To: Huser, Jennifer[Huser.Jennifer@epa.gov]
Cc: Feldman, Michael[Feldman.Michael@epa.gov]
From: Kordzi, Joe
Sent: Mon 1/30/2017 9:55:26 PM
Subject: RE: PM limits for fuel oil sources:
TX BART proposal as published 1-10-17.pdf

See the attached, pages 946-7. I thought you said they didn't have fuel oil limits?

From: Huser, Jennifer
Sent: Monday, January 30, 2017 3:48 PM
To: Kordzi, Joe <Kordzi.Joe@epa.gov>
Cc: Feldman, Michael <Feldman.Michael@epa.gov>
Subject: FW: PM limits for fuel oil sources:

Hey Joe,

So Carrie just sent me this exerpt from Texas. So isn't it enough for Waterford (or any fuel oil source) for PM BART to say that the fuel oil S limit is BART?

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: Thomas, Carrie
Sent: Monday, January 30, 2017 3:43 PM
To: Huser, Jennifer <Huser.Jennifer@epa.gov>
Subject: PM limits for fuel oil sources:

This is what we proposed to codify for Texas:

40 CFR 52.2287:

(d) *Emissions limitations and compliance dates for PM.* The owner/operator of the units listed below shall not emit or cause to be emitted pollutants in excess of the following limitations from the subject unit. Compliance with the requirements of this section is required as listed below unless otherwise indicated by compliance dates contained in specific provisions.

(1) Coal-Fired Units at Big Brown Units 1 and 2; Monticello Units 1, 2, and 3; Martin Lake Units 1, 2, and 3; Coleto Creek Unit 1; J T Deely Units 1 and 2; W A Parish Units 5 and 6; Welsh Unit 1; Harrington Units 061B and 062B; and Fayette Units 1 and 2.

(i) Normal operations: Filterable PM limit of 0.030 lb/MMBtu.

(ii) Work practice standards specified in 40 CFR part 63, subpart UUUUU, Table 3, and using the relevant definitions in 63.10042.

(2) Gas-Fired Units at Newman Unit 4; Wilkes Units 2 and 3; and W A Parish Unit 4 shall burn only pipeline natural gas, as defined in 40 CFR 72.1Start

(3) Gas-fired units that also burn fuel oil at Graham Unit 2; Newman Units 2 and 3; O W Sommers Units 1 and 2; Stryker Creek Unit ST2; and Wilkes shall burn 0.7% sulfur content fuel or pipeline natural gas, as defined in 40 CFR 72.1.

Carrie K. Thomas
Office of Regional Counsel
U.S. Environmental Protection Agency, Region 6
1445 Ross Ave. (6-RC-M)
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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R06–OAR–2016–0611; FRL–9955–77-Region 6]

Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: Pursuant to the Federal Clean Air Act (CAA or Act), the Environmental Protection Agency (EPA) is proposing to promulgate a Federal Implementation Plan (FIP) in Texas to address the remaining outstanding requirements that are not satisfied by the Texas Regional Haze State Implementation Plan (SIP) submission. Specifically, the EPA proposes SO_2 limits on 29 Electric Generating Units (EGUs) located at 14 Texas facilities to fulfill requirements for the installation and operation of the Best Available Retrofit Technology (BART) for SO_2. To address the requirement for NO_X BART for Texas EGU sources, we are proposing a FIP that relies upon two other EPA rulemakings, one already final and one proposed, which together will establish that participation in the Cross-State Air Pollution Rule (CSAPR) continues to qualify as an alternative to NO_X BART for EGUs in Texas. We also are proposing to disapprove the portion of the Texas Regional Haze SIP that addresses the BART requirement for EGUs for Particulate Matter (PM) and proposing a FIP with PM BART limits for EGUs at 29 EGUs located at 14 Texas facilities, based on existing practices and control capabilities. In addition, we propose to reconsider and re-propose disapproval of portions of several SIP revisions submitted to satisfy the requirement to address interstate visibility transport for six NAAQS and that the FIP emission limits we are proposing meet the interstate visibility transport requirements for these NAAQS.

DATES: *Comments:* Comments must be received on or before March 6, 2017. A public hearing will be held January 10, 2017. For additional logistical information regarding the public hearing please see the **SUPPLEMENTARY INFORMATION** section of this action.

ADDRESSES: Submit your comments, identified by Docket No. EPA–R06–OAR–2016–0611, at *http://www.regulations.gov* or via email to *R6_TX–BART@epa.gov*. Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov*. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.* on the web, cloud, or other file sharing system). For additional submission methods, please contact Joe Kordzi, 214–665–7186, *Kordzi.joe@epa.gov*. For the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

Docket: The index to the docket for this action is available electronically at *http://www.regulations.gov* and in hard copy at the EPA Region 6, 1445 Ross Avenue, Suite 700, Dallas, Texas. While all documents in the docket are listed in the index, some information may be publicly available only at the hard copy location (*e.g.,* copyrighted material), and some may not be publicly available at either location (*e.g.,* CBI).

The Texas regional haze SIP is available online at: *https://www.tceq.texas.gov/airquality/sip/bart/haze_sip.html.* It is also available for public inspection during official business hours, by appointment, at the Texas Commission on Environmental Quality, Office of Air Quality, 12124 Park 35 Circle, Austin, Texas 78753.

FOR FURTHER INFORMATION CONTACT: Joe Kordzi, Air Planning Section (6PD–L), Environmental Protection Agency, Region 6, 1445 Ross Avenue, Suite 700, Dallas, Texas 75202–2733, telephone 214–665–7186; fax number 214–665–7263; email address *Kordzi.joe@epa.gov*.

SUPPLEMENTARY INFORMATION: Throughout this document wherever ''we,'' ''us,'' or ''our'' is used, we mean the EPA.

Public Hearing: We are holding an information session, for the purpose of providing additional information and informal discussion for our proposal. We are also holding a public hearing to accept oral comments into the record:

Date: Tuesday, January 10, 2017
Time: Open House: 1:30 p.m.–3:30 p.m.
Public hearing: 4:00 p.m.–8:00 p.m. (including short break)
Location: Joe C. Thompson Conference Center (on the University of Texas (UT) Campus), Room 3.102, 2405 Robert Dedman Drive, Austin, Texas 78712

Joe C. Thompson Conference Center parking is adjacent to the building in Lot 40, located at the intersection of East Dean Keeton Street and Red River Street. Additional parking is available at the Manor Garage, located at the intersection of Clyde Littlefield Drive and Robert Dedman Drive. If arranged in advance, the UT Parking Office will allow buses to park along Dedman Drive near the Manor Garage for a fee.

The public hearing will provide interested parties the opportunity to present information and opinions to us concerning our proposal. Interested parties may also submit written comments, as discussed in the proposal. Written statements and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at the public hearing. We will not respond to comments during the public hearing. When we publish our final action, we will provide written responses to all significant oral and written comments received on our proposal. To provide opportunities for questions and discussion, we will hold an information session prior to the public hearing. During the information session, EPA staff will be available to informally answer questions on our proposed action. Any comments made to EPA staff during an information session must still be provided orally during the public hearing, or formally in writing within 30 days after completion of the hearings, in order to be considered in the record.

At the public hearings, the hearing officer may limit the time available for each commenter to address the proposal to three minutes or less if the hearing officer determines it to be appropriate. We will not be providing equipment for commenters to show overhead slides or make computerized slide presentations. Any person may provide written or oral comments and data pertaining to our proposal at the public hearings. Verbatim English language transcripts of the hearing and written statements will be included in the rulemaking docket.

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I. Background

Regional haze is visibility impairment that is produced by a multitude of sources and activities that are located across a broad geographic area and emit fine particulates ($PM_{2.5}$) (*e.g.,* sulfates, nitrates, Organic Carbon (OC), Elemental Carbon (EC), and soil dust), and their precursors (*e.g.,* Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_X), and in some cases, ammonia (NH_3) and Volatile Organic Compounds (VOCs)). Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that can be seen. $PM_{2.5}$ can also cause serious health effects and mortality in humans and contributes to environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the ''Interagency Monitoring of Protected Visual Environments'' (IMPROVE) monitoring network, show that visibility impairment caused by air pollution occurs virtually all the time at most national parks and wilderness areas. In 1999, the average visual range [1] in many Class I areas (*i.e.,* national parks and memorial parks, wilderness areas, and international parks meeting certain size criteria) in the western United States was 100–150 kilometers, or about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. In most of the eastern Class I areas of the United States, the average visual range was less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions.[2] CAA programs have reduced some haze-causing pollution, lessening some visibility impairment and resulting in partially improved average visual ranges.[3]

CAA requirements to address the problem of visibility impairment are continuing to be addressed and implemented. In Section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the prevention of any future, and the remedying of any existing man-made impairment of visibility in 156 national parks and wilderness areas designated as mandatory Class I Federal areas.[4] On December 2, 1980, EPA promulgated regulations to address visibility impairment in Class I areas that is ''reasonably attributable'' to a single source or small group of sources, *i.e.,* ''reasonably attributable visibility impairment.''[5] These regulations represented the first phase in addressing visibility impairment. EPA deferred action on regional haze that emanates from a variety of sources until monitoring, modeling, and scientific knowledge about the relationships between pollutants and visibility impairment were improved.

Congress added section 169B to the CAA in 1990 to address regional haze issues, and we promulgated regulations addressing regional haze in 1999.[6] The Regional Haze Rule revised the existing visibility regulations to integrate into the regulations provisions addressing regional haze impairment and established a comprehensive visibility protection program for Class I areas. The requirements for regional haze, found at 40 CFR 51.308 and 51.309, are included in our visibility protection regulations at 40 CFR 51.300–309. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia, and the Virgin Islands. States were required to submit the first implementation plan addressing regional haze visibility

[1] Visual range is the greatest distance, in kilometers or miles, at which a dark object can be viewed against the sky.

[2] 64 FR 35715 (July 1, 1999).

[3] An interactive ''story map'' depicting efforts and recent progress by EPA and states to improve visibility at national parks and wilderness areas may be visited at: *http://arcg.is/29tAbS3.*

[4] Areas designated as mandatory Class I Federal areas consist of National Parks exceeding 6000 acres, wilderness areas and national memorial parks exceeding 5000 acres, and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). In accordance with section 169A of the CAA, EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value. 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. 42 U.S.C. 7472(a). Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to ''mandatory Class I Federal areas.'' Each mandatory Class I Federal area is the responsibility of a ''Federal Land Manager.'' 42 U.S.C. 7602(i). When we use the term ''Class I area'' in this action, we mean a ''mandatory Class I Federal area.''

[5] 45 FR 80084 (December 2, 1980).

[6] 64 FR 35714 (July 1, 1999), codified at 40 CFR part 51, subpart P (Regional Haze Rule).

impairment no later than December 17, 2007.[7]

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, often under-controlled, older stationary sources in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the CAA requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress toward the natural visibility goal, including a requirement that certain categories of existing major stationary sources[8] built between 1962 and 1977 procure, install and operate the ''Best Available Retrofit Technology'' (BART). Larger ''fossil-fuel fired steam electric plants'' are included among the BART source categories. Under the Regional Haze Rule, states are directed to conduct BART determinations for ''BART-eligible'' sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. The evaluation of BART for Electric Generating Units (EGUs) that are located at fossil-fuel fired power plants having a generating capacity in excess of 750 megawatts must follow the ''Guidelines for BART Determinations Under the Regional Haze Rule'' at appendix Y to 40 CFR part 51 (hereinafter referred to as the ''BART Guidelines''). Rather than requiring source-specific BART controls, states also have the flexibility to adopt an emissions trading program or alternative program as long as the alternative provides greater reasonable progress towards improving visibility than BART. To the extent a Regional Haze SIP does not meet CAA requirements to address BART, the CAA requires EPA to promulgate a FIP that makes the requisite determinations to ensure the BART requirement is satisfied, as applicable, for sources in the state.[9]

II. Overview of Proposed Actions

A. Regional Haze

On January 5, 2016, we took final action on nearly all portions of a Regional Haze SIP submittal submitted by the State of Texas on March 31, 2009.[10] In that final rule, we did not take action on the portion of the submittal that was intended to satisfy BART requirements for EGUs as mandated by 40 CFR 51.308(e). In an earlier, separate action, we issued a limited disapproval of the Texas Regional Haze SIP concerning EGU BART due to Texas' reliance on the Clean Air Interstate Rule (CAIR).[11] The EGU BART requirements for NO_X and SO_2 remain unmet following the limited disapproval, and Texas has not submitted a revised SIP to address the deficiencies. While we previously proposed to approve the portion of the Regional Haze SIP that was intended to address whether EGUs in Texas must install and operate BART for PM,[12] that part of the proposed action was not finalized.[13] In connection with changed circumstances on how Texas EGUs are able to satisfy NO_X and SO_2 BART, we are now proposing to disapprove the portion of the Texas Regional Haze SIP that evaluated the PM BART requirement for EGUs. The FIP we are proposing today addresses the EGU BART requirement and addresses these deficiencies in the Texas Regional Haze SIP.

Texas' regional haze SIP relied on participation in CAIR as an alternative to meeting the source-specific BART requirements for SO_2 and NO_X. *See* 40 CFR 51.308(e)(4) (2006). At the time that Texas submitted its SIP to EPA, however, the D.C. Circuit had remanded CAIR (without vacatur). *See North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir.), *modified,* 550 F.3d 1176 (D.C. Cir. 2008). The court thereby left CAIR and CAIR FIPs in place in order to ''temporarily preserve the environmental values covered by CAIR'' until we could, by rulemaking, replace CAIR consistent with the court's opinion.[14]

On August 8, 2011, we promulgated the Cross-State Air Pollution Rule (CSAPR), to replace CAIR.[15] In 2012, we issued a limited disapproval of the Texas regional haze SIP because of Texas' reliance on CAIR as an alternative to EGU BART for SO_2 and NO_X.[16] We also determined that CSAPR would provide for greater reasonable progress than BART and amended the Regional Haze Rule to allow CSAPR participation as an alternative to source-specific SO_2 and NO_X BART for EGUs.[17] CSAPR has been subject to extensive litigation, and on July 28, 2015, the D.C. Circuit issued a decision generally upholding CSAPR but remanding without vacating the CSAPR emissions budgets for a number of states in *EME Homer City Generation* v. *EPA,* 795 F.3d 118 (D.C. Cir.). Specifically, the court invalidated a number of the Phase 2 ozone-season NO_X budgets and found that the SO_2 budgets for four states resulted in over-control for purposes of CAA section 110(a)(2)(D)(i)(I). The remand included Texas' ozone-season NO_X budget and annual SO_2 budget.

We had earlier proposed to rely on CSAPR participation to address these BART-related deficiencies in Texas' SIP submittals.[18] Because of the uncertainty caused by the D.C. Circuit Court's partial remand, however, we determined that it was not appropriate to finalize our action. We are in the process of responding to the remand of these CSAPR budgets. On October 26, 2016, we finalized an update to the CSAPR rule that addresses the 1997 ozone NAAQS portion of the remand and the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2008 ozone NAAQS.[19] This rule promulgated a new

[7] See 40 CFR 51.308(b). EPA's regional haze regulations require subsequent updates to the regional haze SIPs. 40 CFR 51.308(g)–(i).

[8] See 42 U.S.C. 7491(g)(7) (listing the set of ''major stationary sources'' potentially subject-to-BART).

[9] See, 42 U.S.C. 7491(b)(2)(A)(citing the potential need for BART as determined by ''the Administrator in the case of a plan promulgated under section 7410(c) of this title'').

[10] 81 FR 296 (January 5, 2016). A preliminary order of the Fifth Circuit Court of Appeals in Case No. 16–60118 was issued on July 15, 2016, and stayed the rule ''in its entirety.'' On December 2, 2016, the U.S. Department of Justice filed a motion for voluntary remand of the parts of the rule under challenge and consenting to continuation of the judicial stay for remanded parts of the rule. The motion also requested affirmance of the partial approvals of the Texas and Oklahoma SIPs and lifting of the stay as to those approvals. This motion is currently pending disposition.

[11] The limited disapproval triggered the EPA's obligation to issue a FIP for Texas unless the State submitted an approvable SIP revision to correct the relevant deficiencies within 2 years of the final limited disapproval action. CAA section 110(c)(1); 77 FR 33641, 33654 (August 6, 2012).

[12] 79 FR 74817, 74851 (proposing to concur with screening analyses conducted by TCEQ including findings that no Texas EGUs are subject to BART for PM).

[13] 81 FR at 302 (January 5, 2016): ''[W]e proposed to approve Texas' determination that for its EGUs no PM BART controls were appropriate, based on a screening analysis of the visibility impacts of from just PM emissions. . . ..we have. . . .decided not to finalize our proposed approval of Texas' PM BART determination [for EGUs].''

[14] 550 F.3d at 1178.

[15] 76 FR 48208.

[16] 77 FR 33641.

[17] While that rulemaking also promulgated FIPs for several states to replace reliance on CAIR with reliance on CSAPR as an alternative to BART, it did not include a FIP for Texas. 77 FR 33641, 33654.

[18] 79 FR 74817, 74823 (December 16, 2014).

[19] ''Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS.'' 81 FR74504. The relevant portion of the remand pertained to the Phase 2 ozone season NO_X emission budget designed to address the 1997 ozone NAAQS. In response to the remand, in this final rule the EPA removed the regulatory requirement for sources in Texas to comply with the phase 2 ozone season NO_X budget calculated to address the 1997 ozone standard because we determined that no additional emission reductions from sources in Texas are necessary to address the State's obligation under 110(a)(2)(D)(i)(I) for the 1997 ozone NAAQS. However, because Texas is linked to downwind air quality problems with respect to the 2008 ozone NAAQS, we promulgated a new ozone season NO_X emission budget to address that standard. 81 FR 74504, 74600–74601.

FIP for Texas that replaced the CSAPR ozone season NO_X emission budget designed to address the 1997 ozone NAAQS for the State with a revised budget designed to address the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2008 ozone NAAQS. Then, on November 10, 2016, we proposed to withdraw the FIP provisions that require affected EGUs in Texas to participate in CSAPR for annual emissions of SO_2 and NO_X with regard to emissions after 2016.[20] Withdrawal of these FIP requirements will address the D.C. Circuit's remand of the CSAPR Phase 2 SO_2 budget for Texas. This recently published proposed rule includes an assessment of the impacts of the set of actions that the EPA has taken or expects to take in response to the D.C. Circuit's remand on our 2012 demonstration that participation in CSAPR would provide for greater reasonable progress than BART.

In 2012, we determined that CSAPR is ''better-than-BART'' based on a comparison of projected visibility in scenarios representing CSAPR implementation and BART implementation, as well as a base case without CSAPR or BART, in relevant locations throughout the country. In the case of the remanded Phase 2 ozone-season NO_X budgets, eight of the states with remanded budgets (including Texas) will continue to be subject to CSAPR to address ozone transport obligations with regard to the more stringent 2008 ozone NAAQS, and North Carolina and South Carolina, although no longer covered by CSAPR to address ozone transport obligations, will continue to be subject to CSAPR annual NO_X requirements in order to address their $PM_{2.5}$ transport obligations. In considering the potential impact of the remand of Phase 2 budgets on the 2012 CSAPR-Better-than-BART analytic demonstration, we therefore believe that only two changes have potential relevance: The withdrawal of the FIP provisions subjecting Florida EGUs to CSAPR ozone-season NO_X requirements that has already been finalized, and the withdrawal of FIP provisions subjecting Texas EGUs to CSAPR SO_2 and annual NO_X requirements that is proposed separately. That proposed analysis supports the continued conclusion that CSAPR participation would achieve greater reasonable progress than BART for NO_X despite the change in the treatment of Texas and Florida EGUs. Consequently, we have proposed that the Regional Haze Rule continues to authorize the use of CSAPR participation as a BART alternative for EGUs.[21] Finalization of that proposal would allow for Texas' regional haze program to rely on CSAPR ozone season control program participation as an alternative to source-specific EGU BART for NO_X.[22] Based on that national proposal, we are now proposing a FIP to replace Texas' reliance on CAIR with reliance on CSAPR to address the NO_X BART requirements for EGUs. Finalization of this portion of the FIP is contingent on our taking final action to find that CSAPR continues to be an appropriate alternative to source specific BART. However, finalization of the portion of our national proposal that would withdraw the FIP provisions for Texas for annual emissions of SO_2 and NO_X described above would mean that Texas will no longer be eligible to rely on CSAPR participation as an alternative to source-specific EGU BART for SO_2. As a result, we are proposing to promulgate a FIP that includes BART screening of sources and a source-by-source analysis for SO_2 BART and controls for this pollutant as appropriate. We are also unable to propose approval of the Texas Regional Haze SIP's PM BART evaluation, as previously proposed, as that demonstration made underlying assumptions that are no longer valid.[23] We instead propose to disapprove that portion of the SIP and, in place of it, promulgate source-specific PM BART requirements for EGUs that we have evaluated to be subject to BART in this proposed FIP.

We believe, however, it is preferable for states to assume primary responsibility for implementing the Regional Haze requirements as envisioned by the CAA. We will work with the State of Texas if it chooses to develop a SIP to meet these overdue Regional Haze requirements and replace or avoid a finalized FIP.

The FIP we are proposing includes BART control determinations for EGUs in Texas without previously approved BART determinations and associated compliance schedules and requirements for equipment maintenance, monitoring, testing, recordkeeping, and reporting for all affected sources and units. The EGU BART sources addressed in this FIP cause or contribute to visibility impairment at one or more Class I areas in Texas, Oklahoma, Arkansas, and New Mexico. The two Class I areas in Texas are Big Bend National Park and the Guadalupe Mountains National Park. The Class I area in Oklahoma is the Wichita Mountains National Wildlife Refuge. The two Class I areas in Arkansas are the Caney Creek Wilderness Area and the Upper Buffalo Wilderness Area. The closest impacted Class I areas in New Mexico are the Carlsbad Caverns National Park, Salt Creek Wilderness Area, and White Mountains Wilderness Area.

In order to remedy these deficiencies in the Texas SIP, we are proposing this FIP to establish the means by which the regional haze program for Texas will meet the BART requirements for SO_2, NO_X, and PM. We are proposing source-specific BART determinations for EGUs subject to BART for SO_2 and PM. We are proposing that NO_X BART requirements for EGUs in Texas will be satisfied by a determination, proposed for separate finalization, that Texas' participation in CSAPR's ozone season control program is a permissible alternative to source-specific NO_X BART.

Addressing the BART requirement for Texas EGUs, as proposed today, with cost-effective and readily available controls, will help ensure that progress

[20] ''Interstate Transport of Fine Particulate Matter: Revision of Federal Implementation Plan Requirements for Texas,'' 81 FR 78954 (November 10, 2016). Although the court's decision specifically remanded only Texas' SO_2 budget, the court's rationale for remanding that budget also implicates Texas' annual NO_X budget because the SO_2 and annual NO_X budgets were developed through an integrated analysis and were promulgated to meet a common $PM_{2.5}$ transport obligation under CAA section 110(a)(2)(D)(i)(I).

[21] 81 FR at 78962–78964.

[22] While we have proposed to remove Texas from CSAPR's annual NO_X program, CSAPR is still an appropriate alternative to BART for NO_X purposes because EGUs in Texas continue to be required to participate in CSAPR's ozone season NO_X program.

[23] We previously proposed approval of Texas' SIP for EGU PM BART on the premise that EGU BART for both SO_2 and NO_X were covered by participation in CSAPR, which allowed Texas to conduct a screening analysis of the visibility impacts from PM emissions in isolation. However, modeling on a pollutant-specific basis for PM is appropriate only in the narrow circumstance where a state relies on a BART alternative to satisfy NO_X and SO_2 BART. Due to the complexity and nonlinear nature of atmospheric chemistry and chemical transformation among pollutants, EPA has not recommended performing modeling on a pollutant-specific basis to determine whether a source is subject to BART, except in the unique situation described above. See discussion in Memorandum from Joseph Paisie to Kay Prince, ''Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations,'' July 19, 2006. More recently, the Ninth Circuit upheld EPA's disapproval of the Arizona regional haze SIP for including a pollutant-specific screening analysis for NO_X. *Phoenix Cement Co.* v. *EPA*, 647 F. App'x 702, 705–06 (9th Cir. Mar. 31, 2016) (upholding EPA's interpretation that the ''Regional Haze Rule [] require[s] a BART determination for any pollutant at a source that exceeds the de minimis threshold, once that source has been determined subject to BART.''). We did not finalize our proposed approval of Texas' EGU PM BART determination because of the uncertainty at that time concerning the CSAPR remand and whether Texas would continue to have CSAPR coverage for both NO_X and SO_2, 81 FR 296, 302, but that uncertainty has now been resolved.

is made toward natural visibility conditions at Class I areas affected by Texas' sources. Please refer to our previous rulemaking on the Texas regional haze SIP for additional background regarding the CAA, regional haze, and our Regional Haze Rule.[24]

B. Interstate Transport of Pollutants That Affect Visibility

Section 110(a) of the CAA directs states to submit a SIP that provides for the implementation, maintenance, and enforcement of each NAAQS, which is commonly referred to as an infrastructure SIP. Among other things, CAA 110(a)(2)(D)(i)(II) requires that SIPs contain adequate provisions to prohibit interference with measures required to protect visibility in other states. This requirement is referred to as ''interstate visibility transport.'' SIPs addressing interstate visibility transport are due to EPA within three years after the promulgation of a new or revised NAAQS (or within such shorter period as we may prescribe). A state's failure to submit a complete, approvable SIP for interstate visibility transport creates an obligation for EPA to promulgate a FIP to address this requirement.[25]

Previously, we issued a finding that Texas failed to submit a SIP revision to satisfy all four requirements of interstate transport under section 110(a)(2)(D)(i) of the CAA for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS.[26] Texas later submitted a SIP revision to address interstate transport for these NAAQS. However, in our January 5, 2016 final action we disapproved the portion of Texas' SIP revisions intended to address interstate visibility transport for six NAAQS, including the 1997 8-hour ozone and 1997 $PM_{2.5}$.[27] We concluded that to meet the requirements of interstate visibility transport: (1) Texas could not rely on its Regional Haze SIP, which relied heavily upon the remanded CAIR, to ensure that emissions from Texas do not interfere with measures to protect visibility in nearby states; and (2) additional control of SO_2 emissions in Texas were needed to prevent interference with measures required to be included in the Oklahoma SIP to protect visibility. However, in that action we did not finalize the portion of our proposed FIP addressing Texas' interstate visibility transport obligations because that portion of the proposed FIP would have partially relied on CSAPR to ensure the emissions from Texas' sources do not interfere with other states' visibility programs. Given the uncertainty that existed at the time arising from the D.C. Circuit's remand of Texas' CSAPR budgets (*EME Homer City Generation* v. *EPA,* 79 F.3d 118 (D.C. Cir.)), we concluded that it was not appropriate to finalize our proposed determination to rely on CSAPR as an alternative to SO_2 and NO_X BART for EGUs in Texas in that action.[28]

Our prior disapproval of interstate visibility transport for the six NAAQS is currently stayed by the Fifth Circuit.[29] We recognize that because our prior disapproval of the Texas SIP submittals addressing interstate visibility transport relied in part on our determinations of the measures needed in Texas to ensure reasonable progress in Oklahoma, the Fifth Circuit's stay of our previous action complicates next steps to ensure that the visibility requirements of CAA 110(a)(2)(D)(i)(II) are met. The Court's stay accordingly calls into question whether our past disapprovals for interstate visibility transport would stand. At the same time, we also note that we continue to have an obligation to issue a FIP for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS as a result of our 2005 finding that Texas failed to timely submit SIPs to address the interstate transport visibility requirements. Given the uncertainties arising from the Fifth Circuit's stay of our prior disapproval, we are now proposing to reconsider the basis of our prior disapproval of Texas' SIP submittals addressing the interstate visibility transport requirement for all six NAAQS. We are now proposing to determine that Texas' SIP submittals addressing interstate visibility transport for the six NAAQS are not approvable because these submittals relied solely on Texas' Regional Haze SIP to ensure that emissions from Texas did not interfere with required measures in other states. Texas' Regional Haze SIP, in turn, relied on the implementation of CAIR as an alternative to EGU BART for SO_2 and NO_X. Specifically, we are proposing disapproval of the following Texas SIP submittals insofar as they address the interstate visibility transport requirement: April 4, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); May 1, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); November 23, 2009: 2006 24-hour $PM_{2.5}$; December 7, 2012: 2010 NO_2; December 13, 2012: 2008 8-hour Ozone; May 6, 2013: 2010 1-hour SO_2 (Primary NAAQS). Texas has not submitted a SIP revision to remove reliance on CAIR for Regional Haze or interstate visibility transport. As CAIR is no longer in effect and has been replaced by CSAPR, we are proposing to find that Texas' Regional Haze SIP does meet its interstate visibility transport obligations. As a result, the Texas SIPs to address interstate visibility transport for these six NAAQS continue to be unapprovable.

We are proposing a FIP to cure the deficiencies in Texas' Regional Haze Program concerning EGU BART. This FIP will replace reliance on CAIR with reliance on CSAPR to meet the requirements for EGU BART for NO_X in Texas. The FIP will also address Texas EGU BART for SO_2 and PM on a source-specific basis. With the absence of CSAPR coverage for SO_2, we must reevaluate what is needed in Texas to address interstate visibility transport. Our proposed FIP to address Texas EGU BART achieves significant reductions of SO_2, which exceed the reductions initially assumed for Texas under either CAIR or CSAPR. In addition, our proposed FIP achieves reductions at large sources of SO_2 emissions (*e.g.,* Monticello, Martin Lake and Big Brown), that have significant impacts on

[24] 81 FR 296. The public docket for this past rulemaking remains accessible under EPA Docket ID: EPA–R06–OAR–2014–0754 at *https://www.regulations.gov.* This proposed rulemaking has a separately established docket (EPA–R06–OAR–2016–0611). Our TSD contains a list of materials from EPA Docket ID: EPA–R06–OAR–2014–0754 that we incorporate by reference and consider to be part of this rulemaking record even as they are not necessarily re-uploaded to the newer docket.

[25] CAA §110(c)(1). Mandatory sanctions under CAA section 179 do not apply because the deficiencies are not with respect to a submission that is required under CAA title I part D. ''Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and (2)'' at pages 34–35 (September 13, 2013) [hereinafter 2013 i-SIP Guidance].

[26] 70 FR 21147 (April 25, 2005). The four components of interstate transport in Section 110(a)(2)(D)(i) are contained in two subsections. Section 110(a)(2)(D)(i)(I) addresses any emissions activity in one state that contributes significantly to nonattainment, or interferes with maintenance, of the NAAQS in another state. Section 110(a)(2)(D)(i)(II) requires SIPs to include provisions prohibiting any source or other type of emissions activity in one state from interfering with measures required of any other state to prevent significant deterioration of air quality or from interfering with measures required of any other state to protect visibility (referring to visibility in Class I areas). This proposal only addresses the fourth requirement concerning visibility.

[27] Specifically, we previously disapproved the relevant portion of these Texas' SIP submittals: April 4, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); May 1, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); November 23, 2009: 2006 24-hour $PM_{2.5}$; December 7, 2012: 2010 NO_2; December 13, 2012: 2008 8-hour Ozone; May 6, 2013: 2010 1-hour SO_2 (Primary NAAQS). 79 FR 74818, 74821; 81 FR 296, at 302.

[28] 81 FR 296, 301–2.

[29] July 15, 2016 Order in *Texas* v. *EPA* (Fifth Cir. Case No. 16–160118). The EPA's filed motion requesting voluntary partial remand and continuation of the judicial stay for remanded parts of the rule includes our prior disapproval of Texas' SIPs concerning interstate visibility transport. This motion is currently pending disposition.

Class I areas in nearby states. The BART FIP requires controls on many but not all of the sources that were controlled in our previous partial FIP for Texas Regional Haze. The EGU BART FIP also includes control requirements at some additional sources not controlled in our previous action on Texas Regional Haze.

We are proposing to find that our proposed EGU BART FIP is adequate to prevent interference with measures required to protect visibility in other states for the first planning period.[30] We, therefore, propose that the measures in our proposed FIP to address Texas EGU BART will fully address Texas' interstate visibility transport obligations for the six NAAQS (1997 8-hour ozone, 1997 $PM_{2.5}$, 2006 $PM_{2.5}$, 2008 8-hour ozone, 2010 1-hour NO_2, and 2010 1-hour SO_2). We also propose that reliance on CSAPR for EGU NO_X BART is appropriate to ensure NO_X emissions from Texas EGUs do not interfere with other states' measures to protect visibility. We are proposing this action based on the reasoning that our BART FIP will achieve more emission reductions than projected under CAIR or CSAPR and the reductions are occurring at sources that have particularly large impacts on Class I areas outside of Texas. To the extent our previous final action concerning Texas Regional Haze is remanded by a Court or otherwise reconsidered in the future, we may revisit whether controls in the EGU BART FIP are adequate to address interstate visibility transport requirements. Nonetheless, we are here proposing that the proposed EGU BART FIP measures will be adequate to address interstate visibility transport based on current information. This proposal concerning the adequacy of the proposed FIP remedy does not depend on our earlier action on the Texas Regional Haze SIP or hinge on its disposition, nor does it foreclose that we may reexamine visibility transport concerns under potential scenarios where we have a responsibility to take new action.[31]

We encourage Texas to consider adopting additional SIP provisions that would allow the EPA to fully approve the Regional Haze SIP and thus to withdraw the FIP and approve Texas' SIP with respect to interstate visibility transport. Texas may also elect to satisfy interstate visibility transport by providing, as an alternative to relying on its Regional Haze SIP alone, a demonstration that emissions within its jurisdiction do not interfere with other states' plans to protect visibility.[32]

C. Our Obligation To Promulgate a FIP

Under section 110(c) of the CAA, whenever we disapprove a mandatory SIP submission in whole or in part, we are required to promulgate a FIP within 2 years unless we approve a SIP revision correcting the deficiencies before promulgating a FIP. Specifically, CAA section 110(c) provides that the Administrator shall promulgate a FIP within 2 years after the Administrator disapproves a state implementation plan submission "unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan."[33] The term "Federal implementation plan" is defined in Section 302(y) of the CAA in pertinent part as a plan promulgated by the Administrator to correct an inadequacy in a SIP.

Beginning in 2012, following the limited disapproval of the Texas Regional Haze SIP, EPA had the authority and obligation to promulgate a FIP to address BART for Texas EGUs for NO_X and SO_2. In proposing to disapprove the Regional Haze SIP component that sought to address the PM BART requirement for Texas EGUs, we also have the obligation to promulgate a PM BART FIP to address the deficiency. Texas has not addressed the EGU BART disapproval, and that requirement is now significantly overdue.[34] We are accordingly empowered and required by the CAA to make determinations and promulgate a FIP to ensure the BART requirement for Texas EGUs is satisfied.

Adding to this background, beginning with our January 5, 2016 disapproval of Texas SIP provisions regarding interstate visibility transport, we obtained the authority and obligation to promulgate a FIP to correct the deficiencies relating to that CAA requirement.[35] As with the BART requirement, we lack a SIP revision that would have any potential to correct the deficiency, necessitating that we now take action under FIP authority.

III. Our Proposed BART Analyses for SO_2 and PM

In our previous action,[36] we determined that due to the CSAPR remand, it was not appropriate at that time to rely on CSAPR as an alternative to SO_2 and NO_X BART for EGUs in Texas. As a consequence, action to satisfy the overdue requirement to address BART for EGUs in the state of Texas was further delayed.[37] In this proposal, we are proposing that CSAPR, once fully revised to address the D.C. Circuit's remand, provides a basis for satisfying EGU BART obligations for NO_X alone. It remains the case that we cannot rely on CSAPR as an alternative to SO_2 BART for Texas EGUs as further confirmed by our proposed action to remove Texas from the annual NO_X and SO_2 control programs. Thus, we have the obligation to consider source-specific requirements for Texas EGUs consistent with the BART Guidelines for SO_2 BART.

Because the component of the Texas Regional Haze SIP regarding the PM BART requirement for EGUs has not been acted on, we have the responsibility under CAA section 110(k) to evaluate the submission and take action to approve or disapprove it. The SIP determinations for PM were based on modeling that was conducted by examining visibility impairment due to PM emissions alone, based on the assumption that the state would be participating in CAIR for SO_2 and NO_X and thereby having BART coverage for those pollutants. The Texas Regional Haze SIP had concluded that no PM BART controls for EGUs were appropriate, because modeling assessment of PM impacts alone showed their impacts to be too small to warrant control consideration. But Texas' screening analysis is no longer reliable or accurate because of the invalid assumption that source-by-source BART for either SO_2 or NO_X would not be

[30] This proposed FIP for interstate visibility transport is premised on the interpretation that this requirement can be addressed even when a Regional Haze SIP is not fully approved and the FIP does not purport to correct all Regional Haze SIP deficiencies. *See e.g.* 76 FR 52388 (August 22, 2011); 76 FR 22036 (April 20, 2011); and 78 FR 14681 (March 7, 2013); *see also,* 2013 i-SIP Guidance, at page 34 (stating that EPA may find it appropriate to supplement the i-SIP Guidance regarding the relationship between Regional Haze SIPs and interstate visibility transport for future planning periods).

[31] *See e.g.* 78 FR 14681, 14685.

[32] 2013 i-SIP Guidance, at pages 34–35.

[33] EPA additionally has the authority to promulgate a FIP any time after finding that "a State has failed to make a required submission" of a SIP. CAA section 110(c)(1)(A); 42 U.S.C. 7410(c)(1)(a).

[34] The Texas Regional Haze SIP stated, "The TCEQ will take appropriate action if CAIR is not replaced with a system that the US EPA considers to be equivalent to BART." BART determinations were due in SIP submissions on December 17, 2007, 40 CFR 51.308(b), putting them on a timeline for controls by 2014 (considering the deadline for SIP action at CAA section 110(k)(2) and allowing five years for installation of BART controls). Additional delay of any amount is not appropriate and not consistent with the law.

[35] Additionally, we continue to have authority to issue a FIP to address interstate visibility transport for 1997 8-hour ozone and 1997 $PM_{2.5}$ due to our 2005 finding that Texas failed to submit SIPs to address interstate transport for these NAAQS under CAA section 110(a)(2)(D)(i). 70 FR 21147.

[36] See the discussion beginning on 81 FR 301 (January 5, 2016).

[37] Id. at 346.

required. In order to appropriately evaluate the BART requirements for EGUs, the visibility impacts from all pollutants must be studied, including PM emissions. Texas' PM BART analysis for EGUs does not do this.[38]

Accordingly, we are proposing to disapprove the portion of the Texas Regional Haze SIP that determined that all Texas EGUs screen out of the BART requirement for PM. The basis for the proposed disapproval is the SIP determination's assumption that EGUs would have coverage for SO_2 and NO_X BART under an alternative measure.[39] Since that assumption is not valid, the technical determinations regarding PM BART cannot be approved. Following the directions of the BART Guidelines on how to identify sources "subject to BART," we have looked at all visibility impairing pollutants from EGUs that are BART-eligible. Our proposed FIP therefore seeks to fill that regulatory gap by assessing BART for Texas EGUs for visibility impairing pollutants other than NO_X, *i.e.,* SO_2 and PM.

A. Identification of BART-Eligible Sources

The BART Guidelines set forth the steps for identifying whether the source is a BART-eligible source:[40]

Step 1: Identify the emission units in the BART categories,

Step 2: Identify the start-up dates of those emission units, and

Step 3: Compare the potential emissions to the 250 ton/yr cutoff.

Following our 2016 final action on the March 31, 2009 Texas RH SIP, we began the process of generating additional technical information and analysis in order to address the above three steps in our BART-eligibility proposal. We started with Texas' facility-specific listing of BART-eligible EGU sources and removed sources we verified had retired. We then gathered additional information from (1) our authority under Section 114(a) of the CAA to request information from potential BART-eligible sources, and (2) the U.S. Energy Information Administration (EIA). We then converted Texas' facility-specific BART-eligible list to a unit-specific BART-eligible list and verified the BART-eligibility of each unit. The following is a list of units we propose have satisfied the above three steps and are BART-eligible:[41]

TABLE 1—SUMMARY OF BART-ELIGIBILITY ANALYSIS

Facility	Unit
Barney M. Davis (Talen/Topaz)	1.
Big Brown (Luminant)	1.
Big Brown (Luminant)	2.
Cedar Bayou (NRG)	CBY1.
Cedar Bayou (NRG)	CBY2.
Coleto Creek (Engie)	1.
Dansby (City of Bryan)	1.
Decker Creek (Austin Energy)	1.
Decker Creek (Austin Energy)	2.
Fayette (LCRA)	1.
Fayette (LCRA)	2.
Graham (Luminant)	2.
Greens Bayou (NRG)	5.
Handley (Exelon)	3.
Handley (Exelon)	4.
Handley (Exelon)	5.
Harrington Station (Xcel)	061B.
Harrington Station (Xcel)	062B.
J T Deely (CPS Energy)	1.
J T Deely (CPS Energy)	2.
Jones Station (Xcel)	151B.
Jones Station (Xcel)	152B.
Knox Lee Power Plant (AEP)	5.
Lake Hubbard (Luminant)	1.
Lake Hubbard (Luminant)	2.
Lewis Creek (Entergy)	1.
Lewis Creek (Entergy)	2.
Martin Lake (Luminant)	1.
Martin Lake (Luminant)	2.
Martin Lake (Luminant)	3.
Monticello (Luminant)	1.
Monticello (Luminant)	2.
Monticello (Luminant)	3.
Newman (El Paso Electric)	2.
Newman (El Paso Electric)	3.
Newman (El Paso Electric)	4.
Nichols Station (Xcel)	143B.
O W Sommers (CPS Energy)	1.
O W Sommers (CPS Energy)	2.
Plant X (Xcel)	4.
Powerlane (City of Greenville)	ST1.
Powerlane (City of Greenville)	ST2.
Powerlane (City of Greenville)	ST3.
R W Miller (Brazos Elec. Coop)	1.
R W Miller (Brazos Elec. Coop)	2.
R W Miller (Brazos Elec. Coop)	3.
Sabine (Entergy)	2.
Sabine (Entergy)	3.
Sabine (Entergy)	4.
Sabine (Entergy)	5.
Sim Gideon (LCRA)	1.
Sim Gideon (LCRA)	2.
Sim Gideon (LCRA)	3.
Spencer (City of Garland)	4.
Spencer (City of Garland)	5.
Stryker Creek (Luminant)	ST2.

TABLE 1—SUMMARY OF BART-ELIGIBILITY ANALYSIS—Continued

Facility	Unit
Trinidad (Luminant)	6.
Ty Cooke (City of Lubbock)	1.
Ty Cooke (City of Lubbock)	2.
V H Braunig (CPS Energy)	1.
V H Braunig (CPS Energy)	2.
V H Braunig (CPS Energy)	3.
W A Parish (NRG)	WAP4.
W A Parish (NRG)	WAP5.
W A Parish (NRG)	WAP6.
Welsh Power Plant (AEP)	1.
Welsh Power Plant (AEP)	2.
Wilkes Power Plant (AEP)	1.
Wilkes Power Plant (AEP)	2.
Wilkes Power Plant (AEP)	3.

The final step in identifying a "BART-eligible source" is to use the information from the previous three steps to identify the collection of emissions units that comprise the BART-eligible source.

B. Identification of Sources That Are Subject to BART

Following our compilation of the BART-eligible sources in Texas, we examined whether these sources cause or contribute to visibility impairment in nearby Class I areas.[42] 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. Those sources are determined to be not subject-to-BART. Sources that are reasonably anticipated to cause or contribute to any visibility impairment in a Class I area are determined to be subject-to-BART. For each source subject to BART, 40 CFR 51.308(e)(1)(ii)(A) requires that states (or EPA, in the case of a FIP) 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 that CALPUFF or another appropriate model can be used to predict the visibility impacts from a single source at a Class I area. We employed a four-fold strategy in determining which units should or should not be subject to BART. A flowchart of the analysis along with a detailed discussion of the subject-to-BART screening analysis is provided in

[38] Texas' Regional Haze SIP determined whether its sources should be subject to review for PM controls by only looking at the impact of PM emissions on visibility. This approach is only appropriate when a state satisfies the requirements for BART for SO_2 and NO_X with an alternative measure. Additionally, as reflected in our TSD on the identification of BART-Eligible Sources, the Texas SIP neglected to identify several BART-eligible sources; this also shows error in the state's PM BART demonstration and conclusions, and it constitutes grounds for the proposed partial SIP disapproval for PM BART.

[39] The requirements for "emissions trading programs or other alternative measures" that may be implemented rather than requiring BART are provided at 40 CFR 51.308(e)(2).

[40] 70 FR 39158 (July 6, 2005).

[41] See our BART FIP TSD for more information concerning how we selected the units we are proposing are BART-eligible and other details concerning our proposed BART determinations.

[42] See 40 CFR part 51, Appendix Y, III, How to Identify Sources "Subject to BART".

the BART Screening TSD.[43] We summarize the methodology and results of this analysis here.

First, we examined whether any of the BART-eligible units should be eliminated from consideration based on the standard model plant exemptions described in the BART Guidelines.[44] Second, we created specific model plants between sources and nearby Class I areas and conducted CALPUFF modeling to evaluate a number of sources for exemption. Third, we performed stand-alone, source specific CALPUFF modeling on a number of units to determine if their visibility impacts were large enough to identify them as being subject to BART. Fourth, for those remaining units outside of the CALPUFF model's range, we contracted to have CAMx modeling performed to determine if their visibility impacts were large enough to merit their being subject to BART. These steps are further described below.

For states using modeling to determine the applicability of BART to single sources, the BART Guidelines note that the first step is to set a contribution threshold to assess whether the impact of a single source is sufficient to cause or contribute to visibility impairment at a Class I area. The BART Guidelines preamble 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."[45] It further advises that "States should have discretion to set an appropriate threshold depending on the facts of the situation," but "[a]s a general matter, any threshold that you use for determining whether a source 'contributes' to visibility impairment should not be higher than 0.5 dv," and describes situations in which states may wish to exercise their discretion to set lower thresholds, mainly in situations in which a large number of BART-eligible sources within the State and in proximity to a Class I area justify this approach. We do not believe that the sources under consideration in this rule, most of which are not in close proximity to a Class I area, merit the consideration of a lesser contribution threshold. Therefore, our analysis employs a contribution threshold of 0.5 deciviews.

1. Our Use of the Standard BART Model Plant Exemption

As the BART Guidelines note:

> [W]e believe that a State that has established 0.5 deciviews as a contribution threshold could reasonably exempt from the BART review process sources that emit less than 500 tons per year of NO_X or SO_2 (or combined NO_X and SO_2), as long as these sources are located more than 50 kilometers from any Class I area; and sources that emit less than 1000 tons per year of NO_X or SO_2 (or combined NO_X and SO_2) that are located more than 100 kilometers from any Class I area. You do, however, have the option of showing other thresholds might also be appropriate given your specific circumstances.[46]

We applied the standard BART model plant exemption described above to the following facilities, exempting them from further analysis:

TABLE 2—STANDARD BART MODEL PLANT EXEMPT SOURCES

Facility	Units
Dansby (City of Bryan)	1.
Greens Bayou (NRG)	5.
Nichols Station (Xcel)	143B.
Plant X (Xcel)	4.
Powerlane (City of Greenville).	ST1, ST2 & ST3.
Spencer (City of Garland)	4 & 5.
Trinidad (Luminant)	6.
Ty Cooke (City of Lubbock)	1 & 2.

2. Our Extension of the BART Model Plant Exemption

As the BART Guidelines note, the standard BART model plant exemption can be extended to values other than the 500 tons/50 km and 1,000 tons/100 km scenarios discussed in the previous section. 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."[47]

Modeling analyses of representative plants are used to reflect groupings of specific sources with important common characteristics. We conducted CALPUFF modeling to establish emission levels and distances from Class I areas on which we could rely to exempt sources with those characteristics. In this approach, a hypothetical facility ("model plant") is located between a group of BART-eligible sources and a Class I area. Predominant wind patterns and elevation are considered in locating the model plant such that conditions that would be anticipated to transport pollution from the group of BART-eligible sources to the Class I area are consistent with conditions anticipated to transport pollution from the model plant to the Class I area. The visibility impacts from this model plant are modeled utilizing CALPUFF following the protocol described in the BART Screening TSD. Model plant emissions are adjusted such that the modeled visibility impact (maximum of 98th percentile values for 2001, 2002, and 2003) is below the screening threshold of 0.5 dv. For each model plant, the Q/d value is calculated as the annual emissions (combined NO_X and SO_2 emissions) divided by distance to the Class I area (km) resulting in a critical Q/d value. The Q/d value for each BART-eligible source is calculated based on annual emissions based on the maximum actual 24-hr emission rate and distance to the Class I area and is then compared to the critical Q/d value. For a BART-eligible source with a lower Q/d value than the critical Q/d, it is reasonably anticipated that the visibility impact from the BART-eligible source is lower than the model plant and therefore below the screening threshold and not subject to BART. See the BART Screening TSD for additional discussion and source-specific information used in this model plant screening analysis. By this extension of the BART model plant exemption, we identified the following additional facilities that can be exempted from further analysis:

TABLE 3—EXTENDED BART MODEL PLANT EXEMPT SOURCES

Facility	Units
Barney M. Davis (Talen/Topaz).	1.
Cedar Bayou (NRG)	CBY1 & CBY2.
Decker Creek (Austin Energy)	1 & 2.
Lewis Creek (Entergy)	1 & 2.
Sabine (Entergy)	2, 3, 4 & 5.
Sim Gideon (LCRA)	1, 2 & 3.
V H Braunig (CPS Energy)	1, 2 & 3.

3. Our Use of CALPUFF Modeling To Exempt Sources From Being Subject to BART

Those sources that did not screen out using the model plant approach were modeled directly with CALPUFF if they were in a range of when CALPUFF has

[43] See our TSD, "Our Strategy for Assessing which Units are Subject to BART for the Texas Regional Haze BART Federal Implementation Plan (BART Screening TSD)" in our docket.

[44] See the discussion beginning on 70 FR 39104, 39162 (July 6, 2005) [40 CFR part 51, App. Y].

[45] 70 FR at 39118.

[46] 70 FR at 39163 [40 CFR part 51, App. Y].

[47] 70 FR at 39163 [40 CFR part 51, App. Y].

been previously used. Historically CALPUFF has been used at distances up to approximately 400 km. The maximum 98th percentile impact from the modeled years (calculated based on annual average natural background conditions) was compared with the 0.5 dv screening threshold following the modeling protocol described in the BART screening TSD. The BART Guidelines 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 of start-up, shutdown, or malfunction. The maximum 24-hour emission rate (lb/hr) for NO_X and SO_2 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.[48] For some BART-eligible sources, evaluation of baseline emissions revealed evidence of the installation of NO_X control technology during the baseline period. For those sources, the maximum emission rate was updated to reflect the identified maximum emission rate from the post-control portion of the baseline period. Because daily emissions are not available for PM, the annual average emission rate was doubled to approximate the 24-hr maximum emission rate for PM. See the BART Screening TSD for additional discussion and source-specific information used in the CALPUFF modeling for this portion of the screening analysis. With the use of CALPUFF modeling results, we identified the following additional facilities that can be exempted from further analysis:

TABLE 4—CALPUFF BART EXEMPT SOURCES

Facility	Units
Handley (Exelon)	3, 4 & 5.
Jones (Xcel)	151B & 152B.
Lake Hubbard (Luminant)	1 & 2.
Knox Lee (AEP)	5.
R W Miller (Brazos Elec. Coop).	1, 2 & 3.

Based on these CALPUFF screening analyses using model plant approaches and direct modeling, the following gas[49]/fuel oil fired facilities did not screen out from being subject to BART: Newman, Stryker, Graham, and Wilkes. None of the coal fired facilities screened out in our CALPUFF modeling for the facilities within CALPUFF range.

4. Our Use of CAMx Modeling To Exempt Sources From Being Subject to BART

Some of the BART-eligible sources in Texas are geographically distant from a Class I area, yet have high enough emissions that they may significantly impact visibility at Class I areas in Texas and surrounding states. However, the use of CALPUFF is not recommended for distances much greater than 300 km, and has typically not been used at distances more than approximately 400 km. To determine which sources are anticipated to contribute to visibility impairment the BART guidelines state that CALPUFF or another appropriate model can be used to predict the visibility impacts from a single source at a Class I area. CAMx provides a scientifically defensible 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, NO_X, VOC and PM emissions as it has a more robust chemistry mechanism. The CAMx PM Source Apportionment Technology (PSAT) modeling was conducted for those BART-eligible sources that have large SO_2 emissions.[50] In 2006/2007, the TCEQ developed a modeling protocol and analysis using CAMx with the same Plume in Grid and PSAT techniques to evaluate visibility impacts from non-EGU BART sources, as well as to evaluate VOC and PM impacts from all BART-eligible sources to inform the 2009 Texas Regional Haze SIP.[51] [52] This modeling protocol was reviewed by the TCEQ, EPA and FLM representatives specialized in air quality analyses and BART prior to performing the analysis and submission of their regional haze SIP. Our subject-to-BART screening modeling for EGU-sources using CAMx is consistent with the protocol developed and utilized by Texas in their regional haze SIP. We are using more recent model versions with updated science in our analysis.

Consistent with the BART guidelines and our CALPUFF modeling, for the selected BART-eligible sources we used the maximum actual 24-hr emission rates for NO_X and SO_2 from the 2000–2004 baseline period from EPA's Air Markets Program Data[53] and modeled these emission rates as constant emission rates for the entire modeled year. For some of the modeled BART-eligible sources, evaluation of baseline emissions revealed evidence of installation of NO_X control technology during the baseline period. For those sources the maximum emission rate was identified from the post-control portion of the baseline period. Because daily emissions are not available for PM, the annual average emission rate was doubled to approximate the 24-hr maximum emission rate for PM. 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. The maximum modeled impact for each source (calculated based on annual average natural background conditions) was compared to the 0.5 dv contribution threshold. See the BART Screening TSD for additional details on the CAMx modeling performed and the model inputs used. The table below summarizes the results of the CAMx screening analysis. As shown in the table below, all sources analyzed with CAMx modeling had impacts greater than 0.5 dv at one or more Class I areas. The most impacted Class I areas based on these results are Wichita Mountains National Wildlife Refuge in Oklahoma (WIMO), Caney Creek Wilderness Area in Arkansas (CACR), and Salt Creek Wilderness Area in New Mexico (SACR). CAMx modeled impacts at single locations for these sources (maximum impact day) ranged from 0.845 dv to 10.498 dv.

[48] *http://ampd.epa.gov/ampd/.*

[49] When we use the term "gas," we mean "pipeline quality natural gas."

[50] CAMx results were also obtained and add to our basis of information for coal-fired facilities that have CALPUFF results.

[51] 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.

[52] We approved Texas' subject-to-BART analysis for non-EGU sources which relied on this CAMx modeling in our January 5, 2016 rulemaking (81 FR 296).

[53] *http://ampd.epa.gov/ampd/.*

TABLE 5—CAMx BART SCREENING SOURCE ANALYSIS RESULTS

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 [2]	Number of modeled days over 1.0 dv [2]
Big Brown	1 & 2	WIMO	4.017	No	65	33
Coleto Creek	1	WIMO	0.845	No	9	0
Fayette Power	1 & 2	CACR	1.894	No	26	9
Harrington	061B & 062B	SACR	5.288	No	13	5
Martin Lake	1, 2, & 3	CACR	6.651	No	141	99
Monticello	1, 2, & 3	CACR	10.498	No	152	111
Calaveras	J T Deely 1 & 2, OW Sommers 1 & 2.	WIMO	1.513	No	47	6
W A Parish	WAP4, WAP5 & WAP6	CACR	3.177	No	54	22
Welsh [1]	1 & 2	CACR	4.576	No	92	39

[1] Welsh unit 2 has recently shutdown. We note that baseline impacts from unit 1 alone are 2.343 dv at Caney Creek.
[2] Number of days over 0.5 or 1.0 dv at the most impacted Class I area.

5. Summary of Sources that are Subject to BART

Based on the four methodologies described above, the BART-eligible sources in the table below have been determined to cause or contribute to visibility impairment at a nearby Class I area, and we therefore propose to find the sources are subject-to-BART. They are subject to review for visibility impairing pollutants other than NO_X.[54] Foremost, they are subject to SO_2 BART, the visibility impairing pollutant that is the main contributor to the regional haze problem at Class I areas in Texas and neighboring states. The sources are also subject to review for source-specific BART requirements for PM.

TABLE 6—SUMMARY: SOURCES THAT ARE SUBJECT-TO-BART

Facility	Units
Big Brown	1 & 2.
Coleto Creek	1.
Fayette Power	1 & 2.
Harrington	061B & 062B.
Martin Lake	1, 2 & 3.
Monticello	1, 2 & 3.
Calaveras	J T Deely 1 & 2, O W Sommers 1 & 2.
W A Parish	WAP4, WAP5 & WAP6.
Welsh	1 & 2*.
Stryker	ST2.
Graham	2.
Wilkes	1, 2 & 3.
Newman	2, 3 & 4.

*Welsh Unit 2 retired in April, 2016.

C. Our BART Five Factor Analyses

The purpose of the BART analysis is to identify and evaluate the best system of continuous emission reduction based on the BART Guidelines.[55] In determining BART, a state, or EPA when promulgating a FIP, must consider the five statutory factors in section 169A of the CAA: (1) The costs of compliance; (2) the energy and nonair quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. See also 40 CFR 51.308(e)(1)(ii)(A). This is commonly referred to as the ''BART five factor analysis.'' The BART Guidelines break the analyses of these requirements down into five steps: [56]

STEP 1—Identify All Available Retrofit Control Technologies,

STEP 2—Eliminate Technically Infeasible Options,

STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies,

STEP 4—Evaluate Impacts and Document the Results, and

STEP 5—Evaluate Visibility Impacts.

The following sections treat these steps individually for SO_2. We are combining these steps into one section in our assessment of PM BART that follows the SO_2 sections.

1. Steps 1 and 2: Technically Feasible SO_2 Retrofit Controls

The BART Guidelines state that in identifying all available retrofit control options,

> [Y]ou must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving.[57]

Adhering to this, we will identify a reasonable set of SO_2 control options, including those that cover the maximum level of control each technology is capable of achieving. In the course of that task, we will note whether any of these technologies are technically infeasible.

The subject-to-BART units identified in Table 6 can be organized into four broad categories, based on their fuel type and the potential types of SO_2 controls that could be retrofitted: (1) Coal-fired EGUs with no SO_2 scrubber, (2) coal-fired EGUs with underperforming SO_2 scrubbers, (3) gas-fired EGUs that do not burn oil, and (4) gas-fired EGUs that occasionally burn fuel oil. This classification is represented below:

[54] The NO_X BART requirement for these EGU sources is not addressed by source-specific limits in this proposal. According to our proposal, participation in CSAPR, in its updated form, would serve as a BART alternative, dispensing with the need for source-specific BART determinations and requirements for NO_X.

[55] See July 6, 2005 BART Guidelines, 40 CFR part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations.

[56] 70 FR 39104, 39164 (July 6, 2005) [40 CFR part 51, App. Y].

[57] 70 FR at 39164, fn 12 [40 CFR part 51, App. Y]

TABLE 7—SUBJECT TO BART FUEL TYPES AND POTENTIAL SO_2 BART CONTROLS

Facility	Unit	Coal no scrubber	Coal underperforming scrubber	Gas no oil	Gas burns oil
Big Brown (Luminant)	1	X			
Big Brown (Luminant)	2	X			
Coleto Creek (Engie)	1	X			
Fayette (LCRA)*	1				
Fayette (LCRA)*	2				
Graham (Luminant)	2				X
Harrington Station (Xcel)	061B	X			
Harrington Station (Xcel)	062B	X			
J T Deely (CPS Energy)	1	X			
J T Deely (CPS Energy)	2	X			
Martin Lake (Luminant)	1		X		
Martin Lake (Luminant)	2		X		
Martin Lake (Luminant)	3		X		
Monticello (Luminant)	1	X			
Monticello (Luminant)	2	X			
Monticello (Luminant)	3		X		
Newman (El Paso Electric)	2				X
Newman (El Paso Electric)	3				X
Newman (El Paso Electric)	4			X	
O W Sommers (CPS Energy)	1				X
O W Sommers (CPS Energy)	2				X
Stryker Creek (Luminant)	ST2				X
W A Parish (NRG)	WAP4			X	
W A Parish (NRG)	WAP5	X			
W A Parish (NRG)	WAP6	X			
Welsh Power Plant (AEP)	1	X			
Wilkes Power Plant (AEP)	1				X
Wilkes Power Plant (AEP)	2			X	
Wilkes Power Plant (AEP)	3			X	

*The Fayette units have high performing wet Flue Gas Desulfurization scrubbers in place.

For the coal-fired EGUs without an existing scrubber, we have identified four potential control technologies: (1) Coal pretreatment, (2) Dry Sorbent Injection (DSI), (3) Spray Dryer Absorber (SDA), and (4) wet Flue Gas Desulfurization (FGD.) For the coal-fired EGUs with an existing underperforming scrubber we will examine whether that scrubber can be upgraded.

Gas-fired EGUs that do not burn oil have inherently very low SO_2 emissions and there are no known SO_2 controls that can be evaluated.

For gas-fired units that occasionally burn fuel oil, we will follow the BART Guidelines recommendations for oil-fired units: ''For oil-fired units, regardless of size, you should evaluate limiting the sulfur content of the fuel oil burned to 1 percent or less by weight.'' [58] In addition, we will also evaluate the potential for post combustion SO_2 controls for these units.

a. Identification of Technically Feasible SO_2 Retrofit Control Technologies for Coal-Fired Units

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.

Coal Pretreatment

Coal pretreatment, or coal 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. Coal pretreatment broadly falls into two categories: coal washing and coal drying.

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).[59] 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.[60] Coal is mechanically sized, then various washing techniques are employed, depending on the particle size, type of coal, and the desired level of preparation.[61] Following the coal washing, the coal is dewatered, and the waste streams are disposed.

Coal washing takes place offsite at large dedicated coal washing facilities, typically located near where the coal is mined. In addition, coal washing carries with it 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.

[58] 70 FR 39171 (July 6, 2005) [40 CFR 51, App. Y].

[59] Couch, G.R., ''Coal Upgrading to Reduce CO_2 emissions,'' CCC/67, October 2002, IEA Clean Coal Centre.

[60] Ibid.

[61] 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.

• 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,[62] and coal washing slurries are typically stored in impoundments, which can, and have, leaked.[63]

Because of these issues, we do not consider coal washing as a part of our reasonable set of options for analysis as BART SO_2 control technology.

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 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 unit burning less coal to make the same amount of power.

Coal drying can be performed onsite and so can be considered a potential BART control. Great River Energy has developed a patented process which is being successfully utilized at the Coal Creek facility and is potentially available for installation at other facilities.[64] 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.

Although we view this new patented technology for coal drying onsite as a promising path in the near future 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). We cannot assess many of these site-specific issues and we believe that requesting that the facilities in question do so would require detailed engineering analysis and extend our review time greatly. As a result of these issues, we do not further assess coal drying as part of our reasonable set of options for BART analysis. We expect that this technology may have matured enough such that it can be better assessed for the second planning period.

DSI

DSI is performed by injecting a dry reagent into the hot flue gas, which chemically reacts with SO_2 and other gases to form a solid product that is subsequently captured by the particulate control device. A blower delivers 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 are 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. For instance, Luminant states in its response to one of our Section 114(a) letters regarding its Big Brown and Monticello units:[65]

Luminant commissioned the study of dry sorbent injection (''DSI'') at these units in 2011. These studies determined that a very high feed rate (in the range of 20–30%) was required to achieve modest SO_2 removal. Further, it was determined that other economic and operational factors make the use of DSI infeasible. For example, sorbent build-up was determined to cause degraded performance of the control equipment over time, as well as significant, repeat down time on a regular basis (*i.e.,* every few days) to remove the buildup. In addition to the high cost of the sorbent required, the disposal and transport of the used sorbent (a Texas Class 1 waste) would result in significant additional cost. Thus, the use of DSI was determined infeasible from both an operational and economic point of view, and further evaluation has been discontinued.

As a consequence of this statement, which is discussed more fully in the CBI material Luminant has submitted and in our TSD, we have concluded that DSI is not a feasible alternative for the Big Brown and Monticello facilities. For all unscrubbed, coal-fired BART-subject units other than the Big Brown and Monticello facilities, although individual installations may present technical difficulties or poor performance due to the suboptimization of one or more of the above factors, we believe that DSI is technically feasible and should be considered as a potential BART control.

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 FGD, and Spray Dry Absorber (SDA). More recently, Circulating Dry Scrubbers (CDS) have been introduced. The EIA reports the following types of flue gas desulfurization systems as being operational in the U.S. for 2015:

TABLE 8—EIA REPORTED DESULFURIZATION SYSTEMS IN 2015

Type	Number of installations
Wet spray tower scrubber	296
Spray dryer absorber	269
Circulating dry scrubber	50
Packed tower wet scrubber	6
Venturi wet scrubber	48
Jet bubbling reactor	31
Tray tower wet scrubber	42
Mechanically aided wet scrubber.	4
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

[62] ''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.

[63] 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.

[64] 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/.*

[65] Luminant's 6/17/14 response to EPA's 5/20/14 Section 114(a) request for information relating to the Big Brown, Martin Lake, Monticello, and Sandow generating stations.

tray type wet scrubbers.[66] 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.

