the 98th percentile for sources analyzed with CAMx, rather than the maximum or 1st high. TCEQ and EPA agreed that evaluation and screening would be done

The map and table below show the BART-eligible units that were tagged for the CAMx BART screening analysis. We note that this modeling also included tagged sources in Texas needed for a separate evaluation of those facilities in support of the proposed TX BART FIP.

Figure 3-2. CAMx modeled sources



In the above, locations of Class I area receptors are represented by green circles and BART-eligible sources/units are represented by red stars. The 12-km resolution CAMx modeling domain, is shown in blue. Sources 8 through 29 are located in Texas and were modeled to support a separate action.

Table 3-2. BART-eligible sources and units in Louisiana for CAMx BART screening Modeling

Index	Plant Name	Unit
1	ENTERGY R.S. Nelson	Aux Boiler
2	ENTERGY R.S. Nelson	4
3	ENTERGY R.S. Nelson	6
4	NRG Big Cajun II	1
5	NRG Big Cajun II	2

using the Maximum (1st High). See EPA-Snyder 2007, TCEQ -Knud 2007, TCEQ BART Screening Clarification 2007

6	Cleco Brame - Nesbitt	1
7	Cleco Brame - Rodemacher	2

3.1. CAMx Model Evaluation

CAMx Model Performance Analysis

To understand the performance of the current CAMx modeling in the context of two previous rounds of CAMx and Community Multi-scale Air Quality modeling system (CMAQ) regional haze modeling and expected model performance EPA and its contractor have conducted evaluations of the model results.

UNC-IE Analysis

Because the current CAMx modeling performed by UNC used the EPA R6 Texas RH CAMx[35] as a platform for the modeling for the impact of the Texas and Louisiana BART sources with (a) changes to the model version, (b) conversion of inputs from the previous version of the model to be used in the current version and, most significantly, (c) modifications to the emission inventory for the BART sources to allow modeling for screening of maximum visibility impacts, analysis was conducted to determine the performance relative to EPA modeling guidelines and determine the relative performance of the modeling system to that of the previous CAMx modeling using the platform. UNC, the EPA contractor, conducted an evaluation documented in the UNC Task 2 BART Screening Memo.[36] Below we briefly summarize UNC's analysis and give further interpretation and supporting information.

In the UNC Task 2 BART Screening Memo several different lines of comparison and evaluation were pursued.

- Ozone model performance (since the atmospheric chemistry of ozone and regional haze are linked.)
    - Normalized Bias to EPA's model performance guidelines for ozone modeling and monthly average concentrations versus observations. *On a monthly average basis the current CAMx run met the EPA ozone modeling performance guideline in all months except October for the 12km domain.*
    - Comparison of spatial concentration plots of the current and previous CAMx modeling. *The current and previous CAMx modeling maximum daily 8-hour ozone results are comparable.*
- PM model performance

[35] The regional photochemical modeling utilized in our earlier action on Texas Reasonable Progress. ENVIRON. 2013. "Memorandum: 2002 Baseline CAMx Simulation, Texas Regional Haze Evaluation", prepared by ENVIRON International Corporation for EPA Region 6 (RTI Contract EP-W-011-029). February 21, 2013.

[36] "Regional Haze Evaluation Under Contract EP-D-11-084 Work Assignment No. 4-17: TASK 5, Subtask 2: Conducting CAMx PiG with PSAT Source Apportionment for BART screening (CAMx Run #1)", Memorandum from Zac Adelman and Uma Shankar, UNC Institute for the Environment to Erik Snyder, EPA Region 6, December 7, 2016. Available in the docket for this action as "EPA-R6_RH_Task2_Memo_UNC_07Dec2016.pdf"

- Comparison of normalized bias to EPAR6 Texas RH CAMx and EPA's model performance guidelines for particulate matter modeling and monthly average concentrations versus observations. *The CAMx Run1 12km simulation meets the model performance goal for total $PM_{2.5}$ in the months of March through September but has an overly high bias in the cooler months of the year.*
- Seasonal analysis of speciated PM2.5 concentrations from the model versus observations. *The modeled total $PM_{2.5}$ positive biases during the winter and fall are driven by overestimates of particulate nitrate (NO_3) and dust and sea salt. During the warmer months all of the inorganic species – including nitrate and sulfate – were underestimated.*
- Comparison of spatial concentrations plots of the current and previous CAMx modeling
  - Max 24-hour PM2.5
  - Annual average PM2.5

  The overall result of the comparison is that the current modeling tends to have higher PM2.5 levels with similar patterns for the locations with the highest concentrations.

- Visibility
  - Comparison by Class I site of model and observed speciated light extinction
    - 20% best visibility days
    - 20% worst visibility days
    - All days

    The speciation results correspond closely to those from the previous modeling. The species plots show that overall the CAMx model tended to underestimate visibility impacts on the worst days and overestimate visibility impacts on the best days. Sulfate is underestimated in the warmer months; nitrate overestimated in the cooler months.

EPA and UNC's overall conclusion was that, with limited exceptions, the current CAMx modeling performance corresponds to the previous modeling and that it meets the EPA performance guidelines. We address the exceptions below.

According to the analysis in the UNC Task 2 BART Screening Memo there are two instances where the current CAMx modeling is significantly differently from the previous modeling; for one of which the performance does not meet the EPA model guidelines. In the first, although CAMx was found to have a high bias for nitrates in the cooler season in the previous modeling, the current result shows an even higher bias which is above the modeling guideline. This finding is explained by considering the emissions that were used in the BART analysis. The NOx emissions in the modeling do not represent the emissions that actually occurred on a daily basis. Rather, due to the requirements of the BART analysis to determine potential impact, maximum observed NOx emissions instead of actual emissions were used across all days. A high bias should be expected versus observed if these sources are impacting the Class I areas and causing

visibility impairment. The analysis of seasonally speciated PM2.5 shows that overestimates of nitrate are important to the high bias in cooler seasons. The increase in the bias in which nitrates play a major role is consistent with the conclusions that these sources are causing impairment.

In the second, the PM2.5 spatial plots show that the current modeling concentrations are elevated relative to the previous modeling. Similar to the explanation for the elevated nitrates, the SO2, NOx, and primary particulate emissions were modeled for the maximum observed emissions for the BART analysis. It would be expected that when modeled emissions are raised for sources which have significant impacts on PM2.5 concentrations that the modeled ambient concentrations would also rise.

EPA Region 6 Model Performance Evaluation versus CENRAP modeling

In 2006/7 an evaluation was conducted by ENVIRON for CENRAP of CMAQ and CAMx modeling for the Regional Haze project. CENRAP's evaluation found that the performance of CMAQ and CAMx were equivalent and published the overall results of the CMAQ evaluation and the source apportionment results of CAMx modeling in their final TSD[37]. Because the current CAMx modeling conducted by UNC for Region 6 relies upon the EPA R6 Texas RH modeling, which depended on the CENRAP Regional Haze modeling dataset as a platform, EPA Region 6 as part of the current CAMx modeling, conducted an analysis to (a) determine the performance relative to EPA modeling guidelines and (b) determine the relative performance of the modeling system to that of the CENRAP CMAQ modeling using the platform. A synopsis of the intercomparison is given below using soccer goal plots[38] summarizing overall model performance for sulfates, nitrates, and organic carbon. In order to represent different prevalent meteorological conditions, four months were compared: January, April, July, and October, the same months documented in the CENRAP TSD. The sites used for the comparisons were the IMPROVE sites in the respective regions of interest e.g. the CENRAP states and portions of the Region 6 states potentially affected by the Texas and Louisiana BART eligible sources. Since the Class I area sets for CENRAP and the Run 1 (base case or BART Screening run) from the CAMx modeling performed by Region 6 differ substantially in the sources impacting them and in source to monitor transport, the comparison is not one-to-one. In addition, the emissions from the tagged BART-eligible sources have been enhanced with more emissions for the purposes of the BART impact analysis in Run 1.

[37] Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans available in the docket for this action

[38] The soccer plot is so named because the dotted lines illustrating performance goals resemble a soccer goal. The plot is a convenient way to visualize model performance of both bias and error on a single plot. As bias and error approach zero, the points are plotted closer to or within the "goal", represented by the dashed boxes. Tesche, T.W., Morris, R., Tonnesen, G., McNally, D., Boylan, J., Brewer, P., 2006. CMAQ/CAMx annual 2002 performance evaluation over the eastern US. Atmospheric Environment 40, 4906-4919 and https://www3.epa.gov/scram001/guidance/guide/Draft_O3-PM-RH_Modeling_Guidance-2014.pdf (page 72)

Figure 3.1-1. Comparison of Improve monitoring sites used for model performance analyses for CENRAP (left) and Region 6 Run 1(right). The Run 1 sites are contained within the rectangle (12 km domain).

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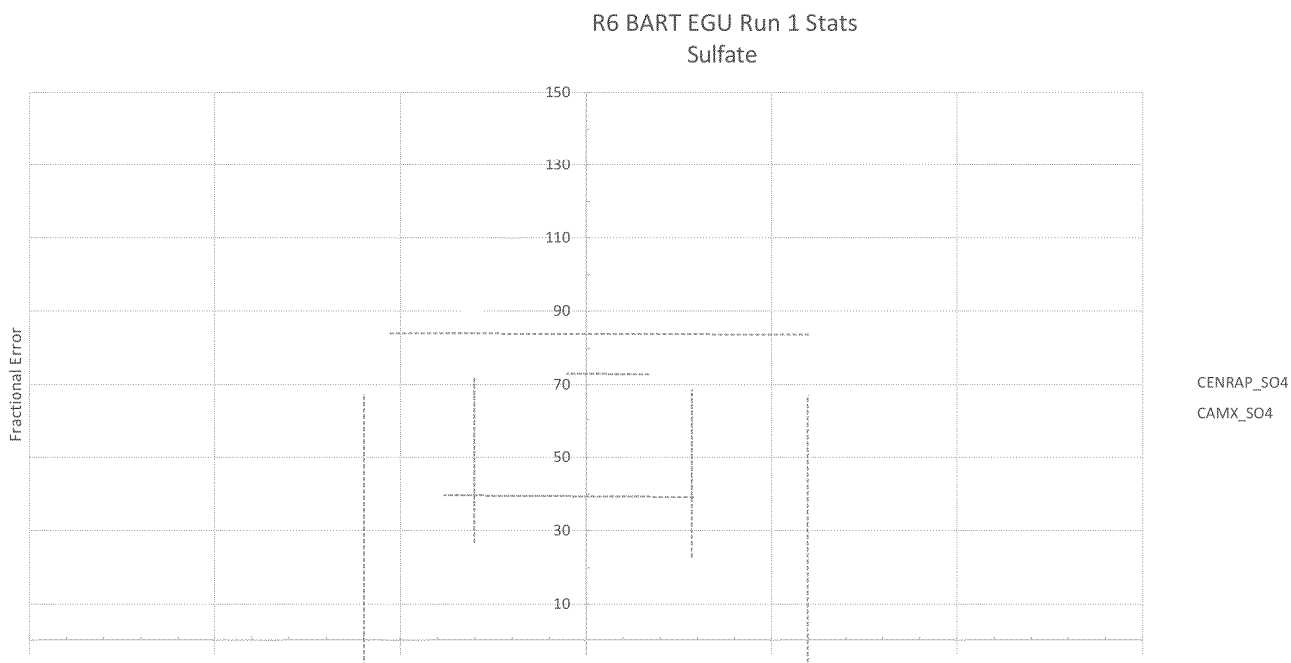
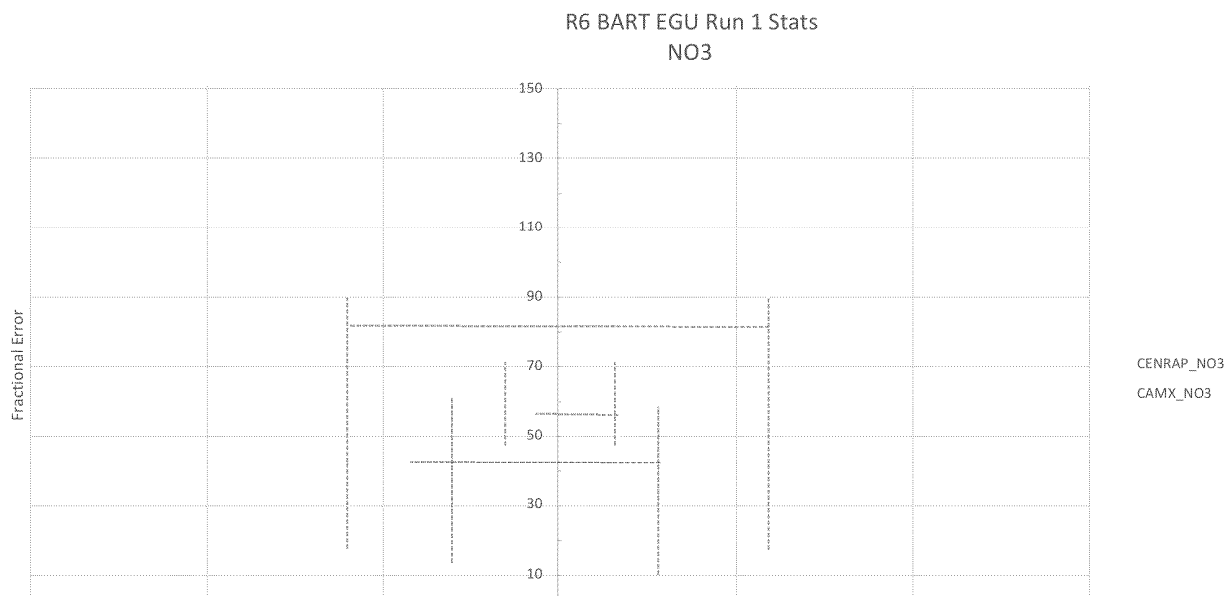
(1) Sulfate

	CENRAP CMAQ		R6 CAMX Run1	
Month	Frac Bias	Frac Error	Frac Bias	Frac Error
January	-12.4	41.9	16	47.2
April	-51.6	58.2	-38.5	54.4
July	-49.6	59.4	-83.2	85.3
October	-6.1	39.6	17.6	62.0



The intercomparison shows that the performance of Run 1 and the CENRAP CMAQ runs were similar for most months except that in the cooler months Run1 had a lower bias than did the CENRAP runs and that for July Run 1 had a larger low bias – outside of the 60% fractional bias / 80% fractional error performance goal for regional particulate modeling.

	CENRAP		R6 CAMX	
Month	Frac Bias	Frac Error	Frac Bias	Frac Error
January	37.8	92.9	76.6	104
April	-67.4	115.2	-78.7	113
July	-140.5	148.4	-137	142
October	39.3	103.6	25.4	115



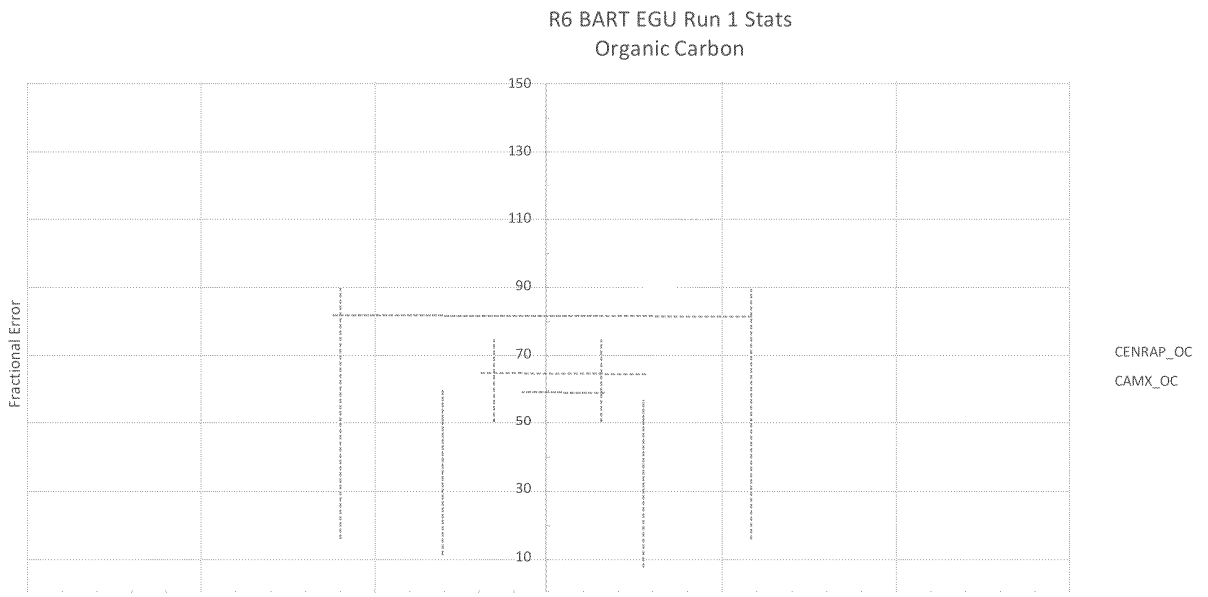
(2) Nitrate

For nitrate, both models had similar performance with underestimates in the summer months and overestimates in the winter months. The performance for all months for both models was outside of the desired performance goal.[39]

[39] See Section 3 of the Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans (available in the docket for this action) for additional discussion of model evaluation.

(3) Organic Carbon

	CENRAP		R6 CAMX	
Month	Frac Bias	Frac Error	Frac Bias	Frac Error
January	-0.2	52.0	24.5	46.7
April	-6.6	53.3	21.5	50.6
July	-17.7	51.2	33.1	72.0
October	5.9	44.6	39.2	61.6



The organic carbon model performance comparison shows that the Run 1 organic carbon was biased high and that the fractional error was higher for July and October versus the CENRAP run.

Because of the differences in the models, chemical mechanism, emissions, and the domain sites used for the performance evaluation the CENRAP and Run1 results are not directly comparable. It is useful for general observation on relative model performance given the caveats. The underestimation of sulfates in Run1 for the warmer months (when maximum sulfate impacts tend to occur) indicates that for the Region 6 Class I areas that the model on the average is underestimating the impact of sources of SO_2 on particulate sulfate concentrations. Extensive QC was done by UNC on the various inputs and model parameters to determine if an inadvertent error may have been introduced in the modeling for the warmer months. No problems were found. Since we are using the absolute values of the modeling, this underestimate of sulfate impacts in the summer results in: (a) the impacts of the BART-eligible sources are likely

underestimated and the actual impacts would be greater, and (b) the visibility benefits modeled for the BART-eligible facilities are likely underestimated, the actual benefits would be greater, when the reduced emission runs, Run 3 and Run 4, are compared to Run 1.[40] The latter is pertinent even in the presence of the high bias for nitrates in the cooler months since the emission reductions being considered are for SO_2 which is a precursor for sulfates.

The Effect of Overall Model Emissions on CAMx Modeled Visibility Impacts

As discussed above, additional CAMx modeling was completed by UNC-IE to evaluate the potential visibility benefit of controls for subject to BART units in Texas and Louisiana. For three tagged units located in Texas we utilized the same emission rates in the base case (Run 1 or BART Screening run) and the low control (Run 4) model scenarios to evaluate the impact of overall increased emission levels to the modeling results.[41] Because the base case model scenario utilized maximum actual daily emission rates year round, the total modeled emissions for SO_2 and NOx in the base case scenario were higher than the typical/actual emission inventory for 2002. This change in overall emissions could impact the overall chemistry and competition for reactants (e.g. ammonia) that lead to formation of visibility impairing particulate. The low control scenario (Run 4) total emissions for the tagged sources are approximately 50% of the base case scenario and are much more similar to the typical/actual emission inventory for 2002. The three figures below compare the maximum modeled impacts in deciviews at each Class I area for the base case (Run 1) and low control runs for the three units in Texas (Run 4) that were modeled at the same emission rates between the two runs.[42] Visibility impacts are similar between the two runs, with the largest differences at those Class I areas (e.g. Caney Creek, Upper Buffalo, Wichita Mountains) most impacted by the large EGU sources concentrated in Northeast Texas and therefore most impacted by the overall emission changes at these sources. For these Class I areas, the low control scenario and lower overall emissions result in higher modeled visibility impacts from the three tagged units with unchanged emissions, possibly due to the cleaner ambient conditions resulting in somewhat less competition for reactants that lead to formation of visibility impairing particulate. The effect of this is seen more for Welsh Unit 2, which is located in in Northeast Texas. The base case modeled impacts for these sources may be underestimated due to the higher overall emissions of SO_2 and NO_x in the base case model scenario. Therefore, we do not believe that the results of our subject-to-BART screening analysis and conclusion on which sources are subject to BART based on CAMx modeling would be impacted by higher overall emissions in the base case modeling.

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[40] In addition to the modeling results from the initial base case modeling (CAMx base case modeling is also referred to as BART Screening Modeling and Run 1), as discussed in more detail elsewhere, we also had additional control scenario modeling performed (low control is also referred to as Run 4, high control is also referred to as Run 3) to estimate the benefits of emission reductions from controls representing a high level and intermediate level of control. These runs are documented by UNC in "Regional Haze Evaluation Under Contract EP-D-11-084 Work Assignment No. 4-17: TASK 5, Subtask 4: Conducting CAMx PiG with PSAT Source Apportionment for BART Control Evaluations (CAMx Run #3 and #4)", Memorandum from Zac Adelman and Uma Shankar, UNC Institute for the Environment to Erik Snyder, EPA Region 6, December 8, 2016. Available in the docket for this action as "EPA-R6_RH_Task4_Memo_UNC_08Dec2016.pdf"

[41] Texas BART sources, Fayette units 1 and 2 and Welsh Unit 2 were selected. Fayette units already have scrubbers installed and Welsh 2 is shut down. There is no need to examine a low control scenario for these units.

[42] See the BART Modeling TSD and BART Screening TSD that accompanied our proposed action for Texas EGU sources (identified by Docket No. EPA-R06-OAR-2016-0611, at *http://www.regulations.gov*) for additional information, including information on emissions for Texas sources included in the modeling and model results.

Figure 3.1-2. Maximum CAMx modeled impact (dv)– Fayette Unit 1

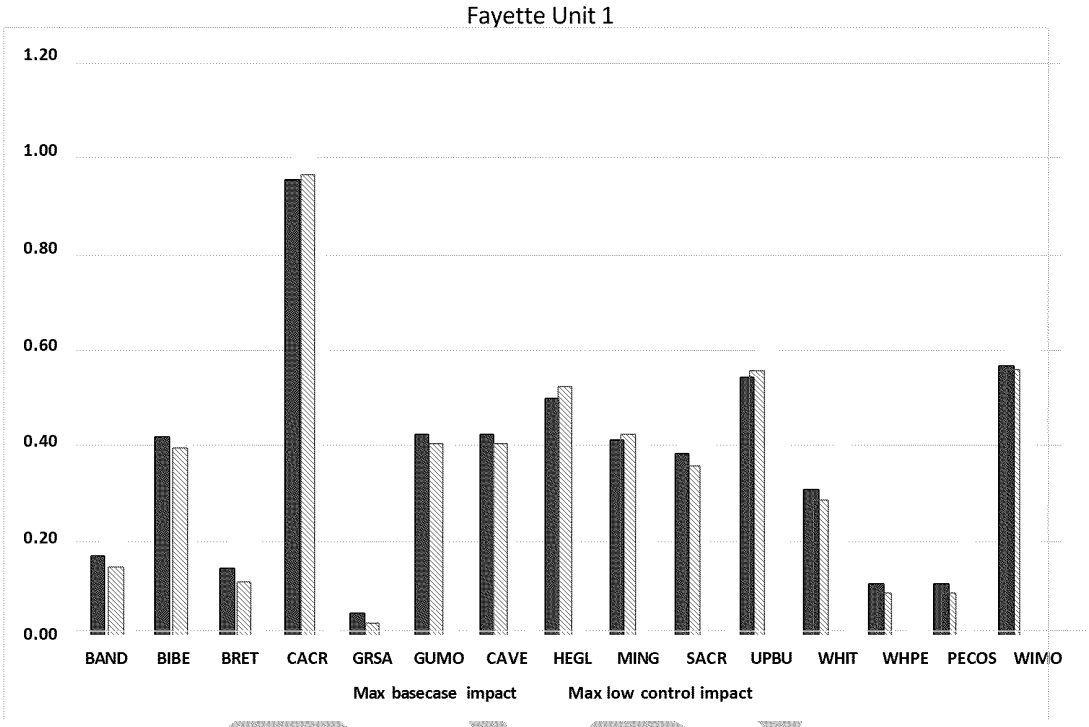


Figure 3.1-3. Maximum CAMx modeled impact (dv)– Fayette Unit 2

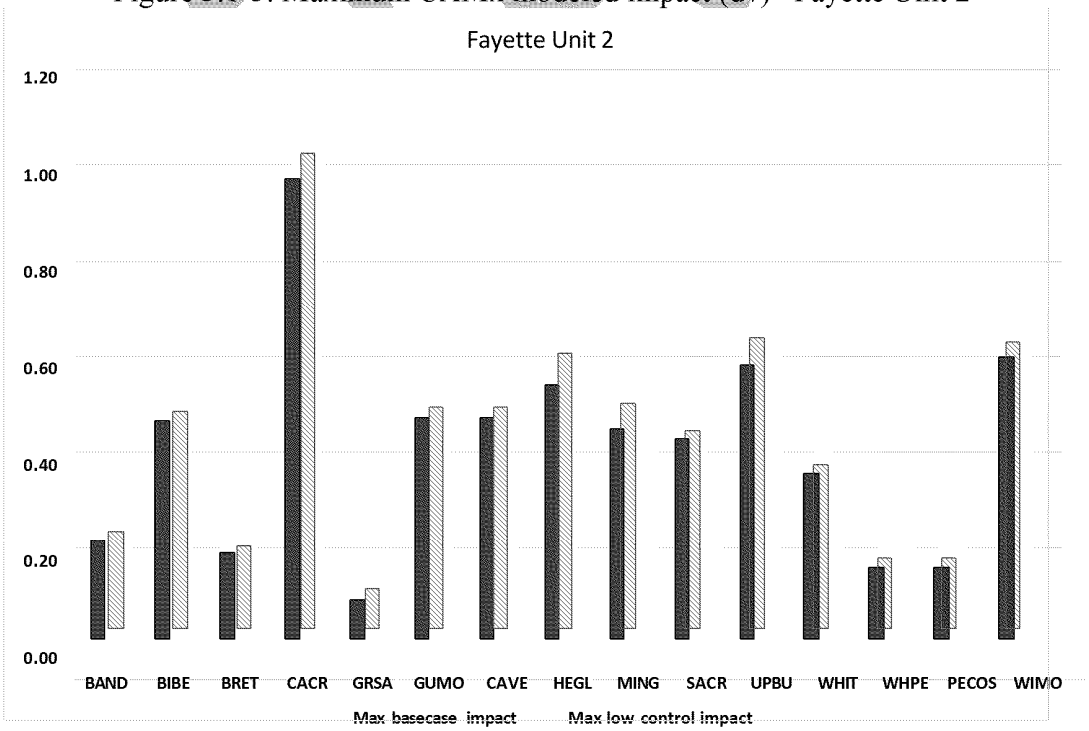
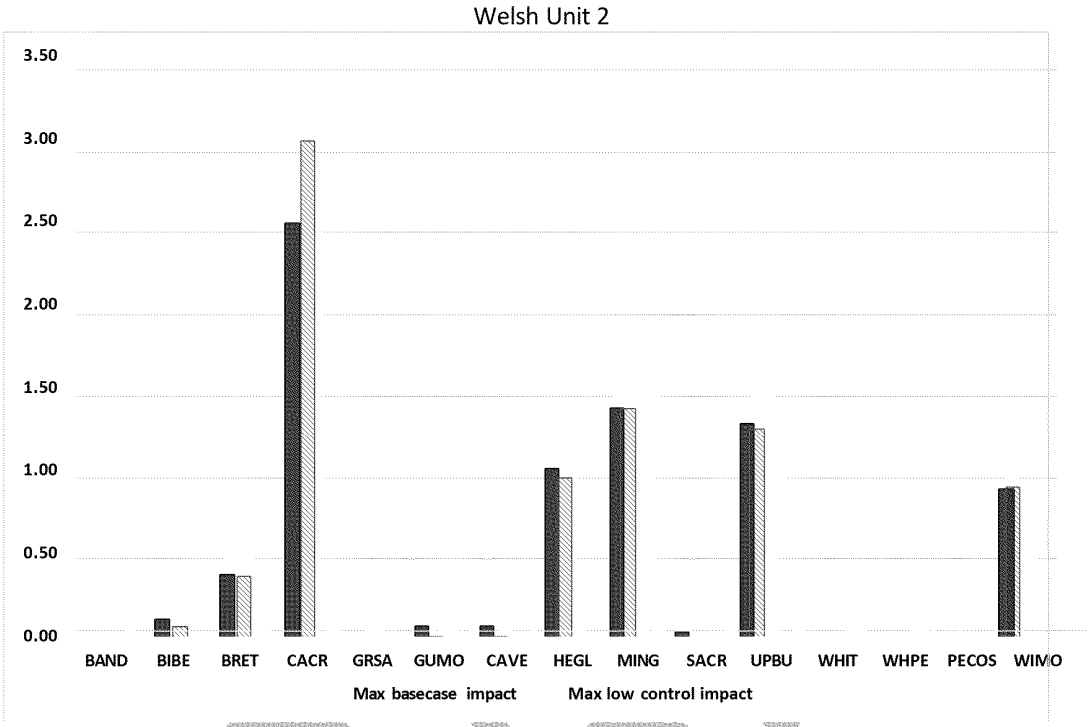


Figure 3.1-4. Maximum CAMx modeled impact (dv)– Welsh Unit 2



3.2. Summary of CAMx BART Screening Model Results

CAMx model results were post-processed to obtain the maximum 24-hour average of delta deciviews relative to natural background for each source and each unit at each Class I area. The table below shows the maximum impacted Class I area for each modeled BART-eligible source. See Appendix B for additional CAMx modeling results.[43]

[43] See ""LA_summary CAMx vis daily.xlsx"" for daily modeled visibility impairment for each source/unit at each class I area; "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for additional model results including daily concentrations for each visibility impairing pollutant from each source/unit at each class I area

Table 3.2-1. Summary of BART screening CAMx results, 2000-2004 basecase

BART-eligible source	Units	Most impacted Class I area	Maximum delta-dv	Less than 0.5 dv?	Number of modeled days over 0.5 dv	Number of modeled days over 1.0 dv
NRG Big Cajun II	1 & 2	BRET	1.644[44]	No	16	2
Cleco Brame	Rodemacher & Nesbitt	CACR	2.833	No	30	10
Entergy Nelson	4,6, and auxiliary boiler	CACR	2.220	No	31	9

We note that all of these sources had impacts equal to or above 0.5 dv that ranged from 16 days to 31 days out of the 365 days modeled at the most impacted Class I area. We discuss additional screening modeling performed to reflect current emission limits at NRG Big Cajun II later in this document.

4. Review of Entergy and Cleco CAMx Modeling

BART Modeling is focused on identifying the maximum potential impact from the source by modeling steady-state[45] maximum actual emissions over a range of meteorological conditions. CALPUFF modeling is performed over a 3-year meteorological period. CAMx modeling is typically done over a period of one year and requires a demonstration that that year is a good representation of the baseline period.[46] Maximum daily impacts are assessed by examining model results on all modeled days. Visibility impairment is calculated using the revised IMPROVE equation to convert concentrations of visibility impairing species into light extinction. The total light extinction is then converted to deciview impacts compared to natural visibility conditions

The BART Guidelines describe the process for individual source attribution, stating:

> *With the accepted protocol and compare the predicted visibility impacts with your threshold for ''contribution.''* **You should calculate daily visibility values for each receptor as the change in deciviews compared against natural visibility conditions**. You can use EPA's ''Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule,'' EPA–454/B–03–005 (September 2003) in making this calculation.

[44] Big Cajun II base case CAMx modeled impact utilizes 2000-2004 emission data. We note that CALPUFF modeling utilizing current emission limits and reflecting controls required to meet CD requirements estimates impacts less than 0.5 dv. See CALPUFF TSD for additional information. See Section 6.1 of this TSD for additional analysis of modeled impacts utilizing current emission limits.

[45] A continual release of emissions at the same rate all the time.

[46] See Section 1.3.6 of the Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans available in the docket for this action for additional discussion on the selection of the 2002 modeling year for the baseline period.

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> To determine whether a source may reasonably be anticipated to cause or contribute to visibility impairment at Class I area, you then compare the impacts predicted by the model against the threshold that you have selected.
>
> **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.

After our initial review of Trinity's initial CAMx modeling[47] provided to us before LDEQ proposed its SIP, we provided additional guidance to LDEQ and Entergy/Cleco/Trinity and also provided the CAMx modeling protocol developed in 2006/2007 by TCEQ and agreed upon by Region 6, FLMs and OAQPS for BART sources in Texas[48,49] as an example of an approved protocol utilizing CAMx modeling for BART screening. Our guidance that we provided to LDEQ, the source owners and Trinity is consistent with the BART Guidelines and is summarized below:

- Use emissions representative of actual 24-hr maximum emissions from the baseline period
- Evaluate the maximum impact for all modeled days, not just the 20% worst days
- Calculation of deciview impact based on natural background visibility conditions
- Analyze direct model results of the baseline modeling

In response to this guidance, Trinity revised their modeling for the Entergy and Cleco units and provided updated model results to LDEQ and us. [50] A description of this revised modeling and a summary of model results is provided in the Louisiana 2017 Regional Haze SIP. The general approach followed by Trinity is described below:

- Used twice the 2002 actual annual emission rate
- Calculated deciview impact based on natural background visibility conditions

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[47]See Updated BART Applicability Screening Analysis Prepared by Trinity Consultants, November 9, 2015. Available in Appendix D of the 2017 Louisiana Regional Haze SIP

[48] Texas had over 120 BART eligible facilities located at a wide range of distances to the nearest class I areas in their original Regional Haze SIP. Due to the distances between sources and Class I areas and the number of sources, Texas worked with EPA and FLM representatives to develop a modeling protocol to conduct BART screening of sources using CAMx photochemical modeling. Texas was the only state that screened sources using CAMx and had a protocol developed for how the modeling was to be performed and what metrics had to be evaluated for determining if a source screened out. See Guidance for the Application of the CAMx Hybrid Photochemical Grid Model to Assess Visibility Impacts of Texas BART Sources at Class I Areas, ENVIRON International, December 13, 2007, available in the docket for this action.

[49] EPA, TCEQ, and FLM representatives verbally approved the approach in 2006 and in email exchange with TCEQ representatives in February 2007 (see email from Erik Snyder (EPA) to Greg Nudd of TCEQ Feb. 13, 2007 and response email from Greg Nudd to Erik Snyder Feb. 15, 2007, available in the docket for this action).

[50] See October 10, 2016 Letter from Cleco Corporation to Vivian Aucoin and Vennetta Hayes, LDEQ, RE: Cleco Corporation Louisiana BART CAMx Modeling, included in Appendix B of the 2017 Louisiana Regional Haze SIP submittal; CAMx Modeling Report, prepared for Entergy Services by Trinity Consultants, Inc. and All 4 Inc, October 14, 2016, included in Appendix D of the 2017 Louisiana Regional Haze SIP submittal

- Used a Relative Reduction Factor (RRF) approach rather than direct modeling
- Developed RRF values for the 20% best and 20% worst days, averaged them, and then applied these RRF values to all monitored days through-out the year

We note that Trinity did not provide model inputs, such as emissions or stack parameters, or provide worksheets utilized for post-processing, or any of the actual CAMx modeling files so our review is limited only to general description of the modeling protocol provided in the various CAMx modeling reports provided by Entergy.

4.1. Baseline emissions for BART-eligible sources

Trinity's revised CAMx modeling performed for Entergy and Cleco utilized 2 times the 2002 actual annual emission rate as "representative estimates of the maximum 24-hr emissions." There is no need for estimated data as CEM data is available to identify maximum 24-hr emissions for NOx and SO2 during the baseline period. In fact, this CEM data was used to identify emission rates utilized in CALPUFF modeling performed by Trinity for Entergy and Cleco sources. We note that for Texas non-EGU BART modeling as described in the Texas BART modeling protocol, no CEM data was available and therefore an estimate, such as using twice the annual emission rate was acceptable. For EGU sources, the use of 2 times the annual emission rate may over or under estimate the 24-hr maximum actual emissions. For the Entergy BART-eligible gas-fired units that occasionally burn fuel oil, 2 times annual emission rate severely underestimates the maximum 24-hr emissions and results in an underestimate of the maximum modeled impacts.[51] The table below illustrates this underestimate by comparing the annual emission rate for SO2 emission from the Entergy Waterford units to the maximum actual emission rate identified from the CEM data. In the case of Waterford unit 2, the maximum 24-hr emission rate is over 6000 times larger than the annual emissions rate.

Table 4.1-1. Comparison of Waterford modeling emission inputs

	2002 annual emissions of SO2 (tons)	2002 Annual Emission rate (lb/hr)	24-hr maximum emission rate (lb/hr) (CAMD, 2000-2004)	Ratio of actual max emissions to annual emission rate
Waterford Unit 1	46.324	15.04	5,274.5	**350.6**
Waterford Unit 2	3.032	0.73	4,532.75	**6237.8**

4.2. Comparison of EPA and Trinity's post-processing approach

Maximum visibility impact at each Class I area should be identified from 2002 baseline modeling and examining all modeled days. Rather than utilize direct modeled results as we advised and as was utilized in the Texas BART modeling protocol we provided, Trinity used a Relative Reduction Factor (RRF) approach that multiplies monitor data by

[51] Entergy's CAMx modeling included model results for Michoud, Little Gypsy, R.S. Nelson, Ninemile Point, Willow Glen, and Waterford.

the ratio of model results (2018 divided by 2002). Monitoring data is only available for every third day so 240 days of the year have no monitoring data and cannot be assessed using the RRF approach.

EPA's Direct Modeling Approach (and Texas EGU PM and non-EGU BART approach):

a. Model maximum actual 24-hour emissions for each BART unit and 2002 baseline emissions for all other sources, and use source apportionment (PSAT) for each BART unit. PSAT tracks contributions to overall concentrations at the Class I areas due to each source.
b. Using revised IMPROVE equation and daily average concentrations from each source at each Class I area, calculate the daily extinction impact from each source.
c. CALPUFF modeling typically used Highest 8th High (98th percentile) from three years of modeling. Due to the more robust chemistry in CAMx and that CAMx analysis is for one year instead of 3 years the maximum daily impacts (1st Daily Max) was used for screening and analysis instead of 98th percentile.

Trinity's RFF Approach:

a. Use Modeled Attainment Test Software (MATS) to compute model-estimated relative response factors (RRFs) that are the ratio of the model-estimated 24-hour $PM_{2.5}$ concentrations for the future-year (2018) to the baseline (2002) emission scenarios for only the 20% worst days and 20% best days.
b. Calculate 2018 modeled visibility conditions and projected visibility conditions (using RRF approach) for 20% worst (W20%) and 20% best (B20%) days
c. To get individual source or group of sources contributions, subtract the PSAT results from the 2018 CAMx output for the source of interest, rerun MATS, and calculate differences of projected visibility conditions by repeating b.

For example, (for illustration purposes only):

	Modeled visibility condition (average 20% worst days)	RRF (2018 divided by 2002)	Monitored visibility condition	Projected visibility condition (monitored x RRF)	Impact from BART source
2002	140 Mm^{-1}	---	150 Mm^{-1}		---
2018	120 Mm^{-1}	0.857	---	128.5 Mm^{-1}	---
2018 (not including BART source #1)	110 Mm^{-1}	0.786	---	117.9 Mm^{-1}	10.6 Mm^{-1}
2018 (not including BART source #2)	119 Mm-1	0.85		127.5 Mm-1	1.0 Mm-1

This extinction impact is then converted to deciview impacts using the following equation, where b_{source} is extinction from the source and $b_{natural}$ is natural background extinction:

$$\text{del-dv} = 10*\ln[(b_{source} + b_{natural})/b_{natural}]$$

The RRF approach attempts to capture the relative change in model results in response to a change in emissions on a specific day or group of days with certain conditions and then apply that change to monitored data for that day or group of days. These conditions include not only meteorology, but also source emissions and background concentrations transported into the modeling domain that can impact the model response to changes in emissions due to differences in transport and chemistry. The RRF value should only be applied to monitored days that have the same set of conditions as those modeled to derive the RRF. In other words, the RRF should only be applied to the monitored days that directly correspond to the modeled days included in the RRF calculation. Trinity developed RRF values for the 20% best and 20% worst days, averaged them, and then applied these RRF values to all monitored days through-out the year.

This approach has a number of short comings when trying to identify the maximum impact from a source over the modeled period:

- The RRF values only capture model behavior and impacts from sources on the 20% best and 20% worst days as defined by monitored data for 2002. Approximately 24 days of monitored data comprise the 20% worst or best days at each Class I area. It is very likely that maximum impact from each BART source occurs on days not included in the small set of days (48 of 365 days or less than 14% of the days) that are included in the 20% worst or 20% best monitored days.
    - Impacts from the Louisiana EGU BART sources are not anticipated to have significant impacts on the 20% best days because, by definition, these are days with the least impact from all sources. These days are representative of days with minimal impacts, not days with the maximum impacts.
    - The 20% worst days at Caney Creek represent days with significant impacts from Northeast Texas or the Eastern U.S. These days do not have meteorological conditions that would result in significant transport from Louisiana EGU BART sources. A subset of 20% worst days at Breton may have significant impacts from Louisiana EGU sources, but many of these days have significant impacts from Eastern U.S. sources. The 20% worst days may not capture the highest impact days from all LA BART sources.
    - The RRF from the 20% worst days and 20% best days were averaged and applied to all monitored days. Since the RRF values for the 20% worst days may not include days with the maximum impacts, use of this RRF approach fails to consider model response on days most conducive to high impacts from each source. The use of the 20% worst days RRF as representative of model response on all days underestimates the maximum impact. Averaging in the RRF value for the 20% best days exacerbates this issue as these days are not anticipated to have any impact from the BART sources and is representative of days with minimal impacts from the BART sources.

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- While modeling data is available for 365 days, monitor data is only available for every third day. Trinity's analysis applied the RRF approach to "all available monitored data in order to calculate individual visibility impacts" and therefore applies and inappropriate RRF value to approximately 120 monitored days and fails to estimate visibility impacts from the sources on the remaining 240 days of the year. Even if a day-specific RRF approach was used to capture model response on specific days and applied to the monitored data, visibility impacts would not be assessed for the 240 days without monitored data.

4.3. Comparison of Trinity and EPA's CAMx modeling:

Table 4.3-1. Trinity's CAMx modeling impact for Cleco Brame Rodemacher Unit 2 and Nelson Unit 6

Class I Area	Rodemacher Unit 2	Nelson Unit 6
	Maximum impact (dv)	Maximum impact (dv)
Caney Creek	0.2673	0.3261
Breton	0.0885	0.1343

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Table 4.3-2. EPA modeled visibility impact from Cleco Brame Rodemacher Unit 2 and Nelson Unit 6 at most impacted Class I areas (CAMx)

Class I area	Rodemacher Unit 2		Nelson Unit 6	
	Baseline Impact dv) (maximum)	Baseline Impact (dv) (average top ten impacted days)	Baseline Impact dv) (maximum)	Baseline Impact (dv) (average top ten impacted days)
Breton	0.713	0.315	0.599	0.314
Caney Creek	2.051	1.005	2.179	1.302
Mingo	0.711	0.460	1.468	0.785
Upper Buffalo	1.102	0.613	1.219	0.934
Hercules-Glade	0.687	0.508	1.287	0.777
Wichita Mountains	0.578	0.274	0.575	0.412
Cumulative[52]	6.733	3.664	8.939	5.444

Table 4.3-3. EPA modeled visibility impact from Cleco Brame Rodemacher Unit 2 and Nelson Unit 6 at most impacted Class I areas – number of days impacted over 0.5 and 1.0 dv (CAMx)

Class I area	Rodemacher Unit 2		Nelson Unit 6	
	Baseline - # of days impacted over		Baseline - # of days impacted over	
	1 dv	0.5 dv	1 dv	0.5 dv
Breton	0	2	0	1
Caney Creek	3	15	6	30
Mingo	0	2	1	9
Upper Buffalo	1	7	4	18
Hercules-Glade	0	5	1	9

[52] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.

Wichita Mountains	0	1	0	2
Cumulative[53]	4	32	12	69

5. Analysis of Visibility Benefits for Potential Controls

Once the subject-to-BART sources were identified, we modeled the visibility impacts of the subject-to-BART sources under different control scenarios to evaluate the degree of visibility benefit anticipated due to the use of controls at each source. We developed emission scenarios to model that spanned the potential control scenarios for each unit. This information would be used to estimate the amount of visibility benefit that could be expected from installation of controls on each of the subject-to-BART units. The BART guidelines recommend the use of CALPUFF or other appropriate dispersion models to determine the visibility improvement expected at a Class I area from the potential BART control technology applied to the source.

5.1. Background and Introduction

LDEQ used the CALPUFF model to analyze the visibility impacts and benefits of controls at the subject-to-BART sources consistent with the approach recommended by the BART Guidelines for comparing visibility improvement from control alternatives at a single source.[54] The BART guidelines recommend use of the CALPUFF air quality dispersion model to estimate the visibility improvements at each Class I area, typically within roughly a 300 km (186 mile) or larger radius of the source, of alternative control technologies, and to compare these to each other and to the impact of the baseline, or current, source configuration. Under the BART guidelines, the measure of the visibility impact to be used in comparisons is the 98th percentile of impacts expressed as 24-hour averages of delta deciviews relative to natural background, as estimated using the CALPUFF air quality modeling system. The CALPUFF modeling protocol followed is described in detail in the CALPUFF Modeling TSD.

As discussed above, some of the BART sources in Louisiana are far away from a Class I area yet have high enough emissions that they may significantly impact visibility at Class I areas in Louisiana and surrounding states. However, the use of CALPUFF is not typically recommended for distances much greater than 300 km - 400km. CAMx provides a scientifically defendable platform for assessment of visibility impacts over a wide range of source to receptor distances. CAMx is also more suited than some other modeling approaches for evaluating the impacts of SO_2, NOX, VOC and PM emissions as it has a more robust chemistry mechanism. The CAMx PM Source Apportionment Technology (PSAT) modeling was conducted for those subject-to-

[53] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.
[54] 70 FR 39170 (July 6, 2005). CALPUFF is the single source air quality model that is recommended in the BART Guidelines. For CALPUFF modeling used for this analysis, the modeling results were post-processed in a manner consistent with the BART Guidelines.

BART sources located outside of the recommended range of CALPUFF to evaluate the visibility benefits of controls. We also used CAMx PSAT modeling on the other coal-fired power plants (within the typical range of CALPUFF) to provide additional data and analysis for these large emission sources. The CAMx modeling protocol followed is described in detail above. See the UNC-IE memorandum that documents these additional CAMx runs.[55]

Regarding how to use modeling to assess visibility benefits from controls, the BART guidelines state:[56]

- For each source, run the model, at pre-control and post-control emission rates according to the accepted methodology in the protocol.
  Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). Calculate the model results for each receptor as the change in deciviews compared against natural visibility conditions. Post-control emission rates are calculated as a percentage of pre-control emission rates. For example, if the 24-hr pre-control emission rate is 100 lb/hr of SO_2, then the post control rate is 5 lb/hr if the control efficiency being evaluated is 95 percent.
- Make the net visibility improvement determination.
  Assess the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. You have flexibility to assess visibility improvements due to BART controls by one or more methods. You may consider the frequency, magnitude, and duration components of impairment.

We used modeling results from the initial base case modeling (CAMx base case modeling is also referred to as BART Screening Modeling and Run 1) and the control scenario modeling (low control is also referred to as Run 4, high control is also referred to as Run 3) to estimate the benefits of emission reductions from controls/control upgrades. We note that for Entergy Nelson, "run 1" contained an error in some of the stack parameter inputs and therefore, "run 4" utilized base case emissions to model the base case visibility impairment due to the Nelson BART-eligible source and units. Below we present a summary of our analysis and our proposed findings regarding the estimated visibility benefits of emission reductions based on the CALPUFF and/or CAMx modeling results.

5.2. Emission Calculation Methodology

[55] "Regional Haze Evaluation Under Contract EP-D-11-084 Work Assignment No. 4-17: TASK 5, Subtask 4: Conducting CAMx PiG with PSAT Source Apportionment for BART Control Evaluations (CAMx Run #3 and #4)", Memorandum from Zac Adelman and Uma Shankar, UNC Institute for the Environment to Erik Snyder, EPA Region 6, December 8, 2016. Available in the docket for this action as "EPA-R6_RH_Task4_Memo_UNC_08Dec2016.pdf"

[56] 40 CFR part 51 Appendix Y Section IV.D.5

2000-2004 baseline Emissions

To estimate baseline period visibility impacts from BART-eligible sources, the BART Guidelines in 40 CFR 51 Appendix Y 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 maximum 24-hour emission rate (lb/hr) for NOx and the maximum 24-hour emission rate (lb/hr) for SO_2 (not paired in time) from the 2000-2004 baseline period for each source was identified through a review of the daily emission data for each BART-eligible unit from EPA's Air Markets Program Data[57], consistent with emissions identified by the sources for the CALPUFF modeling. Because daily emissions are not available for PM, PM emissions were estimated based on permit limits, maximum heat input and AP-42 factors, and/or stack testing.[58]

See Appendix A (CAMx) for a full summary of emissions modeled for the visibility impact analysis and visibility benefit analysis of controls. Below we describe the methodology applied to estimate the emission reductions anticipated from controls used for visibility modeling.

SO_2 emissions

As explained below and in more detail in the TSD, we determined that high level controls on all unscrubbed units of 95% control efficiency not to go below 0.06 lb/MMBtu for SDA and 98% control efficiency not to go below 0.04 lb/MMbtu for WFGD were achievable on these units. For low level controls, we evaluated DSI at the control efficiency identified by the source in their BART five-factor analysis. For high level controls, the 0.04 lb/MMBtu emission rate (or 0.06 lb/MMBtu in the case of SDA) was multiplied by the maximum heat input (MMBtu/hr).

UNC-IE assisted EPA in conducting two additional CAMx runs, with one run being based on using a low SO_2 control such as DSI (Run 4) and one run based on a high SO_2 control that would reflect SDA or wet FGD scrubbing (Run 3). For those units also modeled with CALPUFF, CAMx modeled SO_2 emissions rates are consistent with emission rates used in the CALPUFF modeling. The table below summarizes the SO_2 emissions provided to UNC-IE for the two control scenario CAMx runs and the baseline CAMx run. See Appendix A for a full summary of CAMx modeled emissions for these sources.

Nelson unit 4 is a primarily gas-fired unit and did not burn fuel oil during the baseline period and is not anticipated to burn fuel oil in the future so SO_2 emissions from these units were held at baseline levels for the two control scenarios. NRG Big Cajun II Unit 2 has converted to natural gas as required by a consent decree[59] so SO2 emissions from this unit in the control scenarios

[57] http://ampd.epa.gov/ampd

[58] A copy of the final version of each BART analysis performed by Trinity Consultants or CB&I on behalf of the BART sources can be found in the appendices of the submitted 2017 LA RH SIP.

[59] On March 6, 2013, Louisiana Generating entered a consent decree (CD) with EPA, the LDEQ, and others to resolve a complaint filed against Louisiana Generating for several violations of the CAA at Big Cajun II. *U.S. et al v. Louisiana Generating, LLC*, Civil Action No. 09-100-JJB-RLB (M.D. La.). Among other things, the CD requires

reflect this change in fuels. We note that due to an error in stack parameters for the basecase modeling run for Entergy Nelson units, the high control run (Run 3) utilized baseline emissions for Nelson. Results from run 3 represent baseline visibility impacts from the Nelson source/units.