We consider some of the other scrubber system types (*e.g.,* venturi and packed wet scrubber types) to be older, outdated technologies (that are not existing controls or factor into considerations regarding existing controls) and therefore 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 or their suitability as a retrofit control option. Therefore, they too will not be further considered as part of our reasonable set of options for analysis for BART controls.

In summary, wet FGD and SDA installations account for approximately 81% of all scrubber installations in the U.S. and as such constitute a reasonable set of SO_2 scrubber control options. The vast majority of the wet FGD and SDA installations utilize limestone and lime, respectively as reagents. In addition, these technologies cover the maximum level of SO_2 control available. As described above, these controls are in wide use and have been retrofitted to a variety of boiler types and plant configurations. We therefore see no technical infeasibility issues and believe that limestone wet FGD and lime SDA should be considered as potential BART controls for all of the unscrubbed coal-fired BART-eligible units.

b. Identification of Technically Feasible SO_2 Retrofit Control Technologies for Gas-Fired Units that Burn Oil

Reduction in Fuel Oil Sulfur

A number of the units we proposed in Table 6 as being subject to BART primarily fire gas, but have occasionally fired fuel oil in the past as reported by the EIA databases: EIA–767, EIA–906/920, and EIA–923,[67] which indicate the historic quantities of fuel oil burned and the type and sulfur content of that fuel oil. These units are identified below in Table 9:

TABLE 9—GAS UNITS THAT OCCASIONALLY BURN OIL AND ARE SUBJECT TO BART

Facility	Unit(s)	Gas turbine	Steam turbine
Graham (Luminant)	2		X
Newman (El Paso Electric)	2, 3		X
O W Sommers (CPS Energy)	1, 2		X
Stryker Creek (Luminant)	ST2		X
Wilkes Power Plant (AEP)	1		X

The BART Guidelines advise that for oil-fired units, regardless of size, limits on fuel oil sulfur content should be considered in the BART evaluation.[68] All of the subject units are limited by permit to burning oil with a sulfur content of no more than 0.7% sulfur by weight.[69] In analyzing the technical feasibility under BART of these facilities burning fuel oils of sulfur contents lower than historically burned, we investigated two issues: (1) Is lower sulfur fuel oil available and what is its cost, and (2) are there any technical issues in burning a lower sulfur fuel oil that could add to the cost of that oil? All of the units have either burned Distillate Fuel Oil (DFO) or have switched between DFO and Residual Fuel Oil (RFO), thus demonstrating the ability to burn DFOs of the type under consideration for SO_2 BART. We therefore conclude that lower sulfur DFOs are a technically feasible retrofit control option under BART. Lower sulfur DFOs carry no capital costs. Any cost increases relate to purchase price differences.

SO_2 Scrubber Feasibility for Gas/Oil-Fired Boilers

We are aware of instances in which FGDs of various types have been installed or otherwise deemed feasible on a boiler that burns oil.[70] Consequently, we will consider the installation of various types of scrubbers to be technically feasible.

c. Identification of Technically Feasible SO_2 Control Technologies for Scrubber Upgrades

In our recent Texas-Oklahoma FIP,[71] we presented a great deal of information that concluded that the existing scrubbers for a number of facilities could be very cost-effectively upgraded.[72] That information is included in this proposal.[73] It contains a comprehensive survey of available literature concerning the kinds of upgrades that have been performed by industry on scrubber systems similar to the ones installed on the units included in this proposal. We then reviewed all of the information we had at our disposal regarding the status of the existing scrubbers for each unit, including any upgrades the facility may have already installed. We finished by calculating the cost-effectiveness of scrubber upgrades, using the facility's own information, obtained as a result of our Section 114 collection efforts. The companies that supplied this information have asserted a Confidential Business Information (CBI) claim for much of it, as provided in 40 CFR 2.203(b). We therefore redacted any CBI information we utilize in our analyses, or otherwise disguised it so that it cannot be traced back to its specific source. Of the facilities we evaluated for scrubber upgrades in that action, Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are subject to BART and are thus a part of this proposal.

[66] Trays are often employed in spray type wet scrubbers and EIA lists some of the wet spray tower systems as secondarily including trays.

[67] EIA-767: *http://www.eia.gov/electricity/data/eia767/.* EIA–906/920 and EIA–923: *http://www.eia.gov/electricity/data/eia923/.*

[68] 70 FR at 39171.

[69] In addition, the Newman units 2 and 3 are restricted to burning fuel oil for no more than 10% of their annual operating time.

[70] 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.''

[71] 81 FR 321.

[72] See information presented in Sections 6 and 7 of the Cost TSD.

[73] That information is included in our BART FIP TSD, Appendix B.

2. Step 3: Evaluation of SO_2 Control Effectiveness

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.'' [74] To calculate a 30-day rolling average based on BOD, 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. In effect, this provides a margin of safety by eliminating spikes that occur at the beginning and end of outages.

a. Evaluation of SO_2 Control Effectiveness for Coal Fired Units

Control Effectiveness of DSI

We lack the site-specific information, which we believe requires an individual performance test, in order to be able to accurately determine the maximum DSI SO_2 removal efficiency for the individual units listed in Table 7. We are aware that a number of the subject-to-BART coal-fired units have conducted such testing. However, although we have examined that testing, most of the facilities have claimed it as CBI and requested protection from public disclosure as provided by 40 CFR part 2.

However, we nevertheless must evaluate DSI as a viable, proven method of SO_2 control. We must do the same for SO_2 scrubbing, and in so doing, compare the visibility benefits and costs of each technology in order to inform our proposed BART determinations. We therefore propose the following methodology:

- We will evaluate each unit at its maximum recommended DSI performance level, according to the IPM DSI documentation,[75] assuming milled trona: 80% SO_2 removal for an ESP installation and 90% SO_2 removal for a baghouse installation. This level of control is within the range that can be achieved by SO_2 scrubbers, and thus allows a better comparison of the costs of DSI and scrubbers.
- However, (1) we do not know whether a given 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 all the units at a DSI SO_2 control level of 50%, which we believe is likely achievable for most units.
- We invite comments on whether particular units have performed DSI testing and have concluded they cannot achieve a SO_2 reduction between 50% and 80/90%. Any data to support such a conclusion should be submitted along with those comments.

Control Effectiveness of Wet FGD and SDA

We 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. As we discuss later in this proposal, we will conduct our wet FGD control cost analysis using the wet FGD cost algorithms, as employed in version 5.13 of our IPM model.[76] 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 established in our Oklahoma FIP,[77] this level of control is achievable with wet FGD. This level of control was also employed in our recent Texas-Oklahoma FIP.[78] We received a comment challenging this level of control and we responded to that comment in our final action on our Texas-Oklahoma FIP and incorporate that response in this proposed action.[79] We continue to conclude that our proposed level of control for wet FGD is reasonable.

As with our Oklahoma FIP, 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 lb/MMBtu, in which case, we assume the percentage of control equal to 0.06 lbs/MMBtu. See our response to comments in our previous Oklahoma FIP.[80] In that FIP, we finalized the same emission limit of 0.06 lbs/MMBtu on a 30 BOD average for 6 coal-fired EGUs. We justified those limits based on the same SDA technology, using a combination of industry publications and real world monitoring data. Much of that information is summarized in our response to a comment to that action [81] and in our TSD. We continue to conclude that our proposed level of control for SDA is reasonable.

b. Evaluation of SO_2 Control Effectiveness for Gas Fired Units

The control effectiveness of switching from a higher sulfur fuel oil to a lower sulfur fuel oil lies in the reduction in sulfur emissions. The emissions reduction depends on the percentage reduction from the sulfur contents of the fuel oil that forms the SO_2 baseline to the replacement fuel oil. Ultimately, the highest level of control would result from a switch from the highest percentage sulfur the units are permitted to burn, 0.7% to the lowest DFO available, ultra-low sulfur diesel, which has a sulfur content of 0.0015%. This would equate to a control effectiveness of 99.8%. Lesser levels of controls are also possible. We will evaluate a range of control effectiveness in switching to lower sulfur fuel oils in the next section.

[74] 70 FR 39103, 39172 (July 6, 2005), [40 CFR part 51, App. Y].

[75] 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, p. 7.

[76] 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.*

[77] As discussed previously in our TSD for that action, control efficiencies reasonably achievable by dry scrubbing and wet scrubbing were determined to be 95% and 98% respectively. 76 FR 81742); *Oklahoma* v. *EPA*, 723 F.3d 1201 (July 19, 2013), cert. denied (U.S. May 27, 2014).

[78] 81 FR 321.

[79] That information is included in our BART FIP TSD, Appendix A.

[80] 76 FR 81728.

[81] 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 comment and response beginning on page 91.

Because we are unaware of any scrubber installations on oil fired units in the U.S., we have no information on their control effectiveness. However, we see no technical reason why the control effectiveness of FGDs installed on gas-fired units that occasionally burn fuel oil should not be equal to that of FGDs installed on coal-fired units.

3. Step 4: Evaluate Impacts and Document the Results for SO_2

The BART Guidelines offers the following with regard to how Step 4 should be conducted: [82]

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.

We evaluate the cost of compliance on a unit-by unit basis, because control cost analysis depends on specific factors that can vary from unit to unit. However, we generally evaluate the energy impacts, non-air quality impacts, and the remaining useful life for all the units in question together because in this instance there are no appreciable differences in these factors from unit to unit.[83]

In developing our cost estimates for the units in Table 7, we rely on the methods and principles contained within the EPA Air Pollution Control Cost Manual (the Control Cost Manual, or Manual).[84] 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 each of the units listed in Table 7. For the coal units without any SO_2 control, we calculate the cost of installing DSI, a SDA scrubber, and a wet FGD scrubber. For the gas units that burn oil, we evaluate the cost of switching to lower sulfur fuel oils and installing scrubbers.

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 then performed DSI, SDA and wet FGD cost calculations for each unit listed in Table 7 that did not already have SO_2 control.[85] These cost models were based on costs escalated to 2012 dollars.[86] 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).

a. Impact Analysis Part 1: Cost of Compliance for DSI, SDA, and Wet FGD

As we discuss above and in our Cost TSD, we evaluated each unit at its maximum recommended level of control, considering the type of SO_2 control device. Below, we present a summary of our DSI, SDA, and wet FGD cost analysis: [87]

TABLE 10—SUMMARY OF DSI, SDA, AND WET FGD COST ANALYSIS

Facility	Unit	Control	Control level (%)	SO_2 reduction (tpy)	2016 Annualized cost	2016 Cost effectiveness ($/ton)	2016 Incremental cost-effectiveness ($/ton)
Big Brown	1	DSI	50	14,448	$29,468,587	$2,040	
		DSI	90	26,006	72,131,749	2,774	$3,691
		SDA	95	27,453	35,297,532	1,286	¥25,456
		Wet FGD	98	28,320	33,673,102	1,189	¥1,874
	2	DSI	50	15,320	29,342,350	1,915	
		DSI	90	27,576	71,322,593	2,586	3,425
		SDA	95	29,108	35,359,239	1,215	¥23,475
		Wet FGD	97.9	29,998	33,817,952	1,127	¥1,732
Monticello	1	DSI	50	4,787	11,408,872	2,383	
		DSI	90	8,617	25,409,128	2,949	3,655
		SDA	95	9,095	24,294,319	2,671	¥2,332
		Wet FGD	97	9,286	25,236,699	2,718	4,934
	2	DSI	50	4,129	9,742,648	2,360	
		DSI	90	7,431	21,418,734	2,882	3,536
		SDA	95	7,844	23,126,113	2,948	4,134
		Wet FGD	96.8	7,995	24,233,133	3,031	7,331
Coleto Creek	1	DSI	50	7,376	16,246,169	2,203	
		DSI	90	13,277	34,841,379	2,624	3,151
		SDA	92.4	13,632	29,445,018	2,160	¥15,201
		Wet FGD	94.9	14,005	29,786,106	2,127	914
Harrington	061B	DSI	50	2,477	9,187,608	3,710	
		DSI	80	3,962	16,073,779	4,057	4,637
		SDA	90.2	4,466	17,455,679	3,909	2,742
	062B	DSI	50	2,455	6,524,937	2,658	
		DSI	*88.9	4,364	11,981,111	2,746	2,858
		SDA	88.9	4,364	18,240,127	4,180	N/A
J T Deely	1	DSI	50	3,072	8,854,319	2,883	

[82] 70 FR 39166.

[83] To the extent these factors inform the cost of controls, consistent with the BART Guidelines, they do inform our considerations on a unit-by-unit basis.

[84] 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.*

[85] These spreadsheets are entitled, ''DSI Cost IPM 5–13 TX BART.xlsx,'' ''SDA Cost IPM 5–13 TX BART.xlsx,'' and ''Wet FGD Cost IPM 5–13 TX BART.xlsx,'' and are located in our Docket.

[86] Ibid., p.1: ''The data was converted to 2012 dollars based on the Chemical Engineering Plant Index (CEPI) data.''

[87] In this table, the capital cost is the total cost of constructing the facility. The annualized cost is the sum of the annualized capital cost and the annualized operational cost. See our Cost TSD for more information on how these costs were calculated.

TABLE 10—SUMMARY OF DSI, SDA, AND WET FGD COST ANALYSIS—Continued

Facility	Unit	Control	Control level (%)	SO_2 reduction (tpy)	2016 Annualized cost	2016 Cost effectiveness ($/ton)	2016 Incremental cost-effectiveness ($/ton)
		DSI	90	5,529	18,071,878	3,269	3,752
		SDA	91.3	5,609	21,689,526	3,867	45,221
		Wet FGD	94.2	5,787	22,555,395	3,898	4,864
	2	DSI	50	3,222	9,865,798	3,062	
		DSI	90	5,800	20,229,233	3,488	4,020
		SDA	91.3	5,884	21,812,518	3,707	18,849
		Wet FGD	94.2	6,070	22,530,901	3,712	3,862
Welsh	1	DSI	50	3,343	8,963,761	3,469	
		DSI	*87.2	5,832	23,090,408	3,960	5,676
		SDA	87.2	5,832	22,697,048	3,892	N/A
		Wet FGD	91.5	6,116	23,998,161	3,924	4,581
W.A. Parish	5	DSI	50	6,712	15,002,337	2,235	
		DSI	90	12,081	30,865,711	2,555	2,955
		SDA	92.1	12,364	31,195,787	2,523	1,166
		Wet FGD	94.7	12,717	30,735,030	2,417	¥1,305
	6	DSI	50	7,525	16,014,988	2,128	
		DSI	90	13,545	33,302,528	2,459	2,872
		SDA	92.1	13,862	32,758,784	2,363	¥1,715
		Wet FGD	94.7	14,258	32,215,226	2,259	¥1,373

*DSI control level limited to that of SDA.

b. Impact Analysis Part 1: Cost of Compliance for Scrubber Upgrades

In our BART FIP TSD, we analyze those units listed in Table 7 with an existing SO_2 scrubber in order to determine if cost-effective scrubber upgrades are available. Of our subject-to-BART units, Martin Lake Units 1, 2, 3; Monticello Unit 3, and Fayette Units 1 and 2 are currently equipped with wet FGDs. Of these, all but the Fayette units were analyzed for scrubber upgrades in our Texas-Oklahoma FIP. For all but the Fayette units, we propose to adopt the total annualized cost calculations used to make the cost-effectiveness calculations in our Texas-Oklahoma FIP in this action. We acknowledge that these costs could change slightly, due to changes in the costs of various materials and services. However, these costs were calculated in 2013 dollars. Escalating them to 2015 dollars would result in a reduction in cost, which we conservatively do not take into consideration.[88]

In our Texas-Oklahoma FIP action, after responding to comments we revised our proposed cost-effectiveness basis from where all scrubber upgrades were less than $600/ton, to where all scrubber upgrades ranged from between $368/ton to $910/ton.[89] As with our Texas-Oklahoma FIP, we are limited in what information we can include in this section, because we used information that was claimed as CBI. This information was submitted in response to our Section 114(a) requests. The following summary is based on information not claimed as CBI.

- The absorber system had either already been upgraded to perform at an SO_2 removal efficiency of at least 95%, or it could be upgraded to perform at that level using proven equipment and techniques.
- The SO_2 scrubber bypass could be eliminated, and the additional flue gas could be treated by the absorber system with at least a 95% removal efficiency.
- Additional modifications necessary to eliminate the bypass, such as adding fan capacity, upgrading the electrical distribution system, and conversion to a wet stack could be performed using proven equipment and techniques.
- The additional SO_2 emission reductions resulting from the scrubber upgrade are substantial, ranging from 68% to 89% reduction from the current emission levels, and are cost-effective.

We now update these calculations for 2011–2015 data.[90] The revised scrubber upgrade results for Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are presented below in Table 11:

TABLE 11—SUMMARY OF UPDATED SCRUBBER UPGRADE RESULTS

Unit	2011–2015 3-yr avg. SO_2 emissions (eliminate max and min) (tons)	SO_2 emissions at 95% control (tons)	SO_2 emissions reduction due to scrubber upgrade (tons)	SO_2 emission rate at 95% control (lbs/MMBtu)
Monticello 3	8,136	1,180	6,956	0.05
Martin Lake 1	19,040	3,208	15,832	0.12
Martin Lake 2	17,973	3,393	14,580	0.12
Martin Lake 3	16,113	2,591	13,522	0.11
Total SO_2 Removed			50,890	

[88] The CEPCI for 2013 is 567.3 and that for 2015 is 556.3. Therefore, the costs would be multiplied by a factor of 556.8/567.3, which is approximately 0.98.

[89] 81 FR 318.

[90] See Coal vs CEM data 2011–2015.xlsx.

As we note above, we updated the cost-effectiveness for each of these units. Because those calculations depended on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost-effectiveness was $1,156/ton or less. We invite the facilities listed above to make arrangements with us to view our complete updated cost analysis for their units.

The Fayette Units 1 and 2 are currently equipped with high performing wet FGDs. Both units have demonstrated the ability to maintain a SO_2 30 BOD average below 0.04 lbs/MMBtu for years at a time.[91] As we discuss above, we evaluate BART demonstrating that retrofit wet FGDs should be evaluated at 98% control not to go below 0.04 lbs/MMBtu. Because the Fayette units are performing below this level, we propose that no scrubber upgrades are necessary. We propose to find that the Fayette Units 1 and 2 maintain a 30 Boiler Operating Day rolling average SO_2 emission rate of 0.04 lbs/MMBtu based on the actual emissions data we present above. We believe that based on its demonstrated ability to maintain an emission rate below this value on a 30 BOD basis, it can consistently achieve this emission level.

c. Impact Analysis Part 1: Cost of Compliance for Gas Units That Burn Oil

As we noted in Section III.C.1.b, a number of the units we proposed in Table 9 as being subject to BART primarily fire gas, but have occasionally fired fuel oil in the past as reported by the EIA. These units are limited by their permits to burning oil with a sulfur content of no more than 0.7% sulfur by weight. We proposed to consider both a reduction in fuel oil sulfur and SO_2 scrubbers as potential BART controls. Below we consider the cost of these potential controls.

Reduction in Fuel Oil Sulfur

In order to determine the cost of these facilities switching to lower sulfur content fuel oils, we sent the Graham, Newman, Stryker Creek, and the Wilkes facilities Section 114 letters requesting certain information.[92] We received very limited information in response to one of our questions concerning the present cost of the historic fuel oil burned, and the cost of various lower sulfur replacement fuel oils. Because of this, we were unable to compile facility-specific information on the cost of switching to lower sulfur fuel oils. Consequently, we considered the best available information by consulting more general information from the EIA, which reports the prices for various refinery petroleum products on a monthly and annual basis. Below is a summary of various distillate and residual fuel oil products for 2001 to 2015, averaged across the U.S.[93]

TABLE 12—SELECTED EIA REPORTED ANNUAL REFINER PETROLEUM PRICES

Date	West Texas intermediate crude oil—Cushing Oklahoma ($/bbl)	U.S. no. 2 diesel wholesale/resale price by refiners ($/gallon)	U.S. no. 2 fuel oil wholesale/resale price by refiners ($/gallon)	U.S. no. 4 distillate wholesale/resale price by refiners ($/gallon)
2015	48.66	1.667	1.565	1.215
2014	93.17	2.812	2.741	2.333
2013	97.98	3.028	2.966	2.767
2012	94.05	3.109	3.031	
2011	94.88	3.034	2.907	2.801
2010	79.48	2.214	2.147	
2009	61.95	1.713	1.657	1.561
2008	99.67	2.994	2.745	2.157
2007	72.34	2.203	2.072	1.551
2006	66.05	2.012	1.834	1.395
2005	56.64	1.737	1.623	1.377
2004	41.51	1.187	1.125	1.033
2003	31.08	0.883	0.881	0.793
2002	26.18	0.724	0.694	0.663
2001	25.98	0.784	0.756	0.697
2000	30.38	0.898	0.886	0.778

Lacking facility-specific pricing information, for the purposes of calculating the cost of compliance, we make the following assumptions:

• No. 4 distillate is the type of fuel oil currently available that most closely approximates the types of fuel oil that were historically burned by the facilities. It is available in a range of sulfur up to the facilities' permitted maximum of 0.7% sulfur by weight or 7,000 ppm. We will use the cost of this fuel oil in constructing ''business as usual'' scenarios of the annual cost of fuel oil.

• No. 2 fuel oil is available at approximately 3,000 ppm, which roughly corresponds to the sulfur level present in No. 2 fuel oil prior to our implementation of the Ultra-Low-Sulfur Diesel (ULSD) regulations.[94] We will use the cost of this fuel oil in constructing a ''medium control'' annual cost of fuel oil.

• No. 2 diesel fuel corresponds to ULSD, with a sulfur content of 15 ppm. We will use the cost of this fuel oil in constructing a ''high control'' annual cost of fuel oil.

Having identified a reasonable set of historical and lower sulfur fuel oils, we turned to the matter of establishing SO_2 baselines. We would expect that regardless of the baseline selected, a cost-effectiveness calculation that simply depended on differing fuel oil costs and the resulting reductions in SO_2, would result in the same value. In other words, the cost-effectiveness in $/ton is independent of the SO_2 baseline, since *in this case,* it is calculated on a unit basis—the increased cost in burning a unit of fuel divided by the increased reduction in the resulting

[91] See our BART FIP TSD for graphs of this data.

[92] Copies of these letters and the facilities' responses are in our docket. We inadvertently did not send the O W Sommers a letter.

[93] EIA Refiner Petroleum Product Prices by Sales Type, available here: *http://www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_a.htm; http://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm.*

[94] 69 FR 39073: ''Both high sulfur No. 2–D and No. 2 fuel oil must contain no more than 5000 ppm sulfur,131 and currently [as of the date of our final rule, 6/29/04] averages 3000 ppm nationwide.''

SO_2. While the above is true, reported data for these units does not match this expectation. This can be illustrated by examining selected EIA and emissions data for the Graham Unit 2:

TABLE 13—GRAHAM UNIT 2 EXAMPLE DISCORDANCE IN FUEL OIL BURNED AND REPORTED SO_2

Date (month/year)	Quantity fuel oil burned (bbls)	Reported SO_2 for month (tons)	Reported EIA sulfur content (wt %)
Mar-02	9,800	21.614	0.65
Feb-03	8,400	90.389	0.66
Jun-12	18,177	0.064	0.50
Jul-12	5,657	0.07	0.50

As can be seen from the above table, even though the reported sulfur content of the fuel oil in March 2002 and February 2003 was approximately the same, and the quantity burned was fairly close, the reported SO_2 emissions were significantly different. Similarly, although the amount of fuel oil burned in June 2012 was more than three times that burned in July 2012 (at the same sulfur content), the reported SO_2 emissions in June 2012 were less than that in July 2012. Also, although the fuel oil sulfur content in the 2012 examples was only slightly less than that in the 2002/2003 examples, and the amount of fuel oil burned was the same order of magnitude, the resulting reported SO_2 emissions in 2012 were three orders of magnitude less than that in 2002/2003. We conclude that either the values for the EIA fuel quantities, the EIA fuel oil sulfur contents, and/or the reported SO_2 emissions are in error. Further examination of the CAMD emissions data for Graham and Stryker revealed that the data contained a large amount of substitute data for SO_2 emissions and heat input during periods when the units burned fuel oil.

As a consequence of this discordance between the type and amount of fuel oil burned and the reported SO_2 emissions, we cannot rely on historical SO_2 emissions to construct a baseline, because a barrel of fuel oil with a given sulfur content does not result in a consistent reported SO_2 value over time. Instead, we will conduct our cost-effectiveness analysis on the basis of unit values of 1,000 barrels, using the following assumptions:

- Fuel oil costs will be based on the 2015 U.S. average prices as reported in Table 12 for No. 4 distillate at 0.7 wt. % (the permitted maximum for all units) as the current business as usual fuel, No. 2 fuel oil at 0.3 wt. % as the moderate control option, and No. 2 diesel at 0.0015% as the high control option.
- The emission factor for calculating the tons of sulfur emitted by the three fuel oils are taken from AP 42, *Compilation of Air Pollutant Emissions Factors.*[95]

Below is the result of that calculation:

TABLE 14—COST EFFECTIVENESS OF SWITCHING TO LOWER SULFUR FUEL OILS

Level of control	Cost for 1,000 barrels baseline ($/yr)	Tons reduced for 1,000 barrels	Cost effectiveness for 1,000 barrels ($/ton)	Incremental cost-effectiveness ($/ton)
Business as usual (No. 4 distillate $1.215/gal)	$51,030	N/A	N/A	
Moderate control (No. 2 fuel oil $1.565/gal)	65,730	1.26	11,218	
High control (ULSD $1.667/gal)	70,014	2.20	8,627	¥ 2,756

We suspect our price information for ULSD may be high, as the Wilkes facility indicated in its reply to our Section 114 request that its 8/12/16 contract for oil was for ULSD, which had an index price of $1.423/gallon. Assuming this price and retaining the same price for our business as usual No. 4 distillate fuel oil of $1.215/gallon, results in a cost-effectiveness of $3,970/ton—a significant improvement in cost-effectiveness. We invite the affected facilities to provide site-specific information for delivery of ULSD.

Scrubber Retrofits

Elsewhere in our proposal, we conclude that certain types of wet scrubbers were technically feasible as potential control options for gas boilers that occasionally burn oil, similar to the ones under BART review here. Were we to calculate the cost-effectiveness of a wet FGD, similar to those under consideration for the coal units undergoing BART review, we could expect that the capital and operating costs would be on the same order, as displayed in Table 10. It is a straightforward exercise to demonstrate that the installation of such a scrubber on any of the gas-fired units that occasionally burn oil would result in a very high cost-effectiveness value.

For instance, taking the smallest total annualized wet FGD cost in Table 10, corresponding to the Harrington Unit 0161B (approximately the same size as the Graham Unit 2), results in a value of $19,145,500. Assuming a 98% reduction from a baseline equal to the largest annual SO_2 emissions from any of the gas units, 1,287 tons/year (Graham Unit 2, 2001), results in a SO_2 reduction of 1,261 tons/year. The cost-effectiveness is then $15,183/ton, which is very high for a SO_2 scrubber. In addition, the annual SO_2 values for Graham Unit 2 from 2002 to 2015, and the annual SO_2 values for the remaining units, have always been an order of magnitude less than the 2001 Graham Unit 2 value. Although we have not modeled the visibility benefit of

[95] The emission factor (lb/10^3 gal) used is 150 × S, where S = weight % sulfur, taken from AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.3, Fuel Oil Combustion, available here: *https://www3.epa.gov/ttn/chief/ap42/ch01/index.html*. Boilers >100 Million Btu/hr, No. 4 oil fired.

installing SO_2 scrubbers on these units, the visibility benefit from scrubbers is estimated to be slightly less than the amount of benefit estimated from switching to ULSD.[96]

4. Impact Analysis Parts 2, 3, and 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.'' [97] 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 all cases. 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: [98]

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 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.

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 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. Consequently, we believe that with one possible exception, any non-air quality environmental impacts have been adequately considered in our analyses. We are aware that the Harrington facility has instituted a water recycling program and obtains some of its water from the City of Amarillo.[99] Due to potential non-air quality concerns, we limit our SO_2 control analysis for Harrington to DSI and dry scrubbers.

Regarding the remaining useful life, the BART Guidelines advise: [100]

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 any of the facilities we have analyzed for BART have entered into an enforceable document to shut down the applicable units earlier than what would occur under our assumed 30-year operational life.[101] As we stated in our Oklahoma FIP,[102] we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be well over 60 years. We identified specific scrubbers installed between 1975 and 1985 that were still in operation. 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. Because none of the facilities involved have entered into enforceable documents to shut down the applicable units earlier, we will continue to use a 30-year equipment life for DSI, scrubber retrofits, and scrubber upgrades, as we believe that is proper.

5. Step 5: Evaluate Visibility Impacts

Please see the BART Modeling TSD, where we describe in detail the various modeling runs we conducted, our methodology and selection of emission rates, modeling results, and final modeling analysis that we used to evaluate the benefits of the proposed controls and their associated emission decreases on visibility impairment values. 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.

a. Visibility Benefits of DSI, SDA, and Wet FGD for Coal-Fired Units

We evaluated the visibility benefits of DSI, for the twelve units depicted in Tables 15 and 16 below that currently have no SO_2 control. We evaluated all the units using the control levels we employed in our control cost analyses. In summary, we evaluated these units at a DSI SO_2 control level of 50%, which we believe is likely achievable for any unit. At the lower performance level we assumed, we conclude that the corresponding visibility benefits from DSI in most cases would be close to half of the benefits from scrubbers resulting in the visibility benefits from scrubber retrofits being much more beneficial. We also evaluated the visibility benefits for scrubber retrofits (wet FGD and SDA) for these same units, assuming the same control levels corresponding to SDA and wet FGD that we used in our control cost analyses. For those sources that are within 300 to 400 km of a Class

[96] For example, switching from 0.7% sulfur fuel oil to ULSD at 0.0015% sulfur results in a reduction in sulfur emissions of 99.8% compared to an estimated 98% reduction due to the use of a scrubber.

[97] 70 FR 39103, 39168 (July 6, 2005), [40 CFR part 51, App. Y.].

[98] 70 FR at 39169 (July 6, 2005), [40 CFR part 51, App. Y.].

[99] *http://www.powermag.com/xcel-energys-harrington-generating-station-earns-powder-river-basin-coal-users-group-award/.*

[100] 70 FR 39103, 39169, [40 CFR part 51, App. Y.].

[101] We received a November 21, 2016 letter from the source owner regarding Parish Units 5 & 6. The letter, now added to the docket, explains the units have natural gas firing capabilities and expresses interest in obtaining flexibility to avoid BART or obtaining multiple options for complying with BART. While we acknowledge this interest, the letter does not provide or commit to any specifics in furtherance of the BART analysis that EPA is now required to conduct under the BART Guidelines.

[102] 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.

I area, we utilized CALPUFF and CAMx modeling to assess the visibility benefit of potential controls. For the remaining coal-fired sources (J T Deely, Coleto Creek, Fayette and W A Parish), only CAMx modeling was utilized as these sources are located at much greater distances to the nearest Class I areas. 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.[103] We note that the high control scenario modeling for Fayette units 1 and 2 demonstrate the benefit from existing high performing controls. As discussed elsewhere, we found that for these units no additional controls or upgrades were necessary. For a full discussion of our review of all the modeling results, and factors that we considered in evaluating and weighing all the results, see our BART Modeling TSD. Below, we present a summary of some of those visibility benefits at the Class I areas most impacted by each source:

TABLE 15—VISIBILITY BENEFIT OF RETROFIT CONTROLS: COAL-FIRED UNITS (CAMX MODELING)

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Unit 1 and 2)	WIMO	Max dv	4.017	2.249	0.474	1.768	3.542
			Days >0.5 dv	65	33	0	32	65
			Days >1.0 dv	33	13	0	20	33
		CACR	Max dv	3.775	2.539	0.787	1.236	2.988
			Days >0.5 dv	91	62	4	29	87
			Days >1.0 dv	57	21	0	36	57
	Unit 1	WIMO	Max dv	2.154	1.168	0.245	0.986	1.909
			Days >0.5 dv	33	13	0	20	33
			Days >1.0 dv	12	1	0	11	12
		CACR	Max dv	2.016	1.327	0.409	0.688	1.606
			Days >0.5 dv	58	22	0	36	58
			Days >1.0 dv	17	4	0	13	17
	Unit 2	WIMO	Max dv	2.175	1.181	0.235	0.994	1.940
			Days >0.5 dv	34	13	0	21	34
			Days >1.0 dv	12	1	0	11	12
		CACR	Max dv	2.033	1.338	0.391	0.695	1.642
			Days >0.5 dv	58	23	0	35	58
			Days >1.0 dv	17	4	0	13	17
Monticello	Source (Unit 1, 2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days >0.5 dv	152	107	28	45	124
			Days >1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days >0.5 dv	67	35	4	32	63
			Days >1.0 dv	40	14	0	26	40
	Unit 1	CACR	Max dv	4.516	3.123	0.733	1.393	3.783
			Days >0.5 dv	79	43	3	36	76
			Days >1.0 dv	32	16	0	16	32
		WIMO	Max dv	2.241	1.290	0.252	0.951	1.989
			Days >0.5 dv	30	10	0	20	30
			Days >1.0 dv	8	2	0	6	8
	Unit 2	CACR	Max dv	4.487	3.065	0.563	1.422	3.924
			Days >0.5 dv	78	42	1	36	77
			Days >1.0 dv	30	13	0	17	30
		WIMO	Max dv	2.189	1.252	0.186	0.937	2.003
			Days >0.5 dv	30	10	0	20	30
			Days >1.0 dv	6	2	0	4	6
Coleto Creek	Source (Unit 1)	WIMO	Max dv	0.845	0.526	0.176	0.318	0.668
			Days >0.5 dv	9	1	0	8	9
			Days >1.0 dv	0	0	0	0	0
		CACR	Max dv	0.791	0.458	0.186	0.333	0.606
			Days >0.5 dv	5	0	0	5	5
			Days >1.0 dv	0	0	0	0	0
Harrington[1]	Source (Unit 061B & 062B)	SACR	Max dv	5.288	4.287	3.235	1.001	2.053
			Days >0.5 dv	13	7	3	6	10
			Days >1.0 dv	5	1	1	4	4
		WIMO	Max dv	4.928	4.362	3.798	0.565	1.130
			Days >0.5 dv	15	11	6	4	9
			Days >1.0 dv	6	5	4	1	2
	Unit 061B	SACR	Max dv	2.908	2.322	1.738	0.586	1.170
			Days >0.5 dv	5	1	1	4	4
			Days >1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.708	2.382	2.065	0.326	0.643
			Days >0.5 dv	6	5	4	1	2
			Days >1.0 dv	4	2	1	2	3
	Unit 062B	SACR	Max dv	2.998	2.373	1.719	0.625	1.279
			Days >0.5 dv	5	1	1	4	4
			Days >1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.770	2.407	2.046	0.363	0.723
			Days >0.5 dv	6	5	4	1	2
			Days >1.0 dv	4	1	1	3	3

[103] 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.''

TABLE 15—VISIBILITY BENEFIT OF RETROFIT CONTROLS: COAL-FIRED UNITS (CAMx MODELING)—Continued

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
J T Deely	Source (Sommers 1&2, J T Deely 1&2).	WIMO	Max dv	1.513	0.939	0.814	0.574	0.699
			Days >0.5 dv	47	8	1	39	46
			Days >1.0 dv	6	0	0	6	6
		CACR	Max dv	1.423	1.155	0.905	0.268	0.518
			Days >0.5 dv	7	3	2	4	5
			Days >1.0 dv	2	1	0	1	2
	J T Deely 1	WIMO	Max dv	0.757	0.449	0.270	0.307	0.487
			Days >0.5 dv	4	0	0	4	4
			Days >1.0 dv	0	0	0	0	0
		BIBE	Max dv	0.652	0.373	0.069	0.279	0.583
			Days >0.5 dv	2	0	0	2	2
			Days >1.0 dv	0	0	0	0	0
	J T Deely 2	WIMO	Max dv	0.632	0.387	0.334	0.245	0.298
			Days >0.5 dv	3	0	0	3	3
			Days >1.0 dv	0	0	0	0	0
		CACR	Max dv	0.604	0.490	0.387	0.114	0.217
			Days >0.5 dv	2	0	0	2	2
			Days >1.0 dv	0	0	0	0	0
W.A. Parish	Source (WAP 4, 5, & 6)	CACR	Max dv	3.177	2.032	0.511	1.145	2.665
			Days >0.5 dv	54	26	1	28	53
			Days >1.0 dv	22	9	0	13	22
		UPBU	Max dv	1.994	1.215	0.234	0.779	1.760
			Days >0.5 dv	34	14	0	20	34
			Days >1.0 dv	9	1	0	8	9
	WAP 5	CACR	Max dv	1.698	1.052	0.180	0.646	1.518
			Days >0.5 dv	22	9	0	13	22
			Days >1.0 dv	8	1	0	7	8
		UPBU	Max dv	1.038	0.613	0.094	0.424	0.943
			Days >0.5 dv	11	1	0	10	11
			Days >1.0 dv	1	0	0	1	1
	WAP 6	CACR	Max dv	1.648	1.018	0.156	0.630	1.492
			Days >0.5 dv	22	8	0	14	22
			Days >1.0 dv	6	1	0	5	6
		UPBU	Max dv	1.003	0.591	0.081	0.412	0.922
			Days >0.5 dv	9	1	0	8	9
			Days >1.0 dv	1	0	0	1	1
Welsh [2]	Source (Unit 1 & 2)	CACR	Max dv	4.576	.....	0.822	.....	3.754
			Days >0.5 dv	92	.....	3	.....	89
			Days >1.0 dv	39	.....	0	.....	39
		MING	Max dv	2.544	.....	0.570	.....	1.973
			Days >0.5 dv	9	.....	1	.....	8
			Days >1.0 dv	3	.....	0	.....	3
	Unit 1	CACR	Max dv	2.343	1.659	0.822	0.684	1.521
			Days >0.5 dv	37	18	3	19	34
			Days >1.0 dv	8	3	0	5	8
		MING	Max dv	1.150	0.886	0.570	0.264	0.579
			Days >0.5 dv	2	1	1	1	1
			Days >1.0 dv	1	0	0	1	1
Fayette [2]	Source (Unit 1 & 2)	CACR	Max dv	1.894	.....	0.903	.....	0.991
			Days >0.5 dv	26	.....	2	.....	24
			Days >1.0 dv	9	.....	0	.....	9
		WIMO	Max dv	1.175	.....	0.580	.....	0.595
			Days >0.5 dv	19	.....	1	.....	18
			Days >1.0 dv	2	.....	0	.....	2
	Unit 1	CACR	Max dv	1.002	.....	0.480	.....	0.522
			Days >0.5 dv	9	.....	0	.....	9
			Days >1.0 dv	1	.....	0	.....	1
		WIMO	Max dv	0.609	.....	0.306	.....	0.302
			Days >0.5 dv	2	.....	0	.....	2
			Days >1.0 dv	0	.....	0	.....	0
	Unit 2	CACR	Max dv	0.974	.....	0.441	.....	0.534
			Days >0.5 dv	9	.....	0	.....	9
			Days >1.0 dv	0	.....	0	.....	0
		WIMO	Max dv	0.598	.....	0.282	.....	0.316
			Days >0.5 dv	2	.....	0	.....	2
			Days >1.0 dv	0	.....	0	.....	0

[1] Harrington high control scenario for both units is SDA at 95% reduction.
[2] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD (wet FGD) installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.

TABLE 16—VISIBILITY BENEFIT OF RETROFIT CONTROLS: COAL-FIRED UNITS (CALPUFF MODELING)

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Units 1 and 2).	WIMO	Max dv	4.27	2.54	0.43	1.73	3.83
			Days >0.5 dv Avg.	67.33	43.33	2.67	24.00	64.67
			Days >1.0 dv Avg.	42.00	21.00	1.00	21	41.00
		CACR	Max dv	4.03	2.41	0.47	1.62	3.55
			Days >0.5 dv Avg.	91.67	64.33	4.67	27.33	87.00
			Days >1.0 dv Avg.	60.33	30.00	0.00	30.33	60.33
Monticello [1]	Source (Unit 1, 2 and 3).	CACR	Max dv	6.57	3.68	1.70	2.89	4.87
			Days >0.5 dv Avg.	143.67	115.00	62.33	28.67	81.33
			Days >1.0 dv Avg.	113.00	66.33	23.67	46.67	89.33
		UPBU [4]	Max dv	3.45	1.77	0.77	1.68	2.68
			Days >0.5 dv Avg.	103.00	61.00	13.67	42.00	89.33
			Days >1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days >0.5 dv Avg.	60.00	34.67	6.00	25.33	54.00
			Days >1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67
Harrington [2]	Source (Units 061B & 062B).	SACR	Max dv	1.06	0.86	0.61	0.20	0.45
			Days >0.5 dv Avg.	21.00	15.33	6.33	5.67	14.67
			Days >1.0 dv Avg.	6.67	3.00	0.67	3.67	6.00
		WIMO	Max dv	1.29	0.97	0.55	0.32	0.74
			Days >0.5 dv Avg.	26.00	15.33	8.67	10.67	17.33
			Days >1.0 dv Avg.	9.00	4.67	1.33	4.33	7.67
Welsh [3]	Source (Unit 1)	CACR	Max dv	1.44	1.12	0.72	0.32	0.72
			Days >0.5 dv Avg.	50.33	32.67	12.33	17.67	38
			Days >1.0 dv Avg.	15.33	8.00	2.33	7.33	13.00
		UPBU	Max dv	0.76	0.49	0.22	0.27	0.54
			Days >0.5 dv Avg.	12.00	4.67	0.33	7.33	11.67
			Days >1.0 dv Avg.	0.67	0.00	0.00	0.67	0.67
		WIMO	Max dv	0.56	0.33	0.15	0.23	0.41
			Days >0.5 dv Avg.	7.33	2.67	0.33	4.67	7.00
			Days >1.0 dv Avg.	1.33	0.33	0.00	1.00	1.33

[1] Monticello's controlled level is a combination of scrubber upgrades and scrubber install in the facility impact modeling with CALPUFF.
[2] Harrington high control scenario for both units is SDA at 95% reduction.
[3] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.
[4] UPBU = Upper Buffalo Wilderness Area.

b. Visibility Benefits of Scrubber Upgrades for Coal-Fired Units

We also modeled the visibility benefits of those same units for which we conducted control cost analysis for upgrading their existing scrubbers. We assumed the same 95% control level we used in our control cost analyses. We also modeled a lower level control at 90%. The visibility benefits from these scrubber upgrades are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits and reduction in number of days impacted.

TABLE 17—VISIBILITY BENEFIT OF SCRUBBER UPGRADES: COAL-FIRED UNITS (CAMX MODELING)

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	(90%) control	(95%) control	(90%) benefit	(95%) benefit
Martin Lake	Source (Unit 1, 2 & 3).	CACR	Max dv	6.651	4.491	4.321	2.159	2.329
			Days >0.5 dv	141	75	56	66	85
			Days >1.0 dv	99	31	16	68	83
		UPBU	Max dv	5.803	2.669	2.528	3.134	3.275
			Days >0.5 dv	99	39	22	60	77
			Days >1.0 dv	67	11	7	56	60
	Unit 1	CACR	Max dv	2.633	1.550	1.468	1.083	1.165
			Days >0.5 dv	71	17	6	54	65
			Days >1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.254	0.867	0.805	1.387	1.449
			Days >0.5 dv	44	6	3	38	41
			Days >1.0 dv	10	0	0	10	10
	Unit 2	CACR	Max dv	2.466	1.882	1.811	0.585	0.655
			Days >0.5 dv	68	18	9	50	59
			Days >1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.189	1.077	1.025	1.112	1.164
			Days >0.5 dv	40	6	5	34	35
			Days >1.0 dv	10	1	1	9	9
	Unit 3	CACR	Max dv	2.755	1.682	1.609	1.074	1.146
			Days >0.5 dv	76	15	6	61	70
			Days >1.0 dv	29	2	1	27	28
		UPBU	Max dv	2.368	0.942	0.890	1.425	1.478
			Days >0.5 dv	46	6	4	40	42

TABLE 17—VISIBILITY BENEFIT OF SCRUBBER UPGRADES: COAL-FIRED UNITS (CAMX MODELING)—Continued

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	(90%) control	(95%) control	(90%) benefit	(95%) benefit
			Days >1.0 dv	13	0	0	13	13
Monticello	Source (Unit 1, 2 and 3).	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days >0.5 dv	152	107	28	45	124
			Days >1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days >0.5 dv	67	35	4	32	63
			Days >1.0 dv	40	14	0	26	40
	Unit 3	CACR	Max dv	4.632	0.905	0.914	3.728	3.719
			Days >0.5 dv	79	5	5	74	74
			Days >1.0 dv	32	0	0	32	32
		WIMO	Max dv	2.282	0.462	0.364	1.820	1.918
			Days >0.5 dv	31	0	0	31	31
			Days >1.0 dv	7	0	0	7	7

TABLE 18—VISIBILITY BENEFIT OF SCRUBBER UPGRADES: COAL-FIRED UNITS (CALPUFF MODELING)

Facility name	Emission unit	Class I area	Metric	Visibility impact			Visibility benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Units 1, 2 & 3).	CACR	Max dv	4.46	2.27	1.86	2.18	2.60
			Days >0.5 dv Avg.	129.67	77.33	63.00	52.33	66.67
			Days >1.0 dv Avg.	91.33	32.67	22.33	58.67	69.00
		UPBU	Max dv	2.73	1.10	0.85	1.63	1.88
			Days >0.5 dv Avg.	81.67	30.33	18.67	51.33	63.00
			Days >1.0 dv Avg.	46.67	7.33	3.67	39.33	43.00
Monticello [1]	Source (Unit 1, 2 and 3).	CACR	Max dv	6.57	3.68	1.70	2.89	4.87
			Days >0.5 dv Avg.	143.67	115	62.33	28.67	81.33
			Days >1.0 dv Avg.	113	66.33	23.67	46.67	89.33
		UPBU	Max dv	3.45	1.77	0.765	1.68	2.68
			Days >0.5 dv Avg.	103	61	13.67	42	89.33
			Days >1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days >0.5 dv Avg.	60	34.67	6	25.33	54
			Days >1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67

[1] Monticello's controlled level is a combination of scrubber upgrade on Unit 3 and scrubber retrofits on Units 1 and 2 in the facility impact modeling with CALPUFF.

c. Visibility Benefits of Fuel Oil Switching for Gas/Fuel Oil-Fired Units

We also modeled the visibility benefits of those gas/fuel oil-fired units for which we conducted control cost analysis for switching to lower sulfur fuels. We evaluated the visibility benefits of switching to fuel oils corresponding to ultra-low sulfur diesel at 0.0015% sulfur by weight and 0.3% sulfur by weight as we evaluated in our control cost analyses. The visibility benefits from these fuel switches are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits.

TABLE 19—VISIBILITY BENEFITS FROM LOWER SULFUR FUEL

Facility name	Emission unit	Baseline visibility impact from source (most impacted Class I area)	Visibility benefit of 0.3% S fuel oil	Visibility benefit of 0.0015% S fuel oil
Stryker	ST2	CALPUFF 0.65% S: 0.786 dv @ CACR (Facility).	CALPUFF (0.3% S): 0.263 dv @ CACR (Facility).	CALPUFF: 0.522 dv @ CACR (Facility)
Graham	Unit 2	CALPUFF 0.69% S: 1.228 dv @ WIMO (Facility).	CALPUFF (0.3% S): 0.465 dv @ WIMO (Facility.	CALPUFF: 0.851 dv @ WIMO (Facility)
Wilkes	Units 1, 2, 3	CALPUFF 0.43% S: 0.698 dv @ CACR (Facility).	CALPUFF (0.1% S): 0.029 dv @ CACR (Facility).	CALPUFF: 0.037 dv @ CACR (Facility)
Newman [1]	Unit 2	N/A	N/A	N/A
	Unit 3	N/A	N/A	N/A
	Unit 4	N/A	N/A	N/A
Calaveras	Sommers Unit 1	CAMx: 1.513 dv @ WIMO (Source); 0.106 dv @ CACR (Unit).	0.004 dv @ CACR	0.008 dv @ CACR

TABLE 19—VISIBILITY BENEFITS FROM LOWER SULFUR FUEL—Continued

Facility name	Emission unit	Baseline visibility impact from source (most impacted Class I area)	Visibility benefit of 0.3% S fuel oil	Visibility benefit of 0.0015% S fuel oil
	Sommers Unit 2	CAMx: 1.513 dv @ WIMO (Source); 0.180 dv @ CACR (Unit).	0.023 @ CACR	0.047 @ CACR

[1] Newman is on the edge of the CALMET and CALPUFF modeling grids for the database that were used in this action. Since the facility was near the edge, emissions of the facility's impacts could not be adequately modeled since some of the plumes could have gone out of the grid and not be adequately assessed if they come back into the grid and transport to impact a Class I area.

6. BART Analysis for PM

In our recent Texas-Oklahoma FIP, we initially proposed to approve Texas' determination that no PM BART controls were appropriate for its EGUs, based on a screening analysis of the visibility impacts from just PM emissions and the premise that EGU SO_2 and NO_X were covered separately by participation in CSAPR (allowing consideration of PM emissions in isolation). Because of the CSAPR remand and resulting uncertainty regarding SO_2 and NO_X BART for EGUs, we decided not to finalize our proposed approval of Texas' PM BART determination.[104] For reasons earlier stated we are proposing to disapprove the SIP determination regarding PM BART for EGUs. Following from that proposed disapproval, we are proposing a PM BART FIP for those Texas EGUs that are subject to BART.

The BART Guidelines permit us to conduct a streamlined analysis of PM BART in two key ways. First, the Guidelines allow a streamlined analysis for PM sources subject to MACT standards. Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, the Guidelines state it is permissible to rely on MACT standards for purposes of BART.[105]

Second, with respect to gas-fired units, which have inherently low emissions of PM (as well as SO_2), the Regional Haze Rule did not specifically envision new or additional controls or emissions reductions from the PM BART requirement. The BART guidelines preclude us from stating that PM emissions are *de minimis* when plant-wide emissions exceed 15 tons per years. While we must assign PM BART determinations to the gas-firing units, there are no practical add-on controls to consider for setting a more stringent PM BART emissions limit. The Guidelines state that if the most stringent controls are made federally enforceable for BART, then the otherwise required analyses leading up to the BART determination can be skipped.[106]

With this background, we are providing our evaluation along with some supplementary information on the BART sources as divided into two categories: coal-fired EGUs, and gas-fired EGUs.

BART Analysis for PM for Coal-Fired Units

All of the coal-fired EGUs that are subject to BART are currently equipped with either Electrostatic Precipitators (ESPs) or baghouses, or both, as can be seen from Table 20:

TABLE 20—CURRENT PM CONTROLS FOR COAL-FIRED UNITS SUBJECT TO BART

Facility name	Unit ID	Fuel type (primary)	SO_2 control(s)	PM control(s)
Big Brown	1	Coal		Baghouse + Electrostatic Precipitator.
Big Brown	2	Coal		Baghouse + Electrostatic Precipitator.
Coleto Creek	1	Coal		Baghouse.
Harrington Station	061B	Coal		Electrostatic Precipitator.
Harrington Station	062B	Coal		Baghouse.
J T Deely	1	Coal		Baghouse.
J T Deely	2	Coal		Baghouse.
Martin Lake	1	Coal	Wet Limestone	Electrostatic Precipitator.
Martin Lake	2	Coal	Wet Limestone	Electrostatic Precipitator.
Martin Lake	3	Coal	Wet Limestone	Electrostatic Precipitator.
Monticello	1	Coal		Baghouse + Electrostatic Precipitator.
Monticello	2	Coal		Baghouse + Electrostatic Precipitator.
Monticello	3	Coal	Wet Limestone	Electrostatic Precipitator.
Fayette	1	Coal	Wet Limestone	Electrostatic Precipitator.
Fayette	2	Coal	Wet Limestone	Electrostatic Precipitator.
W A Parish	WAP5	Coal		Baghouse.
W A Parish	WAP6	Coal		Baghouse.
Welsh Power Plant	1	Coal		Baghouse (Began Nov 15, 2015) + Electrostatic Precipitator.

As an initial matter, we examine the control efficiencies of both baghouses and ESPs. We consider a baghouse, widely reported to be capable of 99.9% control of PM, to be the maximum level control for PM and so the units equipped with a baghouse will not be further analyzed for PM BART. The remaining units are fitted with ESPs.

The particulate matter control efficiency of ESPs varies somewhat with

[104] 81 FR 302 (January 5, 2016).

[105] 70 FR 39163–39164.

[106] 70 FR 39165 (". . . you may skip the remaining analyses in this section, including the visibility analysis . . .")

the design, the resistivity of the particulate matter, and the maintenance of the ESP. We do not have any information on the control level efficiency of any of the ESPs for the units in question. However, reported control efficiencies for well-maintained ESPs typically range from greater than 99% to 99.9%.[107] We consider this pertinent in concluding that the potential additional particulate control that a baghouse can offer over an ESP is relatively minimal.[108] In other words, if we did obtain control information specific to the ESP units in question, we do not believe that additional information would lead us to a different conclusion.

Nevertheless, w'e will examine the potential cost of retrofitting a typical 500 MW coal fired unit with a baghouse. Using our baghouse cost algorithms, as employed in version 5.13 of our IPM model,[109] and assuming a conservative air to cloth ratio of 6.0, results in a capital engineering and construction cost of $77,428,000.[110] Applied to the subject units, this cost assumes a retrofit factor of 1.0, and does not consider the demolition of the existing ESP, should it be required in order to make space for the baghouse.

We do not calculate the cost-effectiveness resulting from replacing an ESP with a baghouse. However, we expect that the tons of additional PM removed by a baghouse over an ESP to be very small, which would result in a very high cost-effectiveness figure. Also, we do not model the visibility benefit of replacing an ESP with a baghouse. However, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from replacing an ESP with a baghouse to be a small fraction of that. For instance, our CAMx baseline modeling shows that on a source-wide level, impacts from PM emissions on the maximum impacted days from each source at each Class I area was 3% of the total visibility impairment or less (calculated as percent of total extinction due to the source). Therefore additional PM controls are anticipated to result in very little visibility benefit on the maximum impacted days. Similarly, our CALPUFF modeling indicates that visibility impairment from PM is also a small fraction (typically only a few percent) of the total visibility impairment due to each source.

Adding to the above discussion, we are tasked to assign the enforceable emission limitations that constitute PM BART. We believe a stringent control level that would be met with existing or otherwise-required controls is a filterable PM limit of 0.03 lb/MMBtu for each of the coal-fired units subject to BART. We note that the Mercury and Air Toxics (MATS) Rule establishes an emission standard of 0.03 lb/MMBtu filterable PM (as a surrogate for toxic non-mercury metals) as representing Maximum Achievable Control Technology (MACT) for coal-fired EGUs.[111] This standard derives from the average emission limitation achieved by the best performing 12 percent of existing coal-fired EGUs, as based upon test data used in developing the MATS Rule. We are not familiar with any new technologies subsequent to this standard that could lead to any cost effective increases in the level of control; thus, consistent with the BART Guidelines, we are proposing to rely on this limit for purposes of PM BART for all of the coal-fired units as part of our FIP. We understand the coal-fired units covered by this proposal to be subject to MATS, but to the extent the units may be following alternate limits that differ from the surrogate PM limits found in MATS, we welcome comments on different, appropriately stringent limits reflective of current control capabilities.[112] Because we anticipate that any limit we assign should be achieved by current control capabilities, we propose that compliance can be met at the effective date of the rule. To address periods of startups and shutdowns, we are further proposing that PM BART for these units will additionally be met by following the work practice standards specified in 40 CFR part 63, subpart UUUUU, Table 3, and using the relevant definitions in 63.10042. We are proposing that the demonstration of compliance can be satisfied by the methods for demonstrating compliance with filterable PM limits that are specified in 40 CFR part 63, subpart UUUUU, Table 7. However, we would give consideration to commenter-submitted requests for alternate or additional methods of demonstrating compliance.

BART Analysis for PM for Gas-Fired Units

We note that PM emissions for the gas-only fired units that are subject to BART are inherently low.[113] We therefore conclude that PM emissions from natural gas firing is so minimal that the installation of any additional PM controls on the unit would likely achieve very low emissions reductions and have minimal visibility benefits. As there are no appropriate add-on controls and the status quo reflects the most stringent controls, we are proposing to make the requirement to burn pipeline natural gas federally enforceable. We note that in addition to satisfying PM BART, this limitation will also serve to satisfy SO_2 BART for these gas-fired units, as well as the fuel-oil units when they fire natural gas. We are proposing that PM and SO_2 BART for gas fired-units will limit fuel to pipeline natural gas, as defined at 40 CFR 72.2.

The available PM controls for gas units that also burn fuel oil are the same for the coal-fired units. We would expect similar costs for installing a baghouse on a typical gas-fired boiler that occasionally burns fuel oil. Again, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from the installation of a baghouse to be a small fraction on the order of 1–3% of the visibility impacts from the facility. We are confident that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted with an ESP. We conclude that the cost of a baghouse does not justify the minimal expected improvement in visibility for these units. Accordingly, we are proposing that the fuel content limits for oil burning that we propose to meet SO_2 BART will also satisfy PM BART.

[107] EPA, "Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP)—Wire Plate Type," EPA–452/F–03–028. Grieco, G., "Particulate Matter Control for Coal-fired Generating Units: Separating Perception from Fact," *apcmag.net*, February, 2012. Moretti, A. L.; Jones, C. S., "Advanced Emissions Control Technologies for Coal-Fired Power Plants, Babcox and Wilcox Technical Paper BR–1886, Presented at Power-Gen Asia, Bangkok, Thailand, October 3–5, 2012.

[108] We do not discount the potential health benefits this additional control can have for ambient PM. However, the regional haze program is only concerned with improving the visibility at Class I areas.

[109] IPM Model—Updates to Cost and Performance for APC Technologies, Particulate 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 5–7: PM Cost Methodology, downloaded from: *https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-7_pm_cost_methodology.pdf.*

[110] *Id.* See page 9.

[111] 77 FR 9304, 9450, 9458 (February 16, 2012) (codified at 40 CFR 60.42 Da(a), 60.50 Da(b)(1)); 40 CFR part 63 Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units.

[112] The various limits are provided at 40 CFR part 63, subpart UUUUU, Table 2 ("Emission Limits for Existing EGUs").

[113] AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.4, Natural Gas Combustion, available here: *https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.*

Lastly, should our assumptions regarding the frequency and type of fuel oil burned in these units significantly change, we expect that Texas will address such a change appropriately in its SIP, which we will review in the next planning period.

D. How, if at all, do issues of ''Grid Reliability'' relate to the proposed BART determinations?

On July 15, 2016, a preliminary order of the Fifth Circuit Court of Appeals took the view that EPA's Texas-Oklahoma FIP (81 FR 295, January 5, 2016) gave a ''truncated discussion of grid reliability'' and additionally stated that ''the agency may not have fulfilled its statutory obligation to consider the energy impacts of the FIP.'' The Court's preliminary ruling made particular reference to ''the explicit directive in the [CAA] that implementation plans 'take[] into consideration . . . the energy . . . impacts of compliance,' 42 U.S.C. 7491(g)(1).'' [114] Because the BART requirement at issue in this proposal has similar language on *energy impacts of compliance* appearing at 42 U.S.C. 7491(g)(2), we wish to provide a clear explanation on how grid-related considerations for EGUs could bear on this proposal.

First, the BART factor for *energy impacts of compliance* does not call for the examination of grid reliability considerations from alleged plans to shut down or retire a unit rather than comply with a more stringent emission limit or limits. The language instead calls for consideration of energy impacts from *complying* by installing retrofit controls on a source that continues in operation. In this regard, our proposal follows the required BART Guidelines for EGUs.[115] The Guidelines explain that the energy impacts factor relates to the penalties and benefits that may be associated with the assessment of a control option, *e.g.,* whether (for power penalties) the operation of add-on control technology subtracts from the productive yield of electricity from an EGU (what is sometimes termed an auxiliary or parasitic load).[116] It is also useful to note that the statutory text, while using the word ''energy,'' can apply to sources that do not produce energy or electricity. Thus, the statutory text regarding ''energy impacts'' of compliance with BART is not confined to the power generating industry and does not dictate that we study grid reliability issues.

We have considered whether this topic has any separate relevance to our proposal. Various court filings, news accounts, and industry market reports suggest that some source operators for some Texas BART units may be contemplating unit retirements. The BART Guidelines directly address such scenarios under the ''remaining useful life'' factor: ''there may be situations where a source operator intends to shut down a source . . . but wishes to retain the flexibility to continue operating beyond that date in the event, for example, the market conditions change.'' [117] The Guidelines advise that a source that is willing to assure a permanent stop in operations with a federally- or State-enforceable restriction preventing further operation may obtain a short remaining useful life for BART analysis purposes that could then factor in the overall cost analysis.[118] As the Guidelines state, ''Where the remaining useful life is less the than the time period for amortizing costs, you should use this shorter period in your cost calculations.'' [119] We have no information on enforceable restrictions of this type for any of the units that we propose to be subject to BART. Absent that, we must assume that controls installed on the BART units will experience their full useful life. Affected sources are free to submit information as part of their comments containing appropriate enforceable documentation of shorter remaining useful lives.

We note, however, that the Guidelines recognize there may be cases where the installation of controls, even when cost-effective, would ''affect the viability of continued plant operations.'' [120] Under the Guidelines, where there are ''unusual circumstances,'' we are permitted to take into consideration ''the conditions of the plant and the economic effects of requiring the use of a control technology.'' [121] If the effects are judged to have a ''severe impact,'' those effects can be considered in the selection process. In such cases, the Guidelines counsel that any determinations be made with an economic analysis with sufficient detail for public review on the ''specific economic effects, parameters, and reasoning.'' [122] It is recognized, by the language of the Guidelines, that any such review process may entail the use of sensitive business information that may be confidential. The **ADDRESSES** section of this proposal explains how to submit confidential information with comments, and when claims of confidential business information, or CBI, are asserted with respect to any information that is submitted, the EPA regulations at 40 CFR part 2, subpart B-Confidentiality Business Information apply to protect it. All of that said, the Guidelines also advise that we may ''consider whether other competing plants in the same industry have been required to install BART controls if this information is available.'' [123] Because Texas EGUs are among the last to have SO_2 BART determinations, this information is available. It is indeed the case that other similar EGUs have been required to install the same types of SO_2 BART controls that we are proposing as very cost effective.[124]

We have considered the state of available information on whether the proposed controls could affect the viability of continued plant operations. On this point, we note that we are proposing BART determinations for several units where SO_2 control requirements were separately promulgated as part of the Texas-Oklahoma FIP. These under-controlled EGU sources are: Big Brown 1 and 2; Monticello 1, 2 and 3; Martin Lake 1, 2 and 3; and Coleto Creek 1. In litigation over the reasonable progress FIP, various declarations were filed on the issues of alleged forced closures and alleged reliability impacts. These declarations have been compiled and added to the docket for this rulemaking.

[114] EPA Guidance on this statutory language specifically explains that energy impacts are a matter of whether ''energy requirements associated with a control technology result in energy penalties.'' U.S. EPA, Office of Air Quality Planning and Standards, ''Guidance for Setting Reasonable Progress Goals under the Regional Haze Program,'' (June 1, 2007 rev), at Page 5–2.

[115] The promulgation of the Guidelines was required by 42 U.S.C. 7491(b)(1). Adherence to the Guidelines is mandatory for fossil-fuel fired generating power plants having total generating capacities ''in excess of 750 megawatts.''

[116] Other CAA provisions requiring consideration of ''energy impacts'' or ''energy requirements of the control technology'' are understood similarly. *See, e.g.,* CAA section 169 (the 1977 ''best available control technology'' requirement with consideration of ''energy . . . impacts''); *see also* CAA section 108 (''energy requirements . . . of the emission control technology; ''energy . . . impact of such processes, procedures, and methods [to reduce or control air pollution''); section 111 (''taking into account . . . energy requirements'' of an emission limitation), etc.

[117] *Id.* at 39169–39170.

[118] Similar to calculating a mortgage, remaining useful life is used in our cost-effectiveness analysis to calculate the annual cost of a particular control. The longer the remaining useful life, the smaller the total annualized cost, and the more cost-effective the control.

[119] *Id.* at 39169.

[120] 70 FR 39103, 39171 (July 6, 2005), [40 CFR part 51, App. Y].

[121] *Id.*

[122] 70 FR at 39171.

[123] *Id.*

[124] See for instance, the EIA information we present elsewhere in this notice in which we summarize the hundreds of scrubber installations that have been performed on similar EGUs.

By our review, these declarations do not appropriately inform or substantiate source-specific allegations of ''unusual circumstances'' that may have a severe impact on plant operations, because they do not offer any site-specific information.[125] Thus, we are unable to conclude that the proposed cost-effective BART controls would severely impact plant operations. Generalized claims of possible retirements and discussions on attributes of the market design of the Electric Reliability Council of Texas (ERCOT) cannot inform the statutorily required, source-specific BART determinations.