Table 5.2-1. CAMx modeled SO_2 emission rates

Source	Unit	SO_2 (tons/day)		
		Base case (run 1) (2000-2004)	**Low control (run 4)**	**High Control (run 3)**
ENTERGY R.S. NELSON	Aux. Boiler	1.28	1.28	1.28*
ENTERGY R.S. NELSON	4	0.033	0.033	0.033*
ENTERGY R.S. NELSON	6	89.32	36.44	89.32*
NRG BIG CAJUN II	1	78.97	29.28	3.08
NRG BIG CAJUN II	2	73.11	0.13	0.13
CLECO Brame Nesbit	1	40.26	0.036	0.036
CLECO Brame Rodemacher	2	64.98	32.64	3.18

*Modeled at the baseline rate in the high control scenario. Nelson units were modeled with incorrect stack exit velocity in base case modeling. High control model results represent base case visibility impacts for these units

NOx and PM Emissions for CAMx modeling

NOx emissions were held constant at baseline emission levels for all emission units, with one exception, in order to isolate visibility improvements due to SO_2 reductions from any visibility benefits that would result from reductions in NOx emissions. Because NRG Big Cajun II unit 2 has been converted to natural gas as required by a consent decree[60], the emissions of SO2, NOx, and PM were adjusted to reflect this change in operation for this unit in both the high and low control scenarios.

Louisiana Generating to refuel Big Cajun II Unit 2 to natural gas, and install and continuously operate DSI at Big Cajun II Unit 1 and maintain a 30-Day Rolling Average Emission Rate for SO2 of no greater than 0.380 lb/mmBTU no later than April 15, 2015.

[60] On March 6, 2013, Louisiana Generating entered a consent decree (CD) with EPA, the LDEQ, and others to resolve a complaint filed against Louisiana Generating for several violations of the CAA at Big Cajun II. *U.S. et al v. Louisiana Generating, LLC*, Civil Action No. 09-100-JJB-RLB (M.D. La.). Among other things, the CD requires Louisiana Generating to refuel Big Cajun II Unit 2 to natural gas, and install and continuously operate DSI at Big Cajun II Unit 1 and maintain a 30-Day Rolling Average Emission Rate for SO2 of no greater than 0.380 lb/mmBTU no later than April 15, 2015.

For the high control scenarios for dry scrubbing and wet scrubbing retrofits for Big Cajun II unit 1 and Cleco Rodemacher unit 2, PM10 emissions were reduced by 50% to estimate an anticipated additional removal of PM. While this is not a refined estimate of the additional PM reduction anticipated for the control scenarios, PM emissions are already reduced significantly due to the existing ESP and/or baghouses and the visibility impact from direct PM emissions are a very small portion of the overall visibility impact due to the facilities emissions. Therefore, we do not anticipate a more refined approach to estimate PM emissions for these scenarios would significantly impact the modeling results. PM emissions were held at baseline emission rates for the low control scenario and for units with existing scrubbers.

6. Visibility Benefits of DSI, SDA, and Wet FGD for Coal-Fired Units

We evaluated the visibility benefits of DSI using CAMx using the control levels identified by the sources in their BART five-factor analyses included in the 2017 Louisiana Regional Haze SIP. We also evaluated the visibility benefits for scrubber retrofits for these same units. In evaluating the impacts and benefits of potential controls, we utilized a number of metrics, including change in deciviews and number of days impacted over 0.5 dv and 1.0 dv. Consistent with the BART Guidelines, the visibility impacts and benefits modeled in CALPUFF and CAMx are calculated as the change in deciviews compared against natural visibility conditions.[61]

For the CAMx modeling, the benefit is calculated as the difference between the maximum impact modeled for the baseline (Run 1) and the maximum impact level modeled under the two control scenarios (Run 3 and Run 4). The low control scenario (Run 4) estimates the visibility impacts and benefits from DSI level controls. The high control scenario (Run 3) estimates visibility impacts and benefits for WFGD/SDA level. Also summarized are the cumulative benefit and the number of days impacted over 0.5 and 1.0 dv. Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario summed across the 15 Class I areas included in the CAMx modeling. The baseline total cumulative number of days over 0.5 (1.0) dv is calculated as the sum of the number of modeled days at each of the 15 Class I area impacted over the threshold in the baseline modeling. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the 15 Class I areas included in the CAMx modeling for the baseline scenario subtracted by the number of days over the threshold for the control scenario. See Appendix B for CAMx modeled maximum impact at each Class I area for each model scenario. See Appendix C for CAMx modeled number of days over 0.5 and 1.0 dv at each Class I area for each model scenario for each source and individual units.

In addition to the metrics comparing the maximum impact level of the base case to the maximum impact level of the control case, and comparing the number of days impacted over the 0.5 dv and 1 dv threshold described above, to further inform the impacts and potential benefits of emission reductions we also reviewed the modeled potential impacts from CAMx on a broader set of days to assess the potential visibility benefits that could be anticipated due to controls during varying

[61] 40 CFR 51 Appendix Y, IV.D.5: "Calculate the model results for each receptor as the change in deciviews compared against natural visibility conditions."

meteorological/transport conditions. These varying conditions affect the reaction rates and transport of pollutants which can be simulated within the photochemical grid model. While the BART analysis is focused on examination of the maximum potential visibility impairment and benefits, these additional metrics provide a sense for the potential benefit across days other than just the maximum impact day. We reviewed additional information on impacts and benefit on a broader set of the highest impact days by showing the average impact across the top ten highest impacted days at each class I area under each modeled scenario. This shows the average impact and the benefits of controls over the ten days with meteorological/transport conditions that result in the largest visibility impacts. We also reviewed the annual average impacts and benefits under the control scenarios, over a wide set of days with different meteorological/transport conditions. In order to exclude days with very low impact due to transport conditions that do not result in transport and impacts to the Class I area, the annual average only includes days during the baseline modeled scenario with impacts greater than 0.1 dv.[62] Finally, we also examined the contribution to extinction from the unit due to each visibility impairing species[63] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas for the base case modeling scenario.[64],[65]

6.1. NRG Big Cajun II

As discussed in the 2017 Louisiana Regional Haze SIP revision, on March 6, 2013, Louisiana Generating entered a consent decree (CD) with EPA, the LDEQ, and others to resolve a complaint filed against Louisiana Generating for several violations of the CAA at Big Cajun II. *U.S. et al v. Louisiana Generating, LLC*, Civil Action No. 09-100-JJB-RLB (M.D. La.). Among other things, the CD requires Louisiana Generating to refuel Big Cajun II Unit 2 to natural gas, and install and continuously operate dry sorbent injection (DSI) at Big Cajun II Unit 1 while maintaining a 30-day rolling average emission rate of no greater than 0.380 lb of SO_2/MMBtu by no later than April 15, 2015.[66] Prior to the submittal of the 2017 Regional Haze SIP, the LDEQ and Louisiana Generating entered into an Agreed Order on Consent (AOC) that made these existing control requirements and maximum daily emission limits permanent and enforceable for BART. The AOC is included in Louisiana's 2017 Regional Haze SIP revision. Thus, if the EPA finalizes its proposed approval of this portion of the SIP submittal, the control requirements and emission limits will become permanent and federally enforceable for purposes of regional haze. As these controls were not installed to meet BART requirements, and existing enforceable

[62] See spreadsheet: "LA summary CAMx vis daily_Brame_Big_CajunII.xlsx" in the docket for this action for these and additional model results.
[63] Ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)
[64] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specifics extinction and total visibility impairment from each unit and subject-to-BART source. Similar data for the high control model results: "camx_v630.EPA-R6-2016.TX-BART.CAMxRun3.final.xlsx" and low control model results: "camx_v630.EPA-R6-2016.TX-BART.CAMxRun4.final.xlsx" are also available in the docket for this action.
[65] See spreadsheet: "LA summary CAMx vis daily_Brame_Big_CajunII.xlsx" in the docket for this action for these and additional model results.
[66] CD paragraph 62 in the docket for this rulemaking.

emission limits for Units 1 and 2 prevent the source from emitting at levels seen during the 2000-2004 baseline, LDEQ's screening modeling in the 2017 Regional Haze SIP submittal utilizes the current daily emission limits for these units in the AOC as representative of the anticipated 24-hr maximum emissions for screening modeling purposes. Revised CALPUFF screening modeling prepared by CB&I utilizing these emission limits is discussed in the CALPUFF Modeling TSD and demonstrate that the source has an impact less than the 0.5 dv threshold.[67]

Our CAMx modeling included modeling of a DSI control level for Unit 1 along with the conversion of Unit 2 to natural gas. However, this CAMx modeling did not utilize the NOx emission rate consistent with the AOC limit for unit 1. Instead the NOx emission rate modeled for this unit in the CAMx modeling was the higher 2000-2004 baseline NOx emission rate. Table 6.1-1 below provides a comparison between the emission rates utilized in the CALPUFF screening modeling consistent with the AOC limits and the emission rates modeled in the CAMx DSI control scenario. The SO2 emission rates modeled were the same in both modeling. The results of the DSI control scenario modeling is summarized in Table 6.1-2. CAMx modeling results show four Class I areas with maximum impacts greater than the 0.5 dv threshold, with two days impacted over 0.5 dv at Caney Creek and only one day above the threshold at the other three Class I areas. Examination of the contribution to extinction from the source for the DSI control scenario due to each visibility impairing species[68] in inverse megameters (Mm-1) on the ten highest impact days (see figures 6.1-1,6.1-2,6.1-3, and 6.1-4) show that the maximum impacted days at each Class I area have large impacts from nitrate. Had the CAMx modeling utilized the lower NOx emission rate consistent with the AOC limit (approximately 1/3 of the emission rate modeled), the nitrate impacts would be reduced such that maximum impacts at each Class I area can be anticipated to fall below the 0.5 dv threshold. We find that the results of the CAMx modeling provide additional support to the conclusion in the 2017 Louisiana Regional Haze SIP based on CALPUFF modeling that the anticipated impacts are below the 0.5 dv threshold and the source is not subject to BART.[69, 70]

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[67] Revised Baseline Modeling for Big Cajun II for BART Analysis, Prepared by CB&I, July 13, 2016. Available in Appendix C of the 2017 Louisiana Regional Haze SIP submittal

[68] Ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[69] See spreadsheet: "LA summary CAMx vis daily_Brame_Big_CajunII.xlsx" in the docket for this action for these and additional model results.

[70] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specifics extinction and total visibility impairment from each unit and subject-to-BART source. Similar data for the high control model results: "camx_v630.EPA-R6-2016.TX-BART.CAMxRun3.final.xlsx" and low control model results: "camx_v630.EPA-R6-2016.TX-BART.CAMxRun4.final.xlsx" are also available in the docket for this action.

Table 6.1-1. Comparison of modeled emissions for NRG Big Cajun II

	Unit	**NOx (lbs/hr)**	**SO_2 (lbs/hr)**
CD limits (CALPUFF Modeling)	**Unit 1**	963.00	2439.60
	Unit 2	963.00	10.79
DSI Control Scenario (CAMx)	**Unit 1**	2709.33	2439.60
	Unit 2	963.33	10.79

Table 6.1-2. EPA modeled anticipated visibility benefit due to DSI controls on Big Cajun Unit 1 and Unit 2 conversion to gas at most impacted Class I areas (CAMx)

Class I area	DSI Control level (maximum impact, dv)	# of Days impacted over 0.5 dv
Breton	**0.556**	**1**
Caney Creek	**0.775**	**2**
Mingo	**0.582**	**1**
Hercules-Glade	**0.605**	**1**

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Figure 6.1-1. Species Contribution (Mm-1) on ten highest impact days (DSI control case) at Caney Creek Class I area – Big Cajun II

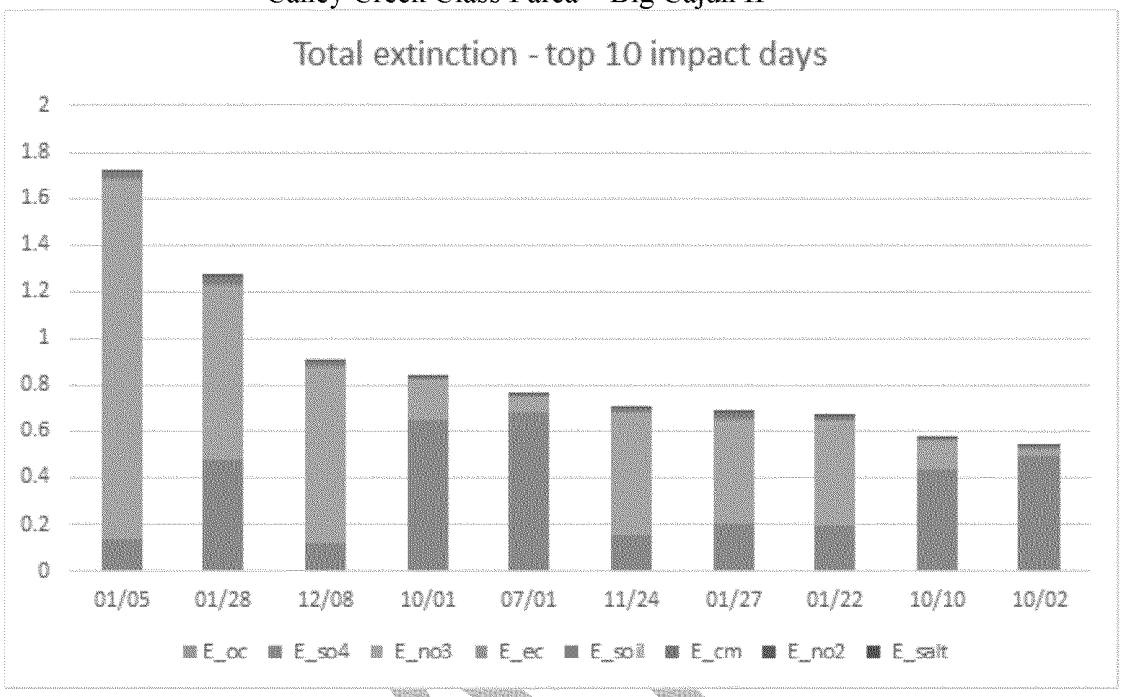


Figure 6.1-2. Species Contribution (Mm-1) on ten highest impact days (DSI control case) at Breton Class I area – Big Cajun II

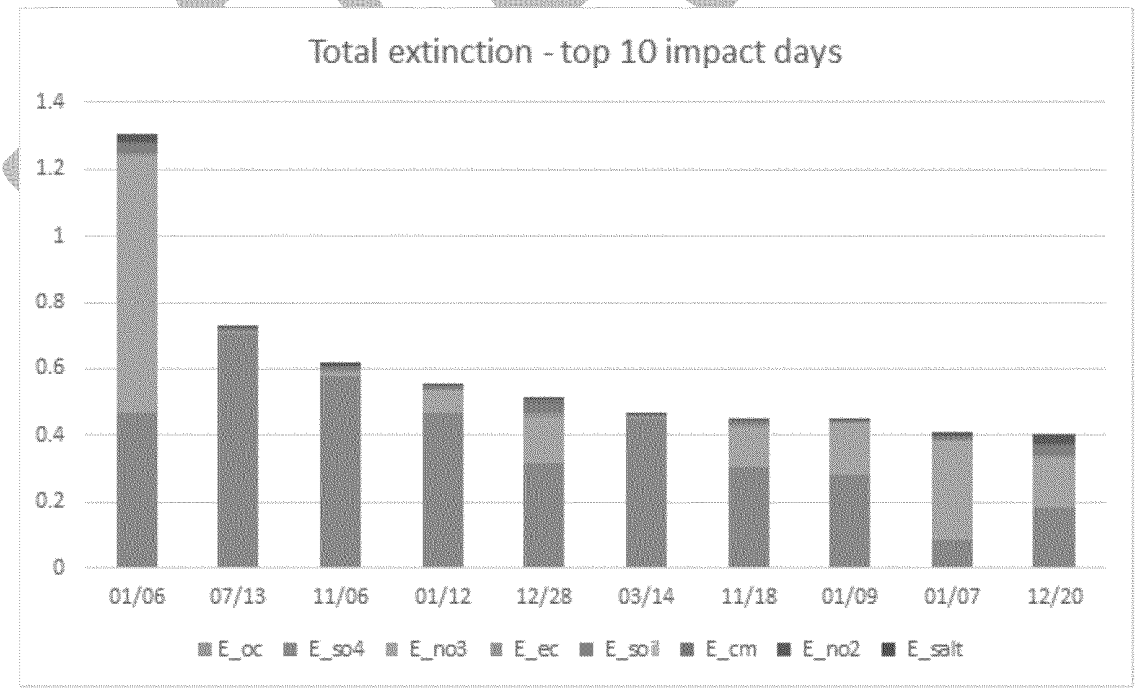


Figure 6.1-3. Species Contribution (Mm-1) on ten highest impact days (DSI control case) at Mingo Class I area – Big Cajun II

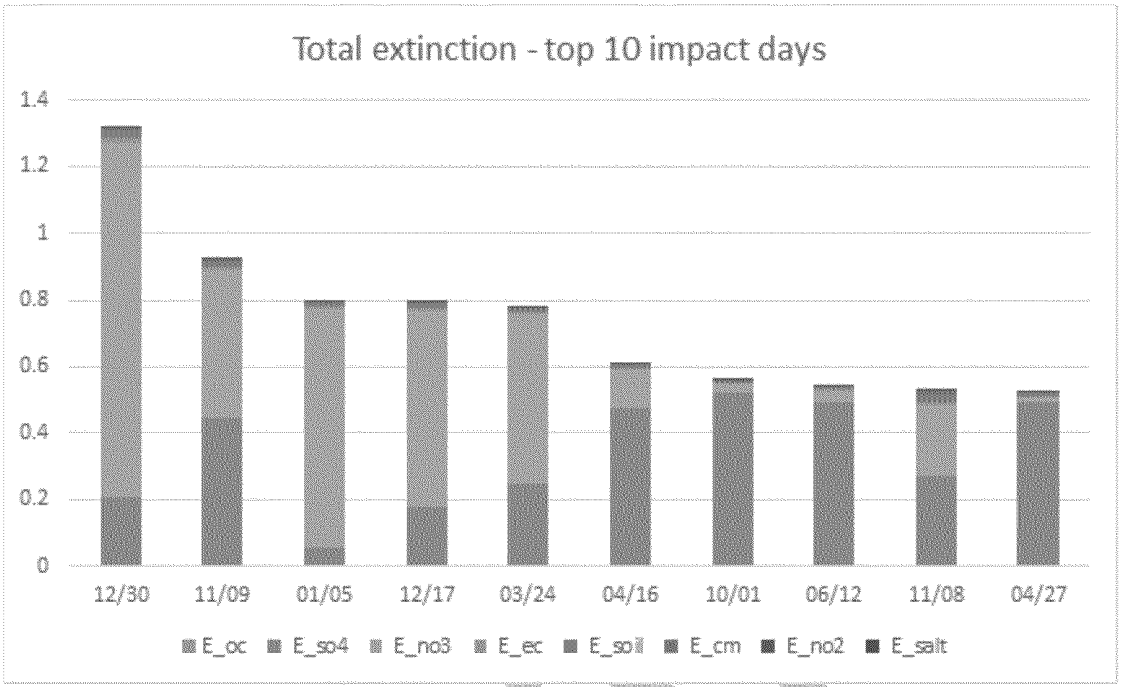
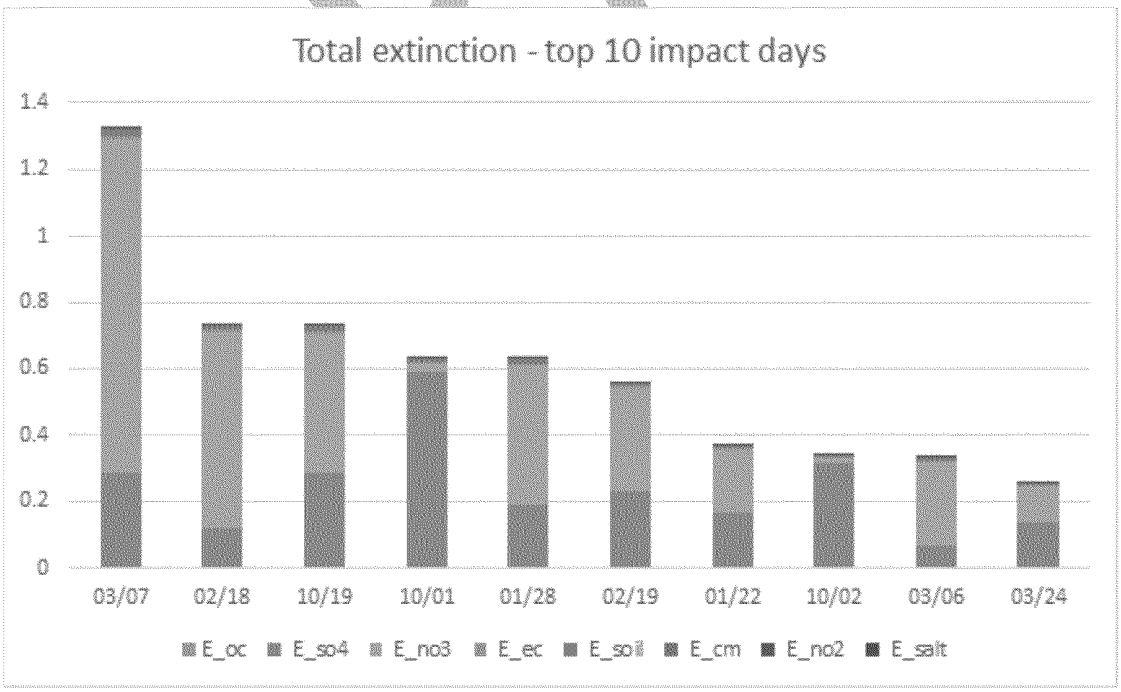


Figure 6.1-4. Species Contribution (Mm-1) on ten highest impact days (DSI control case) at Hercules Glade Class I area – Big Cajun II



6.2. Cleco Brame Energy Center

The CAMx modeled control scenarios for Cleco Nebbitt Unit 1 reflect the restriction to only burn natural gas consistent with the BART determination for this unit. No modeling evaluation of benefits of additional SO2 controls needed to be performed. The CAMx modeling analysis for Cleco Rodemacher Unit 2 evaluates the maximum baseline visibility impacts and potential benefits from two levels of controls, DSI at 0.41 lb/MMBtu and wet FGD at 0.04 lb/MMBtu, to supplement the CALPUFF modeling. [71, 72] The results of this modeling for the maximum impacts and the average across the top ten most impacted baseline days are summarized in the table below.

Table 6.2-1. Anticipated visibility benefit due to controls on Cleco Rodemacher Unit 2 (CAMx)

Class I area	Baseline Impact (dv) (maximum)	Baseline Impact (dv) (average top ten impacted days)	Visibility benefit of controls over baseline (dv) maximum impact		Visibility benefit of controls over baseline (dv) average top ten impacted days	
			DSI[73]	WFGD	DSI[74]	WFGD
Breton	0.713	0.315	0.187	0.399	0.117	0.271
Caney Creek	2.051	1.005	0.119	0.238	0.271	0.459

The CAMx-modeled visibility benefits of WFGD yield an additional 0.212 dv at Breton and 0.119 dv at Caney Creek over those from DSI for the most impacted day. Examining the top ten impacted days during the baseline period, the average benefit on this set of days of WFGD over DSI is 0.154 dv at Breton and 0.188 dv at Caney Creek. As enhanced DSI would reduce SO_2 emissions from an emission rate of 0.41 lb/MMBtu to 0.3 lb/MMBtu, enhanced DSI would lead to greater visibility benefits than DSI. Thus, the visibility benefits of WFGD compared to enhanced DSI would be smaller than those discussed above. The table below summarizes the number of days impacted over 0.5 dv and 1.0 dv for each modeled scenario. The largest difference between the two control scenarios is the elimination of 5 days over 0.5 dv at Caney Creek. We note however that the number of days impacted over 1.0 dv remains the same in both modeled control scenarios. The figures below show the modeled impacts for each modeled

[71] See spreadsheet: "LA summary CAMx vis daily_Brame_Big_CajunII.xlsx" in the docket for this action for these and additional model results.
[72] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specifics extinction and total visibility impairment from each unit and subject-to-BART source. Similar data for the high control model results: "camx_v630.EPA-R6-2016.TX-BART.CAMxRun3.final.xlsx" and low control model results: "camx_v630.EPA-R6-2016.TX-BART.CAMxRun4.final.xlsx" are also available in the docket for this action.
[73] DSI modeled at 0.41 lb/MMBtu, DSI and fabric filter are already installed and operational.
[74] DSI modeled at 0.41 lb/MMBtu, DSI and fabric filter are already installed and operational.

scenario for the maximum impacts, average across the top ten impacted days, and the annual average impacts (excluding days impacted less than 0.1 dv).

Table 6.2-2. EPA modeled visibility impact from Cleco Brame Rodemacher Unit 2at most impacted Class I areas – number of days impacted over 0.5 and 1.0 dv (CAMx)

Class I area	Baseline - # of days impacted over		DSI control - # of days impacted over		WFGD control- # of days impacted over	
	1 dv	0.5 dv	1 dv	0.5 dv	1 dv	0.5 dv
Breton	0	2	0	1	0	0
Caney Creek	3	15	2	7	2	2
Mingo	0	2	0	1	0	0
Upper Buffalo	1	7	1	1	0	1
Hercules-Glade	0	5	0	1	0	1
Wichita Mountains	0	1	0	0	0	0
Cumulative[75]	4	32	3	11	2	4

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[75] Cumulative benefit is calculated as the difference in the number of days impacted above the threshold from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.

Figure 6.2-1. Maximum CAMx modeled impact (dv) – Cleco Rodemacher Unit 2

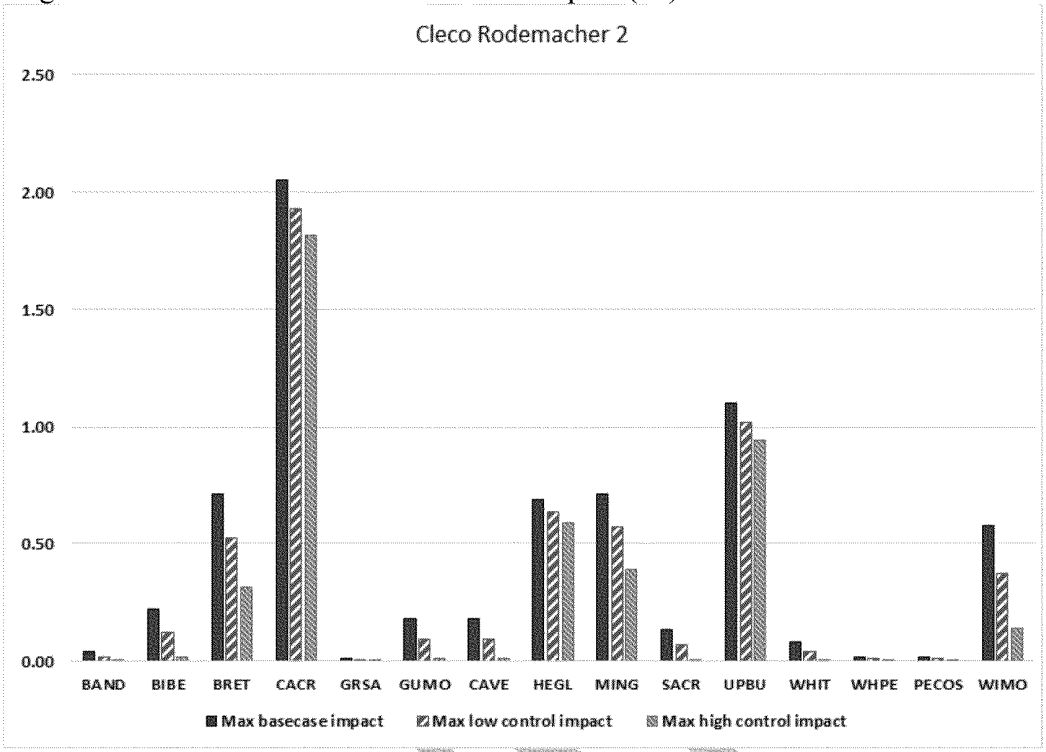


Figure 6.2-2. Average of top ten CAMx modeled impact (dv) – Cleco Rodemacher Unit 2

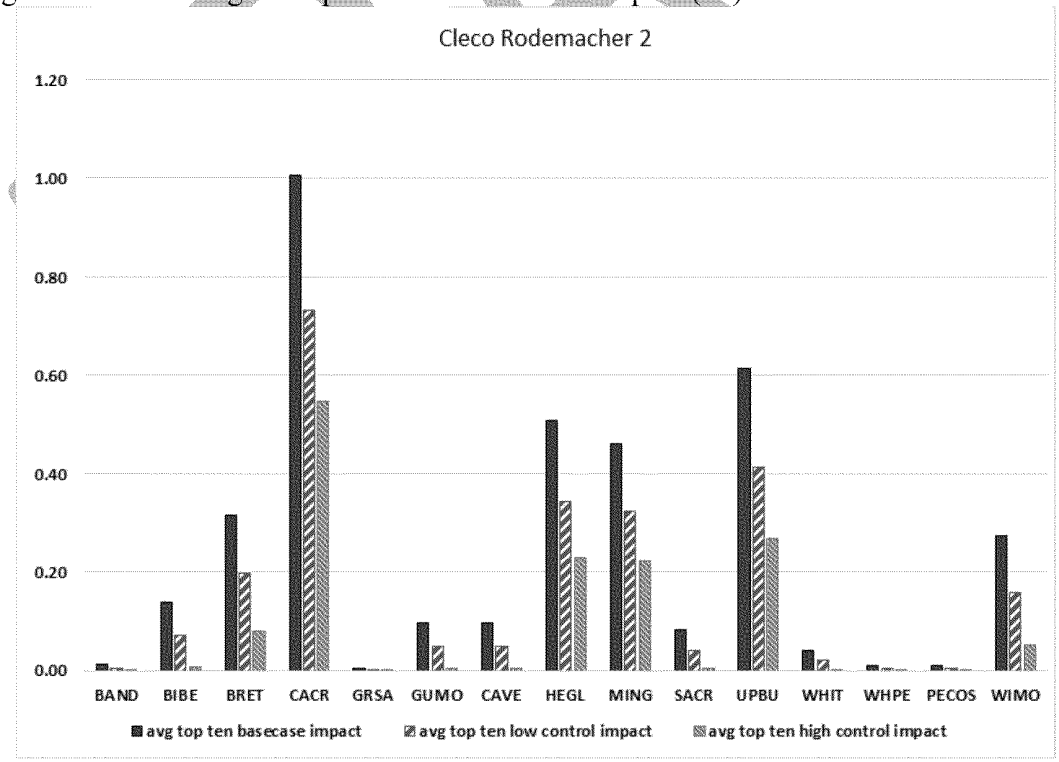
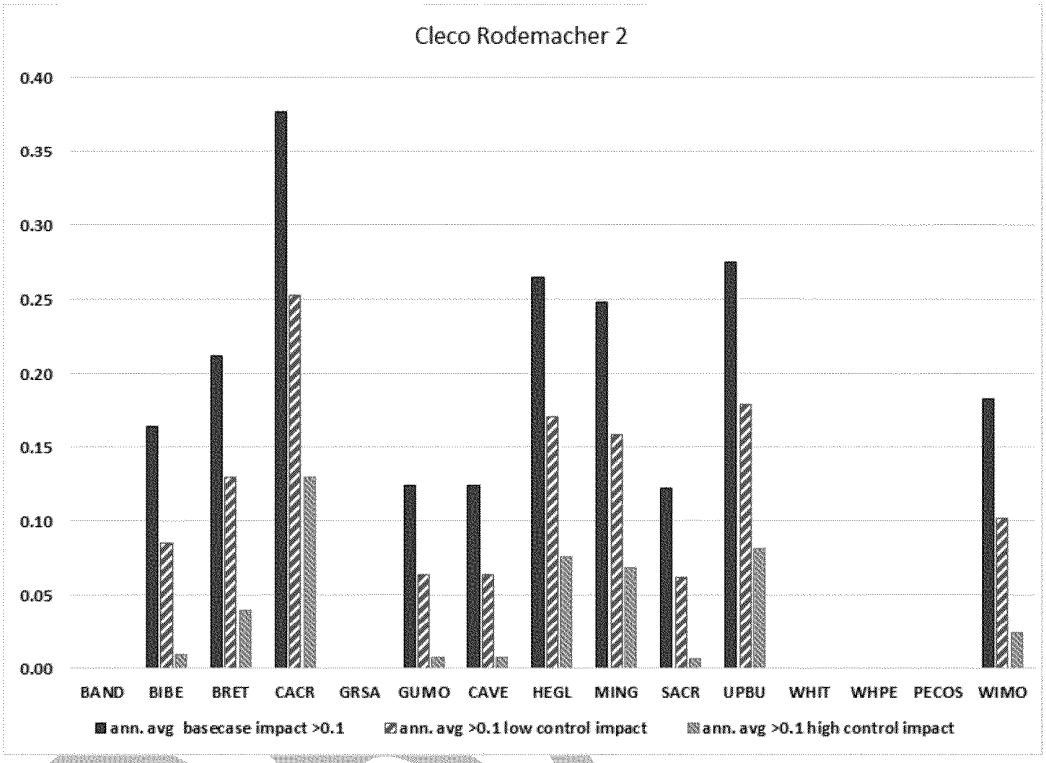


Figure 6.2-3. Annual Average CAMx modeled impact (dv) excluding baseline days impacted less than 0.1 dv – Cleco Rodemacher Unit 2



6.3. Entergy R.S. Nelson

EPA's CAMx modeling analysis for Nelson Unit 6 evaluates the maximum baseline visibility impacts and potential benefits from DSI at 0.47 lb/MMBtu, to supplement the CALPUFF modeling.[76, 77] In addition to the DSI modeled benefits, visibility benefits for SDA (0.06lb/MMBtu) and low-sulfur coal (0.6 lb/MMBtu) for the average of the top ten impacted days were estimated based on linear extrapolation using the modeled baseline and DSI visibility impacts.[78] The results of this modeling for the maximum impacts and the average across the top ten most impacted baseline days are summarized in the table below.

[76] See spreadsheet: "LA_summary CAMx vis daily.xlsx" in the docket for this action for these and additional model results.

[77] See results: "camx_v630.EPA-R6-2016.TX-BART.CAMxRun3.final.xlsx" for base case model results, including species specifics extinction and total visibility impairment from each unit and subject-to-BART source. Similar data for the low control model results: "camx_v630.EPA-R6-2016.TX-BART.CAMxRun4.final.xlsx" are also available in the docket for this action.

[78] See "Nelson CAMx LSC.xlsx" and "Nelson CAMx DFGD WFGD.xlsx"

Table 6.3-1 EPA modeled anticipated visibility benefit due to controls on Nelson Unit 6 at most impacted Class I areas (CAMx)

Class I area	Baseline Impact (dv) (maximum)	Baseline Impact (dv) (average top ten impacted days)	Visibility benefit of controls over baseline (dv) maximum impact	Visibility benefit of controls over baseline (dv) average top ten impacted days		
			DSI[79]	Low-Sulfur Coal[80]	DSI[81]	SDA[82]
Breton	**0.599**	**0.314**	0.250	0.133	0.165	0.266
Caney Creek	**2.179**	**1.302**	1.187	0.411	0.511	0.831
Mingo	**1.468**	**0.785**	0.370	0.215	0.265	0.430
Upper Buffalo	**1.219**	**0.934**	0.374	0.330	0.408	0.663
Hercules-Glade	**1.287**	**0.777**	0.473	0.273	0.338	0.548
Wichita Mountains	**0.575**	**0.412**	0.287	0.180	0.223	0.360
Cumulative[83]	**8.939**	**5.444**	3.869	---	2.437	---

The CAMx-modeled visibility benefits of DSI yield a 1.187 dv visibility benefit at Caney Creek over the baseline for the most impacted day. Due to the additional emission reductions that would result from use of SDA, the visibility benefit for the most impacted day would be larger than that from DSI (greater than 1.2 dv) at Caney Creek. Examining the top ten impacted days during the baseline period, the average benefit over this set of days of DSI is 0.511 dv at Caney Creek and 0.408 dv at Upper Buffalo. The estimated benefit from SDA over this set of days is 0.831 dv at Caney Creek and 0.663 dv at Upper Buffalo. Low sulfur coal benefits are estimated to be 0.411 dv at Caney Creek and 0.330 dv at Upper Buffalo over this same set of top ten impacted days.

[79] DSI at 0.47 lb/MMBtu
[80] Low-Sulfur Coal benefit (at 0.6 lb/MMBtu) estimated based on linear extrapolation of baseline and DSI visibility impacts at each Class I area
[81] DSI at 0.47 lb/MMBtu
[82] SDA benefit estimated based on linear extrapolation of baseline and DSI visibility impacts at each Class I area
[83] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.

The table below summarizes the number of days impacted over 0.5 dv and 1.0 dv for each modeled scenario. DSI level of control results in the elimination of all but one day where impacts are greater than 1 dv and decreases the number of days impacted over 0.5 dv from 69 to 23. Additional reduction in number of days impacted over 0.5 dv is anticipated with SDA level controls given the significant additional reduction in emissions and the estimated benefits discussed above.

Table 6.3-2 EPA modeled anticipated visibility benefit due to controls on Nelson Unit 6 at most impacted Class I areas – number of days impacted over 0.5 and 1.0 dv (CAMx)

Class I area	Baseline - # of days impacted over		DSI - # of days impacted over	
	1 dv	0.5 dv	1 dv	0.5 dv
Breton	0	1	0	0
Caney Creek	6	30	0	11
Mingo	1	9	1	5
Upper Buffalo	4	18	0	5
Hercules-Glade	1	9	0	2
Wichita Mountains	0	2	0	0
Cumulative[84]	12	69	1	23

The figures below (Figures 6.3-1, 6.3-2, and 6.3-3) show the modeled impacts for each modeled scenario for the maximum impacts, average across the top ten impacted days, and the annual average impacts (excluding days impacted less than 0.1 dv). Figure 6.3-4 shows the contribution to extinction from the source for the base case scenario due to each visibility impairing species[85] in inverse megameters (Mm-1) on the ten highest impact days.

[84] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across 15 Class I areas included in the CAMx modeling.

[85] Ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

Figure 6.3-1. Maximum CAMx modeled impact (dv) – Entergy Nelson Unit 6

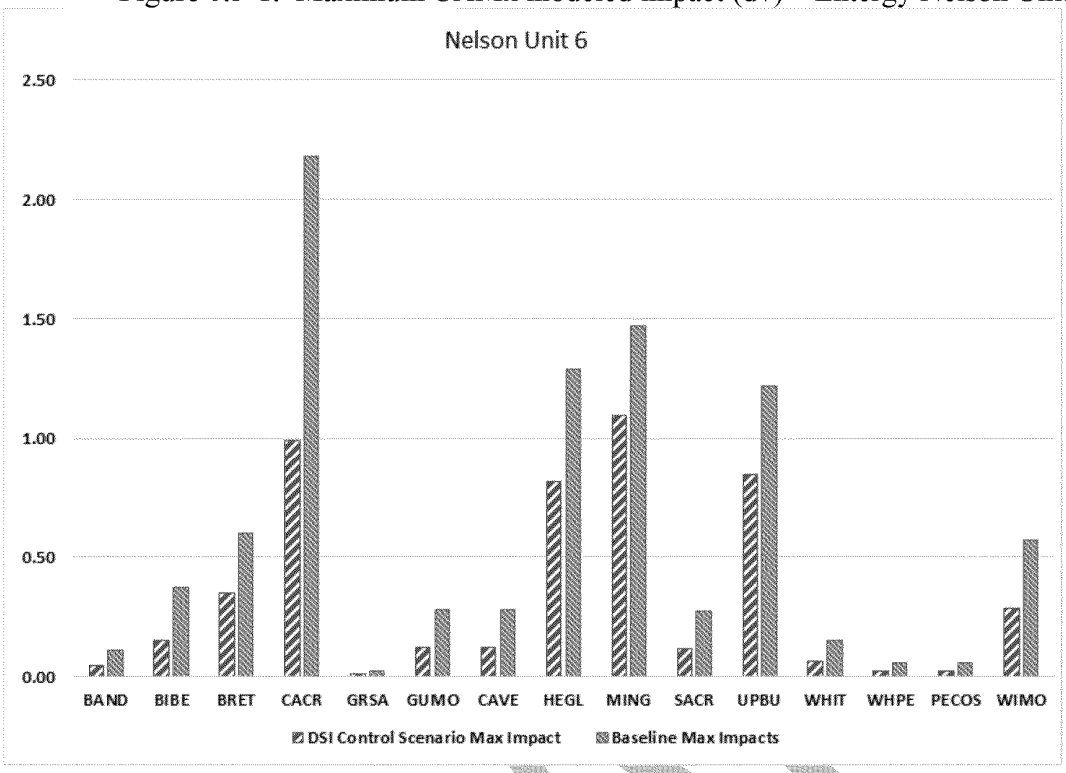


Figure 6.3-2. Average of top ten CAMx modeled impact (dv) – Entergy Nelson Unit 6

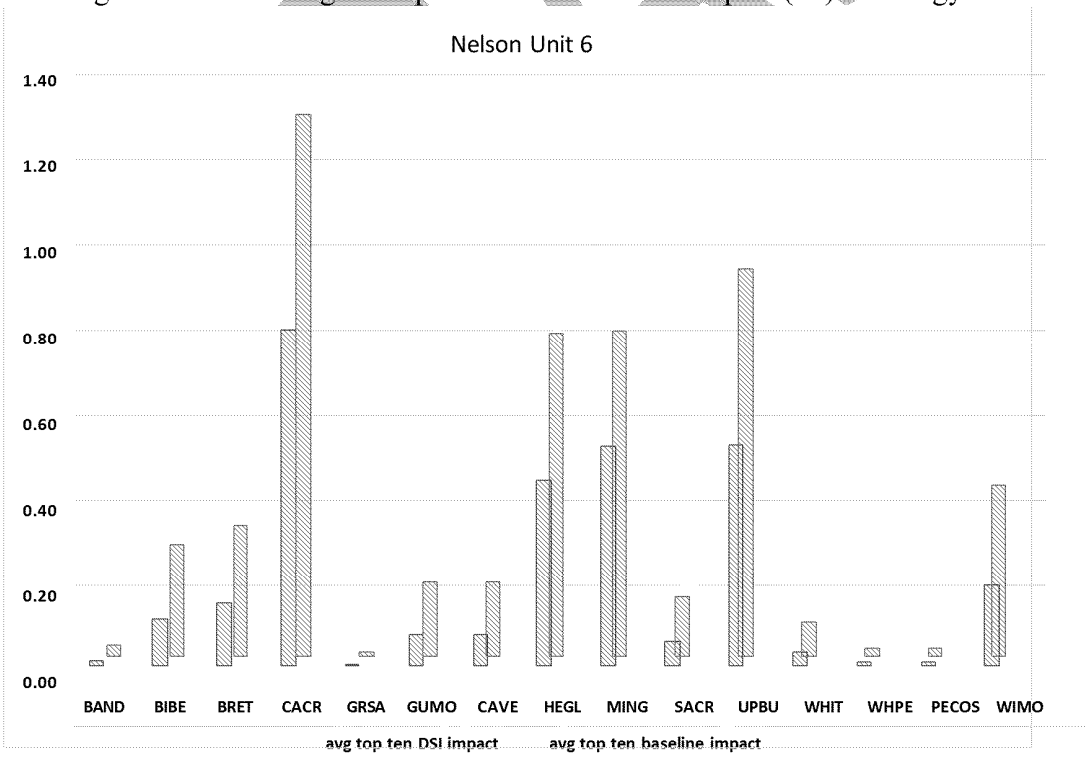


Figure 6.3-3. Annual Average CAMx modeled impact (dv) excluding baseline days impacted less than 0.1 dv – Entergy Nelson Unit 6

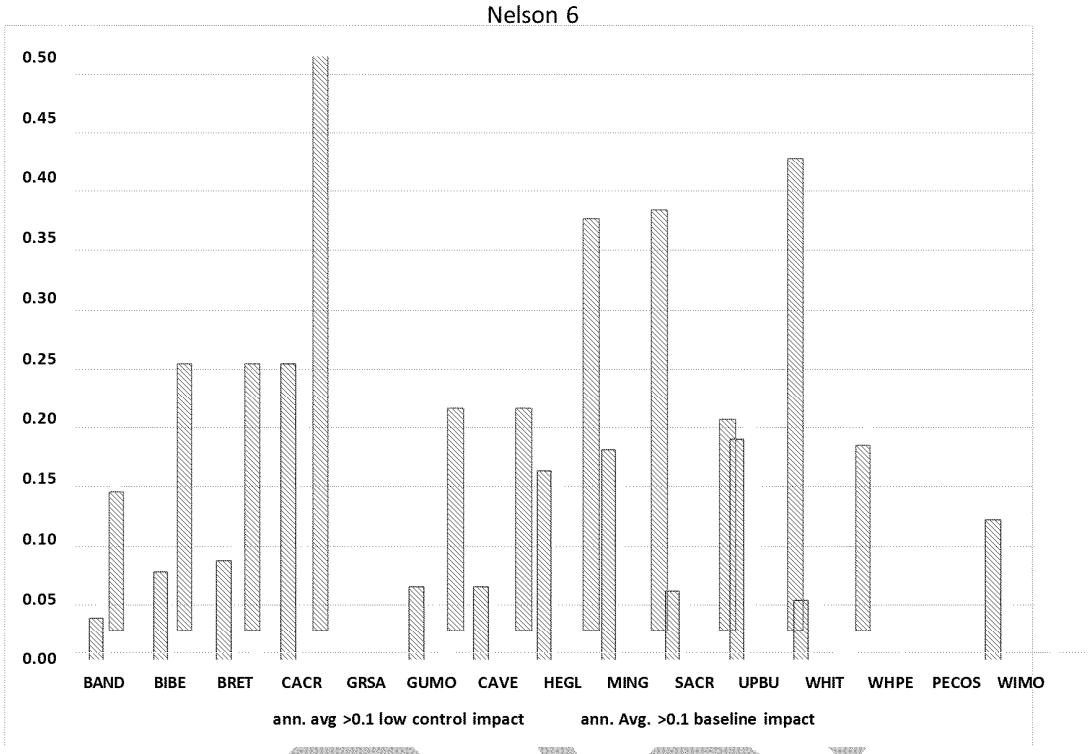


Figure 6.3-4. Species Contribution (Mm-1) on ten highest impact days (base case) at Caney Creek Class I area – Nelson Unit 6

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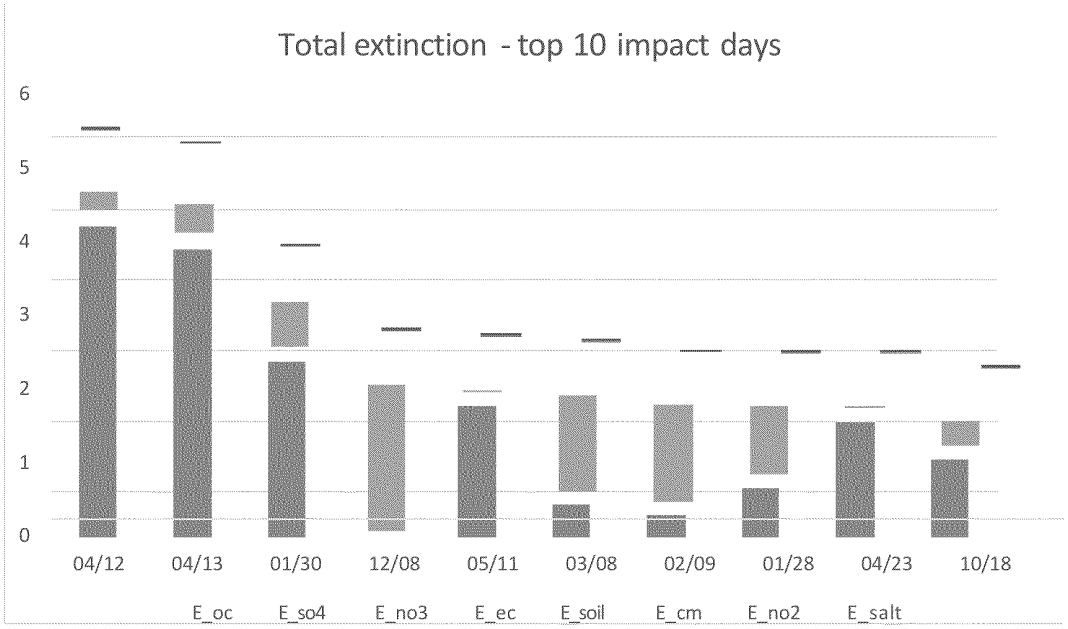
Total extinction - top 10 impact days
6
5
4
3
2
1
0
04/12
04/13
01/30
12/08
05/11
03/08
02/09
01/28
04/23
10/18
E_oc
E_so4
E_no3
E_ec
E_soil
E_cm
E_no2
E_salt

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Note: Modeling files (CALPUFF and CAMx) are large and due to size and/or file type cannot be added to the electronic docket available at www.regulations.gov. Electronic files are available upon request. Contact Erik Snyder (Snyder.erik@epa.gov 214-665-7305) or Michael Feldman (Feldman.Michael@epa.gov 214-665-9793).

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Appendix A. Modeled parameters: Stack and emissions for CAMx modeled sources

Table A-1. Base Case (Run 1)

PLANT NAME	BOILER ID	Height (ft)	Diameter (ft)	Exit Temp (F)	Flow Rate (ft3/sec)	Exit Velocity (ft/s)	SO_2 Max Day (tpy)	NOx Max Day (tpy)	PM10 Max Day (tpy)	PM 2.5 Max Day
ENTERGY R.S. NELSON	6	500	23	277	4111.124	9.9	89.32	69.92	4.146	3.127
ENTERGY R.S. NELSON	4	400	19	300	2550.465	9	0.033	9.561	0.310	0.310
ENTERGY R.S. NELSON	0	196	10	301	392.5	5	1.28	0.68	0.101	0.101
NRG BIG CAJUN II	2B1	600	26.5	325	30666.67	53.53	78.974	32.512	8.721	5.214
NRG BIG CAJUN II	2B2	600	26.5	325	30666.67	53.53	73.118	33.632	7.638	4.567
CLECO Brame Nesbit	1	195	16.9	287	21613.82	74.61	40.26	15.86	0.334	0.334
CLECO Brame Rodemacher	2	266	18	307	36000	118	64.98	39.58	1.756	0.529

Table A-2. Low Control Scenario (Run 4)

PLANT NAME	BOILER ID	Height (ft)	Diameter (ft)	Exit Temp (F)	Flow Rate (ft3/sec)	Exit Velocity (ft/s)	SO_2 Max Day (tpy)	NOx Max Day (tpy)	PM10 Max Day (tpy)	PM 2.5 Max Day
ENTERGY R.S. NELSON	6	500	23	277	41132.1	99	36.44	69.92	4.146	3.127
ENTERGY R.S. NELSON	4	400	19	300	25517.6	90	0.033	9.561	0.310	0.310
ENTERGY R.S. NELSON	0	196	10	301	3926.99	50	1.28	0.68	0.101	0.101
NRG BIG CAJUN II	2B1	600	26.5	316.2	36407.5	66.01	29.28	32.512	8.721	5.214
NRG BIG CAJUN II	2B2	600	26.5	304.97	33114.8	60.04	0.13	11.56	0	0.143

CLECO Brame Nesbit	1	195	16.9	287	21613.82	74.61	0.036	15.86	0.334	0.334
CLECO Brame Rodemacher	2	266	18	307	36000	118	32.64	39.58	1.756	0.529

Table A-3. High Control Scenario Run 3

PLANT NAME	BOILER ID	Height (ft)	Diameter (ft)	Exit Temp (F)	Flow Rate (ft3/sec)	Exit Velocity (ft/s)	SO_2 Max Day (tpy)	NOx Max Day (tpy)	PM10 Max Day (tpy)	PM 2.5 Max Day
ENTERGY R.S. NELSON	6	500	23	277	41132.1	99	89.32	69.92	4.146	3.127
ENTERGY R.S. NELSON	4	400	19	300	25517.6	90	0.033	9.561	0.310	0.310
ENTERGY R.S. NELSON	0	196	10	301	3926.99	50	1.28	0.68	0.101	0.101
NRG BIG CAJUN II	2B1	600	26.5	125	25316	45.9	3.08	32.512	4.36	2.607
NRG BIG CAJUN II	2B2	600	26.5	304.97	33114.8	60.04	0.13	11.56	0	0.143
CLECO Brame Nesbit	1	195	16.9	287	21613.82	74.61	0.036	15.86	0.334	0.334
CLECO Brame Rodemacher	2	266	18	307	36000	118	3.18	39.58	0.878	0.264

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Appendix B. CAMx Maximum Impact at each Class I Area

Table B-1. Base Case (Run 1) Maximum Impact*

Class I Area	Big Cajun II 1	Big Cajun II 2	Cleco Nesbitt 1	Cleco Rodemacher 2
BAND	0.038	0.035	0.022	0.038
BIBE	0.167	0.154	0.129	0.224
BRET	0.885	0.818	0.398	0.713
CACR	0.851	0.815	0.935	2.051
CAVE	0.148	0.137	0.107	0.181
GRSA	0.011	0.010	0.005	0.009
GUMO	0.148	0.137	0.107	0.181
HEGL	0.708	0.657	0.419	0.687
MING	0.649	0.615	0.420	0.711
PECO	0.037	0.035	0.012	0.020
SACR	0.103	0.096	0.085	0.135
UPBU	0.751	0.700	0.524	1.102
WHIT	0.062	0.057	0.049	0.082
WHPE	0.037	0.035	0.012	0.020
WIMO	0.393	0.366	0.322	0.578
Cumulative	4.991	4.668	3.545	6.733

* Entergy Nelson modeled impacts not shown for Run 1. Run 1 included incorrect stack parameters for these units

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Table B-2. High Control (Run 3) Maximum Impact

Class I Area	Big Cajun II 1	Big Cajun II 2	Cleco Nesbitt 1	Cleco Rodemacher 2	Nelson Aux. Boiler*	Nelson Unit 4*	Nelson Unit 6*
BAND	0.001	0.000	0.000	0.002	0.001	0.001	0.111
BIBE	0.008	0.001	0.002	0.015	0.005	0.002	0.373
BRET	0.289	0.095	0.122	0.314	0.007	0.028	0.599
CACR	0.530	0.189	0.765	1.813	0.034	0.125	2.179
CAVE	0.008	0.001	0.002	0.011	0.003	0.002	0.279
GRSA	0.000	0.000	0.000	0.001	0.000	0.000	0.024
GUMO	0.008	0.001	0.002	0.011	0.003	0.002	0.279
HEGL	0.238	0.111	0.231	0.587	0.018	0.100	1.287
MING	0.417	0.136	0.170	0.391	0.018	0.147	1.468
PECO	0.001	0.000	0.000	0.001	0.001	0.000	0.060
SACR	0.005	0.000	0.001	0.008	0.004	0.001	0.276
UPBU	0.242	0.070	0.377	0.947	0.019	0.107	1.219
WHIT	0.002	0.000	0.000	0.004	0.002	0.001	0.152
WHPE	0.001	0.000	0.000	0.001	0.001	0.000	0.060
WIMO	0.038	0.010	0.043	0.139	0.008	0.017	0.575
Cumulative	1.790	0.615	1.716	4.245	0.124	0.533	8.939

* Entergy Nelson modeled impacts for Run 3 are the corrected base case impacts, not high control scenario impacts

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Table B-3. Low Control (Run 4) Maximum Impact

Class I Area	Big Cajun II 1	Big Cajun II 2	Cleco Nesbitt 1	Cleco Rodemacher 2	Nelson Aux. Boiler	Nelson Unit 4	Nelson Unit 6
BAND	0.014	0.000	0.000	0.020	0.001	0.001	0.049
BIBE	0.063	0.001	0.002	0.121	0.005	0.002	0.151
BRET	0.469	0.092	0.115	0.527	0.007	0.027	0.349
CACR	0.596	0.188	0.765	1.933	0.034	0.123	0.992
CAVE	0.057	0.001	0.002	0.093	0.003	0.002	0.121
GRSA	0.004	0.000	0.000	0.005	0.000	0.000	0.010
GUMO	0.057	0.001	0.002	0.093	0.003	0.002	0.121
HEGL	0.493	0.117	0.230	0.635	0.018	0.100	0.814
MING	0.452	0.136	0.167	0.573	0.018	0.145	1.099
PECO	0.014	0.000	0.000	0.011	0.001	0.000	0.026
SACR	0.039	0.000	0.001	0.070	0.004	0.001	0.114
UPBU	0.373	0.070	0.377	1.022	0.019	0.107	0.845
WHIT	0.024	0.000	0.001	0.042	0.002	0.001	0.066
WHPE	0.014	0.000	0.000	0.011	0.001	0.000	0.026
WIMO	0.160	0.010	0.040	0.372	0.008	0.016	0.288
Cumulative	2.829	0.616	1.702	5.525	0.123	0.525	5.070

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Appendix C. CAMx Modeled Number of Days impacted

Table C-1. Base Case (Run 1) Number of days impacted over 0.5 dv*

Class I Area	Big Cajun II (Units 1 & 2)	Big Cajun II 1	Big Cajun II 2	Cleco Brame (Nesbitt & Rodemacher)	Cleco Nesbitt 1	Cleco Rodemacher 2
BAND	0	0	0	0	0	0
BIBE	0	0	0	0	0	0
BRET	16	4	2	2	0	2
CACR	17	6	6	30	6	15
CAVE	0	0	0	0	0	0
GRSA	0	0	0	0	0	0
GUMO	0	0	0	0	0	0
HEGL	9	3	2	14	0	5
MING	22	7	7	15	0	2
PECO	0	0	0	0	0	0
SACR	0	0	0	0	0	0
UPBU	11	2	2	14	1	7
WHIT	0	0	0	0	0	0
WHPE	0	0	0	0	0	0
WIMO	4	0	0	4	0	1
Cumulative	79	22	19	79	7	32

* Entergy Nelson modeled impacts not shown for Run 1. Run 1 included incorrect stack parameters for these units

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Table C-2. Base Case (Run 1) Number of days impacted over 1 dv*

Class I Area	Big Cajun II (Units 1 & 2)	Big Cajun II 1	Big Cajun II 2	Cleco Brame (Nesbitt & Rodemacher)	Cleco Nesbitt 1	Cleco Rodemacher 2
BAND	0	0	0	0	0	0
BIBE	0	0	0	0	0	0
BRET	2	0	0	1	0	0
CACR	6	0	0	10	0	3
CAVE	0	0	0	0	0	0
GRSA	0	0	0	0	0	0
GUMO	0	0	0	0	0	0
HEGL	2	0	0	1	0	0
MING	7	0	0	1	0	0
PECO	0	0	0	0	0	0
SACR	0	0	0	0	0	0
UPBU	2	0	0	3	0	1
WHIT	0	0	0	0	0	0
WHPE	0	0	0	0	0	0
WIMO	0	0	0	0	0	0
Cumulative	19	0	0	16	0	4

* Entergy Nelson modeled impacts not shown for Run 1. Run 1 included incorrect stack parameters for these units

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Table C-3. High Control (Run 3) Number of days impacted over 0.5 dv*

Class I Area	Big Cajun II (Units 1 & 2)	Big Cajun II 1	Big Cajun II 2	Cleco Brame (Nesbitt & Rodemacher)	Cleco Nesbitt 1	Cleco Rodemacher 2	Entergy Nelson (Aux. Boiler, Units 4 & 6)	Nelson Aux. Boiler	Nelson Unit 4	Nelson Unit 6
BAND	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	1	0	0	1
CACR	1	1	0	4	1	2	31	0	0	30
CAVE	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	1	0	1	11	0	0	9
MING	1	0	0	1	0	0	11	0	0	9
PECO	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	1	0	1	20	0	0	18
WHIT	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	2	0	0	2
Cumulative	2	1	0	7	1	4	76	0	0	69

* Entergy Nelson modeled impacts for Run 3 are the corrected base case impacts, not high control scenario impacts

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Table C-4. High Control (Run 3) Number of days impacted over 1 dv*

Class I Area	Big Cajun II (Units 1 & 2)	Big Cajun II 1	Big Cajun II 2	Cleco Brame (Nesbitt & Rodemacher)	Cleco Nesbitt 1	Cleco Rodemacher 2	Entergy Nelson (Aux. Boiler, Units 4 & 6)	Nelson Aux. Boiler	Nelson Unit 4	Nelson Unit 6
BAND	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	2	0	2	9	0	0	6
CAVE	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	2	0	0	1
MING	0	0	0	0	0	0	1	0	0	1
PECO	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	1	0	0	5	0	0	4
WHIT	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	0	0	0	0
Cumulative	0	0	0	3	0	2	17	0	0	12

* Entergy Nelson modeled impacts for Run 3 are the corrected base case impacts, not high control scenario impacts

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Table C-5. Low Control (Run 4) Number of days impacted over 0.5 dv

Class I Area	Big Cajun II (Units 1 & 2)	Big Cajun II 1	Big Cajun II 2	Cleco Brame (Nesbitt & Rodemacher)	Cleco Nesbitt 1	Cleco Rodemacher 2	Entergy Nelson (Aux. Boiler, Units 4 & 6)	Nelson Aux. Boiler	Nelson Unit 4	Nelson Unit 6
BAND	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0
BRET	1	0	0	1	0	1	0	0	0	0
CACR	2	1	0	10	1	7	16	0	0	11
CAVE	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0
HEGL	1	0	0	2	0	1	4	0	0	2
MING	1	0	0	2	0	1	6	0	0	5
PECO	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	2	0	1	6	0	0	5
WHIT	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	0	0	0	0
Cumulative	5	1	0	17	1	11	32	0	0	23

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Table C-6. Low Control (Run 4) Number of days impacted over 1 dv

Class I Area	Big Cajun II (Units 1 & 2)	Big Cajun II 1	Big Cajun II 2	Cleco Brame (Nesbitt & Rodemacher)	Cleco Nesbitt 1	Cleco Rodemacher 2	Entergy Nelson (Aux. Boiler, Units 4 & 6)	Nelson Aux. Boiler	Nelson Unit 4	Nelson Unit 6
BAND	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	2	0	2	3	0	0	0
CAVE	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	0
MING	0	0	0	0	0	0	1	0	0	1
PECO	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	1	0	1	0	0	0	0
WHIT	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	0	0	0	0
Cumulative	0	0	0	3	0	3	4	0	0	1

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STATE OF LOUISIANA
DEPARTMENT OF ENVIRONMENTAL QUALITY

OFFICE OF ENVIRONMENTAL ASSESSMENT

IN THE MATTER OF	*	
	*	
ENTERGY LOUISIANA, LLC	*	**REGIONAL HAZE**
R.S. NELSON GENERATING PLANT	*	**STATE IMPLEMENTATION PLAN**
CALCASIEU PARISH, LOUISIANA	*	**EGU BART ANALYSIS**
	*	
	*	**AGENCY INTEREST NO. 19588**
	*	
PROCEEDINGS UNDER THE LOUISIANA	*	
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 **ENTERGY LOUISIANA, LLC (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 the R. S. Nelson Generating Plant located at 3500 Houston River Road, Westlake, Calcasieu Parish, Louisiana (Facility). The Facility currently operates pursuant to Title V and PAL Permit Number 6250-00014-V4 issued on April 11, 2017.

II.

Under Clean Air Act (CAA) section 110, each state must prepare and submit for the EPA approval, a 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 is concurrently submitting a proposed SIP on behalf of the State of Louisiana to EPA Region VI that addresses Best Available Retrofit Technology (BART) for the Facility. The BART analysis is based in part on submittals made by RESPONDENT to the Department on May 12, 2015.

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 no later than the effective date of a final SIP pursuant to 40 CFR PART 51, Appendix Y:

> Before fuel oil firing is allowed to take place at Unit 4 and the auxiliary boiler at the Facility, a revised BART determination must be promulgated for SO_2 and PM for the fuel oil firing scenario through a FIP or an action by the LDEQ as a SIP revision and approved by EPA such that the action is federally enforceable.

II.

The Respondent shall comply with the sulfur dioxide (SO2) emission limitations set forth below as expeditiously as practicable, but no later than three years of the effective date of a final SIP pursuant to 40 CFR PART 51, Appendix Y:

Unit	**Pollutant**	**Emission Limit lb/ MMBtu (30-day rolling average)**
6	**SO_2**	**0.6**

III.

The Respondent shall comply with the particulate matter less than 10 microns (PM10) emissions limit set forth below no later than the effective date of a final SIP pursuant to 40 CFR PART 51, Appendix Y:

Unit 6

Unit	**Pollutant**	**Emission Limit lb/hr (30-day rolling average)**
6	**PM_{10}**	**317.61**

IV.

The Respondent shall continue to comply with all reporting and record keeping requirements contained within all applicable permits.

V.

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*.

VI.

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.

VII.

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.

VIII.

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.

IX.

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 State 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** 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 **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**.

X.

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 _____ day of June, 2017.

_____
Chuck Carr Brown, Ph.D.
Secretary

Entergy Louisiana LLC

By:_____ Date:_____

Name:

Title: President

Technical Assistance Document

for the Louisiana State Implementation Plan for the Entergy Nelson Facility

June 2017

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Louisiana Regional Haze BART Technical Assessment Document

1 Introduction

The purpose of this Technical Assessment Document (TAD) is to provide technical and supplementary information for consideration by Louisiana in its revision to the State Implementation Plan (SIP) revision, submitted by the Louisiana Department of Environmental Quality (LDEQ) on February 10, 2017 to address BART requirements at the Entergy Nelson facility. This document does not represent EPA's final determination concerning BART for the Nelson facility. We will address LDEQ's SIP submittal for BART for the Nelson facility separately through full notice and comment rulemaking.

2 Best Available Retrofit Technology (BART)

2.1 Overview of Our Previous Proposal as it Relates to the Nelson Facility

States are required to identify all BART-eligible sources within their boundaries by utilizing the three eligibility crieteria in the BART Guidelines (70 FR 39103, 39158, March 6, 2005) and the Regional Haze regulations (40 CFR 51.301). Because Louisiana's 2008 Regional Haze SIP relied on CAIR as better than BART for EGUs, that submittal did not include a determination of which BART-eligible EGUs were subject to BART.

2.2 Information Relating to the Subject to BART Determination for Nelson

The LDEQ submitted a revised SIP submittal on February 10, 2017, that evaluates BART-eligible EGUs in the State and provides a BART determination for each such source for all visibility impairing pollutants except NO_x.

In Louisiana's initial 2008 Regional Haze SIP submittal, the LDEQ used a contribution threshold of 0.5 dv for determining which sources are subject to BART, and we approved this threshold in our previous action.[1] In our separate proposal (82 FR 22936 (May 19, 2017)), we proposed to find that the use of the same threshold is appropriate for these EGU sources. Our CAMx modeling indicates that the Nelson source has a maximum impact of 2.22 dv at Caney Creek, with 31 days out of the 365 days modeled exceeding 0.5 dv, and 9 days exceeding 1.0 dv.[2] Both CALPUFF and our CAMx modeling support the conclusion that Nelson is subject to BART.

2.3 NOx BART for the Nelson Facility

Separately, we have proposed to find that the NO_X BART requirements for EGUs in Louisiana will be satisfied by our determination, proposed for separate finalization, that Louisiana's

[1] See, 77 FR 11839, 11849 (February 28, 2012).
[2] We note that CALPUFF modeling also estimates impacts from the Nelson source to be above the threshold.

participation in CSAPR's ozone-season NO_X program is a permissible alternative to source-specific NO_X BART. 82 FR 22936 (May 19, 2017). We noted that we cannot finalize this portion of the proposed SIP approval unless and until we finalize the proposed finding that CSAPR continues to be better than BART[3] because finalization of that proposal provides the basis for Louisiana to rely on CSAPR participation as an alternative to source-specific EGU BART for NO_X.

3 Our Analysis of Louisiana's SO_2 BART Determinations for the Nelson Unit 6

Louisiana incorporated the BART analyses Entergy prepared for the Nelson Unit 6 into its SIP.[4] This analyses includes consideration of two types of SO_2 scrubbers: Spray Dryer Absorber (SDA) and wet Flue Gas Desulfurization (wet FGD), Dry Sorbent Injection (DSI), enhanced DSI, and lower sulfur coal. Below we provide our analysis of Entergy's control-cost analyses, and provide our own control cost analyses. We also address how we believe our control cost analyses addresses the BART five factors.

3.1 Identification of Technically Feasible SO_2 Control Technologies for Nelson Unit 6

Energy Information Agency (EIA) data indicates that the Nelson Unit 6 primarily burns subbituminous coal, but also burns significant quantities of Distilled Fuel Oil (DFO).[5] Available SO_2 control technologies for coal-fired EGUs consist of either pretreating the coal in order to improve its qualities, or treating the flue gas through the installation of either DSI or some type of scrubbing technology. In addition, we are aware of instances in which FGDs of various types have been installed or otherwise deemed feasible on a boiler that burns oil either primarily or secondarily.[6] Consequently, we will consider the installation of various types of scrubbers to be technically feasible for either coal or fuel oil for this unit. We also will consider the use of low sulfur coal to be technically feasible for this unit.

3.1.1 Coal Pretreatment

Coal pretreatment, or upgrading, has the potential to reduce emissions by reducing the amount of coal that must be burned in order to result in the same heat input to the boiler and by reducing the

---

[3] 81 FR 78954.

[4] Entergy BART Five-Factor Analysis, for the Roy S. Nelson Electric Generating Plant, prepared by Trinity Consultants, November 9, 2015, *Revised April 15, 2016*. Heareafter referred to as the "Entergy Nelson BART Analysis."

[5] See EIA Form 923, Schedules 2, 3, 4, and 5 available here: http://www.eia.gov/electricity/data/eia923/.

[6] Crespi, M. "Design of the FLOWPAC WFGD System For The Amager Power Plant." Power-Gen FGD Operating Experience, November 29, 2006, Orlando, FL.
Babcock and Wilcox. "Wet Flue Gas Desulfurization (FGD) Systems Advanced Multi-Pollutant Control Technology." See Page 4: "We have also provided systems for heavy oil and Orimulsion fuels."
DePriest, W; Gaikwad, R. "Economics of Lime and Limestone for Control of Sulfur Dioxide." See page 7: "A CFB unit, in Austria, is on a 275 MW size oil-fired boiler burning 1.0-2.0% sulfur oil."

amount of sulfur in the coal burned. Coal pretreatment broadly falls into two categories: coal washing and coal drying.

Coal Washing

Coal washing is often described as preparation (for particular markets) or cleaning (by reducing the amount of mineral matter and/or sulphur in the product coal).[7] Washing operations are carried out mainly on bituminous and anthracitic coals, as the characteristics of subbituminous coals and lignite (brown coals) do not lend themselves to separation of mineral matter by this means, except in a few cases.[8] Coal is mechanically sized, then various washing techniques are employed, depending on the particle size, type of coal, and the desired level of preparation.[9] Following the coal washing, the coal is dewatered, and the waste streams are disposed.

Coal washing takes place at large dedicated coal washing facilities, typically located near where the coal is mined. Consideration of coal washing as a viable SO_2 control technology presents a number of problems:

- Coal washing is not typically performed on the types of coals used in the power plants under consideration, Powder River Basin (PRB) subbituminous and Texas lignites.
- Because coal washing is not typically conducted onsite of the power plant, it is viewed as a consideration in the selection of the coal, and not as an air pollution control.
- Coal washing poses significant energy and non-air quality considerations under section 51.308(e)(1)(ii)(A) For instance, it results in the use of large quantities of water,[10] and coal washing slurries are typically stored in impoundments, which can, and have, leaked.[11]

Because of these issues, coal washing is not further considered as a potential BART control.

Coal Drying

In general, coal drying consists of reducing the moisture content of lower rank coals, thereby improving the heating value of the coal and so reducing the amount of coal that has to be

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[7] Couch, G. R., "Coal Upgrading to Reduce CO_2 emissions," CCC/67, October 2002, IEA Clean Coal Centre.
[8] Ibid.
[9] Various coal washing techniques are treated in detail in Chapter 4 of *Meeting Projected Coal Production Demands in the USA, Upstream Issues, Challenges, and Strategies*, The Virginia Center for Coal and Energy Research, Virginia Polytechnic Institute and State University, contracted for by the National Commission on Energy Policy, 2008.
[10] "Water requirements for coal washing are quite variable, with estimates of roughly 20 to 40 gallons per ton of coal washed (1 to 2 gal per MMBtu) (Gleick, 1994; Lancet, 1993)." Energy Demands on Water Resources, Report to Congress on the Interdependency of Energy and Water, U.S. Department Of Energy, December 2006.
[11] Committee on Coal Waste Impoundments, Committee on Earth Resources, Board on Earth Sciences and Resources, Division on Earth and Life Studies; *Coal Waste Impoundments, Risks, Responses, and Alternatives*; National Research Council; National Academy Press, 2002.

combusted to achieve the same power, thus improving the efficiency of the boiler. In the process, certain pollutants are reduced as a result of (1) mechanical separation of mineralized sulfur (e.g., and iron pyrite) and rocks, and (2) the a result of the unit burning less coal to make the same amount of power.

Coal drying can be performed onsite, so it can be considered a potential BART control. Great River Energy has a patented process being successfully utilized at the Coal Creek facility available for installation.[12] This process utilizes excess waste heat to run trains of moving fluidized bed dryers. The process offers a number of co-benefits, such as general savings due to lower coal usage (e.g., coal cost, ash disposal), less power required to run mills and ID fans, and lower maintenance on coal handling equipment air preheaters, etc.

In general, the greatest benefit to both improving the efficiency of the boiler and in reducing pollutants is derived from the lowest rank coals. Lignites, for instance, generally have the greatest moisture content and the highest concentration of pyrites. Higher rank coals, such as Powder River Basin subbituminous, show a somewhat lower benefit.

Although we view this new patented technology as a promising path for generally improving boiler efficiency and obtaining some reduction in SO_2, its analysis presents a number of difficulties. For instance, the degree of reduction in SO_2 is dependent on a number of factors. These include (1) the quality and quantity of the waste heat available at the unit, (2) the type of coal being dried (amount of bound sulfur, i.e., pyrites, moisture content), and (3) the design of the boiler (e.g., limits to steam temperatures, which can decrease due to the reduced flue gas flow through the convective pass of the boiler). Because we lack the necessary operating information for this new technology, we cannot assess many of these issues at this time. Therefore, coal drying is not further considered as a potential BART control.

3.1.2 Dry Sorbent Injection

Dry Sorbent Injection (DSI) is performed by injecting a dry reagent into the hot flue gas, which subsequently chemically reacts with SO_2 and other gases to form a solid product that is subsequently captured by the particulate device. A blower is used to deliver the sorbent from its storage silos through piping directly to the flue gas ducting via injection lances. The most commonly used sorbent is trona, a naturally occurring mineral primarily mined from the Green River Formation in Wyoming. Trona can also be processed into sodium bicarbonate, which is more reactive with SO_2 than trona, but more expensive. Hydrated lime is another potential sorbent but it is less frequently used and little data is available regarding its potential performance and cost. In general, trona is considered the most cost effective of the sorbents for SO_2 removal. There are many examples of DSI being used on coal fired EGUs to control SO_2. However, DSI may not be technically feasible at every coal fired EGU. We are unaware that the Nelson Unit 6 has any technical limitation on the use of DSI. Therefore, at this time we believe DSI is a technically feasible control option for this unit.

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[12] DryFining™ is the company's name for the process. It is described here: http://www.powermag.com/improve-plant-efficiency-and-reduce-co2-emissions-when-firing-high-moisture-coals/

3.1.3 SO_2 Scrubbing Systems

In contrast to DSI, SO_2 scrubbing techniques utilize a large dedicated vessel in which the chemical reaction between the sorbent and SO_2 takes place either completely or in large part. Also in contrast to DSI systems, SO_2 scrubbers add water to the sorbent when introduced to the flue gas. The two predominant types of SO_2 scrubbing employed at coal fired EGUs are wet Flue Gas Desulfurization (wet FGD), and Spray Dry Absorber (SDA). More recently, Circulating Dry Scrubbers (CDS) have been introduced. Babcock and Wilcox provides a summary comparison of the technologies: [13]

Wet FGD systems provide the highest levels of SO_2 control (up to 99%) at generally the lowest unit operating costs for high sulfur applications. However, they typically have the highest initial capital costs. They are applicable to coals of all sulfur content and systems are available to generate usable byproducts for sale. They are the most frequently applied technology for new coal-fired capacity outside of the United States. Wet FGD systems include wet spray tower scrubbers and tray tower wet scrubbers.

SDA and CDS systems are frequently utilized for medium and low sulfur coal applications where lower removal efficiencies of 90 to 98% are required to achieve the desired emission targets. These systems have lowest initial capital costs and simpler process and control steps than wet FGD systems. They use less water and auxiliary power, and the end product is dry for easier use or disposal. However, spent reagent reuse remains limited in the U.S. The need for wastewater treatment is eliminated and the FGD processes can be used to consume plant wastewater streams. An SDA or CDS scrubber retrofit typically includes a new or upgraded fabric filter which provides an opportunity for reducing filterable and total particulate matter emissions. For smaller utility and industrial applications, the simplicity in process and design has enabled semi-dry technologies to be used in higher sulfur coal applications.

The Energy Information Administration reports[14] the following types of flue gas desulfurization systems as being operational in the U.S. for 2015:

Table 1. EIA Reported Desulfurization Systems in 2015

Type	Number of installations
Wet spray tower scrubber	296
Spray dryer absorber (SDA)	269

[13] Babcock and Wilcox. *Steam, Its Generation and Use*. Forty-second edition, 2015. Chapter 34.

[14] See EIA-860 data available here: http://www.eia.gov/electricity/data/eia860/index.html. EIA states in the "FGD" tab of the "EnviroEquip_Y2015_Early_Release.xlsx" file that plants with combustible-fueled steam-electric generators with a sum of 10 MW or more steam-electric nameplate capacity (including combined cycle steam-electric generators with duct firing) are required to report information about their flue gas desulfurization units. (These plants are designated as Steam Plant Types 1 and 2). Some plants that are neither Steam Plant Type 1 or 2 have voluntarily reported flue gas desulfurization unit information; this voluntarily reported information is also displayed.

Circulating dry scrubber (CDS)	50
Packed tower wet scrubber	6
Venturi wet scrubber	48
Jet bubbling reactor	31
Tray tower wet scrubber	42
Mechanically aided wet scrubber	4
Dry Sorbent Injection (DSI)	106
Other	1
Unspecified	1
Total	854

Excluding the DSI installations, EIA lists 748 SO_2 scrubber installations in operation in 2015. Of these, 296 are listed as being spray type wet scrubbers, with an additional 42 listed as being tray type wet scrubbers.[15] An additional 269 are listed as being spray dry absorber types. Consequently, spray type or tray type wet scrubbers (wet FGD) account for approximately 45% of all scrubber systems, and spray dry scrubbers (SDA) account for approximately 36% of all scrubber systems that were operational in the U.S. in 2015.

Some of the other scrubber system types (e.g., venturi and packed wet scrubber types) are usually considered to be older, outdated technologies and will not be considered in our BART analysis. Jet bubbling reactors and circulating dry scrubbers are relatively new technologies, with limited installations, and little information is available with which to characterize them. Therefore, they will not be further considered as BART controls.

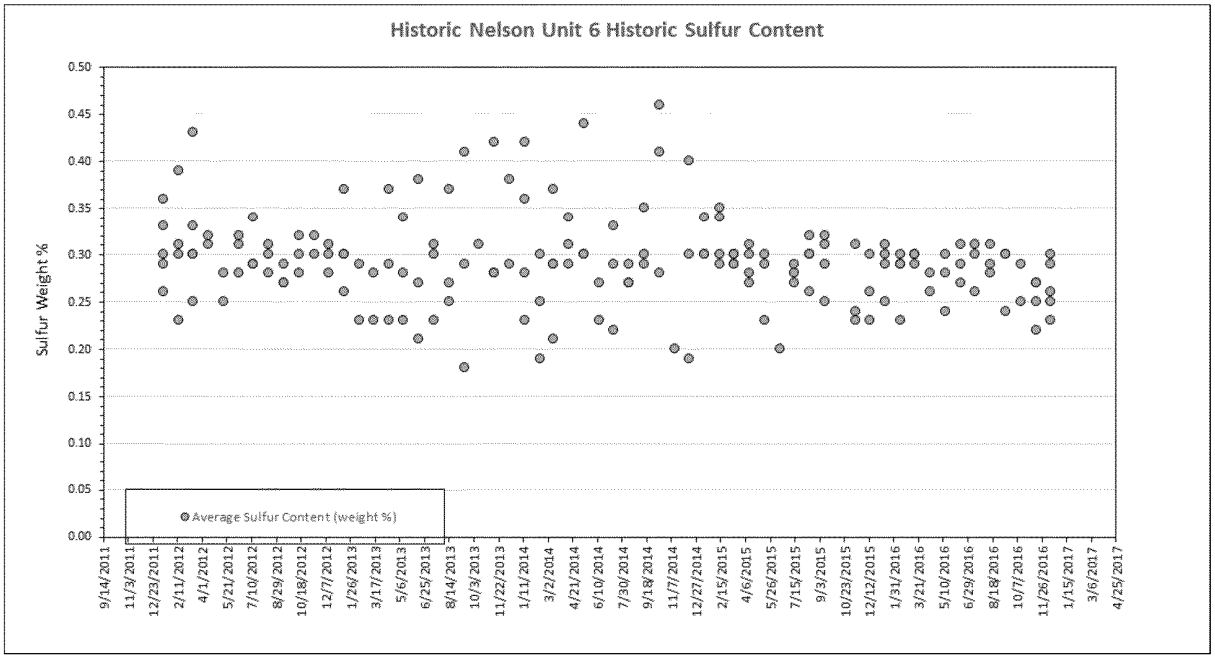
In summary, we believe limestone wet FGD and SDA are technically feasible control options for this unit.

3.1.4 Switching to Lower Sulfur Coal

Switching to a lower sulfur coal is a feasible method for lowering SO_2 emissions. In fact, Entergy has been purchasing lower sulfur coals and blending them in its feed stream for a number of years. The following graph illustrates how the Nelson Unit 6 has been able to lower its SO_2 emissions by buying lower sulfur coals for at least the last five years:

Figure 1. The Nelson Unit 6 Historic Coal Sulfur Content

[15] This is somewhat confusing since trays are often employed in spray type wet scrubbers and EIA lists some of the wet spray tower systems as secondarily including trays.



It can be seen from this figure that beginning in the Spring of 2015, Entergy began purchasing coals with lower sulfur contents that occur in a tighter range in comparison to those it has purchased in the past. This indicates that lower sulfur coal is a feasible control option.

3.2 Evaluation of Control Effectiveness of Remaining Control Technologies for Nelson Unit 6

In the following subsections we evaluate the control levels each technically feasible technology is capable of achieving for the coal and gas units. In so doing, we consider the maximum level of control each technology is capable of delivering based on a 30 Boiler Operating Day (BOD) period. As the BART Guidelines direct, "[y]ou should consider a boiler operating day to be any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit."[16] To calculate a 30 day rolling average based on boiler operating day, the average of the last 30 "boiler operating days" is used. In other words, days are skipped when the unit is down, as for maintenance. This, in effect, provides a margin of safety by eliminating spikes that occur at the beginning and end of outages.

3.2.1 Evaluation of Control Effectiveness of DSI

The efficiency of DSI system depends on many factors, such as[17]:

- Sorbent particle size: Finer particles result in better performance.

[16] 70 FR 39103, 39172 (July 6, 2005) [40 CFR 51, App. Y]

[17] Wood, M., Kong, Y., "Dry Sorbent Injection with Trona or Sodium Bicarbonate Meets HCl Limit in Utility MACT, SOLVAir® Solutions, Solvay Chemicals, Inc.

- Sorbent residence time in flue gas stream: Longer residence time gives more time for mixing and chemical reactions, thus better performance.
- Sorbent penetration and mixing with flue gas: Better sorbent penetration into flue gas and mixing gives higher removal efficiencies.
- Particulate control device used (ESP or Baghouse): Since sorbents can build up on the fabric filters of the bag house and provide a layer of sorbent for further reactions with acid gases, baghouse filters have higher efficiencies.
- Temperature at injection site: The minimum flue gas temperature at the sorbent injection should be at least 275 °F. Higher temperatures normally result in better performance.
- The recommended maximum temperature is 1500 °F.

Solvay Chemicals, Inc., a manufacturer of DSI sorbents, provides general performance information: [18]

[18] "Dry Sorbent Injection of Sodium Sorbents," presented at the LADCO Lake Michigan Air Directors Consortium, Emission Control and Measurement Technology for Industrial Sources Workshop, March 24, 2010. We note that a number of different DSI trona SO_2 performance curves exist and our use of these curves is as a general reference only.

Figure 2. Typical Trona SO_2 Removal Rates with ESP or Baghouse Installations

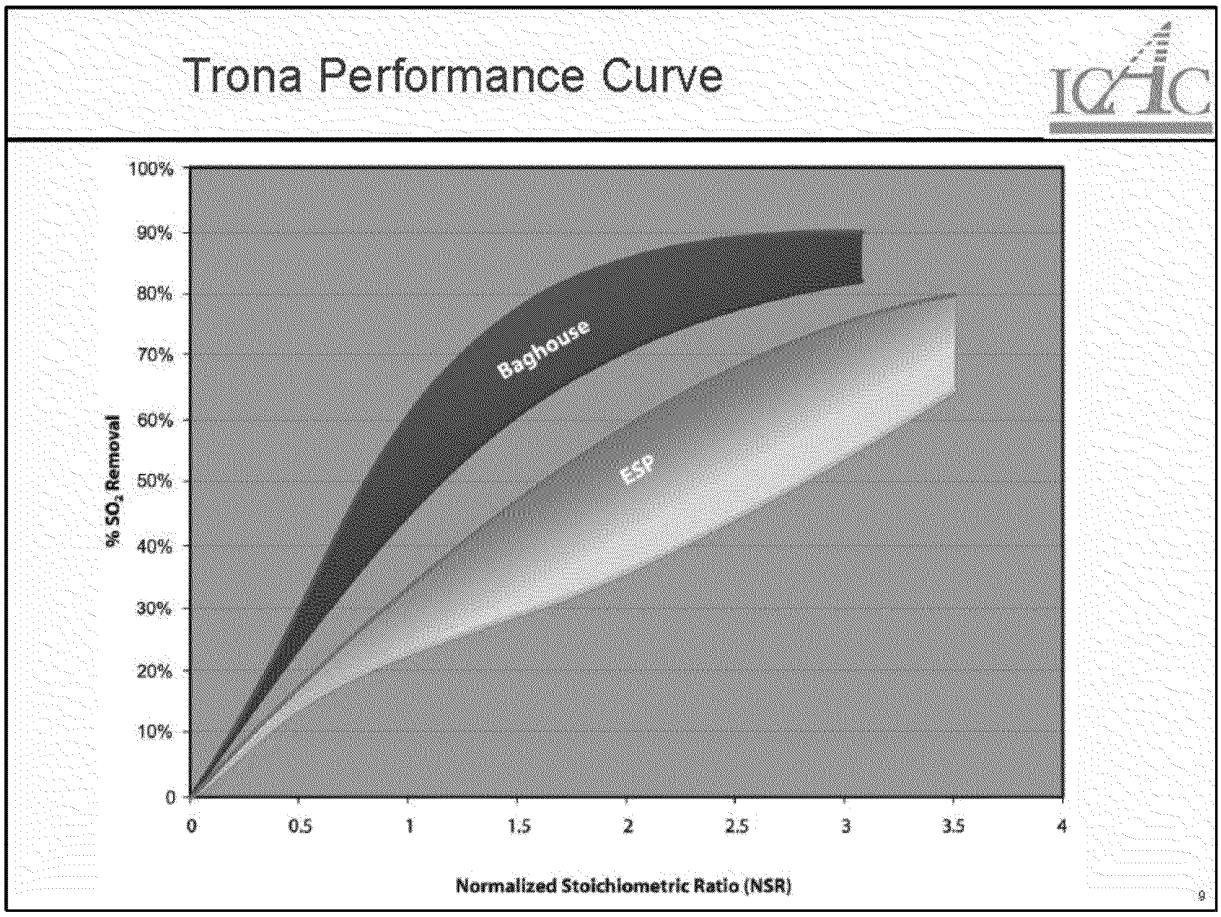


Figure 2 illustrates a number of important concepts concerning the performance potential of DSI:

- SO_2 removal efficiencies for trona DSI installations perform better when a baghouse rather than an ESP particulate control device is employed.
- The Normalized Stoichiometric Ratio (NSR), which is simply a measure of the actual usage needed compared to the theoretical need, governs the SO_2 removal efficiency. In other words, for a given particulate control device, greater SO_2 removal efficiencies require increasingly greater amounts of trona, with diminishing returns.
- A wide range of SO_2 removal efficiency is possible for a given NSR and particulate control device. We interpret this range to be in part dependent on site specific conditions.

To address this range, we will use the following methodology:

- We will evaluate the Nelson Unit 6 at its maximum theoretical DSI performance level, according to the IPM DSI cost model documentation,[19] assuming milled trona: 80% SO_2 removal for an ESP installation. This level of control is within that of SO_2 scrubbers, and thus allows a better comparison of the costs of DSI and scrubbers.

- However, because we do not have performance testing for Unit 6 (1) we do not know whether this unit is actually capable of achieving these control levels and (2) we believe it is useful to evaluate lesser levels of DSI control (and correspondingly lower costs). We therefore also evaluate the Nelson Unit 6 at a DSI SO_2 control level of 50%, which we believe is likely achievable.

3.2.2 Evaluation of Control Effectiveness of Wet FGD and SDA

Our wet FGD control cost analysis uses the wet FGD cost algorithms, as employed in version 5.13 of our IPM model. [20] The IPM wet FGD Documentation states: "The least squares curve fit of the data was defined as a "typical" wet FGD retrofit for removal of 98% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufacturers of wet FGD systems, are 0.04 lb/MMBtu." This level of control is achievable with wet FGD.[21] We therefore have assumed a wet FGD level of control to be a maximum of 98% not to go below 0.04 lbs/MMBtu, in which case, we assume the percentage of control equal to 0.04 lbs/MMBtu.

Based upon industry publications and real world monitoring data, we have assumed a SDA level of control equal to 95%, unless that level of control would fall below an outlet SO_2 level of 0.06

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[19] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO2 Control Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy, p. 7.

[20] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5-5: DSI Cost Methodology, downloaded https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-5_dsi_cost_methodology.pdf.
IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5-2: SDA FGD Cost Methodology, downloaded from https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-2_sda_fgd_cost_methodology_3.pdf.
IPM Model – Updates to Cost and Performance for APC Technologies, wet FGD Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5-1: Wet FGD Cost Methodology, downloaded from https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-1_wet_fgd_cost_methodology.pdf.

[21] The control efficiencies reasonably achieveable by dry scrubbing and wet scrubbing are 95% and 98%, respectively. See 76 FR 81727, 81742 (December 28, 2011) and the accompanying TSD and Response to Commentsd document for that action; *Oklahoma v. EPA*, 723 F.3d 1201 (10th Cir. - 2013), cert. denied 134 S. Ct. 2662 (2014).

lb/MMBtu, in which case, we assume the percentage of control equal to 0.06 lbs/MMBtu. We believe that this level of control for SDA is reasonable.

3.2.3 Evaluation of Control Effectiveness of Switching to Lower Sulfur Coal

Entergy's BART analysis states, "Switching to a lower sulfur coal can reduce SO_2 emissions to approximately 0.6 lb/MMBtu."[22]

Below we provide a summary of some of the information Entergy is required to report to the Energy Information Agency (EIA) regarding where it purchases its coal, the heat content of that coal, and its sulfur content.[23]

Table 2. Recent Entergy Nelson Coal Characteristics

Date (assume 15th day)	Quantity (short tons)	Average Heat Content (Btu/lb)	Average Sulfur Content (weight %)	Calculated SO_2 (lbs/MMBtu)	Fuel Cost (cents/MMBtu)
9/15/2013	14,729.0	8,810	0.18	0.409	270.5
2/15/2014	29,954.0	9,035	0.19	0.421	247.7
12/15/2014	15,214.0	8,915	0.19	0.426	247.8
11/15/2014	15,204.0	9,030	0.20	0.443	279.5
6/15/2015	15,239.0	9,025	0.20	0.443	279.5
3/15/2014	15,201.0	8,890	0.21	0.472	261.4
6/15/2013	75,780.0	8,850	0.21	0.475	267.5
7/15/2014	15,089.0	8,895	0.22	0.495	247.1
11/15/2016	15,098.0	8,635	0.22	0.510	229.5
2/15/2016	30,032.0	8,985	0.23	0.512	254.5
12/15/2016	30,465.0	8,985	0.23	0.512	229.7
4/15/2013	60,850.0	8,955	0.23	0.514	268.9
5/15/2013	60,267.0	8,950	0.23	0.514	264.7
2/15/2013	45,256.0	8,945	0.23	0.514	273.3
5/15/2015	45,633.0	8,940	0.23	0.515	252.1
11/15/2015	14,370.0	8,940	0.23	0.515	233.6
12/15/2015	90,214.0	8,940	0.23	0.515	242.0
7/15/2013	59,893.0	8,940	0.23	0.515	262.3
2/15/2012	15,141.0	8,925	0.23	0.515	244.9
1/15/2014	60,893.0	8,910	0.23	0.516	196.9

[22] Entergy Nelson BART Analysis, pdf 15.
[23] See the file, "Nelson control costs with Entergy Corrections.xlsx," Tab "EIA 923 Purchased Coal Data."

3/15/2013	91,081.0	8,885	0.23	0.518	265.3
11/15/2015	75,413.0	8,990	0.24	0.534	239.8
6/15/2014	15,173.0	8,590	0.23	0.536	288.0
5/15/2016	45,486.0	8,945	0.24	0.537	242.7
9/15/2016	30,298.0	8,800	0.24	0.545	253.2
1/15/2016	44,982.0	9,060	0.25	0.552	255.8
10/15/2016	15,071.0	9,010	0.25	0.555	239.1
3/15/2012	14,481.0	8,990	0.25	0.556	244.3
9/15/2015	14,883.0	8,965	0.25	0.558	240.7
11/15/2016	29,963.0	8,940	0.25	0.559	229.9
2/15/2014	29,717.0	8,895	0.25	0.562	274.4
8/15/2013	30,067.0	8,865	0.25	0.564	269.6
5/15/2012	30,372.0	8,850	0.25	0.565	274.1
12/15/2015	104,960.0	8,990	0.26	0.578	230.8
7/15/2016	45,167.0	8,980	0.26	0.579	246.2
1/15/2013	45,592.0	8,975	0.26	0.579	259.4
12/15/2016	15,096.0	8,610	0.25	0.581	229.5
1/15/2012	15,049.0	8,945	0.26	0.581	246.8
12/15/2016	45,480.0	8,910	0.26	0.584	245.3
8/15/2015	45,219.0	8,910	0.26	0.584	240.7
6/15/2016	30,286.0	9,080	0.27	0.595	241.4
6/15/2014	30,815.0	8,990	0.27	0.601	257.4
9/15/2012	60,712.0	8,990	0.27	0.601	259.3
8/15/2014	30,679.0	8,965	0.27	0.602	249.6
11/15/2016	14,230.0	8,955	0.27	0.603	249.5
11/15/2016	30,160.0	8,950	0.27	0.603	229.9
8/15/2014	30,790.0	8,925	0.27	0.605	247.7
7/15/2015	59,978.0	8,910	0.27	0.606	245.0
4/15/2016	15,242.0	8,415	0.26	0.618	243.0
11/15/2013	29,889.0	8,990	0.28	0.623	232.6
6/15/2012	45,251.0	8,980	0.28	0.624	263.1
8/15/2016	30,335.0	8,950	0.28	0.626	202.5
4/15/2015	15,196.0	8,605	0.27	0.628	262.7
7/15/2015	45,337.0	8,920	0.28	0.628	236.7
4/15/2015	45,367.0	8,910	0.28	0.629	246.9
9/15/2012	76,286.0	8,540	0.27	0.632	253.0
10/15/2012	90,992.0	8,855	0.28	0.632	262.2
9/15/2015	15,476.0	9,150	0.29	0.634	244.6
6/15/2013	60,761.0	8,490	0.27	0.636	268.8
8/15/2013	75,957.0	8,470	0.27	0.638	269.5
1/15/2016	29,786.0	8,970	0.29	0.647	253.6

3/15/2014	45,408.0	8,915	0.29	0.651	239.4
3/15/2013	15,260.0	8,605	0.28	0.651	268.0
3/15/2015	14,611.0	8,880	0.29	0.653	256.0
3/15/2015	28,779.0	8,880	0.29	0.653	242.0
1/15/2012	43,697.0	8,875	0.29	0.654	246.8
12/15/2012	45,801.0	8,560	0.28	0.654	248.8
11/15/2013	149,068.0	8,545	0.28	0.655	266.6
3/15/2016	29,577.0	8,825	0.29	0.657	204.4
1/15/2014	61,008.0	8,520	0.28	0.657	270.4
5/15/2013	75,953.0	8,480	0.28	0.660	269.0
5/15/2016	30,464.0	8,445	0.28	0.663	241.9
10/15/2014	45,893.0	8,420	0.28	0.665	274.8
4/15/2016	45,487.0	8,415	0.28	0.665	237.6
5/15/2012	30,466.0	8,380	0.28	0.668	276.0
8/15/2012	45,378.0	8,380	0.28	0.668	258.4
9/15/2014	29,553.0	8,910	0.30	0.673	248.8
8/15/2012	45,902.0	8,895	0.30	0.675	263.1
1/15/2015	105,546.0	8,880	0.30	0.676	246.6
5/15/2014	45,512.0	8,830	0.30	0.680	255.5
7/15/2012	15,204.0	8,535	0.29	0.680	255.4
8/15/2014	60,819.0	8,515	0.29	0.681	278.2
2/15/2013	30,419.0	8,495	0.29	0.683	277.3
12/15/2013	150,814.0	8,490	0.29	0.683	270.7
9/15/2013	105,527.0	8,480	0.29	0.684	272.7
6/15/2016	75,831.0	8,470	0.29	0.685	240.5
7/15/2012	75,539.0	8,465	0.29	0.685	264.0
4/15/2014	75,351.0	8,460	0.29	0.686	273.0
7/15/2014	45,700.0	8,455	0.29	0.686	281.3
9/15/2012	45,814.0	8,430	0.29	0.688	263.5
7/15/2015	30,343.0	8,425	0.29	0.688	234.4
3/15/2014	74,167.0	8,410	0.29	0.690	272.9
4/15/2013	30,297.0	8,405	0.29	0.690	276.6
2/15/2016	15,202.0	8,385	0.29	0.692	253.5
10/15/2016	45,497.0	8,380	0.29	0.692	235.8
2/15/2015	44,559.0	8,375	0.29	0.693	268.4
9/15/2014	91,198.0	8,375	0.29	0.693	280.7
8/15/2016	44,522.0	8,355	0.29	0.694	247.8
12/15/2016	60,244.0	8,355	0.29	0.694	244.8
5/15/2015	29,933.0	8,355	0.29	0.694	244.3
4/15/2014	60,204.0	8,880	0.31	0.698	244.5
2/15/2016	30,316.0	8,300	0.29	0.699	245.2

12/15/2012	106,105.0	8,870	0.31	0.699	252.1
7/15/2013	75,285.0	8,860	0.31	0.700	236.0
5/15/2014	30,481.0	8,505	0.30	0.705	279.0
4/15/2015	60,424.0	8,785	0.31	0.706	242.5
1/15/2012	42,897.0	8,500	0.30	0.706	249.1
1/15/2013	75,769.0	8,495	0.30	0.706	263.2
1/15/2013	15,233.0	8,495	0.30	0.706	265.6
3/15/2012	30,572.0	8,495	0.30	0.706	256.9
3/15/2015	45,112.0	8,490	0.30	0.707	238.0
7/15/2016	45,259.0	8,480	0.30	0.708	242.4
2/15/2014	29,618.0	8,480	0.30	0.708	281.9
12/15/2014	60,635.0	8,455	0.30	0.710	277.4
3/15/2015	44,109.0	8,450	0.30	0.710	270.0
7/15/2013	90,849.0	8,450	0.30	0.710	270.1
11/15/2012	121,611.0	8,450	0.30	0.710	256.3
8/15/2015	60,296.0	9,010	0.32	0.710	244.6
2/15/2016	45,486.0	8,445	0.30	0.710	246.3
5/15/2015	30,430.0	8,445	0.30	0.710	274.2
12/15/2012	91,373.0	8,445	0.30	0.710	242.2
1/15/2016	41,169.0	8,430	0.30	0.712	240.2
3/15/2012	60,609.0	8,425	0.30	0.712	254.0
12/15/2015	15,106.0	8,420	0.30	0.713	260.7
5/15/2016	30,307.0	8,415	0.30	0.713	237.5
1/15/2015	89,750.0	8,415	0.30	0.713	273.4
8/15/2015	15,104.0	8,415	0.30	0.713	266.6
8/15/2015	60,634.0	8,415	0.30	0.713	238.9
2/15/2012	75,592.0	8,415	0.30	0.713	253.4
2/15/2015	30,350.0	8,400	0.30	0.714	245.6
3/15/2016	15,203.0	8,395	0.30	0.715	242.0
10/15/2012	91,530.0	8,395	0.30	0.715	261.3
12/15/2016	45,027.0	8,390	0.30	0.715	238.5
3/15/2016	30,422.0	8,365	0.30	0.717	233.5
9/15/2016	60,383.0	8,350	0.30	0.719	243.5
9/15/2016	60,464.0	8,340	0.30	0.719	239.9
4/15/2015	15,102.0	8,310	0.30	0.722	248.8
11/15/2012	105,820.0	8,850	0.32	0.723	264.2
4/15/2012	15,320.0	8,805	0.32	0.727	294.1
11/15/2015	30,273.0	8,470	0.31	0.732	236.1
6/15/2016	29,570.0	8,465	0.31	0.732	235.4
1/15/2016	29,696.0	8,450	0.31	0.734	244.6
10/15/2013	45,842.0	8,435	0.31	0.735	284.7

3/15/2012	15,213.0	8,975	0.33	0.735	229.0
6/15/2012	45,654.0	8,425	0.31	0.736	258.5
8/15/2012	61,249.0	8,420	0.31	0.736	265.4
7/15/2016	90,559.0	8,415	0.31	0.737	236.7
8/15/2016	59,922.0	8,385	0.31	0.739	240.0
4/15/2012	15,108.0	8,380	0.31	0.740	296.1
2/15/2012	45,027.0	8,355	0.31	0.742	262.0
9/15/2015	15,207.0	8,335	0.31	0.744	238.9
7/15/2014	76,017.0	8,850	0.33	0.746	254.8
6/15/2012	30,069.0	8,450	0.32	0.757	264.7
1/15/2015	75,928.0	8,965	0.34	0.759	256.1
2/15/2015	59,315.0	8,950	0.34	0.760	254.4
9/15/2015	15,416.0	8,390	0.32	0.763	266.6
5/15/2013	105,572.0	8,885	0.34	0.765	238.0
10/15/2012	60,420.0	8,345	0.32	0.767	260.1
4/15/2014	75,564.0	8,835	0.34	0.770	252.0
7/15/2012	91,116.0	8,825	0.34	0.771	265.7
1/15/2012	88,552.0	8,415	0.33	0.784	258.5
9/15/2014	45,530.0	8,825	0.35	0.793	252.9
2/15/2015	45,383.0	8,735	0.35	0.801	251.9
1/15/2012	73,280.0	8,810	0.36	0.817	259.9
1/15/2014	75,070.0	8,775	0.36	0.821	243.5
4/15/2013	45,483.0	8,885	0.37	0.833	240.7
3/15/2014	76,000.0	8,875	0.37	0.834	245.6
8/15/2013	90,517.0	8,825	0.37	0.839	238.4
1/15/2013	45,504.0	8,770	0.37	0.844	239.3
12/15/2013	60,076.0	8,760	0.38	0.868	238.0
6/15/2013	59,717.0	8,750	0.38	0.869	240.2
2/15/2012	60,153.0	8,890	0.39	0.877	259.1
12/15/2014	30,380.0	8,995	0.40	0.889	246.2
10/15/2014	15,220.0	9,020	0.41	0.909	244.0
9/15/2013	15,186.0	8,695	0.41	0.943	240.1
1/15/2014	45,140.0	8,810	0.42	0.953	243.4
11/15/2013	30,170.0	8,755	0.42	0.959	237.4
3/15/2012	30,381.0	8,755	0.43	0.982	264.6
5/15/2014	14,851.0	8,765	0.44	1.004	250.4
10/15/2014	30,238.0	8,700	0.46	1.057	252.1

In Table 2 above, we have ordered the data based on increasing sulfur content. This information indicates that Entergy has been able to consistently purchase coal with a sulfur content that would enable the Nelson Unit 6 to comply with the 0.60 lbs/MMBtu level Entergy has selected for its low sulfur coal BART case. Note that the color coding of the 2016 coal purchases is

utilized in Section 3.2.9, where we discuss our calculations of the cost-effectiveness of switching to a lower sulfur coal.