As a predicate to studying effects on transmission or reliability as ''unusual circumstances,'' we would require site-specific information from any source that would wish for us to potentially consider ''affordability of controls,'' under the terms specified in the Guidelines. Source owners may submit information, including information claimed to be CBI, for our assessment and consideration to potentially support an economic analysis that might be used in the BART selection process. As suggested by the Guidelines, the information necessary to inform our judgment would likely entail source-specific information on ''product prices, the market share, and the profitability of the source.'' Consideration of such information does not dictate what will be selected as a ''best'' alternative under the Guidelines, but it will substantiate the likelihood of a retirement scenario that would then give the parameters for: A non-conjectural examination of grid reliability issues; judging the significance or insignificance of such issues; and assessing whether such issues could be avoided through appropriate transmission planning. In sum, unless we are able to substantiate an ''affordability of controls'' problem for any particular unit and substantiate that a particular unit retirement would not be happening anyway at about the same time, alleged grid reliability impacts are speculative and are not able to inform these required BART determinations. As a final note, we acknowledge Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, and Use''). In cases where it does apply, agencies are ordered to prepare a Statement of Energy Effects for submission to the Administrator of the Office of Information and Regulatory Affairs (OIRA), Office of Management and Budget. This EGU BART proposal is not considered a significant regulatory action under Executive Order 12866, so the proposed action cannot be a ''significant energy action'' for purposes of Executive Order 13211 on that basis. This proposed action has also not been designated a significant energy action by the Administrator of OIRA, so Executive Order 13211 could not apply under that separate basis. With this proposal, there are no anticipated adverse effects on energy supply, distribution, or use that are meaningful or distinguishable from any other scenario where an EGU is expected to install cost-effective pollution controls required by the CAA.

IV. Our Weighing of the Five BART Factors

Below we present our reasoning for proposing our BART determinations for 29 EGUs in Texas, based on our analysis and weighing of the Five BART Factors: (1) Proposed SO_2 and PM BART determinations for 12 coal-fired units with no SO_2 controls, (2) proposed BART SO_2 and PM BART determinations for 6 coal-fired units with existing scrubbers, (3) proposed SO_2 and PM BART determinations 7 gas-fired units that occasionally burn fuel oil, and (4) proposed PM BART determinations for 4 gas-fired units.

In previous sections of this proposal, we have described how we assessed the five BART factors. In no case do we see any instance in which our assessment of energy impacts is a determining factor in assessing BART.[126] Also, in no case do we see any instance in which our assessment of the remaining useful life is a determining factor in assessing BART. Should a facility indicate in comments to us that the remaining useful life is less than the 30 years we have assumed in our control cost analyses, and is willing to enter into an enforceable document to that effect, we will adjust our cost-effectiveness calculation accordingly in making our final decision. In two cases, Harrington units 061B and 062B, we have limited our SO_2 control analysis for Harrington to DSI and dry scrubbers due to potential non-air quality concerns. In all other instances, we conclude that the cost of compliance, and the visibility benefits of controls are the controlling BART factors in our weighing of the five BART factors.

In considering cost-effectiveness and visibility benefit, we do not eliminate any controls based solely on the magnitude of the cost-effectiveness value, nor do we use cost-effectiveness as the primary determining factor. Rather, we compare the cost-effectiveness to the anticipated visibility benefit, and we take note of any additional considerations.[127] Also, in judging the visibility benefit we do not simply examine the highest value for a given Class I area, or a group of Class I areas, but we also consider the cumulative visibility benefit for all affected Class I areas, the number of days in a calendar year in which we see significant improvements, and other factors.[128]

First, we note that all of the sources addressed in our proposed BART determinations have already been shown to cause or contribute to visibility impairment at a Class I area as a condition of being subject-to-BART as part of the BART screening analysis. This analysis eliminated any BART-eligible source that emits lower amounts of visibility impacting pollutants, or otherwise impacts any Class I area at less than 0.5 deciviews. In fact, all of the individual units that we are proposing for BART controls exceed 0.5 deciviews on a unit basis, with most exceeding 1.0 deciview impact on a unit basis. As a consequence, all of the units we are proposing for BART controls are among the largest emitters of visibility impacting pollutants in Texas. A number of these units (*i.e.,* Big Brown, Martin Lake, Monticello, and Coleto Creek) were previously determined by us to require the same type and level of controls under the reasonable progress and long-term strategy provisions of the Regional Haze Rule that we are proposing here.[129]

Second, not discounting our approach of considering both cost-effectiveness and visibility benefit in unison, the cost-effectiveness of all of the controls that form the basis of our proposed BART determinations are within a range found to be acceptable in other cases.[130] As we

[125] Certain statements in declarations from representatives of both Luminant and Coleto Creek, who are the source owners of these facilities, cited compliance planning efforts that would be consistent with continued plant operations.

[126] In addition to our assessment of energy impacts, also see our discussion in Section III.D concerning our conclusion that energy impact considerations do not relate to potential electrical grid reliability issues.

[127] For instance, as we discuss later in Section IV.C why we believe that there are certain mitigating factors that should be considered when assessing BART for the gas-fired units that occasionally burn fuel oil.

[128] See for example 70 39130: ''comparison thresholds can be used in a number of ways in evaluating visibility improvement (*e.g.* the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, a threshold representing an x percent change in improvement, etc.).''

[129] See our recent Texas-Oklahoma FIP, 81 FR 321.

[130] See for instance 79 FR 5048 (January 30, 2014): Jim Bridger BART determination of LNB/SOFA + SCR on Units 1–4; 77 FR 18070 (March 26, 2012): EPA proposed approval of Colorado's BART

stated in the BART Rule, ''[a] reasonable range would be a range that is consistent with the range of cost effectiveness values used in other similar permit decisions over a period of time.'' [131]

A. SO_2 BART for Coal-fired Units With No SO_2 Controls

As we have discussed in this proposal and in our TSD, we have assumed two DSI control levels corresponding to 50% control and either a maximum of 80% or 90% control, depending on the particulate matter control device in use.[132] We did this to address the BART Guidelines directive that in evaluating technically feasible alternatives we ''(1) [ensure we] express the degree of control using a metric that ensures an ''apples to apples'' comparison of emissions performance levels among options, and (2) [give] appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels.'' [133] In most cases, the cost-effectiveness of the higher control level of DSI was higher than either SDA or wet FGD. This was not the case for Monticello Unit 2; Harrington Unit 062B; and J T Deely Units 1 and 2.

However, these maximum DSI control levels are theoretical and we believe that any DSI control level above 50% must be confirmed by onsite testing before we could propose a BART control based on it. As is evident in comparing the 50% control level to the higher control level, the cost-effectiveness of DSI worsens (higher $/ton) as the control level increases, and the certainty of any unit attaining that control level decreases. We therefore regard the cost-effectiveness values of the maximum DSI control levels as being useful in a basic comparison of cost-effectiveness between DSI and scrubbers, but we place much less weight on these values. We therefore conclude that given the uncertainty concerning the maximum control level of DSI, the greater control efficiency and resulting visibility benefit offered by scrubbers overrides any possible advantage DSI may hold in cost-effectiveness. Should the affected facilities provide site-specific information to us in their comments that conflicts with this assumption, we will incorporate it into our final decision on SO_2 BART and potentially re-evaluate DSI.

As we indicate elsewhere in our proposal, both SDA and wet FGD are mature technologies that are in wide use throughout the United States. We are not aware of any unusual circumstances that exist for any of the sources that would serve to indicate they should not be viewed similarly to these hundreds of previous scrubber retrofits. In comparing wet FGD versus SDA we note that in a number of cases the cost-effectiveness of wet FGD is lower than the cost-effectiveness of SDA. In the remaining cases, we conclude that the incremental cost-effectiveness of wet FGD over SDA, which we review in Section III.C.3.a is reasonable, and the improved control and visibility benefit offered by wet FGD overrides the small penalty in cost-effectiveness FGD has in comparison to SDA. We propose that with the exception of the Harrington units, SO_2 BART for all other coal-fired units should be based on the wet FGD control levels we have used in our BART analyses. We propose that SO_2 BART for the Harrington units should be based on the SDA control levels we have used in our BART analyses. Below we discuss our consideration of the cost-effectiveness and anticipated visibility benefits of controls. See section III.C.5 for additional information on the anticipated visibility benefits from each level of control modeled. See the BART Modeling TSD for a complete summary of our visibility benefit analysis of controls, including modeled benefits and impacts at all Class I areas included in the modeling analyses and additional metrics considered in the assessment of visibility benefits.

CAMx model results shown in the tables below summarize the benefits from the recommended controls at the two Class I areas most impacted by the source or unit in the baseline modeling. The benefit is calculated as the difference between the maximum impact modeled for the baseline and the maximum impact level modeled under the control scenario. 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. The CALPUFF cumulative model results only consider those Class I areas within the typical range of CALPUFF and not all 15 Class I areas included in the CAMx modeling.

1. Big Brown 1 & 2

In reviewing the Big Brown units, we conclude that the installation of wet FGD will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 21—WET FGD VISIBILITY BENEFITS AT BIG BROWN (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total cumulative visibility benefit (dv) [1]	Cumulative reduction in number of days above 0.5 dv [2]	Cumulative reduction in number of days above 1.0 dv [2]
Big Brown Units 1 & 2	3.83	3.55	7.38	151.67	101.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek and Wichita Mountains.

[2] Using the three years (2001–2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek and Wichita Mountains.

determination of SCR for Hayden Unit 2, later finalized at 77 FR 76871 (December 31, 2012).

[131] 70 FR 39168 (July 6, 2005).

[132] Note for Harrington Unit 062B and Welsh 1, we further limited the maximum DSI control level to that of our calculated SDA control level.

[133] 70 FR 39166 (July 6, 2005).

In evaluating Big Brown, we note there are two Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001–2003 CALPUFF modeling results, we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the two Class I areas that are within the range that CALPUFF is typically used, the 2001–2003 CALPUFF modeling results indicate that wet FGD on both units will eliminate 151.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the visibility benefits in terms of dv benefits at the most impacted Class I areas and about 1/3rd to half the cumulative benefits over the class I areas included in the modeling analysis.

TABLE 22—WET FGD VISIBILITY BENEFITS AT BIG BROWN (CAMX)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total cumulative visibility benefit (dv)[1]	Baseline total cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Big Brown 1	1.909	1.606	12.728	174/44	174/44
Big Brown 2	1.940	1.642	12.924	175/45	175/45
Source	3.542	2.988	24.274	372/170	362/170

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv at all Class I areas on a unit and source-wide basis, and eliminate all but 10 days across the impacted Class I areas where the source-wide impacts exceeds 0.5 dv. At the most impacted Class I area, wet FGD will on each unit result in visibility improvements of 1.9 dv on the most impacted day. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the CAMx modeling.

We also conclude that wet FGD is very cost-effective for both units at less than $1,200/ton and more cost-effective than DSI. Based on this consideration of the BART factors, we propose that SO_2 BART for Big Brown Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

2. Monticello 1 & 2

Similar to the Big Brown units, the installation of wet FGD at Monticello Units 1 and 2 will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 23—WET FGD VISIBILITY BENEFITS AT MONTICELLO (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total cumulative visibility benefit (dv)[1]	Baseline total cumulative number of days over 0.5/1.0 dv[2]	Cumulative reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	4.87	2.70	10.25	224.67	164.67

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.
[2] Using the three years (2001–2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Monticello, we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001–2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001–2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 224.6

days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I area and half of the cumulative benefits.

TABLE 24—WET FGD VISIBILITY BENEFITS AT MONTICELLO (CAMX)

Unit	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
Monticello 1	3.783	1.989	12.708	197/67	191/67
Monticello 2	3.924	2.003	13.025	192/57	191/57
Source (including unit 3)	8.419	4.962	31.553	520/293	460/278

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1 dv at all Class I areas on a unit basis, and eliminate all but 15 days across the impacted Class I areas where the source-wide impacts exceeds 1 dv. We note that source-wide modeled benefits include benefits of 95% control scrubber upgrade on Unit 3. At the most impacted Class I area, wet FGD on each unit will each result in visibility improvements of 3.8–3.9 dv on the most impacted day at Caney Creek and 2 dv visibility benefits at Wichita Mountains. DSI operated at 50% control results in less than half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

The wet FGD cost-effectiveness of $2,718/ton and $3,031/ton are higher than those for Big Brown, but these figures remain well within a range that we have previously found to be acceptable for BART, and we consider the very significant visibility benefits that will result justify the cost of wet FGD at the Monticello Units 1 and 2. The 50% control DSI cost-effectiveness is slightly less than that for wet-FGD, but results in much less visibility benefits. Based on our consideration of the BART factors, we therefore propose that SO_2 BART for Monticello Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

3. Coleto Creek 1

In reviewing Coleto Creek Unit 1, we conclude that in comparison with the Monticello units, the installation of a wet FGD is more cost-effective and results in lesser, but still significant visibility benefits. We summarize some of these visibility benefits in the table below:

TABLE 25—WET FGD VISIBILITY BENEFITS AT COLETO CREEK UNIT 1 (CAMX)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
Coleto Creek 1	0.668	0.606	5.233	17/0	17/0

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 0.5 dv at all Class I areas. At the most impacted Class I area, wet FGD will result in visibility improvements of 0.6 or more on the most impacted days at both Caney Creek and the Wichita Mountains. In addition, seven other Class I areas are improved by amounts ranging from 0.356 to 0.531 dv on the maximum impacted days with wet FGD. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 Class I areas included in the modeling.

We also conclude that wet FGD is very cost-effective at $2,127/ton and well within a range that we have previously found to be acceptable and more cost-effective than DSI. We consider the significant visibility benefits that will result justify the cost of wet FGD at the Coleto Creek Unit 1. We therefore propose that SO_2 BART for Coleto Creek Unit 1 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

4. Welsh 1

In reviewing Welsh Unit 1, we conclude that the installation of a wet FGD will result in significant visibility

benefits. We summarize some of these visibility benefits in the tables below:

TABLE 26—WET FGD VISIBILITY BENEFITS AT WELSH UNIT 1 (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total cumulative visibility benefit (dv) [1]	Cumulative reduction in number of days above 0.5 dv [2]	Cumulative reduction in number of days above 1.0 dv [2]
Welsh 1	0.72	0.41	1.66	56.67	15

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.
[2] Using the three years (2001–2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Welsh we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001–2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001–2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 56.67 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

TABLE 27—WET FGD VISIBILITY BENEFITS AT WELSH UNIT 1 (CAMX)

Unit	Improvement at Caney Creek (dv)	Improvement at Mingo Wilderness (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
Welsh 1	1.521	0.579	4.683	65/9	60/9
Source (Welsh 1 & 2)	3.754	1.973	13.179	211/72	206/72

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD on unit 1 will eliminate all days impacted by the unit over 1 dv at all Class I areas and all but 5 days impacted over 0.5 dv. At the most impacted Class I area, wet FGD on unit 1 will result in visibility improvements of 1.521 dv on the most impacted days at Caney Creek. In addition to the visibility benefits at Caney Creek and Mingo, visibility benefits at two additional Class I areas exceed 0.5 dv. We note that source-wide benefits shown include the benefits from the shutdown of unit 2. In addition, cumulative benefits from wet FGD on unit 1 over all 15 Class I areas exceeds 4.5 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We conclude that although at $3,824/ton, the cost-effectiveness of wet FGD is higher than for other facilities, it remains within a range that we have previously found to be acceptable. We consider the significant visibility benefits that will result from the installation of wet FGD at Welsh Unit 1 to justify the cost. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for Welsh Unit 1 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

5. Harrington 061B & 062B

In reviewing Harrington, we conclude that the installation of SDA on Units 061B and 062B will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 28—SDA VISIBILITY BENEFITS AT HARRINGTON (CALPUFF)

Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total cumulative visibility benefit (dv) [1]	Cumulative reduction in number of days above 0.5 dv [2]	Cumulative reduction in number of days above 1.0 dv [2]
Harrington 061B & 062B	0.45	0.74	2.56	53.67	26

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.
[2] Using the three years (2001–2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

In evaluating Harrington we note there are five Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001–2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the five Class I areas that are within the range that CALPUFF is typically used, the 2001–2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 53.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

TABLE 29—SDA VISIBILITY BENEFITS AT HARRINGTON (CAMX)

Unit	Improvement at Salt Creek (dv)	Improvement at Wichita Mountains (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
Harrington 061B	1.170	0.643	4.832	17/5	11/3
Harrington 062B	1.279	0.723	5.379	17/5	11/3
Source (061B & 0622B)	2.053	1.130	9.329	51/17	37/11

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate SDA on these units will eliminate more than half of all days impacted by the units over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, SDA on each unit will each result in visibility improvements of approximately 1.2 dv on the most impacted days at Salt Creek and 0.6–0.7 dv at Wichita Mountains, reducing the number of days impacted over 0.5 and 1.0 dv at these Class I areas. In addition, cumulative benefits from SDA on both units over all 15 Class I areas exceeds 9.3 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the SDA visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We also conclude that SDA is cost-effective at $3,904 for Unit 061B and $4,180/ton for Unit 062B and, remains within a range that we have previously found to be acceptable. In contrast to other units we have reviewed, the 50% control DSI cost-effectiveness is much less than that for SDA. However, given the additional large total cumulative visibility benefits that will result from the installation of SDA over DSI at 50% control, we consider SDA to justify the additional cost. We therefore propose that SO_2 BART for Harrington Units 061B and 062B should be based on the installation of SDA at an emission limit of 0.06 lbs/MMBtu based on a 30 BOD.

6. W. A. Parish WAP 5 & 6

In reviewing W A Parish, we conclude that the installation of wet FGD on Units 5 and 6 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 30—WET FGD VISIBILITY BENEFITS AT W A PARISH (CAMX)

Unit	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
W A Parish 5	1.518	0.943	8.171	51/9	51/9
W A Parish 6	1.492	0.922	7.979	48/7	48/7
Source (WAP 4, 5 & 6)	2.665	1.760	15.301	163/49	162/49

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD on each of these units will eliminate all days impacted by each unit over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of approximately 1.5 dv on the most impacted days at Caney Creek and 0.9 dv at Upper Buffalo. Nine Class I areas have modeled source-wide baseline impacts over 1 dv, and wet FGD on both units results in source-wide improvements of 1 dv or greater on the maximum impacted days at eight of these Class I areas. In addition, cumulative benefits from wet FGD on both units over all 15 Class I areas exceeds 15 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. We note that source-wide modeling includes a small impact from WAP 4. This unit is gas-fired and was modeled at baseline emissions levels for both the baseline and control case scenarios.

We conclude that wet FGD is cost-effective at $2,417/ton for Unit 5 and $2,259/ton for Unit 6, and remains well within a range that we have previously found to be acceptable. DSI at 50% control is approximately the same cost-effectiveness but results in significantly less visibility benefit. We consider the cost of wet FGD at the W A Parish units to be justified by the significant visibility benefits that will result. We therefore propose that SO_2 BART for W A Parish Units 5 and 6 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

7. J T Deely 1 & 2

In reviewing J T Deely, we conclude that the installation of wet FGD on Units 1 and 2 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

TABLE 31—WET FGD VISIBILITY BENEFITS AT J T DEELY (CAMX)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total cumulative visibility benefit (dv) [1]	Baseline total cumulative number of days over 0.5/1.0 dv [2]	Reduction in number of days above 0.5/1.0 dv [3]
J T Deely 1	0.487	0.283	4.785	10/0	10/0
J T Deely 2	0.298	0.217	3.650	7/0	7/0
Source (J T Deely 1 & 2, Sommers 1 & 2)	0.699	0.518	8.943	89/13	84/13

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate wet FGD on each of these units will eliminate all days impacted by each unit over 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of 0.487 dv and 0.298 dv on the most impacted days at Wichita Mountains and 0.283 dv and 0.217 dv at Caney Creek. Larger visibility improvements on the most impacted days are anticipated at other Class I areas. Benefits from wet FGD on unit 1 are 0.583 dv at Big Bend, 0.511 dv at Salt Creek, 0.449 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.475 dv at White Mountains. Benefits from wet FGD on unit 2 are 0.583 dv at Big Bend, 0.441 dv at Salt Creek, 0.354 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.375 dv at White Mountains. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 Class I areas included in the modeling. We note that source-wide modeling includes the impact from Sommers units 1 and 2, and as discussed in the BART Modeling TSD, control case scenarios for these units included benefits from switching to lower sulfur fuel oil. However, these modeled improvements are a small fraction of the total visibility benefits from controls at the source.

We conclude that wet FGD is cost-effective at $3,898/ton for Unit 1 and $3,712/ton for Unit 2, and remains within a range that we have previously found to be acceptable. We consider the cost of wet FGD at the J T Deely units

to be justified by the significant visibility benefits that will result at a number of impacted Class I areas. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for J T Deely Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.[134]

B. SO_2 BART for Coal-fired Units With Underperforming Scrubbers

The BART Guidelines state that underperforming scrubber systems should be evaluated for upgrades.[135] Other than upgrading the existing scrubbers, all of which are wet FGDs, there are no competing control technologies that could be considered for these units. The CALPUFF modeling generated facility-wide impacts and the benefits of the scrubber upgrade on Monticello Unit 3 and the three Martin Lake facilities are included in Table 17 above. The following is a listing of each of the affected units along with the resulting CAMx modeled visibility benefits from upgrading their existing scrubbers:

TABLE 32—VISIBILITY BENEFIT FOR COAL-FIRED UNITS WITH EXISTING SO_2 CONTROLS (CAMX)

Unit	Improvement at most impacted (dv)	Improvement at 2nd most impacted (dv)	Total cumulative visibility benefit (dv)	Reduction in number of days above 0.5 dv at——	Reduction in number of days above 1.0 dv at——
Monticello 3	3.719 (CACR)	1.918 (WIMO)	11.940	200/66	188/66
Martin Lake 1	1.165 (CACR)	1.449 (UPBU)	7.575	160/41	151/40
Martin Lake 2	0.655 (CACR)	1.164 (UPBU)	6.199	150/41	134/39
Martin Lake 3	1.146 (CACR)	1.478 (UPBU)	7.863	173/47	163/46

As we state elsewhere in this proposal, because our cost-effectiveness calculations depend on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost effectiveness was $1,156/ton or less. We conclude that in all cases, scrubber upgrades are very cost-effective and result in very significant visibility benefits, significantly reducing the impacts from these units and reducing the number of days that Class I areas are impacted over 1.0 dv and 0.5 dv. We propose that SO_2 BART for all other coal-fired units with underperforming scrubbers should be based on the wet FGD upgrade control levels we have used in our BART analyses of them.

C. SO_2 BART for Gas-Fired Units That Burn Oil

In analyzing potential controls for those gas-fired units that occasionally burn fuel oil we considered scrubber retrofits and lower sulfur fuel oil. We concluded that the cost-effectiveness of scrubber retrofits for these units were likely very high, and not worth the potential visibility benefit.

We also concluded that the cost-effectiveness of switching to a No. 2 fuel oil with a sulfur content of 0.3% is $11,218/gallon, and the cost-effectiveness of switching to ULSD with a sulfur content of 0.0015% is $8,627/gallon. We further noted that one facility already had a contract in place for ULSD at a lower price than we assumed, which if used in our analysis would result in a cost effectiveness of $3,970/ton. Although the cost-effectiveness of switching to a lower sulfur oil (assuming our price for ULSD of $1.667/gal) is higher than other controls that we have typically required under BART, we note certain mitigating factors.

For instance, arguing against control, our calculated cost-effectiveness values are high in relation to other BART controls we have required in the past. Also, our visibility modeling necessarily utilized the maximum SO_2 emissions over a 24-hour timeframe,[136] resulting in the configuring of our visibility modeling to analyze the maximum short-term potential impacts that could occur when the unit burns fuel oil. However, as we discuss elsewhere in our proposal, these units are primarily gas-fired, and have only occasionally burned fuel oil. Their most recent practices appear to reinforce this trend.

Arguing for control, unlike the wet FGD and SDA scrubbers we have costed in other sections of this TSD, which have large capital costs, we are unaware of any significant capital costs involved in switching fuels. This means the overall annual costs are relatively minor, if the units in question adhere to their historical usages. Also, because the units in question have only occasionally burned fuel oil, they have the option to avoid the cost of fuel switching entirely by not continuing to burn fuel oil and instead relying solely on their primary fuel of natural gas. Lastly, we note that the prevalence of ULSD in the fuel oil market is such that it appears to be gradually replacing most other No. 2 fuel oil applications.[137]

The preamble to the Regional Haze Rule counseled that a one percent sulfur content limitation on fuel oil should be considered as a "starting point," [138] and the existing sulfur content limits are lower than one percent. Considering all of this information, we propose that SO_2 BART for the gas-fired units that occasionally burn fuel oil should be no further control. In so doing, we acknowledge the data quality issues we have discussed concerning these units and we specifically request comments on all aspects of our proposed BART analysis for these units from all interested parties. Based on the comments we receive, we may either finalize our BART determinations for these units as proposed, or we may revise them without a re-proposal.

D. PM BART

We propose to disapprove the portion of the Texas Regional Haze SIP that sought to address the BART requirement for EGUs for PM. We note that all of the coal-fired units are either currently fitted with a baghouse, an ESP and a polishing baghouse, or an ESP. We conclude that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted with an ESP.

[134] We have read reports that CPS Energy, is planning to retire J T Deely Units 1 and 2 by the end of 2018, but we have no enforceable documents to that effect.

[135] 70 FR 39171 (July 6, 2005).

[136] See the BART Guidelines at 70 FR 39162, July 6, 2005: "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."

[137] *http://www.eia.gov/todayinenergy/detail.php?id=5890. http://blogs.platts.com/2014/05/07/heating-oil-new-york-sulfur/. http://oilandenergyonline.com/challenges-to-the-northeast-supply-picture/.*

[138] 70 FR at 39134.

Consequently, we propose that PM BART for the coal-fired units is an emission limit of 0.030 lb/MMBtu along with work practice standards. We propose that PM and SO_2 BART for the units that only fire gas be pipeline natural gas. We propose that PM and SO_2 BART for those gas-fired units that occasionally burn fuel oil be the existing permitted fuel oil sulfur content of 0.7% sulfur by weight or pipeline natural gas.

V. Proposed Actions

A. Regional Haze

We are proposing to disapprove the portion of the Texas Regional Haze SIP that sought to address the BART requirement for EGUs for PM. We are proposing to promulgate a FIP as described in this notice and summarized in this section to satisfy the remaining outstanding regional haze requirements that are unmet by the Texas' regional haze SIP and that we did not take action on in our January 5, 2016 final action.[139] Our proposed FIP includes SO_2 and PM BART emission limits for sources in Texas to reduce emissions that contribute to regional haze in Texas' two Class I areas and other nearby Class I areas and make reasonable progress for the first regional haze planning period for Texas' two Class I areas.

1. NO_X BART

As discussed elsewhere in this proposal, we are proposing a FIP to replace Texas' reliance on CAIR with reliance on CSAPR to address the NO_X BART requirements for EGUs. This portion of our proposal is based on: The recent update to the CSAPR rule;[140] and the EPA's finalization of a separate proposed finding that the 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.[141] We cannot finalize this portion of the proposed FIP unless and until the EPA finalizes the proposed finding that CSAPR continues to be better than BART because finalization of that proposal would allow for reliance on CSAPR participation as an alternative to source-specific EGU BART for NO_X in Texas.

2. SO_2 BART for Coal-Fired Units

We propose that SO_2 BART for the coal-fired units be the following SO_2 emission limits to be met on a 30 Boiler Operating Day (BOD) period:

TABLE 33—PROPOSED SO_2 BART EMISSIONS LIMITS FOR COAL-FIRED UNITS

Unit	Proposed SO_2 emission limit (lbs/MMBtu)
Scrubber Upgrades	
Martin Lake 1	0.12
Martin Lake 2	0.12
Martin Lake 3	0.11
Monticello 3	0.05
Scrubber Retrofits	
Big Brown 1	0.04
Big Brown 2	0.04
Monticello 1	0.04
Monticello 2	0.04
Coleto Creek 1	0.04
Fayette 1	0.04
Fayette 2	0.04
Harrington 061B	0.06
Harrington 062B	0.06
J T Deely 1	0.04
J T Deely 2	0.04
W A Parish 5	0.04
W A Parish 6	0.04
Welsh 1	0.04

We propose that compliance with these limits be within five years of the effective date of our final rule for Big Brown Units 1 and 2; Monticello Units 1 and 2; Coleto Creek Unit 1; Harrington Units 061B and 062B; J T Deely Units 1 and 2; W A Parish Units 5 and 6; and Welsh Unit 1. This is the maximum amount of time allowed under the Regional Haze Rule for BART compliance. We based our cost analysis on the installation of wet FGD and SDA scrubbers for these units, and in the past we have typically required that scrubber retrofits under BART be operational within five years.

We propose that compliance with these limits be within three years of the effective date of our final rule for Martin Lake Units 1, 2, and 3; and Monticello Unit 3. We believe that three years is appropriate for these units, as we based our cost analysis on upgrading the existing wet FGD scrubbers of these units, which we believe to be less complex and time consuming that the construction of a new scrubber.

We propose that compliance with these limits be within one year for Fayette Units 1 and 2. We believe that one year is appropriate for these units because the Fayette units have already demonstrated their ability to meet these emission limits.

3. Potential Process for Alternative Scrubber Upgrade Emission Limits

In our BART FIP TSD, we discuss how we calculated the SO_2 removal efficiency of the units we analyzed for scrubber upgrades. We note that due to a number of factors we could not accurately quantify, our calculations of scrubber efficiency may contain some error. Based on the results of our scrubber upgrade cost analysis, we do not believe that any reasonable error in calculating the true tons of SO_2 removed affects our proposed decision to require emission reductions, as all of the scrubber upgrades we analyzed are cost-effective (low $/ton). In other words, were we to make reasonable adjustments in the tons removed to account for any potential error in our scrubber efficiency calculation, we would still propose to upgrade these SO_2 scrubbers. We believe we have demonstrated that upgrading an underperforming SO_2 scrubber is one of the most cost-effective pollution control upgrades a coal fired power plant can implement to improve the visibility at Class I areas. However, our proposed FIP does specify a SO_2 emission limit that is based on 95% removal in all cases. This is below the upper end of what an upgraded wet SO_2 scrubber can achieve, which is 98–99%, as we have noted in our BART FIP TSD. We believe that a 95% control assumption provides an adequate margin of error for any of the units for which we have proposed scrubber upgrades, such that they should be able to comfortably attain the emission limits we have proposed. However, for the operator of any unit that disagrees with us on this point, we propose the following:

(1) The affected unit should comment why it believes it cannot attain the SO_2 emission limit we have proposed, based on a scrubber upgrade that includes the kinds of improvements (*e.g.,* elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically included in a scrubber upgrade.

(2) After considering those comments, and responding to all relevant comments in a final rulemaking action, should we still require a scrubber upgrade in our final FIP we will provide the company the following option in the FIP to seek a revised emission limit after taking the following steps:

(a) Install a CEMS at the inlet to the scrubber.

(b) Pre-approval of a scrubber upgrade plan conducted by a third party engineering firm that considers the kinds of improvements (*e.g.,* elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically performed during a scrubber upgrade. The goal of this plan will be to maximize the unit's overall SO_2 removal efficiency.

[139] 81 FR 296.
[140] 81 FR 74504.
[141] 81 FR 78954.

(c) Installation of the scrubber upgrades.

(d) Pre-approval of a performance testing plan, followed by the performance testing itself.

(e) A pre-approved schedule for 2.a through 2.d.

(f) Should we determine that a revision of the SO_2 emission limit is appropriate, we will have to propose a modification to the BART FIP after it has been promulgated. It should be noted that any proposal to modify the SO_2 emission limit will be based largely on the performance testing and may result in a proposed increase or decrease of that value.

4. SO_2 BART for Gas-fired Units That Burn Oil

We propose that SO_2 BART for the following gas-fired units that occasionally burn fuel oil be the existing permit limits for the sulfur content of the fuel oil:

TABLE 34—PROPOSED BART SO_2 EMISSION LIMITS GAS UNITS THAT OCCASIONALLY BURN OIL

Facility	Fuel Oil Sulfur Content (percent by weight)
Graham 2	0.7
Newman 2*	0.7
Newman 3*	0.7
O W Sommers 1	0.7
O W Sommers 2	0.7
Stryker Creek ST2	0.7
Wilkes 1	0.7

*The Newman Units 2 and 3 are further limited to burning fuel oil for no more than 876 hours per year.

5. PM BART

We propose that PM BART limits for the coal units, Big Brown Units 1 and 2; Monticello Units 1, 2, and 3; Martin Lake Units 1, 2, and 3; Coleto Creek Unit 1; J T Deely Units 1 and 2; W A Parish Units 5 and 6; Welsh Unit 1; Harrington Units 061B and 062B; and Fayette Units 1 and 2 are 0.030 lb/MMBtu and work practice standards, which we present below:

TABLE 35—PM BART EMISSIONS STANDARDS AND WORK PRACTICE STANDARDS

Unit Type	PM BART Proposal
Coal-Fired BART Units	0.03 lb/MMBtu filterable PM Table 3 to Subpart UUUUU
Gas-Fired Only BART Units	Pipeline quality natural gas
Oil-Fired BART Units when not firing natural gas	Fuel Content not to exceed 0.7% sulfur by weight (also SO_2 BART)

We propose that compliance with these emissions standards and work practice standards be the effective date of our final rule, as the affected facilities' should already be meeting them.

We propose that PM and SO_2 BART for the units that only fire gas, Newman Unit 4; W A Parish Unit 4; and Wilkes Units 2 and 3 be pipeline natural gas.

We propose that PM and SO_2 BART for those gas-fired units that occasionally burn fuel oil, Newman Unit 2 and 3; O W Sommers Units 1 and 2; Stryker Creek Unit ST2; and Wilkes Unit 1 be the existing permitted fuel oil sulfur content of 0.7% sulfur by weight.

B. Interstate Visibility Transport

We are proposing to disapprove Texas' SIP revisions addressing interstate visibility transport under CAA section 110(a)(2)(D)(i)(II) for six NAAQS. We further are proposing a FIP to fully address Texas' interstate visibility transport obligations for: (1) 1997 8-hour ozone, (2) 1997 $PM_{2.5}$ (annual and 24 hour), (3) 2006 $PM_{2.5}$ (24-hour), (4) 2008 8-hour ozone, (5) 2010 1-hour NO_2 and (6) 2010 1-hour SO_2. The proposed FIP is based on the finding that our proposed action to fully address the Texas Regional Haze BART program is adequate to ensure that emissions from Texas do not interfere with measures to protect visibility in nearby states in accordance with CAA section 110(a)(2)(D)(i)(II).

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Overview

This proposed action is not a ''significant regulatory action'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011). The proposed FIP would not constitute a rule of general applicability, because it only proposes source specific requirements for particular, identified facilities (8 total).

B. Paperwork Reduction Act

This proposed action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. Section 3501 *et seq*. Because it does not contain any information collection activities, the Paperwork Reduction Act does not apply. See 5 CFR 1320(c).

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and small governmental jurisdictions. For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's proposed rule on small entities, I certify that this action will not have a significant impact on a substantial number of small entities. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule. This rule does not impose any requirements or

create impacts on small entities. This proposed FIP action under Section 110 of the CAA will not create any new requirement with which small entities must comply. This action, when finalized, will apply to 14 facilities owned by 8 companies, none of which are small entities. Accordingly, it affords no opportunity for the EPA to fashion for small entities less burdensome compliance or reporting requirements or timetables or exemptions from all or part of the rule. The fact that the CAA prescribes that various consequences (*e.g.,* emission limitations) may or will flow from this action does not mean that the EPA either can or must conduct a regulatory flexibility analysis for this action. We have therefore concluded that, this action will have no net regulatory burden for all directly regulated small entities.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on state, local, and Tribal governments and the private sector. Under Section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to state, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more (adjusted for inflation) in any one year. Before promulgating an EPA rule for which a written statement is needed, Section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of Section 205 of UMRA do not apply when they are inconsistent with applicable law. Moreover, Section 205 of UMRA allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under Section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that Title II of UMRA does not apply to this proposed rule. In 2 U.S.C. Section 1502(1) all terms in Title II of UMRA have the meanings set forth in 2 U.S.C. Section 658, which further provides that the terms ''regulation'' and ''rule'' have the meanings set forth in 5 U.S.C. Section 601(2). Under 5 U.S.C. Section 601(2), ''the term 'rule' does not include a rule of particular applicability relating to . . . facilities.'' Because this proposed rule is a rule of particular applicability relating to 12 named facilities, EPA has determined that it is not a ''rule'' for the purposes of Title II of UMRA.

E. Executive Order 13132: Federalism

This proposed action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This proposed rule does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments. Thus, Executive Order 13175 does not apply to this rule.

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks[142] applies to any rule that: (1) Is determined to be economically significant as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children. EPA interprets EO 13045 as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under Section 5–501 of the EO has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action is not subject to EO 13045 because it implements specific standards established by Congress in statutes. However, to the extent this proposed rule will limit emissions of SO_2, NO_X, and PM, the rule will have a beneficial effect on children's health by reducing air pollution.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This proposed action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12 of the National Technology Transfer and Advancement Act (NTTAA) of 1995 requires Federal agencies to evaluate existing technical standards when developing a new regulation. To comply with NTTAA, EPA must consider and use ''voluntary consensus standards'' (VCS) if available and applicable when developing programs and policies unless doing so would be inconsistent with applicable law or otherwise impractical. EPA believes that VCS are inapplicable to this action. Today's action does not require the public to perform activities conducive to the use of VCS.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994), establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. We have determined that this proposed rule, if finalized, will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population.

[142] 62 FR 19885 (Apr. 23, 1997).

This proposed federal rule limits emissions of NO_X, SO_2, and PM from 14 facilities in Texas.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxides, Visibility, Interstate transport of pollution, Regional haze, Best available control technology.

Dated: December 9, 2016.

Ron Curry,

Regional Administrator, Region 6.

Title 40, chapter I, of the Code of Federal Regulations is proposed to be amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

* 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart SS—Texas

* 2. Section 52.2287 is added to read as follows:

§52.2287 Best Available Retrofit Requirements (BART) for SO_2 and Particulate Matter and Interstate pollutant transport provisions; What are the FIP requirements for visibility protection?

(a) *Applicability.* The provisions of this section shall apply to each owner or operator, or successive owners or operators, of the coal or natural gas burning equipment designated below.

(b) *Definitions.* All terms used in this part but not defined herein shall have the meaning given them in the CAA and in parts 51 and 60 of this title. For the purposes of this section:

24-hour period means the period of time between 12:01 a.m. and 12 midnight.

Air pollution control equipment includes selective catalytic control units, baghouses, particulate or gaseous scrubbers, and any other apparatus utilized to control emissions of regulated air contaminants that would be emitted to the atmosphere.

Boiler-operating-day means 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.

Daily average means the arithmetic average of the hourly values measured in a 24-hour period.

Heat input means heat derived from combustion of fuel in a unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources. Heat input shall be calculated in accordance with 40 CFR part 75.

Owner or Operator means any person who owns, leases, operates, controls, or supervises any of the coal or natural gas burning equipment designated below.

PM means particulate matter.

Regional Administrator means the Regional Administrator of EPA Region 6 or his/her authorized representative.

Unit means one of the natural gas, gas and/or fuel oil, or coal-fired units covered in this section.

(c) *Emissions limitations and compliance dates for SO_2.* The owner/operator of the units listed below shall not emit or cause to be emitted pollutants in excess of the following limitations from the subject unit. Compliance with the requirements of this section is required as listed below unless otherwise indicated by compliance dates contained in specific provisions.

Unit	Proposed SO_2 emission limit (lbs/MMBtu)	Compliance date (from the effective date of the final rule) (years)
Martin Lake 1	0.12	3
Martin Lake 2	0.12	3
Martin Lake 3	0.11	3
Monticello 3	0.05	3
Big Brown 1	0.04	5
Big Brown 2	0.04	5
Monticello 1	0.04	5
Monticello 2	0.04	5
Coleto Creek 1	0.04	5
Fayette 1	0.04	1
Fayette 2	0.04	1
Harrington 061B	0.06	5
Harrington 062B	0.06	5
J T Deely 1	0.04	5
J T Deely 2	0.04	5
W A Parish 5	0.04	5
W A Parish 6	0.04	5
Welsh 1	0.04	5

(d) *Emissions limitations and compliance dates for PM.* The owner/operator of the units listed below shall not emit or cause to be emitted pollutants in excess of the following limitations from the subject unit. Compliance with the requirements of this section is required as listed below unless otherwise indicated by compliance dates contained in specific provisions.

(1) Coal-Fired Units at Big Brown Units 1 and 2; Monticello Units 1, 2, and 3; Martin Lake Units 1, 2, and 3; Coleto Creek Unit 1; J T Deely Units 1 and 2; W A Parish Units 5 and 6; Welsh Unit 1; Harrington Units 061B and 062B; and Fayette Units 1 and 2.

(i) Normal operations: Filterable PM limit of 0.030 lb/MMBtu.

(ii) Work practice standards specified in 40 CFR part 63, subpart UUUUU, Table 3, and using the relevant definitions in 63.10042.

(2) Gas-Fired Units at Newman Unit 4; Wilkes Units 2 and 3; and W A Parish Unit 4 shall burn only pipeline natural gas, as defined in 40 CFR 72.1

(3) Gas-fired units that also burn fuel oil at Graham Unit 2; Newman Units 2 and 3; O W Sommers Units 1 and 2; Stryker Creek Unit ST2; and Wilkes shall burn 0.7% sulfur content fuel or pipeline natural gas, as defined in 40 CFR 72.1.

(4) Compliance for the units included in Section (d) shall be as of the effective date of the final rule.

(e) *Testing and monitoring.* (1) No later than the compliance date of this regulation, the owner or operator shall install, calibrate, maintain and operate Continuous Emissions Monitoring Systems (CEMS) for SO_2 on the units covered under paragraph (c) of this section. Compliance with the emission limits for SO_2 shall be determined by using data from a CEMS.

(2) Continuous emissions monitoring shall apply during all periods of operation of the coal or natural gas burning equipment, including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments. Continuous monitoring systems for measuring SO_2 and diluent gas shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant in an hour) if data are unavailable as a result of performance of calibration, quality assurance, preventive maintenance activities, or backups of data from data acquisition and handling system, and recertification events. When valid SO_2 pounds per hour, or SO_2 pounds per million Btu emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments, emission data must be obtained by using other monitoring systems approved by the EPA to provide emission data for a minimum of 18 hours in each 24 hour period and at least 22 out of 30 successive boiler operating days.

(3) Compliance with the PM emission limits for units in paragraph (d)(1) shall be demonstrated by the filterable PM methods specified in 40 CFR part 63, subpart UUUUU, Table 7.

(f) *Reporting and recordkeeping requirements.* Unless otherwise stated all requests, reports, submittals, notifications, and other communications to the Regional Administrator required by this section shall be submitted, unless instructed otherwise, to the Director, Multimedia Division, U.S. Environmental Protection Agency, Region 6, to the attention of Mail Code: 6MM, at 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733. For each unit subject to the emissions limitation in this section and upon completion of the installation of CEMS as required in this section, the owner or operator shall comply with the following requirements:

(1) For SO_2 each emissions limit in this section, comply with the notification, reporting, and recordkeeping requirements for CEMS compliance monitoring in 40 CFR 60.7(c) and (d).

(2) For each day, provide the total SO_2 emitted that day by each emission unit. For any hours on any unit where data for hourly pounds or heat input is missing, identify the unit number and monitoring device that did not produce valid data that caused the missing hour.

(3) Records for demonstrating compliance with the SO_2 and PM emission limitations in this section shall be maintained for at least five years.

(g) *Equipment operations.* At all times, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and operate the unit including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Regional Administrator which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the unit.

(h) *Enforcement.* (1) Notwithstanding any other provision in this implementation plan, any credible evidence or information relevant as to whether the unit would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed, can be used to establish whether or not the owner or operator has violated or is in violation of any standard or applicable emission limit in the plan.

(2) Emissions in excess of the level of the applicable emission limit or requirement that occur due to a malfunction shall constitute a violation of the applicable emission limit.

* 3. In §52.2304, paragraph (f) is added to read as follows:

§52.2304 Visibility protection.

* * * * *

(f) *Measures addressing disapproval associated with NO_X, SO_2, and PM.* (1) The deficiencies associated with NO_X identified in EPA's disapproval of the regional haze plan submitted by Texas on March 31, 2009, are satisfied by Section 52.2283.

(2) The deficiencies associated with SO_2 and PM identified in EPA's disapproval of the regional haze plan submitted by Texas on March 31, 2009, are satisfied by Section 52.2287.

[FR Doc. 2016–30713 Filed 1–3–17; 8:45 am]

BILLING CODE 6560–50–P

To: Feldman, Michael[Feldman.Michael@epa.gov]
From: Kordzi, Joe
Sent: Wed 1/25/2017 10:08:14 PM
Subject: FW: Webinar to Discuss the Final Regional Haze Rule Revisions?

Do you know if this is still on?

From: Margaret Earnest [mailto:margaret.earnest@tceq.texas.gov]
Sent: Wednesday, January 25, 2017 3:17 PM
To: Kordzi, Joe <Kordzi.Joe@epa.gov>
Subject: Webinar to Discuss the Final Regional Haze Rule Revisions?

Joe,

Just ckecking to make sure this webinar in on for Thurs? The previous Jan webinar was cancelled but I didn't get the message and thought I was having technical difficulties! ☺ Mostly I thought it was operator error or ME.

Webinar Announcement: Informational Public Webinar to Discuss the Final Regional Haze Rule Revisions

EPA plans to hold an informational public webinar on Thursday, January 26, 2017 from 12:30-2:00pm EST. During this webinar, we will provide an overview of the final Regional Haze Rule revisions. There is no phone line; audio will be only via the webinar.

Webinar URL: https://epawebconferencing.acms.com/reghazeamend

Hope all is well.

Margaret Earnest

State Implementation Plan Team, TCEQ

Austin TX

512-239-4581

To: Medina, Dayana[Medina.Dayana@epa.gov]; Huser, Jennifer[Huser.Jennifer@epa.gov]; Kordzi, Joe[Kordzi.Joe@epa.gov]; Feldman, Michael[Feldman.Michael@epa.gov]; Snyder, Erik[snyder.erik@epa.gov]; Grady, James[Grady.James@epa.gov]
From: Donaldson, Guy
Sent: Thur 1/12/2017 2:40:43 PM
Subject: FW: RH rule published today and notice of webinar reschedule

From: Theresa Pella [mailto:tpella@censara.org]
Sent: Tuesday, January 10, 2017 11:35 AM
To: Ashley Jurgensmeyer <ashley.jurgensmeyer@dnr.mo.gov>; Ashley Keas <Ashley.Keas@dnr.mo.gov>; Ann Spitz <aspitz@kdheks.gov>; Avey, Lance <Avey.Lance@epa.gov>; Beverly Botchlet-Smith <beverly.botchlet-smith@deq.ok.gov>; Bret Anderson <baanderson02@fs.fed.us>; Brooks Kirlin <brooks.kirlin@deq.ok.gov>; Carrie Wiese <carrie.wiese@nebraska.gov>; Catharine Fitzsimmons <catharine.fitzsimmons@dnr.iowa.gov>; Cheryl Bradley <Cheryl.Bradley@deq.ok.gov>; David Clark <CLARKD@adeq.state.ar.us>; David Brown <dave.l.brown@nebraska.gov>; Donna Huff <dhuff@tceq.texas.gov>; Douglas Watson <dwatson@kdheks.gov>; Eddie Terrill <eterrill@deq.ok.gov>; Gilberto Cuadra <Gilberto.Cuadra@LA.GOV>; Donaldson, Guy <Donaldson.Guy@epa.gov>; Heather.Lerch@deq.ok.gov; japrentice@kdheks.gov; Jim Price <jim.price@tceq.texas.gov>; Jocelyn Mellberg <jocelyn.mellberg@tceq.texas.gov>; Harper, Jodi <Harper.Jodi@epa.gov>; Kordzi, Joe <Kordzi.Joe@epa.gov>; john babin <john.babin@la.gov>; John Minter <john.minter@tceq.texas.gov>; jprentice@kdheks.gov; Kathy Pendleton <kathy.pendleton@tceq.texas.gov>; Kevin Stoner <kevin.j.stoner@nebraska.gov>; Kim Herndon <kim.herndon@tceq.texas.gov>; Kyra Moore <kyra.moore@dnr.mo.gov>; laura.finley@deq.ok.gov; Lee Warden <Lee.Warden@deq.ok.gov>; lisa.alam@nebraska.gov; Logan, Judy <jlogan@fs.fed.us>; Lynn Deahl <LDeahl@kdheks.gov>; margaret.earnest@tceq.texas.gov; Mark McCorkle <MAC@adeq.state.ar.us>; Matthew Johnson <matthew.johnson@dnr.iowa.gov>; Feldman, Michael <Feldman.Michael@epa.gov>; Jay, Michael <Jay.Michael@epa.gov>; montgomery@adeq.state.ar.us; patricia_f_brewer@nps.gov; patricia.maliro@dnr.mo.gov; Petre, Jacob <Jacob.Petre@deq.ok.gov>; Rick Brunetti <rbrunetti@kdheks.gov>; Ron Thomas <ron.thomas@tceq.texas.gov>; Sonya Eastern <Sonya.Eastern@LA.GOV>; spencer@adeq.state.ar.us; Stacy Allen <stacy.allen@dnr.mo.gov>; stephanie.shirley@tceq.texas.gov; Krabbe, Stephen <Krabbe.Stephen@epa.gov>; Stephen M. Hall <stephen.hall@dnr.mo.gov>; Terry Salem <terry.salem@tceq.texas.gov>; Theresa Pella <tpella@censara.org>; Tim Allen <tim_allen@fws.gov>; Tim E. Burns (PWks) <tim.burns@cityofomaha.org>; vennetta.hayes@la.gov; Vivian Aucoin <Vivian.Aucoin@LA.GOV>; Walker Williamson <walker.williamson@tceq.texas.gov>; Wendy Walker <wendy.walker@dnr.iowa.gov>; Wharton, Tracy <tracy.wharton@nebraska.gov>; Wilbur, Emily <emily.wilbur@dnr.mo.gov>; Wolkins, Jed <wolkins.jed@epa.gov>; Melanie Foster <Melanie.foster@deq.ok.gov>; melissa.mcdonald@ks.gov
Subject: Fw: RH rule published today and notice of webinar reschedule
Importance: High

looks like this only went to the tribal distribution list - sorry..

Theresa

Theresa Pella, Executive Director

Central States Air Resource Agencies Association (CenSARA)

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From: Theresa Pella
Sent: Tuesday, January 10, 2017 9:03 AM
To: alisha.bartling@santeeoep.com; Andres Monreal; Anita Hicks; April Hathcoat; Arthur Muller; Bob Haskins; Chris Spencer; Craig Kreman; Darren Shields; Ernie Redbird; Felix Kitto; Gardner Rose; Heather Webb; Jenna Battise; Joseph Painter; Ken Jones; Sara Aultman; Summer King; Susie Attocknie; Tom Elkins; Tony Darden; Virginia LeClere
Subject: RH rule published today and notice of webinar reschedule

The final rule revisions published today (link below). Also just found out the webinar scheduled for today is postponed until Jan. 26th.

https://www.gpo.gov/fdsys/pkg/FR-2017-01-10/pdf/2017-00268.pdf

“This is just note to let you know that the public webinar regarding the final regional haze rule revisions which was originally planned for tomorrow, January 10, 2017, has been moved to January 26, 2017 from 12:30 to 2:00pm EST. Information on how to participate in the webinar is located at: https://www.epa.gov/visibility/webinar-announcement-informational-public-webinar-discuss-final-regional-haze-rule. “

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To: Tomasovic, Brian[Tomasovic.Brian@epa.gov]; Donaldson, Guy[Donaldson.Guy@epa.gov]; Medina, Dayana[Medina.Dayana@epa.gov]; Steib, Clovis[steib.clovis@epa.gov]; Kordzi, Joe[Kordzi.Joe@epa.gov]; Feldman, Michael[Feldman.Michael@epa.gov]
Cc: Deese, William[deese.william@epa.gov]
From: Deese, William
Sent: Tue 1/10/2017 7:03:47 PM
Subject: FW: Now posted to Regulations.gov: TX187.0056 Compilation of Select Declarations From Litigation Over Texas Oklahoma FIP. RE: Please Add to Files for the Docket (Declarations cited in Grid Reliability Section)
Compilation of Select Declarations from Litigation over TX-OK FIP.pdf

From: Deese, William
Sent: Tuesday, January 10, 2017 12:47 PM
To: Deese, William <deese.william@epa.gov>
Subject: FYI: Now posted to Regulations.gov: TX187.0056 Compilation of Select Declarations From Litigation Over Texas Oklahoma FIP. RE: Please Add to Files for the Docket (Declarations cited in Grid Reliability Section)

Feld, Kor Med brian steib donald

https://www.regulations.gov/docketBrowser?rpp=25&so=DESC&sb=docId&po=0&dct=SR%2BO%2BFR%2BR06-OAR-2016-0611

From: Kordzi, Joe
Sent: Monday, January 09, 2017 3:47 PM
To: Deese, William <deese.william@epa.gov>
Subject: FW: Please Add to Files for the Docket (Declarations cited in Grid Reliability Section)

Pls add ASAP

From: Tomasovic, Brian
Sent: Monday, January 09, 2017 2:47 PM
To: Kordzi, Joe <Kordzi.Joe@epa.gov>; Deese, William <deese.william@epa.gov>

Cc: Donaldson, Guy <Donaldson.Guy@epa.gov>
Subject: FW: Please Add to Files for the Docket (Declarations cited in Grid Reliability Section)

Joe,

Correct me if I'm wrong, but I don't think the attached ever got added to the docket.

I think it should be added as soon as possible.

-Brian

From: Tomasovic, Brian
Sent: Tuesday, December 06, 2016 8:51 AM
To: Kordzi, Joe <Kordzi.Joe@epa.gov>
Subject: Please Add to Files for the Docket (Declarations cited in Grid Reliability Section)

1. Please add attached to docket.

2. I offered some edits to TSD yesterday. Ex. 5 - Deliberative Process, Attorney Clientt

Ex. 5 - Deliberative Process, Attorney Clientt

Brian Tomasovic

U.S. EPA Region 6 | Office of Regional Counsel

tomasovic.brian@epa.gov | 214.665.9725

DECLARATION OF KEN SMITH

1. I am vice president of construction management at Luminant, a competitive power generation subsidiary of Energy Future Holdings Corp. I will use "Luminant" in this declaration to refer to all Luminant entities that are petitioners in this matter. I make this declaration in support of Luminant's motion to stay the Texas regional haze rule issued by the U.S. Environmental Protection Agency. *See Approval and Promulgation of Implementation Plans; Texas and Oklahoma; Regional Haze State Implementation Plans; Interstate Visibility Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze; Federal Implementation Plan for Regional Haze*, 81 Fed. Reg. 296 (Jan. 5, 2016) ("Final Rule"). This declaration is based on my personal knowledge and opinions which I am qualified to provide based on my education, training, and extensive experience in the power generation industry as discussed below.

2. As discussed in more detail below, the Final Rule, if not stayed by the Court, will cause immediate and irreparable harm to Luminant. The Final Rule imposes a massive build-out requirement on the majority of Luminant's coal-fueled electric generating units. The harm from the Final Rule includes unrecoverable costs and expenditures, in the hundreds of millions of dollars, which Luminant would incur in the near term in order to begin work on the additional equipment and upgrades that EPA is requiring at Luminant's generating units. Because Luminant operates in Texas's competitive power market, these costs cannot be recovered if the Final Rule is found illegal by the Court, as Luminant contends it should be.

My Background

3. I have been with Luminant, including its predecessor, for over 40 years and have a broad expertise in power generation and project management. During my tenure, I have worked on a wide variety of projects involving the design and construction of pollution control systems, including project management for Luminant's environmental retrofit program with full accountability for design, construction, and start-up of new pollution-control equipment on the existing coal generating fleet. I am currently involved

in analyzing and advising executive management on the implications of the Final Rule, including the cost and timeline for compliance projects.

4. I joined Luminant's generating business, known then as Texas Utilities Generating Company, in 1975 as a chemical technician at the Big Brown lignite-fueled generating plant in Fairfield, Texas. Over the course of my career, I have held various positions regarding plant operations and management. Since 2004, I have, among other duties, led the development and rollout of Luminant's system to improve efficiency of operational processes as well as its assessment of emission control equipment to meet new environmental requirements.

5. I graduated from Texas A&M University in 1975 with a bachelor's degree in biomedical science. I received my master's degree in business administration from Baylor University in 2001.

Luminant's Electricity Generating Fleet

6. Luminant is the largest power generation company in Texas, with more than 13,700 megawatts ("MW") of generating capacity. Luminant operates nine lignite mines and generates electricity at twelve solid fuel-fired generating units, in addition to natural gas and nuclear units. Luminant's generating portfolio on a capacity basis is composed of 58% coal, 17% nuclear, and 25% natural gas, based on 2015 data. Not included in these figures is Luminant's recently announced planned acquisition of nearly 3,000 MW of additional gas-fired generation capacity.[1]

7. Luminant's coal-fueled generating fleet, described below, is comprised of twelve units at five plants that can generate approximately 8,017 MW of electricity. For perspective, the Martin Lake plant generates enough electricity to power about 1.125 million homes in normal conditions.

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[1] Luminant, *Luminant Announces the Acquisition of the La Frontera Portfolio from NextEra Energy Resources*, (Nov. 27, 2015), https://www.luminant.com/luminant-announces-the-acquisition-of-the-la-frontera-portfolio-from-nextera-energy-resources/#.Vmbu1bgrJQI.

a. Oak Grove: This plant has two units, both fueled by 100% lignite, that produce approximately 1,600 MW of power.

b. Sandow: This plant has two units which are also fueled by 100% lignite and which currently produce approximately 1,137 MW of power.

c. Martin Lake: This plant has three units producing approximately 2,250 MW of power. These units are currently fueled by a blend of lignite and Powder River Basin ("PRB") coal.

d. Big Brown: This plant has two units, produces approximately 1,150 MW of power, and is presently fueled by a blend of lignite and PRB coal.

e. Monticello: This plant has three units, produces approximately 1,880 MW of power, and is presently fueled by a blend of lignite and PRB coal.

8. In 2014, Luminant contributed approximately 20% of the electricity dispatched to Texas consumers and businesses by the Electric Reliability Council of Texas ("ERCOT"), the independent system operator that manages the state's unique competitive power market and the electric power grid that serves the majority of the state. The ERCOT market is a "power island" contained within Texas and separated from neighboring interconnections by asynchronous ties that limit imports and exports to and from the ERCOT market. Approximately 98% of the electricity generated in the ERCOT market is consumed in the ERCOT market. Texas's economic growth (as measured by gross state product year-over-year growth) has been one of the highest in the United States for the period 2005-2015, and Texas's electric consumption has followed its growth. The state of Texas relies upon access to affordable, reliable generation to continue to fuel its economic expansion and that of the United States. Luminant's generating units are critical to the reliable operation of the ERCOT grid, and ERCOT relies heavily on Luminant to meet the area's increasing demand. In the summer of 2015, for example, the hourly demand on the ERCOT system broke the all-

time peak record three times in one week.[2] Demand ultimately peaked at 69,783 MW on August 10, 2015,[3] with all Luminant plants available and supplying nearly 14,000 MW to the grid at the time.

EPA's Regional Haze Rule for Texas

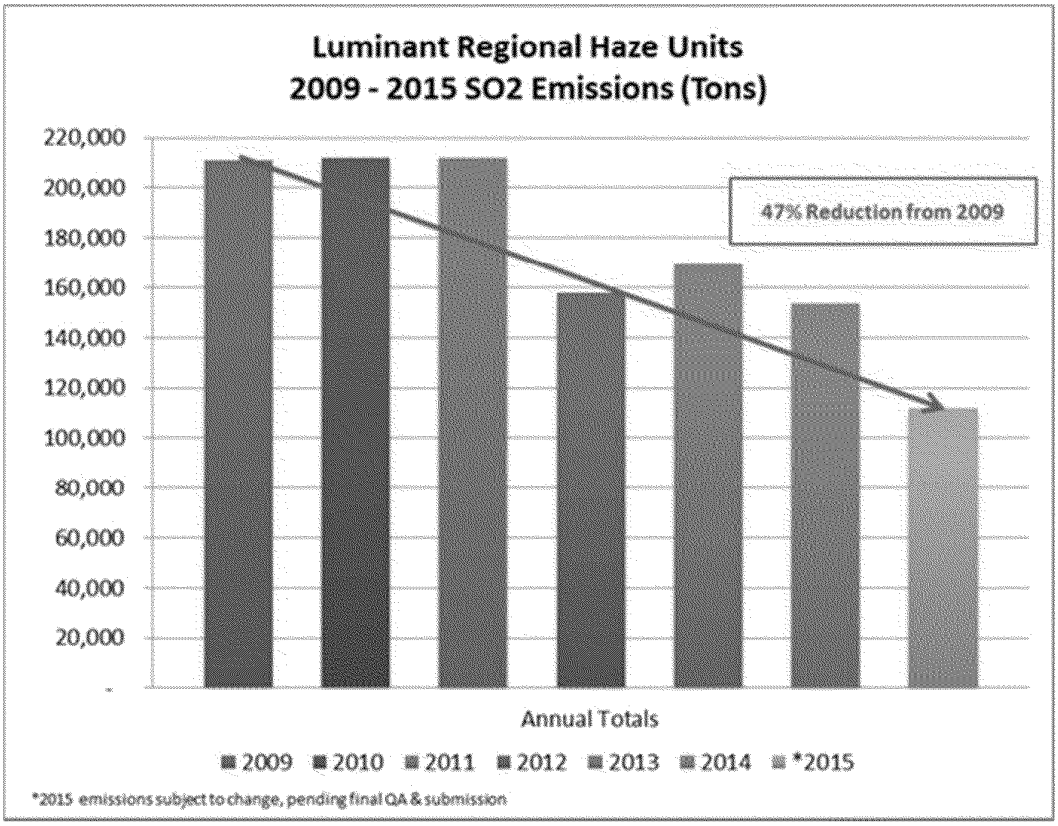
9. The Final Rule imposes various sulfur dioxide ("SO_2") emission limits on fifteen units at eight Texas coal-fueled power plants, including Luminant's Sandow Unit 4, Martin Lake Units 1-3, Big Brown Units 1 & 2, and Monticello Units 1-3. These units are already subject to limits on their SO_2 emissions by various state and federal regulations, including the federal Acid Rain Program and the Cross State Air Pollution Rule, and they reduce their emissions through various means, including operating flue gas desulfurization systems (known as "scrubbers") and/or using low-sulfur content coal.

10. Contrary to EPA's assumptions in the Final Rule, these units have decreased their SO_2 emissions substantially over the last 5-10 years. For example, SO_2 emissions from Luminant's units included in the Final Rule were reduced by over 47% from 2009 to 2015, as shown in the table below. Luminant expects this trend of lower SO_2 emissions from these units to continue through 2018.

---

[2] ERCOT, *ERCOT System Breaks 69,000 MW in Hourly Peak Demand for the First Time Ever* (Aug. 10, 2015), http://www.ercot.com/news/press_releases/show/73057.

[3] *Id.*



11. The more stringent emission limits in the Final Rule could be satisfied only by either upgrading current scrubbers or installing new scrubbers at tremendous expense. EPA's limits would require the installation of new scrubbers at four of Luminant's units (Big Brown Units 1 & 2 and Monticello Units 1 & 2) and scrubber upgrades at five of Luminant's units (Sandow Unit 4, Martin Lake Units 1-3, and Monticello Unit 3). No company is more heavily impacted by the Final Rule than Luminant.

12. Based on its analysis of the time needed for compliance, EPA has established separate compliance timeframes for the new scrubbers and the scrubber upgrades. The new scrubbers must be installed and operational within five years (February 4, 2021), and the scrubber upgrades must be installed and operational within three years (February 4, 2019). Our internal analysis confirms that at least this amount of lead time is needed to complete the work EPA is mandating.

13. EPA has projected that the Final Rule will result in approximately $2 billion in expenditures by five Texas electric generators, over half of which would be borne by Luminant. As projected by EPA, however, these expenditures would result in visibility improvements by 2018 that are not perceptible to the human eye—0.14 deciviews at Wichita Mountains National Wildlife Refuge, 0.03 deciviews at Big Bend National Park, and 0.04 deciviews at Guadalupe Mountains National Park. But in fact, visibility monitoring data shows that the goals that EPA establishes for these areas have already been met, without the costly requirements in the Final Rule.

Compliance Efforts Required by the Final Rule

14. The construction of four scrubbers by February 2021 and the installation of scrubber upgrades at five units by February 2019 would require an immense and unprecedented construction effort on behalf of Luminant and its contractors. Luminant has experience constructing this type of equipment at its units, but not on the scale and magnitude as required by the Final Rule within the same three to five year period. Extensive planning has already begun and requires immediate expenditures by Luminant. For Luminant's units, EPA has estimated a total capital-only cost of approximately $1.02 billion for the four new scrubbers. Of this amount, over $300 million would need to be spent in 2016 and 2017 in order to be on track to meet EPA's deadlines. Even more money would need to be committed for equipment, with the imposition of termination exposure should the project get cancelled in the future. Due to the overlapping construction schedules across four different facilities, Luminant must plan carefully to avoid any potential reliability issues. All of these units cannot be taken off-line at the same time due to reliability concerns. The work must be coordinated to ensure that Luminant can meet its load requirements during outages. This further extends the timeline required, and means that, in the absence of a stay from the Court, Luminant would need to begin planning, design, and other pre-construction work immediately to meet EPA's emission limits.