3.2.4 Entergy's Cost Analysis:

The Entergy Nelson BART analysis is contained in a report by Trinity Consultants, which incorporates control cost analyses prepared by Sargent & Lundy (S&L). This report was revised April 15, 2016, in response to comments made by us on March 16, 2016. Entergy made some adjustments in response to our comments. However, it did not remove certain cost items that are not allowed by the Control Cost Manual. For instance, although Entergy deleted Allowance for Funds Used During Construction (AFUDC), it did not remove escalation during construction, and owner's costs. These costs are not allowed by the Control Cost Manual. We also believe Entergy's use of a 25% contingency factor is not supported We are not aware of any characteristics of Nelson Unit 6 would present any unusual difficulty that would serve to distinguish it from any other scrubber retrofit and thus justify a high estimate for contingency. The Control Cost Manual uses contingency values ranging from 5 to 15%, depending upon the control device in question and the precise nature of the factors requiring contingency.[24] ,Below is a summary of Entergy's SDA control cost-effectiveness in order to illustrate the effect of those disallowed costs and our contingency adjustment.[25] We have used a contingency value of 10% for this estimate, which lies in the middle of the range employed in the Control Cost Manual, which we believe is appropriate for mature technologies such as SDA and wet FGD.

Table 3. Impact of Disallowed Costs on Entergy's SDA Control Cost Calculation

Entergy SDA Cost Calculation	
TCI	$394,845,800
Annualized capital costs	$31,819,203
Variable O&M	$10,168,000
Fixed O&M	$5,700,000
Total Annual Cost	$47,687,203
$/ton	**$5,094***

Entergy's SDA Cost Calculation with Deletion of Escalation and Owner's Costs	
TCI	$394,845,800
Subtract escalation	($39,743,100)
Subtract escalation addition	($4,358,800)

[24] "A contingency factor should be reserved (and applied to) only those items that could incur a reasonable but unanticipated increase but are not directly related to the demolition, fabrication, and installation of the system. For example, a hundred year flood may postpone delivery of materials, but their arrival at the job site is not a problem unique to a retrofit situation." Control Cost Manual, 6th Edition, Section 2.5.4.2.

[25] See the file, "Nelson control costs with Entergy Corrections.xlsx" for details of these and our other control cost calculations.

Subtract Owner's costs	($20,185,200)
Adjusted TCI	$330,558,700
Annualized capital costs	$26,638,537
Variable O&M	$10,168,000
Fixed O&M	$5,700,000
Total Annual Cost	$42,506,537
$/ton	**$4,541***

Entergy's SDA Cost Calculation with Deletion of Escalation and Owner's Costs and Reducing Contingency to 10%	
TCI	$394,845,800
Subtract escalation	($39,743,100)
Subtract escalation addition	($4,358,800)
Subtract Owner's costs	($20,185,200)
Subtract original 25% contingency	($70,148,800)
Add 10% contingency	25,231,490
Adjusted TCI	$285,641,390
Annualized capital costs	$23,018,812
Variable O&M	$10,168,000
Fixed O&M	$5,700,000
Total Annual Cost	$38,886,812
$/ton	**$4,154***

* Note these figures are obtained by dividing Entergy's total annual cost by a SO_2 reduction of 9,361 tpy, which represents a reduction of 92.11% to a floor of 0.06 lbs/MMBtu, from a baseline of 10,1163 tpy. This baseline, which differs slightly from Entergy's value, is used here to enable an apples-to-apples comparison with our cost analyses which we present elsewhere in this TAD.

As can be seen from the above tables, removing the costs not allowed in the Control Cost Manual and adjusting contingency to 10% has a significant impact.

In addition to the above issues, Entergy's cost analysis is based on a proprietary database. Therefore, the cost estimates cannot be independently verified.

3.2.5 Our Control Cost Analyses for the Nelson Unit 6

In consideration of the issues we have outlined above, we have conducted our own cost analyses for the Nelson Unit 6.

The BART Guidelines offers the following with regard to how Step 4 should be conducted:[26]

After you identify the available and technically feasible control technology options, you are expected to conduct the following analyses when you make a BART determination:

Impact analysis part 1: Costs of compliance,
Impact analysis part 2: Energy impacts, and
Impact analysis part 3: Non-air quality environmental impacts.
Impact analysis part 4: Remaining useful life.

In developing our cost estimates for the Nelson Unit 6, we relied on the methods and principles contained within the EPA Air Pollution Control Cost Manual (the Control Cost Manual, or Manual).[27] The Control Cost Manual uses the "overnight" method of cost estimation: [28]

The Control Cost Manual uses the overnight method of cost estimation, widely used in the utility industry. The U.S. Energy Information Administration (EIA) defines ''overnight cost'' as ''an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day. This concept is useful to avoid any impact of financing issues and assumptions on estimated costs.'' The overnight cost is the present value cost that would have to be paid as a lump sum up front to completely pay for a construction project. The overnight method is appropriate for BART determinations because it allows different pollution control equipment to be compared in a meaningful manner. Because ''different controls have different expected useful lives and will result in different cash flows, the first step in comparing alternatives is to normalize their returns using the principle of the time value of money. The process through which future cash flows are translated into current dollars is called present value analysis. When the cash flows involve income and expenses, it is also commonly referred to as net present value analysis. In either case, the calculation is the same: Adjust the value of future money to values based on the same point in time (generally year zero of the project), employing an appropriate interest (discount) rate and then add them together.''

We proceed in our SO_2 costing analyses by examining the current SO_2 emissions and the level of SO_2 control, if any, for the Nelson Unit 6. Noting that this unit has no post-combustion SO_2 control, we calculate the cost of installing DSI, a SDA scrubber, and a wet FGD scrubber.

In order to estimate the costs for DSI, SDA scrubbers, and wet FGD scrubbers, we programmed the DSI, SDA and wet FGD cost algorithms, as employed in version 5.13 of our IPM model, referenced above, into three spreadsheets. These cost algorithms calculate the Total Project Cost (TPC), Fixed Operating and Maintenance (Fixed O&M) costs, and Variable Operating and Maintenance (Variable O&M) costs. We verified these spreadsheets by reproducing the costs

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[26] 70 FR 39103, 39166 (July 6, 2005) [40 CFR Part 51, App. Y].
[27] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002 available at http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf.
[28] 76 FR 81727, 81744 (December 28, 2011).

estimated by Sargent & Lundy in the project reports. We further extended these cost algorithms to calculate the annualized costs per ton of SO_2 removed ($/ton). We then performed DSI, SDA and wet FGD cost calculations for the Nelson Unit 6.[29] We discuss the inputs and outputs for the DSI, SDA, and wet FGD cost models below. These cost models were based on costs escalated to 2012 dollars.[30] Because the IPM 5-13 cost algorithms were calculated in 2012 dollars, we have escalated them to 2016, using the annual Chemical Engineering Plant Cost Indices (CEPCI). We present the results of our DSI, SDA, and wet FGD cost analyses in sections 3.2.6, 3.2.7, and 3.2.8.

3.2.6 Impact Analysis Part 1: Cost of Compliance for DSI

Table 4, below, is a depiction of the input section of the DSI cost spreadsheet. Sample input parameters for the DSI cost calculation are represented by yellow highlighted cells. The input values designated "A" through "U" have the same meaning as those contained within the documentation for the IPM DSI cost algorithms (hereafter referred to as the "IPM DSI documentation") referenced above. The last four input values, (i.e., Interest rate, Equipment Lifetime, Gross Load, and Baseline) were added by us in order to calculate the annualized costs per ton of SO_2 removed ($/ton). Those cells that are not highlighted in yellow are interim calculations performed by the spreadsheet.

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[29] These calculations are present in the spreadsheet, "Nelson Control Costs with Entergy Corrections.xlsx," and are located in our Docket.

[30] Ibid., p.1: "The data was converted to 2012 dollars based on the Chemical Engineering Plant Index (CEPI) data."

Table 4. Sample Input DSI Cost Model

Variable	Designation	Units	Value	Calculation	
Unit Size (Gross)	A	(MW)	500	**<---- User Input**	
Retrofit Factor	B		1	**<---- User Input (An "average" retrofit has a factor = 1.0)**	
Gross Heat Rate	C	(Btu/kWh)	9,500	**<---- User Input**	Max annual value from 2011-2015
SO2 Rate	D	(lb/MMBtu)	2.00	**<---- User Input**	Max monthly value from 2011-2015
Type of Coal	E		Bituminous	**<---- User Input (PRB, BIT, LIG, or LIG-PRB Blend)**	
HHV Bituminous		BTU/lb	11,000	**<---- User Input (default is 11,000 Btu/lb if applicable; else no meaning)**	
HHV PRB		BTU/lb	8,400	**<---- User Input (default is 8,400 Btu/lb if applicable; else no meaning)**	Three year average from 2011-2015, excluding max and min values
HHV Lignite		BTU/lb	7,200	**<---- User Input (default is 7,200 Btu/lb if applicable; else no meaning)**	
Percent Lignite if Blended			50	**<---- User Input (If Type of Coal = "LIG-PRB Blend," Enter % Lignite. Remainder assumed PRB. If not "LIG-PRB Blend," no meaning)**	
Particulate Capture	F		ESP	**<---- User Input**	
Milled Trona	G		TRUE	**<---- User Input**	
Removal Target	H	%	50	**Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a BGH = 80% Milled Trona with a BGH = 90%**	One run with 50%, and another with either 80% or 90% based on particulate control device used
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000	
NSR	K		1.43	Unmilled Trona with an ESP = If(H<40,0.0350*H,0.352e ^(0.0345*H)) Milled Trona with an ESP = If(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = If(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = If(H<40,0.0160*H,0.208e^(0.0281*H))	Pg 3 of the documentation lists example calculated NSRs which differ from those calculated from the formulae here. Per emails from Bill Stevens, the documentation is in error.
Trona Feed Rate	M	(ton/hr)	16.33	(1.2011*10^-6)*K*A*C*D	
Sorbent Waste Rate	N	(ton/hr)	11.65	(0.7387-0.00073696*H/K)*M; Based on a final reaction product of NA2SO4 and unreacted drysorbent as NA2CO3. Waste product adjusted for a maximum of 5% inert in the Trona sorbent.	
Include Fly Ash Waste Rate in VOM	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV= 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV= 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2 HHV= 7200 For Blend Coal: Ash is proportional to lignite and PRB; Boiler Ash Removal = 0.2; HHV is proportional to lignite and PRB	Assume fly ash waste rate is included in VOM
Include Aux Power in VOM	Q	(%)	0.65	If Milled Trona M*20/A, else M*18/A	Assume aux power is included in VOM
Trona Cost	R	($/ton)	170	**<---- User Input**	default value
Waste Disposal Cost	S	($/ton)	50	**<---- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more difficult to dispose = $100)**	default value
Aux Power Cost	T	($/kWh)	0.06	**<---- User Input**	default value
Operating Labor Rate	U	($/hr)	60	**<---- User Input (Labor cost including all benefits)**	default value
Interest Rate		(%)	7	**<---- User Input**	
Equipment Lifetime		(years)	30	**<---- User Input**	
Gross Load		(MW-hours)	4,000,000	**<---- User Input**	3 -yr avg. 2011-2015, excluding max and min
SO2 Emission Baseline		(tons/year)	30,000	**<---- User Input**	3 -yr avg. 2011-2015, excluding max and min

3.2.6.1 Selection of DSI Cost Model Input Parameters

Below, we review the DSI Cost Model input values and discuss the procedures we employed in selecting them when constructing the costs for the DSI installation. For selected input parameters, we also discuss uncertainties in their values and how we dealt with them. Our overall goal was to select input parameters that would result in a cost that would be a reasonably conservative value. We took this approach in order to ensure that the DSI system was designed to address any operating conditions the unit had experienced in the last five years.

Unit Size (Gross). This parameter is simply the unit size expressed in Megawatts (MW). Although our intent was to use gross and not net values, we are aware that MW values are often reported incorrectly, inconsistently, or the reported values are not specified as to whether they are gross or net values.

Retrofit Factor. The retrofit factor represents a subjective estimation of the average retrofit difficulty. Because we are not aware of any significant retrofit issues at any of the facilities we evaluated, we adopted the default retrofit value of 1.0, which represents an average retrofit difficulty, for all the units we evaluated.

Gross Heat Rate. We calculated the gross heat rate by dividing the Heat Input (MMBtu) by the Gross Load (MW-h), downloaded from our Air Markets Program Data website,[31] and multiplying the result by 1000W/kW to get (BTU/kWh). We chose the gross heat rate to be the maximum annual gross heat rate (Btu/kWh) value from 2011 – 2015 for each unit.

SO_2 Rate. The SO_2 emission rate was calculated from monthly emission data.[32] It was selected as the maximum monthly value from 2011 – 2015. As per the IPM DSI documentation, the SO_2 emission rate has a built-in upper limit of 2.0 lbs/MMBtu.

Type of Coal. The cost algorithms allows the input of three types of coal: bituminous, lignite, and Powder River Basin (PRB) coal from Wyoming. Within the DSI cost algorithms, the type of coal is an input to an interim calculation (P), which is partly dependent on High Heat Value (HHV) of the coal. Also, the cost algorithms assume default values for the HHV of 11,000 Btu/lb for bituminous coal, 8,400 Btu/lb for PRB, and 7,200 Btu/lb for lignite. The interim calculation, P, itself is an input to the variable O&M cost for waste disposal (VOMW).

We note that the cost algorithms are somewhat sensitive to the selection of the type of coal. In addition, we wished to allow for the input of more accurate HHV coal values. Therefore, we adjusted the cost algorithms by (1) adding an option for a lignite-PRB coal blend, which if selected requires (2) the input of the percentage of lignite burned (remaining percentage is assumed to be PRB), plus (3) inputs for the HHV of the coals being burned. Our adjusted cost model accounts for this information in the calculation of the VOMW.

Particulate Capture. The cost model allows for the input of either an Electrostatic Precipitator (ESP) or a Baghouse (BGH) as the particulate control device. As the IPM DSI documentation states, "Baghouses generally achieve greater SO_2 removal efficiencies than ESPs by virtue of the filter cake on the bags, which allows for longer reaction time between the sorbent solids and the flue gas."[33] We assumed the existing particulate control device has the capacity to handle the additional load due to the addition of the trona. Entergy has verbally indicated that may not be the case but we have not been able to confirm.

Milled Trona. As discussed in the IPM DSI documentation, trona is the most commonly used sodium based sorbent material for DSI installations and the DSI cost algorithms assume trona. For a given mass, increasing the surface area of the trona has the effect of improving its ability to

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[31] http://ampd.epa.gov/ampd/
[32] Ibid.
[33] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO2 Control Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy, p.1.

remove SO_2 from the flue gas. One common method for increasing the surface area is to mill the trona to a particle size of 30 µm or smaller, using in-line mills. This usually results in slightly higher capital costs, but the overall cost effectiveness of milling the trona improves (lower $/ton), due to the reduction in trona required to achieve a given SO_2 removal target. We assumed that trona would be milled.

We note, however, that other reagents have important advantages over the use of trona. Hydrated lime, for example, is less sensitive to the conditions of the pneumatic transport air, so less dehumidification or cooling is required for handling; the waste generated by lime injection is not soluble, so normal landfill disposal is feasible without encapsulation, lowering disposal costs; milling is not required; and hydrated lime is usually cheaper.

Removal Target. The removal target is the percentage reduction in SO_2 desired from the SO_2 rate discussed above. The IPM DSI documentation states, "When the sorbent is captured in an ESP, a 40 to 50% SO_2 removal is typically achieved without an increase in particulate emissions. A higher efficiency (70 – 75%) is generally achieved with a baghouse."[34] In section 3.2.1, we reproduce general DSI performance information from Solvay Chemicals, Inc., a manufacturer of DSI sorbents and we discuss our rational for selecting our proposed level of control.

Include Fly Ash Waste Rate in VOM. The cost model allows for the inclusion or exclusion of the fly ash in the Variable O&M costs for waste disposal via a drop down menu. As the IPM DSI documentation notes, when the sodium sorbent (e.g., trona) is captured in the same particulate control device as the fly ash, the resulting waste must be land filled. We are aware that a number of facilities sell their fly ash, and that the addition of trona may render that fly ash unsalable. We chose this option in all cases.

We note that a few of the units we analyzed use an ESP with a polishing baghouse. Such a configuration could allow for the injection of the trona between the ESP and the baghouse, thus allowing for excluding the fly ash from the VOM calculation. This would have the effect of significantly improving the cost effectiveness (reducing the $/ton). However, as the IPM DSI documentation notes, the disposal cost (discussed below) should be increased to account for the additional difficulty in handling the pure sodium waste product. This has the effect of diminishing the cost effectiveness (increasing the $/ton), and erasing much of the gain from excluding the fly ash waste rate from the VOM.

Include Aux Power in VOM. The cost model allows for the inclusion or exclusion of the additional auxiliary power required for the DSI system to be included in the variable operating costs via a drop down menu. We chose to include this additional auxiliary power.

Trona Cost. The cost of trona is the largest portion of the variable operating costs. It is partly dependent on the delivery costs. We used the value obtained from 4/15/16 Trinity Nelson BART analysis.

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[34] Ibid., p.2.

Waste Disposal Cost. The waste disposal cost is the second largest portion of the variable operating costs. The cost model suggests a cost of $50/ton if the trona waste and fly ash are comingled and disposed of together, and $100/ton, if the trona waste is not comingled with the fly ash and is disposed of separately. The value used in the 4/15/16 Trinity Nelson BART analysis is $7.50/ton, which is very low in comparison to typical values we have seen. We assumed a value of $50/ton, corresponding to the trona waste and fly ash being comingled, which we use pending documentation from Entergy. We note that the waste disposal cost is an area in which our cost model could be under predicting the true cost. Because adding trona to the fly ash increases the water solubility of the waste, an upgraded landfill may be required.[35]

Aux Power Cost. Auxiliary power cost is the additional power required by the DSI control system. It is the smallest portion of the variable operating costs. We note from our examination of CBI material we received in response to our Section 114(a) requests that the true power cost for most if not all of the units we analyze is considerably less than this value. However, the cost model is fairly insensitive to the value used for the auxiliary power cost, and we assumed the default value of $0.06/kWh in all cases.

Operating Labor Rate. The operating labor rate is the largest portion of the fixed operating and maintenance cost. We chose the default value of $60/hour for all cases.

Interest Rate. The interest rate is used in the calculation of the capital recovery factor, which itself is used in the calculation of the annualized capital costs. This input value is not a part of the IPM DSI cost algorithms and was added by us in order to calculate the cost effectiveness in $/ton. For cost analyses related to government regulations, an appropriate "social" interest (discount) rate should be used, unless site specific informaton is available. We calculated capital recoveries using 3 percent and 7 percent interest rates in determining cost -effectiveness for the Regulatory Impact Analysis (RIA) for the BART Guidelines. [36] Also, a 7 percent interest rate is recommended by Office of Management and Budget.[37]

Equipment Lifetime. The equipment lifetime is another factor used in the in the calculation of the capital recovery factor. This input value is not a part of the IPM DSI cost algorithms and was added by us in order to calculate the cost effectiveness in $/ton. It represents the actual or service life of the equipment in question. Because a DSI system is relatively simple and reliable, we have no reason to conclude that its service life would be any less than what we typically use for scrubber cost analyses. We therefore adopt that same value here, which is 30 years.

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[35] The Ins and Outs of SO_2 Control, Lindsay Morris, Power Engineering, 6-1-2012. "Jonas Klingspor, vice president of business development and marketing for URS, said one potential concern for using DSI systems with trona is the disposal of the product. 'Unless you have a double-lined, capped landfill, the water soluble byproduct may be a serious concern.'"

[36] Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations, EPA-0452/R-05-004 (June 2005).

[37] A 7.0 percent interest rate is recommended by Office of Management and Budget, Circular A-4, Regulatory Analysis, https://www.whitehouse.gov/omb/circulars_a004_a-4

Gross Load. The gross load (MW-h) was obtained from emissions data downloaded from our Air Markets Program Data website.[38] It was selected as the 2011 – 2015 five year average of the SO_2 annual emissions, excluding the maximum and minimum values. We concluded that using this kind of an average was a reasonable compromise between simply selecting the maximum value from 2011 – 2015, or using the average of the values from 2011 – 2015. This input value is not a part of the IPM DSI cost algorithms. It was added by us in order to convert the variable and operating costs, which the cost algorithms express in $/MW-h and $/kW-yr, respectively, into dollars which are subsequently used in calculating the cost effectiveness in dollars per ton of SO_2 removed ($/ton).

SO_2 Emission Baseline. The SO_2 emission baseline is calculated from emissions data downloaded from our Air Markets Program Data website.[39] It was selected as the 20011 – 2015 five year average of the SO_2 annual emissions, excluding the maximum and minimum values. This input value is not a part of the IPM DSI cost algorithms. It was added by us in order to calculate the annual SO_2 emission reduction from the installation of DSI, which itself is an input to the cost effectiveness in $/ton. We concluded that using this kind of an average was a reasonable compromise between simply selecting the maximum value from 2011 – 2015, or using the average of the values from 2011 – 2015.

In addition to the above inputs to our DSI cost model, we note that Entergy states that the addition of DSI would result in the loss of revenue from fly ash sales. Entergy reports that the loss of fly ash sales due to the installation of DSI will cost it $621,000 per year, and adds this value to its operating and maintenance costs.[40] It states that this assumes 100% of the station's fly ash was being sold on an annual basis for an average of approximately $8.00 per ton. In this case, it appears that at least as recently as October, 2016, Nelson Unit 6 was disposing of some fly ash in an onsite disposal landfill.[41] Consequently, we did not include this cost.

Loss of Fly Ash Sales: Note that our DSI cost analysis does not include the loss in fly ash sales that Entergy states it would incur as a result of contamination of DSI sorbent rendering the fly ash unsalable.[42] Entergy estimates this cost as $8/ton of fly ash generated for a total of $621,000 a year added to the variable O&M cost. However, this estimate was based on assuming 100% of fly ash sales, and in its 4/15/16 letter, Entergy clarified that although historically approximately

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[38] http://ampd.epa.gov/ampd/

[39] Ibid.

[40] See page 11of the S&L Nelson Unit 6 Dsi Cost Estimate Basis Document, November 6, 2015, attached to the 4/15/16 Trinity Nelson BART analysis.

[41] See the Coal Combustion Residuals (CCR) Landfill Post-Closure Plan, Entergy Louisiana LLC - Nelson Coal Ash Disposal Landfill Westlake, Louisiana October 17, 2016, available here: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=2&cad=rja&uact=8&ved=0ahUKEwjrpKTkuc7RAhVK4yYKHSjfAGYQFggfMAE&url=http%3A%2F%2Fwww.entergy-louisiana.com%2Fcontent%2Fccr%2Fdocs%2FNelsonCADLCCRPOSTCLOSUREPLANStampled10-13-16.pdf&usg=AFQjCNEFgGBDcUFVQ5B0t7cc5qChXWDNeg&bvm=bv.144224172,d.eWE. This CCR (fly ash) landfill post-closure plan is required by 40 CFR §257.104 for post closure of a CCR landfill.

[42] See Entergy's response to our questions in its 4/15/16 letter to Guy Donaldson from Kelly McQueen, in our docket.

74% of fly ash had been sold, it received between $15 - $20/ton in compensation, concluding its estimate was conservative. Because we have not received any further documentation of these figures, we have not included the loss of fly ash sales in our DSI cost estimate. We note that adding the revenue from the loss of fly ash sales will result in worsening (higher $/ton) the cost-effectiveness of DSI.

3.2.6.2 DSI Cost Model Output

A sample of the IPM DSI cost model output is depicted below in Table 5. The cost algorithms calculate the Capital, Engineering and Construction Cost (CECC) and the fixed and variable operating costs (FOM and VOM, respectively). Following this, we add a calculation for the capital recovery factor, based on the interest rate and the equipment lifetime, and use it to annualize the CECC. In so doing, we exclude any Allowance for Funds Used During Construction (AFUDC) and "owner's costs."[43] To the annualized CECC, we add the FOM and VOM to arrive at the total annualized costs. Lastly, we divide this figure by the SO_2 emissions reduction to calculate the cost effectiveness in $/ton.

[43] We exclude any AFUDC and "owner's costs" from regional haze control cost calculations, as they are disallowed by the "overnight" cost method used in the Control Cost Manual. In this case, however, AFUDC is assumed by the cost algorithms to be zero anyway, since a DSI project is expected to be completed within one year.

Table 5. Sample DSI Output

Capital Cost Calculation		Explanation of Calculation	Comments
		Includes: equipment, installation, buildings, foundations, electrical, and retrofit difficulty.	
BM ($)	$18,348,000	Base DSI module includes all equipment from unloading to injection.	
BM ($/kW)	37	Base module cost per kW	
Total Project Cost			
A1	$917,000	Engineering and construction management costs	
A2	$917,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc..	
A3	$917,000	Contractor profit and fees	
CECC($)	**$21,099,000**	Capital, engineering and construction cost subtotal	excludes owner's costs
CECC($/kW)	**42**	Capital, engineering and construction cost subtotal per kW	excludes owner's costs
B1	$1,055,000	Owners costs including "home office" costs (owner engineering, management, and procurement activities)	
TPC ($)	**$22,154,000**	Total project cost without AFUDC	includes owner's costs
TPC ($/kw)	**44**	Total project cost per kW without AFUDC	includes owner's costs
B2	$0	AFUDC (zero for less than 1 year engineering and construction cycles)	
TPC ($)	**$22,154,000**	Total project cost	includes owner's costs and AFUDC
TPC ($/kw)	**44**	Total project cost per kW	includes owner's costs and AFUDC
Fixed O&M Cost			
FOMO ($/kW yr)	0.50	Fixed O&M additional operating labor costs. Based on two additional operators.	
FOMM ($/kW yr)	0.37	Fixed O&M maintenance material and labor costs	
FOMA ($/kW yr)	0.02	Fixed O&M additional addministrative labor costs	
FOM ($/kW yr)	**0.89**	Total Fixed O&M costs	
Variable O&M			
VOMR ($/MWh)	5.55	Variable O&M costs for trona reagent	
VOMW ($/MWh)	3.24	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent	
VOMP ($/MWh)	0.39	Variable O&M costs for additional auxillary power required (refer to Aux Power % above)	
VOM ($/MWh)	**9.18**	Total variable O&M costs	
Annualization			
Capital, engineering and construction cost	$21,099,000	Excludes owner's costs and AFUDC	
Capital Recovery factor	0.0806		
Annualized capital costs	$1,700,293		
Variable operating costs	$36,731,218	VOM*(Gross Load)	
Fixed operating costs	$404,356	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)	
Total annualized costs	**$38,835,867**		
SO2 emissions reduction (tons)	15,000	H/(100%)*(SO2 emission baseline)	
$/ton	**2,589**		

3.2.6.3 Summary of DSI Cost Model Results

Below in Table 6 is a summary of our DSI cost model results:

Table 6. Summary of DSI Cost Model Results for the Nelson Unit 6

DSI Control (%)	50	80
DSI SO_2 Reduction (tpy)	5,082	8,130
DSI Capital Cost	$17,840,000	$22,646,000
DSI Annualized Capital Cost	$1,437,661	$1,824,960
DSI Variable Operating Cost	$17,442,629	$34,672,607
DSI Fixed Operating Cost	$207,608	$229,492
DSI Total Annualized Cost	$19,087,899	$36,727,059
DSI Cost Effectiveness 2012 ($/ton)	$3,756	$4,517
DSI Cost Effectiveness 2016 ($/ton)	$3,578	$4,302

Some observations are apparent from the DSI cost model results displayed above:

- The vast majority of the total annualized cost of DSI is due to the variable operating cost, VOM. This is due to the relatively low capital cost of the equipment, and the relatively high cost of the trona.
- Unlike the cost effectiveness of scrubbers, which we will discuss below, for a given facility, the cost effectiveness of DSI worsens (higher $/ton) with increasing control levels. This is due to the inefficient use of the sorbent in DSI systems. Unlike scrubbers, in which the reaction of the reagent and the SO_2 in the exhaust gas occurs within a large vessel (e.g., an absorber), which can be highly controlled, DSI lacks an absorber. Greater SO_2 removal efficiencies require increasingly greater amounts of trona, with diminishing returns.

3.2.7 Impact Analysis Part 1: Cost of Compliance for SDA

Table 7, below, is a depiction of the input section of the SDA cost spreadsheet. Sample input parameters for the SDA cost calculation are represented by the yellow highlighted cells. The input values designated "A" through "T" have the same meaning as those contained within the documentation for the IPM SDA cost algorithms (hereafter referred to as the "IPM SDA documentation") referenced above. The last four input values, (i. e., Interest rate, Equipment Lifetime, Gross Load, and Baseline) were added by us in order to calculate the annualized costs per ton of SO_2 removed ($/ton). Those cells that are not highlighted in yellow are interim calculations performed by the spreadsheet.

Table 7. Sample Input SDA Cost Model

Variable	Designation	Units	Value	Calculation	
Unit Size (Gross)	A	(MW)	500	**<--- User Input (Greater than 50 MW)**	
Retrofit Factor	B		1	**<--- User Input (an "average" retrofit has a factor =1.0)**	
Gross Heat Rate	C	(Btu/kWh)	9,800	**<--- User Input**	Max annual value from 2011-2015
SO2 Rate	D	(lb/MMBtu)	2.00	**<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)**	Avg. of months with full operating time
Type of Coal	E		PRB	**<--- User Input (PRB, BIT, or LIG)**	
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07	
Heat Rate Factor	G		0.98	C/10000	
Heat Input	H	(Btu/Hr)	4,900,000,000	A*C*1000	
Operating SO_2 Removal	J	(%)	95.00	**<--- User Input (Used to adjust actual operating costs)**	**Assume 95%. If outlet < 0.06 lbs/MMBtu, then assume % control for 0.06 lbs/MMBtu.**
Lime Rate	K	(Ton/Hr)	7	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)	
Waste Rate	L	(Ton/Hr)	16	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)	
Include Aux Power in VOM	M	(%)	1.35	(0.000547*D^2+0.00649*D+1.3)*F*G	Assume aux power is included in VOM
Makeup Water Rate	N	(1000 gph)	29	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000	
Lime Cost	P	($/Ton)	125	**<--- User Input**	Default - appears reasonable - see USGS lime report
Waste Disposal Cost	Q	($/Ton)	30	**<--- User Input**	default value
Aux Power Cost	R	($/kWh)	0.06	**<--- User Input**	default value
Makeup Water Cost	S	($/1000[gal])	1	**<--- User Input**	default value
Operating Labor Rate	T	($/hr)	60	**<--- User Input (Labor cost including all benefits)**	default value
Elevation adjustment if > 500 Feet		(feet)	0	**<--- User Input (no entry needed if less than 500 feet)**	Default value - check elevation.
Interest Rate		(%)	7	**<---- User Input**	
Equipment Lifetime		(years)	30	**<---- User Input**	
Gross Load		(MW-hours)	4,295,229	**<---- User Input**	5 -yr avg. excluding max and min
SO2 Emission Baseline		(tons/year)	30,591	**<---- User Input**	5 -yr avg. excluding max and min

3.2.7.1 Selection of SDA Cost Model Input Parameters

Below, for those input values that are different than our DSI cost model, we review the SDA cost model input values and discuss the procedures we employed in selecting them when developing the cost estimates for the individual SDA installations.

Type of Coal: Unlike the DSI cost algorithms discussed above, the SDA cost algorithms are relatively insensitive to the type of coal.

Operating SO_2 Removal. The operating SO_2 removal is the percentage reduction in SO_2 desired from the SO_2 rate. The IPM SDA Documentation states: "The curve fit was set to represent proprietary in-house cost data of a "typical" SDA FGD retrofit for removal of 95% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufacturers of SDA FGD systems, are 0.06 lb/MMBtu." As we discuss in Section 3.2.2, we have assumed a level of control equal to 95%, unless that level of control would fall below an outlet SO_2 level of 0.06 lb/MMBtu, in which case, we assume the percentage of control equal to 0.06 lbs/MMBtu.

Lime Cost. The cost of lime is the largest portion of the variable operating costs. At most dry scrubber facilities, the lime reagent is produced by onsite slaking of quicklime (calcium oxide) to

produce a slurry of solid hydrated lime (calcium hydroxide) particles.[44] Therefore, we assume in our cost model that quicklime is delivered to the facility where it is then slaked onsite, and that this cost is a part of the "base reagent preparation and waste recycle/handling" cost module.[45] The USGS estimates the average 2012 cost of quicklime to be $116/ton at the lime plant.[46] The cost algorithm default value is $125/ton. We have employed a value of $130/ton based on the 4/15/16 Trinity Nelson BART analysis, which is included in the 2017 Louisiana Regional Haze SIP as Appendix x.

Waste Disposal Cost. The waste disposal cost is the second largest portion of the variable operating costs. As with its DSI cost estimate, the value used in the 4/15/16 Trinity Nelson BART analysis is $7.50/ton, which is low in comparison to typical values we have seen. We are assuming the default value is $30/ton. This has the effect of significantly worsening (increased $/ton) the cost effectiveness.

Elevation Adjustment. The IPM SDA documentation states that the cost methodology is based on a unit located within 500 feet of sea level:[47]

> The actual elevation of the site should be considered separately and factored into the cost due to the effects on the flue gas volume. The base absorber island and balance of plant costs are directly impacted by the site elevation. These two base cost modules should be increased based on the ratio of the atmospheric pressure between sea level and the unit location. As an example, a unit located 1 mile above sea level would have an approximate atmospheric pressure of 12.2 psia. Therefore, the base absorber island and balance of plant costs should be increased by:
>
> 14.7 psia/12.2 psia = 1.2 multiplier to the base absorber island and balance of plant costs.

Although the cost algorithms call for this correction, no implementation was provided by S&L. Consequently, we included this atmospheric pressure adjustment in our SDA cost model by incorporating an atmospheric pressure change with elevation calculation provided by NASA.[48] In the case of the Nelson Unit 6, which is considerably below the 500 foot threshold value, this adjustment does not apply.

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[44] Primex Process Specialists. "Optimizing Scrubber Performance," p. 3. Available at http://www.primexprocess.com/pdf/Paper_4.pdf

[45] IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final, March 2013. Sargent & Lundy, p. 3

[46] U.S. Department of the Interior U.S. Geological Survey Mineral Commodity Summaries 2013, p. 92. Available at http://minerals.usgs.gov/minerals/pubs/mcs/2013/mcs2013.pdf

[47] IPM SDA documentation, p. 2.

[48] http://exploration.grc.nasa.gov/education/rocket/atmosmet.html. It should be noted that in addition to the NASA algorithm, this calculation requires converting the input feet to meters (multiplying elevation*0.3048) and K-Pa to psi (multiplying the calculation by 0.145038).

Equipment Lifetime. Similar to what we describe above in our DSI input analysis, this input value is not a part of the IPM SDA cost algorithms and was added by us in order to calculate the cost effectiveness in $/ton. It represents the actual or service life of the equipment in question. In past EPA rulemakings, we have note that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might be over 60 years.[49] We identified specific scrubbers installed between 1975 and 1985 that were still in operation. Consequently, we used a 30 year equipment life for scrubber retrofits and upgrades.

3.2.7.2 SDA Cost Model Output

A sample of the IPM SDA cost model output is depicted below in Table 8. As with our DSI cost model, the cost algorithms calculate the CECC and the FOM and VOM, and we add a calculation for the capital recovery factor, based on the interest rate and the equipment lifetime, and use it to annualize the CECC. We exclude AFUDC and "owner's costs." To the annualized CECC, we add the FOM and VOM to arrive at the total annualized costs. Lastly, we divide this figure by the SO_2 emissions reduction to calculate the cost effectiveness in $/ton.

[49] Response to Technical Comments for Sections E. through H. of the Federal Register Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan, Docket No. EPA-R06-OAR-2010-0190, 12/13/2011. See discussion beginning on page 36.

Table 8. Sample SDA Output

Capital Cost Calculation		Explanation of Calculation	Comments
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit difficulty	
BMR($)	51,886,000	Base module absorber island cost	
BMF($)	31,337,000	Base module reagent preparation and waste recycle/handling cost	
BMB($)	73,422,000	Base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.)	
BMBA($)	73,422,000	Adjustment to base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.), if elevation is greater than 500 feet. See page 2 of the S&L documentation.	
BM($)	**156,645,000**	Total Base module cost including retrofit factor	Page 6 of the S&L report gives BM=BMR+BMF+BMW+BMB. BMW appears to be an error (holdover from wet scrubber algorithm), as no formula is given for BMW.
BM($/kW)	313	Base module cost per kW	
Total Project Cost			
A1	15,665,000	Engineering and Construction Mnagement costs	
A2	15,665,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.	
A3	15,665,000	Contractor profit and fees.	
CECC ($)	**203,640,000**	Capital, engineering and construction cost subtotal	Excludes Owner's Costs.
CECC($/kW)	**407**	Capital, engineering and construction cost subtotal per kW	Excludes Owner's Costs.
B1	10,182,000	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)	
TPC' ($)	**213,822,000**	Total project cost without AFUDC	Includes Owner's Costs
TPC' ($/kw)	**428**	Total project cost per kW without AFUDC	Includes Owner's Costs
B2	21,382,000	AFUDC (Based on a 3 year engineering and construction cycle)	
TPC ($)	**235,204,000**	Total Project Cost (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
TPC ($/kW)	**470**	Total Project Cost per kW (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
Fixed O&M Cost			
FOMO ($/kW-yr)	2.00	Fixed O&M additional operating labor costs. Based on eight additional operators.	
FOMM ($/kW-yr)	4.70	Fixed O&M costs for waste disposal	
FOMA ($/kW-yr)	0.12	Fixed O&M additional administrative labor costs	
FOM ($/kW-yr)	**6.81**	Total Fixed O&M costs	
Variable O&M Cost			
VOMR ($/MWh)	1.81	Variable O&M costs for lime reagent	
VOMW ($/MWh)	0.96	Variable O&M costs for waste disposal	
VOMP ($/MWh)	0.81	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)	In the calculation, the factor of "10" results from dividing the conversion from kilo to mega (1000) by 100% , since the input for M is a percentage.
VOMM ($/MWh)	0.06	Variable O&M costs for makeup water	
VOM ($/MWh)	**3.64**	Total Variable O&M Costs	
Annualization			
Capital, engineering and construction cost	$203,640,000	Excludes owner's costs and AFUDC	
Capital Recovery factor	0.0806		
Annualized capital costs	$16,410,615		
Variable operating costs	$15,645,084	VOM*(Gross Load)	
Fixed operating costs	$3,340,299	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)	
Total annualized costs	**$35,395,997**		
SO2 emissions reduction (tons)	29,061	J/(100%)*(SO2 emission baseline)	
$/ton	**1,218**		

3.2.7.3 Summary of SDA Cost Model Results

Below in Table 9 is a summary of our SDA cost model results:

Table 9. Summary of SDA Cost Model Results for Nelson Unit 6

SDA Control (%)	92.11
SDA SO_2 Reduction (tpy)	9,361
SDA Capital Cost	$243,310,000
SDA Annualized Capital Cost	$19,607,478
SDA Variable Operating Cost	$5,014,430
SDA Fixed Operating Cost	$1,975,645
SDA Total Annualized Cost	$26,597,552
SDA Cost Effectiveness 2012 ($/ton)	$2,841
SDA Cost Effectiveness 2016 ($/ton)	$2,706

In contrast to our DSI cost model results, a greater portion of the total annualized cost of SDA is due to the annualized capital costs and the annualized capital cost is greater than the total operating cost in most cases. However, the annualized capital costs and the operating costs are much closer in magnitude.

3.2.8 Impact Analysis Part 1: Cost of Compliance for Wet FGD

Table 10, below, is a depiction of the input section of the wet FGD cost spreadsheet. Sample input parameters for the wet FGD cost calculation are represented by the yellow highlighted cells. The input values designated "A" through "T" have the same meaning as those contained within the documentation for the IPM wet FGD cost algorithms (hereafter referred to as the "IPM wet FGD documentation") referenced above. The last four input values, (i. e., Interest rate, Equipment Lifetime, Gross Load, and Baseline) were added by us in order to calculate the annualized costs per ton of SO_2 removed ($/ton). Those cells that are not highlighted in yellow are interim calculations performed by the spreadsheet.

Table 10. Sample Wet FGD Input Parameters

Variable	Designation	Units	Value	Calculation	
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 50 MW)	S&L has a drop down menu for selection of an additional WWTP facility, but no capital or operational cost are implemented so it is not reproduced here.
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor =1.0)	
Gross Heat Rate	C	(Btu/kWh)	9,500	<--- User Input	Max annual value from 2011-2015
SO2 Rate	D	(lb/MMBtu)	3.00		Avg. of months with full operating time
Type of Coal	E		BIT	<--- User Input (PRB, BIT, or LIG)	If blending, run once for PRB and one for LIG
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07	
Heat Rate Factor	G		0.95	C/10000	
Heat Input	H	(Btu/Hr)	4,750,000,000	A*C*1000	
Operating SO_2 Removal	J	(%)	95.00	<--- User Input (Used to adjust actual operating costs)	
Design Limestone Rate	K	(Ton/Hr)	12	(17.52*A*D*G/2000 (Based on 98% SO2 removal)	
Design Waste Rate	L	(Ton/Hr)	23	1.811*K (Based on 98% SO2 removal)	
Include Aux Power in VOM	M	(%)	1.59	(1.05e^(0.155*D+1.3))*F*G	Assume aux power is included in VOM
Makeup Water Rate	N	(1000 gph)	38	(1.674*D+74.68)*A*F*G/1000	
Limestone Cost	P	($/Ton)	30	<--- User Input	
Waste Disposal Cost	Q	($/Ton)	30	<--- User Input	default value
Aux Power Cost	R	($/kWh)	0.06	<--- User Input	default value
Makeup Water Cost	S	($/1000[gal])	1	<--- User Input	default value
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)	default value
Elevation adjustment if > 500 Feet		(feet)	0	<--- User Input (no entry needed if less than 500 feet)	Default value - check elevation.
Interest Rate		(%)	7	<---- User Input	
Equipment Lifetime		(years)	30	<---- User Input	
Gross Load		(MW-hours)	4,295,229	<---- User Input	5 -yr avg. excluding max and min
SO2 Emission Baseline		(tons/year)	30,591	<---- User Input	5 -yr avg. excluding max and min

3.2.8.1 Selection of Wet FGD Cost Model Input Parameters

Below, for those input values that are different than our SDA cost model, we review the wet FGD Cost Model input values and discuss the procedures we employed in selecting them when developing the cost estimates for the individual wet FGD installations.

Operating SO_2 Removal. The operating SO_2 removal is the percentage reduction in SO_2 desired from the SO_2 rate. The IPM wet FGD Documentation states: "The least squares curve fit of the data was defined as a "typical" wet FGD retrofit for removal of 98% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufacturers of wet FGD systems, are 0.04 lb/MMBtu." As we discuss in Section 3.2.2, we have assumed a level of control equal to 98%, unless that level of control would fall below an outlet SO_2 level of 0.04 lb/MMBtu, in which case, we assume the percentage of control equal to 0.04 lbs/MMBtu.

Limestone Cost. Unlike the DSI and SDA cost algorithms, the wet FGD cost algorithms are fairly insensitive to the cost of the reagent – limestone. The cost algorithm default cost for delivered lime is $30/ton. We have employed a value of $40/ton based on the 4/15/16 Trinity Nelson BART analysis.

Elevation Adjustment. Our wet FGD cost model incorporates the same elevation adjustment discussed above with regard to the SDA cost model.

Wastewater Treatment. The IPM wet FGD documentation states:

> The evaluation includes a user selected option for a wastewater treatment facility. The base capital cost includes minor physical and chemical wastewater treatment. However, in the future more extensive wastewater handling may be required. Although an option for wastewater treatment is provided, no logic has been developed to accommodate the additional wastewater treatment costs.

Consequently, our cost model incorporates minor physical and chemical wastewater treatment.

3.2.8.2 Wet FGD Cost Model Output

A sample of the IPM wet FGD cost model output is depicted below in Table 11. As with our DSI and SDA cost models, the cost algorithms calculate the CECC and the FOM and VOM, and we add a calculation for the capital recovery factor, based on the interest rate and the Equipment lifetime, and use it to annualize the CECC. We exclude AFUDC and "owner's costs." To the annualized CECC, we add the FOM and VOM to arrive at the total annualized costs. Lastly, we divide this figure by the SO_2 emissions reduction to calculate the cost effectiveness in $/ton.

Table 11. Sample Wet FGD Output

Capital Cost Calculation		Explanation of Calculation	Comments
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit difficulty	
BMR($)	61,153,000	Base absorber island cost	
BMF($)	18,869,000	Base reagent preparation and waste recycle/handling cost	
BMW($)	9,607,000	Base reagent	
BMB($)	111,481,000	Base balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.)	The cost algorithms present an additional factor, BMWW, for a possible future base wastewater treatment facility. It is currently not used, so it is not included here.
BMBA($)	111,481,000	Adjustment to base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.), if elevation is greater than 500 feet. See page 2 of the S&L documentation.	
BM($)	**201,110,000**	Total Base module cost including retrofit factor	
BM($/kW)	327	Base cost per kW	
Total Project Cost			
A1	20,111,000	Engineering and Construction Mnagement costs	
A2	20,111,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.	
A3	20,111,000	Contractor profit and fees.	
CECC ($)	**261,443,000**	Capital, engineering and construction cost subtotal	Excludes Owner's Costs.
CECC($/kW)	**425**	Capital, engineering and construction cost subtotal per kW	Excludes Owner's Costs.
B1	13,072,000	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)	
TPC' ($)	**274,515,000**	Total project cost without AFUDC	Includes Owner's Costs
TPC' ($/kw)	**447**	Total project cost per kW without AFUDC	Includes Owner's Costs
B2	27,452,000	AFUDC (Based on a 3 year engineering and construction cycle)	
TPC ($)	**301,967,000**	Total Project Cost (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
TPC ($/kW)	**491**	Total Project Cost per kW (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
Fixed O&M Cost			The cost algorithms present additional factors, FOMWW and VOMWW, for a possible future base wastewater treatment facility. They are currently not used, so they are not included here.
FOMO ($/kW-yr)	3.09	Fixed O&M additional operating labor costs. IF MW > 500, then 16 operators, else 12 operators	
FOMM ($/kW-yr)	4.91	Fixed O&M additional maintenance material and labor costs	
FOMA ($/kW-yr)	0.15	Fixed O&M additional administrative labor costs	
FOM ($/kW-yr)	**8.15**	Total Fixed O&M costs	
Variable O&M Cost			
VOMR ($/MWh)	0.28	Variable O&M costs for limestone reagent	
VOMW ($/MWh)	0.38	Variable O&M costs for waste disposal	In the calculation, the factor of "10"
VOMP ($/MWh)	0.53	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)	results from dividing the conversion from kilo to mega (1000) by 100% , since the input for M is a percentage.
VOMM ($/MWh)	0.05	Variable O&M costs for makeup water	
VOM ($/MWh)	**1.23**	Total Variable O&M Costs	
Annualization			
Capital, engineering and construction cost	$261,443,000	Excludes owner's costs and AFUDC	
Capital Recovery factor	0.0806		
Annualized capital costs	$21,068,751		
Variable operating costs	$3,817,787	VOM*(Gross Load)	
Fixed operating costs	$2,877,622	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)	
Total annualized costs	**$27,764,161**		
SO2 emissions reduction (tons)	10,896	J/(100%)*(SO2 emission baseline)	
$/ton	**2,548**		

3.2.8.3 Summary of Wet FGD Cost Model Results

Below in Table 12 is a summary of our wet FGD cost model results:

Table 12. Summary of Wet FGD Cost Model Results for Nelson Unit 6

wet FGD Control (%)	94.74
wet FGD SO2 Reduction (tpy)	9,628
wet FGD Capital Cost	$266,892,000
wet FGD Annualized Capital Cost	$21,507,866
wet FGD Variable Operating Cost	$3,596,879
wet FGD Fixed Operating Cost	$2,623,645
wet FGD Total Annualized Cost	$27,728,390
wet FGD Cost Effectiveness 2012 ($/ton)	$2,880
wet FGD Cost Effectiveness 2016 ($/ton)	$2,743

As with our SDA cost model results, the majority of the total annualized cost of SDA is due to the annualized capital costs. However, the annualized capital costs is much greater than the operational costs. This is due to the slightly higher capital cost of the equipment and the lower cost of reagent (limestone versus lime), in relation to SDA.

Table 13 compares the capital cost and cost effectiveness of both technologies:

Table 13. Capital cost and cost effectiveness of wet FGD versus SDA for Nelson Unit 6

Capital Cost SDA	Capital Cost Wet FGD	% Difference Capital Cost Wet FGD over SDA	SDA Cost Effectiveness 2016 ($/ton)	Wet FGD Cost Effectiveness 2016 ($/ton)	% Difference $/ton Wet FGD over SDA
$243,310,000	$266,892,000	8.8	$2,706	$2,743	1.3

The capital cost of wet FGD is higher than SDA by approximately 8.8%. However, the cost-effectiveness of wet FGD versus SDA is very close. This is mainly due to the greater level of control (98% maximum versus 95% maximum) of wet FGD over SDA, which tends to offset the additional cost of wet FGD.

3.2.9 Impact Analysis Part 1: Cost of Compliance for Switching to Lower Sulfur Coal

Regarding the cost of this switch, Entergy states that the cost of the lower sulfur coal, "is based on a cost premium of $0.50 per ton, which was provided by Entergy's fuel purchasing department." No further support for this figure was provided. Entergy uses this cost premium to calculate a cost-effectiveness for switching to lower sulfur coal of $597/ton. In an effort to confirm this estimate, EPA has developed its own cost analysis as described below.

Our analysis is based on an evaluation of a control level of 0.60 lbs/MMBtu, which should serve as a general comparison to DSI, SDA, and wet FGD. Use of coals resulting in SO_2 emissions lower than 0.60 lbs/MMBtu would impact the cost-effectiveness.

In Table 2 above, we calculate the theoretical SO_2 emissions that would result from the burning of the coal, using the reported sulfur content, from the following equation:

Equation 1

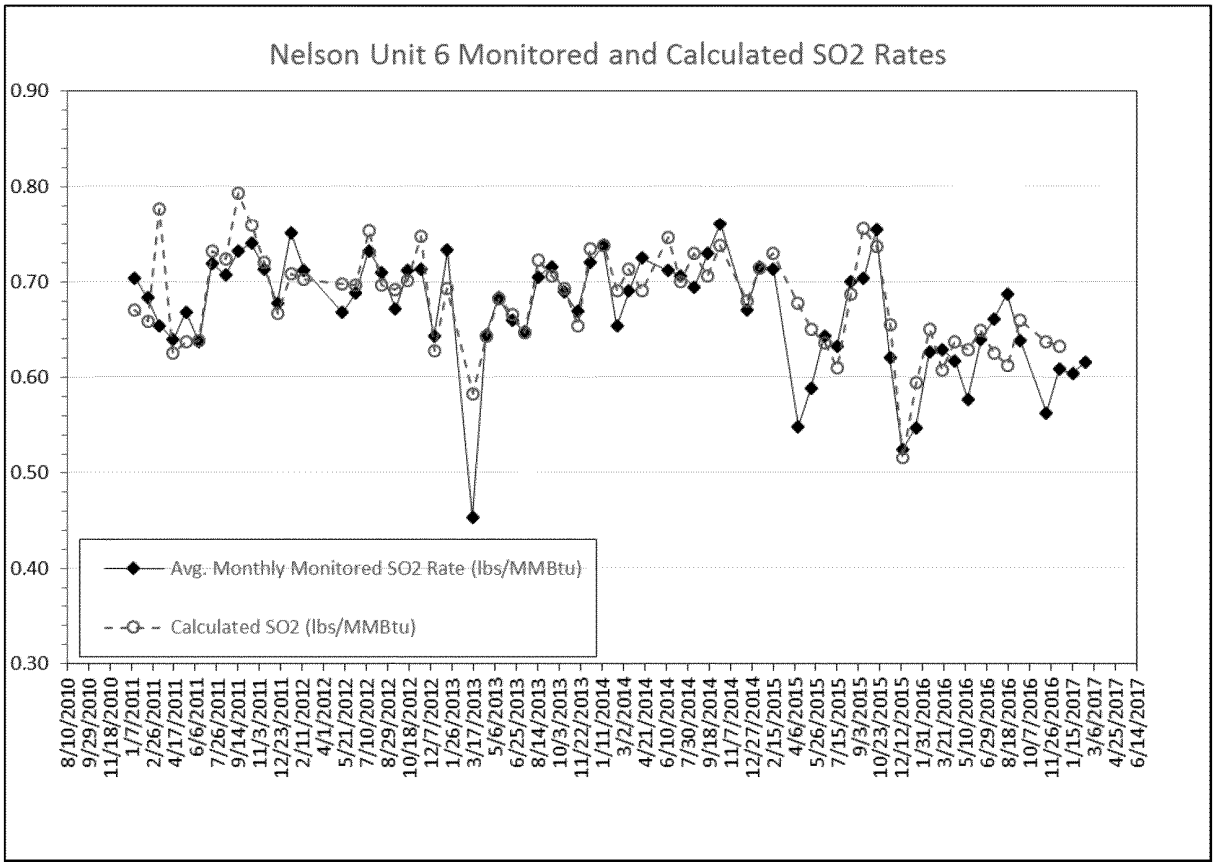
$$\% \quad \frac{1{,}000{,}000}{} \quad \frac{64 \quad / \quad ^2}{32 \quad / \quad} \quad \frac{1}{100\%}$$

Where: S = sulfur
% S = percent sulfur by weight
lb = pound
Btu = British Thermal Unit

Because the above equation is a theoretical calculation we tested it against Entergy's own monitoring data, as reported to us:[50]

Figure 3. Nelson Unit 6 Monitored and Calculated SO_2 Rates

[50] Monitoring data were obtained from https://ampd.epa.gov/ampd/. In this comparison, we used the information from "Page 3 Boiler Fuel Data," which we believe reflects the fuel that was burned by the Nelson facility.



The difference between these two values could be due to a number of factors, generally acknowledged in the literature, which include:

- Inadequate coal sampling including factors such as sample size, frequency, location (at the mine, train manifest, pile, blending hopper, silos, conveyor belts);
- Errors in reporting of the coal sulfur data, the heating value of the coals, and the amount of coal burned.
- Our assumption that all coal sulfur will be oxidized to SO_2 in equation (1) at the theoretical rate of 2 pounds SO_2 for every pound of S. Some of the sulfur is in fact converted to other sulfur compounds such as SO_3 that are not measured by the SO_2 CEMS.[51]
- Potential effects of the Nelson Unit 6 ESP. ESPs reduce sulfur by removing particulate matter with absorbed SO_3.[52]
- Losses of sulfur, such as pyrite, when the coal is pulverized or in bottom ash.

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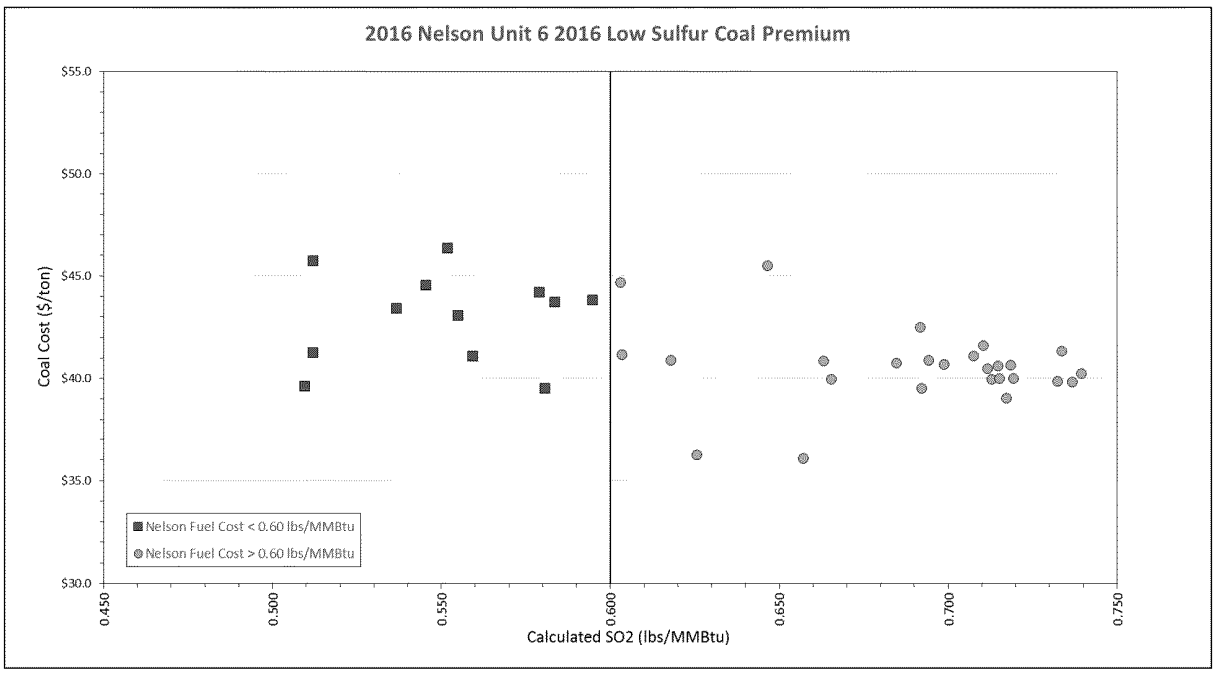
[51] Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, Technical Update, EPRI, March 2012.
[52] R. Hardman, et al, Estimating Sulfuric Acid Aerosol Emissions from Coal-Fired Power Plants, U. S. Department of Energy-FETC Conference on Formation, Distribution, Impact, and Fate of Sulfur Trioxide in Utility Flue Gas Streams, March 1998; R. K., Srivastava, et al, Emission of Sulfur Trioxide from Coal-Fired Power Plants, J. Air Waste Manag Assoc. 2004 Jun;54(6):750-62.

- Sulfur reported on an as-received basis rather than dry basis; the as-received sample includes moisture, which would dilute (or lower) the sulfur content.

Nevertheless, as can be seen from the above figure, there is a fairly good correspondence between the Nelson Unit 6 calculated SO_2 emissions and the actual monitored Nelson Unit 6 SO_2 emissions. We believe this validates the analysis we present below which relies on coal purchasing data.

After ordering the data in increasing sulfur content, we identified all the coal purchases in 2016 for which the calculated SO_2 emissions are below (shaded in green) and above (shaded in yellow) the 0.60 lbs/MMBtu level Entergy has selected for its low sulfur coal BART case. That information is presented below graphically:[53]

Figure 4. 2016 Nelson Unit 6 Low Sulfur Premium



Although the data is somewhat scattered, it does appear that the actual premium Entergy paid for coals that would result in a SO_2 emission limit below 0.60 lbs/MMBtu is higher than the $0.50 Entergy reports in its BART analysis. The average costs of these coals are as follows:

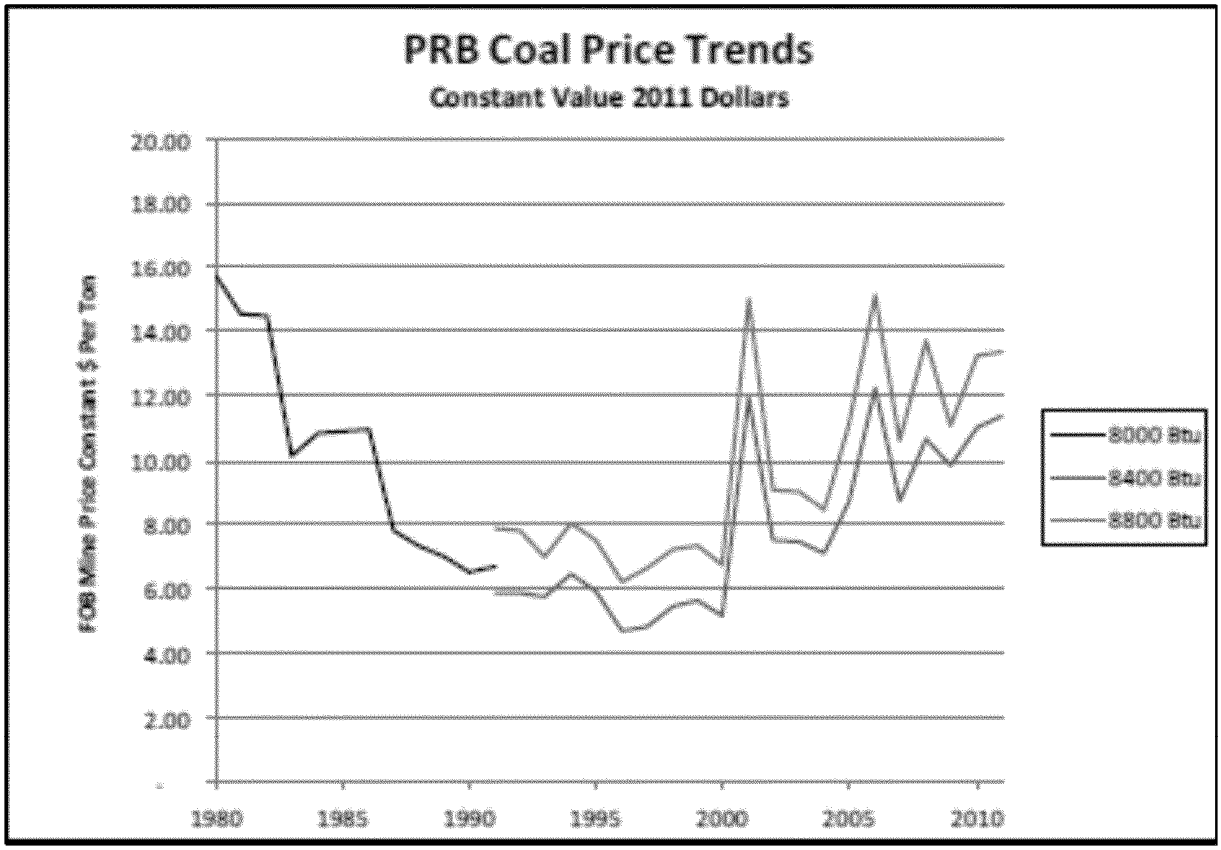
Table 14. Estimate of 2016 Entergy Low Sulfur Coal Premium

2016 Average Coal Price > 0.60 lbs/MMBtu	$43.43
2016 Average Coal Price < 0.60 lbs/MMBtu	$40.56
2016 Lower Sulfur Coal Premium	$2.48

[53] See the file, "Nelson control costs with Entergy Corrections.xlsx," Tab "EIA 923 Purchased Coal Data."

Our calculated lower sulfur coal premium of $2.48 appears to be consistent with information published by *Coal Outlook*, at least as of 2011.[54]

Figure 5. Published Price Differential for PRB Coals



Although the above figure compares the heating value of the coal (Btu), it is directly translatable to sulfur content. As in indicated by Table 2, above, the lower sulfur coals purchased by Entergy in almost all cases also convey higher heating values. Those higher heating values are captured by the generalized 8,800 Btu coal category in the above figure.

The actual premium Entergy must pay for lower sulfur coal is an important determinant in the cost-effectiveness calculation, as it is a direct multiplier. Entergy reports that cost-effectiveness, based on a $0.50/ton premium, is $597/ton. If instead, the actual premium is higher, the cost-effectiveness is multiplied accordingly. Entergy does not report how it made this calculation so we cannot duplicate it. However, below we calculate the cost-effectiveness of a lower sulfur

[54] Referenced in the study, "Powder River Basin Coal Resource And Cost Study Campbell, Converse and Sheridan Counties, Wyoming, Big Horn, Powder River, Rosebud and Treasure Counties, Montana. Prepared for Xcel Energy by, John T. Boyd Company, Mining and Geological Consultants, Denver, Colorado. Report No. 3155.001, September 2011." See pdf 74.

coal from the same SO_2 baseline we used above in our critique of Entergy's SDA cost-effectiveness calculation (and which we use in our own cost-effectiveness calculations) to illustrate the effect of the low sulfur coal premium.

We start by noting that, as Table 15 indicates, Entergy has purchased both higher and lower sulfur coals, so were we to apply a lower sulfur coal premium to the Nelson historical coal purchases in order to calculate a resulting capital cost, we must make two adjustments: (1) We must account for the amount of lower sulfur coal purchased, and, as we discuss above, (2) we must also account for the fact that lower sulfur PRB coals typically convey higher heating values. Regarding the first adjustment, below we present a tally of the amount of higher and lower sulfur coals purchased by Entergy for the Nelson Unit 6 during the baseline years. As above, this is based on the same calculated 0.60 lbs/MMBtu level Entergy has selected for its low sulfur BART case.

Table 15. Nelson Unit 6 Higher and Lower Sulfur Coal Purchases in the Baseline Years

	Baseline Years		
	2013	2014	2016
Total Fuel Purchased (tons)	1,962,663	1,528,286	1,457,784
Total Fuel Purchased above 0.60 lbs/MMBtu (tons)	1,479,148	1,331,841	1,080,360
Total Fuel Purchased below 0.60 lbs/MMBtu (tons)	483,515	196,445	377,424
Fraction Fuel Purchased above 0.60 lbs/MMBtu	0.754	0.871	0.741

The above fractions are used in the capital cost we present below.

Regarding the second adjustment, we averaged the heating value reported by Entergy to EIA in Form 923 for the baseline years to obtain a value of 8,589 Btu/lb. Similar to the higher/lower sulfur coal fractions, we divide the resulting average heating value of 8,589 Btu/lb by 8,800 Btu/lb, resulting in a fraction that we will apply in the capital costs we present below.

Table 16. Entergy and EPA Low Sulfur Coal Cost-effectiveness Calculations

Low Sulfur Coal Cost-effectiveness Calculations					
Year	**Total Fuel Consumed (tons)**	**Annual SO_2 Averages used in baseline**	**Total Fuel Quantity Reported to EIA for EPA Baseline Years**	**Percentage Fuel Purchased above 0.60 lbs/MMBtu**	**Annual Heat Input for EPA Baseline Years**
2011	2,382,479				
2012	2,062,674				
2013	1,978,331	11,455	1,978,331	0.754	3.37E+07
2014	1,791,371	10,540	1,791,371	0.871	2.95E+07

2015	1517593				
2016	1,563,472	8,495	1,563,472	0.741	2.69E+07

Entergy's BART $0.50 Lower Sulfur Premium & EPA SO_2 Baseline	
Calculated Additional Annual Lower Sulfur Coal Cost (using Entergy's $0.50/ton premium)	$684,936
SO_2 Baseline (tpy)	10,163
SO_2 Emissions assuming SO_2 Baseline Heat Input @ 0.60 lbs/MMBtu (tpy)	9,015
SO_2 Emissions Reduction @ 0.60 lbs/MMBtu (tpy)	1,149
Low Sulfur Coal Cost-effectiveness ($/ton)	$596

Entergy's 2016 $2.48 Lower Sulfur Premium & EPA SO_2 Baseline	
Calculated Annual Lower Sulfur Coal Cost (using Entergy's 2016 $2.48/ton premium)	$3,397,281
SO_2 Baseline (tpy)	10,163
SO_2 Emissions assuming SO_2 Baseline Heat Input @ 0.60 lbs/MMBtu (tpy)	9,015
SO_2 Emissions Reduction @ 0.60 lbs/MMBtu (tpy)	1,149
Low Sulfur Coal Cost-effectiveness ($/ton)	$2,957

Note that in the above tables, the annual lower sulfur coal costs were calculated by multiplying each of the baseline year fuel quantities by its corresponding high/low sulfur percentage, averaging the result, and then multiplying it by the Btu fraction we discuss above. The resulting value is then multiplied by lower sulfur coal cost premiums.

3.2.10 Impact Analysis Part 1 Incremental Cost of Compliance

The BART Guidelines state:

> In addition to the average cost effectiveness of a control option, you should also calculate incremental cost effectiveness. You should consider the incremental cost effectiveness in combination with the average cost effectiveness when considering whether to eliminate a control option. 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 (with respect to cost per emissions reduction):
>
> Incremental Cost Effectiveness (dollars per incremental ton removed) = (Total annualized costs of control option) - (Total annualized costs of next control option) ÷ (Control option annual emissions) - (Next control option annual emissions).

We have integrated this concept into our Entergy Nelson Unit 6 BART analyses by calculating the incremental cost-effectiveness of lower sulfur coal to DSI_{50}, DSI_{50} to SDA, and SDA to wet

FGD. We did not include DSI_{80} because we do not believe this technology would likely be selected, based on the cost-effectiveness of DSI_{50} and scrubbers. This information is presented below:

Table 17. Summary of SO_2 BART Incremental Cost-Effectiveness for Nelson Unit 6

Control	Control level (%)	SO_2 reduction (tpy)	2012 Capital Cost	2012 Total Annualized Cost	2016 Total Annualized Cost	2016 Cost Effectiveness ($/ton)	2016 Incremental $/ton
Lower Sulfur Coal		1,149			$3,397,281	$2,957	
DSI	50	5,082	$17,840,000	$19,087,899	$18,180,195	$3,578	$3,759
SDA	92.11	9,361	$243,310,000	$26,597,552	$25,332,736	$2,706	$1,671
Wet FGD	94.74	9,628	$266,892,000	$27,728,390	$26,409,798	$2,743	$4,027

3.2.11 Impact Analysis Parts 2, 3, 4: Energy and Non-air Quality Environmental Impacts, and Remaining Useful Life

Regarding the analysis of energy impacts, the BART Guidelines advise, "You should examine the energy requirements of the control technology and determine whether the use of that technology results in energy penalties or benefits."[55] As discussed above in our cost analyses for DSI, SDA, and wet FGD, our cost model allows for the inclusion or exclusion of the cost of the additional auxiliary power required for the pollution controls we considered to be included in the variable operating costs. We chose to include this additional auxiliary power in these cases. There is no auxiliary power requirement associated with switching to a lower sulfur coal. Consequently, we believe that any energy impacts of compliance have been adequately considered in our analyses.

Regarding the analysis of non-air quality environmental impacts, the BART Guidelines advise:[56]

> Such environmental impacts include solid or hazardous waste generation and discharges of polluted water from a control device. You should identify any significant or unusual environmental impacts associated with a control alternative that have the potential to affect the selection or elimination of a control alternative. Some control technologies may have potentially significant secondary environmental impacts. Scrubber effluent, for example, may affect water quality and land use. Alternatively, water availability may affect the feasibility and costs of wet scrubbers. Other examples of secondary environmental impacts could include hazardous waste discharges, such as spent catalysts or contaminated carbon. Generally, these types of environmental concerns become important when sensitive site-specific receptors exist or when

[55] 70 FR 39104, 39168 (July 6, 2005) [40 CFR Part 51, App. Y].
[56] *Id.* At 39169.

> the incremental emissions reductions potential of the more stringent control is only marginally greater than the next most-effective option. However, the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BART, particularly if the control device has been applied to similar facilities elsewhere and the solid or liquid waste is similar to those other applications. On the other hand, where you or the source owner can show that unusual circumstances at the proposed facility create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control alternative as BART.

Two of the SO_2 control technologies we considered in our analysis – DSI and scrubbers – are in wide use in the coal-fired electricity generation industry. Both technologies add spent reagent to the waste stream already generated by the facilities we analyzed, but do not present any significant or unusual environmental impacts. As discussed below in our cost analyses for DSI and SDA SO_2 scrubbers, our cost model includes waste disposal costs in the variable operating costs. There are no non-air quality environmental impacts associated with switching to a lower sulfur coal. Consequently, we believe any non-air quality environmental impacts have been adequately considered in our analyses.

Regarding the remaining useful life, the BART Guidelines advise:[57]

> You may decide to treat the requirement to consider the source's ''remaining useful life'' of the source for BART determinations as one element of the overall cost analysis. The ''remaining useful life'' of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's OAQPS Control Cost Manual require the use of a specified time period for amortization that varies based upon the type of control. If the remaining useful life will clearly exceed this time period, the remaining useful life has essentially no effect on control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, you should use this shorter time period in your cost calculations.

We are unaware that the Nelson Unit 6 has entered into an enforceable document to shut down that unit earlier. In the DSI, SDA, wet FGD, and scrubber upgrades sections above, we have provided our reasoning why we believe that a 30 year equipment life for DSI, scrubber retrofits, and scrubber upgrades is appropriate.

As discussed above, we see no energy and non-air quality environmental impacts, or remaining useful life considerations for switching to a lower sulfur coal.

---

[57] 70 FR 39104, 39169 (July 6, 2005) [40 CFR Part 51, App. Y].

To: Donaldson, Guy[Donaldson.Guy@epa.gov]
From: LDEQ Dropoff
Sent: Sat 2/11/2017 1:24:52 AM
Subject: [LDEQ Dropoff] Vennetta Hayes has dropped off files for you

This is an automated message sent to you by the LDEQ Dropoff service.

Vennetta Hayes (Vennetta.Hayes@LA.GOV) has dropped-off 12 files for you.

IF YOU TRUST THE SENDER, and are expecting to receive a file from them, you may choose to retrieve the drop-off by clicking the following link (or copying and pasting it into your web browser):

https://dropoff.deq.louisiana.gov/pickup.php?claimID= Ex. 6 - Personal Privacy &claimPasscode= Ex. 6 - Personal Privacy &emailAddr=donaldson.guy%40epa.gov

You have 20 days to retrieve the drop-off; after that the link above will expire. If you wish to contact the sender, just reply to this email.

The sender has left you a note:

Entergy files

Full information about the drop-off:

Claim ID: Ex. 6 - Personal Privacy
Claim Passcode: Ex. 6 - Personal Privacy
Date of Drop-Off: 2017-02-10 19:24:51-0600

-- Sender --
Name: Vennetta Hayes
Organisation: Department of Environmental Quality
Email Address: Vennetta.Hayes@LA.GOV
IP Address: 159.39.19.98 (x19098.deq.louisiana.gov)

-- Files --
Name: Ltr 2016-11-10 from KMM to LDEQ re Waterford BART.pdf
Description:
Size: 52.0 KB
Content Type: application/pdf

Name: Reply to EPA on LA BART Issues_Final 4-15-16.pdf
Description:
Size: 245.8 KB
Content Type: application/pdf

Name: Entergy LA BART Screening Report 2015-1109 (FINAL).pdf
Description:
Size: 4.5 MB
Content Type: application/pdf

Name: Cover Letter Regarding Response to Section 114 Requests.pdf
Description:
Size: 128.4 KB
Content Type: application/pdf

Name: Entergy Services Modeling Report (FINAL).pdf
Description:
Size: 2.9 MB
Content Type: application/pdf

Name: Ltr 2015-08-24 from FHyman to VAucoin re N4-WG3-LG3 Aux Boilers BART eligibility.pdf
Description:
Size: 343.5 KB
Content Type: application/pdf

Name: [Untitled].pdf
Description:
Size: 366.7 KB
Content Type: application/pdf

Name: Ltr 7-29-15 from KMM to GDonalson re 114 Request requesting extension of 7-31-15 response.pdf
Description:
Size: 107.9 KB
Content Type: application/pdf

Name: Ltr 6-15-15 from KMM to GDonaldson re Entergy Companies Initial Response to 114 LA RH Request.pdf
Description:
Size: 299.5 KB
Content Type: application/pdf

Name: EPA reply to Entergy 5-20-15.pdf
Description:
Size: 1.7 MB
Content Type: application/pdf

Name: Entergy - BART 5-12-2015.pdf
Description:
Size: 246.1 KB
Content Type: application/pdf

Name: Scanned from a Xerox multifunction device001.pdf
Description:
Size: 167.2 KB
Content Type: application/pdf

To: Huser, Jennifer[Huser.Jennifer@epa.gov]; Donaldson, Guy[Donaldson.Guy@epa.gov]
Cc: Donald Trahan[Donald.Trahan@LA.GOV]; Bijan Sharafkhani[Bijan.Sharafkhani@LA.GOV]; Stenger, Wren[stenger.wren@epa.gov]; Thomas, Carrie[Thomas.Carrie@epa.gov]
From: Vivian Aucoin
Sent: Sat 2/11/2017 1:04:56 AM
Subject: RE: Louisiana's Regional Haze EGU BART SIP Submittal (1 of 3)
RH EGU BARt Louisiana Final_2.pdf

Greetings,

The LDEQ has not changed its position on accepting the language as provided. It was a matter of working with the wrong draft version as we had received 2 from EPA.

As you will see in the attached version, all changes have been accepted as agreed; the only language that had not been accepted was that which was incorporated in the 2/6/2017 version dealing with the Entergy Waterford facility. The document now reflects the language that is included in the AOC that was executed by the LDEQ and the facility as an enforceable mechanism constituting BART controls.

This document will be substituted for the one the will be electronically submitted, as well as the hard copy version that will be FedEx'd to your offices on Monday. The changes will also be reflected in the document to be submitted to EDMS. Please note the version now has a 2 in the title.

I am sorry for any confusion this might have caused.

Vivian H. Aucoin

Environmental Scientist, Senior

Air Permits Division, State Implementation Plan

225-219-3482

vivian.aucoin@la.gov

From: Huser, Jennifer [mailto:Huser.Jennifer@epa.gov]
Sent: Friday, February 10, 2017 5:56 PM
To: Vivian Aucoin; Donaldson, Guy
Cc: Donald Trahan; Bijan Sharafkhani; Stenger, Wren; Thomas, Carrie
Subject: RE: Louisiana's Regional Haze EGU BART SIP Submittal (1 of 3)

Hi Vivian,

The SIP narrative does not include the red line strikeout language we provided on Monday 2/6/17, and you confirmed would be acceptable to LDEQ on 2/7/17.

Please let me know if something changed in LDEQ's position between 2/7/17 and today to result in the changes not being incorporated.

Thanks,

Jennifer Huser

Environmental Scientist

Air Planning Section (6MM-AA)
USEPA Region 6
1445 Ross Ave. Suite 1200
Dallas, TX 75202-2733
214-665-7347

From: Vivian Aucoin [mailto:Vivian.Aucoin@LA.GOV]
Sent: Friday, February 10, 2017 3:44 PM
To: Donaldson, Guy <Donaldson.Guy@epa.gov>; Huser, Jennifer <Huser.Jennifer@epa.gov>
Cc: Donald Trahan <Donald.Trahan@LA.GOV>; Bijan Sharafkhani <Bijan.Sharafkhani@LA.GOV>
Subject: Louisiana's Regional Haze EGU BART SIP Submittal (1 of 3)

Importance: High

Greetings,

Attached please find the SIP document with the transmittal letter and the response to comment document. Two more emails will follow that will have enclosed the executed AOCs for NRG, CLECO and Entergy.

The remainder of the documents will be loaded into a drop-box and address to both Guy Donaldson and Jennifer Huser. A complete copy of the SIP will be mailed on Monday and an additional copy will be placed into LDEQ's EDMS. Once the document is loaded into EDMS, I will forward the DOC ID#.

If you need anything further, please do not hesitate to contact me at the number below.

Vivian H. Aucoin

Environmental Scientist, Senior

Air Permits Division, State Implementation Plan

225-219-3482

vivian.aucoin@la.gov

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

Regional Haze State Implementation Plan

EGU BART Analysis

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

FINAL February 2017

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 CAA 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 EPA further outlined those elements that were included in the partial disapproval. Furthermore, EPA found that certain elements of the BART evaluations and determinations were not fully adequate to meet the federal regulations. In a separate rulemaking, the US EPA issued a limited disapproval of the regional haze SIPs for several states including Louisiana because, among other things, these states relied on CAIR as an alternative to BART for SO_2 and NO_X for electric generating units (EGUs). 77 FR 33641, June 7, 2012. In this submittal, the LDEQ will address only those BART-eligible units that are EGUs. This RH SIP submittal is intended to supersede the portions of LDEQ's 2008 SIP submittal addressing EGU BART that EPA found deficient in the limited disapproval action at 77 FR 33641. This submittal fulfills the requirements of Phase I of the Regional Haze Rule.

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 October 20, 2016 in the *Louisiana Register*. No public hearings were requested. A copy of the potpourri notice and all comments and responses are included in Appendix A.

D. Commitment to Plan Revision

The consultation process will continue between LDEQ, the EPA 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

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

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

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

chain is constantly altered by tropical storms, wind, and tidal action. The area above mean high tide is approximately 6,923 acres; however, Hurricanes 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 (Phase I) 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, which provided a review of the long-term strategy to ensure that the SIP was adequate for preventing impairment of visibility at Breton in agreement with Phase I EPA visibility regulations. Further, it was used to provide the public and EPA a comprehensive analysis of the progress toward the national visibility goal.

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[3] ibid

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

II. BART Analysis

In its original submittal on June 13, 2008, the LDEQ relied on the CAIR in lieu of BART for EGUs. The RH rule allowed states to implement an alternative program in lieu of BART so long as the alternative program could demonstrate that it would achieve greater reasonable progress toward the national visibility goal than would BART. CAIR introduced a cap-and-trade program, either by FIP or SIP, that through participation provided that BART-eligible EGUs were not required to install, operate, and/or maintain BART for emissions of SO_2 and NO_x. Facilities were required to complete the screening and subsequent analysis for particulate matter (PM).

Challenges to CAIR resulted in the remand of the rule to the EPA. Subsequent iterations of the rule have been proposed, namely the Transport Rule and the Cross State Air Pollution Rule (CSAPR), both of which have been approved as a substitute for BART. These challenges, either directly or indirectly through stay orders, resulted in the facilities participating in CAIR until December 31, 2014. While EGUs in Louisiana were required to participate in CAIR for both SO_2 and NO_X, Louisiana EGUs are only included in CSAPR for ozone season NO_X. Therefore, in Louisiana, there is no federally approved alternative to source specific BART for SO_2. Source specific BART is also required for PM for Louisiana's subject to BART EGUs. Because Louisiana is included in the CSAPR program for ozone season NO_x, the State intends to rely on CSAPR as an alternative to source specific BART for NO_x for the BART-eligible EGUs.

Given that EPA directly addressed the EGUs in the limited disapproval by stating that the SO_2 portion of CSAPR was not applicable to the facilities, a source-specific BART determination is necessary. LDEQ has identified 13 units that are BART-eligible and has applied either screening or refined modeling to determine if a facility will have a greater than 0.5 deciview (Δdv) impact on the nearest Class I areas and the control strategies that will afford the necessary emission reductions to maintain the uniform rate of progress toward the 2064 visibility goal. As of this writing, Louisiana has surpassed the Reasonable Progress Goals projections and remains below the glide path mapping a direct course toward the final visibility goal.

A. CLECO

CLECO Teche Power Station, located in Baldwin, St. Mary Parish, Louisiana, is an electrical utility power station. Unit 3 operates a 359 MW boiler/turbine system which is permitted for natural gas, No. 2 fuel oil, or No. 4 fuel oil. Based on the results of the screening analysis conducted, visibility impacts from Teche Unit 3 are less than the 0.5Δdv screening threshold and are therefore not subject to BART.[4]

CLECO BRAME operates two electric utility units in Lena, Rapides Parish, Louisiana:

- **Nesbit I (Unit 1)**, a 440 MW fossil-fuel fired boiler/turbine system and is not equipped with any air pollution control devices. While the unit is permitted to combust oil, it has not done so in many years and due to the Mercury Air Toxics Standards (MATS) rule, it will not combust oil in the future. Results of the modeling and analysis indicate the following for Unit 1: SO_2 BART controls are satisfied through the conversion to natural gas; NO_x BART controls are satisfied by the requirements of the CSAPR; PM_{10} BART -no additional controls constitute BART.
- **Rodemacher II (Unit 2)** is a 523 MW fossil-fuel fired boiler/turbine system that burns Powder River Basin (PRB) coal. Cleco has recently made several changes that reduce emissions, such as: Low NOx burners were installed in 2008; Low-sulfur fuel began to be burned in 2009; Selective non-catalytic reduction (SNCR) was installed in 2014 for complying with ozone season NOx requirements of CSAPR; and Dry Sorbent Injection (DSI) activated carbon injection (ACI) and a fabric filter (FF) were installed in 20155 for compliance with MATS. Results of the modeling and analysis indicated the following for Unit 2: SO_2 BART controls are satisfied with the installation of enhanced DSI,[5] NO_x BART controls are satisfied by the requirements of CSAPR, and PM_{10} BART-no additional controls constitute BART.

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[4] See *CALPUFF Modeling Report BART Applicability Screening Analysis* conducted by Trinity Consultants, July 30, 2015; page 1-2

[5] Cleco has executed an Administrative Order on Consent with the LDEQ stating that these enforceable emissions limits are dependent upon the EPA's approval of the SIP. If EPA does not approve this SIP, the AOC will be rendered void.

LDEQ included Unit 1 among the BART-affected sources that were listed in the original Regional Haze SIP submitted on June 13, 2008, however Unit 2 was not previously listed as a BART-affected source; it was later determined to be a BART-eligible source and is therefore included in this SIP revision. In response to EPA's Section 114 request,[6] Cleco submitted a BART-applicability screening analysis to the LDEQ and EPA on August 31, 2015. Brame Units 1 and 2 were determined to be BART-affected emission units established upon the CALPUFF – based screening analysis; therefore, Cleco has submitted a BART five-factor analysis on each of the emissions units. (See Appendix B)

Understanding that SO_2 is the predominant sulfur compound emitted from Brame Unit 2, the BART analysis was specific to the those emissions; it should be noted that the reductions in SO_2 emissions will further reduce visibility impairment by reducing sulfate formation. The analysis identified available SO_2 control technologies and evaluated each according to the statutory requirements. The available control technologies evaluated were Dry Sorbent Injection (DSI); Enhanced DSI; Dry/Semi-dry scrubbing and Wet Scrubbing. The results of the analysis indicated that enhancing the DSI system at Unit 2 can achieve an outlet emission rate of 0.30lb/MMBtu on an annual-average basis.

The LDEQ finds that, with the addition of the enhanced DSI along with the controls installed as well as the current operating conditions and permit limits included in the Administrative Order on Consent, the Cleco Brame facility has satisfied the BART requirements.

It should be noted that Cleco presented the LDEQ with CAMx modeling as a further demonstration that the facilities have no visibility impact on the Class I areas. While LDEQ did not use this information to make a BART requirement determination, the information contained in the model results was useful toward making the final decision that CLECO has indeed satisfied all BART requirements. The CAMx model is included in Appendix B.

[6] Wren Stenger, Section 114(a) Information Request letter to Darren Olagues (CLECO), May 19, 2015.

B. Louisiana Generating, LLC, a subsidiary of NRG

Big Cajun I is a steam generating plant located in Jarreau, Pointe Coupee Parish, Louisiana. The station includes two separate natural gas-fired boilers and two natural gas fired combustion turbines. Based on the results of the screening analysis conducted, visibility impacts from Big Cajun I are less than the 0.5Δdv screening threshold and are therefore not subject to BART.[7]

Big Cajun II plant Unit 1 (1B1-Boiler 1) and Unit 2 (1B2-Boiler 2) were identified as BART-eligible. The facility has installed several emission control systems and operation modifications on the units as part of a Consent Decree entered on March 5, 2013, Civil Action 009-100-JJB-RLB and to comply with MATS. The details of the emission controls on the units since 2004 are summarized as follows:

- **Unit 1:** Selective non-catalytic reduction (SNCR) for NOx control; Firing of lower-sulfur PRB fuel; DSI for SO_2 control; Modifications to the existing electrostatic precipitator (ESP) for maximizing controls of particulate matter (PM); and Activated carbon injection (ACI) for mercury control.
- **Unit 2**: SNCR for NOx control and Refuel conversion from coal to natural gas.

These controls significantly reduced the emission of SO_2, NOx and PM, which are the main contributors to visibility degradation; therefore NRG was allowed to model the period following the installation of controls instead of using the 2000-2004 baselines that was established in the original SIP submittal. Based on the use of the more current baseline and revised operating conditions using the actual stack flow and stack gas temperatures under high load conditions the facility was able to provide a more accurate assessment of potential visibility impacts.[8] Model results indicate the units identified have an impact less than the 0.5Δdv screening threshold and are therefore not subject to BART. The LDEQ has entered into an

[7] See *Source-Specific Refined Screening Assessment for BART-Eligible Sources for Big Cajun I Facility*, CB&I Environmental and Infrastructure, Inc., July 29, 2015. Page 4-1

[8] See "*Revised Baseline Modeling for Big Cajun II for BART Analysis*", July 13, 2016 in Appendix C

Administrative Order on Consent (AOC) establishing the emission limits into this revision SIP. The AOC emission limits are as follows:

Big Cajun II, Unit 1

Pollutant	Daily Limit Tons/Day	Compliance Methodology
PM_{10}	2.312	PM CEMS
$PM_{2.5}$	1.001	PM CEMS[1]
SO_2	29.275	SO_2 CEMS
NOx	11.556	NOX CEMS

[1] $PM_{2.5}$ compliance is the calculated result of measured PM from the PM CEMs multiplied by 0.433

Big Cajun II, Unit 2

Pollutant	Daily Limit Tons/Day	Compliance Methodology
PM_{10}	0.144	AP-42 Emission Factor for Natural Gas (all PM < 1.0 um)
$PM_{2.5}$	0.144	AP-42 Emission Factor for Natural Gas (all PM < 1.0 um)
SO_2	0.129	Mass balance based on S content of natural gas
NOx	11.556	NO_X CEMS

C. Entergy Louisiana LLC

Entergy submitted to LDEQ CALPUFF modeling for SO_2 and PM for the various units that were found to be BART-eligible; all reports are included in Appendix D. In the course of this exercise, Entergy has submitted not only CALPUFF modeling and a five-factor analysis to satisfy the RH and BART requirements, but has also submitted CAMx modeling to support their findings. While LDEQ has not used the CAMx modeling to ascertain that the units have satisfied the BART requirements, the model results have been included to add substance to the standpoint that these units do not impact visibility at either Breton or Caney Creek.

- **Entergy Ninemile Point Units**: Entergy Louisiana, LLC, owns and operates the Ninemile Point Electric Generating Plant, which is capable of generating 1,827 MW of electricity using natural gas as the primary fuel and No. 2 fuel oil as a secondary fuel. Units 4 and 5 were identified as BART applicable units. Fuel Oil burn heat input is limited to $\leq$ 15% on an annual basis for each unit. While no fuel changes or add-on controls constitute BART for SO_2 or PM_{10} in these units, the facility has agreed to burn on Ultra Low Sulfur Diesel in the units. An AOC has been executed and is included in this document as the enforceable mechanism constituting BART controls. Based upon the CALPUFF modeling results, the five-factor analysis, and the executed AOC which becomes enforceable upon the effective date of this SIP revision, the LDEQ affirms that the facility is BART compliant.

- **Entergy Little Gypsy Units**: Entergy Louisiana, LLC, owns and operates the Little Gypsy Electric Generating Plant, which consists of three electrical generating units: Unit 1, Unit 2 and Unit 3. All three boiler units combust natural gas as the primary fuel and No. 2 and No. 4 Fuel Oil as their secondary fuel. Of these, only Unit 2 Boiler and Unit 3 Boiler are BART applicable. Unit 2 Boiler has a maximum heat input rating of 4550 MMBtu/hr. for natural gas and 3,692 MMBtu/hr. for fuel oil. The Unit 3 Boiler has a maximum hear input rating of 5578 MMBtu/hr. for natural gas and 5328 MMBtu/hr. for fuel oil. Fuel Oil burn heat input is limited to $\leq$ 15% on an annual basis for each unit. While no fuel changes or add-on controls constitute BART for SO_2 or PM_{10} in these units, the facility has agreed to burn only Ultra Low Sulfur

Diesel in the units. An AOC has been executed and is included in this document as the enforceable mechanism constituting BART controls. Based upon the CALPUFF modeling results, the five-factor analysis, and the executed AOC which becomes enforceable upon the effective date of this SIP revision, the LDEQ affirms that the facility is BART compliant.

- **Entergy Willow Glen Units**: The Willow Glen Electric Generating Plant generates approximately 2045 MW of power for the surround area and the city of St. Gabriel. The facility generated electricity from the combustion of natural gas, No. 2 fuel oil, No. 4 fuel oil and No. 6 fuel oil in five main boilers. While these boilers are permitted to burn fuel oil, the action has not taken place in several years. There are no current operational plans to burn fuel oil. See the table below:

Boiler #	MMBtu/hr Nat Gas	MMBtu/hr Fuel Oil
Unit 2	2188	2158
Unit 3	RETIRED 10/16	RETIRED 10/16
Unit 4	5400	5400
Unit 5	RETIRED 10/16	RETIRED 10/16
Auxiliary Boiler	206	206

The facility and LDEQ have executed an AOC that states following the effective date of the SIP revision, before fuel oil firing is allowed to take place at the Willow Glen facility a revised BART determination must be promulgated for SO_2 and NOx for the fuel oil firing scenario through an action by the LDEQ as a SIP revision, which will then have to be approved by EPA and such action will become federally enforceable. Based upon the CALPUFF modeling results, the five-factor analysis, and the executed AOC, the LDEQ affirms that the facility is BART compliant.

- **Entergy Sterlington Units**: The Sterlington Plant is a fossil fuel steam/electric generation facility. It is located on the left descending bank of the Ouachita River approximately 3/10ths of a mile upstream of the United States Corp. of Engineer's Lock and Dam No. 5. The plant is comprised of four electric generating units, including two steam turbine-driven

generators and two gas turbine driven generators. Units 7AB and C7AB were identified as BART eligible units. Based on the results of the screening analysis conducted, visibility impacts from the Sterlington facility are less than the 0.5Δdv screening threshold and are therefore not subject to BART.

- **Entergy Michoud Units**: The Michoud Plant is an existing fossil fueled steam/electric generation facility consisting of two electric generating boiler units and one steam generating unit. Entergy has permanently retired these existing generating units (Unit 1, Unit 2, and Unit 3 identified as EPNs C1A &B-NG, C2 & B-NG, and EPN C3), effective June 1, 2016. This action was set out in detail to the state through a permit application; a public hearing has been set for February 16, 2017. Therefore BART for this facility is no longer applicable. (See the public notice located in Appendix D.)

- **Roy S. Nelson Generating Plant (Nelson)**: The facility is located in Westlake, Calcasieu Parish, Louisiana and is located 264 miles west of the Breton National Wilderness Area and 286 miles south of the Caney Creek Wilderness Area in Arkansas. The facility is a fossil-fuel steam electric power generating facility and operates three BART-eligible steam generating units: Unit 4, Unit 4 Auxiliary Boiler and Unit 6.

The Unit 4 Boiler is permitted to combust natural gas, No. 2, No. 4 and No. 6 fuel oils and refinery fuel gas. Unit 4 has a maximum heat rated capacity of 5400 MMBtu/hour and exhausts out of one stack. It has flue gas recirculation equipment installed for control of NOx emissions. The Auxiliary Boiler for Unit 4 burns natural gas and fuel oil.

The Unit 6 Boiler burns coal as its primary fuel, with No. 2 and No. 4 fuel oils as its secondary fuels. Unit 6 has maximum heat rated capacity of 6216 MMBtu/hour and exhausts out of one stack. It has an electrostatic precipitator (ESP) with flue gas condition for control of particulate matter (PM) emissions. Unit 6 has installed Separated Overfire Air Technology (SOFA) and a Low NOx Concentric Firing System (LNCFS) for NOx control. Steam from these boilers is used to drive steam turbines which in turn generate rotary motion that is used to drive electric generators. The electric generators then produce electricity.

While Entergy has performed the traditional CALPUFF analysis, it has also chosen to run CAMx due to the limitations and deficiencies that cause inaccuracies in the visibility impact

predictions when using CALPUFF. Although the LDEQ does not have the expertise with which to review those model runs, they are included in the appendices for review and comment.

In the BART five-factor analysis, Entergy has reviewed a number of emission reduction controls including low sulfur coal, DSI, enhanced DSI, dry flue-gas desulfurization (FGD) and wet FGD for use in the Unit 6 Boiler. The use of low sulfur coal presents the most feasible control based on economics and impacts to visibility. The other controls are not cost effective based on the small incremental improvement in visibility. As noted, the Unit 4 Boiler and its auxiliary boiler both burn natural gas; therefore no controls would be considered BART for SO_2. This conclusion is consistent for similar units in the proposed Arkansas federal implementation plan (FIP).

Based upon the CALPUFF results using the 2000-2004 baseline data, the results of the CAMx modeling using both the 2000-2004 baselines and the 2012-2014 baseline, coupled with the emission reductions that have occurred at the facility, LDEQ believes that the visibility improvement that would be achieved through the installation and operation of controls at each of the Nelson units would be negligible, therefore the facility's existing controls satisfy the BART requirements and no further controls are necessary. See Table 1.1 below.

Table 1.1: Certified Emission Reductions for Roy S. Nelson

	NOx (tpy)	SO2 (tpy)	PM-10 (tpy)
2011	4960.39	14199.55	554.02
2012	4576.79	12512.94	567.24
2013	4071.23	11460.91	513.11
2014	3506.88	10543.56	446.48
2015	3678.59	8122.13	363.26

- **Waterford 1 & 2 Electric Generating Plant (Waterford)**: Entergy Louisiana, L.L.C., owns and operates the Waterford 1 & 2 Electric Generating Plant, an existing fossil-fueled steam/electric generation facility. It is located in Killona, St. Charles Parish, Louisiana and is 81.2 miles west of the Breton National Wildlife Refuge.

The facility consists of three generating units: Units 1, Unit 2 and an Auxiliary Boiler. Both Units 1 and 2 boilers use natural gas as their primary fuel and No. 6 fuel oil as its secondary fuel; the units have a normal operating heat input of 4440 MMBtu/hour while burning natural gas and 3920 MMBtu/hour while burning fuel oil. The Auxiliary Boiler burns only natural gas.

The resulting steam from the boilers is used to drive steam turbines which are connected to the electric generators that produce electricity.

Entergy prepared the required five-factor analysis to determine BART controls. The controls investigated were fuel switching, DSI, dry-semi dry scrubbing and wet scrubbing for SO_2 control and wet electrostatic precipitators, wet scrubbing, fuel switching and cyclone technology for PM control. However because the facility burns natural gas almost exclusively, the facility has entered an AOC with LDEQ that limits any fuel oil burned at Units 1 & 2 to 1% sulfur content, which is consistent with current operating conditions. The AOC is included in this SIP revision as the enforceable mechanism constituting BART controls. The LDEQ holds that Waterford Units 1 & 2 have fulfilled the requirements of BART. The AOC is included in the appendices along with the modeling analysis and results. For the Auxiliary Boiler, no technically feasible control options are available for SO_2 or PM control for natural gas fired boilers. Therefore, LDEQ finds that the Auxiliary Boiler has met the BART requirements.

All documentation, including 5-factor analysis and correspondence for the Entergy units, can be found in Appendix D.

D. Municipal Facility Units

The following facilities have either screened out or have been retired; please see Appendix E for documentation.

a. <u>Morgan City Steam Plant Facility (Joseph J. Cefalu Sr. Plant)</u>
<u>Louisiana Energy & Power Authority (LEPA) AI 26326</u>

The steam plant is located in Morgan City in St. Mary Parish. The plant is no longer in operation, therefore BART screening is not applicable to this facility. Please refer to enclosed copy of the facility's permit rescission notice and related letter to the EPA.

b. <u>City of Ruston, Ruston Electrical Generation Station AI 8167</u>

The Ruston Electrical Generation Station is located in the city of Ruston in Lincoln Parish. The station is no longer in operation, therefore BART screening is not applicable to this facility. Please refer to enclosed copy of the facility's permit rescission notice.

c. <u>City of Natchitoches, Power Plant #1, AI 19375</u>

Power Plant #1 was located in the City of Natchitoches, Natchitoches Parish. The power plant was shut down and dismantled as indicated in the enclosed copy of the facility's permit rescission notice. BART screening, is therefore, not applicable to this facility.

d. Lafayette Utility System (LUS): Louis "Doc" Bonin, AI 31135

LUS operates the Louis "Doc" Bonin Generating Station located in Lafayette Parish, Louisiana. By letter dated December 11, 2015, LUS notified the EPA Clean Air Markets Division of the long term cold storage Units 1, 2, and 3. Unit 1 last operated on June 22, 2011 and was put into cold storage on June 1, 2013. Unit 2 last operated on July 5, 2013 and was put into cold storage on June 29, 2014. Unit 3 last operated on August 27, 2013 and was put into cold storage on June 29, 2014.

MISO is currently conducting a study to predict the future use of these unit(s) for peaking purposes. If it is determined that these units are no longer necessary to facilitate electrical power generation, they will be retired. If the facilities are necessary, new permit applications will be submitted to LDEQ; therefore any future BART discussions will be instituted at that point in time. (See Appendix E)

Appendix A

Public Notice and Participation

Appendix B

CLECO

BART Determination and Evaluation

Appendix C

NRG

BART Determination and Evaluation

Appendix D

Entergy Louisiana LLC

BART Determination and Evaluation

Appendix E

Municipal Facilities

To: Vivian Aucoin[Vivian.Aucoin@LA.GOV]; Donaldson, Guy[Donaldson.Guy@epa.gov]
Cc: Donald Trahan[Donald.Trahan@LA.GOV]; Bijan Sharafkhani[Bijan.Sharafkhani@LA.GOV]; Stenger, Wren[stenger.wren@epa.gov]; Thomas, Carrie[Thomas.Carrie@epa.gov]
From: Huser, Jennifer
Sent: Fri 2/10/2017 9:56:13 PM
Subject: RE: Louisiana's Regional Haze EGU BART SIP Submittal (1 of 3)

Thanks, Vivian. Can you please send the attachments as well so we know you've included the documents we requested.

Entergy Initial Modeling Report (8/31/15)

Entergy BART Screening Report (2015_1109 final)

Entergy Michoud draft permit/permit briefing sheet

NRG Supplemental Information and Revised Baseline Modeling Report (7/19/16)

Jennifer Huser

Environmental Scientist

Air Planning Section (6MM-AA)
USEPA Region 6
1445 Ross Ave. Suite 1200
Dallas, TX 75202-2733
214-665-7347

From: Vivian Aucoin [mailto:Vivian.Aucoin@LA.GOV]
Sent: Friday, February 10, 2017 3:44 PM
To: Donaldson, Guy <Donaldson.Guy@epa.gov>; Huser, Jennifer <Huser.Jennifer@epa.gov>
Cc: Donald Trahan <Donald.Trahan@LA.GOV>; Bijan Sharafkhani <Bijan.Sharafkhani@LA.GOV>
Subject: Louisiana's Regional Haze EGU BART SIP Submittal (1 of 3)
Importance: High

Greetings,

Attached please find the SIP document with the transmittal letter and the response to comment document. Two more emails will follow that will have enclosed the executed AOCs for NRG, CLECO and Entergy.

The remainder of the documents will be loaded into a drop-box and address to both Guy Donaldson and Jennifer Huser. A complete copy of the SIP will be mailed on Monday and an additional copy will be placed into LDEQ's EDMS. Once the document is loaded into EDMS, I will forward the DOC ID#.

If you need anything further, please do not hesitate to contact me at the number below.