15. Luminant is currently involved in the preliminary phases of assessing and planning for the installation of four new scrubbers at Big Brown and Monticello. This, in

and of itself, costs the company money that would not be spent absent the rule. Further work is required in the near-term. To meet EPA's deadlines, the formal bid process for engineering work would begin in mid-2016, and front-end engineering and design would begin in the third quarter of 2016. The bid process includes developing system specification for bid, bid period, evaluation, selection, and negotiation of contracts. The front-end engineering and design includes developing design criteria, site arrangement drawings, and engineering studies. Commitment for the major equipment would be required as early as the fourth quarter of 2016. Detailed engineering would begin in mid-2017 and would include ductwork design, piping, electrical, and substructure. Permitting for the new scrubbers would begin in the second quarter of 2017 and would include the retainer of consultants, modeling, applicability determinations, developing and submitting the permit application, and meeting with regulators. Based on a reasonable cash flow analysis for projects of this magnitude and EPA's own estimate of costs, combined spending in 2016 and 2017 would be over $300 million for the new scrubbers.

16. Luminant has also begun the preliminary phases of assessing planning for the scrubber upgrades at Sandow, Martin Lake, and Monticello. Again, this, in and of itself, costs the company money that would not be spent absent the rule. Further work is required in the near-term to meet EPA's schedule. Design and engineering for the upgrades would take place in 2016, and, beginning in early 2017, Luminant would procure and begin installation of the necessary equipment for the scrubber upgrades. EPA has estimated the construction costs for the scrubber upgrades at the five additional Luminant units to be between $225 - $270 million.

17. To meet the three- and five-year deadlines imposed by EPA, Luminant must immediately proceed with steps to install new scrubbers and upgrade current scrubbers. If a stay of the Final Rule is not granted, Luminant would need to spend several hundred million dollars in 2016 and 2017 in order to comply with EPA's schedules. If Luminant is successful in its challenge to the Final Rule, it would have no recourse against EPA to recover these costs.

I, Ken Smith, declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed this 1st day of March, 2016.

Ken Smith
Luminant Generation Company LLC

Declaration of Robert Frenzel,
Sr. Vice President and Chief Financial Officer,
Luminant Generation Company LLC

DECLARATION OF ROBERT FRENZEL

1. I am the Senior Vice President and Chief Financial Officer ("CFO") of Luminant Generation Company LLC ("Luminant"), a subsidiary of Energy Future Holdings Corp. ("EFH Corp."). I am providing this declaration in support of Luminant's motion to stay the Texas regional haze rule issued by the U.S. Environmental Protection Agency ("EPA") on January 5, 2016. *See Approval and Promulgation of Implementation Plans; Texas and Oklahoma; Regional Haze State Implementation Plans; Interstate Visibility Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze; Federal Implementation Plan for Regional Haze*, 81 Fed. Reg. 296 (Jan. 5, 2016) ("Final Rule"). This declaration is based on my personal knowledge and analysis conducted by Luminant staff and me.

2. The Final Rule, if not stayed, would impose substantial unrecoverable costs on Luminant during the next 12-18 months and would further threaten the long-term economic viability of several of Luminant's electric generating units. Were these units to shut down because they could not operate economically under the rule, it would cause significant job losses and economic impacts in the local communities that depend on these plants. The impact of the rule and the harm it will cause Luminant are detailed below.

MY BACKGROUND

3. I joined EFH Corp. in 2009 and served as the senior vice president for corporate development, strategy, and mergers and acquisitions prior to beginning my current role as CFO in 2012. Before joining EFH Corp., I was a senior vice president in the investment banking division of Goldman Sachs & Co. and focused on strategic and financial transactions within the energy industry. Prior to my career in business, I served as a nuclear engineering officer and weapons officer in the United States Navy and in the Navy Reserves as a lieutenant commander

before resigning my commission in 2007. I earned a Bachelor's Degree in Industrial Engineering from Georgia Tech and a Master's of Business Administration from the University of Chicago Graduate School of Business.

4. As CFO of Luminant, I am familiar with the Texas electricity market and Luminant's business, day-to-day operations, financial matters, the value of its assets, and its underlying books and records.

SUMMARY OF IRREPARABLE HARMS CAUSED BY EPA'S FINAL RULE

5. The Final Rule will have severe and detrimental impacts on Luminant's operations. As detailed below, these harms are already occurring and would continue to occur in 2016 and 2017 without a stay. In summary, EPA's rule:

a. Requires substantial unrecoverable compliance costs in 2016 and 2017 in order to begin the work required to meet EPA's deadlines;

b. Is likely to force the closure of the Big Brown and Monticello plants and remaining mines by requiring hundreds of millions of dollars of capital investment that would make the plants, which are already under significant economic pressure due to depressed wholesale power prices in the state, uneconomic to operate at all; and

c. Is likely to cause substantial loss of jobs, both at the plants and the remaining mines that support them, and negatively impact the local communities that depend on the plants.

6. These harms would be irreversible. Luminant cannot recover these costs from EPA or anyone else, and plant closures cannot likely be reversed due to loss of skilled workforce. Without a stay of the Final Rule, irreparable harm will occur immediately and well in advance of the deadlines for meeting the emission limitations in the Final Rule.

7. These harms are imminent and acute because Luminant operates in a highly competitive marketplace in which the price of electricity—and ultimately Luminant's profitability—is set by market forces, not by regulated rates. Luminant operates in the Texas market overseen by the

Electric Reliability Council of Texas ("ERCOT"). The ERCOT market is unique in its competitive market design. Because ERCOT lies wholly within the boundaries of the state, Texas was able to restructure the ERCOT market to convert Texas's investor-owned utilities from a traditional rate-regulated structure into a "deregulated" competitive market at both the wholesale and retail levels. Luminant is thus unable to recover the costs associated with the Final Rule from "ratepayers." Instead, those costs are borne by Luminant and directly impact the economic viability of the plants at issue.

LUMINANT'S OPERATIONS AND ECONOMIC IMPACT

8. Luminant is the largest power generation company in Texas. Luminant owns and operates over 13,700 megawatts ("MW") of installed generation capacity in Texas. This includes approximately 8,017 MW fueled by lignite and subbituminous coal. Luminant's generating portfolio is made up of 58% coal (including approximately 2,200 MW of new coal generation that came online in 2009 and 2010), 17% nuclear, and 25% natural gas, based on 2015 data.[1] Luminant's nuclear units are considered "baseload" units that operate at full capacity consistently throughout the year. Luminant's natural gas units are simple cycle steam gas units that are economical to operate a very limited amount of time during the year to satisfy electricity "peak" demand—they do not operate as baseload units. Thus, the electricity generated by Luminant's coal units—which are threatened by the Final Rule—cannot simply be replaced by Luminant's other units.

[1] Not included in these figures is Luminant's recently announced planned acquisition of nearly 3,000 MW of additional gas-fired generation capacity. *See* Luminant, *Luminant Announces the Acquisition of the La Frontera Portfolio from NextEra Energy Resources*, (Nov. 27, 2015), https://www.luminant.com/luminant-announces-the-acquisition-of-the-la-frontera-portfolio-from-nextera-energy-resources/#.Vmbu1bgrJQI.

9. Company-wide, Luminant employs approximately 4,000 full-time employees and contracts with independent contractors that provide approximately 2,000 individual independent contractors to work at Luminant's plants and mines in the state of Texas. Luminant spends approximately $2.2 billion annually in the form of salaries, taxes, fuel, maintenance, and other operating and capital expenditures, and its impact on gross state product and gross domestic product is substantial.

10. Luminant's coal-fueled generating units are located at five generating plants (Big Brown, Martin Lake, Monticello, Sandow, and Oak Grove) that produce approximately 8,017 MW of power used by approximately three million Texans across the state. Luminant's coal-fueled units are "mine mouth" plants that often use lignite coal from mines located near the plants to fuel the generating units.

11. In 2014, Luminant contributed approximately 20% of the electricity dispatched to Texas consumers and businesses by ERCOT, the independent system operator that manages the state's unique competitive power market and the electric power grid that serves the majority of the state. The ERCOT market is a "power island" contained within Texas and separated from neighboring interconnections by asynchronous ties that limit imports and exports to and from the ERCOT market. Approximately 98% of the electricity generated in the ERCOT market is consumed in the ERCOT market.

12. Texas's economic growth (as measured by gross state product year-over-year growth) has been one of the highest in the United States for the period 2005-2015, and Texas's electric consumption has followed its growth. The state of Texas relies upon access to affordable, reliable generation to continue to fuel its economic expansion and that of the United States. Luminant's generating units are critical to the reliable operation of the ERCOT grid, and ERCOT

relies heavily on Luminant to meet the area's increasing demand. In the summer of 2015, for example, the hourly demand on the ERCOT system broke the all-time peak record three times in one week.[2] Demand ultimately peaked at 69,783 MW on August 10, 2015,[3] with all Luminant plants available and supplying nearly 14,000 MW to the grid at the time.

THE REGIONAL HAZE RULE'S REQUIREMENTS FOR TEXAS

13. EPA claims that the Final Rule is needed to improve visibility at three Class I areas—Big Bend and Guadalupe Mountains National Parks in Texas and the Wichita Mountains National Wildlife Refuge in Oklahoma. All three of these areas, however, are located hundreds of kilometers from Luminant's plants. The map below shows Luminant's units at issue in the Final Rule in relation to the three areas. The map also shows industrial facilities in Texas and Oklahoma that are much closer than Luminant's facilities to these areas, but that EPA did not include in the rule. The yellow dots represent industrial facilities in Oklahoma that EPA did not even evaluate for their impacts on the Wichita Mountains.

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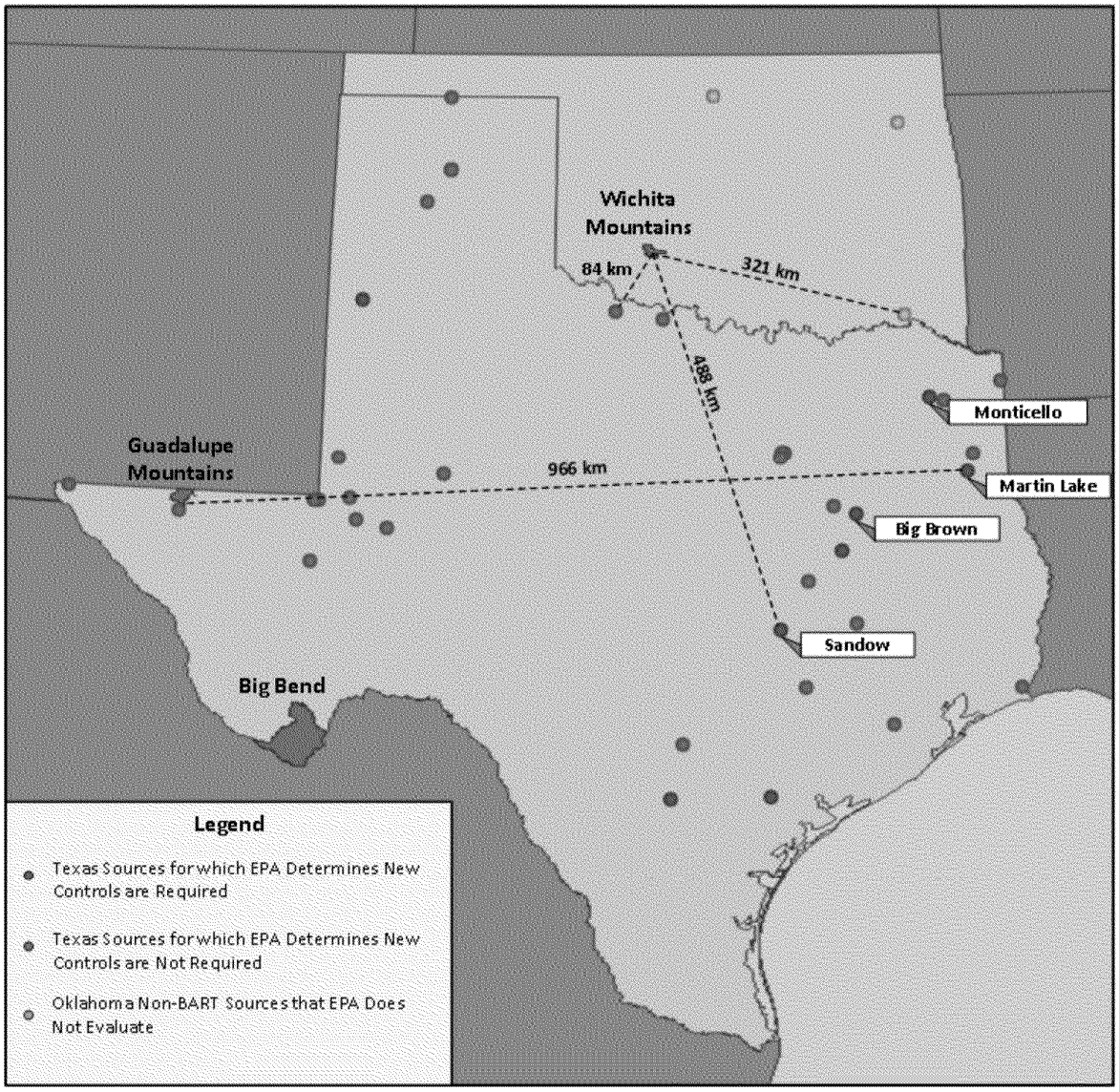
[2] ERCOT, *ERCOT System Breaks 69,000 MW in Hourly Peak Demand for the First Time Ever* (Aug. 10, 2015), http://www.ercot.com/news/press_releases/show/73057.

[3] *Id.*



14. EPA claims that stringent new emission limits for sulfur dioxide ("SO_2") are needed at Luminant's units. These units are already subject to SO_2 emission limits under various state and federal regulations, but the Final Rule would impose even more stringent limits. The Final Rule imposes various SO_2 emission limits on fifteen units at eight Texas coal-fueled power plants, including Luminant's Sandow Unit 4, Martin Lake Units 1-3, Big Brown Units 1 & 2, and Monticello Units 1-3.

15. Emissions of SO_2 can be reduced by various means, including operating flue gas desulfurization systems (known as "scrubbers"), using low-sulfur content coal, and applying various sorbents to the coal or at various places in the combustion process to reduce sulfur. EPA's Final Rule imposes the most stringent and costly means of reducing SO_2 emissions and sets overreaching limits that may not be able to be achieved or sustained by upgrades or retrofits.

16. The only possibility of meeting the stringent emission limits in the Final Rule would require upgrading current scrubbers at some facilities and installing new scrubbers at others at tremendous expense. EPA's limits would require the installation of new scrubbers at four of Luminant's units (Big Brown Units 1 & 2 and Monticello Units 1 & 2) and scrubber upgrades at five of Luminant's units (Sandow Unit 4, Martin Lake Units 1-3, and Monticello Unit 3). No company is more impacted by the Final Rule or required to spend more than Luminant.

17. EPA has established separate compliance timeframes for the new scrubbers and the scrubber upgrades. The new scrubbers must be installed and operational within five years (February 4, 2021), and the scrubber upgrades must be installed and operational within three years (February 4, 2019).

18. Under the Final Rule, EPA has projected that five Texas electric generators will spend approximately $2 billion to comply with the newly established SO_2 emission limits. Per EPA's estimates, Luminant's share of these required expenditures would total more than $1 billion. However, in the Final Rule, EPA projects only miniscule visibility improvements at three Class I areas by the end of the first regional haze planning period (2018) that would not even be perceptible to the human eye—0.14 deciviews at Wichita Mountains, 0.03 deciviews at Big Bend, and 0.04 deciviews at Guadalupe Mountains, according to EPA.

EPA'S RULE CAUSES IMMEDIATE, IRREPARABLE HARM TO LUMINANT

19. The Final Rule will impose massive costs on Luminant in order to comply. For Luminant's four units that are required to install, maintain, and operate new scrubbers, EPA has estimated a total capital-only cost of approximately $1.02 billion, as shown below.

EPA-Calculated Capital Costs for New Scrubbers at Luminant Units[4]

Unit	Capital Costs
Big Brown Unit 1	$256 million
Big Brown Unit 2	$259 million
Monticello Unit 1	$250 million
Monticello Unit 2	$254 million
Total Capital-Only Costs for New Scrubbers	**$1.02 billion**

20. In addition to these capital-only costs, EPA estimates the variable and fixed operating costs for these new scrubbers as follows:

[4] 79 Fed. Reg. 74,818, 74,877 (Dec. 16, 2014).

EPA-Calculated Variable and Fixed Operating Costs for New Scrubbers at Luminant Units[5]

Unit	Variable and Fixed Annual Operating Costs
Big Brown Unit 1	$17 million
Big Brown Unit 2	$17 million
Monticello Unit 1	$13 million
Monticello Unit 2	$14 million
Total Variable and Fixed Annual Operating Costs for New Scrubbers	**$61 million**

21. In addition, EPA is imposing substantial additional costs at five additional Luminant units in the form of upgrade work to existing scrubbers. EPA has estimated the construction costs for the scrubber upgrades at the five additional Luminant units to be between $225 - $270 million.

22. EPA overestimated SO_2 emission reductions that are continuously achievable on a long-term basis for the scrubber upgrades and retrofit scrubber technologies. This is particularly concerning for Luminant to expend extraordinary amounts of money and potentially be unable to comply with the ultra-low emission limits EPA has mandated.

23. As discussed in more detail below, costs of this magnitude will harm Luminant financially in at least two ways—by requiring substantial and immediate expenditures for necessary work such as planning and design and long-lead time procurement as to all of the plants at issue and by threatening the economic viability of the four units that would be required to install, maintain, and operate new scrubbers.

[5] EPA, Technical Support Document for the Cost of Controls Calculations for the Texas Regional Haze Federal Implementation Plan (Cost TSD) 24 (Nov. 2014) ("Cost TSD").

EPA's Rule Requires Unrecoverable Compliance Costs in 2016 and 2017

24. Luminant personnel have assessed the expenditures necessary to comply with EPA's Final Rule, as detailed in the declaration of my colleague Ken Smith, vice president of construction management at Luminant. As explained in his declaration, due to the three- and five-year deadlines imposed by EPA, Luminant would need to immediately proceed with steps to install new scrubbers and upgrade current scrubbers if it is to meet EPA's deadlines. If a stay of the Final Rule is not granted, Luminant would need to spend over $300 million just in 2016 and 2017 in order to meet EPA's three- and five-year compliance schedules.

25. Importantly, these expenditures are unrecoverable from either "ratepayers" or the EPA. Given Texas's competitive market structure, these costs are borne by Luminant alone and directly impact Luminant's profitability. Moreover, given the need to immediately begin to assess and plan for EPA's Final Rule, even if these units are ultimately shut down because the Final Rule has made them uneconomic to operate, these near-term costs will still be necessary unless the rule is stayed.

EPA's Final Rule Threatens the Long-Term Viability of Big Brown and Monticello Plants

26. The Final Rule would require the construction and installation of new scrubbers at Big Brown Units 1 & 2 and Monticello Units 1 & 2. Each unit would require its own new scrubber installation for a total capital-only cost of over $1 billion, as calculated by EPA

27. As indicated in EFH Corp.'s recent quarterly SEC filing, the costs associated with the stringent emission limits imposed on Big Brown and Monticello threaten the long-term economic viability of these units. In its 10-K Report for the fiscal year ended December 31, 2015, Luminant's parent (EFH Corp.) explained that "new scrubbers at the Big Brown and Monticello units necessary to achieve the emission limits required by the [regional haze] FIP (if those limits are even possible to attain), along with the existence of low wholesale power prices in ERCOT,

would likely challenge the long-term economic viability of those units."[6] As explained in this 10-K Report, these units are already under significant economic pressure due to currently depressed wholesale power prices in the state, and the requirements of the Final Rule would likely challenge their overall economic viability.

28. Similarly, ERCOT has determined that the Final Rule will require Luminant and other operators subject to the Final Rule to shut down their plants, impacting reliability. In a 2014 assessment, ERCOT determined that "3,000 MW to 8,500 MW of coal-fired capacity in ERCOT can be considered to have a moderate to high risk of retirement—due primarily to the costs of EPA's proposed requirements for the Regional Haze program."[7] The closure of Luminant's Big Brown and Monticello plants alone would result in the loss of over 3,000 MW. As calculated by ERCOT, the cost of EPA's Final Rule "is an order of magnitude larger than the capital costs associated with other environmental regulations" assessed by ERCOT.[8] Based on this assessment, ERCOT concluded that "[t]he retirement of existing capacity in ERCOT could result in localized transmission reliability issues due to the loss of fossil fuel-fired generation resources in and around major urban centers, and will strain ERCOT's ability to integrate new intermittent renewable generation resources."[9]

29. Indeed, even before the decision to shut down the plants is made, the economic implications of the Final Rule are causing financial harm to Luminant in the market. Financial analysts are already predicting the closure of Luminant's units and others, and these reports

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[6] Form 10-K, Energy Future Holdings Corp. (March. 1, 2016) (emphasis added).

[7] ERCOT, *Impacts of Environmental Regulations in the ERCOT Region*, at ii (Dec. 16, 2014), http://www.ercot.com/content/news/presentations/2014/Impacts%20of%20Environmental%20Regulations%20in%20the%20ERCOT%20Region.pdf.

[8] *Id.* at 26.

[9] *Id.* at 36.

create economic uncertainty and disadvantage Luminant. For example, research reports prepared by UBS Securities LLC ("UBS") project that the viability of Monticello and Big Brown and other units subject to the Final Rule are threatened by its stringent and costly requirements. In a December 2015 report, UBS stated that it "suspect[s] all of [the units identified in the Final Rule] could be at risk of premature retirement either upon rule implementation or prior, as any material investment in the states' coal portfolio would appear unpalatable given the weak power price outlook."[10] UBS further stated that it "suspect[s] multiple plants may opt to retire earlier than the actual implementation date given the negative FCF [free cash flow] projected in the interim."[11] Reports like these change investment decisions, impact the cost and availability of capital, and have other financial impacts in the ERCOT's highly competitive market.

Plant Closures Would Have Negative Impacts in Surrounding Communities

30. Closure of Luminant's Big Brown and Monticello Plants and the remaining mines that support the plants would not just impact Luminant, it would have impacts on the surrounding communities. The jobs that would be lost due to these closures are typically among the highest-paying jobs in these communities, and similar job opportunities may be limited or nonexistent. There will also be a significantly reduced tax base for the local communities where these plants and mines are located, which will negatively impact local schools and hospitals. While the economics of these plants are already under significant pressure, the requirements of the Final Rule would ensure their closure in light of current conditions, in my assessment.

31. The closure of two EGUs at Big Brown, two EGUs at Monticello, and the remaining mines would eliminate hundreds of jobs. This will be a heavy blow to Luminant, its employees,

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[10] UBS, US Electric Utilities & IPPs, *ERCOT: Ever More Hazed and Confused*, at 1 (Dec. 10, 2015).

[11] *Id.*

and its employees' families. In many cases, Luminant employees have been working for the company for decades and some families have multiple generations working for Luminant.

32. The impact of these closures on the local communities where Luminant's affected plants and mines are located will be significant. The impacted communities are rural Texas communities where Luminant is one of the largest taxpayers, employers, and community supporters. The value of Luminant's facilities, and therefore the amount of local taxes paid to these communities, will also be substantially reduced. In addition, the dollars that Luminant employees spend in these communities will be significantly reduced and relocation away from the communities will impact property values, further reducing the tax base of those communities.

33. EPA previously attempted to subject these plants to stringent new SO_2 limits through its Cross State Air Pollution Rule ("CSAPR"), like it is doing here. Fortunately, the U.S. Court of Appeals for the D.C. Circuit stayed CSAPR pending judicial review, and it later determined that EPA's limits for Texas and Luminant's plants were illegal. Without the stay and the court's ruling, Luminant would have been forced at that time to cease operations at three Texas lignite mines in east Texas and idle two EGUs at Monticello, resulting in similar effects on local communities that would occur in this case.

34. EPA also previously attempted to subject these plants to new limits on carbon dioxide ("CO_2") emissions starting in 2022 (a year after the new SO_2 limits for Big Brown Units 1 & 2 and Monticello Units 1 & 2 in the Final Rule). Those limits, like those in the Final Rule, would have threatened the plants' economic viability. This was part of EPA's so-called "Clean Power Plan." Fortunately, the U.S. Supreme Court issued a stay of that EPA rule on February 9, 2016, pending judicial review of the rule.

I, Robert Frenzel, declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct. Executed this 2nd day of March, 2016.

Robert Frenzel
Senior Vice President and Chief Financial Officer
Luminant Generation Company LLC

Declaration of David Hudson,
President, Southwestern Public Service Company

DECLARATION OF DAVID HUDSON IN SUPPORT OF MOTION TO STAY FINAL RULE OF THE U.S. ENVIRONMENTAL PROTECTION AGENCY BY LUMINANT GENERATION COMPANY LLC, SOUTHWESTERN PUBLIC SERVICE COMPANY, AND COLETO CREEK POWER LP

I, David Hudson, hereby state as follows:

1. I am President of Southwestern Public Service Company ("SPS"), a wholly owned subsidiary of Xcel Energy Inc. I am making this declaration in support of the Luminant Generation Company LLC, Southwestern Public Service Company, and Coleto Creek Power LP ("Texas Energy Petitioners") motion to stay the final regional haze plan for Texas issued by the U.S. Environmental Protection Agency, titled "Approval and Promulgation of Implementation Plans; Texas and Oklahoma; Regional Haze State Implementation Plans; Interstate Visibility Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze; Federal Implementation Plan for Regional Haze," 81 Fed. Reg. 296 (Jan. 5, 2016) ("Final Rule").

2. I am over 18 years of age, of sound mind, and in all respects competent to make this declaration. I have personal knowledge of all facts stated in this declaration and those facts are true and correct.

3. I have been employed by SPS and its related companies for over 32 years. I received a Bachelor of Science degree in Industrial Engineering from Texas Tech University in 1983 and a Master of Business Administration degree from West Texas State University (now West Texas A&M University) in 1990. I am a licensed professional engineer by the State of Texas.

4. SPS is an electric utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in portions of west Texas and eastern New Mexico. SPS provides electrical utility service to approximately 378,000 retail customers, deriving approximately 75% of its operating revenues from retail customers in 2015. SPS is a regulated utility company subject to the rate and general operating jurisdiction of the Public Utility Commission of Texas ("PUCT"), the New Mexico Public Regulation Commission ("NMPRC"), and the Federal Energy Regulatory Commission.

5. The SPS system consists of two coal plants (five units), five natural gas plants (18 units), and one fuel oil unit for a total of 4487 megawatts ("MW") of generating capacity. SPS also has 2,308 MW of wind generation connected to the electrical system that includes 1,775 MW of long-term purchased energy contract and qualifying facilities, and 50 MW of solar generation. SPS's summer peak load in 2015 was 4694 MW.

6. One of the two coal plants owned and operated by SPS, the Tolk Generating Station ("Tolk Plant"), located in Lamb County, Texas, and near the town of Muleshoe, Texas, is subject to the Final Rule. The Tolk Plant consists of two coal-fired electric generating units. Unit 1 has a net capacity of 532 MW and Unit 2 has a net capacity of 535 MW. The two Tolk Plant

generating units were built and placed into commercial operation in 1982 and 1985 respectively. Tolk Plant Units 1 and 2 are an integral part of the SPS system, constituting 24% of the capacity owned by SPS on its system.

7. The Final Rule will require Tolk Plant Units 1 and 2 to each meet a sulfur dioxide ("SO_2") emissions limit of 0.06 lb/mmBtu by February 2021. These emission limits are based on the installation of dry scrubbers, one on each Tolk Plant unit.

8. The Final Rule, if not stayed by the Court, will expose SPS to immediate and irreparable harm. To meet the Final Rule's SO_2 emission limits at Tolk Plant, SPS must make plans now for compliance, which will require SPS to begin making commitments and significant financial investments in the near future. SPS will either need to design, gain regulatory approval for, construct, and make operational dry scrubbers on both Tolk Plant units by February 2021 or cease operation of the units by that date. It will subject SPS to irreparable harm to have to make this "fork in the road" decision before the Court determines the merits of SPS's appeal of the Final Rule. To avoid making an irrevocable decision that could jeopardize the company and its customers, SPS likely will need to pursue both options absent a stay of the Final Rule, at substantially greater expense.

9. Generation from the Tolk Plant is necessary for SPS to provide reliable electricity generation to its customers and meet its obligations to the Southwestern Power Pool ("SPP"), of which SPS is a member. If SPS decides to shut down the Tolk Plant units by February 2021, SPS will have to provide new generating capacity and energy by that date so that it will be able to continue to meet its customer's peak power demands and energy requirements and the SPP's planning reserve margin criteria.

10. The Tolk Plant provides 1067 MW of net dependable summer capacity to the SPS system. In the last three years, the Tolk Plant units have operated at a 76% capacity factor. This high capacity factor reflects nearly continual operation of the Tolk Plant to provide reliable base-load power to SPS customers. SPS cannot meet its reserve responsibilities without the Tolk Plant. To provide reliable service, all electric utilities must have more capacity available than the projected peak load because actual load can exceed the projected peak. The available capacity in excess of the projected peak load is referred to as the "reserve margin." The SPP requires that the projected peak demand of each member utility, including SPS, not exceed 88% of each utility's total firm capacity, which is a 12% capacity reserve margin. Accordingly, if SPS decides to shut down the Tolk Plant units, it will need to provide replacement capacity and energy in accordance with SPP planning and operating criteria.

11. A capacity replacement plan would consist of designing, gaining regulatory approval for, constructing and making operational a new alternative generating unit or units to provide peak demand capacity and electricity to our customers. These activities will need to commence immediately to allow startup of the new unit or units by February 2021.

12. Because SPS is a rate-regulated utility, costs incurred are recoverable from customers, but cost recovery from SPS's Texas and New Mexico retail customers can occur only after the costs are reviewed and approved by the PUCT and NMPRC. If costs are not approved or if recovery is significantly delayed, SPS could receive inadequate recovery of costs incurred.

For these reasons, extensive regulatory proceedings are likely that will generate substantial public interest and participation; a lengthy process that could take 10-13 months to complete.

13. In addition, construction of a new plant will require a Certificate of Convenience and Necessity ("CCN") from the PUCT and a Certificate of Public Convenience and Necessity ("CPCN") from the NMPRC. These regulatory proceedings will likely generate significant public and customer participation and could take 6-12 months to complete.

14. To construct replacement generation by February 2021, SPS will need to begin environmental permit preparation and engineering selection in March 2016, prepare a SPP interconnection filing beginning in July 2016 for filing by October 2016, prepare and apply for an operating air permit by February 2017, prepare and apply for a CCN and a CNPC by March 2017, and start ordering long lead time equipment by January 2017. By the end of 2017, SPS will need to have contracted for approximately $363 million for construction of a replacement plant. *See* Declaration of Alan Davidson for a more detailed explanation of the timeline and costs involved.

15. Ceasing operations at the Tolk Plant and constructing new generating units elsewhere also will cause irreparable harm to the Tolk Plant employees and local businesses. SPS employs 109 highly skilled full-time employees at the Tolk Plant. If SPS ceases operations of the Tolk Plant, the company will have to lay off or reassign all of these employees. If a decision to cease operations is made, it also will be difficult or impossible to retain and replace qualified employees in the interim period before the plant shuts down. In addition, the coal handling and other contractors who support operations at the Tolk Plant employ approximately 45 people who work almost exclusively at the Tolk Plant and will be adversely affected if the Tolk Plant shuts down.

16. The premature retirement of the Tolk Plant also will result in significant financial burdens. The Tolk Plant currently has a net asset balance of approximately $346 million. If the Tolk Plant is retired by February 2021, these stranded assets will have to be borne by the company's customers.

17. If SPS were to choose to continue operating the Tolk Plant and instead install dry scrubbers on the two Tolk Plant units to comply with the Final Rule, this would be a massive construction effort that also would require extensive planning and logistical coordination. SPS would have to begin planning and make financial commitments starting this year. SPS would need to begin preparing bid documents by August 2016, and negotiate and award engineering design contracts by November 2016 to allow engineering to begin in December 2016. SPS also would need to prepare and apply for environmental permits, file applications for a CCN and a CPCN beginning in January 2017, and order the scrubbers by November 2017.

18. Of the approximately $568 million in capital costs that SPS estimates for scrubbers on the Tolk Plant units, SPS will need to have contracted for approximately $148 million by the end of 2017. This is in addition to the expenses associated with obtaining the necessary environmental permits, a CCN and a CPCN. *See* Declaration of Alan Davidson for a more detailed explanation of the timeline and costs involved.

19. Given the necessary and long lead times associated with either compliance option available to SPS, if the Final Rule is not stayed, SPS will need to commit to a path forward before its appeal of the Final Rule is decided to ensure it does not risk non-compliance if the Final Rule is upheld. If SPS is successful in its appeal of the Final Rule, SPS and its customers will have expended tens of millions of dollars preparing an alternative generation source or designing dry scrubbers that would be unnecessary and SPS would have no recourse against EPA to recover these costs.

* * *

I declare under penalty of perjury that the foregoing statements are true and correct based on my personal knowledge and information gathered and provided to me by SPS personnel.

Executed this 2nd day of March, 2016.

David Hudson

David Hudson

Declaration of Alan Davidson,
Director, Regional Capital Projects, Xcel Energy Inc.

DECLARATION OF ALAN DAVIDSON IN SUPPORT OF MOTION TO STAY FINAL RULE OF THE U.S. ENVIRONMENTAL PROTECTION AGENCY BY LUMINANT GENERATION COMPANY LLC, SOUTHWESTERN PUBLIC SERVICE COMPANY, AND COLETO CREEK POWER LP

I, Alan Davidson, hereby state as follows:

1. I am making this declaration on behalf of Southwestern Public Service Company ("SPS"), a wholly owned subsidiary of Xcel Energy Inc. I am employed by Xcel Energy Services Inc. ("XES"), the service company subsidiary of Xcel Energy, as Director, Regional Capital Projects in the Engineering and Construction Department of Energy Supply, which is the generation operation and maintenance business unit of Xcel Energy.

2. This declaration is in support of the Luminant Generation Company LLC, Southwestern Public Service Company, and Coleto Creek Power LP ("Texas Energy Petitioners") motion to stay the final regional haze plan for Texas issued by the U.S. Environmental Protection Agency, titled "Approval and Promulgation of Implementation Plans; Texas and Oklahoma; Regional Haze State Implementation Plans; Interstate Visibility Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze; Federal Implementation Plan for Regional Haze," 81 Fed. Reg. 296 (Jan. 5, 2016) ("Final Rule").

3. I am over 18 years of age, of sound mind, and in all respects competent to make this declaration. I have personal knowledge of all facts stated in this declaration and those facts are true and correct.

4. I received a Bachelor of Science degree in Mechanical Engineering from Texas Tech University in 1984. I am a Registered Professional Engineer in the State of Texas.

5. I have worked in the electric power industry for over 30 years in various positions with Xcel Energy and SPS. In my current position as Director, Regional Capital Projects in the Engineering and Construction Department of Energy Supply, I am responsible for managing the capital budget process and projects for the SPS region within the Energy Supply business unit.

6. I am responsible for the regional capital budget, schedules, development, and construction for all of SPS's capital electric generating projects. I directly manage the major projects for SPS and supervise other managers handling smaller projects. My management duties include safety, technical design selection, engineering and contractor oversight, managing the bidding process, and negotiating major equipment supply agreements. I work with the Environmental, Regulatory, and Resource Planning departments to assist with scoping and planning of new generation and major generation retrofit projects.

7. My experience has included: plant engineering responsibilities for boilers, turbines, and the balance of plant equipment; performance testing and analysis responsibilities for combustion turbines and fossil units; control system design and installation for combustion turbines and

fossil units; photovoltaic systems installation; plant refurbishments; operation and maintenance ("O&M") management; project director for environmental controls projects on coal units; and project director for installation of simple cycle combustion turbines.

8. One of the two coal plants owned and operated by SPS, the Tolk Generating Station ("Tolk Plant"), located in Lamb County, Texas, and near the town of Muleshoe, Texas, is subject to the Final Rule. The Tolk Plant consists of two coal-fired electric generating units. Unit 1 has a net capacity of 532 MW and Unit 2 has a net capacity of 535 MW. The two Tolk Plant generating units were built and placed into commercial operation in 1982 and 1985 respectively.

9. The Final Rule will require Tolk Plant Units 1 and 2 to each meet a sulfur dioxide ("SO_2") emissions limit of 0.06 lb/mmBtu by February 2021. These emission limits are based on the installation of dry scrubbers, one on each Tolk Plant unit.

10. The Final Rule, if not stayed by the Court, will expose SPS to immediate and irreparable harm. SPS will either need to design, gain regulatory approval for, construct, and make operational dry scrubbers on both Tolk Plant units by February 2021 or cease operation of the units by that date.

11. Because SPS may need to pursue both options absent a stay of the Final Rule, SPS has estimated the planning, engineering, and construction timelines to (1) install scrubbers to meet the Final Rule's SO_2 emission limits at the Tolk Plant and (2) construct replacement electric capacity if SPS decides to shutter the Tolk Plant. Both options are significant capital projects that require long lead times. Construction on either of these projects cannot even begin until all necessary permits are issued.

12. Under either scenario, SPS must start work in 2016 to comply with the rule, including making substantial financial commitments in the near future before the Court determines the merits of SPS's appeal of the Final Rule.

13. In my role as Director, Regional Capital Projects in the Engineering and Construction Department of Energy Supply, it has been my responsibility to work with internal resources and engineering vendors to estimate the timeline and costs involved with installing scrubbers at the Tolk Plant or to build new capacity at the Tolk Plant site.

14. The installation of scrubbers is a massive retrofit construction project. The following major construction components will be required according to an engineering vendor: spray dry absorbers; a new fabric filter polishing baghouse and ash removal system (downstream of the scrubber); new induced draft fans; new ductwork; lime storage and preparation systems; all balance of plant infrastructure for the scrubbers; and a new coal ash landfill. To meet the Final Rule's compliance deadline of February 2021, work must begin in 2016 to start the design and acquire the permits necessary for the project. *See* Declaration of David Hudson.

15. According to my estimates, and based on input from the engineering contractors, SPS would need to start by August 2016 to develop a request for proposals for engineering services, and award an engineering contract for the new scrubbers by November 2016. Engineering would need to begin in December 2016. Permit development likely would have to start in January

2017 to assure issuance of an operating air permit by April 2018, which will be required before construction can commence. The scrubbers would have to be ordered by November 2017, and a new polishing baghouse ordered by January 2018.

16. Once all permits are obtained, construction of scrubbers could start around May 2018 and would take approximately 28 months to start the tie-in of the first unit. Start-up and testing of the first unit likely would start around October 2020. A four- to six-week outage of each Tolk Plant unit will be required in the fall of 2020 to tie in the new systems. Since both generation units cannot be off line at the same time, start-up and testing must be phased along with the outages during this period. This schedule is necessary to allow for final compliance by February 2021.

17. My estimate for the committed costs SPS would incur in planning to install scrubbers and meet a February 2021 compliance date is $1.5 million in 2016, $148 million by the end of 2017, $419 million by the end of 2018, $513 million by the end of 2019, $565 million by the end of 2020, and a total of $568 million by 2021. If the appeal of the Final Rule is not decided by the end of 2017, SPS would incur significant irreversible expense just in the time the case is being decided.

18. My cost estimate does not include the costs associated with obtaining the necessary permits, water rights, and infrastructure to obtain and deliver to the Tolk Plant the additional water required to operate the scrubbers. *See* Declaration of David Hudson. My estimate also does not include the approximately $17 million that will be required to build the first phase of a landfill that will be needed for disposal of the flyash when the scrubbers are operating.

19. If scrubbers are not installed, SPS will have to construct replacement generation that will need to be online by February 2021 to prevent interruption of service to SPS customers. *See* Declaration of David Hudson. SPS also will need to begin environmental permit preparation, Southwestern Power Pool ("SPP") interconnection development, and engineering selection in 2016.

20. To construct new replacement capacity that will be in operation by February 2021, I estimate that development of a request for proposals for engineering support would need to commence in March 2016, and that SPS would have to start preparing a SPP interconnection filing in July 2016 for submission by the end of October 2016. The SPP only accepts interconnection requests twice per year. SPS also would need to prepare and apply for a Certificate of Convenience and Necessity ("CCN") from the Public Utilities Commission of Texas and a Certificate of Public Convenience and Necessity ("CPCN") from the New Mexico Public Regulation Commission by March 2017. *See* Declaration of David Hudson.

21. SPS estimates it would need to file for an operating air permit by February 2017 to meet a construction start date of July 2018. SPS would have to start ordering long lead time equipment by January 2017 for construction to commence in July 2018. SPS estimates that start-up and commissioning of the first combustion turbine at a new plant would start in May of 2020, with the start-up and commissioning of the associated steam generating unit and equipment estimated to occur in September 2020.

22. Estimated costs for constructing the replacement capacity would be $10 million in 2016, $363 million by the end of 2017, $717 million by the end of 2018, $810 million by the end of 2019, $859 million by the end of 2020, and $872 million by 2021. These cost estimates do not include the substantial potential expenses of required transmission upgrades that the SPP could impose on the project, or the cost of installing a new natural gas supply pipeline to the plant.

23. If the Final Rule is not stayed, SPS will need to commit to a path forward and incur irrecoverable expenses before its appeal of the Final Rule is decided to ensure it does not risk non-compliance if the Final Rule is upheld. If SPS is successful in its appeal of the Final Rule, it will have expended tens of millions of dollars preparing an alternative generation source or designing dry scrubbers that would be unnecessary and SPS would have no recourse against EPA to recover these costs.

* * *

I declare under penalty of perjury that the foregoing statements are true and correct based on my personal knowledge and information gathered and provided to me by SPS personnel and consulting engineers.

Executed this 2nd day of March, 2016.

Alan Davidson

Declaration of Robert Stevens, Plant Manager, Coleto Creek Power LP

IN THE UNITED STATES COURT OF APPEALS
FOR THE FIFTH CIRCUIT

COLETO CREEK POWER, LP,	)	
	)	**Case No. _____**
Petitioner,	)	
	)	
v.	)	
	)	
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and GINA McCARTHY, Administrator, United States Environmental Protection Agency,	)	
	)	
Respondents.	)	

DECLARATION OF ROBERT STEVENS

I, Robert Stevens, hereby state as follows:

1. I am the Plant Manager at the Coleto Creek Power Plant ("Coleto Creek Plant"), which is owned and operated by Coleto Creek Power, LP ("CCP" or "Petitioner"). I am making this declaration in support of Petitioner's motion to stay the final regional haze plan for Texas and Oklahoma issued by the U.S. Environmental Protection Agency, titled "Approval and Promulgation of Implementation Plans; Texas and Oklahoma; Regional Haze State Implementation Plans; Interstate Visibility Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze; Federal Implementation Plan for Regional Haze," 81 Fed. Reg. 296 (Jan. 5, 2016) ("Final Rule").

2. I am over 18 years of age, of sound mind, and in all respects competent to make this declaration. I have personal knowledge of all facts stated in this declaration and those facts are true and correct.

3. I have worked in the power generation industry since 1985. I have been employed at the Coleto Creek Plant since 1991, when I began serving Maintenance Superintendent. In 2008, I was promoted to my current position as Plant Manager. I graduated from Texas A&I University in Kingsville, Texas in December 1984 with a Bachelor of Science degree in Mechanical Engineering, and I am a professional engineer registered in the state of Texas.

4. Over my 31 years of working in the power generation industry, I have managed the scope design, budget, procurement activities, and installation and commissioning of many large capital improvement projects. I have also managed several major capital improvement

projects to enhance plant performance and efficiency, such as the installation of fabric filters and major repair of boilers, generators and turbines, and control systems.

5. The Coleto Creek Power Plant is located near Fannin in Goliad County, Texas. CCP derived 100% of its operating revenues from the Coleto Creek Plant in 2015. The Coleto Creek Plant consists of one coal-fired electric generating unit with a net power production capacity of 632 megawatts, supplying electricity to approximately 400,000 homes on the Texas electricity grid. Over the last five years, the Coleto Creek Plant has operated at an average capacity of 83 percent. Over 80 employees work at the Coleto Creek Plant, and CCP is the largest industrial taxpayer in Goliad County.

6. The Final Rule imposes a sulfur dioxide ("SO_2") emission limit of 0.04 pounds per million British thermal units ("lb/mmBtu") on the Coleto Creek Plant starting on February 4, 2021. While the Coleto Creek Plant is already subject to the conditions of federal and state air quality permits and standards that strictly limit emissions of air pollutants including SO_2, the emissions limit imposed by the Final Rule, if allowed to stand, would require further reductions of approximately 96 percent in SO_2 emissions.

7. If the Final Rule is not stayed, CCP will need to commit to a path forward this year to ensure it does not risk non-compliance if the Final Rule is upheld. It would subject CCP to irrevocable harm to be required to make this "fork in the road" decision before the Court determines the merits of this appeal. Either way, CCP would incur significant costs to timely comply with the Final Rule's requirements.

8. Prior to the issuance of the Final Rule, CCP and an independent third-party engineer evaluated available control options that would be required to reduce SO_2 emissions to meet the emissions limit imposed by the Final Rule. CCP's prior evaluation in 2011 identified wet flue gas desulfurization ("FGD") scrubber technology as the only available pollution control technology that would reduce SO_2 emissions from the Coleto Creek Plant by 96 percent.

9. The installation of a wet FGD scrubber on the Coleto Creek Plant would require a massive construction effort requiring extensive planning and logistical coordination. CCP determined that the estimated total capital cost of the project to be in the range of $315 to 340 million in 2011 dollars for the project's permitting, design, procurement, fabrication, and construction. CCP's evaluation in 2011 of the costs and schedule for the installation of wet FGD technology is significantly more than the cost estimate on which EPA based its Final Rule. *See* 79 Fed. Reg. 74,818, 74,877 (Dec. 16, 2014) (estimating capital costs of approximately $262 million).

10. The Final Rule, published subsequently to completion of the work summarized in Paragraphs 8 and 9, did not fully consider the impacts of other regulatory actions affecting the choice of SO_2 pollution control technologies for the Coleto Creek Plant. On November 3, 2015, EPA published a final rule titled "Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category," 80 Fed. Reg. 67,838 (Nov. 3, 2015). This final rule issued under the authority of the federal Clean Water Act establishes stringent numerical limits on wastewater discharges from wet FGD scrubber systems based on use of chemical precipitation and biological treatment technologies. On April 17, 2015, EPA

published a final rule titled "Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities," 80 Fed. Reg. 21,302 (Apr. 17, 2015). This final rule issued under the authority in subtitle D of the Resource Conservation and Recovery Act establishes technical requirements for landfills and surface impoundments that manage coal combustion residuals, including materials generated by wet FGD scrubber systems.

11. These two rules have forced CCP to further evaluate available pollution control technologies that are available to meet the Final Rule and these other regulatory actions affecting the design, operation, and cost of pollution control technologies for the Coleto Creek Plant. CCP is incurring costs for this further evaluation, including procurement of outside consulting, that would not be necessary if the Final Rule were stayed by the court. CCP has so far incurred $4,000 in third-party engineering costs in conducting this further evaluation.

12. I am advised that the merits of this appeal may not be decided until late 2017. However, CCP must begin planning and making investment commitments now to be in a position to meet the February 2021 compliance deadline. As a result, failure to grant a stay of the Final Rule pending its review by the courts would expose CCP to irreparable harm.

13. In light of the other regulatory actions mentioned above, CCP and its third-party engineers completed a study after promulgation of the Final Rule, and have concluded that CCP would be required to design, procure, permit, construct, and operate a circulating dry scrubber ("CDS") system at the Coleto Creek Plant to comply with the SO_2 emission limit in the Final Rule. The total capital cost of the CDS scrubber system is estimated to be in the range of $280 to 300 million in 2016 dollars, which, with escalation adjustments for when the work would be performed, corresponds to the range of $330 to 350 million in 2020 dollars. The estimated total capital cost is allocated as follows:

    - 18% for purchased equipment costs, including the CDS itself, a pebble lime system, induced draft fans, and a new pulse jet fabric filter;
    - 27% for direct installation costs, including engineering, demolition, sitework, foundations and concrete, buildings, and process and mechanical equipment;
    - 22% for indirect costs; and
    - 33% for contingencies, general and administrative costs, and fees.

14. The planning, design, procurement, permitting, and construction of a CDS system is estimated to take 56 months, which is consistent with the 60 months EPA has stated is typical for scrubber installations. *See* 79 Fed. Reg. at 74,874. The Final Rule's compliance deadline is less than 60 months away, and CCP will have to commence the project immediately to ensure that it meets the deadline. By May 2016, CCP will have to have selected an owner's engineer, begun an open book procurement process, and issued specifications for the project's engineering, procurement, and construction program. By September 2016, the project will have to have entered the design phase, and by February 2017 the procurement phase will have to have begun in order to meet the compliance deadline. CCP estimates it will have to spend $2 to 3 million in planning and design costs prior to procurement and that it will incur nonrefundable costs of approximately 20% of the total equipment cost in the procurement phase. By Summer 2017, the project's main specifications will have been

issued and major contract packages will have been awarded. Accordingly, by the end of 2017 an estimated $12 to 14 million will have been expended and CCP will have entered into contracts for the construction of the project that will not be cancellable without substantial monetary penalty.

15. Alternatively, CCP will make the decision in 2016 that it will not install the CDS scrubber system if as required to meet the Final Rule and therefore will not continue operations at the Coleto Creek Plant after February 4, 2021. Ceasing operations at the Coleto Creek Plant also will cause irreparable harm to CCP, CCP employees, local businesses, and local government in the region. Ceasing operations would result in the retirement of an asset of CCP with an appraised 2015 market value of $255 million. The Coleto Creek Plant employs approximately 80 operators and staff. CCP is also Goliad County's largest taxpayer. Cessation of CCP's operations would have a significant detrimental effect on economic activity in the region and would cost Goliad County and other local taxing authorities approximately $5 million in annual tax revenue.

16. If CCP is successful in its rehearing or appeal, it will have unnecessarily expended an estimated $12 to 14 million planning designing and procuring equipment for a CDS scrubber system in attempting to comply with the Final Rule. Additionally, CCP will have entered into contracts for the construction of the CDS scrubber system that will not be cancellable without substantial monetary penalty. CCP will have no recourse against the EPA and would never be able to recoup these expenses. Accordingly, absent a temporary stay, the costs of efforts to comply with the Final Rule will be incurred by CCP regardless of whether the Final Rule is ultimately upheld.

* * *

I declare under penalty of perjury that the foregoing statements are true and correct based on my personal knowledge and information gathered and provided to me by CCP personnel.

Executed this 2ND day of March, 2016.

Robert Stevens

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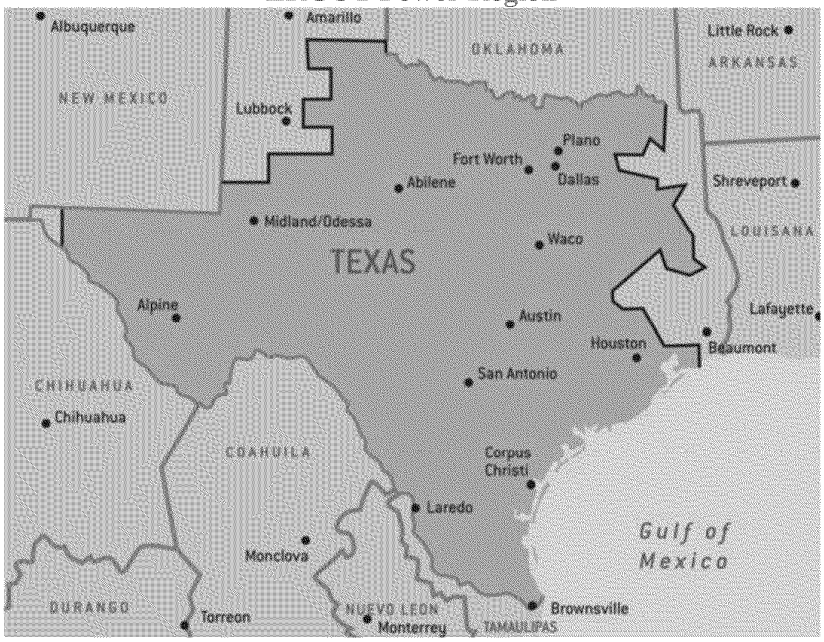

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DECLARATION OF BRIAN H. LLOYD, EXECUTIVE DIRECTOR, PUBLIC UTILITY COMMISSION OF TEXAS

I, Brian H. Lloyd, declare as follows:

1. The purpose of this declaration is to respond to the declarations of Robert M. Fagan and Jeremy I. Fisher filed on behalf of the Environmental Protection Agency (EPA) in this proceeding.

2. The declarations of Messrs. Fagan and Fisher attempt to minimize the reliability concerns voiced by the State of Texas that are likely to be caused by implementation of the Final Rule.

Response to Declaration of Mr. Fisher

3. Mr. Fisher attempts to discount the reliability threats caused by the Final Rule under a speculative rationale that the "affected coal-fired units are likely to retire…regardless of the Final Rule" because "coal fired units in Texas are becoming less economic, largely due to falling gas and wholesale market energy prices…".[1]

4. Power plant owners must constantly assess the economic viability of their power plants on a continual basis, and in the current market, coal plants have seen lower revenues. I, however, disagree with the leap Mr. Fisher takes to presume that Luminant

[1] Declaration of Jeremy I. Fisher at paragraphs 5-6.

(and theoretically owners of the other affected units) "will seek to retire its coal-fired resources in the near future…"[2]

5. Mr. Fisher appears to take the position that coal plant operators have only two choices: to continue to operate their power plants in the traditional manner or permanently retire them. Mr. Fisher fails to mention a variety of other strategies that power plant operators have utilized in the Electric Reliability Council of Texas (ERCOT) market to manage their assets short of the false binary choice that he presents.

6. It has been a common practice for many years for power plant owners to temporarily or seasonally idle power plants in response to market conditions. For coal plant owners, this typically occurs during the spring and fall months when power demand is the lowest, and renewable energy production – especially wind – tends to be the highest. Power plant owners will then re-commence operations of the plants when power prices warrant it. Such strategies are rational methods of reducing operating losses and maximizing the value of their assets.

7. For example, only two years ago, Luminant temporarily idled three coal power plants over the winter months, originally intending the plants to be idled from October 2013 through May of 2014, in large part due to low power prices. However,

[2] *Id.* at paragraph 28.

Luminant brought the power plants back into operation three months early because market conditions had changed enough to warrant them restarting the units.[3]

8. It has been my experience that these types of decisions are common among power plant owners in competitive markets, as would be expected given these owners' desire and duty to maximize the value of their assets across a wide range of market prices and forecasts. Mr. Fisher's suggestion that power plant owners in competitive markets instead make a simplistic "permanently on/permanently off" decision at a single point in time bears no resemblance to actual experience in the ERCOT market. While owners have temporarily idled their power plants – at times for a duration of years -- to date, I am not aware that any of the owners of the affected power plants have announced plans to permanently shut down those facilities absent implementation of the Final Rule.

9. What is unquestioned, however, is that the Final Rule requires a substantial amount of Texas' coal fired power plants to install very expensive new equipment in order to be able to operate *at all*. Merchant generators will certainly have to assess whether such investment will ever be recouped. The declarations filed in support of the Luminant, Southwestern Public Service Co. and Coleto Creek Power Joint Motion for Stay make it clear that they do not expect that will be the case, leading

[3] http://fuelfix.com/blog/2014/02/04/luminant-plans-to-turn-on-nearly-2000-megawatts-two-months-early/

to the likely retirement of the affected units.[4] This is what has created the instant dilemma for the Public Utility Commission of Texas (PUCT) regarding the potential need to commence transmission planning and increase costs to consumers to mitigate the impacts of a rule the State of Texas believes will ultimately be invalidated.

10. Further, the Final Rule creates a date certain by which the affected units must install their controls, or must cease operating, leading to the potential for a large amount of simultaneous retirements. It has been my experience that where market pressures have caused power plant owners to temporarily idle or retire power plants, those decisions rarely happen concurrently, which provides a longer "runway" for dealing with impacts to the transmission system.

11. I strongly disagree with Mr. Fisher's representations about the 2015 ERCOT Report. Mr. Fisher fails to note that this Report did not analyze specific transmission system overloads that are the primary concern discussed in my prior declaration. That said, the 2015 ERCOT Report discussed likely transmission system impacts *by referring to the exact Regional Haze analysis that I relied upon* in my prior declaration.[5] The fact that the 2015 ERCOT Report indicates that the Final Rule, by itself, is projected to cause incremental retirements is inconsistent with Mr. Fisher's

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[4] *See* Declaration of Robert Frenzel (Luminant) at paragraphs 2, 5-7, and Declaration of Robert Stevens (Coleto Creek Power, LP) at paragraph 15.

[5] *ERCOT Analysis of the Impacts of the Clean Power Plan—Final Rule Update* at 11 and footnote 12 (October 16, 2015). Available online at: http://www.ercot.com/content/news/presentations/2015/ERCOT_Analysis_of_the_Impacts_of_the_Clean_Power_Plan-Final_.pdf

unfounded assumptions that all of the affected coal plants are likely to retire in the absence of the Final Rule anyway. In fact, the 2015 ERCOT Report concludes, "[m]odel results indicate that many of the retirements will occur before the start of CPP [Clean Power Plan] compliance in 2022, *due to the timing of the proposed Regional Haze FIP [Federal Implementation Plan] requirements.*"[6] Significantly, Mr. Fisher also fails to note that the 2015 ERCOT Report indicates that "…these results likely represent a *lower bound* on the number of potential coal unit retirements."[7]

12. Additionally, Mr. Fisher fails to note that the J.T. Deely power plant, an 840 MW coal power plant outside of San Antonio that is unaffected by the Final Rule, is already slated to be retired in 2019. Thus, more than one-half of the "baseline" retirements identified in the 2015 ERCOT Report cannot possibly, under any set of assumptions, represent any of the units affected by the Final Rule.

13. Mr. Fisher's belief that "an appropriate reference point from which to assess the impacts of the Final Rule is within the context of an economy where CO2 emissions bear a price"[8] is also flawed for a number of reasons. First, the U.S. Supreme Court has stayed the EPA's proposed regulations for carbon dioxide emissions for existing power plants. It is unclear when, or if, such regulations will ever be permitted to go into effect, and it is the State of Texas' position that the regulations are so fatally

[6] *Id.* at 11 (emphasis added).
[7] *Id.* at 11.
[8] Fisher Declaration at paragraph 13.

flawed such that they will never go into effect. Secondly, once again, the effective date of any regulations on carbon dioxide will be well past the compliance deadlines for the Final Rule.

14. Finally, Mr. Fisher argues that that the Final Rule is unlikely to create ERCOT-wide capacity shortfalls.[9] However, *no such argument has been made* by the State of Texas. Instead, my declaration focused on the *local reliability impacts* arising from the retirement of the discrete coal plants affected by the Final Rule. Such impacts can, and do, occur even if there is no ERCOT-wide generation capacity shortfall.

15. Mr. Fisher goes to great lengths to discuss closure of coal plants around the rest of the nation and cites the general analysis of the Energy Information Agency (EIA) discussing changes in the generation mix between coal and natural gas power plants.[10]

16. First, closures of coal plants in other states bear no relevance on Texas' experience. Mr. Fisher fails to disclose the portion of the 25,000 MW of coal plants retirements from 2010-2014[11] that occurred in the ERCOT region of Texas. This is unsurprising because none of ERCOT's coal plants retired during that period. As discussed above, ERCOT's competitive market place has motivated power plant owners to be extremely innovative with their operations to maximize their assets in a

[9] *Id.* at paragraph 10.
[10] *Id.* at paragraphs, 15-18.
[11] *Id.* at paragraph 6.

wide variety of market pricing outcomes without resorting to a permanent retirement of the assets. That is not to say retirements won't occur, but as discussed above, orderly exit based on market prices has never resulted in the simultaneous retirement of large amounts of generation at the exact same time as is threatened by the Final Rule.

17. Second, there is no question that in the past year, low natural gas prices have meant that natural gas-fired generation has often displaced coal generation. But that does not mean that the displaced coal generation has permanently retired in all cases, and the EIA publications Mr. Fisher cites make no such claim. In fact, the March 16, 2016 publication cited by Mr. Fisher[12] specifically discusses how dispatch changes are sometimes relatively short lived, saying, "For example, particularly low natural gas prices throughout much of 2012 following an extremely mild 2011-12 winter led to a significant rise in the natural gas generation share between 2011 and 2012, often displacing coal-fired generation. With higher natural gas prices in 2013 and 2014, coal regained some of its generation share. However, with a return to lower natural gas prices in 2015 favoring increased natural gas-fired generation, coal's generation share dropped again."[13] Markets for natural gas, coal, and electricity price can be volatile, and efficient electricity markets like ERCOT's will respond to those changes. However, Mr. Fisher's argument that power plant owners should extrapolate from one year trends and

[12] *Id.* at paragraph 17.
[13] US Energy Information Administration, *Today in Energy*, (March 16, 2016). Available online at: https://www.eia.gov/todayinenergy/detail.cfm?id=25392.

retire their assets is an overly simplistic view of the operation of competitive markets and completely ignores the fiduciary duty of power plant owners to their shareholders to maximize the value of their plants.

18. In short, there is nothing in Mr. Fisher's declaration that effectively rebuts the problems caused for Texas by the Final Rule that are outlined in my original declaration. The Final Rule, if it is ultimately upheld, imposes substantial costs on the affected units, and these costs "threaten the long term economic viability of these units"[14] such that they will likely make the plants uneconomic to continue to operate, leading to permanent retirements.

Response to Declaration of Mr. Fagan

19. Mr. Fagan generally takes issue with my reliance on certain reports by system planners at ERCOT that analyzed the potential for a need for transmission system improvements if the Final Rule is implemented.

20. Mr. Warren Lasher from ERCOT, Inc. has addressed the specifics of the ERCOT, Inc. studies in greater detail in his declaration.

21. It is completely reasonable and appropriate for the PUCT to rely upon the expertise of ERCOT, Inc. in assessing the need for transmission system planning. The PUCT is required by statute to designate an independent organization to ensure the

[14] *See* Declaration of Robert Frenzel (Luminant) at paragraphs 2, 5-7, and 19-27.

reliability and adequacy of the regional electrical network.[15] The PUCT designated ERCOT as the independent organization in January 2001. . . .[16] The PUCT has complete authority to oversee this independent organization and ensure it is adequately performing these functions,[17] and it diligently performs this duty. The PUCT has such confidence in ERCOT, Inc.'s performance of these duties that it gives "great weight" to certain analyses conducted by ERCOT in evaluating the need for new transmission lines.[18] Simply put, ERCOT, Inc. possesses the personnel, systems, and unique expertise to model the ERCOT power region's electrical network, and the PUCT relies heavily on this expertise to fulfill its statutory duties to ensure the reliability of the ERCOT power grid. While Mr. Fagan suggests that ERCOT's findings can be simply wished away by making "changes to input assumptions (that) would result in elimination of the violation,"[19] I do not believe such actions would be a faithful execution of the PUCT's statutory duty.

22. While there may be transmission system additions that may involve options other than new transmission lines, the ERCOT Regional Haze study shows a wide variety of potential overloads depending on which specific units may end up retiring. It is simply not possible at this point to know the precise units that may retire—

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[15] TEX. UTIL. CODE ANN. §39.151(c) (West 2007 & Supp. 2015).
[16] PUCT Docket No. 22061, *Application Of The ERCOT ISO For Certification As An Independent Organization To Perform Transmission And Distribution Access, Reliability, Information Exchange, And Settlement Functions*, Final Order (Jan. 31, 2001).
[17] TEX. UTIL. CODE ANN. §39.151(d) (West 2007 & Supp. 2015).
[18] 16 Tex. Admin. Code §25.101.
[19] Declaration of Robert M. Fagan at footnote 6.

hence the need to begin the in depth transmission planning analysis now such that there is adequate time for new transmission lines to be built if they are deemed necessary. Again, simply assuming that there will be viable short term solutions that will mitigate local reliability problems would not be a faithful execution of the PUCT's responsibilities.

23. Even if solutions short of new transmission lines end up being feasible options, all options identified by Mr. Fagan will have added costs to utilities, and consequently to ratepayers – the only question is the size of those costs. Mr. Fagan discusses certain "demand-side" solutions that may be available to lower peak demand and therefore alleviate the transmission system overloads. However, Texas currently does not have any energy efficiency or demand response programs that are designed to target a local reliability problem such as this, and it is unclear whether such programs would be effective in resolving particular reliability concerns anyway. Development and implementation of such programs would require new PUCT and ERCOT, Inc. regulations. Complete implementation of such programs would likely take at least several years to fully develop and market to potential consumers such that a sufficient amount of customer demand would be enrolled.

24. The problem therefore remains the same. Absent a stay and tolling of deadlines, the PUCT, ERCOT, and Texas utilities will be required to begin planning – and incurring costs – to mitigate the expected reliability impacts that will be caused by the Final Rule.