Vivian H. Aucoin

Environmental Scientist, Senior

Air Permits Division, State Implementation Plan

225-219-3482

vivian.aucoin@la.gov

To: Donaldson, Guy[Donaldson.Guy@epa.gov]; Huser, Jennifer[Huser.Jennifer@epa.gov]
Cc: Donald Trahan[Donald.Trahan@LA.GOV]; Bijan Sharafkhani[Bijan.Sharafkhani@LA.GOV]
From: Vivian Aucoin
Sent: Fri 2/10/2017 9:46:24 PM
Subject: Louisiana's Regional Haze EGU BART SIP Submittal (3 of 3)
Waterford Units 1&2 AOC Executed.pdf
Willow Glen AOC executed.pdf
Ninemile Point AOC Executed.pdf
Little Gypsy AOC executed.pdf

AOCs for Entergy facilities

Vivian H. Aucoin

Environmental Scientist, Senior

Air Permits Division, State Implementation Plan

225-219-3482

vivian.aucoin@la.gov

STATE OF LOUISIANA
DEPARTMENT OF ENVIRONMENTAL QUALITY

OFFICE OF ENVIRONMENTAL ASSESSMENT

IN THE MATTER OF	*	
	*	
ENTERGY LOUISIANA, LLC	*	**REGIONAL HAZE**
LITTLE GYPSY GENERATING PLANT	*	**STATE IMPLEMENTATION PLAN**
	*	**EGU BART ANALYSIS**
ST. CHARLES PARISH, LOUISIANA	*	
	*	**AGENCY INTEREST NO. 687**
	*	
PROCEEDINGS UNDER THE LOUISIANA	*	
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 **ENTERGY LOUISIANA, LLC (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, subject to the U.S. Environmental Protection Agency's (EPA) approval of the State Implementation Plan (SIP) prepared for the subject Facility.

FINDINGS OF FACT

I.

The Respondent owns and/or operates the Little Gypsy Electric Generating Plant located at 17420 River Road, Montz, St. Charles Parish, Louisiana (Facility). The Facility currently operates pursuant to Title V Permit Number 2520-0009-V4 issued on October 24, 2014.

II.

Under Clean Air Act (CAA) section 110, each state must prepare and submit for the EPA approval, a 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 is concurrently submitting a proposed SIP on behalf of the State of Louisiana to EPA Region VI that includes a Best Available Retrofit Technology (BART) screening modeling for the Facility. The BART analysis is based on submittals made by RESPONDENT to the Department on November 9, 2015 and revised on April 14, 2016.

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:

> The facility will burn only ultra-low sulfur diesel at Little Gypsy Units 2, 3 and the auxiliary boiler during oil-burn periods of operation.

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.

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.

V.

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.

VI.

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.

VII.

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 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** 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 **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.**

VIII.

This **ADMINISTRATIVE ORDER ON CONSENT** shall be final and effective upon final approval of a SIP by EPA and signature by an authorized representative of the Department and signature by the authorized representative of the Respondent, provided that the federally enforceable limits set forth herein shall not become effective until the final approval by EPA of the SIP as it relates to the BART Five Factor Analysis for the Facility based upon those federally-enforceable limits. If the SIP as it relates to the BART Five Factor Analysis for the Facility is not approved by EPA, this **ADMINISTRATIVE ORDER ON CONSENT** shall be void.

Baton Rouge, Louisiana, this _____ day of February, 2017.

Chuck Carr Brown, Ph.D.
Secretary

Entergy Louisiana LLC

By: Warren Dale Claudel

Date: 2/8/17

Name: Warren Dale Claudel

Title: VP, Power Plant Operations

STATE OF LOUISIANA
DEPARTMENT OF ENVIRONMENTAL QUALITY

OFFICE OF ENVIRONMENTAL ASSESSMENT

IN THE MATTER OF	*	
	*	
ENTERGY LOUISIANA, LLC	*	**REGIONAL HAZE**
NINEMILE POINT ELECTRIC	*	**STATE IMPLEMENTATION PLAN**
GENERATING PLANT	*	**EGU BART ANALYSIS**
JEFFERSON PARISH, LOUISIANA	*	
	*	**AGENCY INTEREST NO. 2841**
	*	
PROCEEDINGS UNDER THE LOUISIANA	*	
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 **ENTERGY LOUISIANA, LLC (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, subject to the U.S. Environmental Protection Agency's (EPA) approval of the State Implementation Plan (SIP) prepared for the subject Facility.

FINDINGS OF FACT

I.

The Respondent owns and/or operates the Ninemile Point Electric Generating Plant located at 1617 River Road, Westwego, Jefferson Parish, Louisiana (Facility). The Facility currently operates pursuant to Title V Permit Number 1340-00006-V4 issued on August 26, 2016.

II.

Under Clean Air Act (CAA) section 110, each state must prepare and submit for the EPA approval, a 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 is concurrently submitting a proposed SIP on behalf of the State of Louisiana to EPA Region VI that includes a Best Available Retrofit Technology (BART) screening modeling for the Facility. The BART analysis is based on submittals made by RESPONDENT to the Department on November 9, 2015 and revised on April 14, 2016.

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:

> The facility will burn only ultra-low sulfur diesel at Ninemile Units 4 and 5 during oil-burn periods of operation.

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.

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.

V.

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.

VI.

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.

VII.

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 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** 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 **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.**

VIII.

This **ADMINISTRATIVE ORDER ON CONSENT** shall be final and effective upon final approval of a SIP by EPA and signature by an authorized representative of the Department and signature by the authorized representative of the Respondent, provided that the federally enforceable limits set forth herein shall not become effective until the final approval by EPA of the SIP as it relates to the BART Five Factor Analysis for the Facility based upon those federally-enforceable limits. If the SIP as it relates to the BART Five Factor Analysis for the Facility is not approved by EPA, this **ADMINISTRATIVE ORDER ON CONSENT** shall be void.

Baton Rouge, Louisiana, this 9th day of February, 2017.

Chuck Carr Brown, Ph.D.
Secretary

Entergy Louisiana LLC

By: _____ Date: 2/8/2017

Name: Warren Dale Claudel

Title: VP, Power Plant Operations

STATE OF LOUISIANA
DEPARTMENT OF ENVIRONMENTAL QUALITY

OFFICE OF ENVIRONMENTAL COMPLIANCE

IN THE MATTER OF	*	
	*	
ENTERGY LOUISIANA, LLC	*	**AGENCY INTEREST NO. 83898**
WATERFORD 1 & 2 ELECTRICAL	*	
GENERATING PLANT	*	
ST. CHARLES PARISH	*	
	*	
PROCEEDINGS UNDER THE LOUISIANA	*	**REGIONAL HAZE BART ANALYSIS**
ENVIRONMENTAL QUALITY ACT,	*	**STATE IMPLEMENTATION PLAN**
La. R.S. 30:2001, ET SEQ.	*	

ADMINISTRATIVE ORDER ON CONSENT

The following **ADMINISTRATIVE ORDER ON CONSENT** is issued this day to **ENTERGY LOUISIANA, LLC (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, subject to the U.S. Environmental Protection Agency's (EPA) approval of the State Implementation Plan (SIP) prepared for the subject Facility.

FINDINGS OF FACT

I.

The Respondent owns and/or operates the Waterford 1 & 2 Electric generation station located at 17705 River Road in Killona, St. Charles Parish, Louisiana (Facility). The Facility currently operates pursuant to Part 70 permit No. 2435-V7 issued September 9, 2015.

II.

Under Clean Air Act (CAA) section 110, each state must prepare and submit for the EPA approval, a 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 is concurrently submitting a proposed SIP on behalf of the State of Louisiana to EPA Region VI that includes a Best Available Retrofit Technology (BART) screening modeling for the Facility. The BART analysis is based on submittals made by RESPONDENT to the Department in November 2015 and April 2016.

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:

> **Respondent agrees to burn only 1% sulfur content or less in the Fuel Oil in both Units 1 and 2 during oil-burn periods of operation.**

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.

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.

V.

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.

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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.

VII.

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 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** 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 **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**.

VIII.

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, provided that the federally enforceable limits set forth herein shall not become effective until the final approval by EPA of the SIP as it relates to the BART Five Factor Analysis for the Facility based upon those federally enforceable limits. If the SIP as it relates to the BART Five Factor Analysis for the Facility is not approved by EPA, this ADMINISTRATIVE ORDER ON CONSENT shall be void.

Baton Rouge, Louisiana, this 9th day of February 2017.

Chuck Carr Brown, Ph. D.
Secretary

Entergy Louisiana, LLC

By: _____ Date: 2/8/2017

Name: Warren Dale Claudel

Title: VP, Power Plant Operations

STATE OF LOUISIANA
DEPARTMENT OF ENVIRONMENTAL QUALITY

OFFICE OF ENVIRONMENTAL ASSESSMENT

IN THE MATTER OF	*	
	*	
ENTERGY LOUISIANA, LLC	*	**REGIONAL HAZE**
WILLOW GLEN GENERATING PLANT	*	**STATE IMPLEMENTATION PLAN**
IBERVILLE PARISH, LOUISIANA	*	**EGU BART ANALYSIS**
	*	
	*	**AGENCY INTEREST NO. 2625**
	*	
PROCEEDINGS UNDER THE LOUISIANA	*	
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 **ENTERGY LOUISIANA, LLC (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, subject to the U.S. Environmental Protection Agency's (EPA) approval of the State Implementation Plan (SIP) prepared for the subject Facility.

FINDINGS OF FACT

I.

The Respondent owns and/or operates the Willow Glen Generating Plant located at 2605 Highway 75 in St. Gabriel, Iberville Parish, Louisiana (Facility). The Facility currently operates pursuant to Title V and PAL Permit Number 1280-00010-V3 issued on February 22, 2012, administratively amended on April 2, 2015.

II.

Under Clean Air Act (CAA) section 110, each state must prepare and submit for the EPA approval, a 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 is concurrently submitting a proposed SIP on behalf of the State of Louisiana to EPA Region VI that includes a Best Available Retrofit Technology (BART) screening modeling for the Facility. The BART analysis is based on submittals made by RESPONDENT to the Department on November 9, 2015.

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:

> Before fuel oil firing is allowed to take place at Units 2, 3, 4, 5, and the auxiliary boiler at the Facility, a revised BART determination must be promulgated for SO2 and PM for the fuel oil firing scenario through a FIP or an action by the LDEQ as a SIP revision and approved by EPA such that the action will become federally enforceable.

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.

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.

V.

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.

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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.

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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**.

VIII.

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 9th day of February, 2017.

Chuck Carr Brown, Ph.D.
Secretary

Entergy Louisiana LLC

By: _____ Date: 2/8/2017

Name: Warren Dale Claudel

Title: VP, Power Plant Operations

To: Donaldson, Guy[Donaldson.Guy@epa.gov]; Huser, Jennifer[Huser.Jennifer@epa.gov]
Cc: Donald Trahan[Donald.Trahan@LA.GOV]; Bijan Sharafkhani[Bijan.Sharafkhani@LA.GOV]
From: Vivian Aucoin
Sent: Fri 2/10/2017 9:44:12 PM
Subject: Louisiana's Regional Haze EGU BART SIP Submittal (1 of 3)
RH EGU BART Louisiana Final.pdf
Response to Comment final.pdf

Greetings,

Attached please find the SIP document with the transmittal letter and the response to comment document. Two more emails will follow that will have enclosed the executed AOCs for NRG, CLECO and Entergy.

The remainder of the documents will be loaded into a drop-box and address to both Guy Donaldson and Jennifer Huser. A complete copy of the SIP will be mailed on Monday and an additional copy will be placed into LDEQ's EDMS. Once the document is loaded into EDMS, I will forward the DOC ID#.

If you need anything further, please do not hesitate to contact me at the number below.

Vivian H. Aucoin

Environmental Scientist, Senior

Air Permits Division, State Implementation Plan

225-219-3482

vivian.aucoin@la.gov

Comment Response Louisiana Regional Haze SIP

1. **LDEQ's source-specific BART analyses for Sulfur Dioxide are flawed.**
    a. **Rodemacher 2**: The LDEQ and CLECO have agreed in that the installation of the enhanced DSI as a control constitutes BART. The parties have entered into an Administrative Order of Consent (AOC) providing that upon final approval of this SIP submittal, the facility will install as expeditiously as practicable, not to exceed 1 year, the enhanced DSI to comply with BART.
    b. **Big Cajun II, Unit I**: The body of the document currently reflects the results of the CALPUFF screening indicating that the units have "screened-out". An AOC restricting emission limits to current rates has been executed and is being submitted as part of this final document.
2. **Louisiana's proposed reliance on CSAPR as a BART alternative is unlawful and the rule itself if fundamentally flawed.**
    a. On December 30, 2011, the EPA proposed to find that the trading programs in the Transport Rule would achieve greater reasonable progress towards the national visibility goal than would source-specific BART in states in which the Transport Rule applies. Based on this finding, the EPA also revised the Regional Haze Rule to allow states to substitute participating the in the trading programs under the Transport Rule for source-specific BART. (77 FR 33642)
    b. Commenter's opinion as to whether or not a federal rule is flawed is not an indicator as to the state's obligation to meet the requirements set forth in said rule.
3. **Louisiana's proposed SIP revision fails to satisfy the Regional Haze Program's Reasonable Progress Requirements.**
    a. Louisiana provided EPA with the first phase reasonable progress goal in its June 13, 2008 submittal; a follow-up to this submittal will be made as required in the newly promulgated and updated regional haze rule.
4. **Louisiana should not rely on CAMx modeling for BART determinations.**
    a. The LDEQ did not rely on the CAMx modeling, but rather relied on CALPUFF modeling as is required by the Clean Air Act and the BART rules. The LDEQ has included all CAMx modeling as a weight-of –evidence argument for those facilities that have provided such modeling to be included in the SIP.
5. **Entergy's five-factor BART analysis is flawed.**
    a. The LDEQ did not rely on the CAMx modeling, but rather relied on CALPUFF modeling as is required by the Clean Air Act and the BART rules. The LDEQ has included all CAMx modeling as a weight-of –evidence argument for those facilities that have provided such modeling to be included in the SIP.
6. **LDEQ's BART analysis for Nelson is fundamentally flawed due to lack of specific, enforceable emission limits.**
    a. The LDEQ has reviewed the CALPUFF modeling that was submitted and has based its decision on the 5-factor analysis as well as emission reductions that have occurred at the facility.
7. **The Lafayette Utilities System Louis "Doc" Bonin Generating Station must submit the required analysis or another enforceable mechanism to show that plant is not operational.**
    a. The necessary documents have been submitted and are contained in Appendix E, Municipal Facilities.

8. **Entergy Michoud Generating Station must submit documentation proving that the facility cannot start up again without obtaining a new permit.**
    a. The necessary documents have been submitted and are contained in Appendix D, Entergy Louisiana LLC.
9. **Entergy Nine Mile Point Generating Station: The state should establish enforceable emission limits or elect to set a fuel oil sulfur content standard consistent with a BART level of control.**
    a. The state elected to set a fuel oil sulfur content standard. The parties have executed an AOC which is contained in Appendix D, Entergy Louisiana LLC.
10. **Entergy Little Gypsy: The state should establish enforceable emission limits or elect to set a fuel oil sulfur content standard consistent with a BART level of control.**
    a. The state elected to set a fuel oil sulfur content standard. The parties have executed an AOC which is contained in Appendix D, Entergy Louisiana LLC.
11. **Entergy Willow Glen: The proposed SIP states that before fuel oil firing is allowed at the facility, a revised BART determination must be promulgated.**
    a. An AOC has been executed and will be included in the SIP. Upon approval of the SIP, this document will become federally enforceable.
12. **Entergy Waterford: The state should establish enforceable emission limits or elect to set a fuel oil sulfur content standard consistent with a BART level of control.**
    a. The state elected to set a fuel oil sulfur content standard. The parties have executed an AOC which is contained in Appendix D, Entergy Louisiana LLC.
13. **Entergy RS Nelson and Waterford Facilities: EPA posed a number of comments related to the Sargent and Lundy cost analyses.**
    a. See Appendix A, Public Notice and Comment for a copy of the answers to those specific questions that was provided by Entergy.
14. **Commenter does not recommend using CAMx for BART determinations:**
    a. The LDEQ did not rely on the CAMx modeling, but rather relied on CALPUFF modeling as is required by the Clean Air Act and the BART rules. The LDEQ has included all CAMx modeling as a weight-of –evidence argument for those facilities that have provided such modeling to be included in the SIP.
15. **Commenter stated that primary and supporting information was incomplete:**
    a. All information involved in decision making process is in body of SIP or respective appendices. Modeling files can be made available upon request.
16. **Commenter recommended that respondent use Sargent and Lundy models to project correct control cost.**
    a. In the April 18, 2016 submittal to Guy Donaldson, Region 6 EPA, Table 5-3. Summary of Cost Effectiveness for Unit 2, Footnote 3 states that this was based on a cost evaluation prepared by Sargent and Lundy.
17. **Commenter believes that conclusions for Big Cajun Unit II are inconsistent and suspect, and recommended that the conclusion be revisited.**
    a. The section on Big Cajun II has been edited. The units screened out and are therefore not BART eligible.
18. **Commenter recommended that LDEQ work closely with Region 6 to evaluate BART controls and final determinations.**
    a. LDEQ has worked very closely with EPA on this SIP and believes that the document presented is a culmination of the work from both parties.

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

Regional Haze State Implementation Plan

EGU BART Analysis

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

FINAL February 2017

JOHN BEL EDWARDS
GOVERNOR

CHUCK CARR BROWN, PH.D.
SECRETARY

State of Louisiana

DEPARTMENT OF ENVIRONMENTAL QUALITY
OFFICE OF THE SECRETARY

February 10, 2017

Mr. Samuel Coleman
Acting Regional Administrator
US EPA Region 6, 6-RA
1445 Ross Avenue, Suite 1200
Dallas Texas 75202-2733

RE: Louisiana's State Implementation Plan (SIP) Revisions
Regional Haze Rule EGU Best Available Retrofit Technology (BART)

Dear Mr. Coleman:

The Louisiana Department of Environmental Quality has revised its Regional Haze SIP to fulfill the requirements of Phase I. Enclosed, please find one bound copy of the document.

If you have any questions concerning this matter, please feel free to contact Donald Trahan, Administrator, Office of Environmental Assessment at 225-219-3408 or at donald.trahan@la.gov.

Sincerely,

Chuck Carr Brown, Ph.D.
Secretary

Enclosures

Cc: Wren Stenger, 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

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 CAA 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 EPA further outlined those elements that were included in the partial disapproval. Furthermore, EPA found that certain elements of the BART evaluations and determinations were not fully adequate to meet the federal regulations. In a separate rulemaking, the US EPA issued a limited disapproval of the regional haze SIPs for several states including Louisiana because, among other things, these states relied on CAIR as an alternative to BART for SO_2 and NO_X for electric generating units (EGUs). 77 FR 33641, June 7, 2012. In this submittal, the LDEQ will address only those BART-eligible units that are EGUs. This RH SIP submittal is intended to supersede the portions of LDEQ's 2008 SIP submittal addressing EGU BART that EPA found deficient in the limited disapproval action at 77 FR 33641. This submittal fulfills the requirements of Phase I of the Regional Haze Rule.

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 October 20, 2016 in the *Louisiana Register*. No public hearings were requested. A copy of the potpourri notice and all comments and responses are included in Appendix A.

D. Commitment to Plan Revision

The consultation process will continue between LDEQ, the EPA 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

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

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

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

chain is constantly altered by tropical storms, wind, and tidal action. The area above mean high tide is approximately 6,923 acres; however, Hurricanes 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 (Phase I) 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, which provided a review of the long-term strategy to ensure that the SIP was adequate for preventing impairment of visibility at Breton in agreement with Phase I EPA visibility regulations. Further, it was used to provide the public and EPA a comprehensive analysis of the progress toward the national visibility goal.

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[3] ibid

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

II. BART Analysis

In its original submittal on June 13, 2008, the LDEQ relied on the CAIR in lieu of BART for EGUs. The RH rule allowed states to implement an alternative program in lieu of BART so long as the alternative program could demonstrate that it would achieve greater reasonable progress toward the national visibility goal than would BART. CAIR introduced a cap-and-trade program, either by FIP or SIP, that through participation provided that BART-eligible EGUs were not required to install, operate, and/or maintain BART for emissions of SO_2 and NO_x. Facilities were required to complete the screening and subsequent analysis for particulate matter (PM).

Challenges to CAIR resulted in the remand of the rule to the EPA. Subsequent iterations of the rule have been proposed, namely the Transport Rule and the Cross State Air Pollution Rule (CSAPR), both of which have been approved as a substitute for BART. These challenges, either directly or indirectly through stay orders, resulted in the facilities participating in CAIR until December 31, 2014. While EGUs in Louisiana were required to participate in CAIR for both SO_2 and NO_X, Louisiana EGUs are only included in CSAPR for ozone season NO_X. Therefore, in Louisiana, there is no federally approved alternative to source specific BART for SO_2. Source specific BART is also required for PM for Louisiana's subject to BART EGUs. Because Louisiana is included in the CSAPR program for ozone season NO_x, the State intends to rely on CSAPR as an alternative to source specific BART for NO_x for the BART-eligible EGUs.

Given that EPA directly addressed the EGUs in the limited disapproval by stating that the SO_2 portion of CSAPR was not applicable to the facilities, a source-specific BART determination is necessary. LDEQ has identified 13 units that are BART-eligible and has applied either screening or refined modeling to determine if a facility will have a greater than 0.5 deciview (Δdv) impact on the nearest Class I areas and the control strategies that will afford the necessary emission reductions to maintain the uniform rate of progress toward the 2064 visibility goal. As of this writing, Louisiana has surpassed the Reasonable Progress Goals projections and remains below the glide path mapping a direct course toward the final visibility goal.

A. CLECO

CLECO Teche Power Station, located in Baldwin, St. Mary Parish, Louisiana, is an electrical utility power station. Unit 3 operates a 359 MW boiler/turbine system which is permitted for natural gas, No. 2 fuel oil, or No. 4 fuel oil. Based on the results of the screening analysis conducted, visibility impacts from Teche Unit 3 are less than the 0.5Δdv screening threshold and are therefore not subject to BART.[4]

CLECO BRAME operates two electric utility units in Lena, Rapides Parish, Louisiana:

- **Nesbit I (Unit 1)**, a 440 MW fossil-fuel fired boiler/turbine system and is not equipped with any air pollution control devices. While the unit is permitted to combust oil, it has not done so in many years and due to the Mercury Air Toxics Standards (MATS) rule, it will not combust oil in the future. Results of the modeling and analysis indicate the following for Unit 1: SO_2 BART controls are satisfied through the conversion to natural gas; NO_x BART controls are satisfied by the requirements of the CSAPR; PM_{10} BART -no additional controls constitute BART.
- **Rodemacher II (Unit 2)** is a 523 MW fossil-fuel fired boiler/turbine system that burns Powder River Basin (PRB) coal. Cleco has recently made several changes that reduce emissions, such as: Low NOx burners were installed in 2008; Low-sulfur fuel began to be burned in 2009; Selective non-catalytic reduction (SNCR) was installed in 2014 for complying with ozone season NOx requirements of CSAPR; and Dry Sorbent Injection (DSI) activated carbon injection (ACI) and a fabric filter (FF) were installed in 20155 for compliance with MATS. Results of the modeling and analysis indicated the following for Unit 2: SO_2 BART controls are satisfied with the installation of enhanced DSI,[5] NO_x BART controls are satisfied by the requirements of CSAPR, and PM_{10} BART-no additional controls constitute BART.

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[4] See *CALPUFF Modeling Report BART Applicability Screening Analysis* conducted by Trinity Consultants, July 30, 2015; page 1-2

[5] Cleco has executed an Administrative Order on Consent with the LDEQ stating that these enforceable emissions limits are dependent upon the EPA's approval of the SIP. If EPA does not approve this SIP, the AOC will be rendered void.

LDEQ included Unit 1 among the BART-affected sources that were listed in the original Regional Haze SIP submitted on June 13, 2008, however Unit 2 was not previously listed as a BART-affected source; it was later determined to be a BART-eligible source and is therefore included in this SIP revision. In response to EPA's Section 114 request,[6] Cleco submitted a BART-applicability screening analysis to the LDEQ and EPA on August 31, 2015. Brame Units 1 and 2 were determined to be BART-affected emission units established upon the CALPUFF – based screening analysis; therefore, Cleco has submitted a BART five-factor analysis on each of the emissions units. (See Appendix B)

Understanding that SO_2 is the predominant sulfur compound emitted from Brame Unit 2, the BART analysis was specific to the those emissions; it should be noted that the reductions in SO_2 emissions will further reduce visibility impairment by reducing sulfate formation. The analysis identified available SO_2 control technologies and evaluated each according to the statutory requirements. The available control technologies evaluated were Dry Sorbent Injection (DSI); Enhanced DSI; Dry/Semi-dry scrubbing and Wet Scrubbing. The results of the analysis indicated that enhancing the DSI system at Unit 2 can achieve an outlet emission rate of 0.30lb/MMBtu on an annual-average basis.

The LDEQ finds that, with the addition of the enhanced DSI along with the controls installed as well as the current operating conditions and permit limits included in the Administrative Order on Consent, the Cleco Brame facility has satisfied the BART requirements.

It should be noted that Cleco presented the LDEQ with CAMx modeling as a further demonstration that the facilities have no visibility impact on the Class I areas. While LDEQ did not use this information to make a BART requirement determination, the information contained in the model results was useful toward making the final decision that CLECO has indeed satisfied all BART requirements. The CAMx model is included in Appendix B.

[6] Wren Stenger, Section 114(a) Information Request letter to Darren Olagues (CLECO), May 19, 2015.

B. Louisiana Generating, LLC, a subsidiary of NRG

Big Cajun I is a steam generating plant located in Jarreau, Pointe Coupee Parish, Louisiana. The station includes two separate natural gas-fired boilers and two natural gas fired combustion turbines. Based on the results of the screening analysis conducted, visibility impacts from Big Cajun I are less than the 0.5Δdv screening threshold and are therefore not subject to BART.[7]

Big Cajun II plant Unit 1 (1B1-Boiler 1) and Unit 2 (1B2-Boiler 2) were identified as BART-eligible. The facility has installed several emission control systems and operation modifications on the units as part of a Consent Decree entered on March 5, 2013, Civil Action 009-100-JJB-RLB and to comply with MATS. The details of the emission controls on the units since 2004 are summarized as follows:

- **Unit 1:** Selective non-catalytic reduction (SNCR) for NOx control; Firing of lower-sulfur PRB fuel; DSI for SO_2 control; Modifications to the existing electrostatic precipitator (ESP) for maximizing controls of particulate matter (PM); and Activated carbon injection (ACI) for mercury control.
- **Unit 2**: SNCR for NOx control and Refuel conversion from coal to natural gas.

These controls significantly reduced the emission of SO_2, NOx and PM, which are the main contributors to visibility degradation; therefore NRG was allowed to model the period following the installation of controls instead of using the 2000-2004 baselines that was established in the original SIP submittal. Based on the use of the more current baseline and revised operating conditions using the actual stack flow and stack gas temperatures under high load conditions the facility was able to provide a more accurate assessment of potential visibility impacts.[8] Model results indicate the units identified have an impact less than the 0.5Δdv screening threshold and are therefore not subject to BART. The LDEQ has entered into an

[7] See *Source-Specific Refined Screening Assessment for BART-Eligible Sources for Big Cajun I Facility*, CB&I Environmental and Infrastructure, Inc., July 29, 2015. Page 4-1

[8] See "*Revised Baseline Modeling for Big Cajun II for BART Analysis*", July 13, 2016 in Appendix C

Administrative Order on Consent (AOC) establishing the emission limits into this revision SIP. The AOC emission limits are as follows:

Big Cajun II, Unit 1

Pollutant	Daily Limit Tons/Day	Compliance Methodology
PM_{10}	2.312	PM CEMS
$PM_{2.5}$	1.001	PM CEMS[1]
SO_2	29.275	SO_2 CEMS
NOx	11.556	NOX CEMS

[1] $PM_{2.5}$ compliance is the calculated result of measured PM from the PM CEMs multiplied by 0.433

Big Cajun II, Unit 2

Pollutant	Daily Limit Tons/Day	Compliance Methodology
PM_{10}	0.144	AP-42 Emission Factor for Natural Gas (all PM < 1.0 um)
$PM_{2.5}$	0.144	AP-42 Emission Factor for Natural Gas (all PM < 1.0 um)
SO_2	0.129	Mass balance based on S content of natural gas
NOx	11.556	NO_X CEMS

C. Entergy Louisiana LLC

Entergy submitted to LDEQ CALPUFF modeling for SO_2 and PM for the various units that were found to be BART-eligible; all reports are included in Appendix D. In the course of this exercise, Entergy has submitted not only CALPUFF modeling and a five-factor analysis to satisfy the RH and BART requirements, but has also submitted CAMx modeling to support their findings. While LDEQ has not used the CAMx modeling to ascertain that the units have satisfied the BART requirements, the model results have been included to add substance to the standpoint that these units do not impact visibility at either Breton or Caney Creek.

- **Entergy Ninemile Point Units**: Entergy Louisiana, LLC, owns and operates the Ninemile Point Electric Generating Plant, which is capable of generating 1,827 MW of electricity using natural gas as the primary fuel and No. 2 fuel oil as a secondary fuel. Units 4 and 5 were identified as BART applicable units. Fuel Oil burn heat input is limited to $\leq$ 15% on an annual basis for each unit. While no fuel changes or add-on controls constitute BART for SO_2 or PM_{10} in these units, the facility has agreed to burn on Ultra Low Sulfur Diesel in the units. An AOC has been executed and is included in this document as the enforceable mechanism constituting BART controls. Based upon the CALPUFF modeling results, the five-factor analysis, and the executed AOC which becomes enforceable upon the effective date of this SIP revision, the LDEQ affirms that the facility is BART compliant.

- **Entergy Little Gypsy Units**: Entergy Louisiana, LLC, owns and operates the Little Gypsy Electric Generating Plant, which consists of three electrical generating units: Unit 1, Unit 2 and Unit 3. All three boiler units combust natural gas as the primary fuel and No. 2 and No. 4 Fuel Oil as their secondary fuel. Of these, only Unit 2 Boiler and Unit 3 Boiler are BART applicable. Unit 2 Boiler has a maximum heat input rating of 4550 MMBtu/hr. for natural gas and 3,692 MMBtu/hr. for fuel oil. The Unit 3 Boiler has a maximum hear input rating of 5578 MMBtu/hr. for natural gas and 5328 MMBtu/hr. for fuel oil. Fuel Oil burn heat input is limited to $\leq$ 15% on an annual basis for each unit. While no fuel changes or add-on controls constitute BART for SO_2 or PM_{10} in these units, the facility has agreed to burn only Ultra Low Sulfur

Diesel in the units. An AOC has been executed and is included in this document as the enforceable mechanism constituting BART controls. Based upon the CALPUFF modeling results, the five-factor analysis, and the executed AOC which becomes enforceable upon the effective date of this SIP revision, the LDEQ affirms that the facility is BART compliant.

- **Entergy Willow Glen Units**: The Willow Glen Electric Generating Plant generates approximately 2045 MW of power for the surround area and the city of St. Gabriel. The facility generated electricity from the combustion of natural gas, No. 2 fuel oil, No. 4 fuel oil and No. 6 fuel oil in five main boilers. While these boilers are permitted to burn fuel oil, the action has not taken place in several years. There are no current operational plans to burn fuel oil. See the table below:

Boiler #	MMBtu/hr Nat Gas	MMBtu/hr Fuel Oil
Unit 2	2188	2158
Unit 3	RETIRED 10/16	RETIRED 10/16
Unit 4	5400	5400
Unit 5	RETIRED 10/16	RETIRED 10/16
Auxiliary Boiler	206	206

The facility and LDEQ have executed an AOC that states following the effective date of the SIP revision, before fuel oil firing is allowed to take place at the Willow Glen facility a revised BART determination must be promulgated for SO_2 and NOx for the fuel oil firing scenario through an action by the LDEQ as a SIP revision, which will then have to be approved by EPA and such action will become federally enforceable. Based upon the CALPUFF modeling results, the five-factor analysis, and the executed AOC, the LDEQ affirms that the facility is BART compliant.

- **Entergy Sterlington Units**: The Sterlington Plant is a fossil fuel steam/electric generation facility. It is located on the left descending bank of the Ouachita River approximately 3/10ths of a mile upstream of the United States Corp. of Engineer's Lock and Dam No. 5. The plant is comprised of four electric generating units, including two steam turbine-driven

generators and two gas turbine driven generators. Units 7AB and C7AB were identified as BART eligible units. Based on the results of the screening analysis conducted, visibility impacts from the Sterlington facility are less than the 0.5Δdv screening threshold and are therefore not subject to BART.

- **Entergy Michoud Units**: The Michoud Plant is an existing fossil fueled steam/electric generation facility consisting of two electric generating boiler units and one steam generating unit. Entergy has permanently retired these existing generating units (Unit 1, Unit 2, and Unit 3 identified as EPNs C1A &B-NG, C2 & B-NG, and EPN C3), effective June 1, 2016. This action was set out in detail to the state through a permit application; a public hearing has been set for February 16, 2017. Therefore BART for this facility is no longer applicable. (See the public notice located in Appendix D.)

- **Roy S. Nelson Generating Plant (Nelson)**: The facility is located in Westlake, Calcasieu Parish, Louisiana and is located 264 miles west of the Breton National Wilderness Area and 286 miles south of the Caney Creek Wilderness Area in Arkansas. The facility is a fossil-fuel steam electric power generating facility and operates three BART-eligible steam generating units: Unit 4, Unit 4 Auxiliary Boiler and Unit 6.

The Unit 4 Boiler is permitted to combust natural gas, No. 2, No. 4 and No. 6 fuel oils and refinery fuel gas. Unit 4 has a maximum heat rated capacity of 5400 MMBtu/hour and exhausts out of one stack. It has flue gas recirculation equipment installed for control of NOx emissions. The Auxiliary Boiler for Unit 4 burns natural gas and fuel oil.

The Unit 6 Boiler burns coal as its primary fuel, with No. 2 and No. 4 fuel oils as its secondary fuels. Unit 6 has maximum heat rated capacity of 6216 MMBtu/hour and exhausts out of one stack. It has an electrostatic precipitator (ESP) with flue gas condition for control of particulate matter (PM) emissions. Unit 6 has installed Separated Overfire Air Technology (SOFA) and a Low NOx Concentric Firing System (LNCFS) for NOx control. Steam from these boilers is used to drive steam turbines which in turn generate rotary motion that is used to drive electric generators. The electric generators then produce electricity.

While Entergy has performed the traditional CALPUFF analysis, it has also chosen to run CAMx due to the limitations and deficiencies that cause inaccuracies in the visibility impact

predictions when using CALPUFF. Although the LDEQ does not have the expertise with which to review those model runs, they are included in the appendices for review and comment.

In the BART five-factor analysis, Entergy has reviewed a number of emission reduction controls including low sulfur coal, DSI, enhanced DSI, dry flue-gas desulfurization (FGD) and wet FGD for use in the Unit 6 Boiler. The use of low sulfur coal presents the most feasible control based on economics and impacts to visibility. The other controls are not cost effective based on the small incremental improvement in visibility. As noted, the Unit 4 Boiler and its auxiliary boiler both burn natural gas; therefore no controls would be considered BART for SO_2. This conclusion is consistent for similar units in the proposed Arkansas federal implementation plan (FIP).

Based upon the CALPUFF results using the 2000-2004 baseline data, the results of the CAMx modeling using both the 2000-2004 baselines and the 2012-2014 baseline, coupled with the emission reductions that have occurred at the facility, LDEQ believes that the visibility improvement that would be achieved through the installation and operation of controls at each of the Nelson units would be negligible, therefore the facility's existing controls satisfy the BART requirements and no further controls are necessary. See Table 1.1 below.

Table 1.1: Certified Emission Reductions for Roy S. Nelson

	NOx (tpy)	SO2 (tpy)	PM-10 (tpy)
2011	4960.39	14199.55	554.02
2012	4576.79	12512.94	567.24
2013	4071.23	11460.91	513.11
2014	3506.88	10543.56	446.48
2015	3678.59	8122.13	363.26

- **Waterford 1 & 2 Electric Generating Plant (Waterford)**: Entergy Louisiana, L.L.C., owns and operates the Waterford 1 & 2 Electric Generating Plant, an existing fossil-fueled steam/electric generation facility. It is located in Killona, St. Charles Parish, Louisiana and is 81.2 miles west of the Breton National Wildlife Refuge.

The facility consists of three generating units: Units 1, Unit 2 and an Auxiliary Boiler. Both Units 1 and 2 boilers use natural gas as their primary fuel and No. 6 fuel oil as its secondary fuel; the units have a normal operating heat input of 4440 MMBtu/hour while burning natural gas and 3920 MMBtu/hour while burning fuel oil. The Auxiliary Boiler burns only natural gas.

The resulting steam from the boilers is used to drive steam turbines which are connected to the electric generators that produce electricity.

Entergy prepared the required five-factor analysis to determine BART controls. The controls investigated were fuel switching, DSI, dry-semi dry scrubbing and wet scrubbing for SO_2 control and wet electrostatic precipitators, wet scrubbing, fuel switching and cyclone technology for PM control. However, because the facility burns natural gas almost exclusively, the facility has entered into an AOC with the LDEQ. The order encompasses the permit conditions, required by 40 CFR 63 Subpart UUUUU, which provides: "should the units exceed the applicability threshold that would reclassify the units from gas-fired to oil-fired," a BART five-factor analysis will be submitted to the LDEQ and a SIP revision will be proposed to EPA for approval. The LDEQ holds that Waterford Units 1 & 2 have fulfilled the requirements of BART. The AOC is included in the appendices along with the modeling analysis and results. For the Auxiliary Boiler, no technically feasible control options are available for SO_2 or PM control for natural gas fired boilers. Therefore, LDEQ finds that the Auxiliary Boiler has met the BART requirements.

All documentation, including 5-factor analysis and correspondence for the Entergy units, can be found in Appendix D.

D. Municipal Facility Units

The following facilities have either screened out or have been retired; please see Appendix E for documentation.

a. <u>Morgan City Steam Plant Facility (Joseph J. Cefalu Sr. Plant)</u>
<u>Louisiana Energy & Power Authority (LEPA) AI 26326</u>

The steam plant is located in Morgan City in St. Mary Parish. The plant is no longer in operation, therefore BART screening is not applicable to this facility. Please refer to enclosed copy of the facility's permit rescission notice and related letter to the EPA.

b. <u>City of Ruston, Ruston Electrical Generation Station AI 8167</u>

The Ruston Electrical Generation Station is located in the city of Ruston in Lincoln Parish. The station is no longer in operation, therefore BART screening is not applicable to this facility. Please refer to enclosed copy of the facility's permit rescission notice.

c. **City of Natchitoches, Power Plant #1, AI 19375**

Power Plant #1 was located in the City of Natchitoches, Natchitoches Parish. The power plant was shut down and dismantled as indicated in the enclosed copy of the facility's permit rescission notice. BART screening, is therefore, not applicable to this facility.

d. **Lafayette Utility System (LUS): Louis "Doc" Bonin, AI 31135**

LUS operates the Louis "Doc" Bonin Generating Station located in Lafayette Parish, Louisiana. By letter dated December 11, 2015, LUS notified the EPA Clean Air Markets Division of the long term cold storage Units 1, 2, and 3. Unit 1 last operated on June 22, 2011 and was put into cold storage on June 1, 2013. Unit 2 last operated on July 5, 2013 and was put into cold storage on June 29, 2014. Unit 3 last operated on August 27, 2013 and was put into cold storage on June 29, 2014.

MISO is currently conducting a study to predict the future use of these unit(s) for peaking purposes. If it is determined that these units are no longer necessary to facilitate electrical power generation, they will be retired. If the facilities are necessary, new permit applications will be submitted to LDEQ; therefore any future BART discussions will be instituted at that point in time. (See Appendix E)

To: Terry.Salem@tceq.texas.gov[Terry.Salem@tceq.texas.gov]; Thomas, Carrie[Thomas.Carrie@epa.gov]
Cc: Donaldson, Guy[Donaldson.Guy@epa.gov]; Tomasovic, Brian[Tomasovic.Brian@epa.gov]
From: Feldman, Michael
Sent: Thur 6/22/2017 5:42:52 PM
Subject: FW: RH BART June 20, 2017 SIP Proposal
20 June 2017 Potpourri Notice.docx
RH EGU BART Revision Proposed June 2017.pdf

Terry – I believe this is the language that Sam was referring to. Please see Carrie's email below.

Thanks,

Michael Feldman, PhD
Environmental Engineer
Air Planning Section
U.S. EPA Region 6, 6PD-L
Phone: 214-665-9793
feldman.michael@epa.gov

From: Thomas, Carrie
Sent: Thursday, June 22, 2017 11:39 AM
To: Feldman, Michael <Feldman.Michael@epa.gov>
Cc: Donaldson, Guy <Donaldson.Guy@epa.gov>; Wiley, Adina <Wiley.Adina@epa.gov>; Tomasovic, Brian <Tomasovic.Brian@epa.gov>
Subject: FW: RH BART June 20, 2017 SIP Proposal
Importance: High

Hi Michael,

Is this the language that TCEQ is looking for? It's on the 7th page of LDEQ's proposed submittal in the attached pdf.

"As the energy industry evolves, LDEQ continues to work with EGUs throughout Louisiana to evaluate the operation of utilities. As such, LDEQ will engage in discussions with Entergy about any potential changes in

usage or emission rates at the Nelson facility. Any such changes will be considered for reasonable progress for future planning periods as appropriate."

Please forward to anyone else. I'm not sure who all was on the call.

Thanks,

Carrie K. Thomas
Office of Regional Counsel
U.S. Environmental Protection Agency, Region 6
1445 Ross Ave. (6-RC-M)
Dallas, TX 75202
Tel: (214) 665-7121
Fax: (214) 665-2182

NOTICE: This communication may contain privileged or other confidential information. If you are not the intended recipient, or believe you have received this communication in error, please delete the copy you received, and do not print, copy, re-transmit, disseminate or otherwise use the information. Thank you.

POTPOURRI

Department of Environmental Quality
Office of the Secretary
Legal Division

State Implementation Plan for Regional Haze Program
Electrical Generating Units BART

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 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 defined as visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area. (1706Pot1)

On July 3, 2012, the Environmental Protection Agency (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 electrical generating unit (EGU) at the Entergy Gulf States Louisiana, Roy S. Nelson facility, located in Westlake, Calcasieu Parish, Louisiana, which was addressed under the best available retrofit technology (BART) section and that is subject to the EPA partial disapproval.

All interested persons are invited to submit written comments concerning the SIP revision no later than 4:30 p.m., Wednesday, July 26, 2017, to Vivian H. Aucoin, Office of Environmental Services, Box 4313, Baton Rouge, LA 70821-4314, Fax (225) 219-3482, or e-mail at vivian.aucoin@la.gov. A public hearing will be held upon request. The deadline for requesting a public hearing is Friday, July 7, 2017.

A copy of the proposal may be viewed on the Louisiana Department of Environmental Quality website, or at LDEQ headquarters at 602 North 5th Street, Baton Rouge, Louisiana 70802.

Herman Robinson
General Counsel

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

Regional Haze State Implementation Plan

EGU BART Analysis

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

Revision Proposed June 2017

JOHN BEL EDWARDS
GOVERNOR

CHUCK CARR BROWN, PH.D.
SECRETARY

State of Louisiana

DEPARTMENT OF ENVIRONMENTAL QUALITY
OFFICE OF THE SECRETARY

June 19, 2017

Mr. Sam Coleman, Acting Administrator
US EPA Region 6, 6-RA
1445 Ross Avenue, Suite 1200
Dallas Texas 75202-2733

RE: Louisiana's State Implementation Plan (SIP) Revisions Addendum
Regional Haze Rule EGU Best Available Retrofit Technology (BART)

Dear Mr. Coleman:

Please find enclosed 2 bound copies of the draft revision to the SIP for the Regional Haze Rule. An electronic copy will be forwarded via electronic mail presently to the Region 6 staff.

Written comments regarding the proposed SIP revision are due no later than July 26, 2017 and should be mailed to Vivian H. Aucoin, Office of Environmental Services, P. O. Box 4314, Baton Rouge, La., 70821-4314 or emailed to vivian.aucoin@la.gov.

If you have any questions concerning this matter, please feel free to contact Donald Trahan, Air Permits Administrator at 225-219-3408 or at donald.trahan@la.gov.

Sincerely,

Chuck Carr Brown, Ph.D.
Secretary

Enclosures

c: Wren Stenger, 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

I. Background on the Regional Haze Rule

A. Plan Submission

[No Change]

B. Legal Authority

[No Change]

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 June 20, 2017 in the *Louisiana Register*. Public comments on the proposal should be submitted no later than July 26, 2017. A public hearing will be held if requested. A copy of the potpourri notice is included in Appendix A

D. Commitment to Plan Revision

[No Change]

E. History of Regional Haze

[No Change]

F. Breton National Wilderness Area (Class I)

[No Change]

G. Louisiana's Visibility History

[No Change]]

H. Class I Areas outside the State Boundaries

[No Change]

II. BART Analysis

[No Change]

A. CLECO

[No Change]

B. Louisiana Generating, LLC, a subsidiary of NRG

[No Change]

C. Entergy Louisiana LLC

Entergy submitted to LDEQ CALPUFF modeling for SO_2 and PM for the various units that were found to be BART-eligible; all reports are included in Appendix D. In the course of this exercise, Entergy has submitted not only CALPUFF modeling and a five-factor analysis to satisfy the RH and BART requirements, but has also submitted CAMx modeling to support their findings. While LDEQ has not used the CAMx modeling to ascertain that the units have satisfied the BART requirements, the model results have been included for consideration. Following Louisiana's final revision submittal, a discussion between EPA, LDEQ and Entergy took place and based upon the results of that discussion, EPA provided additional information on Entergy's proposed BART five-factor analysis and EPA's draft analyses for LDEQ's review. Therefore this SIP is being revised to include the EPA information. The additional information submitted by EPA is included in Appendix F.

- **Entergy Ninemile Point Units:**

[No Change]

- **Entergy Little Gypsy Units:**

[No Change]

- **Entergy Willow Glen Units:**

[No Change]

- **Entergy Sterlington Units:**

[No Change]

- **Entergy Michoud Units:**

[No Change]

- **Roy S. Nelson Generating Plant (Nelson):** The facility is located in Westlake, Calcasieu Parish, Louisiana and is located 264 miles west of the Breton National Wilderness Area and 286 miles south of the Caney Creek Wilderness Area in Arkansas. The facility is a fossil-fuel steam electric power generating facility and operates three BART-eligible steam generating units: Unit 4, Unit 4 Auxiliary Boiler and Unit 6.

The Unit 4 Boiler is permitted to combust natural gas, No. 2, No. 4 and No. 6 fuel oils And refinery fuel gas. Unit 4 has a maximum heat rated capacity of 5400 MMBtu/hour and exhausts out of one stack. It has flue gas recirculation equipment installed for control of NOx emissions. The Auxiliary Boiler for Unit 4 is permitted to burn natural gas and fuel oil.

The Unit 6 Boiler is permitted to burn coal as its primary fuel, with No. 2 and No. 4 fuel oils as its secondary fuels which are mainly used for start-up. Unit 6 has maximum heat rated capacity of 6216 MMBtu/hour and exhausts out of one stack. It has an electrostatic precipitator (ESP) with flue gas condition for control of particulate matter (PM) emissions. Unit 6 has installed Separated Overfire Air Technology (SOFA) and a Low NOx Concentric Firing System (LNCFS) for NOx control. Steam from these boilers is used to drive steam turbines which in turn generate rotary motion that is used to drive electric generators. The electric generators then produce electricity.

Entergy has performed the traditional CALPUFF analysis as well as CAMx based upon EPA modeling guidance. The guidance, Appendix Y of the BART rule (July 6, 2005), states that CALPUFF shall be used for single-source modeling where the distance between the BART source and the Class I area is less than 300 kilometers (km). Since CALPUFF may significantly over predict impacts at greater distances, CAMx is approved for situations where the distance is greater than 300km. The facility is 425 km from Breton and 460km from Caney Creek.

Unit 4 and the auxiliary boiler are permitted to burn fuel oil. However, fuel oil has not been burned at either unit in several years and there are no current operational plans to burn fuel oil. Entergy and LDEQ have executed an Administrative Order on Consent (AOC) that states before fuel oil firing is allowed to take place at Unit 4 and/or the auxiliary boiler, a revised BART determination must be promulgated for SO_2 and PM for the fuel oil firing scenario through a SIP revision, which will then have to be approved by EPA and such action will become federally enforceable.

In the Entergy BART five-factor SO_2 analysis for the Unit 6 Boiler, a number of emission reduction controls were reviewed. Those controls included lower sulfur coal, DSI, enhanced DSI, dry flue-gas desulfurization (FGD) and wet FGD. LDEQ has weighed the five factors and after a review of both Entergy's and EPA's information has concluded that BART is the emission limit of 0.6 lbs./MMBtu based on at 30 day rolling average as defined in the AOC. While additional visibility benefits may be available through the use of FGD, the lower sulfur coal option results in visibility benefits at a lower annual cost. In addition, FGD use results in additional waste due to spent reagent and has some power demands to run the equipment. LDEQ believes, at present, that the use of lower sulfur coal presents the appropriate SO_2 control based on consideration of economics, energy impacts, non-air quality environmental impacts, and impacts to visibility.

Regarding PM, Unit 6 is currently equipped with an ESP to control PM emissions. Impacts from PM emissions are small and any additional controls beyond the ESP would have

minimal visibility benefits and would not be cost–effective. Therefore, the existing controls are sufficient to meet BART for PM.

Based upon this decision and the inclusion of the emission limits in the AOC, LDEQ has determined that the conditions are sufficient to meet BART. As the energy industry evolves, LDEQ continues to work with EGUs throughout Louisiana to evaluate the operation of utilities. As such, LDEQ will engage in discussions with Entergy about any potential changes in usage or emission rates at the Nelson facility. Any such changes will be considered for reasonable progress for future planning periods as appropriate.

- **Waterford 1 & 2 Electric Generating Plant (Waterford):**

[No Change]

D. Municipal Facility Units

[No Change]

Appendix A

Public Notice and Participation

Appendix B

CLECO

BART Determination and Evaluation

[No Change]

Appendix C

NRG
BART Determination and Evaluation

[No Change]

Appendix D

Entergy Louisiana LLC
BART Determination and Evaluation

[AOC for R. S. Nelson Facility add; otherwise no change]

STATE OF LOUISIANA
DEPARTMENT OF ENVIRONMENTAL QUALITY

OFFICE OF ENVIRONMENTAL ASSESSMENT

IN THE MATTER OF	*	
	*	
ENTERGY LOUISIANA, LLC	*	**REGIONAL HAZE**
R.S. NELSON GENERATING PLANT	*	**STATE IMPLEMENTATION PLAN**
CALCASIEU PARISH, LOUISIANA	*	**EGU BART ANALYSIS**
	*	
	*	**AGENCY INTEREST NO. 19588**
	*	
PROCEEDINGS UNDER THE LOUISIANA	*	
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 **ENTERGY LOUISIANA, LLC (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 the R. S. Nelson Generating Plant located at 3500 Houston River Road, Westlake, Calcasieu Parish, Louisiana (Facility). The Facility currently operates pursuant to Title V and PAL Permit Number 6250-00014-V4 issued on April 11, 2017.

II.

Under Clean Air Act (CAA) section 110, each state must prepare and submit for the EPA approval, a 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 is concurrently submitting a proposed SIP on behalf of the State of Louisiana to EPA Region VI that addresses Best Available Retrofit Technology (BART) for the Facility. The BART analysis is based in part on submittals made by RESPONDENT to the Department on August 31, 2015, November 9, 2015 and April 15, 2016.

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:

> Before fuel oil firing is allowed to take place at Unit 4 and the auxiliary boiler at the Facility, a revised BART determination must be promulgated for SO_2 and PM for the fuel oil firing scenario through a FIP or an action by the LDEQ as a SIP revision and approved by EPA such that the action is federally enforceable.

II.

The Respondent shall comply with the sulfur dioxide (SO_2) emission limitations set forth below as expeditiously as practicable, following the effective date of a final SIP pursuant to 40 CFR PART 51, Appendix Y:

Unit	**Pollutant**	**Emission Limit lb./ MMBtu (30-day rolling average, conventional rounding)**
6	**SO_2**	**0.6**

III.

The Respondent shall comply with the particulate matter less than 10 microns (PM_{10}) emissions limit set forth below no later than the effective date of a final SIP pursuant to 40 CFR PART 51, Appendix Y:

Unit 6

Unit	**Pollutant**	**Emission Limit lb/hr (30-day rolling average)**
6	**PM_{10}**	**317.61**

IV.

The Respondent shall continue to comply with all reporting and record keeping requirements contained within all applicable permits.

V.

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*.

VI.

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.

VII.

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.

VIII.

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.

IX.

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 State 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** 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 **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**.

X.