25. Mr. Fagan also states that I failed to address the role that new generation within the study region could play in addressing the impacts of retiring generation. While there is certainly a possibility that new generation might be developed in close enough proximity to retiring plants to mitigate the impact of the Final Rule, neither the PUCT nor ERCOT can compel such development, and it is therefore unreasonable for the PUCT and ERCOT to sit by and hope such development occurs. In fact, ERCOT included all new generation that was sufficiently developed across the region to meet the criteria for inclusion in transmission planning studies, as is prudent for any transmission planning effort.[20]

26. EPA claims that "there is no reason ERCOT could not evaluate the need for a 'Reliability Must-Run (RMR)' contract for the affected units in the near term,"[21] but EPA misses the point entirely. The issue is not whether ERCOT can execute RMR contracts in the near term prior to the compliance deadlines of the Final Rule. The issue is that such a contract *cannot* be used after the compliance deadline because the units, if they do not install the controls required by the Final Rule, *will not be compliant and therefore cannot operate under any regulatory paradigm.*

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[20] ERCOT, *Transmission Impact of the Regional Haze Environmental Regulation*, Appendix (October 15, 2015). Available online at: http://www.ercot.com/content/wcm/key_documents_lists/76860/Transmission_Impact_of_the_Regional_Haze_Environmental_Regulation__Oct_RPG.pdf.

[21] *EPA's Consolidated Response In Opposition To The Motions For Stay Of The Final Rule* at 31 (April 7, 2016).

27. This is the exact problem I identified in my original declaration in support of the Motion for Stay. If Texas does not start planning for new transmission soon (or begin creating new demand side solutions of a type not currently operating), then there will likely be degraded reliability at the compliance deadline, because the normal tool that Texas has to deal with these local reliability problems becomes inoperable in this case– *because and only because of the Final Rule.* This means Texas must expend resources, including having utilities incur costs that ratepayers will ultimately bear, even though those would have been unnecessary if the Final rule is ultimately declared invalid.

28. As I stated in my prior declaration, this harm to Texas can only be remedied through a stay and tolling of the compliance deadlines. This is the only remaining path because EPA failed to take the reasonable step of allowing for a reliability safety valve that would have allowed uncontrolled units to continue operating for reliability purposes for the limited period of time it would take to make transmission system upgrades that could be thoughtfully and rationally planned after resolution of the court challenges to the Final Rule.

29. I declare, under penalty of perjury, that the foregoing is true and correct.

Executed on April ¶ ←_____, 2016.

Brian H. Lloyd
Executive Director
Public Utility Commission of Texas

DECLARATION OF WARREN P. LASHER

1. I am the Director of System Planning for Electric Reliability Council of Texas, Inc. (ERCOT), where I am responsible for transmission planning, system load forecasting, and resource adequacy analyses. I have worked at ERCOT for the past eleven years. I was previously employed by Southern Company, where I worked in the engineering and the generation planning and development organizations. Prior to my employment with Southern Company, I worked in a consulting role focused on compliance with a range of federal and state environmental regulations. I have a Bachelor of Arts degree in Mathematics from Yale University, a Master of Environmental Management degree from Duke University, and a Master of Science degree in Computer Science from the University of Alabama at Birmingham. I am providing this declaration on behalf of ERCOT.

2. I am submitting this declaration because studies completed by the ERCOT Planning organization have been inappropriately criticized and misinterpreted by representatives of Synapse Energy Economics, Inc., who have limited knowledge of the unique ERCOT market design, on behalf of the U. S. Environmental Protection Agency. In addition, I do not believe that the declarations provided by Dr. Jeremy Fisher and Mr. Robert Fagan adequately describe the reliability risks to the ERCOT system from significant regulatory changes such as the Regional Haze FIP.

Background: ERCOT's Role in Managing Texas's Electric Grid

3. Founded in 1970, ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas (PUC) and the Texas Legislature. ERCOT's mission is to serve the public by ensuring a reliable grid, efficient electricity markets, open access, and retail choice.

4. ERCOT is responsible for overseeing the reliable operation of the electric grid for the ERCOT region of Texas. ERCOT manages the flow of electric power to approximately 24 million Texas customers – representing approximately 90 percent of the state's electric load (*i.e.*, demand for electricity) and approximately 75 percent of the Texas land area. As the independent system operator for the region, ERCOT schedules and dispatches power on a grid that connects approximately 43,000 miles of transmission lines and more than 550 power generation units.

5. Ensuring reliable electrical power is critical to economic stability as well as human health and safety. The Federal Energy Policy Act of 2005 recognized the importance of ensuring reliability of electric grids by creating an Electric Reliability Organization (ERO). The ERO function for North America is performed by the North American Electric Reliability Corporation (NERC), which oversees a vast set of reliability standards that govern operations and planning and are designed to ensure the reliability of the bulk power system. Under the NERC reliability construct, ERCOT is designated as, among other roles, the Reliability Coordinator, Balancing Authority, and Planning

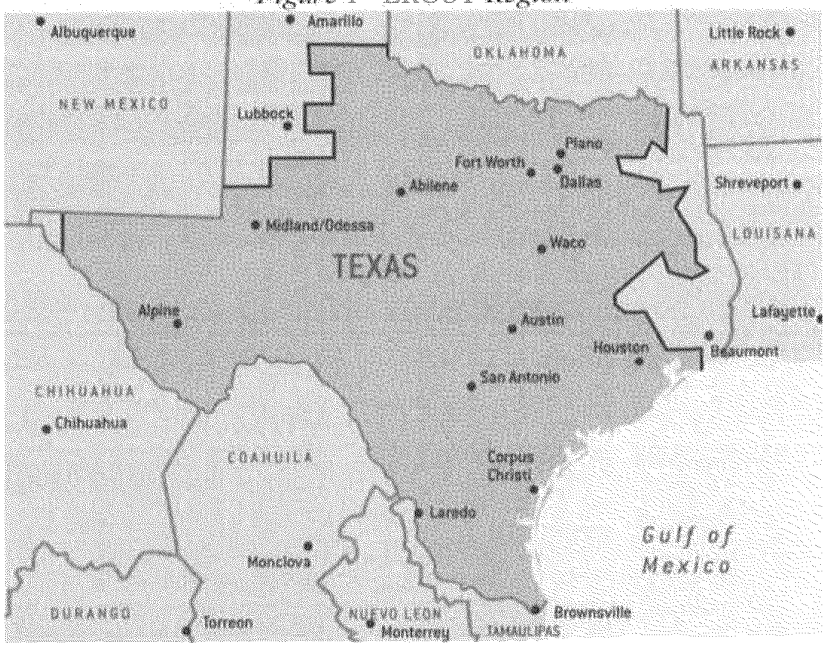
Coordinator for the ERCOT region. ERCOT is also registered as a Transmission Operator in the ERCOT region.

6. ERCOT is accountable to the Texas Reliability Entity, NERC, and the Federal Energy Regulatory Commission for federal reliability standards. To ensure its independence as set forth in the Public Utility Regulatory Act and best fulfill its mission as described above, ERCOT does not engage in advocacy – except where its core functions, including electric grid reliability, may be affected. ERCOT's only interests are relative to its core functions – especially the reliable operation of the ERCOT grid.

Texas's Electric Grid is an Independent Interconnection

7. The ERCOT region, identified in Figure 1 below, covers most of Texas and includes the major load centers of Houston, Dallas, Fort Worth, San Antonio, Austin, Corpus Christi, and the Rio Grande Valley.

Figure 1 –ERCOT Region



8. The ERCOT grid is unique in the United States in that it is wholly intra-state and is not directly (also referred to as synchronously) connected to the two other U.S. grid interconnections (the Western and the Eastern Interconnections). Import and export of power from the ERCOT region is limited to the capacity of five asynchronous ties linking ERCOT and other interconnections: two between ERCOT and the Eastern Interconnection (with a combined capacity of 820 megawatts), and three between ERCOT and the electrical grid in Mexico (with a combined capacity of 430 megawatts). Aside from these limited asynchronous ties, from an electrical standpoint, the ERCOT region is an island that must independently ensure its own electric reliability.

9. As the ERCOT region is located entirely within one state, it is not subject to federal oversight of market design and policy. Under state law, the region employs a competitive market construct for generation supply, implemented as an energy-only market, in which generation units are paid for the energy they produce and for the ancillary services that they provide for real-time operations. Unlike other regions with organized markets, there is no forward capacity market in ERCOT. In this way the ERCOT market is unlike other coordinated electricity markets in the United States. This market design, along with generation-friendly interconnection policies, fosters strong competition between existing generation and new entrants and, historically, has effectively dispatched efficient, cleaner energy including the deployment of record amounts of wind.

10. In this environment, generation owners bear the risk of investment when deciding the timing and location of new generation or the retirement of existing generation based on market conditions. No state or other authority allows or provides directives or guidance regarding when or where to add generation resources. Rather, the ERCOT market is designed to provide financial signals to competitive generation companies to develop adequate generation capacity. As part of its Planning Coordinator responsibilities, ERCOT evaluates the impacts to grid reliability of possible and/or pending changes in generation capacity.

11. This market design and ERCOT's electrical isolation place it in a uniquely vulnerable position with regard to changes in environmental regulations that would change the economic return of multiple generation resources. In order to assess the likely future impacts of significant regulatory changes on the ERCOT grid, data inputs and assumptions used in planning studies must be consistent with the unique nature of the ERCOT market. The Synapse Memorandum and the declarations provided by Dr. Fisher and Mr. Fagan indicate that they are not sufficiently familiar with the ERCOT market to appropriately assess recent ERCOT studies and statements regarding grid reliability made in Mr. Lloyd's declaration.

The Synapse Memorandum and Declarations Incorrectly Characterize the ERCOT Energy-Only Market Design

12. The Synapse Memorandum authored by Mr. Fisher and others and the Declarations by Dr. Fisher and Mr. Fagan contain several misconceptions and inaccurate statements about the ERCOT market design. Dr. Fisher, in both the Memorandum and his own declaration, seems to equate ERCOT's energy-only market design with capacity markets present in other regions. For example, Mr. Fisher makes several incorrect statements about ERCOT's authority over new generation in the region:

    - "[…] ERCOT taking reasonable steps to […] finding new capacity to replace existing non-economic units" (Fisher Declaration paragraph 38)

    - "While we agree that appropriate siting and transmission buildout are important components of designing an efficient and reliable power system, this concern is well within ERCOT's jurisdiction and capability to address" (Synapse Memorandum page 5).

13. Both of these statements about ERCOT's authority to procure and site new generation capacity are incorrect. Neither ERCOT nor the PUCT have this authority. In ERCOT's energy-only market design, construction of new capacity is entirely driven by market forces, and there is no capacity market to enforce that a reserve margin be maintained within the region. Market outcomes may result in reserve margins below the target level, particularly when a regulatory shift results in changes to the resource mix more quickly than the market can respond with new investment. In addition, there is no mechanism in the ERCOT market to require new generation to be sited in locations that will mitigate transmission constraints. In fact, the opposite is occurring in ERCOT – a variety of regulatory and market forces (including air quality restrictions, property values, prevalence of renewable resources) are causing generation resources to be located further from urban centers where transmission constraints are most likely to develop.

14. Mr. Fisher's misunderstanding of ERCOT market fundamentals is also clearly demonstrated in the assessment of planned gas capacity in the region (Synapse Memorandum pages 5-7). The argument put forth by Mr. Fisher in the memo presumes that all currently planned capacity within the ERCOT region will be built:

    - "Combined, the amount of planned generation resources in the CDR reports since May 2014 and the pending construction permits in the queue at TCEQ (a total of approximately 14,500 MW) represent a significant amount of new generation that can mitigate reliability concerns [...]" (Synapse Memorandum page 7).

    - "It is notable that many of these new gas units will come online in the next 2-5 years [...]", (Synapse Memorandum page 7).

    - "New construction permit applications that are submitted represent a relatively serious commitment from the applicant to build this generating capacity" (Synapse Memorandum page 6).

15. These are not reasonable assumptions for the ERCOT market. ERCOT's significant experience with studying and monitoring planned generation capacity in the region indicates that successful completion of planned projects is dependent on a range of factors, including current and expected future market conditions, availability of capital, regulatory requirements, and competition between generation technologies. In addition, receipt of an air permit or qualification for the ERCOT Capacity, Demand, and Reserves report (CDR) is not a guarantee of successful project implementation. Permitting costs are small compared to the full cost of building a new power plant. Many market participants will file for interconnection agreements or air permits to preserve the option to construct future capacity, which will ultimately be built *if* future market conditions make it appear to be a worthwhile investment opportunity. Analyses of ERCOT's interconnection queue have suggested that a much smaller percentage of planned projects are successfully completed.[1] Construction timelines reported to ERCOT or the TCEQ

[1] An ERCOT analysis of projects in the ERCOT interconnection queue indicated a 9% operational success rate for natural gas capacity applying for interconnection agreements with ERCOT between 2004 and 2011. See http://www.ercot.com/content/meetings/gatf/keydocs/2014/0624/GINR_Project_Status_Statistics_PUBLIC.xls

also often shift due to changing market economics and project delays, and projects reported as coming online in the near-term are frequently delayed or canceled.

16. Mr. Fisher is also incorrect when discussing the process for setting market rules in the ERCOT region: "ERCOT's charge as reliability coordinator may obligate it to implement rules requiring reasonable notice for economic retirements" (Synapse Memorandum page 2). This statement mischaracterizes the process for setting market rules in the ERCOT region. ERCOT cannot unilaterally change its market rules. Market rules are set and approved through an often lengthy stakeholder committee approval process, under the oversight of the PUCT. Depending on the scope and scale of such changes, market protocol revisions can take a significant amount of time and ERCOT and stakeholder effort to complete.

17. In his declaration, Mr. Fagan attempts to show that grid reliability risks due to any Regional Haze retirements are likely to be minimal because of the many options available to solve these risks (Fagan Declaration paragraphs 9 and 10). He lists several such options, including development of new generation, demand-side resources (controlled changes in customer electricity usage) and energy efficiency programs. None of these options are currently available in the ERCOT market. As I note above, in ERCOT, generation resources are developed by investors seeking return on capital with no control or guidance from ERCOT or any regulatory authority. There is no mechanism to require investors to construct new generation units in the specific locations necessary in order to correct future grid reliability violations. Similarly, there are no programs in ERCOT to promote development of demand-side resources in specific locations on the grid that would mitigate future transmission constraints, nor any market rules that would allow grid operators at ERCOT to utilize existing or new demand-side resources in real-time operations to maintain local grid reliability. Similarly, energy efficiency programs in Texas are not designed or implemented in a way that would allow program funds to be focused on specific locations that could support local grid reliability.

18. Mr. Fagan also uses the fact that the ERCOT region requires a significant amount of transmission development to conclude that the new infrastructure needed to mitigate the loss of affected units will be minimal (Fagan Declaration paragraph 8). This supposition is incorrect. The ERCOT market drives the need for transmission improvements: customer demand is growing due to a strong economy, and generation resources (as noted above) are being developed by investors without direction from ERCOT or the PUCT. Many of these new resources are being developed in West Texas, far from urban centers, where wind and solar resources are strongest. As a result, new transmission is required in order to connect these new resources to the grid and to improve grid capability in urban regions where customer demand is growing. Again, this is why ERCOT is uniquely vulnerable to significant regulatory changes: the region needs a significant investment in transmission improvements in order to keep up with the changing resource fleet and to serve growing customer demand. Regulatory changes that result in significant unit retirements will just make the need for more transmission that much greater.

The Fisher Declaration Unreasonably Misinterprets ERCOT's Study Results

19. Mr. Fisher references the results presented in ERCOT's 2015 study, *ERCOT Analysis of the Impacts of the Clean Power Plan: Final Rule Update*[2] to draw inferences about current and future coal plant economics in the region, and from these inferences concludes that the incremental impact of compliance with the Regional Haze FIP will be minimal (Fisher Declaration paragraphs 5, 10 and 11). Several of these conclusions reflect unreasonable interpretations of the study results and fail to recognize the important reliability concerns raised by the study.

20. Mr. Fisher asserts that the ERCOT study indicated that "the vast majority of non-economic coal capacity in the ERCOT region is likely to retire in the near term, even in the absence of the Final Rule" (paragraph 10). This is incorrect. In the baseline scenario of the study, which estimated a baseline of the ERCOT system under current market trends, only 1,500 MW of coal capacity was retired. Of this amount, 840 MW represents the planned mothballing in 2018 of J.T. Deely power plant by CPS Energy.[3] Thus, less than 700 MW of economic retirements were predicted in the baseline scenario, a small percentage of the over 19,000 MW of coal capacity in the ERCOT region, and of the 8,500 MW of coal capacity that face the imposition of significant capital costs under the Regional Haze FIP. Thus, Mr. Fisher's conclusion that ERCOT's analysis "indicates that the coal-fired units affected by the Final Rule are non-economic on a forward-looking basis" (paragraph 5) is an incorrect reading of the study results.

21. Mr. Fisher goes on to say that "the ERCOT 2015 Economic Study finds that [...] the Final Rule might result in the incremental retirement of only 700 MW of coal-fired capacity" (paragraph 10). Again, this is not an appropriate interpretation of the study. The 2015 ERCOT study did not evaluate the Regional Haze FIP individually, but only in combination with EPA's Clean Power Plan. Since that time, the Clean Power Plan has been stayed by the Supreme Court, and its future is unknown. Regardless, while the study did not consider the individual impacts of the Regional Haze FIP, the results do indicate a potential impact in excess of 700 MW. As noted in the study, in the scenario that included Regional Haze, "many of the units retire before 2022 due to the timing of the Regional Haze requirements" (ERCOT 2015 study, page 7). The retirement of units in that scenario before the Clean Power Plan compliance deadlines indicate that the Regional Haze rule, by itself, is likely to result in the retirement of coal-fired generation capacity. This is consistent with the findings of ERCOT's earlier 2014 study, which had indicated that "3,000 MW to 8,500 MW of coal-fired capacity in ERCOT can be considered to have a moderate to high risk of retirement – due primarily to the costs of EPA's proposed requirements for the Regional Haze program" (ERCOT 2014 study,

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[2] Available at http://ercot.com/content/news/presentations/2016/ERCOT_Analysis_of_the_Impacts_of_the_Clean_Power_Plan-Final_.pdf.

[3] This retirement has been planned for several years and is noted in footnote 9 on page 7 of the 2015 ERCOT Study: "This includes the announced mothballing of CPS Energy's J.T. Deely units 1 and 2 in 2018."

page ii).[4] In addition, the earlier retirement of units has important implications for transmission planning timelines.

22. Mr. Fisher also comments on the use of carbon prices in long-term utility planning (Fisher Declaration paragraphs 12 and 13). In applying the discussion of utility long-term planning and carbon price assumptions to the results of the 2015 ERCOT study, Mr. Fisher indicates that he does not understand ERCOT's role as planning authority for the ERCOT region, and the purpose of the study. ERCOT is not a resource owner evaluating the value of its own generation assets under future scenarios (ERCOT does not own or operate any generation assets). Rather, ERCOT's long-term planning processes, chiefly through ERCOT's biennial Long-Term System Assessments, do look at future market trends under a range of scenarios, including the possibility of future carbon prices, in order to assess the need for future grid infrastructure improvements. In addition, as the entity responsible for ensuring reliability in the region, it is prudent and necessary for ERCOT to conduct reliability studies on specific and discrete risks that could potentially impact reliability in the region. The 2015 ERCOT study was intended to identify discrete reliability implications of certain *specific* pending environmental regulations. Mr. Fisher's assertion that the Clean Power Plan CO_2 price scenario, and not the baseline scenario, represents an appropriate reference point is entirely at odds with the design of the 2015 ERCOT study, and the current regulatory regime facing resource owners in the ERCOT region. In short, Mr. Fisher's focus on the use of carbon prices in utility (i.e., resource owner) long-term *economic* planning is not relevant to the 2015 ERCOT study's focus on assessing possible implications for *reliability* in the region.

The Synapse Documents Understate Potential Reliability Concerns due to a Limited Understanding of the ERCOT Market Design

23. Contrary to statements made by Dr. Fisher and Mr. Fagan, grid reliability in ERCOT can be impacted by regulatory initiatives such as the Regional Haze FIP. While it is true that normal market forces will drive older resources to run less frequently as their variable costs become less competitive in real-time markets, there are market options to keep these units available to support grid reliability. These units can be designated by their owners as seasonal mothball units, allowing the resources to only be available during the peak season from June through September, when both grid reliability needs are highest and when the likelihood of resource scarcity conditions (and resulting high real-time prices) is greatest.[5] In this way, older units are still able to support grid reliability while maintaining the potential for future operating profits. Yet when faced with near-term requirements for significant capital improvements due to changing environmental regulations, resource owners are much more likely to retire these units. The resulting loss of generating capacity can result in grid reliability impacts.

24. In addition, for units being retired due to market conditions, ERCOT can seek a reliability-must-run contract in order to maintain resources that are necessary to preserve

[4] Available at http://ercot.com/content/news/presentations/2015/Impacts%20of%20Environmental%20Regulations%20in%20the%20ERCOT%20Region.pdf.

[5] The current system-wide offer cap is $9,000/MWh, higher than any other organized market in the United States.

localized transmission reliability. These RMR contracts cover the operating costs of the resources and typically remain in force until transmission upgrades can be completed that eliminate the reliability need for the resource. Changing environmental requirements, such as those in the Regional Haze FIP, significantly reduce the effectiveness of this option. If a unit is not compliant with its emissions requirements, ERCOT cannot ask the resource owner to operate the unit to maintain grid reliability.

25. In paragraphs 11 – 13 of his declaration, Mr. Fagan indicates that most or all of the transmission needs resulting from retirements due to the Regional Haze FIP can be met by easily implementable transmission improvements such as static and dynamic reactive devices and additional transformers. While some of the transmission system reliability violations noted in our Regional Haze Transmission Impact study from last year can be solved with reactive devices, most cannot. An increasing amount of our resource mix is distant from urban centers. Without older generation to help serve customer demand on peak days, the existing transmission system will not be sufficient to maintain grid reliability, and new transmission lines will be required to move power from new resources to urban centers. And even in the ERCOT region, these new circuits require at least 5 years to plan, permit and construct. In the event of unexpected retirements due to new regulatory requirements, grid reliability will be reduced until these new circuits can be completed.

26. With large regulatory changes such as the Regional Haze FIP, grid reliability risks can be difficult to assess. Mr. Fisher incorrectly states that ERCOT can "determine which units are likely to retire, [...] and address any concerns well before the compliance deadline" (Synapse Memorandum page 5). In the ERCOT region, resource decisions are made by individual investors based on their business positions and expectations of future market conditions. These decisions are unknown to ERCOT and the market until formal notification is made. As required by stakeholder-approved protocols, formal notification of unit retirements is required prior to including resource changes in the development and endorsement of new transmission projects. In the meantime, ERCOT can conduct studies to identify possible future reliability issues under different retirement scenarios, but due to the location-specific sensitivity of transmission analyses, incorrect assumptions about which units will retire will typically result in an improper identification of transmission needs.

27. Mr. Fisher also mischaracterizes a transmission impact study that is described by Mr. Lloyd in his declaration.[6] The ERCOT study referenced by Mr. Lloyd was an initial analysis of potential transmission impacts due to the rule, looking at a range of potential retirement scenarios, as ERCOT does not know at this time which units may be retired as a result of the Regional Haze FIP. Given the design of the ERCOT market and current market rules, this type of broad initial assessment is the only way to begin to assess the potential transmission impacts due to a regulation such as the Regional Haze FIP. As the disclaimer in footnote 12 of Mr. Fisher's declaration says, the study "[...] is not intended

[6] *Transmission Impact of the Regional Haze Environmental Regulation.* Available at http://www.ercot.com/content/wcm/key_documents_lists/76860/Transmission_Impact_of_the_Regional_Haze_Environmental_Regulation__Oct_RPG.pdf.

to evaluate the viability of specific units [...]" not because, as Mr. Fisher presumes, the study is somehow separate from the effort to understand the transmission impacts of the Regional Haze FIP, but rather because ERCOT is not in a position to know the market viability of any of these specific units and must use scenarios like those in this study to begin the process of assessing what may be significant impacts to transmission reliability.

28. This initial transmission reliability impact analysis was presented at the October 2015 meeting of our Regional Planning Group, a stakeholder committee that assists ERCOT with evaluating transmission planning studies and other planning issues, to promote a discussion regarding the need for future, more detailed, study. The analysis documented in the presentation cited by Mr. Lloyd represented approximately 400 hours of engineering analysis. The primary finding was that across a broad range of potential unit retirement scenarios, significant reliability violations were noted. These reliability violations would require transmission projects, likely one or more significant (either 138-Kilovolt or 345-Kilovolt) new transmission lines, in order to maintain future grid reliability.

29. This initial study will be supplemented by a sensitivity case included in this year's interconnection-wide annual transmission plan. The ongoing analysis will include specific transmission solutions to resolve any observed transmission reliability violations, but will only review one possible combination of unit retirements. As such this ongoing detailed analysis will have limited applicability if some other combination of the 12 affected units becomes unavailable to grid operators.

30. Given that legal review of this rule will take a year or more, if the deadlines in the Regional Haze FIP are not adjusted following legal proceedings, there will not be sufficient time to complete any of the required retrofits that are not aggressively pursued during the legal review. And although ERCOT can study potential impacts from the Regional Haze FIP, we cannot identify and endorse necessary transmission improvements until we receive formal notification of unit retirements, which will most likely be delayed until the end of the legal proceedings. If, as ERCOT's preliminary studies indicate, these future retirements result in the need for new transmission lines, there will be a time gap between the compliance deadlines in the rule and the completion of the necessary grid improvements to maintain reliability.

31. I declare, under penalty of perjury, that the foregoing is true and correct. Executed on April 18, 2016.

Warren P. Lasher
Director, System Planning
Electric Reliability Council of Texas, Inc.

To: Ashley Jurgensmeyer[ashley.jurgensmeyer@dnr.mo.gov]; Ashley Keas[Ashley.Keas@dnr.mo.gov]; Ann Spitz[aspitz@kdheks.gov]; Avey, Lance[Avey.Lance@epa.gov]; Beverly Botchlet-Smith[beverly.botchlet-smith@deq.ok.gov]; Bret Anderson[baanderson02@fs.fed.us]; Brooks Kirlin[brooks.kirlin@deq.ok.gov]; Carrie Wiese[carrie.wiese@nebraska.gov]; Catharine Fitzsimmons[catharine.fitzsimmons@dnr.iowa.gov]; Cheryl Bradley[Cheryl.Bradley@deq.ok.gov]; David Clark[CLARKD@adeq.state.ar.us]; David Brown[dave.l.brown@nebraska.gov]; Donna Huff[dhuff@tceq.texas.gov]; Douglas Watson[dwatson@kdheks.gov]; Eddie Terrill[eterrill@deq.ok.gov]; Gilberto Cuadra[Gilberto.Cuadra@LA.GOV]; Donaldson, Guy[Donaldson.Guy@epa.gov]; Heather.Lerch@deq.ok.gov[Heather.Lerch@deq.ok.gov]; japrentice@kdheks.gov[japrentice@kdheks.gov]; Jim Price[jim.price@tceq.texas.gov]; Jocelyn Mellberg[jocelyn.mellberg@tceq.texas.gov]; Harper, Jodi[Harper.Jodi@epa.gov]; Kordzi, Joe[Kordzi.Joe@epa.gov]; john babin[john.babin@la.gov]; John Minter[john.minter@tceq.texas.gov]; jprentice@kdheks.gov[jprentice@kdheks.gov]; Kathy Pendleton[kathy.pendleton@tceq.texas.gov]; Kevin Stoner[kevin.j.stoner@nebraska.gov]; Kim Herndon[kim.herndon@tceq.texas.gov]; Kyra Moore[kyra.moore@dnr.mo.gov]; laura.finley@deq.ok.gov[laura.finley@deq.ok.gov]; Lee Warden[Lee.Warden@deq.ok.gov]; lisa.alam@nebraska.gov[lisa.alam@nebraska.gov]; Logan, Judy[jlogan@fs.fed.us]; Lynn Deahl[LDeahl@kdheks.gov]; margaret.earnest@tceq.texas.gov[margaret.earnest@tceq.texas.gov]; Mark McCorkle[MAC@adeq.state.ar.us]; Matthew Johnson[matthew.johnson@dnr.iowa.gov]; Feldman, Michael[Feldman.Michael@epa.gov]; Jay, Michael[Jay.Michael@epa.gov]; montgomery@adeq.state.ar.us[Montgomery@adeq.state.ar.us]; patricia_f_brewer@nps.gov[patricia_f_brewer@nps.gov]; patricia.maliro@dnr.mo.gov[patricia.maliro@dnr.mo.gov]; Petre, Jacob[Jacob.Petre@deq.ok.gov]; Rick Brunetti[rbrunetti@kdheks.gov]; Ron Thomas[ron.thomas@tceq.texas.gov]; Sonya Eastern[Sonya.Eastern@LA.GOV]; spencer@adeq.state.ar.us[spencer@adeq.state.ar.us]; Stacy Allen[stacy.allen@dnr.mo.gov]; stephanie.shirley@tceq.texas.gov[stephanie.shirley@tceq.texas.gov]; Krabbe, Stephen[Krabbe.Stephen@epa.gov]; Stephen M. Hall[stephen.hall@dnr.mo.gov]; Terry Salem[terry.salem@tceq.texas.gov]; Theresa Pella[tpella@censara.org]; Tim Allen[tim_allen@fws.gov]; Tim E. Burns (PWks)[tim.burns@cityofomaha.org]; vennetta.hayes@la.gov[vennetta.hayes@la.gov]; Vivian Aucoin[Vivian.Aucoin@LA.GOV]; Walker Williamson[walker.williamson@tceq.texas.gov]; Wendy Walker[wendy.walker@dnr.iowa.gov]; Wharton, Tracy[tracy.wharton@nebraska.gov]; Wilbur, Emily[emily.wilbur@dnr.mo.gov]; Wolkins, Jed[wolkins.jed@epa.gov]; Melanie Foster[Melanie.foster@deq.ok.gov]; melissa.mcdonald@ks.gov[melissa.mcdonald@ks.gov]
From: Theresa Pella
Sent: Tue 1/10/2017 5:35:11 PM
Subject: Fw: RH rule published today and notice of webinar reschedule

looks like this only went to the tribal distribution list - sorry..

Theresa

Theresa Pella, Executive Director

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From: Theresa Pella
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To: alisha.bartling@santeeoep.com; Andres Monreal; Anita Hicks; April Hathcoat; Arthur Muller; Bob Haskins; Chris Spencer; Craig Kreman; Darren Shields; Ernie Redbird; Felix Kitto; Gardner Rose; Heather Webb; Jenna Battise; Joseph Painter; Ken Jones; Sara Aultman; Summer King; Susie Attocknie; Tom Elkins; Tony Darden; Virginia LeClere
Subject: RH rule published today and notice of webinar reschedule

The final rule revisions published today (link below). Also just found out the webinar scheduled for today is postponed until Jan. 26th.

https://www.gpo.gov/fdsys/pkg/FR-2017-01-10/pdf/2017-00268.pdf

"This is just note to let you know that the public webinar regarding the final regional haze rule revisions which was originally planned for tomorrow, January 10, 2017, has been moved to January 26, 2017 from 12:30 to 2:00pm EST. Information on how to participate in the webinar is located at: https://www.epa.gov/visibility/webinar-announcement-informational-public-webinar-discuss-final-regional-haze-rule. "

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From: Young, Carl
Sent: Tue 12/27/2016 3:42:27 PM
Subject: RE: 16-30713; FRL-9955-77-Region 6
EPA 2016-30713.docx

Thanks Stephanie,

We accept the OFR edits and have an additional edit in redline to the summary. (We added the phrase "…and that the FIP emission limits we are proposing meet the interstate visibility transport requirements for these NAAQS" to the end of the summary).

The file with OFR edits and our additional edit to the summary are attached.

Carl

Carl Young

EPA Region 6 Air Quality Program

(214) 665-6645

From: Morris, Stephanie **On Behalf Of** EPA-FederalRegisterLiaison
Sent: Tuesday, December 27, 2016 8:30 AM
To: Wiley, Adina <Wiley.Adina@epa.gov>; Paige, Carrie <Paige.Carrie@epa.gov>; Mohr, Ashley <Mohr.Ashley@epa.gov>; Young, Carl <young.carl@epa.gov>; Tomasovic, Brian <Tomasovic.Brian@epa.gov>; Kordzi, Joe <Kordzi.Joe@epa.gov>
Cc: Brooks, Patricia <Brooks.Patricia@epa.gov>
Subject: FW: 16-30713; FRL-9955-77-Region 6

Good morning,

I am sending this in the absence of your reviewer, Patricia Brooks. Please respond to this proxy email box when responding.

Attach you will find OFR edits, questions and comments regarding your document for your review and responses.

As a **Reminder:** Please do not use the "accept" nor "reject" feature for any of the changes, please leave the redline/strikeout if it's apparent in the OFR Word file and make sure your edits, if any, are also apparent in redline/strikeout.

Stephanie Morris

Federal Register Liaison, Senior Editor

Regulatory Management Division,

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*****Many FR questions can be answered via our*** intranet website! **

Have an IBR question? You can now contact us at EPA-IBR@epa.gov

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA-R06-OAR-2016-0611; FRL-9955-77-Region 6]

Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: Pursuant to the Federal Clean Air Act (CAA or Act), the Environmental Protection Agency (EPA) is proposing to promulgate a Federal Implementation Plan (FIP) in Texas to address the remaining outstanding requirements that are not satisfied by the Texas Regional Haze State Implementation Plan (SIP) submission. Specifically, the EPA proposes SO_2 limits on 29 Electric Generating Units (EGUs) located at 14 Texas facilities to fulfill requirements for the installation and operation of the Best Available Retrofit Technology (BART) for SO_2. To address the requirement for NO_X BART for Texas EGU sources, we are proposing a FIP that relies upon two other EPA rulemakings, one already final and one proposed, which together will establish that participation in the Cross-State Air Pollution Rule (CSAPR) continues to qualify as an alternative to NO_X BART for EGUs in Texas. We also are proposing to disapprove the portion of the Texas Regional Haze SIP that addresses the BART requirement for EGUs for Particulate Matter (PM) and proposing a FIP with PM BART limits for EGUs at 29 EGUs located at 14 Texas facilities, based on existing practices and control capabilities. In

addition, we propose to reconsider and re-propose disapproval of portions of several SIP revisions submitted to satisfy the requirement to address interstate visibility transport for six NAAQS and that the FIP emission limits we are proposing meet the interstate visibility transport requirements for these NAAQS.

DATES: *Comments:* Comments must be received on or before **[Insert date 60 days from date of publication in the Federal Register]**. A public hearing will be held January 10, 2017. For additional logistical information regarding the public hearing please see the **SUPPLEMENTARY INFORMATION** section of this action.

ADDRESSES: Submit your comments, identified by Docket No. EPA-R06-OAR-2016-0611, at *http://www.regulations.gov* or via email to *R6_TX-BART@epa.gov*. Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from Regulations.gov. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (i.e. on the web, cloud, or other file sharing system). For additional submission methods, please contact Joe Kordzi, 214-665-7186, Kordzi.joe@epa.gov. For the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-*

epa-dockets.

Docket: The index to the docket for this action is available electronically at *http://www.regulations.gov* and in hard copy at the EPA Region 6, 1445 Ross Avenue, Suite 700, Dallas, Texas. While all documents in the docket are listed in the index, some information may be publicly available only at the hard copy location (e.g., copyrighted material), and some may not be publicly available at either location (e.g., CBI).

The Texas regional haze SIP is available online at: *https://www.tceq.texas.gov/airquality/sip/bart/haze_sip.html*. It is also available for public inspection during official business hours, by appointment, at the Texas Commission on Environmental Quality, Office of Air Quality, 12124 Park 35 Circle, Austin, Texas 78753.

FOR FURTHER INFORMATION CONTACT: Joe Kordzi, Air Planning Section (6PD-L), Environmental Protection Agency, Region 6, 1445 Ross Avenue, Suite 700, Dallas, Texas 75202-2733, telephone 214-665-7186; fax number 214-665-7263; e-mail address *Kordzi.joe@epa.gov*.

SUPPLEMENTARY INFORMATION: Throughout this document wherever "we," "us," or "our" is used, we mean the EPA.

Public Hearing:

We are holding an information session, for the purpose of providing additional information and informal discussion for our proposal. We are also holding a public hearing to accept oral comments into the record:

Date: Tuesday, January 10, 2017

Time: Open House: 1:30 p.m. - 3:30 p.m.

Public hearing: 4:00 p.m. – 8:00 p.m. (including short break)

Location: Joe C. Thompson Conference Center

(on the University of Texas (UT) Campus)

Room 3.102

2405 Robert Dedman Drive

Austin, Texas 78712

Joe C. Thompson Conference Center parking is adjacent to the building in Lot 40, located at the intersection of East Dean Keeton Street and Red River Street. Additional parking is available at the Manor Garage, located at the intersection of Clyde Littlefield Drive and Robert Dedman Drive. If arranged in advance, the UT Parking Office will allow buses to park along Dedman Drive near the Manor Garage for a fee.

The public hearing will provide interested parties the opportunity to present information and opinions to us concerning our proposal. Interested parties may also submit written comments, as discussed in the proposal. Written statements and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at the public hearing. We will not respond to comments during the public hearing. When we publish our final action, we will provide written responses to all significant oral and written comments received on our proposal. To provide opportunities for questions and discussion, we will hold an information session prior to the public hearing. During the information session, EPA staff will be available to informally answer questions on our proposed action. Any comments made to EPA staff during an information session must still be provided

orally during the public hearing, or formally in writing within 30 days after completion of the hearings, in order to be considered in the record.

At the public hearings, the hearing officer may limit the time available for each commenter to address the proposal to three minutes or less if the hearing officer determines it to be appropriate. We will not be providing equipment for commenters to show overhead slides or make computerized slide presentations. Any person may provide written or oral comments and data pertaining to our proposal at the public hearings. Verbatim English language transcripts of the hearing and written statements will be included in the rulemaking docket.

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I. Background

Regional haze is visibility impairment that is produced by a multitude of sources and activities that are located across a broad geographic area and emit fine particulates ($PM_{2.5}$) (e.g., sulfates, nitrates, Organic Carbon (OC), Elemental Carbon (EC), and soil dust), and their precursors (e.g., Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_X), and in some cases, ammonia (NH_3) and Volatile Organic Compounds (VOCs)). Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that can be seen. $PM_{2.5}$ can also cause serious health effects and mortality in humans and contributes to environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the "Interagency Monitoring of Protected Visual Environments" (IMPROVE) monitoring network, show that visibility impairment caused by air pollution occurs virtually all the time at most national parks and wilderness areas. In 1999, the average visual range[1] in many Class I areas (i.e., national parks and memorial parks, wilderness areas, and international parks meeting certain size criteria) in the western United States was 100-150 kilometers, or about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. In most of the eastern Class I areas of the United States, the average visual range was less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions.[2] CAA programs have

[1] Visual range is the greatest distance, in kilometers or miles, at which a dark object can be viewed against the sky.
[2] 64 FR 35715 (July 1, 1999).

reduced some haze-causing pollution, lessening some visibility impairment and resulting in partially improved average visual ranges.[3]

CAA requirements to address the problem of visibility impairment are continuing to be addressed and implemented. In Section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the prevention of any future, and the remedying of any existing man-made impairment of visibility in 156 national parks and wilderness areas designated as mandatory Class I Federal areas.[4] On December 2, 1980, EPA promulgated regulations to address visibility impairment in Class I areas that is "reasonably attributable" to a single source or small group of sources, i.e., "reasonably attributable visibility impairment."[5] These regulations represented the first phase in addressing visibility impairment. EPA deferred action on regional haze that emanates from a variety of sources until monitoring, modeling, and scientific knowledge about the relationships between pollutants and visibility impairment were improved.

Congress added section 169B to the CAA in 1990 to address regional haze issues, and we promulgated regulations addressing regional haze in 1999.[6] The Regional Haze Rule revised the existing visibility regulations to integrate into the regulations provisions addressing regional

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[3] An interactive "story map" depicting efforts and recent progress by EPA and states to improve visibility at national parks and wilderness areas may be visited at: http://arcg.is/29tAbS3.

[4] Areas designated as mandatory Class I Federal areas consist of National Parks exceeding 6000 acres, wilderness areas and national memorial parks exceeding 5000 acres, and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). In accordance with section 169A of the CAA, EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value. 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. 42 U.S.C. 7472(a). Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to "mandatory Class I Federal areas." Each mandatory Class I Federal area is the responsibility of a "Federal Land Manager." 42 U.S.C. 7602(i). When we use the term "Class I area" in this action, we mean a "mandatory Class I Federal area."

[5] 45 FR 80084 (December 2, 1980).

[6] 64 FR 35714 (July 1, 1999), codified at 40 CFR part 51, subpart P (Regional Haze Rule).

haze impairment and established a comprehensive visibility protection program for Class I areas. The requirements for regional haze, found at 40 CFR 51.308 and 51.309, are included in our visibility protection regulations at 40 CFR 51.300–309. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia, and the Virgin Islands. States were required to submit the first implementation plan addressing regional haze visibility impairment no later than December 17, 2007.[7]

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, often under-controlled, older stationary sources in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the CAA requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress toward the natural visibility goal, including a requirement that certain categories of existing major stationary sources[8] built between 1962 and 1977 procure, install and operate the "Best Available Retrofit Technology" (BART). Larger "fossil-fuel fired steam electric plants" are included among the BART source categories. Under the Regional Haze Rule, states are directed to conduct BART determinations for "BART-eligible" sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. The evaluation of BART for Electric Generating Units (EGUs) that are located at fossil-fuel fired power plants having a generating capacity in excess of 750 megawatts must follow the "Guidelines for BART Determinations Under the Regional Haze Rule" at appendix Y to 40 CFR Part 51 (hereinafter referred to as the "BART Guidelines"). Rather than requiring source-specific BART controls, states also have the flexibility to adopt an emissions trading program or alternative program as long as the alternative provides greater

[7] See 40 CFR 51.308(b). EPA's regional haze regulations require subsequent updates to the regional haze SIPs. 40 CFR 51.308(g)–(i).
[8] See 42 U.S.C. 7491(g)(7) (listing the set of "major stationary sources" potentially subject-to-BART).

reasonable progress towards improving visibility than BART. To the extent a Regional Haze SIP does not meet CAA requirements to address BART, the CAA requires EPA to promulgate a FIP that makes the requisite determinations to ensure the BART requirement is satisfied, as applicable, for sources in the state.[9]

II. Overview of Proposed Actions

A. Regional Haze

On January 5, 2016, we took final action on nearly all portions of a Regional Haze SIP submittal submitted by the State of Texas on March 31, 2009.[10] In that final rule, we did not take action on the portion of the submittal that was intended to satisfy BART requirements for EGUs as mandated by 40 CFR 51.308(e). In an earlier, separate action, we issued a limited disapproval of the Texas Regional Haze SIP concerning EGU BART due to Texas' reliance on the Clean Air Interstate Rule (CAIR).[11] The EGU BART requirements for NO_X and SO_2 remain unmet following the limited disapproval, and Texas has not submitted a revised SIP to address the deficiencies. While we previously proposed to approve the portion of the Regional Haze SIP that was intended to address whether EGUs in Texas must install and operate BART for PM,[12] that part of the proposed action was not finalized.[13] In connection with changed circumstances

[9] See, 42 U.S.C. 7491(b)(2)(A)(citing the potential need for BART as determined by "the Administrator in the case of a plan promulgated under section 7410(c) of this title").
[10] 81 FR 296 (January 5, 2016). A preliminary order of the Fifth Circuit Court of Appeals in Case No. 16-60118 was issued on July 15, 2016, and stayed the rule "in its entirety." On December 2, 2016, the U.S. Department of Justice filed a motion for voluntary remand of the parts of the rule under challenge and consenting to continuation of the judicial stay for remanded parts of the rule. The motion also requested affirmance of the partial approvals of the Texas and Oklahoma SIPs and lifting of the stay as to those approvals. This motion is currently pending disposition.
[11] The limited disapproval triggered the EPA's obligation to issue a FIP for Texas unless the State submitted an approvable SIP revision to correct the relevant deficiencies within 2 years of the final limited disapproval action. CAA section 110(c)(1); 77 FR 33641, 33654 (August 6, 2012).
[12] 79 FR 74817, 74851 (proposing to concur with screening analyses conducted by TCEQ including findings that no Texas EGUs are subject to BART for PM)
[13] 81 FR at 302 (January 5, 2016): "[W]e proposed to approve Texas' determination that for its EGUs no PM BART controls were appropriate, based on a screening analysis of the visibility impacts of from just PM

on how Texas EGUs are able to satisfy NO_X and SO_2 BART, we are now proposing to disapprove the portion of the Texas Regional Haze SIP that evaluated the PM BART requirement for EGUs. The FIP we are proposing today addresses the EGU BART requirement and addresses these deficiencies in the Texas Regional Haze SIP.

Texas' regional haze SIP relied on participation in CAIR as an alternative to meeting the source-specific BART requirements for SO_2 and NO_X. *See* 40 CFR 51.308(e)(4) (2006). At the time that Texas submitted its SIP to EPA, however, the D.C. Circuit had remanded CAIR (without vacatur). *See North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir.), *modified*, 550 F.3d 1176 (D.C. Cir. 2008). The court thereby left CAIR and CAIR FIPs in place in order to "temporarily preserve the environmental values covered by CAIR" until we could, by rulemaking, replace CAIR consistent with the court's opinion.[14]

On August 8, 2011, we promulgated the Cross-State Air Pollution Rule (CSAPR), to replace CAIR.[15] In 2012, we issued a limited disapproval of the Texas regional haze SIP because of Texas' reliance on CAIR as an alternative to EGU BART for SO_2 and NO_X.[16] We also determined that CSAPR would provide for greater reasonable progress than BART and amended the Regional Haze Rule to allow CSAPR participation as an alternative to source-specific SO_2 and NO_X BART for EGUs.[17] CSAPR has been subject to extensive litigation, and on July 28, 2015, the D.C. Circuit issued a decision generally upholding CSAPR but remanding without vacating the CSAPR emissions budgets for a number of states in *EME Homer City Generation* v. *EPA,* 795 F.3d 118 (D.C. Cir.). Specifically, the court invalidated a number of the

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emissions…..we have….decided not to finalize our proposed approval of Texas' PM BART determination [for EGUs]."

[14] 550 F.3d at 1178.

[15] 76 FR 48208.

[16] 77 FR 33641.

[17] While that rulemaking also promulgated FIPs for several states to replace reliance on CAIR with reliance on CSAPR as an alternative to BART, it did not include a FIP for Texas. 77 FR 33641, 33654.

Phase 2 ozone-season NO_X budgets and found that the SO_2 budgets for four states resulted in over-control for purposes of CAA section 110(a)(2)(D)(i)(I). The remand included Texas' ozone-season NO_X budget and annual SO_2 budget.

We had earlier proposed to rely on CSAPR participation to address these BART-related deficiencies in Texas' SIP submittals.[18] Because of the uncertainty caused by the D.C. Circuit Court's partial remand, however, we determined that it was not appropriate to finalize our action. We are in the process of responding to the remand of these CSAPR budgets. On October 26, 2016, we finalized an update to the CSAPR rule that addresses the 1997 ozone NAAQS portion of the remand and the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2008 ozone NAAQS.[19] This rule promulgated a new FIP for Texas that replaced the CSAPR ozone season NO_X emission budget designed to address the 1997 ozone NAAQS for the State with a revised budget designed to address the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2008 ozone NAAQS. Then, on November 10, 2016, we proposed to withdraw the FIP provisions that require affected EGUs in Texas to participate in CSAPR for annual emissions of SO_2 and NO_X with regard to emissions after 2016.[20] Withdrawal of these FIP requirements will address the D.C. Circuit's remand of the CSAPR Phase 2 SO_2 budget for Texas. This recently published proposed rule includes an assessment of the impacts of the set of actions that the EPA has taken

[18] 79 FR 74817, 74823 (December 16, 2014).

[19] "Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS." 81 FR74504. The relevant portion of the remand pertained to the Phase 2 ozone season NO_X emission budget designed to address the 1997 ozone NAAQS. In response to the remand, in this final rule the EPA removed the regulatory requirement for sources in Texas to comply with the phase 2 ozone season NO_X budget calculated to address the 1997 ozone standard because we determined that no additional emission reductions from sources in Texas are necessary to address the State's obligation under 110(a)(2)(D)(i)(I) for the 1997 ozone NAAQS. However, because Texas is linked to downwind air quality problems with respect to the 2008 ozone NAAQS, we promulgated a new ozone season NO_X emission budget to address that standard. 81 FR 74504, 74600-74601.

[20] "Interstate Transport of Fine Particulate Matter: Revision of Federal Implementation Plan Requirements for Texas," 81 FR 78954 (November 10, 2016). Although the court's decision specifically remanded only Texas' SO_2 budget, the court's rationale for remanding that budget also implicates Texas' annual NO_X budget because the SO_2 and annual NO_X budgets were developed through an integrated analysis and were promulgated to meet a common $PM_{2.5}$ transport obligation under CAA section 110(a)(2)(D)(i)(I).

or expects to take in response to the D.C. Circuit's remand on our 2012 demonstration that participation in CSAPR would provide for greater reasonable progress than BART.

In 2012, we determined that CSAPR is "better-than-BART" based on a comparison of projected visibility in scenarios representing CSAPR implementation and BART implementation, as well as a base case without CSAPR or BART, in relevant locations throughout the country. In the case of the remanded Phase 2 ozone-season NO_X budgets, eight of the states with remanded budgets (including Texas) will continue to be subject to CSAPR to address ozone transport obligations with regard to the more stringent 2008 ozone NAAQS, and North Carolina and South Carolina, although no longer covered by CSAPR to address ozone transport obligations, will continue to be subject to CSAPR annual NO_X requirements in order to address their $PM_{2.5}$ transport obligations. In considering the potential impact of the remand of Phase 2 budgets on the 2012 CSAPR-Better-than-BART analytic demonstration, we therefore believe that only two changes have potential relevance: the withdrawal of the FIP provisions subjecting Florida EGUs to CSAPR ozone-season NO_X requirements that has already been finalized, and the withdrawal of FIP provisions subjecting Texas EGUs to CSAPR SO_2 and annual NO_X requirements that is proposed separately. That proposed analysis supports the continued conclusion that CSAPR participation would achieve greater reasonable progress than BART for NO_X despite the change in the treatment of Texas and Florida EGUs. Consequently, we have proposed that the Regional Haze Rule continues to authorize the use of CSAPR participation as a BART alternative for EGUs.[21] Finalization of that proposal would allow for Texas' regional haze program to rely on CSAPR ozone season control program participation as an alternative to source-specific EGU BART for NO_X.[22] Based on that national proposal, we are

[21] 81 FR at 78962-78964.

[22] While we have proposed to remove Texas from CSAPR's annual NO_X program, CSAPR is still an appropriate

now proposing a FIP to replace Texas' reliance on CAIR with reliance on CSAPR to address the NO_X BART requirements for EGUs. Finalization of this portion of the FIP is contingent on our taking final action to find that CSAPR continues to be an appropriate alternative to source specific BART. However, finalization of the portion of our national proposal that would withdraw the FIP provisions for Texas for annual emissions of SO_2 and NO_X described above would mean that Texas will no longer be eligible to rely on CSAPR participation as an alternative to source-specific EGU BART for SO_2. As a result, we are proposing to promulgate a FIP that includes BART screening of sources and a source-by-source analysis for SO_2 BART and controls for this pollutant as appropriate. We are also unable to propose approval of the Texas Regional Haze SIP's PM BART evaluation, as previously proposed, as that demonstration made underlying assumptions that are no longer valid.[23] We instead propose to disapprove that portion of the SIP and, in place of it, promulgate source-specific PM BART requirements for EGUs that we have evaluated to be subject to BART in this proposed FIP.

We believe, however, it is preferable for states to assume primary responsibility for implementing the Regional Haze requirements as envisioned by the CAA. We will work with

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alternative to BART for NO_X purposes because EGUs in Texas continue to be required to participate in CSAPR's ozone season NO_X program.

[23] We previously proposed approval of Texas' SIP for EGU PM BART on the premise that EGU BART for both SO_2 and NO_X were covered by participation in CSAPR, which allowed Texas to conduct a screening analysis of the visibility impacts from PM emissions in isolation. However, modeling on a pollutant-specific basis for PM is appropriate only in the narrow circumstance where a state relies on a BART alternative to satisfy NO_X and SO_2 BART. Due to the complexity and nonlinear nature of atmospheric chemistry and chemical transformation among pollutants, EPA has not recommended performing modeling on a pollutant-specific basis to determine whether a source is subject to BART, except in the unique situation described above. See discussion in Memorandum from Joseph Paisie to Kay Prince, "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations," July 19, 2006. More recently, the Ninth Circuit upheld EPA's disapproval of the Arizona regional haze SIP for including a pollutant-specific screening analysis for NO_X. *Phoenix Cement Co. v. EPA*, 647 F. App'x 702, 705-06 (9th Cir. Mar. 31, 2016) (upholding EPA's interpretation that the "Regional Haze Rule [] require[s] a BART determination for any pollutant at a source that exceeds the de minimis threshold, once that source has been determined subject to BART."). We did not finalize our proposed approval of Texas' EGU PM BART determination because of the uncertainty at that time concerning the CSAPR remand and whether Texas would continue to have CSAPR coverage for both NO_X and SO_2, 81 FR 296, 302, but that uncertainty has now been resolved.

the State of Texas if it chooses to develop a SIP to meet these overdue Regional Haze requirements and replace or avoid a finalized FIP.

The FIP we are proposing includes BART control determinations for EGUs in Texas without previously approved BART determinations and associated compliance schedules and requirements for equipment maintenance, monitoring, testing, recordkeeping, and reporting for all affected sources and units. The EGU BART sources addressed in this FIP cause or contribute to visibility impairment at one or more Class I areas in Texas, Oklahoma, Arkansas, and New Mexico. The two Class I areas in Texas are Big Bend National Park and the Guadalupe Mountains National Park. The Class I area in Oklahoma is the Wichita Mountains National Wildlife Refuge. The two Class I areas in Arkansas are the Caney Creek Wilderness Area and the Upper Buffalo Wilderness Area. The closest impacted Class I areas in New Mexico are the Carlsbad Caverns National Park, Salt Creek Wilderness Area, and White Mountains Wilderness Area.

In order to remedy these deficiencies in the Texas SIP, we are proposing this FIP to establish the means by which the regional haze program for Texas will meet the BART requirements for SO_2, NO_X, and PM. We are proposing source-specific BART determinations for EGUs subject to BART for SO_2 and PM. We are proposing that NO_X BART requirements for EGUs in Texas will be satisfied by a determination, proposed for separate finalization, that Texas' participation in CSAPR's ozone season control program is a permissible alternative to source-specific NO_X BART.

Addressing the BART requirement for Texas EGUs, as proposed today, with cost-effective and readily available controls, will help ensure that progress is made toward natural visibility conditions at Class I areas affected by Texas' sources. Please refer to our previous

rulemaking on the Texas regional haze SIP for additional background regarding the CAA, regional haze, and our Regional Haze Rule.[24]

B. Interstate Transport of Pollutants that Affect Visibility

Section 110(a) of the CAA directs states to submit a SIP that provides for the implementation, maintenance, and enforcement of each NAAQS, which is commonly referred to as an infrastructure SIP. Among other things, CAA 110(a)(2)(D)(i)(II) requires that SIPs contain adequate provisions to prohibit interference with measures required to protect visibility in other states. This requirement is referred to as "interstate visibility transport." SIPs addressing interstate visibility transport are due to EPA within three years after the promulgation of a new or revised NAAQS (or within such shorter period as we may prescribe). A state's failure to submit a complete, approvable SIP for interstate visibility transport creates an obligation for EPA to promulgate a FIP to address this requirement.[25]

Previously, we issued a finding that Texas failed to submit a SIP revision to satisfy all four requirements of interstate transport under section 110(a)(2)(D)(i) of the CAA for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS.[26] Texas later submitted a SIP revision to address interstate

[24] 81 FR 296. The public docket for this past rulemaking remains accessible under EPA Docket ID: EPA-R06-OAR-2014-0754 at https://www.regulations.gov. This proposed rulemaking has a separately established docket (EPA-R06-OAR-2016-0611). Our TSD contains a list of materials from EPA Docket ID: EPA-R06-OAR-2014-0754 that we incorporate by reference and consider to be part of this rulemaking record even as they are not necessarily re-uploaded to the newer docket.

[25] CAA § 110(c)(1). Mandatory sanctions under CAA section 179 do not apply because the deficiencies are not with respect to a submission that is required under CAA title I part D. "Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and (2)" at pages 34–35 (September 13, 2013) [hereinafter 2013 i-SIP Guidance].

[26] 70 FR 21147 (April 25, 2005). The four components of interstate transport in Section 110(a)(2)(D)(i) are contained in two subsections. Section 110(a)(2)(D)(i)(I) addresses any emissions activity in one state that contributes significantly to nonattainment, or interferes with maintenance, of the NAAQS in another state. Section 110(a)(2)(D)(i)(II) requires SIPs to include provisions prohibiting any source or other type of emissions activity in one state from interfering with measures required of any other state to prevent significant deterioration of air quality or from interfering with measures required of any other state to protect visibility (referring to visibility in Class I areas). This proposal only addresses the fourth requirement concerning visibility.

transport for these NAAQS. However, in our January 5, 2016 final action we disapproved the portion of Texas' SIP revisions intended to address interstate visibility transport for six NAAQS, including the 1997 8-hour ozone and 1997 $PM_{2.5}$.[27] We concluded that to meet the requirements of interstate visibility transport: (1) Texas could not rely on its Regional Haze SIP, which relied heavily upon the remanded CAIR, to ensure that emissions from Texas do not interfere with measures to protect visibility in nearby states; and (2) additional control of SO_2 emissions in Texas were needed to prevent interference with measures required to be included in the Oklahoma SIP to protect visibility. However, in that action we did not finalize the portion of our proposed FIP addressing Texas' interstate visibility transport obligations because that portion of the proposed FIP would have partially relied on CSAPR to ensure the emissions from Texas' sources do not interfere with other states' visibility programs. Given the uncertainty that existed at the time arising from the D.C. Circuit's remand of Texas' CSAPR budgets (*EME Homer City Generation v. EPA*, 79 F.3d 118 (D.C. Cir.)), we concluded that it was not appropriate to finalize our proposed determination to rely on CSAPR as an alternative to SO_2 and NO_X BART for EGUs in Texas in that action.[28]

Our prior disapproval of interstate visibility transport for the six NAAQS is currently stayed by the Fifth Circuit.[29] We recognize that because our prior disapproval of the Texas SIP submittals addressing interstate visibility transport relied in part on our determinations of the measures needed in Texas to ensure reasonable progress in Oklahoma, the Fifth Circuit's stay of

[27] Specifically, we previously disapproved the relevant portion of these Texas' SIP submittals: April 4, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); May 1, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); November 23, 2009: 2006 24-hour $PM_{2.5}$; December 7, 2012: 2010 NO_2; December 13, 2012: 2008 8-hour Ozone; May 6, 2013: 2010 1-hour SO_2 (Primary NAAQS). 79 FR 74818, 74821; 81 FR 296, at 302.
[28] 81 FR 296, 301-2.
[29] July 15, 2016 Order in *Texas v. EPA* (Fifth Cir. Case No. 16-160118). The EPA's filed motion requesting voluntary partial remand and continuation of the judicial stay for remanded parts of the rule includes our prior disapproval of Texas' SIPs concerning interstate visibility transport. This motion is currently pending disposition.

our previous action complicates next steps to ensure that the visibility requirements of CAA 110(a)(2)(D)(i)(II) are met. The Court's stay accordingly calls into question whether our past disapprovals for interstate visibility transport would stand. At the same time, we also note that we continue to have an obligation to issue a FIP for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS as a result of our 2005 finding that Texas failed to timely submit SIPs to address the interstate transport visibility requirements. Given the uncertainties arising from the Fifth Circuit's stay of our prior disapproval, we are now proposing to reconsider the basis of our prior disapproval of Texas' SIP submittals addressing the interstate visibility transport requirement for all six NAAQS. We are now proposing to determine that Texas' SIP submittals addressing interstate visibility transport for the six NAAQS are not approvable because these submittals relied solely on Texas' Regional Haze SIP to ensure that emissions from Texas did not interfere with required measures in other states. Texas' Regional Haze SIP, in turn, relied on the implementation of CAIR as an alternative to EGU BART for SO_2 and NO_X. Specifically, we are proposing disapproval of the following Texas SIP submittals insofar as they address the interstate visibility transport requirement: April 4, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); May 1, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); November 23, 2009: 2006 24-hour $PM_{2.5}$; December 7, 2012: 2010 NO_2; December 13, 2012: 2008 8-hour Ozone; May 6, 2013: 2010 1-hour SO_2 (Primary NAAQS). Texas has not submitted a SIP revision to remove reliance on CAIR for Regional Haze or interstate visibility transport. As CAIR is no longer in effect and has been replaced by CSAPR, we are proposing to find that Texas' Regional Haze SIP does meet its interstate visibility transport obligations. As a result, the Texas SIPs to address interstate visibility transport for these six NAAQS continue to be unapprovable.

We are proposing a FIP to cure the deficiencies in Texas' Regional Haze Program concerning EGU BART. This FIP will replace reliance on CAIR with reliance on CSAPR to meet the requirements for EGU BART for NO_X in Texas. The FIP will also address Texas EGU BART for SO_2 and PM on a source-specific basis. With the absence of CSAPR coverage for SO_2, we must reevaluate what is needed in Texas to address interstate visibility transport. Our proposed FIP to address Texas EGU BART achieves significant reductions of SO_2, which exceed the reductions initially assumed for Texas under either CAIR or CSAPR. In addition, our proposed FIP achieves reductions at large sources of SO_2 emissions (e.g., Monticello, Martin Lake and Big Brown), that have significant impacts on Class I areas in nearby states. The BART FIP requires controls on many but not all of the sources that were controlled in our previous partial FIP for Texas Regional Haze. The EGU BART FIP also includes control requirements at some additional sources not controlled in our previous action on Texas Regional Haze.

We are proposing to find that our proposed EGU BART FIP is adequate to prevent interference with measures required to protect visibility in other states for the first planning period.[30] We, therefore, propose that the measures in our proposed FIP to address Texas EGU BART will fully address Texas' interstate visibility transport obligations for the six NAAQS (1997 8-hour ozone, 1997 $PM_{2.5}$, 2006 $PM_{2.5}$, 2008 8-hour ozone, 2010 1-hour NO_2, and 2010 1-hour SO_2). We also propose that reliance on CSAPR for EGU NO_X BART is appropriate to ensure NO_X emissions from Texas EGUs do not interfere with other states' measures to protect visibility. We are proposing this action based on the reasoning that our BART FIP will achieve

[30] This proposed FIP for interstate visibility transport is premised on the interpretation that this requirement can be addressed even when a Regional Haze SIP is not fully approved and the FIP does not purport to correct all Regional Haze SIP deficiencies. *See e.g.* 76 FR 52388 (August 22, 2011); 76 FR 22036 (April 20, 2011); and 78 FR 14681 (March 7, 2013); *see also*, 2013 i-SIP Guidance, at page 34 (stating that EPA may find it appropriate to supplement the i-SIP Guidance regarding the relationship between Regional Haze SIPs and interstate visibility transport for future planning periods).

more emission reductions than projected under CAIR or CSAPR and the reductions are occurring at sources that have particularly large impacts on Class I areas outside of Texas. To the extent our previous final action concerning Texas Regional Haze is remanded by a Court or otherwise reconsidered in the future, we may revisit whether controls in the EGU BART FIP are adequate to address interstate visibility transport requirements. Nonetheless, we are here proposing that the proposed EGU BART FIP measures will be adequate to address interstate visibility transport based on current information. This proposal concerning the adequacy of the proposed FIP remedy does not depend on our earlier action on the Texas Regional Haze SIP or hinge on its disposition, nor does it foreclose that we may reexamine visibility transport concerns under potential scenarios where we have a responsibility to take new action.[31]

We encourage Texas to consider adopting additional SIP provisions that would allow the EPA to fully approve the Regional Haze SIP and thus to withdraw the FIP and approve Texas' SIP with respect to interstate visibility transport. Texas may also elect to satisfy interstate visibility transport by providing, as an alternative to relying on its Regional Haze SIP alone, a demonstration that emissions within its jurisdiction do not interfere with other states' plans to protect visibility.[32]

C. Our Obligation to Promulgate a FIP

Under section 110(c) of the CAA, whenever we disapprove a mandatory SIP submission in whole or in part, we are required to promulgate a FIP within 2 years unless we approve a SIP revision correcting the deficiencies before promulgating a FIP. Specifically, CAA section 110(c) provides that the Administrator shall promulgate a FIP within 2 years after the Administrator

[31] *See e.g.* 78 FR 14681, 14685.
[32] 2013 i-SIP Guidance, at pages 34-35.

disapproves a state implementation plan submission "unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan."[33] The term "Federal implementation plan" is defined in Section 302(y) of the CAA in pertinent part as a plan promulgated by the Administrator to correct an inadequacy in a SIP.

Beginning in 2012, following the limited disapproval of the Texas Regional Haze SIP, EPA had the authority and obligation to promulgate a FIP to address BART for Texas EGUs for NO_X and SO_2. In proposing to disapprove the Regional Haze SIP component that sought to address the PM BART requirement for Texas EGUs, we also have the obligation to promulgate a PM BART FIP to address the deficiency. Texas has not addressed the EGU BART disapproval, and that requirement is now significantly overdue.[34] We are accordingly empowered and required by the CAA to make determinations and promulgate a FIP to ensure the BART requirement for Texas EGUs is satisfied.

Adding to this background, beginning with our January 5, 2016 disapproval of Texas SIP provisions regarding interstate visibility transport, we obtained the authority and obligation to promulgate a FIP to correct the deficiencies relating to that CAA requirement.[35] As with the BART requirement, we lack a SIP revision that would have any potential to correct the deficiency, necessitating that we now take action under FIP authority.