A.)"This **ADMINISTRATIVE ORDER ON CONSENT** shall be final and effective upon final approval of a SIP by EPA and signature by an authorized representative of the Department and signature by the authorized representative of the Respondent, provided that the federally

enforceable limits set forth herein shall not become effective until the final approval by EPA of the SIP as it relates to the BART Five Factor Analysis for the Facility based upon those federally-enforceable limits".

Baton Rouge, Louisiana, this _____ day of June, 2017.

_____
Chuck Carr Brown, Ph.D.
Secretary

Entergy Louisiana LLC

By:_____ Date:_____

Name:

Title: President

Appendix E

Municipal Facilities

[No Change]

Appendix F

EPA DRAFT BART Modeling and Costs Information

To: Spencer, Stuart[SPENCER@adeq.state.ar.us]
Cc: Todd, Robert[Todd.Robert@epa.gov]; Medina, Dayana[Medina.Dayana@epa.gov]; Montgomery, William[Montgomery@adeq.state.ar.us]
From: Donaldson, Guy
Sent: Wed 6/7/2017 9:29:36 PM
Subject: FW: Comments on ADEQ draft SIP revision
EPA Comments on draft AR RH SIP revision.docx

Stuart,

Here are some recommendations for your draft SIP revision. Please take them in the spirit of recommendations but we think they will improve the accuracy of the document.

From: Medina, Dayana
Sent: Wednesday, June 07, 2017 4:01 PM
To: Donaldson, Guy <Donaldson.Guy@epa.gov>
Cc: Todd, Robert <Todd.Robert@epa.gov>; Nann, Barbara <nann.barbara@epa.gov>
Subject: RE: Comments on ADEQ draft SIP revision

Guy- Here is the revised version. It sounds like you are ok with me sending the comments to Tricia Treece, or did you want this to be sent by you to Stuart?

Dayana Medina

U.S. Environmental Protection Agency, Region 6

Multimedia Division

State Implementation Section A (6MM-AA)

214-665-7241

From: Donaldson, Guy
Sent: Wednesday, June 07, 2017 3:48 PM
To: Medina, Dayana <Medina.Dayana@epa.gov>
Subject: RE: Comments on ADEQ draft SIP revision

Sure include it if not too late.

From: Medina, Dayana
Sent: Wednesday, June 07, 2017 2:54 PM
To: Donaldson, Guy <Donaldson.Guy@epa.gov>
Cc: Nann, Barbara <nann.barbara@epa.gov>
Subject: FW: Comments on ADEQ draft SIP revision

Guy- one more comment sent by Carrie T. Should we include it in our comments to the state?

Dayana Medina

U.S. Environmental Protection Agency, Region 6

Multimedia Division

State Implementation Section A (6MM-AA)

214-665-7241

From: Nann, Barbara
Sent: Wednesday, June 07, 2017 2:49 PM
To: Medina, Dayana <Medina.Dayana@epa.gov>
Subject: FW: Comments on ADEQ draft SIP revision

From: Thomas, Carrie
Sent: Wednesday, June 07, 2017 2:48 PM
To: Nann, Barbara <nann.barbara@epa.gov>
Subject: RE: Comments on ADEQ draft SIP revision

Feel free to disregard because this may be too nitpicky, but here are my only comments:

"ADEQ has determined that it is appropriate under 40 C.F.R § 51.308, and provides additional flexibility for CSAPR participating subject-to-BART units in Arkansas, to rely upon participation in the CSAPR ozone season NOx trading program rather than source-specific BART requirements for NOx. Participation in CSAPR for ozone season NOx is federally enforceable under 40 C.F.R. 52.38 and the ozone season NOx requirements under CSAPR apply to ~~for~~ the following BART-eligible units:"

CSAPR as an alternative to BART applies to all EGUs in the state over a certain size, rather than being an alternative to BART for only the BART sources (this is one of the issues that's come up for Texas). Without the commas and the extra language, it could be read to mean that only the subject to BART units need to participate in CSAPR for it to be a sufficient alternative to BART. There are other (probably better) ways to address my concern, but this was the least invasive way I could think of.

Carrie K. Thomas
Office of Regional Counsel
U.S. Environmental Protection Agency, Region 6
1445 Ross Ave. (6-RC-M)
Dallas, TX 75202
Tel: (214) 665-7121
Fax: (214) 665-2182

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From: Nann, Barbara
Sent: Wednesday, June 07, 2017 1:44 PM
To: Thomas, Carrie <Thomas.Carrie@epa.gov>
Subject: FW: Comments on ADEQ draft SIP revision

From: Anderson, Lea
Sent: Wednesday, June 07, 2017 1:42 PM
To: Nann, Barbara <nann.barbara@epa.gov>
Cc: Zenick, Elliott <Zenick.Elliott@epa.gov>; Beaver, Melinda <Beaver.Melinda@epa.gov>
Subject: Re: Comments on ADEQ draft SIP revision

Thanks, Barbara. I don't have anything to add beyond the comments that have been pulled together. The two key points are (1) that the SIP doesn't address the NOx controls required for Independence (which I'm fine with, but I imagine will not satisfy Entergy); and (2) Arkansas' apparent belief that if it complies with the original CSAPR budget, it will have satisfied the NOx BART requirements regardless of what happens to the update rule.

From: Nann, Barbara
Sent: Wednesday, June 7, 2017 11:18 AM
To: Anderson, Lea
Subject: FW: Comments on ADEQ draft SIP revision

From: Donaldson, Guy
Sent: Wednesday, June 07, 2017 7:42 AM
To: Medina, Dayana <Medina.Dayana@epa.gov>; Nann, Barbara <nann.barbara@epa.gov>; Feldman, Michael <Feldman.Michael@epa.gov>
Cc: Todd, Robert <Todd.Robert@epa.gov>
Subject: RE: Comments on ADEQ draft SIP revision

Here are my thoughts. Let's discuss at the team meeting.

From: Medina, Dayana
Sent: Tuesday, June 06, 2017 6:21 PM
To: Nann, Barbara <nann.barbara@epa.gov>; Donaldson, Guy <Donaldson.Guy@epa.gov>; Feldman, Michael <Feldman.Michael@epa.gov>
Cc: Todd, Robert <Todd.Robert@epa.gov>
Subject: RE: Comments on ADEQ draft SIP revision

Here are revised comments that include input from Michael and Barbara, as well as some of the feedback we received from Phil and Melinda. We can discuss at the RH team meeting tomorrow, or I can set up a separate call if we run out of time.

Dayana Medina

U.S. Environmental Protection Agency, Region 6

Multimedia Division

State Implementation Section A (6MM-AA)

214-665-7241

From: Nann, Barbara
Sent: Tuesday, June 06, 2017 9:34 AM
To: Medina, Dayana <Medina.Dayana@epa.gov>; Donaldson, Guy <Donaldson.Guy@epa.gov>; Feldman, Michael <Feldman.Michael@epa.gov>
Cc: Todd, Robert <Todd.Robert@epa.gov>
Subject: RE: Comments on ADEQ draft SIP revision

I had a few thoughts for your consideration (prior to any proposed inclusion into our comments).

1) RP/Independence:

I think we should comment to Arkansas that what they are wanting to do is not an Independence analysis but since they are proposing to adopt CSAPR better than BART for NOx that when doing an analysis for RP NOx CSAPR better than Bart will address the reductions needed for EGUs. Additional analysis/statements are required as to why that is enough under NOx (e.g. proposed emission reductions under NOx CSAPR better than BART will be better than BART and RP NOx controls for Independence, NOx is responsible for X% of visibility impairment as compared to Y% for SO2)

2) Draft Timeline for Processing SIP

I took the request in the Governor's draft letter for a stay of the emission limits as to highlighting the need to give the state a draft schedule to show that EPA processing of SIP will occur prior to April 2018 deadline. (I can have something by this afternoon.) Narrow FIP in actuality would really alleviate a timing concern but in lieu of that we can do what was done in NM (comfort letter). For NM, there was a stay for the negotiations (90 day then 45 day extension) and then there was a comfort letter for the SIP processing. Staying while EPA processes a SIP has several optic as well as legal issues tied to it. I recommend we talk with the state at the end of this week to walk through our comments and ideas for timing.

Barbara

From: Medina, Dayana
Sent: Friday, June 02, 2017 5:33 PM
To: Nann, Barbara <nann.barbara@epa.gov>; Donaldson, Guy <Donaldson.Guy@epa.gov>; Feldman, Michael <Feldman.Michael@epa.gov>
Cc: Todd, Robert <Todd.Robert@epa.gov>
Subject: RE: Comments on ADEQ draft SIP revision

I only have a few comments. Regarding Independence, I figured it may be better to encourage the State to talk to us about how they can address this source in this SIP revision rather than providing specific written comments on this issue.

Also, the draft cover letter to be signed by the Governor has language requesting that we "stay the NOx emission limits" of the BART EGUs while we review and process our action on the SIP revision. Should we tell ADEQ that we can't stay the emission limits, but that extending the administrative stay of the effectiveness of the NOx compliance dates could be an option?

Dayana Medina

U.S. Environmental Protection Agency, Region 6

Multimedia Division

State Implementation Section A (6MM-AA)

214-665-7241

From: Nann, Barbara
Sent: Thursday, June 01, 2017 4:56 PM
To: Donaldson, Guy <Donaldson.Guy@epa.gov>; Medina, Dayana <Medina.Dayana@epa.gov>; Feldman, Michael <Feldman.Michael@epa.gov>
Subject: AR RH: Quick Question

What is our target date for getting comments to AR on the NOx CSAPR better than BART SIP?

6/7/17

EPA Comments on Draft Arkansas RH SIP Revision

1. If the State is interested in requesting EPA to parallel process the SIP revision, we recommend that the Governor's cover letter make this request.
2. In the "Introduction" and "Background" sections summarizing EPA's 2012 action on the 2008 SIP revision, the draft SIP only mentions that EPA disapproved the RPGs, without mentioning that we also disapproved the RPG analysis. We encourage the State to clarify that EPA's 2012 action included disapproval of the RPGs and the RPG analysis. We find that this clarification would be helpful, especially if Arkansas ultimately decides to adopt in the SIP revision the same RPGs we disapproved in our 2012 action but including a revised analysis.
3. We recommend that the last sentence on page 1 of the draft SIP revision be revised as follows: "This SIP revision replaces source-specific NO_X BART determinations *for the EGUs* included in the 2008 AR RH SIP, as well as *NO_X* limits *for the EGUs* promulgated under the 2016 federal implementation plan (FIP), with reliance on the Cross-State Air Pollution Rule (CSAPR) emissions trading program …"
4. Page 6 of the draft SIP revision includes a statement that "Arkansas also requested reconsideration of the use of low-sulfur coal as BART for SO2 at Entergy White Bluff during the 2008-2018 planning period." Since the BART requirement is not specific to the planning period, we encourage ADEQ to revise the statement by removing reference to the planning period.
5. Section III of the draft SIP includes a discussion of the history of CSAPR, including the 2012 rulemaking EPA issued allowing states participating in the CSAPR trading program to use CSAPR to satisfy BART. We remind ADEQ that the EPA's 2012 determination that implementation of CSAPR meets the criteria for a BART alternative was based on an analytic demonstration that implementation of CSAPR (across all states subject to CSAPR) would result in greater reasonable progress than BART toward restoring natural visibility conditions in relevant locations. However, in response to the D.C. Circuit's remand of various CSAPR Phase 2 budgets, the EPA has since withdrawn the FIP provisions subjecting Florida's EGU's to CSAPR ozone-season NO_X requirements and has proposed to withdraw the FIP provisions subjecting Texas EGUs to CSAPR SO_2 and annual NO_X requirements. In order to address any potential concern about continuing to rely on CSAPR participation as a BART alternative for EGUs in the remaining CSAPR states, the EPA also proposed a sensitivity analysis showing that the 2012 analytic demonstration supporting the conclusion that CSAPR participation qualifies as a BART alternative would not be adversely affected by modifying the assumptions to reflect the actions that have been or are expected to be taken in response to the D.C. Circuit's remand of CSAPR Phase 2 budgets (81 FR 78954). In that proposed rulemaking, EPA requested comment on the sensitivity analysis and on EPA's proposed determination that CSPAR participation would continue to achieve greater reasonable progress than BART despite the changes in the treatment of Texas and Florida EGUs. EPA has not yet taken final action on that rulemaking. Therefore, we remind ADEQ that EPA final approval of

a SIP revision that relies on CSAPR to satisfy NO_X BART for Arkansas' EGUs is contingent on our taking final action to find that CSAPR continues to be an appropriate alternative to source specific BART. To provide a more up to date history of CSAPR, we also encourage ADEQ to mention in the SIP narrative the D.C. Circuit's remand of the CSAPR Phase 2 budgets as well as EPA's not yet finalized rulemaking to withdraw provisions subjecting Texas EGUs to CSAPR SO_2 and annual NO_X requirements and to re-affirm that CSAPR is better than BART.

6. We recommend that the sentence at the end of page 7 be revised as follows: "ADEQ has determined that it is appropriate under 40 C.F.R § 51.308, and provides additional flexibility for CSAPR participating subject-to-BART units in Arkansas, to rely upon participation in the CSAPR ozone season NO_X trading program rather than source-specific BART requirements for NO_X. Participation in CSAPR for ozone season NO_X is federally enforceable under 40 C.F.R. 52.38 *and the ozone season NOx requirements under CSAPR apply to* the following BART-eligible units…"
7. We encourage the State to address NO_X for Independence Units 1 and 2 in this SIP revision. We recommend including a reasonable progress analysis addressing NO_X for all EGUs in Arkansas instead of developing an analysis specific only to Independence. One potential option for addressing reasonable progress for NO_X is to provide a discussion explaining why participation in CSAPR for ozone season NO_X addresses the NO_X reductions needed for all EGUs in Arkansas taking into consideration the percent contribution to visibility impairment from NO_X, especially when compared to that of SO_2. We encourage ADEQ to work with EPA in the development of the reasonable progress analysis.
8. Based on feedback received from the FLMs, we encourage ADEQ to share with the FLMs as soon as possible a draft of the proposed SIP revision so that the FLMs can make a determination as to whether they can commit to an abbreviated or expedited consultation period. Additionally, we recommend that the SIP revision narrative include a discussion of the requirements under section 51.308(i)(2) regarding FLM consultation, as well as a discussion of consultations between ADEQ and the FLMs.
9. For greater accuracy, we recommend that a statement at the beginning of page 3 be revised to the following: "*Around the time of* the 1999 RHR*, the EPA and FLMs* also expanded the existing Class I visibility monitoring network to 108 Class I areas.

To: Pruitt, Scott[Pruitt.Scott@epa.gov]
Cc: Dunham, Sarah[Dunham.Sarah@epa.gov]; Werner, Christopher[Werner.Christopher@epa.gov]; Jones, Rhea[Jones.Rhea@epa.gov]; Ann.M.Seha@xcelenergy.com[Ann.M.Seha@xcelenergy.com]; kmcque1@entergy.com[kmcque1@entergy.com]; william.matthews@cleco.com[william.matthews@cleco.com]; allison.mallick@bakerbotts.com[allison.mallick@bakerbotts.com]
From: debra.jezouit@bakerbotts.com
Sent: Mon 3/13/2017 8:58:17 PM
Subject: Petition for Reconsideration of Regional Haze Rule Revisions
removed.txt
Cover Letter for SPS, Entergy, Cleco Petition for Reconsideration.pdf
SPS, Entergy, Cleco Petition for Reconsideration of RH Revision Rule.pdf

Administrator Pruitt:

Enclosed please find a cover letter and Petition for Reconsideration of the final Regional Haze Rule revisions on behalf of Southwestern Public Service Company, Entergy Services, Inc. and Cleco Power LLC. If you have any questions about the attached Petition for Reconsideration, please do not hesitate to contact me.

Debra J. Jezouit

Partner

Baker Botts L.L.P.

debra.jezouit@bakerbotts.com

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Ex. 6 - Personal Privacy

The Warner

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Washington, DC 20004

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March 13, 2017

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VIA EMAIL AND HAND DELIVERY

Mr. Scott Pruitt
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Mail Code: 1101A
Washington, DC 20460

Re: Petition for Reconsideration of Southwestern Public Service Company, Entergy Services, Inc., and Cleco Power LLC, of the final rule entitled "Protection of Visibility: Amendments to Requirements for State Plans," EPA Docket No. EPA–HQ–OAR–2015–0531

Dear Administrator Pruitt:

Southwestern Public Service Company, Entergy Services, Inc., and Cleco Power LLC respectfully submit the enclosed Petition for Reconsideration of the U.S. Environmental Protection Agency's ("EPA" or "Agency") final rule entitled "Protection of Visibility: Amendments to Requirements for State Plans" ("Final Rule"). 82 Fed. Reg. 3,078 (Jan. 10, 2017). An additional copy of the Petition is enclosed to be time-stamped and returned in the attached envelope.

Thank you for your consideration of the enclosed Petition for Reconsideration. If you have questions, please contact me at (202) 639-7728.

Sincerely,

Debra J. Jezouit

Counsel for Southwestern Public Service Company, Entergy Services, Inc., and Cleco Power LLC

Enclosure

cc: Sarah Dunham

BEFORE THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In re:	)	EPA Docket No.
	)	
Protection of Visibility: Amendments to Requirements for State Plans	)	EPA–HQ–OAR–2015–0531
	)	
	)	

Petition for Reconsideration of the Revisions to the Regional Haze Rule by Southwestern Public Service Company, Entergy Services, Inc., and Cleco Power LLC

Southwestern Public Service Company ("SPS"); Entergy Services, Inc., on behalf of Entergy Corporation and its subsidiaries (collectively, "Entergy"); and Cleco Power LLC ("Cleco") (collectively, "Petitioners") respectfully petition the U.S. Environmental Protection Agency ("EPA" or "Agency") for reconsideration of the final rule entitled "*Protection of Visibility: Amendments to Requirements for State Plans*," Docket No. EPA–HQ–OAR–2015–0531.[1] Specifically, Petitioners request that EPA eliminate (1) provisions codifying an interpretation of the relationship between reasonable progress goals and long-term strategies; and (2) provisions pertaining to the reasonably attributable visibility impairment ("RAVI") program. These provisions contradict the Clean Air Act ("CAA" or "Act") and EPA's previous regulations and impose unnecessary and potentially staggering costs without achieving any corresponding visibility benefits. The Final Rule also improperly interferes with state authority to implement the Regional Haze Program, in direct violation of the cooperative federalism structure of the CAA. As was recently explained in a letter to Administrator Pruitt from the Attorneys General for 19 states, "the primary regulators of the environment are the States and local governments."[2] EPA should reconsider and eliminate these provisions of the Final Rule to restore the proper balance of state and federal authority, as well as to make the Rule consistent with the CAA and prior EPA regulations and effectuate recent Executive Orders.

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[1] 82 Fed. Reg. 3,078 (Jan. 10, 2017) ("Final Rule").

[2] Letter to Hon. Scott Pruitt, Administrator, U.S. EPA, re: Request to reexamine delegation of certain environmental regulation authority to the States in accordance with the express terms of the Clean Air and Water Acts (Mar. 7, 2017).

I. INTRODUCTION

A. Description of Petitioners

The Petitioners are electric generating companies that own and/or operate power plants subject to the Regional Haze Program and are directly affected by the Final Rule.

SPS is a wholly owned subsidiary of Xcel Energy Inc., a utility holding company headquartered in Minneapolis, Minnesota. Xcel Energy Inc.'s operating companies own 75 generating facilities with approximately 16,744 megawatts of electric generating capacity and 20,053 miles of transmission lines, with SPS owning nine generating plants with approximately 4,446 megawatts of electric generating capacity and 6,839 miles of transmission lines. Xcel Energy Inc.'s operating companies, including SPS, serve approximately 3.5 million electricity customers across Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin, with SPS serving approximately 388,000 electric customers in a 52,000 square mile area of the Texas Panhandle and eastern and southern New Mexico. Xcel Energy Inc. has approximately 12,000 employees.

Entergy is an integrated energy company engaged primarily in electric power production and retail distribution operations. Entergy owns and operates power plants with approximately 30,000 megawatts of electric generating capacity. Entergy delivers electricity to 2.8 million utility customers in Arkansas, Louisiana, Mississippi, and Texas and owns and operates wholesale electricity generating units in Massachusetts, Michigan, and New York. Entergy has more than 13,000 employees.

Cleco is a regulated utility company headquartered in Pineville, Louisiana. Cleco owns nine generating units with a total nameplate capacity of 3,310 megawatts, 11,931 miles of distribution lines and 1,305 miles of transmission lines. Cleco delivers electricity to approximately 287,000 customers in Louisiana through its retail business, and supplies wholesale power in Louisiana and Mississippi. Cleco is a wholly owned subsidiary of Cleco Corporate Holdings LLC, a utility holding company headquartered in Pineville, Louisiana. Cleco Corporate Holdings LLC has approximately 1,200 employees.

B. Background

Section 169A of the CAA establishes a national goal of preventing future visibility impairment (*i.e.*, "regional haze") and remedying existing visibility impairment caused by manmade air pollution in certain national parks, wilderness areas, and monuments (collectively defined as "Class I areas").[3] To implement this goal, states must adopt State Implementation Plans ("SIPs") for phased 10-year planning periods that (1) require certain major stationary sources to meet emission limits based on the installation of "best available retrofit technology"

[3] 42 U.S.C. § 7491(a)(1).

("BART"),[4] and (2) include a long-term strategy for the state to make "reasonable progress" towards the national goal of attaining natural visibility conditions by 2064.[5] The long-term strategy consists of "such emission limits, schedules of compliance and other measures as may be necessary" for meeting reasonable progress goals.[6]

In setting a reasonable progress goal, the CAA requires states to consider four factors: "the costs of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements."[7] EPA further specifies that the reasonable progress goal "must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period."[8] EPA has explained that reasonable progress goals are "interim goals that represent incremental visibility improvement over time toward the goal of natural background conditions."[9]

EPA took a two-phased approach in establishing the Regional Haze Program to satisfy the mandate of CAA Section 169A. In the first phase, EPA addressed impairment of visibility in Class I areas that was "reasonably attributable" to a specific source or smaller group of sources.[10] This "reasonably attributable visibility impairment" ("RAVI") program also addressed potential visibility impacts from new and modified major sources already subject to New Source Review permitting requirements.[11] In the second phase, beginning with EPA's 1999 Regional Haze Rule,[12] EPA addressed regional haze in Class I areas through a regional planning approach. This second phase targets visibility impairment that is not reasonably attributable to a single source or small, defined group of sources, but instead is produced by emissions from a wide array of sources over a broad geographic area.

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[4] BART is defined as "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction." 40 C.F.R. § 51.301.

[5] 42 U.S.C. § 7491(b)(2).

[6] *Id.*

[7] 42 U.S.C. § 7491(g)(1).

[8] 40 C.F.R. § 51.308(d)(1).

[9] U.S. EPA, Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, at 1–2 (June 1, 2007) ("Reasonable Progress Guidance"), available at https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/20070601_wehrum_reasonable_progress_goals_reghaze.pdf.

[10] *See* Visibility Protection for Federal Class I Areas ("RAVI Regulation"), 45 Fed. Reg. 80,084, 80,085–86 (Dec. 2, 1980); 40 C.F.R. § 51.300−307.

[11] *Id.*

[12] 64 Fed. Reg. 35,714, 35,731 (July 1, 1999). EPA revised the Regional Haze Rule in 2005. 70 Fed. Reg. 39,104 (July 6, 2005).

The Final Rule revises provisions of both the RAVI and Regional Haze Programs.[13] According to EPA, the revisions remove older provisions that have been superseded by subsequent developments and clarify certain provisions to ensure consistent understanding of requirements as states prepare their Regional Haze SIPs for the second implementation period. Most notably, the Final Rule (1) "clarifies" the relationship between reasonable progress goals and long-term strategies; and (2) modifies and expands the RAVI program.

II. REQUEST FOR RECONSIDERATION

EPA should grant reconsideration because certain provisions of the Final Rule contradict the CAA and EPA's previous regulations, undermine the principles of cooperative federalism, and impose excessive costs with no corresponding visibility benefits. Federal agencies have inherent authority to reconsider their past decisions and to revise, replace or repeal a decision to the extent permitted by law and supported by a reasoned explanation. *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009); *Motor Vehicle Mfrs. Ass'n of U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 42 (1983).

Reconsideration of a rulemaking is "well within an agency's discretion" when it is based "on a reevaluation of which policy would be better in light of the facts." *Nat'l Ass'n of Home Builders v. EPA*, 682 F.3d 1032, 1038, 1042 (D.C. Cir. 2012) (citing *Fox*, 556 U.S. at 514-15). The agency need not demonstrate that the reasons for the new policy are better than the reasons for the old one; rather, "it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency believes it to be better." *Fox*, 556 U.S. at 515 (emphasis omitted). A new Presidential Administration is a valid reason for conducting such a reevaluation of the best policy approach. *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 59 (1983) (Rehnquist, J., concurring in part and dissenting in part) ("A change in administration brought about by the people casting their votes is a perfectly reasonable basis for an executive agency's reappraisal of the costs and benefits of its programs and regulations."). EPA recently exercised this authority when announcing its intent to reconsider the Clean Water Rule.[14]

A. EPA Should Eliminate Provisions "Clarifying" the Relationship Between Long-Term Strategies and Reasonable Progress Goals.

The Final Rule revises certain regulatory provisions to "clarify the relationship between long-term strategies and reasonable progress goals."[15] These revisions include adding provisions (1) requiring states to select emission control measures for long-term strategies *before* calculating reasonable progress goals;[16] and (2) providing that a state, when developing its long-term strategy and considering the time necessary for compliance, "may not reject a control measure because it cannot be installed or become operational until after the end of the

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[13] 40 C.F.R. Pts. 51-52.

[14] 82 Fed. Reg. 12,532 (Mar. 6, 2017).

[15] 82 Fed. Reg. at 3,078.

[16] *See* 40 C.F.R. § 51.308(f)(2)(i).

implementation period."[17] These modifications should be eliminated because they undermine the CAA's intent to achieve gradual and steady improvement in visibility in Class I areas over a 60-year period, as well as limit state authority and increase costs for affected sources without any corresponding visibility benefit.

1. The "Clarifications" Improperly Require Assessment of Reasonable Progress Controls *Before* States Set Reasonable Progress Goals.

EPA's "clarification" turns the statutory scheme on its head by requiring states to identify reasonable progress controls to be included in long-term strategies before they establish their reasonable progress goals, contradicting both the CAA and the Agency's own regulations. The CAA requires states to set reasonable progress goals by considering four factors: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and nonair quality environmental impacts of compliance; and (4) the remaining useful life of any existing source subject to such requirements.[18] The Act then permits states to impose emission reduction requirements in their long term strategies *only* to the extent *necessary* to achieve reasonable progress.[19] Accordingly, Congress directed that states *first* set reasonable progress goals (considering the four statutory factors) and *second*, develop long-term strategies to achieve the reasonable progress goals. As EPA itself has explained, a state's long-term strategy is inextricably linked to the reasonable progress goals because the long-term strategy "must include enforceable emission limitations, compliance schedules, and other measures *as necessary to achieve the reasonable progress goals*…."[20]

The Final Rule effectively reverses this process, violating the statutory mandate that reasonable progress controls be imposed *as necessary* to meet reasonable progress goals. First, when developing long-term strategies, the Final Rule requires states to "evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment."[21] Second, the Final Rule requires states to establish reasonable progress goals that reflect the visibility conditions projected to be achieved by the end of the applicable implementation period as a result of the emission reductions measures identified in the first step.[22] Taken together, these new provisions require states to identify reasonable progress controls to include in their long-term strategies *before* establishing their reasonable progress goals.

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[17] 82 Fed. Reg. at 3,089; *see also* 40 C.F.R. § 51.308(f)(2)(i).

[18] 42 U.S.C. § 7491(g)(1).

[19] *See* 42 U.S.C. § 7491(b)(2) (long term strategies must "contain such emission limits ... *as may be necessary* to make reasonable progress") (emphasis added).

[20] *See* 82 Fed. Reg. at 3,084 (quoting 40 C.F.R. § 51.308(d)(3)) (emphasis added).

[21] 40 C.F.R. § 51.308(f)(2)(i).

[22] *Id.* § 51.308(f)(3)(i).

Not only does this change in sequencing violate the CAA, EPA's new approach leads to the absurd result that states may be required to impose emission control requirements that *are not necessary* to make reasonable progress toward the national visibility goal. In other words, states may be forced to require controls where actual visibility in the Class I area already is better than the reasonable progress goals that would be established based on an evaluation of the four statutory factors. This is the case in Arkansas and Texas, where EPA applied this new sequencing in Federal Implementation Plans ("FIPs") for those states. In both cases, EPA imposed burdensome and expensive emission control requirements in long-term strategies even though visibility in both states already has surpassed EPA's final reasonable progress goals for the first planning period.[23] The outcome in Arkansas is particularly arbitrary, as the Class I areas in that state already have surpassed the uniform rate of progress ("URP"), or glidepath, for the planning period.[24]

This is a plainly arbitrary outcome that far exceeds what the CAA envisions. Under the Act, a state may impose emission reduction requirements only to the extent *necessary* to achieve reasonable progress towards natural visibility levels.[25] But EPA's new approach requires individual source controls without assessing whether those controls are necessary to address visibility impairment. If an evaluation of the four statutory factors identifies control measures, the Final Rule *requires* that states establish reasonable progress goals based on the imposition of such control measures, regardless of whether the controls result in reasonable visibility improvements in a Class I area. As a result, because the reasonable progress goal assumes the installation of these control measures, states are effectively required to mandate that individual sources impose these controls.

The practical effect of this approach will give undue weight to the cost of compliance factor. In recent Regional Haze FIPs, which applied EPA's new interpretation even before EPA codified it in the Final Rule, EPA deemed a control to be "reasonable" for a state's long-term strategy if it is cost-effective. For example, in the Arkansas Regional Haze FIP, EPA required controls on Entergy's Independence Plant in part because EPA concluded that imposing controls on the plant would be cost-effective.[26] EPA gave no consideration to whether the controls and resulting emissions reductions would improve visibility in any Class I area and, in fact, recognized that controls would not be necessary for Arkansas Class I areas to meet their URPs.[27] This is problematic because it does not consider the costs in relation to visibility improvement,

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[23] *See* Brief of Entergy, et al. at 34-35, *Arkansas v. EPA*, No. 16-4270 (8th Cir. Feb. 17, 2017); Brief of State of Arkansas at 34-38, *Arkansas v. EPA*, No. 16-4270 (8th Cir. Feb. 17, 2017); *Texas v. EPA*, 829 F.3d 405, 427 (5th Cir. 2016).

[24] *See* Brief of Entergy, et al. at 34-35, *Arkansas v. EPA*, No. 16-4270 (8th Cir. Feb. 17, 2017); Brief of State of Arkansas at 34-38, *Arkansas v. EPA*, No. 16-4270 (8th Cir. Feb. 17, 2017).

[25] *See* 42 U.S.C. § 7491(b)(2) (implementation plans must "contain such emission limits . . . as may be *necessary* to make reasonable progress") (emphasis added).

[26] *See* 80 Fed. Reg. 18,944, 18,991−92 (Apr. 8, 2015).

[27] *See* 80 Fed. Reg. at 18,992.

or lack thereof. Controls, regardless of their cost-effectiveness, should be required only when they are *necessary* for a state to achieve reasonable progress toward the national visibility goal.

Implementation of the new approach also will illegally proscribe states' authority in setting their reasonable progress goals and developing their long-term strategies. In effect, the Final Rule requires EPA to reject SIPs if the state determines that controls are unnecessary because they would achieve only minute visibility improvements. It also requires EPA to reject SIPs if the state decides not to evaluate any sources for reasonable progress controls because its Class I areas already are meeting or exceeding the URP; instead, states will be forced to select specific sources for evaluation of emission controls. Because such determinations are within the states' purview pursuant to the CAA, the Final Rule unlawfully takes authority away from the states and gives it to EPA. Such arrogation of authority violates the cooperative federalism principles underlying the CAA.[28] The Act limits EPA to a deferential role, under which the Agency must defer to states' determination of their reasonable progress goals so long as they comply with the Act.[29]

2. The "Clarifications" Improperly Sever the Link Between Reasonable Progress Controls and Planning Periods.

The Final Rule severs the link between reasonable progress controls in a state's long-term strategy and the 10-year planning periods on which the Regional Haze Program is based. States' authority to consider planning periods when developing long-term strategies under the Final Rule is explicitly constrained. Specifically, the Final Rule modifies the Regional Haze regulations to explicitly provide that if a state, in selecting control measures for a long-term strategy, "concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress."[30] This revision means that states are required to impose reasonable progress controls without any nexus to an implementation period—that is, regardless of whether or not the control will help meet reasonable progress goals during the relevant 10-year planning period.

This directly conflicts with both the statute and the regulatory requirements in § 51.308. First, the Regional Haze regulations still require states to consider the relevant planning period when setting reasonable progress goals: when setting goals, states must consider "the [URP] and

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[28] *See* 42 U.S.C. § 7401(a)(3); § 7407(a).

[29] *Texas v. EPA*, 829 F.3d 405, 428 (5th Cir. 2016) (citing 42 U.S.C. § 7410(k)(3) (EPA "shall approve" a state implementation plan that satisfies the requirements of the Act)); *Luminant Generation Co. v. EPA*, 675 F.3d 917, 921 (5th Cir. 2012) ("With regard to implementation, the Act confines the EPA to the ministerial function of reviewing SIPs for consistency with the Act's requirements"); *Michigan v. EPA*, 268 F.3d 1075, 1083 (D.C. Cir. 2001) ("[T]he Act intended to create an overarching federal role in air pollution control policy,…but that overarching role is in setting standards, not in implementation.").

[30] 40 C.F.R. § 51.308(f)(2)(i); *see also* 82 Fed. Reg. at 3,089 (a state "may not reject a control measure because it cannot be installed or become operational *until after the end of the implementation period*.") (emphasis added).

the emission reduction measures needed to achieve it *for the period covered by the implementation plan*."[31] Second, § 51.308(d)(3) mandates that long-term strategies include measures "as necessary to achieve the reasonable progress goals."[32] The regulatory text further specifies that reasonable progress goals must consider the emission reduction measures needed to achieve the uniform rate of progress "for the period covered by the implementation plan."[33] Even in the Final Rule, EPA itself emphasized that the reasonable progress goals do not include emission reductions that would occur only *after* the end of the relevant planning period.[34] It is simply illogical, then, that a control measure that could not be implemented until after the planning period would nonetheless be deemed necessary to achieve reasonable progress for that same period.

EPA should not require states to evaluate and impose control measures that are completely divorced from the planning period at issue. This undermines the purpose of the 10-year planning period. Planning periods are mandated by the statute,[35] and indicate Congress's intent to establish a program that takes a gradual approach toward the national goal of eliminating visibility impairment. EPA itself observed this when first promulgating the Regional Haze Rule, providing the states with 60 years to reach natural visibility conditions at Class I areas because, in the long term, facilities built in the latter part of the 20th century will retire and/or be replaced by more fuel-efficient facilities, and innovations in emissions control technologies and renewable energy will allow new plants to meet lower emissions rates.[36] EPA also has explained that states "should take into account the fact that the long-term goal of no manmade impairment encompasses several planning periods. It is reasonable for [the state] to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal."[37]

EPA's approach in the Final Rule contradicts this statutory and regulatory scheme and will force states to mandate emissions controls even if it would be reasonable to defer them to later planning periods.. It also imposes unnecessary costs on regulated sources, which may be required to install costly new control measures without any corresponding benefit in visibility improvement that would help achieve reasonable progress during the relevant planning period.

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[31] 40 C.F.R. § 51.308(d)(1)(i)(B) (emphasis added). This requirement existed in the prior version of the regulation. *See* 40 C.F.R. § 51.308(d)(1)(i)(B) (2012). The Final Rule did not modify this requirement. *See* 40 C.F.R. § 51.308(d)(1)(i)(B) (2017); *see also* 82 Fed. Reg. at 3,089.

[32] 40 C.F.R. § 51.308(d)(3).

[33] 40 C.F.R. § 51.308(d)(1)(i)(B).

[34] 82 Fed. Reg. at 3,089 ("Of course, any emission reductions that will not occur until after the end of the implementation period should not be reflected in the [reasonable progress goals].").

[35] 42 U.S.C. § 7491(b)(2)(B).

[36] 64 Fed. Reg. at 35,732.

[37] Reasonable Progress Guidance at 1-4.

B. EPA Should Eliminate the RAVI Program, Which Is Unnecessary and Impedes State Authority.

EPA should eliminate the outdated RAVI program from the Regional Haze regulations because it serves no purpose in light of the subsequent implementation of the Regional Haze Program and because it unlawfully intrudes upon states' authority under the CAA. In the Final Rule, EPA not only retained the RAVI program but expanded the program's scope to (1) include all states for the first time;[38] (2) allow federal land managers ("FLMs") to certify RAVI in states where the source or sources are located, even if that state does not contain the Class I area where the visibility impairment occurred;[39] and (3) cover both BART-eligible and non-BART-eligible sources.[40] The Final Rule also alters the federal-state relationship by (1) giving FLMs authority to identify (as opposed to suggest) the source or small group of sources responsible for RAVI, thereby triggering mandatory requirements for the state, including the requirement to submit a SIP revision;[41] and (2) revising the definition of "reasonably attributable" to "make clear that a state does not have complete discretion to determine what techniques are appropriate for attributing visibility impairment to specific sources."[42]

As noted above, EPA took a two-phased approach in establishing the Regional Haze Program. In the first phase, EPA established the RAVI program to address impairment of visibility in Class I areas that was "reasonably attributable" to a specific source or smaller group of sources.[43] The RAVI regulations sought to address "plume blight," which is "smoke, dust, colored gas plumes, or layered haze emitted from stacks which obscure the sky or horizon and are relatable to a single source or a small group of sources."[44] EPA "explicitly deferred action on regional haze," defined as "visibility-impairing pollution that is caused by the emission of air pollutants *from numerous sources located over a wide geographic area*."[45] In the second phase, EPA addressed regional haze in Class I areas through a regional planning approach with the promulgation of the Regional Haze Rule. This second phase targets visibility impairment that is not reasonably attributable to a single source or small, defined group of sources, but instead is

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[38] 82 Fed. Reg. at 3,112; 40 C.F.R. § 51.300.

[39] *See* 40 C.F.R. § 51.302.

[40] *See* 82 Fed. Reg. at 3,112-13; *see also* 40 C.F.R. § 51.302(a)-(c). Under the revised RAVI program, a state must revise its Regional Haze SIP to include a reasonable progress control determination for a particular source or small group of sources upon receipt of a RAVI certification of impairment, regardless of whether or not the source is BART-eligible. *See* 40 C.F.R. § 51.302(b).

[41] *See* 40 C.F.R. § 51.302(a)-(c).

[42] 82 Fed. Reg. at 3,112; 40 C.F.R. § 51.301.

[43] *See* RAVI Regulation, 45 Fed. Reg. 80,084, 80,085–86 (Dec. 2, 1980); 40 C.F.R. § 51.300–307.

[44] RAVI Regulation, 45 Fed. Reg. at 80,085.

[45] U.S. EPA, Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period, at 5–6 (July 2016) (emphasis added) Docket No. EPA -HQ-OAR-2016-0289-0020.

produced by emissions from a wide array of sources over a broad geographic area. This expanded the scope of visibility improvement requirements to many more sources.

The Regional Haze Program has, by design, subsumed the RAVI program and rendered it unnecessary. RAVI was designed as a placeholder until techniques for assessing regional haze, particularly from multiple sources, improved sufficiently for EPA to establish a comprehensive program. EPA established this comprehensive program in the 1999 Regional Haze Rule which "fulfill[ed] EPA's responsibility under section 169A, pending since 1980, to put in place a national regulatory program that addresses *both* reasonably attributable *and* regional haze visibility impairment."[46] Specifically, the evaluation of sources for reasonable progress controls under the Regional Haze Program will capture sources that otherwise might be targeted by RAVI.

Instead of eliminating the RAVI program in recognition of the fact that it is unnecessary in light of the Regional Haze Program, the Final Rule expands the RAVI program beyond its original intent, thereby increasing its redundancy with the Regional Haze Program. *First*, EPA's assertion that RAVI is applicable to any source, even if it is not BART-eligible,[47] goes against EPA's own regulations and guidance, which state that RAVI is focused on BART-eligible sources.[48] The Final Rule also suggests that an FLM certification of RAVI would reopen the BART determination process for sources that already were eliminated from BART requirements because their emissions were not determined to be causing or contributing to visibility impairment in any Class I area. This makes no sense. If a source was deemed not subject to BART because it is not causing or contributing to visibility impairment, the FLM certification would necessarily be for *imperceptible* visibility impairment and not the visibility impairment intended to be addressed by the RAVI program. Further, the reasonable progress analysis under the Regional Haze Program already provides an avenue to address non-BART sources. The new RAVI provisions simply provide a mechanism by which the federal government can supplant state determinations on how to address these sources.

Second, the Final Rule's requirement for FLMs to issue RAVI certifications to states *outside* of the state with the affected Class I area[49] effectively alters the RAVI program from one that addresses *intrastate* haze from a source or small group of sources to one addressing *interstate* haze from regional sources. Rather than streamlining the RAVI and Regional Haze programs, this change increases the overlap between the two programs. It also is unnecessary

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[46] 64 Fed. Reg. at 35,717 (emphasis added).

[47] 82 Fed. Reg. at 3,115.

[48] *See* U.S. EPA, Additional Regional Haze Questions, at 16-17 (Sept. 27, 2006) Docket No. EPA-HQ-OAR-2016-0289-0014; U.S. EPA, Guidelines for Determining Best Available Retrofit Technology for Coal-Fired Power Plants and Other Existing Stationary Facilities, at 3-6, 6 (Nov. 1980) EPA-450/3-80-009b ("Once the impact of the existing stationary facility on visibility is identified as being reasonably attributable to that source, the State must conduct an analysis to determine BART for that particular existing stationary facility.").

[49] *See* 40 C.F.R. § 51.302.

because the Regional Haze Program already establishes a comprehensive program for addressing haze from sources outside of a state in which an affected Class I area is located.

Third, EPA suggests that RAVI certifications could be based on modeling alone.[50] Modeled visibility impairment is not what the RAVI program was designed to address and makes the RAVI program even more duplicative of the Regional Haze Program. Modeling that simulates an event that might occur is far from the "visual observation" called for in the original definition of "reasonably attributable."[51] It also strays far from the original intent of RAVI to address plume blight. Modeling would not demonstrate any "smoke," "dust," "colored gas plumes," or "layered haze," or whether such events "obscure the sky or horizon."[52] Instead, the use of modeling would make RAVI indistinguishable from how states are directed to determine whether sources are causing or contributing to regional haze.

Finally, the revised RAVI program improperly alters the federal-state relationship. In developing a "cooperative federalism" framework under the CAA, Congress purposely limited the federal government's authority by creating a statute in which "air pollution prevention . . . and air pollution control . . . is the primary responsibility of States and local governments."[53] The Final Rule undermines this intent. For instance, the revisions giving FLMs the authority to identify (as opposed to merely suggest, as under the prior regulation) the source or small group of sources responsible for RAVI shifts discretion and authority from states to FLMs.[54] While FLMs may be able to identify RAVI, they have no particular expertise in identifying which sources are causing RAVI. States are more appropriate authorities for this identification.

EPA should eliminate the RAVI provisions from its regulations. There are no sources evading the Regional Haze Program that warrant retaining the RAVI program as a backstop. It makes no sense to continue to impose RAVI when reasonable progress planning addresses emissions from sources that would have been subject to RAVI and imposes controls for visibility impairment far below what would warrant controls under RAVI. It also is not necessary to preserve the RAVI program to provide FLMs the ability to work with states or EPA to address visibility concerns given that the Regional Haze Program has existing mechanisms for engaging with FLMs in developing implementation plans. In light of this redundancy, the RAVI

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[50] 82 Fed. Reg. at 3,113 (explaining changes to definition of "reasonably attributable" in 40 C.F.R. § 51.301). In the RAVI regulations, EPA made it clear that RAVI certifications were to be based on *observed* visibility impairment (in evaluating FLM certification, the state needs to review the specific documentation of visibility conditions contained in the certification, which "should include information regarding the type of impairment (*i.e.*, coherent plume or layered haze)[,] the location of both the observer and the observed impairment, the meteorological conditions when the impairment was observed, and the time(s) of day or year of occurrence."). 52 Fed. Reg. 7802, 7804 (Mar. 12, 1987).

[51] *See* 40 C.F.R. § 51.301.

[52] *See* RAVI Regulation, 45 Fed. Reg. at 80,085.

[53] 42 U.S.C. § 7401(a)(3); *see also* 42 U.S.C. § 7407(a) ("Each State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State . . . ."); *see also Texas v. EPA*, 829 F.3d at 411 (EPA's role in reviewing SIPs is "ministerial").

[54] *See* 40 C.F.R. § 51.302(a)-(c).

program's costs cannot justify its benefits. Further, the obligation for states to develop SIP revisions in response to a RAVI certification could strain states' limited resources.

C. Reconsideration Is Appropriate in Light of Recent Executive Orders.

EPA should grant reconsideration of the Final Rule in light of recent executive orders directing federal agencies to reduce regulatory costs and/or eliminate or modify regulations that impose unnecessary costs or burdens. Specifically, President Trump issued an executive order on January 30, 2017, entitled "*Reducing Regulation and Controlling Costs*,"[55] which sets a "zero sum" cost requirement for new regulations, under which the total incremental cost of all new regulations to be finalized in fiscal year 2017 shall be "no greater than zero," unless otherwise required by law or directed by the White House Office of Management and Budget.[56] The Order requires agencies to offset "any new incremental costs associated with new regulations . . . by the elimination of existing costs associated with at least two prior regulations."[57] President Trump issued another executive order on February 24, 2017, entitled "*Enforcing the Regulatory Reform Agenda*,"[58] that directs agencies to establish Regulatory Reform Task Forces to evaluate existing regulations and recommend any which should be repealed, replaced, or modified, including those that (i) eliminate jobs or inhibit job creation; (ii) are outdated, unnecessary, or ineffective, or (iii) impose costs that exceed benefits.[59]

As discussed in this Petition, certain provisions of the Final Rule impose unnecessary costs and burdens. Specifically, EPA's new interpretation of "reasonable progress" requires states to impose controls on sources, even when such controls are unnecessary to achieve reasonable progress during the planning period covered by the SIP. In states where the URP or reasonable progress goals already have been attained without reasonable progress controls, no additional "benefit" in light of the purposes of the Regional Haze Program can be gained through the imposition of such controls. Additionally, the RAVI program adds redundant and potentially costly requirements to the already comprehensive Regional Haze Program. EPA should eliminate those portions of the Final Rule that impose costs with no benefits and all of the RAVI program provisions to further the Agency's efforts to effectuate these Executive Orders. Repealing these provisions also would assist EPA in complying with the One In, Two Out Order, because eliminating program costs will help the Agency offset new mandatory environmental regulations.

---

[55] Exec. Order No. 13,771, 82 Fed. Reg. 9,339 (Jan 30, 2017) ("One In, Two Out Order").

[56] *Id.* at § (2)(b).

[57] *Id.* at § (2)(c).

[58] Exec. Order No. 13,777, 82 Fed. Reg. 12,285 (Feb. 24, 2017) ("Regulatory Reform Task Force Order").

[59] *Id.* at § (3)(d).

III. CONCLUSION

For the reasons discussed above, Petitioners urge EPA to reconsider certain provisions of the Final Rule.

Dated: March 13, 2017

Respectfully submitted,

Debra J. Jezouit
Allison Watkins Mallick
Baker Botts L.L.P.
1299 Pennsylvania Ave, N.W.
Washington, D.C. 20004
(202) 639-7700

Counsel for Southwestern Public Service Company, Entergy Services, Inc., and Cleco Power LLC

To: Stenger, Wren[stenger.wren@epa.gov]
From: Bijan Sharafkhani
Sent: Thur 6/15/2017 9:00:58 PM
Subject: FW: Louisiana Draft Reg Haze SIP
Proposed SIP EGU Transmittal Letter Entergy Addendum June 2017.doc
RH Nelson Louisiana June 2017 Proposal.docx

Wren,

FYI

From: Vivian Aucoin
Sent: Thursday, June 15, 2017 3:59 PM
To: Bijan Sharafkhani
Cc: Chuck Brown
Subject: RE: Louisiana Draft Reg Haze SIP
Importance: High

Greetings!

1.) The statement or phrase concerning the 3 years was in the AOC, not the SIP narrative. The SIP sets an emissions limit of 0.6lbs/MMBtu on a rolling 30-day average as BART; since this emission limit is not based solely on the use of lower sulfur coal, we have removed the phrase in the AOC which gave Entergy 3 years to comply. The phrase now reads "as expeditiously as practicable". Entergy is currently meeting this limit, so there should be no issue with meeting the limit once the SIP becomes final.

2.) Wren is correct; LDEQ must include the information in the SIP as it was used to determine the basis for BART. All information that was submitted will be placed in the proper appendix.

I have completed the revisions and have attached the narrative for your review. I have also asked Marian to print the transmittal letter for Dr. Brown's signature so that we can get the hard copies mailed and into EDMS prior to Tuesday, June 20.

Please let me know if you need anything else.

Vivian H. Aucoin

Environmental Scientist Manager

Office of Environmental Assessment, Air Planning Division

225-219-3482

vivian.aucoin@la.gov

Thanks

June 19, 2017

Mr. Sam Coleman, Acting Administrator
US EPA Region 6, 6-RA
1445 Ross Avenue, Suite 1200
Dallas Texas 75202-2733

RE: Louisiana's State Implementation Plan (SIP) Revisions Addendum
Regional Haze Rule EGU Best Available Retrofit Technology (BART)

Dear Mr. Coleman:

Please find enclosed 2 bound copies of the draft revision to the SIP for the Regional Haze Rule. An electronic copy will be forwarded via electronic mail presently to the Region 6 staff.

Written comments regarding the proposed SIP revision are due no later than July 26, 2017 and should be mailed to Vivian H. Aucoin, Office of Environmental Services, P. O. Box 4314, Baton Rouge, La., 70821-4314 or emailed to vivian.aucoin@la.gov.

If you have any questions concerning this matter, please feel free to contact Donald Trahan, Air Permits Administrator at 225-219-3408 or at donald.trahan@la.gov.

Sincerely,

Chuck Carr Brown, Ph.D.
Secretary

Enclosures

Cc: Wren Stenger, EPA Region 6
Guy Donaldson, EPA Region 6

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

Regional Haze State Implementation Plan

EGU BART Analysis

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

Revision Proposed June 2017

I. Background on the Regional Haze Rule

A. Plan Submission

[No Change]

B. Legal Authority

[No Change]

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 June 20, 2017 in the *Louisiana Register*. Public comments on the proposal should be submitted no later than July 26, 2017. A public hearing will be held if requested. A copy of the potpourri notice is included in Appendix A

D. Commitment to Plan Revision

[No Change]

E. History of Regional Haze

[No Change]

F. Breton National Wilderness Area (Class I)

[No Change]

G. Louisiana's Visibility History

[No Change]]

H. Class I Areas outside the State Boundaries

[No Change]

II. BART Analysis

[No Change]

A. CLECO

[No Change]

B. Louisiana Generating, LLC, a subsidiary of NRG

[No Change]

C. Entergy Louisiana LLC

Entergy submitted to LDEQ CALPUFF modeling for $S0_2$ and PM for the various units that were found to be BART-eligible; all reports are included in Appendix D. In the course of this exercise, Entergy has submitted not only CALPUFF modeling and a five-factor analysis to satisfy the RH and BART requirements, but has also submitted CAMx modeling to support their findings. While LDEQ has not used the CAMx modeling to ascertain that the units have satisfied the BART requirements, the model results have been included for consideration. Following Louisiana's final revision submittal, a discussion between EPA, LDEQ and Entergy took place and based upon the results of that discussion, EPA provided additional information on Entergy's proposed BART five-factor analysis and EPA's draft analyses for LDEQ's review. Therefore this SIP is being revised to include the EPA information. The additional information submitted by EPA is included in Appendix F.