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[33] EPA additionally has the authority to promulgate a FIP any time after finding that "a State has failed to make a required submission" of a SIP. CAA section 110(c)(1)(A); 42 U.S.C. §7410(c)(1)(a).

[34] The Texas Regional Haze SIP stated, "The TCEQ will take appropriate action if CAIR is not replaced with a system that the US EPA considers to be equivalent to BART." BART determinations were due in SIP submissions on December 17, 2007, 40 CFR 51.308(b), putting them on a timeline for controls by 2014 (considering the deadline for SIP action at CAA section 110(k)(2) and allowing five years for installation of BART controls). Additional delay of any amount is not appropriate and not consistent with the law.

[35] Additionally, we continue to have authority to issue a FIP to address interstate visibility transport for 1997 8-hour ozone and 1997 $PM_{2.5}$ due to our 2005 finding that Texas failed to submit SIPs to address interstate transport for these NAAQS under CAA section 110(a)(2)(D)(i). 70 FR 21147.

III. Our Proposed BART Analyses for SO_2 and PM

In our previous action,[36] we determined that due to the CSAPR remand, it was not appropriate at that time to rely on CSAPR as an alternative to SO_2 and NO_X BART for EGUs in Texas. As a consequence, action to satisfy the overdue requirement to address BART for EGUs in the state of Texas was further delayed.[37] In this proposal, we are proposing that CSAPR, once fully revised to address the D.C. Circuit's remand, provides a basis for satisfying EGU BART obligations for NO_X alone. It remains the case that we cannot rely on CSAPR as an alternative to SO_2 BART for Texas EGUs as further confirmed by our proposed action to remove Texas from the annual NO_X and SO_2 control programs. Thus, we have the obligation to consider source-specific requirements for Texas EGUs consistent with the BART Guidelines for SO_2 BART.

Because the component of the Texas Regional Haze SIP regarding the PM BART requirement for EGUs has not been acted on, we have the responsibility under CAA section 110(k) to evaluate the submission and take action to approve or disapprove it. The SIP determinations for PM were based on modeling that was conducted by examining visibility impairment due to PM emissions alone, based on the assumption that the state would be participating in CAIR for SO_2 and NO_X and thereby having BART coverage for those pollutants. The Texas Regional Haze SIP had concluded that no PM BART controls for EGUs were appropriate, because modeling assessment of PM impacts alone showed their impacts to be too small to warrant control consideration. But Texas' screening analysis is no longer reliable or accurate because of the invalid assumption that source-by-source BART for either SO_2 or NO_X would not be required. In order to appropriately evaluate the BART requirements for EGUs, the

[36] See the discussion beginning on 81 FR 301 (January 5, 2016).
[37] Id. at 346.

visibility impacts from all pollutants must be studied, including PM emissions. Texas' PM BART analysis for EGUs does not do this.[38]

Accordingly, we are proposing to disapprove the portion of the Texas Regional Haze SIP that determined that all Texas EGUs screen out of the BART requirement for PM. The basis for the proposed disapproval is the SIP determination's assumption that EGUs would have coverage for SO_2 and NO_X BART under an alternative measure.[39] Since that assumption is not valid, the technical determinations regarding PM BART cannot be approved. Following the directions of the BART Guidelines on how to identify sources "subject to BART," we have looked at all visibility impairing pollutants from EGUs that are BART-eligible. Our proposed FIP therefore seeks to fill that regulatory gap by assessing BART for Texas EGUs for visibility impairing pollutants other than NO_X, i.e., SO_2 and PM.

A. Identification of BART-Eligible Sources

The BART Guidelines set forth the steps for identifying whether the source is a BART-eligible source:[40]

Step 1: Identify the emission units in the BART categories,

Step 2: Identify the start-up dates of those emission units, and

Step 3: Compare the potential emissions to the 250 ton/yr cutoff.

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[38] Texas' Regional Haze SIP determined whether its sources should be subject to review for PM controls by only looking at the impact of PM emissions on visibility. This approach is only appropriate when a state satisfies the requirements for BART for SO_2 and NO_X with an alternative measure. Additionally, as reflected in our TSD on the identification of BART-Eligible Sources, the Texas SIP neglected to identify several BART-eligible sources; this also shows error in the state's PM BART demonstration and conclusions, and it constitutes grounds for the proposed partial SIP disapproval for PM BART.

[39] The requirements for "emissions trading programs or other alternative measures" that may be implemented rather than requiring BART are provided at 40 C.F.R. 51.308(e)(2).

[40] 70 FR 39158 (July 6, 2005).

Following our 2016 final action on the March 31, 2009 Texas RH SIP, we began the process of generating additional technical information and analysis in order to address the above three steps in our BART-eligibility proposal. We started with Texas' facility-specific listing of BART-eligible EGU sources and removed sources we verified had retired. We then gathered additional information from (1) our authority under Section 114(a) of the CAA to request information from potential BART-eligible sources, and (2) the U.S. Energy Information Administration (EIA). We then converted Texas' facility-specific BART-eligible list to a unit-specific BART-eligible list and verified the BART-eligibility of each unit. The following is a list of units we propose have satisfied the above three steps and are BART-eligible:[41]

Table 1. Summary of BART-Eligibility Analysis

Facility	Unit
Barney M. Davis (Talen/Topaz)	1
Big Brown (Luminant)	1
Big Brown (Luminant)	2
Cedar Bayou (NRG)	CBY1
Cedar Bayou (NRG)	CBY2
Coleto Creek (Engie)	1
Dansby (City of Bryan)	1
Decker Creek (Austin Energy)	1
Decker Creek (Austin Energy)	2
Fayette (LCRA)	1

[41] See our BART FIP TSD for more information concerning how we selected the units we are proposing are BART-eligible and other details concerning our proposed BART determinations.

Fayette (LCRA)	2
Graham (Luminant)	2
Greens Bayou (NRG)	5
Handley (Exelon)	3
Handley (Exelon)	4
Handley (Exelon)	5
Harrington Station (Xcel)	061B
Harrington Station (Xcel)	062B
J T Deely (CPS Energy)	1
J T Deely (CPS Energy)	2
Jones Station (Xcel)	151B
Jones Station (Xcel)	152B
Knox Lee Power Plant (AEP)	5
Lake Hubbard (Luminant)	1
Lake Hubbard (Luminant)	2
Lewis Creek (Entergy)	1
Lewis Creek (Entergy)	2
Martin Lake (Luminant)	1
Martin Lake (Luminant)	2
Martin Lake (Luminant)	3
Monticello (Luminant)	1
Monticello (Luminant)	2
Monticello (Luminant)	3
Newman (El Paso Electric)	2
Newman (El Paso Electric)	3
Newman (El Paso Electric)	4
Nichols Station (Xcel)	143B
O W Sommers (CPS Energy)	1
O W Sommers (CPS Energy)	2

Plant X (Xcel)	4
Powerlane (City of Greenville)	ST1
Powerlane (City of Greenville)	ST2
Powerlane (City of Greenville)	ST3
R W Miller (Brazos Elec. Coop)	1
R W Miller (Brazos Elec. Coop)	2
R W Miller (Brazos Elec. Coop)	3
Sabine (Entergy)	2
Sabine (Entergy)	3
Sabine (Entergy)	4
Sabine (Entergy)	5
Sim Gideon (LCRA)	1
Sim Gideon (LCRA)	2
Sim Gideon (LCRA)	3
Spencer (City of Garland)	4
Spencer (City of Garland)	5
Stryker Creek (Luminant)	ST2
Trinidad (Luminant)	6
Ty Cooke (City of Lubbock)	1
Ty Cooke (City of Lubbock)	2
V H Braunig (CPS Energy)	1
V H Braunig (CPS Energy)	2
V H Braunig (CPS Energy)	3
W A Parish (NRG)	WAP 4
W A Parish (NRG)	WAP 5
W A Parish (NRG)	WAP 6
Welsh Power Plant (AEP)	1

Welsh Power Plant (AEP)	2
Wilkes Power Plant (AEP)	1
Wilkes Power Plant (AEP)	2
Wilkes Power Plant (AEP)	3

The final step in identifying a ''BART-eligible source'' is to use the information from the previous three steps to identify the collection of emissions units that comprise the BART-eligible source.

B. Identification of Sources that are Subject to BART

Following our compilation of the BART-eligible sources in Texas, we examined whether these sources cause or contribute to visibility impairment in nearby Class I areas.[42] 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. Those sources are determined to be not subject-to-BART. Sources that are reasonably anticipated to cause or contribute to any visibility impairment in a Class I area are determined to be subject-to-BART. For each source subject to BART, 40 CFR 51.308(e)(1)(ii)(A) requires that states (or EPA, in the case of a FIP) 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 that CALPUFF or another appropriate model can be used to predict the visibility impacts from a single source at a Class I area. We employed a four-fold strategy in determining

[42] See 40 C.F.R. Part 51, Appendix Y, III, How to Identify Sources "Subject to BART"

which units should or should not be subject to BART. A flowchart of the analysis along with a detailed discussion of the subject-to-BART screening analysis is provided in the BART Screening TSD.[43] We summarize the methodology and results of this analysis here.

First, we examined whether any of the BART-eligible units should be eliminated from consideration based on the standard model plant exemptions described in the BART Guidelines.[44] Second, we created specific model plants between sources and nearby Class I areas and conducted CALPUFF modeling to evaluate a number of sources for exemption. Third, we performed stand-alone, source specific CALPUFF modeling on a number of units to determine if their visibility impacts were large enough to identify them as being subject to BART. Fourth, for those remaining units outside of the CALPUFF model's range, we contracted to have CAMx modeling performed to determine if their visibility impacts were large enough to merit their being subject to BART. These steps are further described below.

For states using modeling to determine the applicability of BART to single sources, the BART Guidelines note that the first step is to set a contribution threshold to assess whether the impact of a single source is sufficient to cause or contribute to visibility impairment at a Class I area. The BART Guidelines preamble 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."[45] It further advises that "States should have discretion to set an appropriate threshold depending on the facts of the situation," but "[a]s a general matter, any threshold that you use for determining whether a source 'contributes' to visibility impairment should not be

[43] See our TSD, "Our Strategy for Assessing which Units are Subject to BART for the Texas Regional Haze BART Federal Implementation Plan (BART Screening TSD)" in our docket.
[44] See the discussion beginning on 70 FR 39104, 39162 (July 6, 2005) [40 CFR Part 51, App. Y].
[45] 70 FR at 39118.

higher than 0.5 dv," and describes situations in which states may wish to exercise their discretion to set lower thresholds, mainly in situations in which a large number of BART-eligible sources within the State and in proximity to a Class I area justify this approach. We do not believe that the sources under consideration in this rule, most of which are not in close proximity to a Class I area, merit the consideration of a lesser contribution threshold. Therefore, our analysis employs a contribution threshold of 0.5 deciviews.

1. Our use of the Standard BART Model Plant Exemption

As the BART Guidelines note:

> [W]e believe that a State that has established 0.5 deciviews as a contribution threshold could reasonably exempt from the BART review process sources that emit less than 500 tons per year of NO_X or SO_2 (or combined NO_X and SO_2), as long as these sources are located more than 50 kilometers from any Class I area; and sources that emit less than 1000 tons per year of NO_X or SO_2 (or combined NO_X and SO_2) that are located more than 100 kilometers from any Class I area. You do, however, have the option of showing other thresholds might also be appropriate given your specific circumstances.[46]

We applied the standard BART model plant exemption described above to the following facilities, exempting them from further analysis:

[46] 70 FR at 39163, [40 CFR Part 51, App. Y].

Table 2: Standard BART Model Plant Exempt Sources

Facility	Units
Dansby (City of Bryan)	1
Greens Bayou (NRG)	5
Nichols Station (Xcel)	143B
Plant X (Xcel)	4
Powerlane (City of Greenville)	ST1, ST2 & ST3
Spencer (City of Garland)	4 & 5
Trinidad (Luminant)	6
Ty Cooke (City of Lubbock)	1 & 2

2. Our Extension of the BART Model Plant Exemption

As the BART Guidelines note, the standard BART model plant exemption can be extended to values other than the 500 tons/50 km and 1,000 tons/100 km scenarios discussed in the previous section. 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."[47]

Modeling analyses of representative plants are used to reflect groupings of specific sources with important common characteristics. We conducted CALPUFF modeling to establish emission levels and distances from Class I areas on which we could rely to exempt sources with those characteristics. In this approach, a hypothetical facility ("model plant") is located between a group of BART-eligible sources and a Class I area. Predominant wind patterns and elevation are considered in locating the model plant such that conditions that would be anticipated to transport pollution from the group of BART-eligible sources to the Class I area are consistent

[47] 70 FR at 39163 [40 CFR Part 51, App. Y].

with conditions anticipated to transport pollution from the model plant to the Class I area. The visibility impacts from this model plant are modeled utilizing CALPUFF following the protocol described in the BART Screening TSD. Model plant emissions are adjusted such that the modeled visibility impact (maximum of 98th percentile values for 2001, 2002, and 2003) is below the screening threshold of 0.5 dv. For each model plant, the Q/d value is calculated as the annual emissions (combined NO_X and SO_2 emissions) divided by distance to the Class I area (km) resulting in a critical Q/d value. The Q/d value for each BART-eligible source is calculated based on annual emissions based on the maximum actual 24-hr emission rate and distance to the Class I area and is then compared to the critical Q/d value. For a BART-eligible source with a lower Q/d value than the critical Q/d, it is reasonably anticipated that the visibility impact from the BART-eligible source is lower than the model plant and therefore below the screening threshold and not subject to BART. See the BART Screening TSD for additional discussion and source-specific information used in this model plant screening analysis. By this extension of the BART model plant exemption, we identified the following additional facilities that can be exempted from further analysis:

Table 3: Extended BART Model Plant Exempt Sources

Facility	Units
Barney M. Davis (Talen/Topaz)	1
Cedar Bayou (NRG)	CBY1 & CBY2
Decker Creek (Austin Energy)	1 & 2
Lewis Creek (Entergy)	1 & 2
Sabine (Entergy)	2, 3, 4 & 5
Sim Gideon (LCRA)	1, 2 & 3
V H Braunig (CPS Energy)	1, 2 & 3

3. Our use of CALPUFF Modeling to Exempt Sources from Being Subject to BART

Those sources that did not screen out using the model plant approach were modeled directly with CALPUFF if they were in a range of when CALPUFF has been previously used. Historically CALPUFF has been used at distances up to approximately 400 km. The maximum 98th percentile impact from the modeled years (calculated based on annual average natural background conditions) was compared with the 0.5 dv screening threshold following the modeling protocol described in the BART screening TSD. The BART Guidelines 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 of start-up, shutdown, or malfunction. The maximum 24-hour emission rate (lb/hr) for NO_X and SO_2 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.[48] For some BART-eligible sources, evaluation of baseline emissions revealed evidence of the installation of NO_X control technology during the baseline period. For those sources, the maximum emission rate was updated to reflect the identified maximum emission rate from the post-control portion of the baseline period. Because daily emissions are not available for PM, the annual average emission rate was doubled to approximate the 24-hr maximum emission rate for PM. See the BART Screening TSD for additional discussion and source-specific information used in the CALPUFF modeling for this portion of the screening analysis. With the use of CALPUFF modeling results, we identified the following additional facilities that can be exempted from further analysis:

Table 4: CALPUFF BART Exempt Sources

[48] http://ampd.epa.gov/ampd/

Facility	Units
Handley (Exelon)	3, 4 & 5
Jones (Xcel)	151B & 152B
Lake Hubbard (Luminant)	1 & 2
Knox Lee (AEP)	5
R W Miller (Brazos Elec. Coop)	1, 2 & 3

Based on these CALPUFF screening analyses using model plant approaches and direct modeling, the following gas[49]/fuel oil fired facilities did not screen out from being subject to BART: Newman, Stryker, Graham, and Wilkes. None of the coal fired facilities screened out in our CALPUFF modeling for the facilities within CALPUFF range.

4. Our use of CAMx Modeling to Exempt Sources from Being Subject to BART

Some of the BART-eligible sources in Texas are geographically distant from a Class I area, yet have high enough emissions that they may significantly impact visibility at Class I areas in Texas and surrounding states. However, the use of CALPUFF is not recommended for distances much greater than 300 km, and has typically not been used at distances more than approximately 400 km. To determine which sources are anticipated to contribute to visibility impairment the BART guidelines state that CALPUFF or another appropriate model can be used to predict the visibility impacts from a single source at a Class I area. CAMx provides a scientifically defensible 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, NO_X, VOC and PM emissions as it has a more robust chemistry mechanism. The CAMx PM Source Apportionment Technology (PSAT) modeling was

[49] When we use the term "gas," we mean "pipeline quality natural gas."

conducted for those BART-eligible sources that have large SO_2 emissions.[50] In 2006/2007, the TCEQ developed a modeling protocol and analysis using CAMx with the same Plume in Grid and PSAT techniques to evaluate visibility impacts from non-EGU BART sources, as well as to evaluate VOC and PM impacts from all BART-eligible sources to inform the 2009 Texas Regional Haze SIP.[51,52] This modeling protocol was reviewed by the TCEQ, EPA and FLM representatives specialized in air quality analyses and BART prior to performing the analysis and submission of their regional haze SIP. Our subject-to-BART screening modeling for EGU-sources using CAMx is consistent with the protocol developed and utilized by Texas in their regional haze SIP. We are using more recent model versions with updated science in our analysis.

Consistent with the BART guidelines and our CALPUFF modeling, for the selected BART-eligible sources we used the maximum actual 24-hr emission rates for NO_X and SO_2 from the 2000-2004 baseline period from EPA's Air Markets Program Data[53] and modeled these emission rates as constant emission rates for the entire modeled year. For some of the modeled BART-eligible sources, evaluation of baseline emissions revealed evidence of installation of NO_X control technology during the baseline period. For those sources the maximum emission rate was identified from the post-control portion of the baseline period. Because daily emissions are not available for PM, the annual average emission rate was doubled to approximate the 24-hr

[50] CAMx results were also obtained and add to our basis of information for coal-fired facilities that have CALPUFF results.
[51] 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.
[52] We approved Texas' subject-to-BART analysis for non-EGU sources which relied on this CAMx modeling in our January 5, 2016 rulemaking (81 FR 296)
[53] http://ampd.epa.gov/ampd/

maximum emission rate for PM. 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. The maximum modeled impact for each source (calculated based on annual average natural background conditions) was compared to the 0.5 dv contribution threshold. See the BART Screening TSD for additional details on the CAMx modeling performed and the model inputs used. The table below summarizes the results of the CAMx screening analysis. As shown in the table below, all sources analyzed with CAMx modeling had impacts greater than 0.5 dv at one or more Class I areas. The most impacted Class I areas based on these results are Wichita Mountains National Wildlife Refuge in Oklahoma (WIMO), Caney Creek Wilderness Area in Arkansas (CACR), and Salt Creek Wilderness Area in New Mexico (SACR). CAMx modeled impacts at single locations for these sources (maximum impact day) ranged from 0.845 dv to 10.498 dv.

Table 5: CAMx BART Screening Source Analysis Results

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[2]**	**Number of modeled days over 1.0 dv[2]**
Big Brown	1 & 2	WIMO	4.017	No	65	33
Coleto Creek	1	WIMO	0.845	No	9	0
Fayette Power	1&2	CACR	1.894	No	26	9
Harrington	061B & 062B	SACR	5.288	No	13	5
Martin Lake	1,2,&3	CACR	6.651	No	141	99
Monticello	1,2,&3	CACR	10.498	No	152	111
Calaveras	J T Deely 1&2,	WIMO				

	OW Sommers 1&2		1.513			
W A Parish	WAP4, WAP5&WAP6	CACR	3.177	No	54	22
Welsh[1]	1&2	CACR	4.576	No	92	39

[1] Welsh unit 2 has recently shutdown. We note that baseline impacts from unit 1 alone are 2.343 dv at Caney Creek.

[2] Number of days over 0.5 or 1.0 dv at the most impacted Class I area

5. Summary of Sources that are Subject to BART

Based on the four methodologies described above, the BART-eligible sources in the table below have been determined to cause or contribute to visibility impairment at a nearby Class I area, and we therefore propose to find the sources are subject-to-BART. They are subject to review for visibility impairing pollutants other than NO_X.[54] Foremost, they are subject to SO_2 BART, the visibility impairing pollutant that is the main contributor to the regional haze problem at Class I areas in Texas and neighboring states. The sources are also subject to review for source-specific BART requirements for PM.

Table 6: Summary: Sources that are Subject-to-BART

Facility	Units
Big Brown	1 & 2
Coleto Creek	1
Fayette Power	1 & 2
Harrington	061B & 062B
Martin Lake	1, 2 & 3
Monticello	1, 2 & 3
Calaveras	J T Deely 1 & 2, O W Sommers 1 & 2
W A Parish	WAP4, WAP5 & WAP6
Welsh	1 & 2*
Stryker	ST2
Graham	2
Wilkes	1, 2 & 3

[54] The NO_X BART requirement for these EGU sources is not addressed by source-specific limits in this proposal. According to our proposal, participation in CSAPR, in its updated form, would serve as a BART alternative, dispensing with the need for source-specific BART determinations and requirements for NO_X.

Newman	2, 3 & 4

* Welsh Unit 2 retired in April, 2016.

C. Our BART Five Factor Analyses

The purpose of the BART analysis is to identify and evaluate the best system of continuous emission reduction based on the BART Guidelines.[55] In determining BART, a state, or EPA when promulgating a FIP, must consider the five statutory factors in section 169A of the CAA: (1) The costs of compliance; (2) the energy and nonair quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. See also 40 CFR 51.308(e)(1)(ii)(A). This is commonly referred to as the "BART five factor analysis." The BART Guidelines break the analyses of these requirements down into five steps:[56]

STEP 1—Identify All Available Retrofit Control Technologies,

STEP 2—Eliminate Technically Infeasible Options,

STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies,

STEP 4—Evaluate Impacts and Document the Results, and

STEP 5—Evaluate Visibility Impacts.

The following sections treat these steps individually for SO_2. We are combining these

[55] See July 6, 2005 BART Guidelines, 40 CFR Part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations.
[56] 70 FR 39104, 39164 (July 6, 2005) [40 CFR Part 51, App. Y].

steps into one section in our assessment of PM BART that follows the SO_2 sections.

1. Steps 1 and 2: Technically Feasible SO_2 Retrofit Controls

The BART Guidelines state that in identifying all available retrofit control options,

> [Y]ou must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving.[57]

Adhering to this, we will identify a reasonable set of SO_2 control options, including those that cover the maximum level of control each technology is capable of achieving. In the course of that task, we will note whether any of these technologies are technically infeasible.

The subject-to-BART units identified in Table 6 can be organized into four broad categories, based on their fuel type and the potential types of SO_2 controls that could be retrofitted: (1) coal-fired EGUs with no SO_2 scrubber, (2) coal-fired EGUs with underperforming SO_2 scrubbers, (3) gas-fired EGUs that do not burn oil, and (4) gas-fired EGUs that occasionally burn fuel oil. This classification is represented below:

Table 7: Subject to BART Fuel Types and Potential SO_2 BART Controls

[57] 70 FR at 39164, fn 12 [40 C.F.R. Part 51, App. Y]

Facility	Unit	Coal no scrubber	Coal underperforming scrubber	Gas no oil	Gas burns oil
Big Brown (Luminant)	1	X			
Big Brown (Luminant)	2	X			
Coleto Creek (Engie)	1	X			
Fayette (LCRA)*	1				
Fayette (LCRA)*	2				
Graham (Luminant)	2				X
Harrington Station (Xcel)	061B	X			
Harrington Station (Xcel)	062B	X			
J T Deely (CPS Energy)	1	X			
J T Deely (CPS Energy)	2	X			
Martin Lake (Luminant)	1		X		
Martin Lake (Luminant)	2		X		
Martin Lake (Luminant)	3		X		
Monticello (Luminant)	1	X			
Monticello (Luminant)	2	X			
Monticello (Luminant)	3		X		
Newman (El Paso Electric)	2				X
Newman (El Paso Electric)	3				X
Newman (El Paso Electric)	4			X	
O W Sommers (CPS Energy)	1				X
O W Sommers (CPS Energy)	2				X
Stryker Creek (Luminant)	ST2				X
W A Parish (NRG)	WAP4			X	
W A Parish (NRG)	WAP5	X			
W A Parish (NRG)	WAP6	X			
Welsh Power Plant (AEP)	1	X			
Wilkes Power Plant (AEP)	1				X
Wilkes Power Plant (AEP)	2			X	
Wilkes Power Plant (AEP)	3			X	

* The Fayette units have high performing wet Flue Gas Desulfurization scrubbers in place.

For the coal-fired EGUs without an existing scrubber, we have identified four potential control technologies: (1) coal pretreatment, (2) Dry Sorbent Injection (DSI), (3) Spray Dryer Absorber (SDA), and (4) wet Flue Gas Desulfurization (FGD.) For the coal-fired EGUs with an existing underperforming scrubber we will examine whether that scrubber can be upgraded.

Gas-fired EGUs that do not burn oil have inherently very low SO_2 emissions and there are no known SO_2 controls that can be evaluated.

For gas-fired units that occasionally burn fuel oil, we will follow the BART Guidelines recommendations for oil-fired units: "For oil-fired units, regardless of size, you should evaluate limiting the sulfur content of the fuel oil burned to 1 percent or less by weight."[58] In addition, we will also evaluate the potential for post combustion SO_2 controls for these units.

a. Identification of Technically Feasible SO_2 Retrofit Control Technologies for Coal-Fired Units

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.

Coal Pretreatment

Coal pretreatment, or coal 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. Coal pretreatment broadly falls into two categories: coal washing and coal drying.

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).[59] 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

[58] 70 FR 39171 (July 6, 2005) [40 CFR 51, App. Y].
[59] Couch, G. R., "Coal Upgrading to Reduce CO_2 emissions," CCC/67, October 2002, IEA Clean Coal Centre.

matter by this means, except in a few cases.[60] Coal is mechanically sized, then various washing techniques are employed, depending on the particle size, type of coal, and the desired level of preparation.[61] Following the coal washing, the coal is dewatered, and the waste streams are disposed.

Coal washing takes place offsite at large dedicated coal washing facilities, typically located near where the coal is mined. In addition, coal washing carries with it 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,[62] and coal washing slurries are typically stored in impoundments, which can, and have, leaked.[63]

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[60] Ibid.

[61] 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.

[62] "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.

[63] 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.

Because of these issues, we do not consider coal washing as a part of our reasonable set of options for analysis as BART SO_2 control technology.

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 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 unit burning less coal to make the same amount of power.

Coal drying can be performed onsite and so can be considered a potential BART control. Great River Energy has developed a patented process which is being successfully utilized at the Coal Creek facility and is potentially available for installation at other facilities.[64] 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.

Although we view this new patented technology for coal drying onsite as a promising path in the near future 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). We cannot

[64] 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/

assess many of these site-specific issues and we believe that requesting that the facilities in question do so would require detailed engineering analysis and extend our review time greatly. As a result of these issues, we do not further assess coal drying as part of our reasonable set of options for BART analysis. We expect that this technology may have matured enough such that it can be better assessed for the second planning period.

DSI

DSI is performed by injecting a dry reagent into the hot flue gas, which chemically reacts with SO_2 and other gases to form a solid product that is subsequently captured by the particulate control device. A blower delivers 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 are 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. For instance, Luminant states in its response to one of our Section 114(a) letters regarding its Big Brown and Monticello units:[65]

> Luminant commissioned the study of dry sorbent injection ("DSI") at these units in 2011. These studies determined that a very high feed rate (in the range of 20-

[65] Luminant's 6/17/14 response to EPA's 5/20/14 Section 114(a) request for information relating to the Big Brown, Martin Lake, Monticello, and Sandow generating stations.

> 30%) was required to achieve modest SO_2 removal. Further, it was determined that other economic and operational factors make the use of DSI infeasible. For example, sorbent build-up was determined to cause degraded performance of the control equipment over time, as well as significant, repeat down time on a regular basis (i.e., every few days) to remove the buildup. In addition to the high cost of the sorbent required, the disposal and transport of the used sorbent (a Texas Class 1 waste) would result in significant additional cost. Thus, the use of DSI was determined infeasible from both an operational and economic point of view, and further evaluation has been discontinued.

As a consequence of this statement, which is discussed more fully in the CBI material Luminant has submitted and in our TSD, we have concluded that DSI is not a feasible alternative for the Big Brown and Monticello facilities. For all unscrubbed, coal-fired BART-subject units other than the Big Brown and Monticello facilities, although individual installations may present technical difficulties or poor performance due to the suboptimization of one or more of the above factors, we believe that DSI is technically feasible and should be considered as a potential BART control.

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

FGD, and Spray Dry Absorber (SDA). More recently, Circulating Dry Scrubbers (CDS) have been introduced. The EIA reports the following types of flue gas desulfurization systems as being operational in the U.S. for 2015:

Table 8: EIA Reported Desulfurization Systems in 2015

Type	Number of installations
Wet spray tower scrubber	296
Spray dryer absorber	269
Circulating dry scrubber	50
Packed tower wet scrubber	6
Venturi wet scrubber	48
Jet bubbling reactor	31
Tray tower wet scrubber	42
Mechanically aided wet scrubber	4
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.[66] 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%

[66] Trays are often employed in spray type wet scrubbers and EIA lists some of the wet spray tower systems as secondarily including trays.

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.

We consider some of the other scrubber system types (e.g., venturi and packed wet scrubber types) to be older, outdated technologies (that are not existing controls or factor into considerations regarding existing controls) and therefore 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 or their suitability as a retrofit control option. Therefore, they too will not be further considered as part of our reasonable set of options for analysis for BART controls.

In summary, wet FGD and SDA installations account for approximately 81% of all scrubber installations in the U.S. and as such constitute a reasonable set of SO_2 scrubber control options. The vast majority of the wet FGD and SDA installations utilize limestone and lime, respectively as reagents. In addition, these technologies cover the maximum level of SO_2 control available. As described above, these controls are in wide use and have been retrofitted to a variety of boiler types and plant configurations. We therefore see no technical infeasibility issues and believe that limestone wet FGD and lime SDA should be considered as potential BART controls for all of the unscrubbed coal-fired BART-eligible units.

b. Identification of Technically Feasible SO_2 Retrofit Control Technologies for Gas-Fired Units that Burn Oil

Reduction in Fuel Oil Sulfur

A number of the units we proposed in Table 6 as being subject to BART primarily fire gas, but have occasionally fired fuel oil in the past as reported by the EIA databases: EIA-767,

EIA-906/920, and EIA-923,[67] which indicate the historic quantities of fuel oil burned and the type and sulfur content of that fuel oil. These units are identified below in Table 9:

Table 9: Gas Units that Occasionally Burn Oil and are Subject to BART

Facility	Unit(s)	Gas Turbine	Steam Turbine
Graham (Luminant)	2		X
Newman (El Paso Electric)	2, 3		X
O W Sommers (CPS Energy)	1, 2		X
Stryker Creek (Luminant)	ST2		X
Wilkes Power Plant (AEP)	1		X

The BART Guidelines advise that for oil-fired units, regardless of size, limits on fuel oil sulfur content should be considered in the BART evaluation.[68] All of the subject units are limited by permit to burning oil with a sulfur content of no more than 0.7% sulfur by weight.[69] In analyzing the technical feasibility under BART of these facilities burning fuel oils of sulfur contents lower than historically burned, we investigated two issues: (1) Is lower sulfur fuel oil available and what is its cost, and (2) are there any technical issues in burning a lower sulfur fuel oil that could add to the cost of that oil? All of the units have either burned Distillate Fuel Oil (DFO) or have switched between DFO and Residual Fuel Oil (RFO), thus demonstrating the ability to burn DFOs of the type under consideration for SO_2 BART. We therefore conclude that lower sulfur DFOs are a technically feasible retrofit control option under BART. Lower sulfur DFOs carry no capital costs. Any cost increases relate to purchase price differences.

[67] EIA-767: http://www.eia.gov/electricity/data/eia767/. EIA-906/920 and EIA-923: http://www.eia.gov/electricity/data/eia923/
[68] 70 FR at 39171.
[69] In addition, the Newman units 2 and 3 are restricted to burning fuel oil for no more than 10% of their annual operating time.

SO_2 Scrubber Feasibility for Gas/Oil-Fired Boilers

We are aware of instances in which FGDs of various types have been installed or otherwise deemed feasible on a boiler that burns oil.[70] Consequently, we will consider the installation of various types of scrubbers to be technically feasible.

c. Identification of Technically Feasible SO_2 Control Technologies for Scrubber Upgrades

In our recent Texas-Oklahoma FIP,[71] we presented a great deal of information that concluded that the existing scrubbers for a number of facilities could be very cost-effectively upgraded.[72] That information is included in this proposal.[73] It contains a comprehensive survey of available literature concerning the kinds of upgrades that have been performed by industry on scrubber systems similar to the ones installed on the units included in this proposal. We then reviewed all of the information we had at our disposal regarding the status of the existing scrubbers for each unit, including any upgrades the facility may have already installed. We finished by calculating the cost-effectiveness of scrubber upgrades, using the facility's own information, obtained as a result of our Section 114 collection efforts. The companies that supplied this information have asserted a Confidential Business Information (CBI) claim for much of it, as provided in 40 C.F.R. § 2.203(b). We therefore redacted any CBI information we utilize in our analyses, or otherwise disguised it so that it cannot be traced back to its specific

[70] 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."
[71] 81 FR 321.
[72] See information presented in Sections 6 and 7 of the Cost TSD.
[73] That information is included in our BART FIP TSD, Appendix B.

source. Of the facilities we evaluated for scrubber upgrades in that action, Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are subject to BART and are thus a part of this proposal.

2. Step 3: Evaluation of SO_2 Control Effectiveness

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."[74] To calculate a 30-day rolling average based on BOD, 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. In effect, this provides a margin of safety by eliminating spikes that occur at the beginning and end of outages.

a. Evaluation of SO_2 Control Effectiveness for Coal Fired Units

Control Effectiveness of DSI

We lack the site-specific information, which we believe requires an individual performance test, in order to be able to accurately determine the maximum DSI SO_2 removal efficiency for the individual units listed in Table 7. We are aware that a number of the subject-to-BART coal-fired units have conducted such testing. However, although we have examined that

[74] 70 FR 39103, 39172 (July 6, 2005), [40 CFR Part 51, App. Y].

testing, most of the facilities have claimed it as CBI and requested protection from public disclosure as provided by 40 C.F.R. Part 2.

However, we nevertheless must evaluate DSI as a viable, proven method of SO_2 control. We must do the same for SO_2 scrubbing, and in so doing, compare the visibility benefits and costs of each technology in order to inform our proposed BART determinations. We therefore propose the following methodology:

- We will evaluate each unit at its maximum recommended DSI performance level, according to the IPM DSI documentation,[75] assuming milled trona: 80% SO_2 removal for an ESP installation and 90% SO_2 removal for a baghouse installation. This level of control is within the range that can be achieved by SO_2 scrubbers, and thus allows a better comparison of the costs of DSI and scrubbers.

- However, (1) we do not know whether a given 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 all the units at a DSI SO_2 control level of 50%, which we believe is likely achievable for most units.

- We invite comments on whether particular units have performed DSI testing and have concluded they cannot achieve a SO_2 reduction between 50% and 80/90%. Any data to support such a conclusion should be submitted along with those comments.

[75] 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.

Control Effectiveness of Wet FGD and SDA

We 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. As we discuss later in this proposal, we will conduct our wet FGD control cost analysis using the wet FGD cost algorithms, as employed in version 5.13 of our IPM model.[76] 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 established in our Oklahoma FIP,[77] this level of control is achievable with wet FGD. This level of control was also employed in our recent Texas-Oklahoma FIP.[78] We received a comment challenging this level of control and we responded to that comment in our final action on our Texas-Oklahoma FIP and incorporate that response in this proposed action.[79] We continue to conclude that our proposed level of control for wet FGD is reasonable.

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[76] 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.
[77] As discussed previously in our TSD for that action, control efficiencies reasonably achievable by dry scrubbing and wet scrubbing were determined to be 95% and 98% respectively. 76 FR 81742); Oklahoma v. EPA, 723 F.3d 1201 (July 19, 2013), cert. denied (U.S. May 27, 2014).
[78] 81 FR 321.
[79] That information is included in our BART FIP TSD, Appendix A.

As with our Oklahoma FIP, 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 lb/MMBtu, in which case, we assume the percentage of control equal to 0.06 lbs/MMBtu. See our response to comments in our previous Oklahoma FIP.[80] In that FIP, we finalized the same emission limit of 0.06 lbs/MMBtu on a 30 BOD average for 6 coal-fired EGUs. We justified those limits based on the same SDA technology, using a combination of industry publications and real world monitoring data. Much of that information is summarized in our response to a comment to that action[81] and in our TSD. We continue to conclude that our proposed level of control for SDA is reasonable.

b. Evaluation of SO_2 Control Effectiveness for Gas Fired Units

The control effectiveness of switching from a higher sulfur fuel oil to a lower sulfur fuel oil lies in the reduction in sulfur emissions. The emissions reduction depends on the percentage reduction from the sulfur contents of the fuel oil that forms the SO_2 baseline to the replacement fuel oil. Ultimately, the highest level of control would result from a switch from the highest percentage sulfur the units are permitted to burn, 0.7% to the lowest DFO available, ultra-low sulfur diesel, which has a sulfur content of 0.0015%. This would equate to a control effectiveness of 99.8%. Lesser levels of controls are also possible. We will evaluate a range of control effectiveness in switching to lower sulfur fuel oils in the next section.

Because we are unaware of any scrubber installations on oil fired units in the U.S., we have no information on their control effectiveness. However, we see no technical reason why

[80] 76 FR 81728.
[81] 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 comment and response beginning on page 91.

the control effectiveness of FGDs installed on gas-fired units that occasionally burn fuel oil should not be equal to that of FGDs installed on coal-fired units.

3. Step 4: Evaluate Impacts and Document the Results for SO_2

The BART Guidelines offers the following with regard to how Step 4 should be conducted:[82]

> 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.

We evaluate the cost of compliance on a unit-by unit basis, because control cost analysis depends on specific factors that can vary from unit to unit. However, we generally evaluate the energy impacts, non-air quality impacts, and the remaining useful life for all the units in question together because in this instance there are no appreciable differences in these factors from unit to unit.[83]

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[82] 70 FR 39166.

[83] To the extent these factors inform the cost of controls, consistent with the BART Guidelines, they do inform our considerations on a unit-by-unit basis.

In developing our cost estimates for the units in Table 7, we rely on the methods and principles contained within the EPA Air Pollution Control Cost Manual (the Control Cost Manual, or Manual).[84] 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 each of the units listed in Table 7. For the coal units without any SO_2 control, we calculate the cost of installing DSI, a SDA scrubber, and a wet FGD scrubber. For the gas units that burn oil, we evaluate the cost of switching to lower sulfur fuel oils and installing scrubbers.

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 then performed DSI, SDA and wet FGD cost calculations for each unit listed in Table 7 that did not already have SO_2 control.[85] These cost models were based on costs escalated to 2012 dollars.[86] 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).

a. Impact Analysis Part 1: Cost of Compliance for DSI, SDA, and Wet FGD

As we discuss above and in our Cost TSD, we evaluated each unit at its maximum recommended level of control, considering the type of SO_2 control device. Below, we present a

[84] 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.
[85] These spreadsheets are entitled, "DSI Cost IPM 5-13 TX BART.xlsx," "SDA Cost IPM 5-13 TX BART.xlsx," and "Wet FGD Cost IPM 5-13 TX BART.xlsx," and are located in our Docket.
[86] Ibid., p.1: "The data was converted to 2012 dollars based on the Chemical Engineering Plant Index (CEPI) data."

summary of our DSI, SDA, and wet FGD cost analysis[87]:

Table 10. Summary of DSI, SDA, and Wet FGD Cost Analysis

Facility	Unit	Control	Control level (%)	SO_2 reduction (tpy)	2016 Annualized Cost	2016 Cost Effectiveness ($/ton)	2016 Incremental Cost-Effectiveness ($/ton)
Big Brown	1	DSI	50	14,448	$29,468,587	$2,040	
		DSI	90	26,006	$72,131,749	$2,774	$3,691
		SDA	95	27,453	$35,297,532	$1,286	-$25,456
		Wet FGD	98	28,320	$33,673,102	$1,189	-$1,874
	2	DSI	50	15,320	$29,342,350	$1,915	
		DSI	90	27,576	$71,322,593	$2,586	$3,425
		SDA	95	29,108	$35,359,239	$1,215	-$23,475
		Wet FGD	97.9	29,998	$33,817,952	$1,127	-$1,732
Monticello	1	DSI	50	4,787	$11,408,872	$2,383	
		DSI	90	8,617	$25,409,128	$2,949	$3,655
		SDA	95	9,095	$24,294,319	$2,671	-$2,332
		Wet FGD	97	9,286	$25,236,699	$2,718	$4,934
	2	DSI	50	4,129	$9,742,648	$2,360	
		DSI	90	7,431	$21,418,734	$2,882	$3,536
		SDA	95	7,844	$23,126,113	$2,948	$4,134
		Wet FGD	96.8	7,995	$24,233,133	$3,031	$7,331

[87] In this table, the capital cost is the total cost of constructing the facility. The annualized cost is the sum of the annualized capital cost and the annualized operational cost. See our Cost TSD for more information on how these costs were calculated.

Coleto Creek	1	DSI	50	7,376	$16,246,169	$2,203	
		DSI	90	13,277	$34,841,379	$2,624	$3,151
		SDA	92.4	13,632	$29,445,018	$2,160	-$15,201
		Wet FGD	94.9	14,005	$29,786,106	$2,127	$914
Harrington	061B	DSI	50	2,477	$9,187,608	$3,710	
		DSI	80	3,962	$16,073,779	$4,057	$4,637
		SDA	90.2	4,466	$17,455,679	$3,909	$2,742
	062B	DSI	50	2,455	$6,524,937	$2,658	
		DSI	88.9*	4,364	$11,981,111	$2,746	$2,858
		SDA	88.9	4,364	$18,240,127	$4,180	N/A
J T Deely	1	DSI	50	3,072	$8,854,319	$2,883	
		DSI	90	5,529	$18,071,878	$3,269	$3,752
		SDA	91.3	5,609	$21,689,526	$3,867	$45,221
		Wet FGD	94.2	5,787	$22,555,395	$3,898	$4,864
	2	DSI	50	3,222	$9,865,798	$3,062	
		DSI	90	5,800	$20,229,233	$3,488	$4,020
		SDA	91.3	5,884	$21,812,518	$3,707	$18,849
		Wet FGD	94.2	6,070	$22,530,901	$3,712	$3,862
Welsh	1	DSI	50	3,343	$8,963,761	$3,469	
		DSI	87.2*	5,832	$23,090,408	$3,960	$5,676
		SDA	87.2	5,832	$22,697,048	$3,892	N/A
		Wet FGD	91.5	6,116	$23,998,161	$3,924	$4,581
W. A. Parish	5	DSI	50	6,712	$15,002,337	$2,235	
		DSI	90	12,081	$30,865,711	$2,555	$2,955
		SDA	92.1	12,364	$31,195,787	$2,523	$1,166
		Wet FGD	94.7	12,717	$30,735,030	$2,417	-$1,305

	6	DSI	50	7,525	$16,014,988	$2,128	
		DSI	90	13,545	$33,302,528	$2,459	$2,872
		SDA	92.1	13,862	$32,758,784	$2,363	-$1,715
		Wet FGD	94.7	14,258	$32,215,226	$2,259	-$1,373

* DSI control level limited to that of SDA.

b. Impact Analysis Part 1: Cost of Compliance for Scrubber Upgrades

In our BART FIP TSD, we analyze those units listed in Table 7 with an existing SO_2 scrubber in order to determine if cost-effective scrubber upgrades are available. Of our subject-to-BART units, Martin Lake Units 1, 2, 3; Monticello Unit 3, and Fayette Units 1 and 2 are currently equipped with wet FGDs. Of these, all but the Fayette units were analyzed for scrubber upgrades in our Texas-Oklahoma FIP. For all but the Fayette units, we propose to adopt the total annualized cost calculations used to make the cost-effectiveness calculations in our Texas-Oklahoma FIP in this action. We acknowledge that these costs could change slightly, due to changes in the costs of various materials and services. However, these costs were calculated in 2013 dollars. Escalating them to 2015 dollars would result in a reduction in cost, which we conservatively do not take into consideration.[88]

In our Texas-Oklahoma FIP action, after responding to comments we revised our proposed cost-effectiveness basis from where all scrubber upgrades were less than $600/ton, to where all scrubber upgrades ranged from between $368/ton to $910/ton.[89] As with our Texas-Oklahoma FIP, we are limited in what information we can include in this section, because we

[88] The CEPCI for 2013 is 567.3 and that for 2015 is 556.3. Therefore, the costs would be multiplied by a factor of 556.8/567.3, which is approximately 0.98.
[89] 81 FR 318.

used information that was claimed as CBI. This information was submitted in response to our Section 114(a) requests. The following summary is based on information not claimed as CBI.

- The absorber system had either already been upgraded to perform at an SO_2 removal efficiency of at least 95%, or it could be upgraded to perform at that level using proven equipment and techniques.
- The SO_2 scrubber bypass could be eliminated, and the additional flue gas could be treated by the absorber system with at least a 95% removal efficiency.
- Additional modifications necessary to eliminate the bypass, such as adding fan capacity, upgrading the electrical distribution system, and conversion to a wet stack could be performed using proven equipment and techniques.
- The additional SO_2 emission reductions resulting from the scrubber upgrade are substantial, ranging from 68% to 89% reduction from the current emission levels, and are cost-effective.

We now update these calculations for 2011-2015 data.[90] The revised scrubber upgrade results for Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are presented below in Table 11:

Table 11. Summary of Updated Scrubber Upgrade Results

[90] See Coal vs CEM data 2011-2015.xlsx.

Unit	2011-2015 3-yr Avg. SO_2 Emissions (eliminate max and min) (tons)	SO_2 Emissions at 95% Control (tons)	SO_2 Emissions Reduction Due to Scrubber Upgrade (tons)	SO_2 Emission Rate at 95% Control (lbs/MMBtu)
Monticello 3	8,136	1,180	6,956	0.05
Martin Lake 1	19,040	3,208	15,832	0.12
Martin Lake 2	17,973	3,393	14,580	0.12
Martin Lake 3	16,113	2,591	13,522	0.11
Total SO_2 Removed			50,890	

As we note above, we updated the cost-effectiveness for each of these units. Because those calculations depended on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost-effectiveness was $1,156/ton or less. We invite the facilities listed above to make arrangements with us to view our complete updated cost analysis for their units.

The Fayette Units 1 and 2 are currently equipped with high performing wet FGDs. Both units have demonstrated the ability to maintain a SO_2 30 BOD average below 0.04 lbs/MMBtu for years at a time.[91] As we discuss above, we evaluate BART demonstrating that retrofit wet FGDs should be evaluated at 98% control not to go below 0.04 lbs/MMBtu. Because the Fayette units are performing below this level, we propose that no scrubber upgrades are necessary. We propose to find that the Fayette Units 1 and 2 maintain a 30 Boiler Operating Day rolling average SO_2 emission rate of 0.04 lbs/MMBtu based on the actual emissions data we present above. We believe that based on its demonstrated ability to maintain an emission rate below this value on a 30 BOD basis, it can consistently achieve this emission level.

c. Impact Analysis Part 1: Cost of Compliance for Gas Units that Burn Oil

[91] See our BART FIP TSD for graphs of this data.

As we noted in Section III.C.1.b, a number of the units we proposed in Table 9 as being subject to BART primarily fire gas, but have occasionally fired fuel oil in the past as reported by the EIA. These units are limited by their permits to burning oil with a sulfur content of no more than 0.7% sulfur by weight. We proposed to consider both a reduction in fuel oil sulfur and SO_2 scrubbers as potential BART controls. Below we consider the cost of these potential controls.

Reduction in Fuel Oil Sulfur

In order to determine the cost of these facilities switching to lower sulfur content fuel oils, we sent the Graham, Newman, Stryker Creek, and the Wilkes facilities Section 114 letters requesting certain information.[92] We received very limited information in response to one of our questions concerning the present cost of the historic fuel oil burned, and the cost of various lower sulfur replacement fuel oils. Because of this, we were unable to compile facility-specific information on the cost of switching to lower sulfur fuel oils. Consequently, we considered the best available information by consulting more general information from the EIA, which reports the prices for various refinery petroleum products on a monthly and annual basis. Below is a summary of various distillate and residual fuel oil products for 2001 to 2015, averaged across the U.S.[93]

Table 12: Selected EIA Reported Annual Refiner Petroleum Prices

[92] Copies of these letters and the facilities' responses are in our docket. We inadvertently did not send the O W Sommers a letter.
[93] EIA Refiner Petroleum Product Prices by Sales Type, available here: http://www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_a.htm; http://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm

Date	West Texas Intermediate Crude Oil – Cushing Oklahoma ($/bbl)	U.S. No 2 Diesel Wholesale/Resale Price by Refiners ($/Gallon)	U.S. No. 2 Fuel Oil Wholesale/Resale Price by Refiners ($/Gallon)	U.S. No 4 Distillate Wholesale/Resale Price by Refiners ($/Gallon)
2015	48.66	1.667	1.565	1.215
2014	93.17	2.812	2.741	2.333
2013	97.98	3.028	2.966	2.767
2012	94.05	3.109	3.031	
2011	94.88	3.034	2.907	2.801
2010	79.48	2.214	2.147	
2009	61.95	1.713	1.657	1.561
2008	99.67	2.994	2.745	2.157
2007	72.34	2.203	2.072	1.551
2006	66.05	2.012	1.834	1.395
2005	56.64	1.737	1.623	1.377
2004	41.51	1.187	1.125	1.033
2003	31.08	0.883	0.881	0.793
2002	26.18	0.724	0.694	0.663
2001	25.98	0.784	0.756	0.697
2000	30.38	0.898	0.886	0.778

Lacking facility-specific pricing information, for the purposes of calculating the cost of compliance, we make the following assumptions:

- No. 4 distillate is the type of fuel oil currently available that most closely approximates the types of fuel oil that were historically burned by the facilities. It is available in a range of sulfur up to the facilities' permitted maximum of 0.7% sulfur by weight or 7,000 ppm. We will use the cost of this fuel oil in constructing "business as usual" scenarios of the annual cost of fuel oil.
- No. 2 fuel oil is available at approximately 3,000 ppm, which roughly corresponds to the sulfur level present in No. 2 fuel oil prior to our implementation of the Ultra-Low-Sulfur Diesel (ULSD) regulations.[94] We will use the cost of this fuel oil in constructing a

[94] 69 FR 39073: "Both high sulfur No. 2–D and No. 2 fuel oil must contain no more than 5000 ppm sulfur,131 and

"medium control" annual cost of fuel oil.

- No. 2 diesel fuel corresponds to ULSD, with a sulfur content of 15 ppm. We will use the cost of this fuel oil in constructing a "high control" annual cost of fuel oil.

Having identified a reasonable set of historical and lower sulfur fuel oils, we turned to the matter of establishing SO_2 baselines. We would expect that regardless of the baseline selected, a cost-effectiveness calculation that simply depended on differing fuel oil costs and the resulting reductions in SO_2, would result in the same value. In other words, the cost-effectiveness in $/ton is independent of the SO_2 baseline, since *in this case,* it is calculated on a unit basis—the increased cost in burning a unit of fuel divided by the increased reduction in the resulting SO_2. While the above is true, reported data for these units does not match this expectation. This can be illustrated by examining selected EIA and emissions data for the Graham Unit 2:

Table 13: Graham Unit 2 Example Discordance in Fuel Oil Burned and Reported SO_2

Date (month/year)	**Quantity Fuel Oil Burned (bbls)**	**Reported SO_2 for month (tons)**	**Reported EIA sulfur content (wt %)**
Mar-02	9,800	21.614	0.65
Feb-03	8,400	90.389	0.66
Jun-12	18,177	0.064	0.50
Jul-12	5,657	0.07	0.50

As can be seen from the above table, even though the reported sulfur content of the fuel

currently [as of the date of our final rule, 6/29/04] averages 3000 ppm nationwide."

oil in March 2002 and February 2003 was approximately the same, and the quantity burned was fairly close, the reported SO_2 emissions were significantly different. Similarly, although the amount of fuel oil burned in June 2012 was more than three times that burned in July 2012 (at the same sulfur content), the reported SO_2 emissions in June 2012 were less than that in July 2012. Also, although the fuel oil sulfur content in the 2012 examples was only slightly less than that in the 2002/2003 examples, and the amount of fuel oil burned was the same order of magnitude, the resulting reported SO_2 emissions in 2012 were three orders of magnitude less than that in 2002/2003. We conclude that either the values for the EIA fuel quantities, the EIA fuel oil sulfur contents, and/or the reported SO_2 emissions are in error. Further examination of the CAMD emissions data for Graham and Stryker revealed that the data contained a large amount of substitute data for SO_2 emissions and heat input during periods when the units burned fuel oil.

As a consequence of this discordance between the type and amount of fuel oil burned and the reported SO_2 emissions, we cannot rely on historical SO_2 emissions to construct a baseline, because a barrel of fuel oil with a given sulfur content does not result in a consistent reported SO_2 value over time. Instead, we will conduct our cost-effectiveness analysis on the basis of unit values of 1,000 barrels, using the following assumptions:

- Fuel oil costs will be based on the 2015 U.S. average prices as reported in Table 12 for No. 4 distillate at 0.7 wt. % (the permitted maximum for all units) as the current business as usual fuel, No. 2 fuel oil at 0.3wt. % as the moderate control option, and No. 2 diesel at 0.0015% as the high control option.
- The emission factor for calculating the tons of sulfur emitted by the three fuel oils are

taken from AP 42, *Compilation of Air Pollutant Emissions Factors*.[95]

Below is the result of that calculation:

Table 14: Cost Effectiveness of Switching to Lower Sulfur Fuel Oils

Level of Control	Cost for 1,000 barrels baseline ($/yr)	Tons reduced for 1,000 barrels	Cost effectiveness for 1,000 barrels ($/ton)	Incremental Cost-Effectiveness ($/ton)
Business as usual (No. 4 distillate $1.215/gal)	$51,030	N/A	N/A	
Moderate control (No. 2 fuel oil $1.565/gal)	$65,730	1.26	$11,218	
High control (ULSD $1.667/gal)	$70,014	2.20	$8,627	-$2,756

We suspect our price information for ULSD may be high, as the Wilkes facility indicated in its reply to our Section 114 request that its 8/12/16 contract for oil was for ULSD, which had an index price of $1.423/gallon. Assuming this price and retaining the same price for our business as usual No. 4 distillate fuel oil of $1.215/gallon, results in a cost-effectiveness of $3,970/ton—a significant improvement in cost-effectiveness. We invite the affected facilities to provide site-specific information for delivery of ULSD.

Scrubber Retrofits

Elsewhere in our proposal, we conclude that certain types of wet scrubbers were

[95] The emission factor (lb/10^3 gal) used is 150 X S, where S = weight % sulfur, taken from AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.3, Fuel Oil Combustion, available here: https://www3.epa.gov/ttn/chief/ap42/ch01/index.html. Boilers > 100 Million Btu/hr, No. 4 oil fired.

technically feasible as potential control options for gas boilers that occasionally burn oil, similar to the ones under BART review here. Were we to calculate the cost-effectiveness of a wet FGD, similar to those under consideration for the coal units undergoing BART review, we could expect that the capital and operating costs would be on the same order, as displayed in Table 10. It is a straightforward exercise to demonstrate that the installation of such a scrubber on any of the gas-fired units that occasionally burn oil would result in a very high cost-effectiveness value.

For instance, taking the smallest total annualized wet FGD cost in Table 10, corresponding to the Harrington Unit 0161B (approximately the same size as the Graham Unit 2), results in a value of $19,145,500. Assuming a 98% reduction from a baseline equal to the largest annual SO_2 emissions from any of the gas units, 1,287 tons/year (Graham Unit 2, 2001), results in a SO_2 reduction of 1,261 tons/year. The cost-effectiveness is then $15,183/ton, which is very high for a SO_2 scrubber. In addition, the annual SO_2 values for Graham Unit 2 from 2002 to 2015, and the annual SO_2 values for the remaining units, have always been an order of magnitude less than the 2001 Graham Unit 2 value. Although we have not modeled the visibility benefit of installing SO_2 scrubbers on these units, the visibility benefit from scrubbers is estimated to be slightly less than the amount of benefit estimated from switching to ULSD.[96]

4. Impact Analysis Parts 2, 3, and 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

[96] For example, switching from 0.7% sulfur fuel oil to ULSD at 0.0015% sulfur results in a reduction in sulfur emissions of 99.8% compared to an estimated 98% reduction due to the use of a scrubber.

technology results in energy penalties or benefits."[97] 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 all cases. 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[98]:

> 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 the incremental emissions reductions potential of the more stringent control is only marginally greater than the next most-effective option. However, the fact

[97] 70 FR 39103, 39168 (July 6, 2005), [40 CFR Part 51, App. Y.].
[98] 70 FR at 39169 (July 6, 2005), [40 CFR Part 51, App. Y.].

> 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.

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 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. Consequently, we believe that with one possible exception, any non-air quality environmental impacts have been adequately considered in our analyses. We are aware that the Harrington facility has instituted a water recycling program and obtains some of its water from the City of Amarillo.[99] Due to potential non-air quality concerns, we limit our SO_2 control analysis for Harrington to DSI and dry scrubbers.

Regarding the remaining useful life, the BART Guidelines advise:[100]

> You may decide to treat the requirement to consider the source's ''remaining

[99] http://www.powermag.com/xcel-energys-harrington-generating-station-earns-powder-river-basin-coal-users-group-award/.
[100] 70 FR 39103, 39169, [40 CFR Part 51, App. Y.].

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 any of the facilities we have analyzed for BART have entered into an enforceable document to shut down the applicable units earlier than what would occur under our assumed 30-year operational life.[101] As we stated in our Oklahoma FIP,[102] we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be well over 60 years. We identified specific scrubbers installed between 1975 and 1985 that were still in operation. 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. Because none of the facilities involved have entered

[101] We received a November 21, 2016 letter from the source owner regarding Parish Units 5 & 6. The letter, now added to the docket, explains the units have natural gas firing capabilities and expresses interest in obtaining flexibility to avoid BART or obtaining multiple options for complying with BART. While we acknowledge this interest, the letter does not provide or commit to any specifics in furtherance of the BART analysis that EPA is now required to conduct under the BART Guidelines.

[102] 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.

into enforceable documents to shut down the applicable units earlier, we will continue to use a 30-year equipment life for DSI, scrubber retrofits, and scrubber upgrades, as we believe that is proper.

5. Step 5: Evaluate Visibility Impacts

Please see the BART Modeling TSD, where we describe in detail the various modeling runs we conducted, our methodology and selection of emission rates, modeling results, and final modeling analysis that we used to evaluate the benefits of the proposed controls and their associated emission decreases on visibility impairment values. 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.

a. Visibility Benefits of DSI, SDA, and Wet FGD for Coal-Fired Units

We evaluated the visibility benefits of DSI, for the twelve units depicted in Tables 15 and 16 below that currently have no SO_2 control. We evaluated all the units using the control levels we employed in our control cost analyses. In summary, we evaluated these units at a DSI SO_2 control level of 50%, which we believe is likely achievable for any unit. At the lower performance level we assumed, we conclude that the corresponding visibility benefits from DSI in most cases would be close to half of the benefits from scrubbers resulting in the visibility benefits from scrubber retrofits being much more beneficial. We also evaluated the visibility benefits for scrubber retrofits (wet FGD and SDA) for these same units, assuming the same control levels corresponding to SDA and wet FGD that we used in our control cost analyses. For those sources that are within 300 to 400 km of a Class I area, we utilized CALPUFF and CAMx

modeling to assess the visibility benefit of potential controls. For the remaining coal-fired sources (J T Deely, Coleto Creek, Fayette and W A Parish), only CAMx modeling was utilized as these sources are located at much greater distances to the nearest Class I areas. 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.[103] We note that the high control scenario modeling for Fayette units 1 and 2 demonstrate the benefit from existing high performing controls. As discussed elsewhere, we found that for these units no additional controls or upgrades were necessary. For a full discussion of our review of all the modeling results, and factors that we considered in evaluating and weighing all the results, see our BART Modeling TSD. Below, we present a summary of some of those visibility benefits at the Class I areas most impacted by each source:

Table 15: Visibility Benefit of Retrofit Controls: Coal-Fired Units (CAMx modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD(98%)	DSI benefit	WFGD benefit
Big Brown	Source (Unit 1 and 2)	WIMO	Max dv	4.017	2.249	0.474	1.768	3.542
			Days > 0.5 dv	65	33	0	32	65
			Days>1.0 dv	33	13	0	20	33
		CACR	Max dv	3.775	2.539	0.787	1.236	2.988
			Days > 0.5 dv	91	62	4	29	87
			Days>1.0 dv	57	21	0	36	57
	Unit 1	WIMO	Max dv	2.154	1.168	0.245	0.986	1.909
			Days > 0.5 dv	33	13	0	20	33
			Days>1.0 dv	12	1	0	11	12

[103] 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."

		CACR	Max dv	2.016	1.327	0.409	0.688	1.606
			Days > 0.5 dv	58	22	0	36	58
			Days>1.0 dv	17	4	0	13	17
	Unit 2	WIMO	Max dv	2.175	1.181	0.235	0.994	1.940
			Days > 0.5 dv	34	13	0	21	34
			Days>1.0 dv	12	1	0	11	12
		CACR	Max dv	2.033	1.338	0.391	0.695	1.642
			Days > 0.5 dv	58	23	0	35	58
			Days>1.0 dv	17	4	0	13	17
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63
			Days>1.0 dv	40	14	0	26	40
	Unit 1	CACR	Max dv	4.516	3.123	0.733	1.393	3.783
			Days > 0.5 dv	79	43	3	36	76
			Days>1.0 dv	32	16	0	16	32
		WIMO	Max dv	2.241	1.290	0.252	0.951	1.989
			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	8	2	0	6	8
	Unit 2	CACR	Max dv	4.487	3.065	0.563	1.422	3.924
			Days > 0.5 dv	78	42	1	36	77
			Days>1.0 dv	30	13	0	17	30
		WIMO	Max dv	2.189	1.252	0.186	0.937	2.003
			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	6	2	0	4	6
Coleto Creek	Source (Unit 1)	WIMO	Max dv	0.845	0.526	0.176	0.318	0.668
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.791	0.458	0.186	0.333	0.606
			Days > 0.5 dv	5	0	0	5	5
			Days>1.0 dv	0	0	0	0	0
Harrington[1]	Source (Unit 061B & 062B)	SACR	Max dv	5.288	4.287	3.235	1.001	2.053
			Days > 0.5 dv	13	7	3	6	10
			Days>1.0 dv	5	1	1	4	4
		WIMO	Max dv	4.928	4.362	3.798	0.565	1.130
			Days > 0.5 dv	15	11	6	4	9
			Days>1.0 dv	6	5	4	1	2
	Unit 061B	SACR	Max dv	2.908	2.322	1.738	0.586	1.170
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.708	2.382	2.065	0.326	0.643
			Days > 0.5 dv	6	5	4	1	2

			Days>1.0 dv	4	2	1	2	3
	Unit 062B	SACR	Max dv	2.998	2.373	1.719	0.625	1.279
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.770	2.407	2.046	0.363	0.723
			Days > 0.5 dv	6	5	4	1	2
			Days>1.0 dv	4	1	1	3	3
J T Deely	Source (Sommers 1&2, J T Deely 1&2)	WIMO	Max dv	1.513	0.939	0.814	0.574	0.699
			Days > 0.5 dv	47	8	1	39	46
			Days>1.0 dv	6	0	0	6	6
		CACR	Max dv	1.423	1.155	0.905	0.268	0.518
			Days > 0.5 dv	7	3	2	4	5
			Days>1.0 dv	2	1	0	1	2
	J T Deely 1	WIMO	Max dv	0.757	0.449	0.270	0.307	0.487
			Days > 0.5 dv	4	0	0	4	4
			Days>1.0 dv	0	0	0	0	0
		BIBE	Max dv	0.652	0.373	0.069	0.279	0.583
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
	J T Deely 2	WIMO	Max dv	0.632	0.387	0.334	0.245	0.298
			Days > 0.5 dv	3	0	0	3	3
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.604	0.490	0.387	0.114	0.217
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
W.A. Parish	Source (WAP 4,5, &6)	CACR	Max dv	3.177	2.032	0.511	1.145	2.665
			Days > 0.5 dv	54	26	1	28	53
			Days>1.0 dv	22	9	0	13	22
		UPBU	Max dv	1.994	1.215	0.234	0.779	1.760
			Days > 0.5 dv	34	14	0	20	34
			Days>1.0 dv	9	1	0	8	9
	WAP 5	CACR	Max dv	1.698	1.052	0.180	0.646	1.518
			Days > 0.5 dv	22	9	0	13	22
			Days>1.0 dv	8	1	0	7	8
		UPBU	Max dv	1.038	0.613	0.094	0.424	0.943
			Days > 0.5 dv	11	1	0	10	11
			Days>1.0 dv	1	0	0	1	1
	WAP 6	CACR	Max dv	1.648	1.018	0.156	0.630	1.492
			Days > 0.5 dv	22	8	0	14	22
			Days>1.0 dv	6	1	0	5	6
		UPBU	Max dv	1.003	0.591	0.081	0.412	0.922
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	1	0	0	1	1
Welsh[2]	Source (Unit 1 &	CACR	Max dv	4.576		0.822		3.754
			Days > 0.5 dv	92		3		89

	2)							
			Days>1.0 dv	39		0		39
		MING	Max dv	2.544		0.570		1.973
			Days > 0.5 dv	9		1		8
			Days>1.0 dv	3		0		3
	Unit 1	CACR	Max dv	2.343	1.659	0.822	0.684	1.521
			Days > 0.5 dv	37	18	3	19	34
			Days>1.0 dv	8	3	0	5	8
		MING	Max dv	1.150	0.886	0.570	0.264	0.579
			Days > 0.5 dv	2	1	1	1	1
			Days>1.0 dv	1	0	0	1	1
Fayette[2]	Source (Unit 1 & 2)	CACR	Max dv	1.894		0.903		0.991
			Days > 0.5 dv	26		2		24
			Days>1.0 dv	9		0		9
		WIMO	Max dv	1.175		0.580		0.595
			Days > 0.5 dv	19		1		18
			Days>1.0 dv	2		0		2
	Unit 1	CACR	Max dv	1.002		0.480		0.522
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	1		0		1
		WIMO	Max dv	0.609		0.306		0.302
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0
	Unit 2	CACR	Max dv	0.974		0.441		0.534
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	0		0		0
		WIMO	Max dv	0.598		0.282		0.316
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0

[1] Harrington high control scenario for both units is SDA at 95% reduction

[2] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD (wet FGD) installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.

Table 16: Visibility Benefit of Retrofit Controls: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit

Big Brown	Source (Units 1 and 2)	WIMO	Max dv	4.27	2.54	0.43	1.73	3.83
			Days > 0.5 dv Avg.	67.33	43.33	2.67	24.00	64.67
			Days>1.0 dv Avg.	42.00	21.00	1.00	21	41.00
		CACR	Max dv	4.03	2.41	0.47	1.62	3.55
			Days > 0.5 dv Avg.	91.67	64.33	4.67	27.33	87.00
			Days>1.0 dv Avg.	60.33	30.00	0.00	30.33	60.33
Monticello [1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	3.68	1.70	2.89	4.87
			Days > 0.5 dv Avg.	143.67	115.00	62.33	28.67	81.33
			Days>1.0 dv Avg.	113.00	66.33	23.67	46.67	89.33
		UPBU [4]	Max dv	3.45	1.77	0.77	1.68	2.68
			Days > 0.5 dv Avg.	103.00	61.00	13.67	42.00	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60.00	34.67	6.00	25.33	54.00
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67
Harrington [2]	Source (Units 061B & 062B)	SACR	Max dv	1.06	0.86	0.61	0.20	0.45
			Days > 0.5 dv Avg.	21.00	15.33	6.33	5.67	14.67
			Days>1.0 dv Avg.	6.67	3.00	0.67	3.67	6.00
		WIMO	Max dv	1.29	0.97	0.55	0.32	0.74
			Days > 0.5 dv Avg.	26.00	15.33	8.67	10.67	17.33
			Days>1.0 dv Avg.	9.00	4.67	1.33	4.33	7.67
Welsh [3]	Source (Unit 1)	CACR	Max dv	1.44	1.12	0.72	0.32	0.72
			Days > 0.5 dv Avg.	50.33	32.67	12.33	17.67	38

			Days>1.0 dv Avg.	15.33	8.00	2.33	7.33	13.00
		UPBU	Max dv	0.76	0.49	0.22	0.27	0.54
			Days > 0.5 dv Avg.	12.00	4.67	0.33	7.33	11.67
			Days>1.0 dv Avg.	0.67	0.00	0.00	0.67	0.67
		WIMO	Max dv	0.56	0.33	0.15	0.23	0.41
			Days > 0.5 dv Avg.	7.33	2.67	0.33	4.67	7.00
			Days>1.0 dv Avg.	1.33	0.33	0.00	1.00	1.33

[1] Monticello's controlled level is a combination of scrubber upgrades and scrubber install in the facility impact modeling with CALPUFF.

[2] Harrington high control scenario for both units is SDA at 95% reduction

[3] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.

[4] UPBU = Upper Buffalo Wilderness Area.

b. Visibility Benefits of Scrubber Upgrades for Coal-Fired Units

We also modeled the visibility benefits of those same units for which we conducted control cost analysis for upgrading their existing scrubbers. We assumed the same 95% control level we used in our control cost analyses. We also modeled a lower level control at 90%. The visibility benefits from these scrubber upgrades are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits and reduction in number of days impacted.

Table 17: Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CAMx modeling)

Facility	Emission	Class	Metric	Visibility impact	Visibility Benefit

Name	Unit	I area		Baseline	90% Control	95% Control	90% benefit	95% benefit
Martin Lake	Source (Unit 1, 2 & 3)	CACR	Max dv	6.651	4.491	4.321	2.159	2.329
			Days > 0.5 dv	141	75	56	66	85
			Days>1.0 dv	99	31	16	68	83
		UPBU	Max dv	5.803	2.669	2.528	3.134	3.275
			Days > 0.5 dv	99	39	22	60	77
			Days>1.0 dv	67	11	7	56	60
	Unit 1	CACR	Max dv	2.633	1.550	1.468	1.083	1.165
			Days > 0.5 dv	71	17	6	54	65
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.254	0.867	0.805	1.387	1.449
			Days > 0.5 dv	44	6	3	38	41
			Days>1.0 dv	10	0	0	10	10
	Unit 2	CACR	Max dv	2.466	1.882	1.811	0.585	0.655
			Days > 0.5 dv	68	18	9	50	59
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.189	1.077	1.025	1.112	1.164
			Days > 0.5 dv	40	6	5	34	35
			Days>1.0 dv	10	1	1	9	9
	Unit 3	CACR	Max dv	2.755	1.682	1.609	1.074	1.146
			Days > 0.5 dv	76	15	6	61	70
			Days>1.0 dv	29	2	1	27	28
		UPBU	Max dv	2.368	0.942	0.890	1.425	1.478
			Days > 0.5 dv	46	6	4	40	42
			Days>1.0 dv	13	0	0	13	13
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63
			Days>1.0 dv	40	14	0	26	40
	Unit 3	CACR	Max dv	4.632	0.905	0.914	3.728	3.719

			Days > 0.5 dv	79	5	5	74	74
			Days>1.0 dv	32	0	0	32	32
		WIM O	Max dv	2.282	0.462	0.364	1.820	1.918
			Days > 0.5 dv	31	0	0	31	31
			Days>1.0 dv	7	0	0	7	7

Table 18: Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Units 1, 2 & 3)	CACR	Max dv	4.46	2.27	1.86	2.18	2.60
			Days > 0.5 dv Avg.	129.67	77.33	63.00	52.33	66.67
			Days>1.0 dv Avg.	91.33	32.67	22.33	58.67	69.00
		UPBU	Max dv	2.73	1.10	0.85	1.63	1.88
			Days > 0.5 dv Avg.	81.67	30.33	18.67	51.33	63.00
			Days>1.0 dv Avg.	46.67	7.33	3.67	39.33	43.00
Monticello [1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	3.68	1.70	2.89	4.87
			Days > 0.5 dv Avg.	143.67	115	62.33	28.67	81.33
			Days>1.0 dv Avg.	113	66.33	23.67	46.67	89.33
		UPBU	Max dv	3.45	1.77	0.765	1.68	2.68
			Days > 0.5 dv Avg.	103	61	13.67	42	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIM O	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60	34.67	6	25.33	54
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67

[1] Monticello's controlled level is a combination of scrubber upgrade on Unit 3 and scrubber retrofits on Units 1 and 2 in the facility impact modeling with CALPUFF.

c. Visibility Benefits of Fuel Oil Switching for Gas/Fuel Oil-Fired Units

We also modeled the visibility benefits of those gas/fuel oil-fired units for which we conducted control cost analysis for switching to lower sulfur fuels. We evaluated the visibility benefits of switching to fuel oils corresponding to ultra-low sulfur diesel at 0.0015% sulfur by weight and 0.3% sulfur by weight as we evaluated in our control cost analyses. The visibility benefits from these fuel switches are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits.

Table 19. Visibility Benefits from Lower Sulfur Fuel

Facility Name	Emission Unit	Baseline visibility Impact from Source (most impacted Class I area)	Visibility benefit of 0.3% S fuel oil	Visibility benefit of 0.0015% S fuel oil
Stryker	ST2	CALPUFF 0.65 % S: 0.786 dv @ CACR (Facility)	CALPUFF (0.3 % S) : 0.263 dv @ CACR (Facility)	CALPUFF: 0.522 dv @ CACR (Facility)
Graham	Unit 2	CALPUFF 0.69 % S: 1.228 dv @ WIMO (Facility)	CALPUFF (0.3% S): 0.465 dv @ WIMO (Facility	CALPUFF: 0.851 dv @ WIMO (Facility
Wilkes	Units 1, 2, 3	CALPUFF 0.43 % S: 0.698 dv @ CACR (Facility)	CALPUFF (0.1 % S): 0.029 dv @ CACR (Facility)	CALPUFF: 0.037 dv @ CACR (Facility)
Newman[1]	Unit 2	N/A	N/A	N/A
	Unit 3	N/A	N/A	N/A
	Unit 4	N/A	N/A	N/A
Calaveras	Sommers Unit 1	CAMx: 1.513 dv @ WIMO (Source); 0.106 dv @ CACR (Unit)	0.004 dv @ CACR	0.008 dv @ CACR

	Sommers Unit 2	CAMx: 1.513 dv @ WIMO (Source); 0.180 dv @ CACR (Unit)	0.023 @ CACR	0.047 @ CACR

[1] Newman is on the edge of the CALMET and CALPUFF modeling grids for the database that were used in this action. Since the facility was near the edge, emissions of the facility's impacts could not be adequately modeled since some of the plumes could have gone out of the grid and not be adequately assessed if they come back into the grid and transport to impact a Class I area.

6. BART Analysis for PM

In our recent Texas-Oklahoma FIP, we initially proposed to approve Texas' determination that no PM BART controls were appropriate for its EGUs, based on a screening analysis of the visibility impacts from just PM emissions and the premise that EGU SO_2 and NO_X were covered separately by participation in CSAPR (allowing consideration of PM emissions in isolation). Because of the CSAPR remand and resulting uncertainty regarding SO_2 and NO_X BART for EGUs, we decided not to finalize our proposed approval of Texas' PM BART determination.[104] For reasons earlier stated we are proposing to disapprove the SIP determination regarding PM BART for EGUs. Following from that proposed disapproval, we are proposing a PM BART FIP for those Texas EGUs that are subject to BART.

The BART Guidelines permit us to conduct a streamlined analysis of PM BART in two key ways. First, the Guidelines allow a streamlined analysis for PM sources subject to MACT standards. Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, the Guidelines state it is permissible to rely on MACT standards for purposes of BART.[105]

[104] 81 FR 302 (January 5, 2016).
[105] 70 FR 39163-39164

Second, with respect to gas-fired units, which have inherently low emissions of PM (as well as SO_2), the Regional Haze Rule did not specifically envision new or additional controls or emissions reductions from the PM BART requirement. The BART guidelines preclude us from stating that PM emissions are *de minimis* when plant-wide emissions exceed 15 tons per years. While we must assign PM BART determinations to the gas-firing units, there are no practical add-on controls to consider for setting a more stringent PM BART emissions limit. The Guidelines state that if the most stringent controls are made federally enforceable for BART, then the otherwise required analyses leading up to the BART determination can be skipped.[106]

With this background, we are providing our evaluation along with some supplementary information on the BART sources as divided into two categories: coal-fired EGUs, and gas-fired EGUs.

BART Analysis for PM for Coal-Fired Units

All of the coal-fired EGUs that are subject to BART are currently equipped with either Electrostatic Precipitators (ESPs) or baghouses, or both, as can be seen from Table 20:

Table 20: Current PM Controls for Coal-Fired Units Subject to BART

Facility Name	Unit ID	Fuel Type (Primary)	SO_2 Control(s)	PM Control(s)
Big Brown	1	Coal		Baghouse +Electrostatic Precipitator
Big Brown	2	Coal		Baghouse + Electrostatic Precipitator
Coleto Creek	1	Coal		Baghouse
Harrington Station	061B	Coal		Electrostatic Precipitator

[106] 70 FR 39165 ("…you may skip the remaining analyses in this section, including the visibility analysis…")

Harrington Station	062B	Coal		Baghouse
J T Deely	1	Coal		Baghouse
J T Deely	2	Coal		Baghouse
Martin Lake	1	Coal	Wet Limestone	Electrostatic Precipitator
Martin Lake	2	Coal	Wet Limestone	Electrostatic Precipitator
Martin Lake	3	Coal	Wet Limestone	Electrostatic Precipitator
Monticello	1	Coal		Baghouse + Electrostatic Precipitator
Monticello	2	Coal		Baghouse + Electrostatic Precipitator
Monticello	3	Coal	Wet Limestone	Electrostatic Precipitator
Fayette	1	Coal	Wet Limestone	Electrostatic Precipitator
Fayette	2	Coal	Wet Limestone	Electrostatic Precipitator
W A Parish	WAP5	Coal		Baghouse
W A Parish	WAP6	Coal		Baghouse
Welsh Power Plant	1	Coal		Baghouse (Began Nov 15, 2015) + Electrostatic Precipitator

As an initial matter, we examine the control efficiencies of both baghouses and ESPs. We consider a baghouse, widely reported to be capable of 99.9% control of PM, to be the maximum level control for PM and so the units equipped with a baghouse will not be further analyzed for PM BART. The remaining units are fitted with ESPs.

The particulate matter control efficiency of ESPs varies somewhat with the design, the resistivity of the particulate matter, and the maintenance of the ESP. We do not have any information on the control level efficiency of any of the ESPs for the units in question. However, reported control efficiencies for well-maintained ESPs typically range from greater than 99% to 99.9%.[107] We consider this pertinent in concluding that the potential additional particulate control that a baghouse can offer over an ESP is relatively minimal.[108] In other

[107] EPA, "Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) - Wire Plate Type," EPA-452/F-03-028. Grieco, G., "Particulate Matter Control for Coal-fired Generating Units: Separating Perception from Fact," apcmag.net, February, 2012. Moretti, A. L.; Jones, C. S., "Advanced Emissions Control Technologies for Coal-Fired Power Plants, Babcox and Wilcox Technical Paper BR-1886, Presented at Power-Gen Asia, Bangkok, Thailand, October 3-5, 2012

[108] We do not discount the potential health benefits this additional control can have for ambient PM. However, the regional haze program is only concerned with improving the visibility at Class I areas.

words, if we did obtain control information specific to the ESP units in question, we do not believe that additional information would lead us to a different conclusion.

Nevertheless, we will examine the potential cost of retrofitting a typical 500 MW coal fired unit with a baghouse. Using our baghouse cost algorithms, as employed in version 5.13 of our IPM model,[109] and assuming a conservative air to cloth ratio of 6.0, results in a capital engineering and construction cost of $77,428,000.[110] Applied to the subject units, this cost assumes a retrofit factor of 1.0, and does not consider the demolition of the existing ESP, should it be required in order to make space for the baghouse.

We do not calculate the cost-effectiveness resulting from replacing an ESP with a baghouse. However, we expect that the tons of additional PM removed by a baghouse over an ESP to be very small, which would result in a very high cost-effectiveness figure. Also, we do not model the visibility benefit of replacing an ESP with a baghouse. However, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from replacing an ESP with a baghouse to be a small fraction of that. For instance, our CAMx baseline modeling shows that on a source-wide level, impacts from PM emissions on the maximum impacted days from each source at each Class I area was 3% of the total visibility impairment or less (calculated as percent of total extinction due to the source). Therefore additional PM controls are anticipated to result in very little visibility benefit on the maximum impacted days. Similarly, our CALPUFF modeling indicates that visibility impairment from PM is also a small fraction (typically only a few percent) of the

[109] IPM Model – Updates to Cost and Performance for APC Technologies, Particulate 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 5-7: PM Cost Methodology, downloaded from: https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-7_pm_cost_methodology.pdf

[110] Id. See page 9.

total visibility impairment due to each source.

Adding to the above discussion, we are tasked to assign the enforceable emission limitations that constitute PM BART. We believe a stringent control level that would be met with existing or otherwise-required controls is a filterable PM limit of 0.03 lb/MMBtu for each of the coal-fired units subject to BART. We note that the Mercury and Air Toxics (MATS) Rule establishes an emission standard of 0.03 lb/MMBtu filterable PM (as a surrogate for toxic non-mercury metals) as representing Maximum Achievable Control Technology (MACT) for coal-fired EGUs.[111] This standard derives from the average emission limitation achieved by the best performing 12 percent of existing coal-fired EGUs, as based upon test data used in developing the MATS Rule. We are not familiar with any new technologies subsequent to this standard that could lead to any cost effective increases in the level of control; thus, consistent with the BART Guidelines, we are proposing to rely on this limit for purposes of PM BART for all of the coal-fired units as part of our FIP. We understand the coal-fired units covered by this proposal to be subject to MATS, but to the extent the units may be following alternate limits that differ from the surrogate PM limits found in MATS, we welcome comments on different, appropriately stringent limits reflective of current control capabilities.[112] Because we anticipate that any limit we assign should be achieved by current control capabilities, we propose that compliance can be met at the effective date of the rule. To address periods of startups and shutdowns, we are further proposing that PM BART for these units will additionally be met by following the work practice standards specified in 40 CFR Part 63, subpart UUUUU, Table 3, and using the relevant

[111] 77 FR 9304, 9450, 9458 (February 16, 2012) (codified at 40 CFR 60.42 Da(a), 60.50 Da(b)(1)); 40 CFR Part 63 Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units.

[112] The various limits are provided at 40 CFR Part 63, Subpart UUUUU, Table 2 ("Emission Limits for Existing EGUs")

definitions in 63.10042. We are proposing that the demonstration of compliance can be satisfied by the methods for demonstrating compliance with filterable PM limits that are specified in 40 CFR Part 63, subpart UUUUU, Table 7. However, we would give consideration to commenter-submitted requests for alternate or additional methods of demonstrating compliance.

BART Analysis for PM for Gas-Fired Units

We note that PM emissions for the gas-only fired units that are subject to BART are inherently low.[113] We therefore conclude that PM emissions from natural gas firing is so minimal that the installation of any additional PM controls on the unit would likely achieve very low emissions reductions and have minimal visibility benefits. As there are no appropriate add-on controls and the status quo reflects the most stringent controls, we are proposing to make the requirement to burn pipeline natural gas federally enforceable. We note that in addition to satisfying PM BART, this limitation will also serve to satisfy SO_2 BART for these gas-fired units, as well as the fuel-oil units when they fire natural gas. We are proposing that PM and SO_2 BART for gas fired-units will limit fuel to pipeline natural gas, as defined at 40 CFR 72.2.

The available PM controls for gas units that also burn fuel oil are the same for the coal-fired units. We would expect similar costs for installing a baghouse on a typical gas-fired boiler that occasionally burns fuel oil. Again, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from the installation of a baghouse to be a small fraction on the order of 1-3 % of the visibility impacts from the facility. We are confident that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted

[113] AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.4, Natural Gas Combustion, available here: https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.

with an ESP. We conclude that the cost of a baghouse does not justify the minimal expected improvement in visibility for these units. Accordingly, we are proposing that the fuel content limits for oil burning that we propose to meet SO_2 BART will also satisfy PM BART.

Lastly, should our assumptions regarding the frequency and type of fuel oil burned in these units significantly change, we expect that Texas will address such a change appropriately in its SIP, which we will review in the next planning period.

D. How, If At All, Do Issues of "Grid Reliability" Relate to the Proposed BART Determinations?

On July 15, 2016, a preliminary order of the Fifth Circuit Court of Appeals took the view that EPA's Texas-Oklahoma FIP (81 FR 295, January 5, 2016) gave a "truncated discussion of grid reliability" and additionally stated that "the agency may not have fulfilled its statutory obligation to consider the energy impacts of the FIP." The Court's preliminary ruling made particular reference to "the explicit directive in the [CAA] that implementation plans 'take[] into consideration…the energy…impacts of compliance,' 42 U.S.C. § 7491(g)(1)."[114] Because the BART requirement at issue in this proposal has similar language on *energy impacts of compliance* appearing at 42 U.S.C. § 7491(g)(2), we wish to provide a clear explanation on how grid-related considerations for EGUs could bear on this proposal.

First, the BART factor for *energy impacts of compliance* does not call for the examination of grid reliability considerations from alleged plans to shut down or retire a unit rather than comply with a more stringent emission limit or limits. The language instead calls for

[114]EPA Guidance on this statutory language specifically explains that energy impacts are a matter of whether "energy requirements associated with a control technology result in energy penalties." U.S. EPA, Office of Air Quality Planning and Standards, "Guidance for Setting Reasonable Progress Goals under the Regional Haze Program," (June 1, 2007 rev), at Page 5-2.

consideration of energy impacts from *complying* by installing retrofit controls on a source that continues in operation. In this regard, our proposal follows the required BART Guidelines for EGUs.[115] The Guidelines explain that the energy impacts factor relates to the penalties and benefits that may be associated with the assessment of a control option, e.g., whether (for power penalties) the operation of add-on control technology subtracts from the productive yield of electricity from an EGU (what is sometimes termed an auxiliary or parasitic load).[116] It is also useful to note that the statutory text, while using the word "energy," can apply to sources that do not produce energy or electricity. Thus, the statutory text regarding "energy impacts" of compliance with BART is not confined to the power generating industry and does not dictate that we study grid reliability issues.

We have considered whether this topic has any separate relevance to our proposal. Various court filings, news accounts, and industry market reports suggest that some source operators for some Texas BART units may be contemplating unit retirements. The BART Guidelines directly address such scenarios under the "remaining useful life" factor: "there may be situations where a source operator intends to shut down a source….but wishes to retain the flexibility to continue operating beyond that date in the event, for example, the market conditions change."[117] The Guidelines advise that a source that is willing to assure a permanent stop in operations with a federally- or State-enforceable restriction preventing further operation may obtain a short remaining useful life for BART analysis purposes that could then factor in the

[115] The promulgation of the Guidelines was required by 42 U.S.C. 7491(b)(1). Adherence to the Guidelines is mandatory for fossil-fuel fired generating power plants having total generating capacities "in excess of 750 megawatts."

[116] Other CAA provisions requiring consideration of "energy impacts" or "energy requirements of the control technology" are understood similarly. *See, e.g.,* CAA section 169 (the 1977 "best available control technology" requirement with consideration of "energy…impacts"); *see also* CAA section 108 ("energy requirements…of the emission control technology; "energy…impact of such processes, procedures, and methods [to reduce or control air pollution"); section 111 ("taking into account…energy requirements" of an emission limitation), etc.

[117] *Id.* at 39169-39170.

overall cost analysis.[118] As the Guidelines state, "Where the remaining useful life is less the than the time period for amortizing costs, you should use this shorter period in your cost calculations."[119] We have no information on enforceable restrictions of this type for any of the units that we propose to be subject to BART. Absent that, we must assume that controls installed on the BART units will experience their full useful life. Affected sources are free to submit information as part of their comments containing appropriate enforceable documentation of shorter remaining useful lives.

We note, however, that the Guidelines recognize there may be cases where the installation of controls, even when cost-effective, would "affect the viability of continued plant operations."[120] Under the Guidelines, where there are "unusual circumstances," we are permitted to take into consideration "the conditions of the plant and the economic effects of requiring the use of a control technology."[121] If the effects are judged to have a "severe impact," those effects can be considered in the selection process. In such cases, the Guidelines counsel that any determinations be made with an economic analysis with sufficient detail for public review on the "specific economic effects, parameters, and reasoning."[122] It is recognized, by the language of the Guidelines, that any such review process may entail the use of sensitive business information that may be confidential. The ADDRESSES section of this proposal explains how to submit confidential information with comments, and when claims of confidential business information, or CBI, are asserted with respect to any information that is submitted, the EPA regulations at 40 CFR Part 2, Subpart B-Confidentiality Business Information apply to protect it. All of that said,

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[118] Similar to calculating a mortgage, remaining useful life is used in our cost-effectiveness analysis to calculate the annual cost of a particular control. The longer the remaining useful life, the smaller the total annualized cost, and the more cost-effective the control.
[119] Id. at 39169.
[120] 70 FR 39103, 39171 (July 6, 2005), [40 CFR Part 51, App. Y]
[121] *Id.*
[122] 70 FR at 39171

the Guidelines also advise that we may "consider whether other competing plants in the same industry have been required to install BART controls if this information is available."[123] Because Texas EGUs are among the last to have SO_2 BART determinations, this information is available. It is indeed the case that other similar EGUs have been required to install the same types of SO_2 BART controls that we are proposing as very cost effective.[124]

We have considered the state of available information on whether the proposed controls could affect the viability of continued plant operations. On this point, we note that we are proposing BART determinations for several units where SO_2 control requirements were separately promulgated as part of the Texas-Oklahoma FIP. These under-controlled EGU sources are: Big Brown 1 and 2; Monticello 1, 2 and 3; Martin Lake 1,2 and 3; and Coleto Creek 1. In litigation over the reasonable progress FIP, various declarations were filed on the issues of alleged forced closures and alleged reliability impacts. These declarations have been compiled and added to the docket for this rulemaking. By our review, these declarations do not appropriately inform or substantiate source-specific allegations of "unusual circumstances" that may have a severe impact on plant operations, because they do not offer any site-specific information.[125] Thus, we are unable to conclude that the proposed cost-effective BART controls would severely impact plant operations. Generalized claims of possible retirements and discussions on attributes of the market design of the Electric Reliability Council of Texas (ERCOT) cannot inform the statutorily required, source-specific BART determinations.

As a predicate to studying effects on transmission or reliability as "unusual

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[123] *Id.*

[124] See for instance, the EIA information we present elsewhere in this notice in which we summarize the hundreds of scrubber installations that have been performed on similar EGUs.

[125] Certain statements in declarations from representatives of both Luminant and Coleto Creek, who are the source owners of these facilities, cited compliance planning efforts that would be consistent with continued plant operations.

circumstances," we would require site-specific information from any source that would wish for us to potentially consider "affordability of controls," under the terms specified in the Guidelines. Source owners may submit information, including information claimed to be CBI, for our assessment and consideration to potentially support an economic analysis that might be used in the BART selection process. As suggested by the Guidelines, the information necessary to inform our judgment would likely entail source-specific information on "product prices, the market share, and the profitability of the source." Consideration of such information does not dictate what will be selected as a "best" alternative under the Guidelines, but it will substantiate the likelihood of a retirement scenario that would then give the parameters for: a non-conjectural examination of grid reliability issues; judging the significance or insignificance of such issues; and assessing whether such issues could be avoided through appropriate transmission planning. In sum, unless we are able to substantiate an "affordability of controls" problem for any particular unit and substantiate that a particular unit retirement would not be happening anyway at about the same time, alleged grid reliability impacts are speculative and are not able to inform these required BART determinations. As a final note, we acknowledge Executive Order 13211 ("Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, and Use"). In cases where it does apply, agencies are ordered to prepare a Statement of Energy Effects for submission to the Administrator of the Office of Information and Regulatory Affairs (OIRA), Office of Management and Budget. This EGU BART proposal is not considered a significant regulatory action under Executive Order 12866, so the proposed action cannot be a "significant energy action" for purposes of Executive Order 13211 on that basis. This proposed action has also not been designated a significant energy action by the Administrator of OIRA, so Executive Order 13211 could not apply under that separate basis. With this proposal, there are

no anticipated adverse effects on energy supply, distribution, or use that are meaningful or distinguishable from any other scenario where an EGU is expected to install cost-effective pollution controls required by the CAA.

IV. Our Weighing of the Five BART Factors

Below we present our reasoning for proposing our BART determinations for 29 EGUs in Texas, based on our analysis and weighing of the Five BART Factors. (1) proposed SO_2 and PM BART determinations for 12 coal-fired units with no SO_2 controls, (2) proposed BART SO_2 and PM BART determinations for 6 coal-fired units with existing scrubbers, (3) proposed SO_2 and PM BART determinations 7 gas-fired units that occasionally burn fuel oil, and (4) proposed PM BART determinations for 4 gas-fired units.

In previous sections of this proposal, we have described how we assessed the five BART factors. In no case do we see any instance in which our assessment of energy impacts is a determining factor in assessing BART.[126] Also, in no case do we see any instance in which our assessment of the remaining useful life is a determining factor in assessing BART. Should a facility indicate in comments to us that the remaining useful life is less than the 30 years we have assumed in our control cost analyses, and is willing to enter into an enforceable document to that effect, we will adjust our cost-effectiveness calculation accordingly in making our final decision. In two cases, Harrington units 061B and 062B, we have limited our SO_2 control analysis for Harrington to DSI and dry scrubbers due to potential non-air quality concerns. In all other instances, we conclude that the cost of compliance, and the visibility benefits of controls are the controlling BART factors in our weighing of the five BART factors.

[126] In addition to our assessment of energy impacts, also see our discussion in Section III.D concerning our conclusion that energy impact considerations do not relate to potential electrical grid reliability issues.

In considering cost-effectiveness and visibility benefit, we do not eliminate any controls based solely on the magnitude of the cost-effectiveness value, nor do we use cost-effectiveness as the primary determining factor. Rather, we compare the cost-effectiveness to the anticipated visibility benefit, and we take note of any additional considerations.[127] Also, in judging the visibility benefit we do not simply examine the highest value for a given Class I area, or a group of Class I areas, but we also consider the cumulative visibility benefit for all affected Class I areas, the number of days in a calendar year in which we see significant improvements, and other factors.[128]

First, we note that all of the sources addressed in our proposed BART determinations have already been shown to cause or contribute to visibility impairment at a Class I area as a condition of being subject-to-BART as part of the BART screening analysis. This analysis eliminated any BART-eligible source that emits lower amounts of visibility impacting pollutants, or otherwise impacts any Class I area at less than 0.5 deciviews. In fact, all of the individual units that we are proposing for BART controls exceed 0.5 deciviews on a unit basis, with most exceeding 1.0 deciview impact on a unit basis. As a consequence, all of the units we are proposing for BART controls are among the largest emitters of visibility impacting pollutants in Texas. A number of these units (i.e., Big Brown, Martin Lake, Monticello, and Coleto Creek) were previously determined by us to require the same type and level of controls under the reasonable progress and long-term strategy provisions of the Regional Haze Rule that we are proposing here.[129]

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[127] For instance, as we discuss later in Section IV.C why we believe that there are certain mitigating factors that should be considered when assessing BART for the gas-fired units that occasionally burn fuel oil.
[128] See for example 70 39130: "comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g. the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, a threshold representing an x percent change in improvement, etc.)."
[129] See our recent Texas-Oklahoma FIP, 81 FR 321.

Second, not discounting our approach of considering both cost-effectiveness and visibility benefit in unison, the cost-effectiveness of all of the controls that form the basis of our proposed BART determinations are within a range found to be acceptable in other cases.[130] As we stated in the BART Rule, ''[a] reasonable range would be a range that is consistent with the range of cost effectiveness values used in other similar permit decisions over a period of time.''[131]

A. SO_2 BART for Coal-fired Units with no SO_2 Controls

As we have discussed in this proposal and in our TSD, we have assumed two DSI control levels corresponding to 50% control and either a maximum of 80% or 90% control, depending on the particulate matter control device in use.[132] We did this to address the BART Guidelines directive that in evaluating technically feasible alternatives we "(1) [ensure we] express the degree of control using a metric that ensures an ''apples to apples'' comparison of emissions performance levels among options, and (2) [give] appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels."[133] In most cases, the cost-effectiveness of the higher control level of DSI was higher than either SDA or wet FGD. This was not the case for Monticello Unit 2; Harrington Unit 062B; and J T Deely Units 1 and 2.

However, these maximum DSI control levels are theoretical and we believe that any DSI control level above 50% must be confirmed by onsite testing before we could propose a BART

[130] See for instance 79 FR 5048 (January 30, 2014): Jim Bridger BART determination of LNB/SOFA + SCR on Units 1-4; 77 FR 18070 (March 26, 2012): EPA proposed approval of Colorado's BART determination of SCR for Hayden Unit 2, later finalized at 77 FR 76871 (December 31, 2012).
[131] 70 FR 39168 (July 6, 2005).
[132] Note for Harrington Unit 062B and Welsh 1, we further limited the maximum DSI control level to that of our calculated SDA control level.
[133] 70 FR 39166 (July 6, 2005).

control based on it. As is evident in comparing the 50% control level to the higher control level, the cost-effectiveness of DSI worsens (higher $/ton) as the control level increases, and the certainty of any unit attaining that control level decreases. We therefore regard the cost-effectiveness values of the maximum DSI control levels as being useful in a basic comparison of cost-effectiveness between DSI and scrubbers, but we place much less weight on these values. We therefore conclude that given the uncertainty concerning the maximum control level of DSI, the greater control efficiency and resulting visibility benefit offered by scrubbers overrides any possible advantage DSI may hold in cost-effectiveness. Should the affected facilities provide site-specific information to us in their comments that conflicts with this assumption, we will incorporate it into our final decision on SO_2 BART and potentially re-evaluate DSI.

As we indicate elsewhere in our proposal, both SDA and wet FGD are mature technologies that are in wide use throughout the United States. We are not aware of any unusual circumstances that exist for any of the sources that would serve to indicate they should not be viewed similarly to these hundreds of previous scrubber retrofits. In comparing wet FGD versus SDA we note that in a number of cases the cost-effectiveness of wet FGD is lower than the cost-effectiveness of SDA. In the remaining cases, we conclude that the incremental cost-effectiveness of wet FGD over SDA, which we review in Section III.C.3.a is reasonable, and the improved control and visibility benefit offered by wet FGD overrides the small penalty in cost-effectiveness FGD has in comparison to SDA. We propose that with the exception of the Harrington units, SO_2 BART for all other coal-fired units should be based on the wet FGD control levels we have used in our BART analyses. We propose that SO_2 BART for the Harrington units should be based on the SDA control levels we have used in our BART analyses. Below we discuss our consideration of the cost-effectiveness and anticipated visibility benefits

of controls. See section III.C.5 for additional information on the anticipated visibility benefits from each level of control modeled. See the BART Modeling TSD for a complete summary of our visibility benefit analysis of controls, including modeled benefits and impacts at all Class I areas included in the modeling analyses and additional metrics considered in the assessment of visibility benefits.

CAMx model results shown in the tables below summarize the benefits from the recommended controls at the two Class I areas most impacted by the source or unit in the baseline modeling. The benefit is calculated as the difference between the maximum impact modeled for the baseline and the maximum impact level modeled under the control scenario. 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. The CALPUFF cumulative model results only consider those Class I areas within the typical range of CALPUFF and not all 15 Class I areas included in the CAMx modeling.

1. Big Brown 1 & 2

In reviewing the Big Brown units, we conclude that the installation of wet FGD will result in very significant visibility benefits. We summarize some of these visibility benefits in

the tables below:

Table 21. Wet FGD Visibility Benefits at Big Brown (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Big Brown Units 1 & 2	3.83	3.55	7.38	151.67	101.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek and Wichita Mountains

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek and Wichita Mountains.

In evaluating Big Brown, we note there are two Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results, we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario

subtracted by the cumulative number of days over the threshold for the control scenario. For the two Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate that wet FGD on both units will eliminate 151.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the visibility benefits in terms of dv benefits at the most impacted Class I areas and about 1/3rd to half the cumulative benefits over the class I areas included in the modeling analysis.

Table 22. Wet FGD Visibility Benefits at Big Brown (CAMx)

Unit	Improvement at Wichita mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Big Brown 1	1.909	1.606	12.728	174 / 44	174 / 44
Big Brown 2	1.940	1.642	12.924	175 / 45	175 / 45
Source	3.542	2.988	24.274	372 / 170	362 / 170

[1] 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.

[2] 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.

[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv at all Class I areas on a unit and source-wide basis, and eliminate all but 10 days across the impacted Class I areas where the source-wide impacts exceeds 0.5 dv. At the most impacted Class I area, wet FGD will on each unit result in visibility improvements of 1.9 dv on the most impacted day. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the CAMx modeling.

We also conclude that wet FGD is very cost-effective for both units at less than $1,200/ton and more cost-effective than DSI. Based on this consideration of the BART factors, we propose that SO_2 BART for Big Brown Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

2. Monticello 1 & 2

Similar to the Big Brown units, the installation of wet FGD at Monticello Units 1 and 2 will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 23. Wet FGD Visibility Benefits at Monticello (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	4.87	2.70	10.25	224.67	164.67

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Monticello, we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003

CALPUFF modeling results indicate wet FGD on both units will eliminate 224.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I area and half of the cumulative benefits.

Table 24. Wet FGD Visibility Benefits at Monticello (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 1	3.783	1.989	12.708	197 / 67	191 / 67
Monticello 2	3.924	2.003	13.025	192 / 57	191 / 57
Source (including unit 3)	8.419	4.962	31.553	520 / 293	460 / 278

[1] 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.

[2] 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.

[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv

at all Class I areas on a unit basis, and eliminate all but 15 days across the impacted Class I areas where the source-wide impacts exceeds 1 dv. We note that source-wide modeled benefits include benefits of 95% control scrubber upgrade on Unit 3. At the most impacted Class I area, wet FGD on each unit will each result in visibility improvements of 3.8-3.9 dv on the most impacted day at Caney Creek and 2 dv visibility benefits at Wichita Mountains. DSI operated at 50% control results in less than half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

The wet FGD cost-effectiveness of $2,718/ton and $3,031/ton are higher than those for Big Brown, but these figures remain well within a range that we have previously found to be acceptable for BART, and we consider the very significant visibility benefits that will result justify the cost of wet FGD at the Monticello Units 1 and 2. The 50% control DSI cost-effectiveness is slightly less than that for wet-FGD, but results in much less visibility benefits. Based on our consideration of the BART factors, we therefore propose that SO_2 BART for Monticello Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

3. Coleto Creek 1

In reviewing Coleto Creek Unit 1, we conclude that in comparison with the Monticello units, the installation of a wet FGD is more cost-effective and results in lesser, but still significant visibility benefits. We summarize some of these visibility benefits in the table below:

Table 25. Wet FGD Visibility Benefits at Coleto Creek Unit 1 (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Coleto Creek 1	0.668	0.606	5.233	17 / 0	17 / 0

[1] 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

[2] 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

[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 0.5 dv at all Class I areas. At the most impacted Class I area, wet FGD will result in visibility improvements of 0.6 or more on the most impacted days at both Caney Creek and the Wichita Mountains. In addition, seven other Class I areas are improved by amounts ranging from 0.356 to 0.531 dv on the maximum impacted days with wet FGD. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15class I areas included in the modeling.

We also conclude that wet FGD is very cost-effective at $2,127/ton and well within a range that we have previously found to be acceptable and more cost-effective than DSI. We consider the significant visibility benefits that will result justify the cost of wet FGD at the Coleto Creek Unit 1. We therefore propose that SO_2 BART for Coleto Creek Unit 1 should be

based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

4. Welsh 1

In reviewing Welsh Unit 1, we conclude that the installation of a wet FGD will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 26. Wet FGD Visibility Benefits at Welsh Unit 1 (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Welsh 1	0.72	0.41	1.66	56.67	15

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Welsh we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility

impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 56.67 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

Table 27. Wet FGD Visibility Benefits at Welsh Unit 1 (CAMx)

Unit	**Improvement at Caney Creek (dv)**	**Improvement at Mingo Wilderness (dv)**	**Total Cumulative Visibility Benefit (dv)[1]**	**Baseline Total Cumulative number of days over 0.5/1.0 dv[2]**	**Reduction in number of days above 0.5/1.0 dv[3]**
Welsh 1	1.521	0.579	4.683	65 / 9	60 / 9
Source (Welsh 1 & 2)	3.754	1.973	13.179	211 / 72	206 / 72

[1] 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.

[2] 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.

[3] 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.

CAMx modeling results indicate that wet FGD on unit 1 will eliminate all days impacted by the unit over 1 dv at all Class I areas and all but 5 days impacted over 0.5 dv. At the most impacted Class I area, wet FGD on unit 1 will result in visibility improvements of 1.521 dv on the most impacted days at Caney Creek. In addition to the visibility benefits at Caney Creek and Mingo, visibility benefits at two additional Class I areas exceed 0.5 dv. We note that source-wide benefits shown include the benefits from the shutdown of unit 2. In addition, cumulative benefits from wet FGD on unit 1 over all 15 Class I areas exceeds 4.5 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We conclude that although at $3,824/ton, the cost-effectiveness of wet FGD is higher than for other facilities, it remains within a range that we have previously found to be acceptable. We consider the significant visibility benefits that will result from the installation of wet FGD at Welsh Unit 1 to justify the cost. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for Welsh Unit 1 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

5. Harrington 061B & 062B

In reviewing Harrington, we conclude that the installation of SDA on Units 061B and 062B will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 28. SDA Visibility Benefits at Harrington (CALPUFF)

Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Harrington 061B & 062B	0.45	0.74	2.56	53.67	26

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

In evaluating Harrington we note there are five Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for

each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the five Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 53.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

Table 29. SDA Visibility Benefits at Harrington (CAMx)

Unit	**Improvement at Salt Creek (dv)**	**Improvement at Wichita Mountains (dv)**	**Total Cumulative Visibility Benefit (dv)** [1]	**Baseline Total Cumulative number of days over 0.5/1.0 dv**[2]	**Reduction in number of days above 0.5/1.0 dv**[3]
Harrington 061B	1.170	0.643	4.832	17 / 5	11 / 3
Harrington 062B	1.279	0.723	5.379	17 / 5	11 / 3
Source (061B & 0622B)	2.053	1.130	9.329	51 / 17	37 / 11

[1] 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.

[2] 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.

[3] 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.

CAMx modeling results indicate SDA on these units will eliminate more than half of all days impacted by the units over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, SDA on each unit will each result in visibility improvements of approximately 1.2 dv on the most impacted days at Salt Creek and 0.6 – 0.7 dv at Wichita Mountains, reducing the number of days impacted over 0.5 and 1.0 dv at these Class I areas. In addition, cumulative benefits from SDA on both units over all 15 Class I areas exceeds 9.3 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the SDA visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We also conclude that SDA is cost-effective at $3,904 for Unit 061B and $4,180/ton for Unit 062B and, remains within a range that we have previously found to be acceptable. In contrast to other units we have reviewed, the 50% control DSI cost-effectiveness is much less than that for SDA. However, given the additional large total cumulative visibility benefits that will result from the installation of SDA over DSI at 50% control, we consider SDA to justify the additional cost. We therefore propose that SO_2 BART for Harrington Units 061B and 062B should be based on the installation of SDA at an emission limit of 0.06 lbs/MMBtu based on a 30 BOD.

6. W. A. Parish WAP 5 & 6

In reviewing W A Parish, we conclude that the installation of wet FGD on Units 5 and 6 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 30. Wet FGD Visibility Benefits at W A Parish (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
W A Parish 5	1.518	0.943	8.171	51 / 9	51 / 9
W A Parish 6	1.492	0.922	7.979	48 / 7	48 / 7
Source (WAP 4, 5 & 6)	2.665	1.760	15.301	163 / 49	162 / 49

[1] 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.

[2] 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.

[3] 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.

CAMx modeling results indicate that wet FGD on each of these units will eliminate all days impacted by each unit over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of approximately 1.5

dv on the most impacted days at Caney Creek and 0.9 dv at Upper Buffalo. Nine Class I areas have modeled source-wide baseline impacts over 1 dv, and wet FGD on both units results in source-wide improvements of 1 dv or greater on the maximum impacted days at eight of these Class I areas. In addition, cumulative benefits from wet FGD on both units over all 15 Class I areas exceeds 15 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15class I areas included in the modeling. We note that source-wide modeling includes a small impact from WAP 4. This unit is gas-fired and was modeled at baseline emissions levels for both the baseline and control case scenarios.

We conclude that wet FGD is cost-effective at $2,417/ton for Unit 5 and $2,259/ton for Unit 6, and remains well within a range that we have previously found to be acceptable. DSI at 50% control is approximately the same cost-effectiveness but results in significantly less visibility benefit. We consider the cost of wet FGD at the W A Parish units to be justified by the significant visibility benefits that will result. We therefore propose that SO_2 BART for W A Parish Units 5 and 6 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

7. J T Deely 1 & 2

In reviewing J T Deely, we conclude that the installation of wet FGD on Units 1 and 2 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 31. Wet FGD Visibility Benefits at J T Deely (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
J T Deely 1	0.487	0.283	4.785	10 / 0	10 / 0
J T Deely 2	0.298	0.217	3.650	7 / 0	7 / 0
Source (J T Deely 1 & 2, Sommers 1 & 2)	0.699	0.518	8.943	89 / 13	84 / 13

[1] 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.

[2] 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.

[3] 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.

CAMx modeling results indicate wet FGD on each of these units will eliminate all days impacted by each unit over 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of 0.487 dv and 0.298 dv on the most impacted days at Wichita Mountains and 0.283 dv and 0.217 dv at Caney Creek. Larger visibility improvements on the most impacted days are anticipated at other Class I areas. Benefits from wet FGD on unit 1 are 0.583 dv at Big Bend, 0.511 dv at Salt Creek, 0.449 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.475 dv at White Mountains. Benefits from wet FGD on unit 2 are 0.583 dv at Big Bend, 0.441 dv at Salt Creek, 0.354 dv at Guadalupe

Mountains and Carlsbad Caverns, and 0.375 dv at White Mountains. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 Class I areas included in the modeling. We note that source-wide modeling includes the impact from Sommers units 1 and 2, and as discussed in the BART Modeling TSD, control case scenarios for these units included benefits from switching to lower sulfur fuel oil. However, these modeled improvements are a small fraction of the total visibility benefits from controls at the source.

We conclude that wet FGD is cost-effective at $3,898/ton for Unit 1 and $3,712/ton for Unit 2, and remains within a range that we have previously found to be acceptable. We consider the cost of wet FGD at the J T Deely units to be justified by the significant visibility benefits that will result at a number of impacted Class I areas. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for J T Deely Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.[134]

B. SO_2 BART for Coal-fired Units with Underperforming Scrubbers

The BART Guidelines state that underperforming scrubber systems should be evaluated for upgrades.[135] Other than upgrading the existing scrubbers, all of which are wet FGDs, there are no competing control technologies that could be considered for these units. The CALPUFF modeling generated facility-wide impacts and the benefits of the scrubber upgrade on Monticello Unit 3 and the three Martin Lake facilities are included in Table 17 above. The following is a

[134] We have read reports that CPS Energy, is planning to retire J T Deely Units 1 and 2 by the end of 2018, but we have no enforceable documents to that effect.
[135] 70 FR 39171 (July 6, 2005).

listing of each of the affected units along with the resulting CAMx modeled visibility benefits from upgrading their existing scrubbers:

Table 32. Visibility Benefit for Coal-fired Units with Existing SO_2 Controls (CAMx)

Unit	Improvement at most impacted (dv)	Improvement at 2nd most impacted (dv)	Total Cumulative Visibility Benefit (dv)	Reduction in number of days above 0.5 dv at --------	Reduction in number of days above 1.0 dv at ------
Monticello 3	3.719 (CACR)	1.918 (WIMO)	11.940	200 / 66	188 / 66
Martin Lake 1	1.165 (CACR)	1.449 (UPBU)	7.575	160 / 41	151 / 40
Martin Lake 2	0.655 (CACR)	1.164 (UPBU)	6.199	150 / 41	134 / 39
Martin Lake 3	1.146 (CACR)	1.478 (UPBU)	7.863	173 / 47	163 / 46

As we state elsewhere in this proposal, because our cost-effectiveness calculations depend on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost effectiveness was $1,156/ton or less. We conclude that in all cases, scrubber upgrades are very cost-effective and result in very significant visibility benefits, significantly reducing the impacts from these units and reducing the number of days that Class I areas are impacted over 1.0 dv and 0.5 dv. We propose that SO_2 BART for all other coal-fired units with underperforming scrubbers should be based on the wet FGD upgrade control levels we have used in our BART analyses of them.

C. SO_2 BART for Gas-fired Units that Burn Oil

In analyzing potential controls for those gas-fired units that occasionally burn fuel oil we considered scrubber retrofits and lower sulfur fuel oil. We concluded that the cost-effectiveness of scrubber retrofits for these units were likely very high, and not worth the potential visibility

benefit.

We also concluded that the cost-effectiveness of switching to a No. 2 fuel oil with a sulfur content of 0.3% is $11,218/gallon, and the cost-effectiveness of switching to ULSD with a sulfur content of 0.0015% is $8,627/gallon. We further noted that one facility already had a contract in place for ULSD at a lower price than we assumed, which if used in our analysis would result in a cost effectiveness of $3,970/ton. Although the cost-effectiveness of switching to a lower sulfur oil (assuming our price for ULSD of $1.667/gal) is higher than other controls that we have typically required under BART, we note certain mitigating factors.

For instance, arguing against control, our calculated cost-effectiveness values are high in relation to other BART controls we have required in the past. Also, our visibility modeling necessarily utilized the maximum SO_2 emissions over a 24-hour timeframe,[136] resulting in the configuring of our visibility modeling to analyze the maximum short-term potential impacts that could occur when the unit burns fuel oil. However, as we discuss elsewhere in our proposal, these units are primarily gas-fired, and have only occasionally burned fuel oil. Their most recent practices appear to reinforce this trend.

Arguing for control, unlike the wet FGD and SDA scrubbers we have costed in other sections of this TSD, which have large capital costs, we are unaware of any significant capital costs involved in switching fuels. This means the overall annual costs are relatively minor, if the units in question adhere to their historical usages. Also, because the units in question have only occasionally burned fuel oil, they have the option to avoid the cost of fuel switching entirely by not continuing to burn fuel oil and instead relying solely on their primary fuel of natural gas.

[136] See the BART Guidelines at 70 FR 39162, July 6, 2005: "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."

Lastly, we note that the prevalence of ULSD in the fuel oil market is such that it appears to be gradually replacing most other No. 2 fuel oil applications.[137]

The preamble to the Regional Haze Rule counseled that a one percent sulfur content limitation on fuel oil should be considered as a "starting point,"[138] and the existing sulfur content limits are lower than one percent. Considering all of this information, we propose that SO_2 BART for the gas-fired units that occasionally burn fuel oil should be no further control. In so doing, we acknowledge the data quality issues we have discussed concerning these units and we specifically request comments on all aspects of our proposed BART analysis for these units from all interested parties. Based on the comments we receive, we may either finalize our BART determinations for these units as proposed, or we may revise them without a re-proposal.

D. PM BART

We propose to disapprove the portion of the Texas Regional Haze SIP that sought to address the BART requirement for EGUs for PM. We note that all of the coal-fired units are either currently fitted with a baghouse, an ESP and a polishing baghouse, or an ESP. We conclude that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted with an ESP. Consequently, we propose that PM BART for the coal-fired units is an emission limit of 0.030 lb/MMBtu along with work practice standards. We propose that PM and SO_2 BART for the units that only fire gas be pipeline natural gas. We propose that PM and SO_2 BART for those gas-fired units that occasionally burn fuel oil be the existing permitted fuel oil sulfur content of

[137] http://www.eia.gov/todayinenergy/detail.php?id=5890. http://blogs.platts.com/2014/05/07/heating-oil-new-york-sulfur/. http://oilandenergyonline.com/challenges-to-the-northeast-supply-picture/
[138] 70 FR at 39134

0.7% sulfur by weight or pipeline natural gas.

V. Proposed Actions

A. Regional Haze

We are proposing to disapprove the portion of the Texas Regional Haze SIP that sought to address the BART requirement for EGUs for PM. We are proposing to promulgate a FIP as described in this notice and summarized in this section to satisfy the remaining outstanding regional haze requirements that are unmet by the Texas' regional haze SIP and that we did not take action on in our January 5, 2016 final action.[139] Our proposed FIP includes SO_2 and PM BART emission limits for sources in Texas to reduce emissions that contribute to regional haze in Texas' two Class I areas and other nearby Class I areas and make reasonable progress for the first regional haze planning period for Texas' two Class I areas.

1. NO_X BART

As discussed elsewhere in this proposal, we are proposing a FIP to replace Texas' reliance on CAIR with reliance on CSAPR to address the NO_X BART requirements for EGUs. This portion of our proposal is based on: the recent update to the CSAPR rule[140]; and the EPA's finalization of a separate proposed finding that the 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.[141] We cannot finalize this portion of the proposed FIP unless and until the EPA finalizes

[139] 81 FR 296.
[140] 81 FR 74504.
[141] 81 FR 78954.

the proposed finding that CSAPR continues to be better than BART because finalization of that proposal would allow for reliance on CSAPR participation as an alternative to source-specific EGU BART for NO_X in Texas.

2. SO_2 BART for Coal-fired Units

We propose that SO_2 BART for the coal-fired units be the following SO_2 emission limits to be met on a 30 Boiler Operating Day (BOD) period:

Table 33. Proposed SO_2 BART Emissions Limits for Coal-fired Units

	Unit	Proposed SO_2 emission limit (lbs/MMBtu)
Scrubber Upgrades	Martin Lake 1	0.12
	Martin Lake 2	0.12
	Martin Lake 3	0.11
	Monticello 3	0.05
Scrubber Retrofits	Big Brown 1	0.04
	Big Brown 2	0.04
	Monticello 1	0.04
	Monticello 2	0.04
	Coleto Creek 1	0.04
	Fayette 1	0.04
	Fayette 2	0.04
	Harrington 061B	0.06
	Harrington 062B	0.06
	J T Deely 1	0.04

	J T Deely 2	0.04
	W A Parish 5	0.04
	W A Parish 6	0.04
	Welsh 1	0.04

We propose that compliance with these limits be within five years of the effective date of our final rule for Big Brown Units 1 and 2; Monticello Units 1 and 2; Coleto Creek Unit 1; Harrington Units 061B and 062B; J T Deely Units 1 and 2; W A Parish Units 5 and 6; and Welsh Unit 1. This is the maximum amount of time allowed under the Regional Haze Rule for BART compliance. We based our cost analysis on the installation of wet FGD and SDA scrubbers for these units, and in the past we have typically required that scrubber retrofits under BART be operational within five years.

We propose that compliance with these limits be within three years of the effective date of our final rule for Martin Lake Units 1, 2, and 3; and Monticello Unit 3. We believe that three years is appropriate for these units, as we based our cost analysis on upgrading the existing wet FGD scrubbers of these units, which we believe to be less complex and time consuming that the construction of a new scrubber.

We propose that compliance with these limits be within one year for Fayette Units 1 and 2. We believe that one year is appropriate for these units because the Fayette units have already demonstrated their ability to meet these emission limits.

3. Potential Process for Alternative Scrubber Upgrade Emission Limits

In our BART FIP TSD, we discuss how we calculated the SO_2 removal efficiency of the units we analyzed for scrubber upgrades. We note that due to a number of factors we could not

accurately quantify, our calculations of scrubber efficiency may contain some error. Based on the results of our scrubber upgrade cost analysis, we do not believe that any reasonable error in calculating the true tons of SO_2 removed affects our proposed decision to require emission reductions, as all of the scrubber upgrades we analyzed are cost-effective (low $/ton). In other words, were we to make reasonable adjustments in the tons removed to account for any potential error in our scrubber efficiency calculation, we would still propose to upgrade these SO_2 scrubbers. We believe we have demonstrated that upgrading an underperforming SO_2 scrubber is one of the most cost-effective pollution control upgrades a coal fired power plant can implement to improve the visibility at Class I areas. However, our proposed FIP does specify a SO_2 emission limit that is based on 95% removal in all cases. This is below the upper end of what an upgraded wet SO_2 scrubber can achieve, which is 98–99%, as we have noted in our BART FIP TSD. We believe that a 95% control assumption provides an adequate margin of error for any of the units for which we have proposed scrubber upgrades, such that they should be able to comfortably attain the emission limits we have proposed. However, for the operator of any unit that disagrees with us on this point, we propose the following:

(1) The affected unit should comment why it believes it cannot attain the SO_2 emission limit we have proposed, based on a scrubber upgrade that includes the kinds of improvements (e.g., elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically included in a scrubber upgrade.

(2) After considering those comments, and responding to all relevant comments in a final

rulemaking action, should we still require a scrubber upgrade in our final FIP we will provide the company the following option in the FIP to seek a revised emission limit after taking the following steps:

(a) Install a CEMS at the inlet to the scrubber.

(b) Pre-approval of a scrubber upgrade plan conducted by a third party engineering firm that considers the kinds of improvements (e.g., elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically performed during a scrubber upgrade. The goal of this plan will be to maximize the unit's overall SO_2 removal efficiency.

(c) Installation of the scrubber upgrades.

(d) Pre-approval of a performance testing plan, followed by the performance testing itself.

(e) A pre-approved schedule for 2.a through 2.d.

(f) Should we determine that a revision of the SO_2 emission limit is appropriate, we will have to propose a modification to the BART FIP after it has been promulgated. It should be noted that any proposal to modify the SO_2 emission

limit will be based largely on the performance testing and may result in a proposed increase or decrease of that value.

4. SO_2 BART for Gas-fired Units that Burn Oil

We propose that SO_2 BART for the following gas-fired units that occasionally burn fuel oil be the existing permit limits for the sulfur content of the fuel oil:

Table 34: Proposed BART SO_2 Emission Limits Gas Units that Occasionally Burn Oil

Facility	Fuel Oil Sulfur Content (percent by weight)
Graham 2	0.7
Newman 2*	0.7
Newman 3*	0.7
O W Sommers 1	0.7
O W Sommers 2	0.7
Stryker Creek ST2	0.7
Wilkes 1	0.7

* The Newman Units 2 and 3 are further limited to burning fuel oil for no more than 876 hours per year.

5. PM BART

We propose that PM BART limits for the coal units, Big Brown Units 1 and 2; Monticello Units 1, 2, and 3; Martin Lake Units 1, 2, and 3; Coleto Creek Unit 1; J T Deely Units 1 and 2; W A Parish Units 5 and 6; Welsh Unit 1; Harrington Units 061B and 062B; and Fayette Units 1 and 2 are 0.030 lb/MMBtu and work practice standards, which we present below:

Table 35. PM BART Emissions Standards and Work Practice Standards

Unit Type	**PM BART Proposal**
Coal-Fired BART Units	0.03 lb/MMBtu filterable PM Table 3 to Subpart UUUUU
Gas-Fired Only BART Units	Pipeline quality natural gas
Oil-Fired BART Units when not firing natural gas	Fuel Content not to exceed 0.7% sulfur by weight (also SO_2 BART)

We propose that compliance with these emissions standards and work practice standards be the effective date of our final rule, as the affected facilities' should already be meeting them.

We propose that PM and SO_2 BART for the units that only fire gas, Newman Unit 4; W A Parish Unit 4; and Wilkes Units 2 and 3 be pipeline natural gas.

We propose that PM and SO_2 BART for those gas-fired units that occasionally burn fuel oil, Newman Unit 2 and 3; O W Sommers Units 1 and 2; Stryker Creek Unit ST2; and Wilkes Unit 1 be the existing permitted fuel oil sulfur content of 0.7% sulfur by weight.

B. Interstate Visibility Transport

We are proposing to disapprove Texas' SIP revisions addressing interstate visibility transport under CAA section 110(a)(2)(D)(i)(II) for six NAAQS. We further are proposing a FIP to fully address Texas' interstate visibility transport obligations for: (1) 1997 8-hour ozone, (2) 1997 $PM_{2.5}$ (annual and 24 hour), (3) 2006 $PM_{2.5}$ (24-hour), (4) 2008 8-hour ozone, (5) 2010 1-hour NO_2 and (6) 2010 1-hour SO_2. The proposed FIP is based on the finding that our proposed action to fully address the Texas Regional Haze BART program is adequate to ensure that

emissions from Texas do not interfere with measures to protect visibility in nearby states in accordance with CAA section 110(a)(2)(D)(i)(II).

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Overview

This proposed action is not a "significant regulatory action" under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011). The proposed FIP would not constitute a rule of general applicability, because it only proposes source specific requirements for particular, identified facilities (8 total).

B. Paperwork Reduction Act

This proposed action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. Section 3501 et seq. Because it does not contain any information collection activities, the Paperwork Reduction Act does not apply. See 5 CFR 1320(c).

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and small governmental jurisdictions. For purposes of assessing the impacts

of today's rule on small entities, small entity is defined as: (1) a small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's proposed rule on small entities, I certify that this action will not have a significant impact on a substantial number of small entities. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule. This rule does not impose any requirements or create impacts on small entities. This proposed FIP action under Section 110 of the CAA will not create any new requirement with which small entities must comply. This action, when finalized, will apply to 14 facilities owned by 8 companies, none of which are small entities. Accordingly, it affords no opportunity for the EPA to fashion for small entities less burdensome compliance or reporting requirements or timetables or exemptions from all or part of the rule. The fact that the CAA prescribes that various consequences (e.g., emission limitations) may or will flow from this action does not mean that the EPA either can or must conduct a regulatory flexibility analysis for this action. We have therefore concluded that, this action will have no net regulatory burden for all directly regulated small entities.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104-4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on state, local, and Tribal governments and the private sector. Under Section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to state, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more (adjusted for inflation) in any one year. Before promulgating an EPA rule for which a written statement is needed, Section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of Section 205 of UMRA do not apply when they are inconsistent with applicable law. Moreover, Section 205 of UMRA allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under Section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that Title II of UMRA does not apply to this proposed rule. In 2 U.S.C. Section 1502(1) all terms in Title II of UMRA have the meanings set forth in 2 U.S.C. Section 658, which further provides that the terms "regulation" and "rule" have the meanings set

forth in 5 U.S.C. Section 601(2). Under 5 U.S.C. Section 601(2), "the term 'rule' does not include a rule of particular applicability relating to . . . facilities." Because this proposed rule is a rule of particular applicability relating to 12 named facilities, EPA has determined that it is not a "rule" for the purposes of Title II of UMRA.

E. Executive Order 13132: Federalism

This proposed action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This proposed rule does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments. Thus, Executive Order 13175 does not apply to this rule.

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks[142] applies to any rule that: (1) Is determined to be economically significant as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children. EPA interprets

[142] 62 FR 19885 (Apr. 23, 1997).

EO 13045 as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under Section 5-501 of the EO has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action is not subject to EO 13045 because it implements specific standards established by Congress in statutes. However, to the extent this proposed rule will limit emissions of SO_2, NO_X, and PM, the rule will have a beneficial effect on children's health by reducing air pollution.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This proposed action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12 of the National Technology Transfer and Advancement Act (NTTAA) of 1995 requires Federal agencies to evaluate existing technical standards when developing a new regulation. To comply with NTTAA, EPA must consider and use "voluntary consensus standards" (VCS) if available and applicable when developing programs and policies unless doing so would be inconsistent with applicable law or otherwise impractical. EPA believes that VCS are inapplicable to this action. Today's action does not require the public to perform activities conducive to the use of VCS.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994), establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. We have determined that this proposed rule, if finalized, will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. This proposed federal rule limits emissions of NO_X, SO_2, and PM from 14 facilities in Texas

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxides, Visibility, Interstate transport of pollution, Regional haze, Best available control technology.

Dated: December 9, 2016.

Ron Curry,

Regional Administrator, Region 6.

Title 40, chapter I, of the Code of Federal Regulations is proposed to be amended as follows:

PART 52–APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq*.

Subpart SS – Texas

2. Section 52.2287 is added to read as follows:

§ 52.2287 Best Available Retrofit Requirements (BART) for SO_2 and Particulate Matter and Interstate pollutant transport provisions; What are the FIP requirements for visibility protection?

(a) *Applicability*. The provisions of this section shall apply to each owner or operator, or successive owners or operators, of the coal or natural gas burning equipment designated below.

(b) *Definitions*. All terms used in this part but not defined herein shall have the meaning given them in the CAA and in parts 51 and 60 of this title. For the purposes of this section:

24-hour period means the period of time between 12:01 a.m. and 12 midnight.

Air pollution control equipment includes selective catalytic control units, baghouses, particulate or gaseous scrubbers, and any other apparatus utilized to control emissions of regulated air contaminants that would be emitted to the atmosphere.

Boiler-operating-day means 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.

Daily average means the arithmetic average of the hourly values measured in a 24-hour period.

Heat input means heat derived from combustion of fuel in a unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources. Heat input shall be calculated in accordance with 40 CFR part 75.

Owner or Operator means any person who owns, leases, operates, controls, or supervises any of the coal or natural gas burning equipment designated below.

PM means particulate matter.

Regional Administrator means the Regional Administrator of EPA Region 6 or his/her authorized representative.

Unit means one of the natural gas, gas and/or fuel oil, or coal-fired units covered in this section.

(c) *Emissions limitations and compliance dates for SO_2.* The owner/operator of the units listed below shall not emit or cause to be emitted pollutants in excess of the following limitations from the subject unit. Compliance with the requirements of this section is required as listed below unless otherwise indicated by compliance dates contained in specific provisions.