•**Entergy Ninemile Point Units:**

[No Change]

•**Entergy Little Gypsy Units:**

[No Change]

•**Entergy Willow Glen Units:**

[No Change]

•**Entergy Sterlington Units:**

[No Change]

•**Entergy Michoud Units:**

[No Change]

•**Roy S. Nelson Generating Plant (Nelson):** The facility is located in Westlake, Calcasieu Parish, Louisiana and is located 264 miles west of the Breton National Wilderness Area and 286 miles south of the Caney Creek Wilderness Area in Arkansas. The facility is a fossil-fuel steam electric power generating facility and operates three BART-eligible steam generating units: Unit 4, Unit 4 Auxiliary Boiler and Unit 6.

The Unit 4 Boiler is permitted to combust natural gas, No. 2, No. 4 and No. 6 fuel oils And refinery fuel gas. Unit 4 has a maximum heat rated capacity of 5400 MMBtu/hour and exhausts out of one stack. It has flue gas recirculation equipment installed for control of NOx emissions. The Auxiliary Boiler for Unit 4 is permitted to burn natural gas and fuel oil.

The Unit 6 Boiler is permitted to burn coal as its primary fuel, with No. 2 and No. 4 fuel oils as its secondary fuels which are mainly used for start-up. Unit 6 has maximum heat rated capacity of 6216 MMBtu/hour and exhausts out of one stack. It has an electrostatic precipitator (ESP) with flue gas condition for control of particulate matter (PM) emissions. Unit 6 has installed Separated Overfire Air Technology (SOFA) and a Low NOx Concentric Firing System (LNCFS) for NOx control. Steam from these boilers is used to drive steam turbines which in turn generate rotary motion that is used to drive electric generators. The electric generators then produce electricity.

Entergy has performed the traditional CALPUFF analysis as well as CAMx based upon EPA modeling guidance. The guidance, Appendix Y of the BART rule (July 6, 2005), states that CALPUFF shall be used for single-source modeling where the distance between the BART source and the Class I area is less than 300 kilometers (km). Since CALPUFF may significantly over predict impacts at greater distances, CAMx is approved for situations where the distance is greater than 300km. The facility is 425 km from Breton and 460km from Caney Creek.

Unit 4 and the auxiliary boiler are permitted to burn fuel oil. However, fuel oil has not been burned at either unit in several years and there are no current operational plans to burn fuel oil. Entergy and LDEQ have executed an Administrative Order on Consent (AOC) that states before fuel oil firing is allowed to take place at Unit 4 and/or the auxiliary boiler, a revised BART determination must be promulgated for SO_2 and PM for the fuel oil firing scenario through a SIP revision, which will then have to be approved by EPA and such action will become federally enforceable.

In the Entergy BART five-factor SO_2 analysis for the Unit 6 Boiler, a number of emission reduction controls were reviewed. Those controls included lower sulfur coal, DSI, enhanced DSI, dry flue-gas desulfurization (FGD) and wet FGD. LDEQ has weighed the five factors and after a review of both Entergy's and EPA's information has concluded that BART is the emission limit of 0.6 lbs./MMBtu based on at 30 day rolling average as defined in the AOC. While additional visibility benefits may be available through the use of FGD, the lower sulfur coal option results in visibility benefits at a lower annual cost. In addition, FGD use results in additional waste due to spent reagent and has some power demands to run the equipment. LDEQ believes, at present, that the use of lower sulfur coal presents the appropriate SO_2 control based on consideration of economics, energy impacts, non-air quality environmental impacts, and impacts to visibility.

Regarding PM, Unit 6 is currently equipped with an ESP to control PM emissions. Impacts from PM emissions are small and any additional controls beyond the ESP would have

minimal visibility benefits and would not be cost–effective. Therefore, the existing controls are sufficient to meet BART for PM.

Based upon this decision and the inclusion of the emission limits in the AOC, LDEQ has determined that the conditions are sufficient to meet BART. As the energy industry evolves, LDEQ continues to work with EGUs throughout Louisiana to evaluate the operation of utilities. As such, LDEQ will engage in discussions with Entergy about any potential changes in usage or emission rates at the Nelson facility. Any such changes will be considered for reasonable progress for future planning periods as appropriate.

•Waterford 1 & 2 Electric Generating Plant (Waterford):

[No Change]

D. Municipal Facility Units

[No Change]

Appendix A

Public Notice and Participation

Appendix B

CLECO

BART Determination and Evaluation

[No Change]

Appendix C

NRG
BART Determination and Evaluation

[No Change]

Appendix D

Entergy Louisiana LLC
BART Determination and Evaluation

[no change]

Appendix E

Municipal Facilities

[No Change]

Appendix F

EPA DRAFT BART Modeling and Costs Information

To: Stenger, Wren[stenger.wren@epa.gov]
From: Bijan Sharafkhani
Sent: Wed 5/17/2017 11:43:07 AM
Subject: FW: RS Nelson discussion points Final 5-9

Wren,

LDEQ will need to rewrite the section on RS Nelson to include the AOC. We will make certain that the section is worded properly to include a statement that Louisiana finds the facility is subject to BART. The SIP amendment will have to be published in the Louisiana Register, which will be June 20, 2017.

Based on conversation our staff had with Guy Donaldson yesterday, BART can be an emission limit; he then stated that EPA would entertain the .6 lbs/MMBtu **average** as the emission limit based on the fact that Entergy already burns bituminous coal which has a low sulfur content. In this conversation it was also agreed that burning fuel oil would be treated the same as at the Willow Glen facility. However, that is not possible because Entergy needs to burn fuel oil during start-up, so we will add the clause that it will be used during start up only.

Thanks,

Bijan

From: Stenger, Wren [mailto:stenger.wren@epa.gov]
Sent: Tuesday, May 16, 2017 10:09 AM
To: Bijan Sharafkhani
Subject: RE: RS Nelson discussion points Final 5-9

Bijan, I understand the position.. The question is do you plan to send a SIP revision with narrative and technical support to support the conclusions? If so, we need our folks to work together, with my folks ensuring we have OAQPS and OGC on board.to support it. How would you like to proceed?

Sent from my Windows Phone

From: Bijan Sharafkhani
Sent: 5/12/2017 7:55 AM
To: Stenger, Wren
Subject: FW: RS Nelson discussion points Final 5-9

Wren,

Your thoughts?

To: Stenger, Wren[stenger.wren@epa.gov]
From: Bijan Sharafkhani
Sent: Wed 4/12/2017 11:43:26 AM
Subject: FW: Notes from the Entergy meeting (4/6/17) as per request by Bijan

Wren,

Here is the note from our meeting with Entergy.

Bijan

From: Vivian Aucoin
Sent: Tuesday, April 11, 2017 3:38 PM
To: Bijan Sharafkhani; Donald Trahan; Elliott Vega (DEQ)
Subject: Notes from the Entergy meeting (4/6/17) as per request by Bijan
Importance: High

Greetings,

This is a recap of the meeting held with Entergy on the RS Nelson facility BART analysis::

•□□□□□□□□ Attendees of the meeting besides LDEQ staff were representatives of Entergy, Sergeant and Lundy, All4, Inc., and Baker Botts.

•□□□□□□□□ Entergy presented the cost analysis from their point of view based on S&L's general methodology using the capital costs for large equipment derived from S&L's database of control system costs and recent quotes scaled for the Nelson facility; the annual O&M costs based on site-specific utility and reagent costs; followed BART guidelines and Control Cost Manual; and estimated capital and O&M costs for each of the technologies to control emissions.

•□□□□□□□□ S&L representatives discussed the difference between using the IPM algorithms as suggested by EPA. According to S&L, the IPM cost algorithm was developed to provide order-of-magnitude costs for air pollution controls to be applied to the electric generating industry on a system-wide basis. Accordingly, S&L prepared the information contained in the BART 5-factor analysis following guidelines and the Cost Control Manual.

•□□□□□□□□ The discussion analyzed the differences in the cost of controls as presented by EPA at $2500 per ton.

Respondents further discussed the post-processing of the CAMx modeling, providing technical answers to EPA 's concerns as provided to LDEQ on March 10, 2017. In this discussion, the representatives for All4, Inc. explained the differences between post-processing a clean-vs-dirty background scenario. EPA suggests that respondent should use a clean background which assumes no anthropogenic sources except RS Nelson impact the Class I area. Results of this type of modeling produce an artificial visibility metric which inflates the impact from the source or resulting improvement. By using the dirty background post-processing method, the visibility baseline impact and benefits are calculated by evaluating the source relative to a real background using IMPROVE monitor data; it incorporates contribution from all sources and results in a more realistic visibility metric.

Action items taken from the meeting:

LDEQ staff with discuss information with Dr. Brown and will set up subsequent meeting with EPA and respondent within the next two weeks.

Respondent will supply the Arkansas letter to LDEQ for reference.

Vivian H. Aucoin

Environmental Scientist, Senior

Office of Environmental Assessment, Air Planning Division

225-219-3482

vivian.aucoin@la.gov

To: Vivian Aucoin[Vivian.Aucoin@LA.GOV]; Donaldson, Guy[Donaldson.Guy@epa.gov]
Cc: Donald Trahan[Donald.Trahan@LA.GOV]; Bijan Sharafkhani[Bijan.Sharafkhani@LA.GOV]; Stenger, Wren[stenger.wren@epa.gov]; Thomas, Carrie[Thomas.Carrie@epa.gov]
From: Huser, Jennifer
Sent: Fri 2/10/2017 11:55:30 PM
Subject: RE: Louisiana's Regional Haze EGU BART SIP Submittal (1 of 3)

Hi Vivian,

The SIP narrative does not include the red line strikeout language we provided on Monday 2/6/17, and you confirmed would be acceptable to LDEQ on 2/7/17.

Please let me know if something changed in LDEQ's position between 2/7/17 and today to result in the changes not being incorporated.

Thanks,

Jennifer Huser

Environmental Scientist

Air Planning Section (6MM-AA)
USEPA Region 6
1445 Ross Ave. Suite 1200
Dallas, TX 75202-2733
214-665-7347

From: Vivian Aucoin [mailto:Vivian.Aucoin@LA.GOV]
Sent: Friday, February 10, 2017 3:44 PM
To: Donaldson, Guy <Donaldson.Guy@epa.gov>; Huser, Jennifer <Huser.Jennifer@epa.gov>
Cc: Donald Trahan <Donald.Trahan@LA.GOV>; Bijan Sharafkhani <Bijan.Sharafkhani@LA.GOV>
Subject: Louisiana's Regional Haze EGU BART SIP Submittal (1 of 3)
Importance: High

Greetings,

Attached please find the SIP document with the transmittal letter and the response to comment

document. Two more emails will follow that will have enclosed the executed AOCs for NRG, CLECO and Entergy.

The remainder of the documents will be loaded into a drop-box and address to both Guy Donaldson and Jennifer Huser. A complete copy of the SIP will be mailed on Monday and an additional copy will be placed into LDEQ's EDMS. Once the document is loaded into EDMS, I will forward the DOC ID#.

If you need anything further, please do not hesitate to contact me at the number below.

Vivian H. Aucoin

Environmental Scientist, Senior

Air Permits Division, State Implementation Plan

225-219-3482

vivian.aucoin@la.gov

To: Huser, Jennifer[Huser.Jennifer@epa.gov]
Cc: Donaldson, Guy[Donaldson.Guy@epa.gov]; Donald Trahan[Donald.Trahan@LA.GOV]; Bijan Sharafkhani[Bijan.Sharafkhani@LA.GOV]; Stenger, Wren[stenger.wren@epa.gov]; Thomas, Carrie[Thomas.Carrie@epa.gov]
From: Vivian Aucoin
Sent: Fri 2/10/2017 10:29:59 PM
Subject: Re: Louisiana's Regional Haze EGU BART SIP Submittal (1 of 3)

They will be in the drop box. Once I get it loaded I will send

Sent from my iPhone

On Feb 10, 2017, at 3:56 PM, Huser, Jennifer <Huser.Jennifer@epa.gov> wrote:

Thanks, Vivian. Can you please send the attachments as well so we know you've included the documents we requested.

Entergy Initial Modeling Report (8/31/15)

Entergy BART Screening Report (2015_1109 final)

Entergy Michoud draft permit/permit briefing sheet

NRG Supplemental Information and Revised Baseline Modeling Report (7/19/16)

Jennifer Huser

Environmental Scientist

Air Planning Section (6MM-AA)
USEPA Region 6
1445 Ross Ave. Suite 1200
Dallas, TX 75202-2733
214-665-7347

From: Vivian Aucoin [mailto:Vivian.Aucoin@LA.GOV]
Sent: Friday, February 10, 2017 3:44 PM

To: Donaldson, Guy <Donaldson.Guy@epa.gov>; Huser, Jennifer <Huser.Jennifer@epa.gov>
Cc: Donald Trahan <Donald.Trahan@LA.GOV>; Bijan Sharafkhani <Bijan.Sharafkhani@LA.GOV>
Subject: Louisiana's Regional Haze EGU BART SIP Submittal (1 of 3)
Importance: High

Greetings,

Attached please find the SIP document with the transmittal letter and the response to comment document. Two more emails will follow that will have enclosed the executed AOCs for NRG, CLECO and Entergy.

The remainder of the documents will be loaded into a drop-box and address to both Guy Donaldson and Jennifer Huser. A complete copy of the SIP will be mailed on Monday and an additional copy will be placed into LDEQ's EDMS. Once the document is loaded into EDMS, I will forward the DOC ID#.

If you need anything further, please do not hesitate to contact me at the number below.

Vivian H. Aucoin

Environmental Scientist, Senior

Air Permits Division, State Implementation Plan

225-219-3482

vivian.aucoin@la.gov

To: Vivian Aucoin[Vivian.Aucoin@LA.GOV]; Donaldson, Guy[Donaldson.Guy@epa.gov]
Cc: Donald Trahan[Donald.Trahan@LA.GOV]; Bijan Sharafkhani[Bijan.Sharafkhani@LA.GOV]; Stenger, Wren[stenger.wren@epa.gov]; Thomas, Carrie[Thomas.Carrie@epa.gov]
From: Huser, Jennifer
Sent: Fri 2/10/2017 10:12:35 PM
Subject: RE: Louisiana's Regional Haze EGU BART SIP Submittal (3 of 3)

Hi Vivian,

Do you have a version of the Little Gypsy AOC that was signed by someone at DEQ? The version attached was only signed by Entergy.

Thanks

Jennifer Huser

Environmental Scientist

Air Planning Section (6MM-AA)
USEPA Region 6
1445 Ross Ave. Suite 1200
Dallas, TX 75202-2733
214-665-7347

From: Vivian Aucoin [mailto:Vivian.Aucoin@LA.GOV]
Sent: Friday, February 10, 2017 3:46 PM
To: Donaldson, Guy <Donaldson.Guy@epa.gov>; Huser, Jennifer <Huser.Jennifer@epa.gov>
Cc: Donald Trahan <Donald.Trahan@LA.GOV>; Bijan Sharafkhani <Bijan.Sharafkhani@LA.GOV>
Subject: Louisiana's Regional Haze EGU BART SIP Submittal (3 of 3)
Importance: High

AOCs for Entergy facilities

Vivian H. Aucoin

Environmental Scientist, Senior

Air Permits Division, State Implementation Plan

225-219-3482

vivian.aucoin@la.gov

To: Bijan Sharafkhani[Bijan.Sharafkhani@LA.GOV]
From: Stenger, Wren
Sent: Thur 6/1/2017 10:30:28 PM
Subject: La Reg Haze SIP
Supporting documents for the TAD (oops 3 of 3)
FW: Modeling spreadsheets
Revised SIP Narrative and supporting documents (1 of 2)
RE: Revised SIP Narrative and supporting documents (1 of 2)

Bijan, we got the last of the materials/TSDs/modeling and files/costs/ draft RP language, etc. Let me know if you have any questions or need anything else. I am attaching all that I saw sent as FYI.

Wren Stenger

Director, Multimedia Division

EPA Region 6 Dallas, Texas

214.665.6583

To: Vivian Aucoin[Vivian.Aucoin@LA.GOV]; vennetta.hayes@la.gov[vennetta.hayes@la.gov]; Donald Trahan[Donald.Trahan@LA.GOV]; Charlotte Goudeau[Charlotte.Goudeau@LA.GOV]
Cc: Donaldson, Guy[Donaldson.Guy@epa.gov]; Stenger, Wren[stenger.wren@epa.gov]; Thomas, Carrie[Thomas.Carrie@epa.gov]; Feldman, Michael[Feldman.Michael@epa.gov]; Kordzi, Joe[Kordzi.Joe@epa.gov]
From: Huser, Jennifer
Sent: Wed 5/31/2017 8:07:27 PM
Subject: FW: Modeling spreadsheets
Nelson CAMx DFGD WFGD.xlsx
Nelson CAMx LSC.xlsx
LA_CALPOST_Nelson.xlsx
LA_summary CAMx vis daily.xlsx
Nelson CALPUFF inputs.xlsx

Please find attached the modeling files that accompany the modeling TSDs. (Note: this does not include the CALPUFF files that we will arrange to share). All other referenced files are available via the docket on regulations.gov for our recent proposed BART EGU approval.

Jennifer Huser

Environmental Scientist

Air Planning Section (6MM-AA)
USEPA Region 6
1445 Ross Ave. Suite 1200
Dallas, TX 75202-2733
214-665-7347

To: Huser, Jennifer[huser.jennifer@epa.gov]; Vivian Aucoin[Vivian.Aucoin@LA.GOV]; Donald Trahan[Donald.Trahan@LA.GOV]; Charlotte Goudeau[Charlotte.Goudeau@LA.GOV]; vennetta.hayes@la.gov[vennetta.hayes@la.gov]
Cc: Donaldson, Guy[Donaldson.Guy@epa.gov]; Stenger, Wren[stenger.wren@epa.gov]; Kordzi, Joe[Kordzi.Joe@epa.gov]; Thomas, Carrie[Thomas.Carrie@epa.gov]; Watson, Lucinda[Watson.Lucinda@epa.gov]
From: Feldman, Michael
Sent: Thur 6/1/2017 6:54:07 PM
Subject: RE: Revised SIP Narrative and supporting documents (1 of 2)
RH Nelson Louisiana Final redline_clean 5_26_2017.docx

Resending the Draft Revised SIP narrative. I noticed that the file that was attached to yesterday's email showed up as a SharePoint link rather than an attached Word file.

I am resending as an attached Word file to make sure that LDEQ does not have any difficulties opening the file.

Thank you,

Michael Feldman, PhD
Environmental Engineer
Air Planning Section
U.S. EPA Region 6, 6PD-L
Phone: 214-665-9793
feldman.michael@epa.gov

From: Huser, Jennifer
Sent: Wednesday, May 31, 2017 3:04 PM
To: Vivian Aucoin <Vivian.Aucoin@LA.GOV>; Donald Trahan <Donald.Trahan@LA.GOV>; Charlotte Goudeau <Charlotte.Goudeau@LA.GOV>; vennetta.hayes@la.gov
Cc: Donaldson, Guy <Donaldson.Guy@epa.gov>; Stenger, Wren <stenger.wren@epa.gov>; Kordzi, Joe <Kordzi.Joe@epa.gov>; Feldman, Michael <Feldman.Michael@epa.gov>; Thomas, Carrie <Thomas.Carrie@epa.gov>
Subject: Revised SIP Narrative and supporting documents (1 of 2)

Good afternoon,

Thank you again for making time this afternoon to discuss the LA RH SIP revision for Entergy Nelson. Please find attached the following documents:

- Draft CAMx Modeling Report
- Draft CALPUFF Modeling Report
- Draft Nelson Technical Assistance Document
- Draft revised SIP narrative
- Draft AOC
- Supporting files for CAMx/CALPUFF/TAD

Please note that we have revised the SIP narrative to reflect discussions we had this afternoon. All supporting documents or those referenced in the TAD will be transmitted in a separate email.

Please feel free to contact me if you have any additional questions. We look forward to seeing your draft by the 12th.

Thanks!

Jennifer Huser

Environmental Scientist

Air Planning Section (6MM-AA)
USEPA Region 6
1445 Ross Ave. Suite 1200
Dallas, TX 75202-2733
214-665-7347

LOUISIANA DEPARTMENT OF ENVIRONMENTAL QUALITY

Regional Haze State Implementation Plan

EGU BART Analysis

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

Draft June 2017

I. Background on the Regional Haze Rule

A. Plan Submission

[No Change]

B. Legal Authority

[No Change]

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 June 20, 2017 in the *Louisiana Register*.. A copy of the potpourri notice and all comments and responses are included in Appendix A.

D. Commitment to Plan Revision

[No Change]

E. History of Regional Haze

[No Change]

F. Breton National Wilderness Area (Class I)

[No Change]

DRAFT

G. Louisiana's Visibility History

[No Change]]

H. Class I Areas outside the State Boundaries

[No Change]

II. BART Analysis

[No Change]

A. CLECO

[No Change]

B. Louisiana Generating, LLC, a subsidiary of NRG

[No Change]

DRAFT

C. Entergy Louisiana LLC

Entergy submitted to LDEQ CALPUFF modeling for S02 and PM for the various units that were found to be BART-eligible; all reports are included in Appendix D. In the course of this exercise, Entergy has submitted not only CALPUFF modeling and a five-factor analysis to satisfy the RH and BART requirements, but has also submitted CAMx modeling to support their findings. While LDEQ has not used the CAMx modeling to ascertain that the units have satisfied the BART requirements, the model results have been included for consideration. EPA submitted its draft analysis of Entergy's CALPUFF and CAMx modeling, its own draft CAMx and CALPUFF modeling, and its draft cost analysis for Nelson to LDEQ; all reports are included in Appendix F.

- **Entergy Ninemile Point Units:**

  [No Change]

- **Entergy Little Gypsy Units:**

  [No Change]

DRAFT

- **Entergy Willow Glen Units:**

  [No Change]

- **Entergy Sterlington Units:**

  [No Change]

- **Entergy Michoud Units:**

  [No Change]

- **Roy S. Nelson Generating Plant (Nelson):** The facility is located in Westlake, Calcasieu Parish, Louisiana and is located 264 miles west of the Breton National Wilderness Area and 286 miles south of the Caney Creek Wilderness Area in Arkansas. The facility is a fossil-fuel steam electric power generating facility and operates three BART-eligible steam generating units: Unit 4, Unit 4 Auxiliary Boiler and Unit 6.

The Unit 4 Boiler is permitted to combust natural gas, No. 2, No. 4 and No. 6 fuel oils and refinery fuel gas. Unit 4 has a maximum heat rated capacity of 5400 MMBtu/hour

and exhausts out of one stack. It has flue gas recirculation equipment installed for control of NOx emissions. The Auxiliary Boiler for Unit 4 is permitted to burn natural gas and fuel oil.

The Unit 6 Boiler burns coal as its primary fuel, with No. 2 and No. 4 fuel oils as its secondary fuels. Unit 6 has maximum heat rated capacity of 6216 MMBtu/hour and exhausts out of one stack. It has an electrostatic precipitator (ESP) with flue gas condition for control of particulate matter (PM) emissions. Unit 6 has installed Separated Overfire Air Technology (SOFA) and a Low NOx Concentric Firing System (LNCFS) for NOx control. Steam from these boilers is used to drive steam turbines which in turn generate rotary motion that is used to drive electric generators. The electric generators then produce electricity.

While Entergy has performed the traditional CALPUFF analysis, it has also chosen to runCAMx

. Although the LDEQ does not have the expertise with which to review those model runs, they are included in the appendices for review and comment.

For Unit 4 and the auxiliary boiler, while these units are permitted to burn fuel oil, fuel oil has not been burned at either unit in several years. Further, there are no current operational plans to burn fuel oil. Entergy and LDEQ have executed an agreed order on consent (AOC) that states before fuel oil firing is allowed to take place at Unit 4 and the auxiliary boiler, a revised BART determination must be promulgated for S02 and PM for the fuel oil firing scenario through a FIP or an action by the LDEQ as a SIP revision, which will then have to be approved by EPA and such action will become federally enforceable.

In the Entergy BART five-factor analysis for SO_2, Entergy has reviewed a number of emission reduction controls including low sulfur coal, DSI, enhanced DSI, dry flue-gas desulfurization (FGD) and wet FGD for use in the Unit 6 Boiler. EPA also provided additional information on Entergy's proposed BART five-factor analysis and its draft analyses. LDEQ weighed the five factors looking at both Entergy and EPA information. While additional visibility benefits are available through the use of FGD, the low-sulfur coal option results in visibility benefit at much lower annual cost. In addition, while there are no energy or non-air quality impacts associated with switching to low-sulfur fuel, FGD use results in additional waste due to spent reagent and has some power demands to run the equipment. LDEQ believes that the use of low sulfur coal presents the appropriate SO_2 control based on consideration of economics, energy impacts, non-air quality environmental impacts, and impacts to visibility. As such, the executed AOC sets emissions limits for SO2 at Unit 6 to reflect operation of the unit with low sulfur coal.

For PM, Unit 6 is already equipped with an ESP. Impact from PM emissions alone are small and any additional controls beyond the ESP would have minimal visibility benefits and would not be cost-effective. Therefore, the existing controls are sufficient to meet BART for PM. The executed AOC includes PM emission limits for Unit 6 commensurate with current operation. The AOC makes the BART conditions permanent and enforceable. LDEQ is proposing that the requirements in the AOC are sufficient to meet BART.

As the energy industry evolves, LDEQ continues to work with EGUs throughout Louisiana to evaluate the operation of utilities. As such, LDEQ will engage in discussions with Entergy about any potential changes in usage or emission rates at the Nelson facility. Any such changes will be considered for reasonable progress for future planning periods as appropriate.

- **Waterford 1 & 2 Electric Generating Plant (Waterford):**

[No Change]

DRAFT

D. Municipal Facility Units

[No Change]

Appendix A

Public Notice and Participation

DRAFT

Appendix B

CLECO

BART Determination and Evaluation

[No Change]

DRAFT

Appendix C

NRG

BART Determination and Evaluation

[No Change]

DRAFT

Appendix D Entergy Louisiana LLC BART Determination and Evaluation

DRAFT

Appendix E

Municipal Facilities

[No Change]

DRAFT

Appendix F

EPA DRAFT BART Modeling and Costs Information

DRAFT

To: Vivian Aucoin[Vivian.Aucoin@LA.GOV]; Donald Trahan[Donald.Trahan@LA.GOV]; Charlotte Goudeau[Charlotte.Goudeau@LA.GOV]; vennetta.hayes@la.gov[vennetta.hayes@la.gov]
Cc: Donaldson, Guy[Donaldson.Guy@epa.gov]; Stenger, Wren[stenger.wren@epa.gov]; Kordzi, Joe[Kordzi.Joe@epa.gov]; Feldman, Michael[Feldman.Michael@epa.gov]; Thomas, Carrie[Thomas.Carrie@epa.gov]
From: Huser, Jennifer
Sent: Wed 5/31/2017 8:03:41 PM
Subject: Revised SIP Narrative and supporting documents (1 of 2)
LA_RH_Nelson_TSD.pdf
DRAFT Nelson AOC.docx
DRAFT LA CAMx BART Modeling TSD draft with Nelson.pdf
DRAFT LA CALPUFF BART modeling report draft with Nelson.pdf

[redacted]

RH Nelson Louisiana Final redline _clean 5_26_2017.docx

Good afternoon,

Thank you again for making time this afternoon to discuss the LA RH SIP revision for Entergy Nelson. Please find attached the following documents:

- Draft CAMx Modeling Report
- Draft CALPUFF Modeling Report
- Draft Nelson Technical Assistance Document
- Draft revised SIP narrative
- Draft AOC
- Supporting files for CAMx/CALPUFF/TAD

Please note that we have revised the SIP narrative to reflect discussions we had this afternoon. All supporting documents or those referenced in the TAD will be transmitted in a separate email.

Please feel free to contact me if you have any additional questions. We look forward to seeing

your draft by the 12th.

Thanks!

Jennifer Huser

Environmental Scientist

Air Planning Section (6MM-AA)
USEPA Region 6
1445 Ross Ave. Suite 1200
Dallas, TX 75202-2733
214-665-7347

STATE OF LOUISIANA
DEPARTMENT OF ENVIRONMENTAL QUALITY

OFFICE OF ENVIRONMENTAL ASSESSMENT

IN THE MATTER OF	*	
	*	
ENTERGY LOUISIANA, LLC	*	**REGIONAL HAZE**
R.S. NELSON GENERATING PLANT	*	**STATE IMPLEMENTATION PLAN**
CALCASIEU PARISH, LOUISIANA	*	**EGU BART ANALYSIS**
	*	
	*	**AGENCY INTEREST NO. 19588**
	*	
PROCEEDINGS UNDER THE LOUISIANA	*	
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 **ENTERGY LOUISIANA, LLC (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 the R. S. Nelson Generating Plant located at 3500 Houston River Road, Westlake, Calcasieu Parish, Louisiana (Facility). The Facility currently operates pursuant to Title V and PAL Permit Number 6250-00014-V4 issued on April 11, 2017.

II.

Under Clean Air Act (CAA) section 110, each state must prepare and submit for the EPA approval, a 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 is concurrently submitting a proposed SIP on behalf of the State of Louisiana to EPA Region VI that addresses Best Available Retrofit Technology (BART) for the Facility. The BART analysis is based in part on submittals made by RESPONDENT to the Department on May 12, 2015.

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 no later than the effective date of a final SIP pursuant to 40 CFR PART 51, Appendix Y:

> Before fuel oil firing is allowed to take place at Unit 4 and the auxiliary boiler at the Facility, a revised BART determination must be promulgated for SO_2 and PM for the fuel oil firing scenario through a FIP or an action by the LDEQ as a SIP revision and approved by EPA such that the action is federally enforceable.

II.

The Respondent shall comply with the sulfur dioxide (SO2) emission limitations set forth below as expeditiously as practicable, but no later than three years of the effective date of a final SIP pursuant to 40 CFR PART 51, Appendix Y:

Unit	**Pollutant**	**Emission Limit lb/ MMBtu (30-day rolling average)**
6	**SO_2**	**0.6**

III.

The Respondent shall comply with the particulate matter less than 10 microns (PM10) emissions limit set forth below no later than the effective date of a final SIP pursuant to 40 CFR PART 51, Appendix Y:

Unit 6

Unit	**Pollutant**	**Emission Limit lb/hr (30-day rolling average)**
6	**PM_{10}**	**317.61**

IV.

The Respondent shall continue to comply with all reporting and record keeping requirements contained within all applicable permits.

V.

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*.

VI.

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.

VII.

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.

VIII.

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.

IX.

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 State 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** 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 **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**.

X.

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 _____ day of June, 2017.

_____
Chuck Carr Brown, Ph.D.
Secretary

Entergy Louisiana LLC

By:_____ Date:_____

Name:

Title: President

To: Vivian Aucoin[Vivian.Aucoin@LA.GOV]; Donald Trahan[Donald.Trahan@LA.GOV]; vennetta.hayes@la.gov[vennetta.hayes@la.gov]; Charlotte Goudeau[Charlotte.Goudeau@LA.GOV]
Cc: Donaldson, Guy[Donaldson.Guy@epa.gov]; Stenger, Wren[stenger.wren@epa.gov]; Thomas, Carrie[Thomas.Carrie@epa.gov]; Kordzi, Joe[Kordzi.Joe@epa.gov]; Feldman, Michael[Feldman.Michael@epa.gov]
From: Huser, Jennifer
Sent: Wed 5/31/2017 8:10:25 PM
Subject: Supporting documents for the TAD (oops 3 of 3)
121-RptToCongress-EWwEIAcomments-FINAL2.pdf
2008-12-03_ex._115_srivastava_emissions_of_so3_jawma_6-04.pdf
Atwell_032410.pdf
ccc67.pdf
Design of the FLOWPAC EFGD Amager Power Plant.pdf
Economics of lime and limestone control SO2.pdf
Est H2SO4 from EGUs EPRI 2012.pdf
Estimating H2SO4 from coal fired power plants.pdf
Nelson control costs with Entergy corrections.xlsx
PRB Coal Resource and Cost Study.pdf
Solvay DSI_Trona_and_Sodium_Bicarb-2009.pdf
The Ins and Outs of SO2 Control - Power Engineering.pdf
Wet FGD Advan Multi-Pollutant Control Tech B and W.pdf

Please find attached the documents referenced in the TAD. If you are unable to locate any of the FRs cited, please let me know and we can assist you.

Thanks!

Jennifer Huser

Environmental Scientist

Air Planning Section (6MM-AA)
USEPA Region 6
1445 Ross Ave. Suite 1200
Dallas, TX 75202-2733
214-665-7347

To: Bijan Sharafkhani[Bijan.Sharafkhani@LA.GOV]; Stenger, Wren[stenger.wren@epa.gov]
From: Stenger, Wren
Sent: Wed 5/17/2017 1:07:25 PM
Subject: RE: RS Nelson discussion points Final 5-9

Bijan, this is good news Thanks. Let's keep our staff talking and please share drafts early and often. We want to ensure we can get the revision into an approval process as soon as we get it and able to start drafting our package even before your official submittal. Talk soon.

Sent from my Windows Phone

From: Bijan Sharafkhani
Sent: 5/17/2017 6:44 AM
To: Stenger, Wren
Subject: FW: RS Nelson discussion points Final 5-9

Wren,

LDEQ will need to rewrite the section on RS Nelson to include the AOC. We will make certain that the section is worded properly to include a statement that Louisiana finds the facility is subject to BART. The SIP amendment will have to be published in the Louisiana Register, which will be June 20, 2017.

Based on conversation our staff had with Guy Donaldson yesterday, BART can be an emission limit; he then stated that EPA would entertain the .6 lbs/MMBtu **average** as the emission limit based on the fact that Entergy already burns bituminous coal which has a low sulfur content. In this conversation it was also agreed that burning fuel oil would be treated the same as at the Willow Glen facility. However, that is not possible because Entergy needs to burn fuel oil during start-up, so we will add the clause that it will be used during start up only.

Thanks,

Bijan

From: Stenger, Wren [mailto:stenger.wren@epa.gov]
Sent: Tuesday, May 16, 2017 10:09 AM
To: Bijan Sharafkhani
Subject: RE: RS Nelson discussion points Final 5-9

Bijan, I understand the position.. The question is do you plan to send a SIP revision with narrative and technical support to support the conclusions? If so, we need our folks to work together, with my folks ensuring we have OAQPS and OGC on board.to support it. How would you like to proceed?

Sent from my Windows Phone

From: Bijan Sharafkhani
Sent: 5/12/2017 7:55 AM
To: Stenger, Wren
Subject: FW: RS Nelson discussion points Final 5-9

Wren,

Your thoughts?

To: Bijan Sharafkhani[Bijan.Sharafkhani@LA.GOV]
From: Stenger, Wren
Sent: Wed 4/12/2017 12:18:42 PM
Subject: RE: Notes from the Entergy meeting (4/6/17) as per request by Bijan

Thanks

Sent from my Windows Phone

From: Bijan Sharafkhani
Sent: 4/12/2017 6:43 AM
To: Stenger, Wren
Subject: FW: Notes from the Entergy meeting (4/6/17) as per request by Bijan

Wren,

Here is the note from our meeting with Entergy.

Bijan

From: Vivian Aucoin
Sent: Tuesday, April 11, 2017 3:38 PM
To: Bijan Sharafkhani; Donald Trahan; Elliott Vega (DEQ)
Subject: Notes from the Entergy meeting (4/6/17) as per request by Bijan
Importance: High

Greetings,

This is a recap of the meeting held with Entergy on the RS Nelson facility BART analysis::

•□□□□□□□□ Attendees of the meeting besides LDEQ staff were representatives of Entergy, Sergeant and Lundy, All4, Inc., and Baker Botts.

•□□□□□□□□ Entergy presented the cost analysis from their point of view based on S&L's general methodology using the capital costs for large equipment derived from S&L's database of control system costs and recent quotes scaled for the Nelson facility; the annual O&M costs based on site-specific utility and reagent costs; followed BART guidelines and Control Cost Manual; and estimated capital and O&M costs for each of the technologies to control emissions.

•□□□□□□□□ S&L representatives discussed the difference between using the IPM algorithms as suggested by EPA. According to S&L, the IPM cost algorithm was developed to provide order-of-magnitude costs for air pollution controls to be applied to the electric generating industry on a system-wide basis. Accordingly, S&L prepared the information contained in the BART 5-factor analysis following guidelines and the Cost Control Manual.

•□□□□□□□□ The discussion analyzed the differences in the cost of controls as presented by EPA at $2500 per ton.

Respondents further discussed the post-processing of the CAMx modeling, providing technical answers to EPA 's concerns as provided to LDEQ on March 10, 2017. In this discussion, the representatives for All4, Inc. explained the differences between post-processing a clean-vs-dirty background scenario. EPA suggests that respondent should use a clean background which assumes no anthropogenic sources except RS Nelson impact the Class I area. Results of this type of modeling produce an artificial visibility metric which inflates the impact from the source or resulting improvement. By using the dirty background post-processing method, the visibility baseline impact and benefits are calculated by evaluating the source relative to a real background using IMPROVE monitor data; it incorporates contribution from all sources and results in a more realistic visibility metric.

Action items taken from the meeting:

LDEQ staff with discuss information with Dr. Brown and will set up subsequent meeting with EPA and respondent within the next two weeks.

Respondent will supply the Arkansas letter to LDEQ for reference.

Vivian H. Aucoin

Environmental Scientist, Senior

Office of Environmental Assessment, Air Planning Division

225-219-3482

vivian.aucoin@la.gov

To: treecep@adeq.state.ar.us[treecep@adeq.state.ar.us]
Cc: Medina, Dayana[Medina.Dayana@epa.gov]
From: Todd, Robert
Sent: Wed 6/7/2017 9:36:39 PM
Subject: FW: Comments on ADEQ draft SIP revision
EPA Comments on draft AR RH SIP revision.docx

FYI

From: Donaldson, Guy
Sent: Wednesday, June 07, 2017 4:30 PM
To: Spencer, Stuart <SPENCER@adeq.state.ar.us>
Cc: Todd, Robert <Todd.Robert@epa.gov>; Medina, Dayana <Medina.Dayana@epa.gov>; Montgomery, William <Montgomery@adeq.state.ar.us>
Subject: FW: Comments on ADEQ draft SIP revision

Stuart,

Here are some recommendations for your draft SIP revision. Please take them in the spirit of recommendations but we think they will improve the accuracy of the document.

From: Medina, Dayana
Sent: Wednesday, June 07, 2017 4:01 PM
To: Donaldson, Guy <Donaldson.Guy@epa.gov>
Cc: Todd, Robert <Todd.Robert@epa.gov>; Nann, Barbara <nann.barbara@epa.gov>
Subject: RE: Comments on ADEQ draft SIP revision

Guy- Here is the revised version. It sounds like you are ok with me sending the comments to Tricia Treece, or did you want this to be sent by you to Stuart?

Dayana Medina

U.S. Environmental Protection Agency, Region 6

Multimedia Division

State Implementation Section A (6MM-AA)

214-665-7241

From: Donaldson, Guy
Sent: Wednesday, June 07, 2017 3:48 PM
To: Medina, Dayana <Medina.Dayana@epa.gov>
Subject: RE: Comments on ADEQ draft SIP revision

Sure include it if not too late.

From: Medina, Dayana
Sent: Wednesday, June 07, 2017 2:54 PM
To: Donaldson, Guy <Donaldson.Guy@epa.gov>
Cc: Nann, Barbara <nann.barbara@epa.gov>
Subject: FW: Comments on ADEQ draft SIP revision

Guy- one more comment sent by Carrie T. Should we include it in our comments to the state?

Dayana Medina

U.S. Environmental Protection Agency, Region 6

Multimedia Division

State Implementation Section A (6MM-AA)

214-665-7241

From: Nann, Barbara
Sent: Wednesday, June 07, 2017 2:49 PM
To: Medina, Dayana <Medina.Dayana@epa.gov>
Subject: FW: Comments on ADEQ draft SIP revision

From: Thomas, Carrie
Sent: Wednesday, June 07, 2017 2:48 PM
To: Nann, Barbara <nann.barbara@epa.gov>
Subject: RE: Comments on ADEQ draft SIP revision

Feel free to disregard because this may be too nitpicky, but here are my only comments:

"ADEQ has determined that it is appropriate under 40 C.F.R § 51.308, and provides additional flexibility for CSAPR participating subject-to-BART units in Arkansas, to rely upon participation in the CSAPR ozone season NOx trading program rather than source-specific BART requirements for NOx. Participation in CSAPR for ozone season NOx is federally enforceable under 40 C.F.R. 52.38 and the ozone season NOx requirements under CSAPR apply to ~~for~~ the following BART-eligible units:"

CSAPR as an alternative to BART applies to all EGUs in the state over a certain size, rather than being an alternative to BART for only the BART sources (this is one of the issues that's come up for Texas). Without the commas and the extra language, it could be read to mean that only the subject to BART units need to participate in CSAPR for it to be a sufficient alternative to BART. There are other (probably better) ways to address my concern, but this was the least invasive way I could think of.

Carrie K. Thomas
Office of Regional Counsel
U.S. Environmental Protection Agency, Region 6
1445 Ross Ave. (6-RC-M)
Dallas, TX 75202
Tel: (214) 665-7121
Fax: (214) 665-2182

NOTICE: This communication may contain privileged or other confidential information. If you are not the intended recipient, or believe you have received this communication in error, please delete the copy you received, and do not print, copy, re-transmit, disseminate or otherwise use the information. Thank you.

From: Nann, Barbara
Sent: Wednesday, June 07, 2017 1:44 PM
To: Thomas, Carrie <Thomas.Carrie@epa.gov>

Subject: FW: Comments on ADEQ draft SIP revision

From: Anderson, Lea
Sent: Wednesday, June 07, 2017 1:42 PM
To: Nann, Barbara <nann.barbara@epa.gov>
Cc: Zenick, Elliott <Zenick.Elliott@epa.gov>; Beaver, Melinda <Beaver.Melinda@epa.gov>
Subject: Re: Comments on ADEQ draft SIP revision

Thanks, Barbara. I don't have anything to add beyond the comments that have been pulled together. The two key points are (1) that the SIP doesn't address the NOx controls required for Independence (which I'm fine with, but I imagine will not satisfy Entergy); and (2) Arkansas' apparent belief that if it complies with the original CSAPR budget, it will have satisfied the NOx BART requirements regardless of what happens to the update rule.

From: Nann, Barbara
Sent: Wednesday, June 7, 2017 11:18 AM
To: Anderson, Lea
Subject: FW: Comments on ADEQ draft SIP revision

From: Donaldson, Guy
Sent: Wednesday, June 07, 2017 7:42 AM
To: Medina, Dayana <Medina.Dayana@epa.gov>; Nann, Barbara <nann.barbara@epa.gov>; Feldman, Michael <Feldman.Michael@epa.gov>
Cc: Todd, Robert <Todd.Robert@epa.gov>
Subject: RE: Comments on ADEQ draft SIP revision

Here are my thoughts. Let's discuss at the team meeting.

From: Medina, Dayana
Sent: Tuesday, June 06, 2017 6:21 PM
To: Nann, Barbara <nann.barbara@epa.gov>; Donaldson, Guy <Donaldson.Guy@epa.gov>; Feldman, Michael <Feldman.Michael@epa.gov>
Cc: Todd, Robert <Todd.Robert@epa.gov>
Subject: RE: Comments on ADEQ draft SIP revision

Here are revised comments that include input from Michael and Barbara, as well as some of the feedback we received from Phil and Melinda. We can discuss at the RH team meeting tomorrow, or I can set up a separate call if we run out of time.

Dayana Medina

U.S. Environmental Protection Agency, Region 6

Multimedia Division

State Implementation Section A (6MM-AA)

214-665-7241

From: Nann, Barbara
Sent: Tuesday, June 06, 2017 9:34 AM
To: Medina, Dayana <Medina.Dayana@epa.gov>; Donaldson, Guy <Donaldson.Guy@epa.gov>; Feldman, Michael <Feldman.Michael@epa.gov>
Cc: Todd, Robert <Todd.Robert@epa.gov>
Subject: RE: Comments on ADEQ draft SIP revision

I had a few thoughts for your consideration (prior to any proposed inclusion into our comments).

1) RP/Independence:

I think we should comment to Arkansas that what they are wanting to do is not an Independence analysis but since they are proposing to adopt CSAPR better than BART for NOx that when doing an analysis for RP NOx CSAPR better than Bart will address the reductions needed for EGUs. Additional analysis/statements are required as to why that is enough under NOx (e.g. proposed emission reductions under NOx CSAPR better than BART will be better than BART

and RP NOx controls for Independence, NOx is responsible for X% of visibility impairment as compared to Y% for SO2)

2) Draft Timeline for Processing SIP

I took the request in the Governor's draft letter for a stay of the emission limits as to highlighting the need to give the state a draft schedule to show that EPA processing of SIP will occur prior to April 2018 deadline. (I can have something by this afternoon.) Narrow FIP in actuality would really alleviate a timing concern but in lieu of that we can do what was done in NM (comfort letter). For NM, there was a stay for the negotiations (90 day then 45 day extension) and then there was a comfort letter for the SIP processing. Staying while EPA processes a SIP has several optic as well as legal issues tied to it. I recommend we talk with the state at the end of this week to walk through our comments and ideas for timing.

Barbara

From: Medina, Dayana
Sent: Friday, June 02, 2017 5:33 PM
To: Nann, Barbara <nann.barbara@epa.gov>; Donaldson, Guy <Donaldson.Guy@epa.gov>; Feldman, Michael <Feldman.Michael@epa.gov>
Cc: Todd, Robert <Todd.Robert@epa.gov>
Subject: RE: Comments on ADEQ draft SIP revision

I only have a few comments. Regarding Independence, I figured it may be better to encourage the State to talk to us about how they can address this source in this SIP revision rather than providing specific written comments on this issue.

Also, the draft cover letter to be signed by the Governor has language requesting that we "stay the NOx emission limits" of the BART EGUs while we review and process our action on the SIP revision. Should we tell ADEQ that we can't stay the emission limits, but that extending the administrative stay of the effectiveness of the NOx compliance dates could be an option?

Dayana Medina

U.S. Environmental Protection Agency, Region 6

Multimedia Division

State Implementation Section A (6MM-AA)

214-665-7241

From: Nann, Barbara
Sent: Thursday, June 01, 2017 4:56 PM
To: Donaldson, Guy <Donaldson.Guy@epa.gov>; Medina, Dayana <Medina.Dayana@epa.gov>; Feldman, Michael <Feldman.Michael@epa.gov>
Subject: AR RH: Quick Question

What is our target date for getting comments to AR on the NOx CSAPR better than BART SIP?

6/7/17

EPA Comments on Draft Arkansas RH SIP Revision

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Cc: Medina, Dayana[Medina.Dayana@epa.gov]
From: Todd, Robert
Sent: Wed 6/7/2017 9:35:11 PM
Subject: FW: Comments on ADEQ draft SIP revision
EPA Comments on draft AR RH SIP revision.docx

From: Donaldson, Guy
Sent: Wednesday, June 07, 2017 4:30 PM
To: Spencer, Stuart <SPENCER@adeq.state.ar.us>
Cc: Todd, Robert <Todd.Robert@epa.gov>; Medina, Dayana <Medina.Dayana@epa.gov>; Montgomery, William <Montgomery@adeq.state.ar.us>
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Cc: Todd, Robert <Todd.Robert@epa.gov>; Nann, Barbara <nann.barbara@epa.gov>
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1445 Ross Ave. (6-RC-M)
Dallas, TX 75202
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Fax: (214) 665-2182

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1. If the State is interested in requesting EPA to parallel process the SIP revision, we recommend that the Governor's cover letter make this request.
2. In the "Introduction" and "Background" sections summarizing EPA's 2012 action on the 2008 SIP revision, the draft SIP only mentions that EPA disapproved the RPGs, without mentioning that we also disapproved the RPG analysis. We encourage the State to clarify that EPA's 2012 action included disapproval of the RPGs and the RPG analysis. We find that this clarification would be helpful, especially if Arkansas ultimately decides to adopt in the SIP revision the same RPGs we disapproved in our 2012 action but including a revised analysis.
3. We recommend that the last sentence on page 1 of the draft SIP revision be revised as follows: "This SIP revision replaces source-specific NO_X BART determinations *for the EGUs* included in the 2008 AR RH SIP, as well as *NO_X* limits *for the EGUs* promulgated under the 2016 federal implementation plan (FIP), with reliance on the Cross-State Air Pollution Rule (CSAPR) emissions trading program …"
4. Page 6 of the draft SIP revision includes a statement that "Arkansas also requested reconsideration of the use of low-sulfur coal as BART for SO2 at Entergy White Bluff during the 2008-2018 planning period." Since the BART requirement is not specific to the planning period, we encourage ADEQ to revise the statement by removing reference to the planning period.
5. Section III of the draft SIP includes a discussion of the history of CSAPR, including the 2012 rulemaking EPA issued allowing states participating in the CSAPR trading program to use CSAPR to satisfy BART. We remind ADEQ that the EPA's 2012 determination that implementation of CSAPR meets the criteria for a BART alternative was based on an analytic demonstration that implementation of CSAPR (across all states subject to CSAPR) would result in greater reasonable progress than BART toward restoring natural visibility conditions in relevant locations. However, in response to the D.C. Circuit's remand of various CSAPR Phase 2 budgets, the EPA has since withdrawn the FIP provisions subjecting Florida's EGU's to CSAPR ozone-season NO_X requirements and has proposed to withdraw the FIP provisions subjecting Texas EGUs to CSAPR SO_2 and annual NO_X requirements. In order to address any potential concern about continuing to rely on CSAPR participation as a BART alternative for EGUs in the remaining CSAPR states, the EPA also proposed a sensitivity analysis showing that the 2012 analytic demonstration supporting the conclusion that CSAPR participation qualifies as a BART alternative would not be adversely affected by modifying the assumptions to reflect the actions that have been or are expected to be taken in response to the D.C. Circuit's remand of CSAPR Phase 2 budgets (81 FR 78954). In that proposed rulemaking, EPA requested comment on the sensitivity analysis and on EPA's proposed determination that CSPAR participation would continue to achieve greater reasonable progress than BART despite the changes in the treatment of Texas and Florida EGUs. EPA has not yet taken final action on that rulemaking. Therefore, we remind ADEQ that EPA final approval of

a SIP revision that relies on CSAPR to satisfy NO_X BART for Arkansas' EGUs is contingent on our taking final action to find that CSAPR continues to be an appropriate alternative to source specific BART. To provide a more up to date history of CSAPR, we also encourage ADEQ to mention in the SIP narrative the D.C. Circuit's remand of the CSAPR Phase 2 budgets as well as EPA's not yet finalized rulemaking to withdraw provisions subjecting Texas EGUs to CSAPR SO_2 and annual NO_X requirements and to re-affirm that CSAPR is better than BART.

6. We recommend that the sentence at the end of page 7 be revised as follows: "ADEQ has determined that it is appropriate under 40 C.F.R § 51.308, and provides additional flexibility for CSAPR participating subject-to-BART units in Arkansas, to rely upon participation in the CSAPR ozone season NO_X trading program rather than source-specific BART requirements for NO_X. Participation in CSAPR for ozone season NO_X is federally enforceable under 40 C.F.R. 52.38 *and the ozone season NOx requirements under CSAPR apply to* the following BART-eligible units…"
7. We encourage the State to address NO_X for Independence Units 1 and 2 in this SIP revision. We recommend including a reasonable progress analysis addressing NO_X for all EGUs in Arkansas instead of developing an analysis specific only to Independence. One potential option for addressing reasonable progress for NO_X is to provide a discussion explaining why participation in CSAPR for ozone season NO_X addresses the NO_X reductions needed for all EGUs in Arkansas taking into consideration the percent contribution to visibility impairment from NO_X, especially when compared to that of SO_2. We encourage ADEQ to work with EPA in the development of the reasonable progress analysis.
8. Based on feedback received from the FLMs, we encourage ADEQ to share with the FLMs as soon as possible a draft of the proposed SIP revision so that the FLMs can make a determination as to whether they can commit to an abbreviated or expedited consultation period. Additionally, we recommend that the SIP revision narrative include a discussion of the requirements under section 51.308(i)(2) regarding FLM consultation, as well as a discussion of consultations between ADEQ and the FLMs.
9. For greater accuracy, we recommend that a statement at the beginning of page 3 be revised to the following: "*Around the time of* the 1999 RHR*, the EPA and FLMs* also expanded the existing Class I visibility monitoring network to 108 Class I areas.