Unit	Proposed SO_2 emission limit (lbs/MMBtu)	Compliance Date (from the effective date of the final rule)
Martin Lake 1	0.12	3 years
Martin Lake 2	0.12	3 years
Martin Lake 3	0.11	3 years
Monticello 3	0.05	3 years

Big Brown 1	0.04	5 years
Big Brown 2	0.04	5 years
Monticello 1	0.04	5 years
Monticello 2	0.04	5 years
Coleto Creek 1	0.04	5 years
Fayette 1	0.04	1 year
Fayette 2	0.04	1 year
Harrington 061B	0.06	5 years
Harrington 062B	0.06	5 years
J T Deely 1	0.04	5 years
J T Deely 2	0.04	5 years
W A Parish 5	0.04	5 years
W A Parish 6	0.04	5 years
Welsh 1	0.04	5 years

(d) *Emissions limitations and compliance dates for PM*. The owner/operator of the units listed below shall not emit or cause to be emitted pollutants in excess of the following limitations from the subject unit. Compliance with the requirements of this section is required as listed below unless otherwise indicated by compliance dates contained in specific provisions.

(1) Coal-Fired Units at Big Brown Units 1 and 2; Monticello Units 1, 2, and 3; Martin Lake Units 1, 2, and 3; Coleto Creek Unit 1; J T Deely Units 1 and 2; W A Parish Units 5 and 6; Welsh Unit 1; Harrington Units 061B and 062B; and Fayette Units 1 and 2.

(i) Normal operations: Filterable PM limit of 0.030 lb/MMBtu.

(ii) Work practice standards specified in 40 CFR Part 63, subpart UUUUU, Table 3, and using the relevant definitions in 63.10042.

(2) Gas-Fired Units at Newman Unit 4; Wilkes Units 2 and 3; and W A Parish Unit 4 shall

burn only pipeline natural gas, as defined in 40 CFR 72.1

(3) Gas-fired units that also burn fuel oil at Graham Unit 2; Newman Units 2 and 3; O W Sommers Units 1 and 2; Stryker Creek Unit ST2; and Wilkes shall burn 0.7% sulfur content fuel or pipeline natural gas, as defined in 40 CFR 72.1.

(4) Compliance for the units included in Section (d) shall be as of the effective date of the final rule.

(e) *Testing and monitoring*. (1) No later than the compliance date of this regulation, the owner or operator shall install, calibrate, maintain and operate Continuous Emissions Monitoring Systems (CEMS) for SO_2 on the units covered under paragraph (c) of this section. Compliance with the emission limits for SO_2 shall be determined by using data from a CEMS.

(2) Continuous emissions monitoring shall apply during all periods of operation of the coal or natural gas burning equipment, including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments. Continuous monitoring systems for measuring SO_2 and diluent gas shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant in an hour) if data are unavailable as a result of performance of calibration, quality assurance, preventive maintenance activities, or backups of data from data acquisition and handling system, and recertification events. When valid SO_2 pounds per hour, or

SO_2 pounds per million Btu emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments, emission data must be obtained by using other monitoring systems approved by the EPA to provide emission data for a minimum of 18 hours in each 24 hour period and at least 22 out of 30 successive boiler operating days.

(3) Compliance with the PM emission limits for units in paragraph (d)(1) shall be demonstrated by the filterable PM methods specified in 40 CFR Part 63, subpart UUUUU, Table 7.

(f) *Reporting and recordkeeping requirements*. Unless otherwise stated all requests, reports, submittals, notifications, and other communications to the Regional Administrator required by this section shall be submitted, unless instructed otherwise, to the Director, Multimedia Division, U.S. Environmental Protection Agency, Region 6, to the attention of Mail Code: 6MM, at 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202-2733. For each unit subject to the emissions limitation in this section and upon completion of the installation of CEMS as required in this section, the owner or operator shall comply with the following requirements:

(1) For SO_2 each emissions limit in this section, comply with the notification, reporting, and recordkeeping requirements for CEMS compliance monitoring in 40 CFR 60.7(c) and (d).

(2) For each day, provide the total SO_2 emitted that day by each emission unit. For any hours on any unit where data for hourly pounds or heat input is missing, identify the unit number and monitoring device that did not produce valid data that caused the missing hour.

(3) Records for demonstrating compliance with the SO_2 and PM emission limitations in this section shall be maintained for at least five years.

(g) *Equipment operations*. At all times, including periods of startup, shutdown, and malfunction,

the owner or operator shall, to the extent practicable, maintain and operate the unit including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Regional Administrator which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the unit.

(h) *Enforcement.* (1) Notwithstanding any other provision in this implementation plan, any credible evidence or information relevant as to whether the unit would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed, can be used to establish whether or not the owner or operator has violated or is in violation of any standard or applicable emission limit in the plan.

(2) Emissions in excess of the level of the applicable emission limit or requirement that occur due to a malfunction shall constitute a violation of the applicable emission limit.

3. In § 52.2304, paragraph (f) is added to read as follows:

§ 52.2304 Visibility protection.

* * * * *

(f) *Measures addressing disapproval associated with NO_x, SO_2, and PM.* (1) The deficiencies associated with NO_x identified in EPA's disapproval of the regional haze plan submitted by Texas on March 31, 2009, are satisfied by Section 52.2283.

(2) The deficiencies associated with SO_2 and PM identified in EPA's disapproval of the regional haze plan submitted by Texas on March 31, 2009, are satisfied by Section 52.2287.

To: Feldman, Michael[Feldman.Michael@epa.gov]
Cc: Kordzi, Joe[Kordzi.Joe@epa.gov]; Snyder, Erik[snyder.erik@epa.gov]; Tomasovic, Brian[Tomasovic.Brian@epa.gov]
From: Young, Carl
Sent: Tue 12/27/2016 3:00:09 PM
Subject: OFR edits for the TX RH proposal
EPA 2016-30713.docx

Michael,

I spoke with Guy and he recommended sending this to you.

Would you review the Office of Federal Register edits for the proposal and let me know if it's OK to accept them?

Carl

Carl Young

EPA Region 6 Air Quality Program

(214) 665-6645

From: Morris, Stephanie **On Behalf Of** EPA-FederalRegisterLiaison
Sent: Tuesday, December 27, 2016 8:30 AM
To: Wiley, Adina <Wiley.Adina@epa.gov>; Paige, Carrie <Paige.Carrie@epa.gov>; Mohr, Ashley <Mohr.Ashley@epa.gov>; Young, Carl <young.carl@epa.gov>; Tomasovic, Brian <Tomasovic.Brian@epa.gov>; Kordzi, Joe <Kordzi.Joe@epa.gov>
Cc: Brooks, Patricia <Brooks.Patricia@epa.gov>
Subject: FW: 16-30713; FRL-9955-77-Region 6

Good morning,

I am sending this in the absence of your reviewer, Patricia Brooks. Please

respond to this proxy email box when responding.

Attach you will find OFR edits, questions and comments regarding your document for your review and responses.

As a **Reminder:** Please do not use the “accept” nor “reject” feature for any of the changes, please leave the redline/strikeout if it’s apparent in the OFR Word file and make sure your edits, if any, are also apparent in redline/strikeout.

Stephanie Morris

Federal Register Liaison, Senior Editor

Regulatory Management Division,

US Environmental Protection Agency, #3526D

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202.564.0730

*****Many FR questions can be answered via our*** intranet website! **

Have an IBR question? You can now contact us at EPA-IBR@epa.gov

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA-R06-OAR-2016-0611; FRL-9955-77-Region 6]

Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: Pursuant to the Federal Clean Air Act (CAA or Act), the Environmental Protection Agency (EPA) is proposing to promulgate a Federal Implementation Plan (FIP) in Texas to address the remaining outstanding requirements that are not satisfied by the Texas Regional Haze State Implementation Plan (SIP) submission. Specifically, the EPA proposes SO_2 limits on 29 Electric Generating Units (EGUs) located at 14 Texas facilities to fulfill requirements for the installation and operation of the Best Available Retrofit Technology (BART) for SO_2. To address the requirement for NO_X BART for Texas EGU sources, we are proposing a FIP that relies upon two other EPA rulemakings, one already final and one proposed, which together will establish that participation in the Cross-State Air Pollution Rule (CSAPR) continues to qualify as an alternative to NO_X BART for EGUs in Texas. We also are proposing to disapprove the portion of the Texas Regional Haze SIP that addresses the BART requirement for EGUs for Particulate Matter (PM) and proposing a FIP with PM BART limits for EGUs at 29 EGUs located at 14 Texas facilities, based on existing practices and control capabilities. In

addition, we propose to reconsider and re-propose disapproval of portions of several SIP revisions submitted to satisfy the requirement to address interstate visibility transport for six NAAQS.

DATES: *Comments:* Comments must be received on or before **[Insert date 60 days from date of publication in the Federal Register]**. A public hearing will be held January 10, 2017. For additional logistical information regarding the public hearing please see the **SUPPLEMENTARY INFORMATION** section of this action.

ADDRESSES: Submit your comments, identified by Docket No. EPA-R06-OAR-2016-0611, at *http://www.regulations.gov* or via email to *R6_TX-BART@epa.gov*. Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from Regulations.gov. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (i.e. on the web, cloud, or other file sharing system). For additional submission methods, please contact Joe Kordzi, 214-665-7186, Kordzi.joe@epa.gov. For the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets*.

Docket: The index to the docket for this action is available electronically at *http://www.regulations.gov* and in hard copy at the EPA Region 6, 1445 Ross Avenue, Suite 700, Dallas, Texas. While all documents in the docket are listed in the index, some information may be publicly available only at the hard copy location (e.g., copyrighted material), and some may not be publicly available at either location (e.g., CBI).

The Texas regional haze SIP is available online at: *https://www.tceq.texas.gov/airquality/sip/bart/haze_sip.html*. It is also available for public inspection during official business hours, by appointment, at the Texas Commission on Environmental Quality, Office of Air Quality, 12124 Park 35 Circle, Austin, Texas 78753.

FOR FURTHER INFORMATION CONTACT: Joe Kordzi, Air Planning Section (6PD-L), Environmental Protection Agency, Region 6, 1445 Ross Avenue, Suite 700, Dallas, Texas 75202-2733, telephone 214-665-7186; fax number 214-665-7263; e-mail address *Kordzi.joe@epa.gov*.

SUPPLEMENTARY INFORMATION: Throughout this document wherever "we," "us," or "our" is used, we mean the EPA.

Public Hearing:

We are holding an information session, for the purpose of providing additional information and informal discussion for our proposal. We are also holding a public hearing to accept oral comments into the record:

Date: Tuesday, January 10, 2017

Time: Open House: 1:30 p.m. - 3:30 p.m.

Public hearing: 4:00 p.m. – 8:00 p.m. (including short break)

Location: Joe C. Thompson Conference Center

(on the University of Texas (UT) Campus)

Room 3.102

2405 Robert Dedman Drive

Austin, Texas 78712

Joe C. Thompson Conference Center parking is adjacent to the building in Lot 40, located at the intersection of East Dean Keeton Street and Red River Street. Additional parking is available at the Manor Garage, located at the intersection of Clyde Littlefield Drive and Robert Dedman Drive. If arranged in advance, the UT Parking Office will allow buses to park along Dedman Drive near the Manor Garage for a fee.

The public hearing will provide interested parties the opportunity to present information and opinions to us concerning our proposal. Interested parties may also submit written comments, as discussed in the proposal. Written statements and supporting information submitted during the comment period will be considered with the same weight as any oral comments and supporting information presented at the public hearing. We will not respond to comments during the public hearing. When we publish our final action, we will provide written responses to all significant oral and written comments received on our proposal. To provide opportunities for questions and discussion, we will hold an information session prior to the public hearing. During the information session, EPA staff will be available to informally answer questions on our proposed action. Any comments made to EPA staff during an information session must still be provided orally during the public hearing, or formally in writing within 30 days after completion of the

hearings, in order to be considered in the record.

At the public hearings, the hearing officer may limit the time available for each commenter to address the proposal to three minutes or less if the hearing officer determines it to be appropriate. We will not be providing equipment for commenters to show overhead slides or make computerized slide presentations. Any person may provide written or oral comments and data pertaining to our proposal at the public hearings. Verbatim English language transcripts of the hearing and written statements will be included in the rulemaking docket.

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2. Step 3: Evaluation of Control Effectiveness

a. Evaluation of SO_2 Control Effectiveness for Coal Fired Units

b. Evaluation of SO_2 Control Effectiveness for Gas Fired Units

3. Step 4: Evaluate Impacts and Document the Results for SO_2

a. Impact Analysis Part 1: Cost of Compliance for DSI, SDA, and Wet FGD

b. Impact Analysis Part 1: Cost of Compliance for Scrubber Upgrades

c. Impact Analysis Part 1: Cost of Compliance for Gas Units that Burn Oil

4. Impact Analysis Parts 2, 3, and 4: Energy and Non-air Quality Environmental Impacts, and Remaining Useful Life

5. Step 5: Evaluate Visibility Impacts

a. Visibility Benefits of DSI, SDA, and Wet FGD for Coal-fired Units

b. Visibility Benefits of Scrubber Upgrades for Coal-fired Units

c. Visibility Benefits of Fuel Oil Switching for Gas/Fuel Oil-Fired Units

6. BART Five Factor Analysis for PM

D. How, if at all, Do Issues of "Grid Reliability" Relate to the Proposed BART Determinations?

IV. Our Weighing of the Five BART Factors

A. SO_2 BART for Coal-fired Units with no SO_2 Controls

1. Big Brown 1 & 2
2. Monticello 1 & 2
3. Coleto Creek 1
4. Welsh 1
5. Harrington 061B & 062B
6. W A Parish WAP 5 & 6
7. J T Deely 1 & 2

B. SO_2 BART for Coal-fired Units with Underperforming Scrubbers

C. SO_2 BART for Gas-fired Units that Burn Oil

D. PM BART

V. Proposed Actions

A. Regional Haze

1. NO_X BART
2. SO_2 BART for Coal-fired Units
3. Potential Process for Alternative Scrubber Upgrade Emission Limits
4. SO_2 BART for Gas-fired Units that Burn Oil
5. PM BART

B. Interstate Visibility Transport

VI. Statutory and Executive Order Reviews

I. Background

Regional haze is visibility impairment that is produced by a multitude of sources and activities that are located across a broad geographic area and emit fine particulates ($PM_{2.5}$) (e.g., sulfates, nitrates, Organic Carbon (OC), Elemental Carbon (EC), and soil dust), and their precursors (e.g., Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_X), and in some cases, ammonia (NH_3) and Volatile Organic Compounds (VOCs)). Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that can be seen. $PM_{2.5}$ can also cause serious health effects and mortality in humans and contributes to environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the "Interagency Monitoring of Protected Visual Environments" (IMPROVE) monitoring network, show that visibility impairment caused by air pollution occurs virtually all the time at most national parks and wilderness areas. In 1999, the average visual range[1] in many Class I areas (i.e., national parks and memorial parks, wilderness areas, and international parks meeting certain size criteria) in the western United States was 100-150 kilometers, or about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. In most of the eastern Class I areas of the United States, the average visual range was less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions.[2] CAA programs have reduced some haze-causing pollution, lessening some visibility impairment and resulting in

[1] Visual range is the greatest distance, in kilometers or miles, at which a dark object can be viewed against the sky.
[2] 64 FR 35715 (July 1, 1999).

partially improved average visual ranges.[3]

CAA requirements to address the problem of visibility impairment are continuing to be addressed and implemented. In Section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the prevention of any future, and the remedying of any existing man-made impairment of visibility in 156 national parks and wilderness areas designated as mandatory Class I Federal areas.[4] On December 2, 1980, EPA promulgated regulations to address visibility impairment in Class I areas that is "reasonably attributable" to a single source or small group of sources, i.e., "reasonably attributable visibility impairment."[5] These regulations represented the first phase in addressing visibility impairment. EPA deferred action on regional haze that emanates from a variety of sources until monitoring, modeling, and scientific knowledge about the relationships between pollutants and visibility impairment were improved.

Congress added section 169B to the CAA in 1990 to address regional haze issues, and we promulgated regulations addressing regional haze in 1999.[6] The Regional Haze Rule revised the existing visibility regulations to integrate into the regulations provisions addressing regional haze impairment and established a comprehensive visibility protection program for Class I areas.

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[3] An interactive "story map" depicting efforts and recent progress by EPA and states to improve visibility at national parks and wilderness areas may be visited at: http://arcg.is/29tAbS3.

[4] Areas designated as mandatory Class I Federal areas consist of National Parks exceeding 6000 acres, wilderness areas and national memorial parks exceeding 5000 acres, and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). In accordance with section 169A of the CAA, EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value. 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. 42 U.S.C. 7472(a). Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to "mandatory Class I Federal areas." Each mandatory Class I Federal area is the responsibility of a "Federal Land Manager." 42 U.S.C. 7602(i). When we use the term "Class I area" in this action, we mean a "mandatory Class I Federal area."

[5] 45 FR 80084 (December 2, 1980).

[6] 64 FR 35714 (July 1, 1999), codified at 40 CFR part 51, subpart P (Regional Haze Rule).

The requirements for regional haze, found at 40 CFR 51.308 and 51.309, are included in our visibility protection regulations at 40 CFR 51.300–309. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia, and the Virgin Islands. States were required to submit the first implementation plan addressing regional haze visibility impairment no later than December 17, 2007.[7]

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, often under-controlled, older stationary sources in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the CAA requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress toward the natural visibility goal, including a requirement that certain categories of existing major stationary sources[8] built between 1962 and 1977 procure, install and operate the "Best Available Retrofit Technology" (BART). Larger "fossil-fuel fired steam electric plants" are included among the BART source categories. Under the Regional Haze Rule, states are directed to conduct BART determinations for "BART-eligible" sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. The evaluation of BART for Electric Generating Units (EGUs) that are located at fossil-fuel fired power plants having a generating capacity in excess of 750 megawatts must follow the "Guidelines for BART Determinations Under the Regional Haze Rule" at appendix Y to 40 CFR Part 51 (hereinafter referred to as the "BART Guidelines"). Rather than requiring source-specific BART controls, states also have the flexibility to adopt an emissions trading program or alternative program as long as the alternative provides greater reasonable progress towards improving visibility than BART. To the extent a Regional Haze

[7] See 40 CFR 51.308(b). EPA's regional haze regulations require subsequent updates to the regional haze SIPs. 40 CFR 51.308(g)–(i).
[8] See 42 U.S.C. 7491(g)(7) (listing the set of "major stationary sources" potentially subject-to-BART).

SIP does not meet CAA requirements to address BART, the CAA requires EPA to promulgate a FIP that makes the requisite determinations to ensure the BART requirement is satisfied, as applicable, for sources in the state.[9]

II. Overview of Proposed Actions

A. Regional Haze

On January 5, 2016, we took final action on nearly all portions of a Regional Haze SIP submittal submitted by the State of Texas on March 31, 2009.[10] In that final rule, we did not take action on the portion of the submittal that was intended to satisfy BART requirements for EGUs as mandated by 40 CFR 51.308(e). In an earlier, separate action, we issued a limited disapproval of the Texas Regional Haze SIP concerning EGU BART due to Texas' reliance on the Clean Air Interstate Rule (CAIR).[11] The EGU BART requirements for NO_X and SO_2 remain unmet following the limited disapproval, and Texas has not submitted a revised SIP to address the deficiencies. While we previously proposed to approve the portion of the Regional Haze SIP that was intended to address whether EGUs in Texas must install and operate BART for PM,[12] that part of the proposed action was not finalized.[13] In connection with changed circumstances

[9] See, 42 U.S.C. 7491(b)(2)(A)(citing the potential need for BART as determined by "the Administrator in the case of a plan promulgated under section 7410(c) of this title").

[10] 81 FR 296 (January 5, 2016). A preliminary order of the Fifth Circuit Court of Appeals in Case No. 16-60118 was issued on July 15, 2016, and stayed the rule "in its entirety." On December 2, 2016, the U.S. Department of Justice filed a motion for voluntary remand of the parts of the rule under challenge and consenting to continuation of the judicial stay for remanded parts of the rule. The motion also requested affirmance of the partial approvals of the Texas and Oklahoma SIPs and lifting of the stay as to those approvals. This motion is currently pending disposition.

[11] The limited disapproval triggered the EPA's obligation to issue a FIP for Texas unless the State submitted an approvable SIP revision to correct the relevant deficiencies within 2 years of the final limited disapproval action. CAA section 110(c)(1); 77 FR 33641, 33654 (August 6, 2012).

[12] 79 FR 74817, 74851 (proposing to concur with screening analyses conducted by TCEQ including findings that no Texas EGUs are subject to BART for PM)

[13] 81 FR at 302 (January 5, 2016): "[W]e proposed to approve Texas' determination that for its EGUs no PM BART controls were appropriate, based on a screening analysis of the visibility impacts of from just PM emissions…..we have….decided not to finalize our proposed approval of Texas' PM BART determination [for EGUs]."

on how Texas EGUs are able to satisfy NO_X and SO_2 BART, we are now proposing to disapprove the portion of the Texas Regional Haze SIP that evaluated the PM BART requirement for EGUs. The FIP we are proposing today addresses the EGU BART requirement and addresses these deficiencies in the Texas Regional Haze SIP.

Texas' regional haze SIP relied on participation in CAIR as an alternative to meeting the source-specific BART requirements for SO_2 and NO_X. *See* 40 CFR 51.308(e)(4) (2006). At the time that Texas submitted its SIP to EPA, however, the D.C. Circuit had remanded CAIR (without vacatur). *See North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir.), *modified*, 550 F.3d 1176 (D.C. Cir. 2008). The court thereby left CAIR and CAIR FIPs in place in order to "temporarily preserve the environmental values covered by CAIR" until we could, by rulemaking, replace CAIR consistent with the court's opinion.[14]

On August 8, 2011, we promulgated the Cross-State Air Pollution Rule (CSAPR), to replace CAIR.[15] In 2012, we issued a limited disapproval of the Texas regional haze SIP because of Texas' reliance on CAIR as an alternative to EGU BART for SO_2 and NO_X.[16] We also determined that CSAPR would provide for greater reasonable progress than BART and amended the Regional Haze Rule to allow CSAPR participation as an alternative to source-specific SO_2 and NO_X BART for EGUs.[17] CSAPR has been subject to extensive litigation, and on July 28, 2015, the D.C. Circuit issued a decision generally upholding CSAPR but remanding without vacating the CSAPR emissions budgets for a number of states in *EME Homer City Generation* v. *EPA,* 795 F.3d 118 (D.C. Cir.). Specifically, the court invalidated a number of the

[14] 550 F.3d at 1178.
[15] 76 FR 48208.
[16] 77 FR 33641.
[17] While that rulemaking also promulgated FIPs for several states to replace reliance on CAIR with reliance on CSAPR as an alternative to BART, it did not include a FIP for Texas. 77 FR 33641, 33654.

Phase 2 ozone-season NO_X budgets and found that the SO_2 budgets for four states resulted in over-control for purposes of CAA section 110(a)(2)(D)(i)(I). The remand included Texas' ozone-season NO_X budget and annual SO_2 budget.

We had earlier proposed to rely on CSAPR participation to address these BART-related deficiencies in Texas' SIP submittals.[18] Because of the uncertainty caused by the D.C. Circuit Court's partial remand, however, we determined that it was not appropriate to finalize our action. We are in the process of responding to the remand of these CSAPR budgets. On October 26, 2016, we finalized an update to the CSAPR rule that addresses the 1997 ozone NAAQS portion of the remand and the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2008 ozone NAAQS.[19] This rule promulgated a new FIP for Texas that replaced the CSAPR ozone season NO_X emission budget designed to address the 1997 ozone NAAQS for the State with a revised budget designed to address the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2008 ozone NAAQS. Then, on November 10, 2016, we proposed to withdraw the FIP provisions that require affected EGUs in Texas to participate in CSAPR for annual emissions of SO_2 and NO_X with regard to emissions after 2016.[20] Withdrawal of these FIP requirements will address the D.C. Circuit's remand of the CSAPR Phase 2 SO_2 budget for Texas. This recently published proposed rule includes an assessment of the impacts of the set of actions that the EPA has taken

[18] 79 FR 74817, 74823 (December 16, 2014).

[19] "Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS." 81 FR74504. The relevant portion of the remand pertained to the Phase 2 ozone season NO_X emission budget designed to address the 1997 ozone NAAQS. In response to the remand, in this final rule the EPA removed the regulatory requirement for sources in Texas to comply with the phase 2 ozone season NO_X budget calculated to address the 1997 ozone standard because we determined that no additional emission reductions from sources in Texas are necessary to address the State's obligation under 110(a)(2)(D)(i)(I) for the 1997 ozone NAAQS. However, because Texas is linked to downwind air quality problems with respect to the 2008 ozone NAAQS, we promulgated a new ozone season NO_X emission budget to address that standard. 81 FR 74504, 74600-74601.

[20] "Interstate Transport of Fine Particulate Matter: Revision of Federal Implementation Plan Requirements for Texas," 81 FR 78954 (November 10, 2016). Although the court's decision specifically remanded only Texas' SO_2 budget, the court's rationale for remanding that budget also implicates Texas' annual NO_X budget because the SO_2 and annual NO_X budgets were developed through an integrated analysis and were promulgated to meet a common $PM_{2.5}$ transport obligation under CAA section 110(a)(2)(D)(i)(I).

or expects to take in response to the D.C. Circuit's remand on our 2012 demonstration that participation in CSAPR would provide for greater reasonable progress than BART.

In 2012, we determined that CSAPR is "better-than-BART" based on a comparison of projected visibility in scenarios representing CSAPR implementation and BART implementation, as well as a base case without CSAPR or BART, in relevant locations throughout the country. In the case of the remanded Phase 2 ozone-season NO_X budgets, eight of the states with remanded budgets (including Texas) will continue to be subject to CSAPR to address ozone transport obligations with regard to the more stringent 2008 ozone NAAQS, and North Carolina and South Carolina, although no longer covered by CSAPR to address ozone transport obligations, will continue to be subject to CSAPR annual NO_X requirements in order to address their $PM_{2.5}$ transport obligations. In considering the potential impact of the remand of Phase 2 budgets on the 2012 CSAPR-Better-than-BART analytic demonstration, we therefore believe that only two changes have potential relevance: the withdrawal of the FIP provisions subjecting Florida EGUs to CSAPR ozone-season NO_X requirements that has already been finalized, and the withdrawal of FIP provisions subjecting Texas EGUs to CSAPR SO_2 and annual NO_X requirements that is proposed separately. That proposed analysis supports the continued conclusion that CSAPR participation would achieve greater reasonable progress than BART for NO_X despite the change in the treatment of Texas and Florida EGUs. Consequently, we have proposed that the Regional Haze Rule continues to authorize the use of CSAPR participation as a BART alternative for EGUs.[21] Finalization of that proposal would allow for Texas' regional haze program to rely on CSAPR ozone season control program participation as an alternative to source-specific EGU BART for NO_X.[22] Based on that national proposal, we are

[21] 81 FR at 78962-78964.

[22] While we have proposed to remove Texas from CSAPR's annual NO_X program, CSAPR is still an appropriate

now proposing a FIP to replace Texas' reliance on CAIR with reliance on CSAPR to address the NO_X BART requirements for EGUs. Finalization of this portion of the FIP is contingent on our taking final action to find that CSAPR continues to be an appropriate alternative to source specific BART. However, finalization of the portion of our national proposal that would withdraw the FIP provisions for Texas for annual emissions of SO_2 and NO_X described above would mean that Texas will no longer be eligible to rely on CSAPR participation as an alternative to source-specific EGU BART for SO_2. As a result, we are proposing to promulgate a FIP that includes BART screening of sources and a source-by-source analysis for SO_2 BART and controls for this pollutant as appropriate. We are also unable to propose approval of the Texas Regional Haze SIP's PM BART evaluation, as previously proposed, as that demonstration made underlying assumptions that are no longer valid.[23] We instead propose to disapprove that portion of the SIP and, in place of it, promulgate source-specific PM BART requirements for EGUs that we have evaluated to be subject to BART in this proposed FIP.

We believe, however, it is preferable for states to assume primary responsibility for implementing the Regional Haze requirements as envisioned by the CAA. We will work with

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alternative to BART for NO_X purposes because EGUs in Texas continue to be required to participate in CSAPR's ozone season NO_X program.

[23] We previously proposed approval of Texas' SIP for EGU PM BART on the premise that EGU BART for both SO_2 and NO_X were covered by participation in CSAPR, which allowed Texas to conduct a screening analysis of the visibility impacts from PM emissions in isolation. However, modeling on a pollutant-specific basis for PM is appropriate only in the narrow circumstance where a state relies on a BART alternative to satisfy NO_X and SO_2 BART. Due to the complexity and nonlinear nature of atmospheric chemistry and chemical transformation among pollutants, EPA has not recommended performing modeling on a pollutant-specific basis to determine whether a source is subject to BART, except in the unique situation described above. See discussion in Memorandum from Joseph Paisie to Kay Prince, "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations," July 19, 2006. More recently, the Ninth Circuit upheld EPA's disapproval of the Arizona regional haze SIP for including a pollutant-specific screening analysis for NO_X. *Phoenix Cement Co. v. EPA*, 647 F. App'x 702, 705-06 (9th Cir. Mar. 31, 2016) (upholding EPA's interpretation that the "Regional Haze Rule [] require[s] a BART determination for any pollutant at a source that exceeds the de minimis threshold, once that source has been determined subject to BART."). We did not finalize our proposed approval of Texas' EGU PM BART determination because of the uncertainty at that time concerning the CSAPR remand and whether Texas would continue to have CSAPR coverage for both NO_X and SO_2, 81 FR 296, 302, but that uncertainty has now been resolved.

the State of Texas if it chooses to develop a SIP to meet these overdue Regional Haze requirements and replace or avoid a finalized FIP.

The FIP we are proposing includes BART control determinations for EGUs in Texas without previously approved BART determinations and associated compliance schedules and requirements for equipment maintenance, monitoring, testing, recordkeeping, and reporting for all affected sources and units. The EGU BART sources addressed in this FIP cause or contribute to visibility impairment at one or more Class I areas in Texas, Oklahoma, Arkansas, and New Mexico. The two Class I areas in Texas are Big Bend National Park and the Guadalupe Mountains National Park. The Class I area in Oklahoma is the Wichita Mountains National Wildlife Refuge. The two Class I areas in Arkansas are the Caney Creek Wilderness Area and the Upper Buffalo Wilderness Area. The closest impacted Class I areas in New Mexico are the Carlsbad Caverns National Park, Salt Creek Wilderness Area, and White Mountains Wilderness Area.

In order to remedy these deficiencies in the Texas SIP, we are proposing this FIP to establish the means by which the regional haze program for Texas will meet the BART requirements for SO_2, NO_X, and PM. We are proposing source-specific BART determinations for EGUs subject to BART for SO_2 and PM. We are proposing that NO_X BART requirements for EGUs in Texas will be satisfied by a determination, proposed for separate finalization, that Texas' participation in CSAPR's ozone season control program is a permissible alternative to source-specific NO_X BART.

Addressing the BART requirement for Texas EGUs, as proposed today, with cost-effective and readily available controls, will help ensure that progress is made toward natural visibility conditions at Class I areas affected by Texas' sources. Please refer to our previous

rulemaking on the Texas regional haze SIP for additional background regarding the CAA, regional haze, and our Regional Haze Rule.[24]

B. Interstate Transport of Pollutants that Affect Visibility

Section 110(a) of the CAA directs states to submit a SIP that provides for the implementation, maintenance, and enforcement of each NAAQS, which is commonly referred to as an infrastructure SIP. Among other things, CAA 110(a)(2)(D)(i)(II) requires that SIPs contain adequate provisions to prohibit interference with measures required to protect visibility in other states. This requirement is referred to as "interstate visibility transport." SIPs addressing interstate visibility transport are due to EPA within three years after the promulgation of a new or revised NAAQS (or within such shorter period as we may prescribe). A state's failure to submit a complete, approvable SIP for interstate visibility transport creates an obligation for EPA to promulgate a FIP to address this requirement.[25]

Previously, we issued a finding that Texas failed to submit a SIP revision to satisfy all four requirements of interstate transport under section 110(a)(2)(D)(i) of the CAA for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS.[26] Texas later submitted a SIP revision to address interstate

[24] 81 FR 296. The public docket for this past rulemaking remains accessible under EPA Docket ID: EPA-R06-OAR-2014-0754 at https://www.regulations.gov. This proposed rulemaking has a separately established docket (EPA-R06-OAR-2016-0611). Our TSD contains a list of materials from EPA Docket ID: EPA-R06-OAR-2014-0754 that we incorporate by reference and consider to be part of this rulemaking record even as they are not necessarily re-uploaded to the newer docket.

[25] CAA § 110(c)(1). Mandatory sanctions under CAA section 179 do not apply because the deficiencies are not with respect to a submission that is required under CAA title I part D. "Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and (2)" at pages 34–35 (September 13, 2013) [hereinafter 2013 i-SIP Guidance].

[26] 70 FR 21147 (April 25, 2005). The four components of interstate transport in Section 110(a)(2)(D)(i) are contained in two subsections. Section 110(a)(2)(D)(i)(I) addresses any emissions activity in one state that contributes significantly to nonattainment, or interferes with maintenance, of the NAAQS in another state. Section 110(a)(2)(D)(i)(II) requires SIPs to include provisions prohibiting any source or other type of emissions activity in one state from interfering with measures required of any other state to prevent significant deterioration of air quality or from interfering with measures required of any other state to protect visibility (referring to visibility in Class I areas). This proposal only addresses the fourth requirement concerning visibility.

transport for these NAAQS. However, in our January 5, 2016 final action we disapproved the portion of Texas' SIP revisions intended to address interstate visibility transport for six NAAQS, including the 1997 8-hour ozone and 1997 $PM_{2.5}$.[27] We concluded that to meet the requirements of interstate visibility transport: (1) Texas could not rely on its Regional Haze SIP, which relied heavily upon the remanded CAIR, to ensure that emissions from Texas do not interfere with measures to protect visibility in nearby states; and (2) additional control of SO_2 emissions in Texas were needed to prevent interference with measures required to be included in the Oklahoma SIP to protect visibility. However, in that action we did not finalize the portion of our proposed FIP addressing Texas' interstate visibility transport obligations because that portion of the proposed FIP would have partially relied on CSAPR to ensure the emissions from Texas' sources do not interfere with other states' visibility programs. Given the uncertainty that existed at the time arising from the D.C. Circuit's remand of Texas' CSAPR budgets (*EME Homer City Generation v. EPA*, 79 F.3d 118 (D.C. Cir.)), we concluded that it was not appropriate to finalize our proposed determination to rely on CSAPR as an alternative to SO_2 and NO_X BART for EGUs in Texas in that action.[28]

Our prior disapproval of interstate visibility transport for the six NAAQS is currently stayed by the Fifth Circuit.[29] We recognize that because our prior disapproval of the Texas SIP submittals addressing interstate visibility transport relied in part on our determinations of the measures needed in Texas to ensure reasonable progress in Oklahoma, the Fifth Circuit's stay of

[27] Specifically, we previously disapproved the relevant portion of these Texas' SIP submittals: April 4, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); May 1, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); November 23, 2009: 2006 24-hour $PM_{2.5}$; December 7, 2012: 2010 NO_2; December 13, 2012: 2008 8-hour Ozone; May 6, 2013: 2010 1-hour SO_2 (Primary NAAQS). 79 FR 74818, 74821; 81 FR 296, at 302.
[28] 81 FR 296, 301-2.
[29] July 15, 2016 Order in *Texas v. EPA* (Fifth Cir. Case No. 16-160118). The EPA's filed motion requesting voluntary partial remand and continuation of the judicial stay for remanded parts of the rule includes our prior disapproval of Texas' SIPs concerning interstate visibility transport. This motion is currently pending disposition.

our previous action complicates next steps to ensure that the visibility requirements of CAA 110(a)(2)(D)(i)(II) are met. The Court's stay accordingly calls into question whether our past disapprovals for interstate visibility transport would stand. At the same time, we also note that we continue to have an obligation to issue a FIP for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS as a result of our 2005 finding that Texas failed to timely submit SIPs to address the interstate transport visibility requirements. Given the uncertainties arising from the Fifth Circuit's stay of our prior disapproval, we are now proposing to reconsider the basis of our prior disapproval of Texas' SIP submittals addressing the interstate visibility transport requirement for all six NAAQS. We are now proposing to determine that Texas' SIP submittals addressing interstate visibility transport for the six NAAQS are not approvable because these submittals relied solely on Texas' Regional Haze SIP to ensure that emissions from Texas did not interfere with required measures in other states. Texas' Regional Haze SIP, in turn, relied on the implementation of CAIR as an alternative to EGU BART for SO_2 and NO_X. Specifically, we are proposing disapproval of the following Texas SIP submittals insofar as they address the interstate visibility transport requirement: April 4, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); May 1, 2008: 1997 8-hour Ozone, 1997 $PM_{2.5}$ (24-hour and annual); November 23, 2009: 2006 24-hour $PM_{2.5}$; December 7, 2012: 2010 NO_2; December 13, 2012: 2008 8-hour Ozone; May 6, 2013: 2010 1-hour SO_2 (Primary NAAQS). Texas has not submitted a SIP revision to remove reliance on CAIR for Regional Haze or interstate visibility transport. As CAIR is no longer in effect and has been replaced by CSAPR, we are proposing to find that Texas' Regional Haze SIP does meet its interstate visibility transport obligations. As a result, the Texas SIPs to address interstate visibility transport for these six NAAQS continue to be unapprovable.

We are proposing a FIP to cure the deficiencies in Texas' Regional Haze Program concerning EGU BART. This FIP will replace reliance on CAIR with reliance on CSAPR to meet the requirements for EGU BART for NO_X in Texas. The FIP will also address Texas EGU BART for SO_2 and PM on a source-specific basis. With the absence of CSAPR coverage for SO_2, we must reevaluate what is needed in Texas to address interstate visibility transport. Our proposed FIP to address Texas EGU BART achieves significant reductions of SO_2, which exceed the reductions initially assumed for Texas under either CAIR or CSAPR. In addition, our proposed FIP achieves reductions at large sources of SO_2 emissions (e.g., Monticello, Martin Lake and Big Brown), that have significant impacts on Class I areas in nearby states. The BART FIP requires controls on many but not all of the sources that were controlled in our previous partial FIP for Texas Regional Haze. The EGU BART FIP also includes control requirements at some additional sources not controlled in our previous action on Texas Regional Haze.

We are proposing to find that our proposed EGU BART FIP is adequate to prevent interference with measures required to protect visibility in other states for the first planning period.[30] We, therefore, propose that the measures in our proposed FIP to address Texas EGU BART will fully address Texas' interstate visibility transport obligations for the six NAAQS (1997 8-hour ozone, 1997 $PM_{2.5}$, 2006 $PM_{2.5}$, 2008 8-hour ozone, 2010 1-hour NO_2, and 2010 1-hour SO_2). We also propose that reliance on CSAPR for EGU NO_X BART is appropriate to ensure NO_X emissions from Texas EGUs do not interfere with other states' measures to protect visibility. We are proposing this action based on the reasoning that our BART FIP will achieve

[30] This proposed FIP for interstate visibility transport is premised on the interpretation that this requirement can be addressed even when a Regional Haze SIP is not fully approved and the FIP does not purport to correct all Regional Haze SIP deficiencies. *See e.g.* 76 FR 52388 (August 22, 2011); 76 FR 22036 (April 20, 2011); and 78 FR 14681 (March 7, 2013); *see also*, 2013 i-SIP Guidance, at page 34 (stating that EPA may find it appropriate to supplement the i-SIP Guidance regarding the relationship between Regional Haze SIPs and interstate visibility transport for future planning periods).

more emission reductions than projected under CAIR or CSAPR and the reductions are occurring at sources that have particularly large impacts on Class I areas outside of Texas. To the extent our previous final action concerning Texas Regional Haze is remanded by a Court or otherwise reconsidered in the future, we may revisit whether controls in the EGU BART FIP are adequate to address interstate visibility transport requirements. Nonetheless, we are here proposing that the proposed EGU BART FIP measures will be adequate to address interstate visibility transport based on current information. This proposal concerning the adequacy of the proposed FIP remedy does not depend on our earlier action on the Texas Regional Haze SIP or hinge on its disposition, nor does it foreclose that we may reexamine visibility transport concerns under potential scenarios where we have a responsibility to take new action.[31]

We encourage Texas to consider adopting additional SIP provisions that would allow the EPA to fully approve the Regional Haze SIP and thus to withdraw the FIP and approve Texas' SIP with respect to interstate visibility transport. Texas may also elect to satisfy interstate visibility transport by providing, as an alternative to relying on its Regional Haze SIP alone, a demonstration that emissions within its jurisdiction do not interfere with other states' plans to protect visibility.[32]

C. Our Obligation to Promulgate a FIP

Under section 110(c) of the CAA, whenever we disapprove a mandatory SIP submission in whole or in part, we are required to promulgate a FIP within 2 years unless we approve a SIP revision correcting the deficiencies before promulgating a FIP. Specifically, CAA section 110(c) provides that the Administrator shall promulgate a FIP within 2 years after the Administrator

[31] *See e.g.* 78 FR 14681, 14685.
[32] 2013 i-SIP Guidance, at pages 34-35.

disapproves a state implementation plan submission "unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan."[33] The term "Federal implementation plan" is defined in Section 302(y) of the CAA in pertinent part as a plan promulgated by the Administrator to correct an inadequacy in a SIP.

Beginning in 2012, following the limited disapproval of the Texas Regional Haze SIP, EPA had the authority and obligation to promulgate a FIP to address BART for Texas EGUs for NO_X and SO_2. In proposing to disapprove the Regional Haze SIP component that sought to address the PM BART requirement for Texas EGUs, we also have the obligation to promulgate a PM BART FIP to address the deficiency. Texas has not addressed the EGU BART disapproval, and that requirement is now significantly overdue.[34] We are accordingly empowered and required by the CAA to make determinations and promulgate a FIP to ensure the BART requirement for Texas EGUs is satisfied.

Adding to this background, beginning with our January 5, 2016 disapproval of Texas SIP provisions regarding interstate visibility transport, we obtained the authority and obligation to promulgate a FIP to correct the deficiencies relating to that CAA requirement.[35] As with the BART requirement, we lack a SIP revision that would have any potential to correct the deficiency, necessitating that we now take action under FIP authority.

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[33] EPA additionally has the authority to promulgate a FIP any time after finding that "a State has failed to make a required submission" of a SIP. CAA section 110(c)(1)(A); 42 U.S.C. §7410(c)(1)(a).

[34] The Texas Regional Haze SIP stated, "The TCEQ will take appropriate action if CAIR is not replaced with a system that the US EPA considers to be equivalent to BART." BART determinations were due in SIP submissions on December 17, 2007, 40 CFR 51.308(b), putting them on a timeline for controls by 2014 (considering the deadline for SIP action at CAA section 110(k)(2) and allowing five years for installation of BART controls). Additional delay of any amount is not appropriate and not consistent with the law.

[35] Additionally, we continue to have authority to issue a FIP to address interstate visibility transport for 1997 8-hour ozone and 1997 $PM_{2.5}$ due to our 2005 finding that Texas failed to submit SIPs to address interstate transport for these NAAQS under CAA section 110(a)(2)(D)(i). 70 FR 21147.

III. Our Proposed BART Analyses for SO_2 and PM

In our previous action,[36] we determined that due to the CSAPR remand, it was not appropriate at that time to rely on CSAPR as an alternative to SO_2 and NO_X BART for EGUs in Texas. As a consequence, action to satisfy the overdue requirement to address BART for EGUs in the state of Texas was further delayed.[37] In this proposal, we are proposing that CSAPR, once fully revised to address the D.C. Circuit's remand, provides a basis for satisfying EGU BART obligations for NO_X alone. It remains the case that we cannot rely on CSAPR as an alternative to SO_2 BART for Texas EGUs as further confirmed by our proposed action to remove Texas from the annual NO_X and SO_2 control programs. Thus, we have the obligation to consider source-specific requirements for Texas EGUs consistent with the BART Guidelines for SO_2 BART.

Because the component of the Texas Regional Haze SIP regarding the PM BART requirement for EGUs has not been acted on, we have the responsibility under CAA section 110(k) to evaluate the submission and take action to approve or disapprove it. The SIP determinations for PM were based on modeling that was conducted by examining visibility impairment due to PM emissions alone, based on the assumption that the state would be participating in CAIR for SO_2 and NO_X and thereby having BART coverage for those pollutants. The Texas Regional Haze SIP had concluded that no PM BART controls for EGUs were appropriate, because modeling assessment of PM impacts alone showed their impacts to be too small to warrant control consideration. But Texas' screening analysis is no longer reliable or accurate because of the invalid assumption that source-by-source BART for either SO_2 or NO_X would not be required. In order to appropriately evaluate the BART requirements for EGUs, the

[36] See the discussion beginning on 81 FR 301 (January 5, 2016).
[37] Id. at 346.

visibility impacts from all pollutants must be studied, including PM emissions. Texas' PM BART analysis for EGUs does not do this.[38]

Accordingly, we are proposing to disapprove the portion of the Texas Regional Haze SIP that determined that all Texas EGUs screen out of the BART requirement for PM. The basis for the proposed disapproval is the SIP determination's assumption that EGUs would have coverage for SO_2 and NO_X BART under an alternative measure.[39] Since that assumption is not valid, the technical determinations regarding PM BART cannot be approved. Following the directions of the BART Guidelines on how to identify sources "subject to BART," we have looked at all visibility impairing pollutants from EGUs that are BART-eligible. Our proposed FIP therefore seeks to fill that regulatory gap by assessing BART for Texas EGUs for visibility impairing pollutants other than NO_X, i.e., SO_2 and PM.

A. Identification of BART-Eligible Sources

The BART Guidelines set forth the steps for identifying whether the source is a BART-eligible source:[40]

Step 1: Identify the emission units in the BART categories,

Step 2: Identify the start-up dates of those emission units, and

Step 3: Compare the potential emissions to the 250 ton/yr cutoff.

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[38] Texas' Regional Haze SIP determined whether its sources should be subject to review for PM controls by only looking at the impact of PM emissions on visibility. This approach is only appropriate when a state satisfies the requirements for BART for SO_2 and NO_X with an alternative measure. Additionally, as reflected in our TSD on the identification of BART-Eligible Sources, the Texas SIP neglected to identify several BART-eligible sources; this also shows error in the state's PM BART demonstration and conclusions, and it constitutes grounds for the proposed partial SIP disapproval for PM BART.

[39] The requirements for "emissions trading programs or other alternative measures" that may be implemented rather than requiring BART are provided at 40 C.F.R. 51.308(e)(2).

[40] 70 FR 39158 (July 6, 2005).

Following our 2016 final action on the March 31, 2009 Texas RH SIP, we began the process of generating additional technical information and analysis in order to address the above three steps in our BART-eligibility proposal. We started with Texas' facility-specific listing of BART-eligible EGU sources and removed sources we verified had retired. We then gathered additional information from (1) our authority under Section 114(a) of the CAA to request information from potential BART-eligible sources, and (2) the U.S. Energy Information Administration (EIA). We then converted Texas' facility-specific BART-eligible list to a unit-specific BART-eligible list and verified the BART-eligibility of each unit. The following is a list of units we propose have satisfied the above three steps and are BART-eligible:[41]

Table 1. Summary of BART-Eligibility Analysis

Facility	Unit
Barney M. Davis (Talen/Topaz)	1
Big Brown (Luminant)	1
Big Brown (Luminant)	2
Cedar Bayou (NRG)	CBY1
Cedar Bayou (NRG)	CBY2
Coleto Creek (Engie)	1
Dansby (City of Bryan)	1
Decker Creek (Austin Energy)	1
Decker Creek (Austin Energy)	2
Fayette (LCRA)	1

[41] See our BART FIP TSD for more information concerning how we selected the units we are proposing are BART-eligible and other details concerning our proposed BART determinations.

Fayette (LCRA)	2
Graham (Luminant)	2
Greens Bayou (NRG)	5
Handley (Exelon)	3
Handley (Exelon)	4
Handley (Exelon)	5
Harrington Station (Xcel)	061B
Harrington Station (Xcel)	062B
J T Deely (CPS Energy)	1
J T Deely (CPS Energy)	2
Jones Station (Xcel)	151B
Jones Station (Xcel)	152B
Knox Lee Power Plant (AEP)	5
Lake Hubbard (Luminant)	1
Lake Hubbard (Luminant)	2
Lewis Creek (Entergy)	1
Lewis Creek (Entergy)	2
Martin Lake (Luminant)	1
Martin Lake (Luminant)	2
Martin Lake (Luminant)	3
Monticello (Luminant)	1
Monticello (Luminant)	2
Monticello (Luminant)	3
Newman (El Paso Electric)	2
Newman (El Paso Electric)	3
Newman (El Paso Electric)	4
Nichols Station (Xcel)	143B
O W Sommers (CPS Energy)	1
O W Sommers (CPS Energy)	2

Plant X (Xcel)	4
Powerlane (City of Greenville)	ST1
Powerlane (City of Greenville)	ST2
Powerlane (City of Greenville)	ST3
R W Miller (Brazos Elec. Coop)	1
R W Miller (Brazos Elec. Coop)	2
R W Miller (Brazos Elec. Coop)	3
Sabine (Entergy)	2
Sabine (Entergy)	3
Sabine (Entergy)	4
Sabine (Entergy)	5
Sim Gideon (LCRA)	1
Sim Gideon (LCRA)	2
Sim Gideon (LCRA)	3
Spencer (City of Garland)	4
Spencer (City of Garland)	5
Stryker Creek (Luminant)	ST2
Trinidad (Luminant)	6
Ty Cooke (City of Lubbock)	1
Ty Cooke (City of Lubbock)	2
V H Braunig (CPS Energy)	1
V H Braunig (CPS Energy)	2
V H Braunig (CPS Energy)	3
W A Parish (NRG)	WAP 4
W A Parish (NRG)	WAP 5
W A Parish (NRG)	WAP 6
Welsh Power Plant (AEP)	1

Welsh Power Plant (AEP)	2
Wilkes Power Plant (AEP)	1
Wilkes Power Plant (AEP)	2
Wilkes Power Plant (AEP)	3

The final step in identifying a ''BART-eligible source'' is to use the information from the previous three steps to identify the collection of emissions units that comprise the BART-eligible source.

B. Identification of Sources that are Subject to BART

Following our compilation of the BART-eligible sources in Texas, we examined whether these sources cause or contribute to visibility impairment in nearby Class I areas.[42] 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. Those sources are determined to be not subject-to-BART. Sources that are reasonably anticipated to cause or contribute to any visibility impairment in a Class I area are determined to be subject-to-BART. For each source subject to BART, 40 CFR 51.308(e)(1)(ii)(A) requires that states (or EPA, in the case of a FIP) 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 that CALPUFF or another appropriate model can be used to predict the visibility impacts from a single source at a Class I area. We employed a four-fold strategy in determining

[42] See 40 C.F.R. Part 51, Appendix Y, III, How to Identify Sources "Subject to BART"

which units should or should not be subject to BART. A flowchart of the analysis along with a detailed discussion of the subject-to-BART screening analysis is provided in the BART Screening TSD.[43] We summarize the methodology and results of this analysis here.

First, we examined whether any of the BART-eligible units should be eliminated from consideration based on the standard model plant exemptions described in the BART Guidelines.[44] Second, we created specific model plants between sources and nearby Class I areas and conducted CALPUFF modeling to evaluate a number of sources for exemption. Third, we performed stand-alone, source specific CALPUFF modeling on a number of units to determine if their visibility impacts were large enough to identify them as being subject to BART. Fourth, for those remaining units outside of the CALPUFF model's range, we contracted to have CAMx modeling performed to determine if their visibility impacts were large enough to merit their being subject to BART. These steps are further described below.

For states using modeling to determine the applicability of BART to single sources, the BART Guidelines note that the first step is to set a contribution threshold to assess whether the impact of a single source is sufficient to cause or contribute to visibility impairment at a Class I area. The BART Guidelines preamble 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."[45] It further advises that "States should have discretion to set an appropriate threshold depending on the facts of the situation," but "[a]s a general matter, any threshold that you use for determining whether a source 'contributes' to visibility impairment should not be

[43] See our TSD, "Our Strategy for Assessing which Units are Subject to BART for the Texas Regional Haze BART Federal Implementation Plan (BART Screening TSD)" in our docket.
[44] See the discussion beginning on 70 FR 39104, 39162 (July 6, 2005) [40 CFR Part 51, App. Y].
[45] 70 FR at 39118.

higher than 0.5 dv," and describes situations in which states may wish to exercise their discretion to set lower thresholds, mainly in situations in which a large number of BART-eligible sources within the State and in proximity to a Class I area justify this approach. We do not believe that the sources under consideration in this rule, most of which are not in close proximity to a Class I area, merit the consideration of a lesser contribution threshold. Therefore, our analysis employs a contribution threshold of 0.5 deciviews.

1. Our use of the Standard BART Model Plant Exemption

As the BART Guidelines note:

> [W]e believe that a State that has established 0.5 deciviews as a contribution threshold could reasonably exempt from the BART review process sources that emit less than 500 tons per year of NO_X or SO_2 (or combined NO_X and SO_2), as long as these sources are located more than 50 kilometers from any Class I area; and sources that emit less than 1000 tons per year of NO_X or SO_2 (or combined NO_X and SO_2) that are located more than 100 kilometers from any Class I area. You do, however, have the option of showing other thresholds might also be appropriate given your specific circumstances.[46]

We applied the standard BART model plant exemption described above to the following facilities, exempting them from further analysis:

[46] 70 FR at 39163, [40 CFR Part 51, App. Y].

Table 2: Standard BART Model Plant Exempt Sources

Facility	Units
Dansby (City of Bryan)	1
Greens Bayou (NRG)	5
Nichols Station (Xcel)	143B
Plant X (Xcel)	4
Powerlane (City of Greenville)	ST1, ST2 & ST3
Spencer (City of Garland)	4 & 5
Trinidad (Luminant)	6
Ty Cooke (City of Lubbock)	1 & 2

2. Our Extension of the BART Model Plant Exemption

As the BART Guidelines note, the standard BART model plant exemption can be extended to values other than the 500 tons/50 km and 1,000 tons/100 km scenarios discussed in the previous section. 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."[47]

Modeling analyses of representative plants are used to reflect groupings of specific sources with important common characteristics. We conducted CALPUFF modeling to establish emission levels and distances from Class I areas on which we could rely to exempt sources with those characteristics. In this approach, a hypothetical facility ("model plant") is located between a group of BART-eligible sources and a Class I area. Predominant wind patterns and elevation are considered in locating the model plant such that conditions that would be anticipated to transport pollution from the group of BART-eligible sources to the Class I area are consistent

[47] 70 FR at 39163 [40 CFR Part 51, App. Y].

with conditions anticipated to transport pollution from the model plant to the Class I area. The visibility impacts from this model plant are modeled utilizing CALPUFF following the protocol described in the BART Screening TSD. Model plant emissions are adjusted such that the modeled visibility impact (maximum of 98th percentile values for 2001, 2002, and 2003) is below the screening threshold of 0.5 dv. For each model plant, the Q/d value is calculated as the annual emissions (combined NO_X and SO_2 emissions) divided by distance to the Class I area (km) resulting in a critical Q/d value. The Q/d value for each BART-eligible source is calculated based on annual emissions based on the maximum actual 24-hr emission rate and distance to the Class I area and is then compared to the critical Q/d value. For a BART-eligible source with a lower Q/d value than the critical Q/d, it is reasonably anticipated that the visibility impact from the BART-eligible source is lower than the model plant and therefore below the screening threshold and not subject to BART. See the BART Screening TSD for additional discussion and source-specific information used in this model plant screening analysis. By this extension of the BART model plant exemption, we identified the following additional facilities that can be exempted from further analysis:

Table 3: Extended BART Model Plant Exempt Sources

Facility	Units
Barney M. Davis (Talen/Topaz)	1
Cedar Bayou (NRG)	CBY1 & CBY2
Decker Creek (Austin Energy)	1 & 2
Lewis Creek (Entergy)	1 & 2
Sabine (Entergy)	2, 3, 4 & 5
Sim Gideon (LCRA)	1, 2 & 3
V H Braunig (CPS Energy)	1, 2 & 3

3. Our use of CALPUFF Modeling to Exempt Sources from Being Subject to BART

Those sources that did not screen out using the model plant approach were modeled directly with CALPUFF if they were in a range of when CALPUFF has been previously used. Historically CALPUFF has been used at distances up to approximately 400 km. The maximum 98th percentile impact from the modeled years (calculated based on annual average natural background conditions) was compared with the 0.5 dv screening threshold following the modeling protocol described in the BART screening TSD. The BART Guidelines 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 of start-up, shutdown, or malfunction. The maximum 24-hour emission rate (lb/hr) for NO_X and SO_2 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.[48] For some BART-eligible sources, evaluation of baseline emissions revealed evidence of the installation of NO_X control technology during the baseline period. For those sources, the maximum emission rate was updated to reflect the identified maximum emission rate from the post-control portion of the baseline period. Because daily emissions are not available for PM, the annual average emission rate was doubled to approximate the 24-hr maximum emission rate for PM. See the BART Screening TSD for additional discussion and source-specific information used in the CALPUFF modeling for this portion of the screening analysis. With the use of CALPUFF modeling results, we identified the following additional facilities that can be exempted from further analysis:

Table 4: CALPUFF BART Exempt Sources

[48] http://ampd.epa.gov/ampd/

Facility	Units
Handley (Exelon)	3, 4 & 5
Jones (Xcel)	151B & 152B
Lake Hubbard (Luminant)	1 & 2
Knox Lee (AEP)	5
R W Miller (Brazos Elec. Coop)	1, 2 & 3

Based on these CALPUFF screening analyses using model plant approaches and direct modeling, the following gas[49]/fuel oil fired facilities did not screen out from being subject to BART: Newman, Stryker, Graham, and Wilkes. None of the coal fired facilities screened out in our CALPUFF modeling for the facilities within CALPUFF range.

4. Our use of CAMx Modeling to Exempt Sources from Being Subject to BART

Some of the BART-eligible sources in Texas are geographically distant from a Class I area, yet have high enough emissions that they may significantly impact visibility at Class I areas in Texas and surrounding states. However, the use of CALPUFF is not recommended for distances much greater than 300 km, and has typically not been used at distances more than approximately 400 km. To determine which sources are anticipated to contribute to visibility impairment the BART guidelines state that CALPUFF or another appropriate model can be used to predict the visibility impacts from a single source at a Class I area. CAMx provides a scientifically defensible 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, NO_X, VOC and PM emissions as it has a more robust chemistry mechanism. The CAMx PM Source Apportionment Technology (PSAT) modeling was

[49] When we use the term "gas," we mean "pipeline quality natural gas."

conducted for those BART-eligible sources that have large SO_2 emissions.[50] In 2006/2007, the TCEQ developed a modeling protocol and analysis using CAMx with the same Plume in Grid and PSAT techniques to evaluate visibility impacts from non-EGU BART sources, as well as to evaluate VOC and PM impacts from all BART-eligible sources to inform the 2009 Texas Regional Haze SIP.[51,52] This modeling protocol was reviewed by the TCEQ, EPA and FLM representatives specialized in air quality analyses and BART prior to performing the analysis and submission of their regional haze SIP. Our subject-to-BART screening modeling for EGU-sources using CAMx is consistent with the protocol developed and utilized by Texas in their regional haze SIP. We are using more recent model versions with updated science in our analysis.

Consistent with the BART guidelines and our CALPUFF modeling, for the selected BART-eligible sources we used the maximum actual 24-hr emission rates for NO_X and SO_2 from the 2000-2004 baseline period from EPA's Air Markets Program Data[53] and modeled these emission rates as constant emission rates for the entire modeled year. For some of the modeled BART-eligible sources, evaluation of baseline emissions revealed evidence of installation of NO_X control technology during the baseline period. For those sources the maximum emission rate was identified from the post-control portion of the baseline period. Because daily emissions are not available for PM, the annual average emission rate was doubled to approximate the 24-hr

[50] CAMx results were also obtained and add to our basis of information for coal-fired facilities that have CALPUFF results.
[51] 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.
[52] We approved Texas' subject-to-BART analysis for non-EGU sources which relied on this CAMx modeling in our January 5, 2016 rulemaking (81 FR 296)
[53] http://ampd.epa.gov/ampd/

maximum emission rate for PM. 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. The maximum modeled impact for each source (calculated based on annual average natural background conditions) was compared to the 0.5 dv contribution threshold. See the BART Screening TSD for additional details on the CAMx modeling performed and the model inputs used. The table below summarizes the results of the CAMx screening analysis. As shown in the table below, all sources analyzed with CAMx modeling had impacts greater than 0.5 dv at one or more Class I areas. The most impacted Class I areas based on these results are Wichita Mountains National Wildlife Refuge in Oklahoma (WIMO), Caney Creek Wilderness Area in Arkansas (CACR), and Salt Creek Wilderness Area in New Mexico (SACR). CAMx modeled impacts at single locations for these sources (maximum impact day) ranged from 0.845 dv to 10.498 dv.

Table 5: CAMx BART Screening Source Analysis Results

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[2]**	**Number of modeled days over 1.0 dv[2]**
Big Brown	1 & 2	WIMO	4.017	No	65	33
Coleto Creek	1	WIMO	0.845	No	9	0
Fayette Power	1&2	CACR	1.894	No	26	9
Harrington	061B & 062B	SACR	5.288	No	13	5
Martin Lake	1,2,&3	CACR	6.651	No	141	99
Monticello	1,2,&3	CACR	10.498	No	152	111
Calaveras	J T Deely 1&2,	WIMO				

	OW Sommers 1&2		1.513			
W A Parish	WAP4, WAP5&WAP6	CACR	3.177	No	54	22
Welsh[1]	1&2	CACR	4.576	No	92	39

[1] Welsh unit 2 has recently shutdown. We note that baseline impacts from unit 1 alone are 2.343 dv at Caney Creek.

[2] Number of days over 0.5 or 1.0 dv at the most impacted Class I area

5. Summary of Sources that are Subject to BART

Based on the four methodologies described above, the BART-eligible sources in the table below have been determined to cause or contribute to visibility impairment at a nearby Class I area, and we therefore propose to find the sources are subject-to-BART. They are subject to review for visibility impairing pollutants other than NO_X.[54] Foremost, they are subject to SO_2 BART, the visibility impairing pollutant that is the main contributor to the regional haze problem at Class I areas in Texas and neighboring states. The sources are also subject to review for source-specific BART requirements for PM.

Table 6: Summary: Sources that are Subject-to-BART

Facility	Units
Big Brown	1 & 2
Coleto Creek	1
Fayette Power	1 & 2
Harrington	061B & 062B
Martin Lake	1, 2 & 3
Monticello	1, 2 & 3
Calaveras	J T Deely 1 & 2, O W Sommers 1 & 2
W A Parish	WAP4, WAP5 & WAP6
Welsh	1 & 2*
Stryker	ST2
Graham	2
Wilkes	1, 2 & 3

[54] The NO_X BART requirement for these EGU sources is not addressed by source-specific limits in this proposal. According to our proposal, participation in CSAPR, in its updated form, would serve as a BART alternative, dispensing with the need for source-specific BART determinations and requirements for NO_X.

Newman	2, 3 & 4

* Welsh Unit 2 retired in April, 2016.

C. Our BART Five Factor Analyses

The purpose of the BART analysis is to identify and evaluate the best system of continuous emission reduction based on the BART Guidelines.[55] In determining BART, a state, or EPA when promulgating a FIP, must consider the five statutory factors in section 169A of the CAA: (1) The costs of compliance; (2) the energy and nonair quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. See also 40 CFR 51.308(e)(1)(ii)(A). This is commonly referred to as the "BART five factor analysis." The BART Guidelines break the analyses of these requirements down into five steps:[56]

STEP 1—Identify All Available Retrofit Control Technologies,

STEP 2—Eliminate Technically Infeasible Options,

STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies,

STEP 4—Evaluate Impacts and Document the Results, and

STEP 5—Evaluate Visibility Impacts.

The following sections treat these steps individually for SO_2. We are combining these

[55] See July 6, 2005 BART Guidelines, 40 CFR Part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations.
[56] 70 FR 39104, 39164 (July 6, 2005) [40 CFR Part 51, App. Y].

steps into one section in our assessment of PM BART that follows the SO_2 sections.

1. Steps 1 and 2: Technically Feasible SO_2 Retrofit Controls

The BART Guidelines state that in identifying all available retrofit control options,

> [Y]ou must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving.[57]

Adhering to this, we will identify a reasonable set of SO_2 control options, including those that cover the maximum level of control each technology is capable of achieving. In the course of that task, we will note whether any of these technologies are technically infeasible.

The subject-to-BART units identified in Table 6 can be organized into four broad categories, based on their fuel type and the potential types of SO_2 controls that could be retrofitted: (1) coal-fired EGUs with no SO_2 scrubber, (2) coal-fired EGUs with underperforming SO_2 scrubbers, (3) gas-fired EGUs that do not burn oil, and (4) gas-fired EGUs that occasionally burn fuel oil. This classification is represented below:

Table 7: Subject to BART Fuel Types and Potential SO_2 BART Controls

[57] 70 FR at 39164, fn 12 [40 C.F.R. Part 51, App. Y]

Facility	Unit	Coal no scrubber	Coal underperforming scrubber	Gas no oil	Gas burns oil
Big Brown (Luminant)	1	X			
Big Brown (Luminant)	2	X			
Coleto Creek (Engie)	1	X			
Fayette (LCRA)*	1				
Fayette (LCRA)*	2				
Graham (Luminant)	2				X
Harrington Station (Xcel)	061B	X			
Harrington Station (Xcel)	062B	X			
J T Deely (CPS Energy)	1	X			
J T Deely (CPS Energy)	2	X			
Martin Lake (Luminant)	1		X		
Martin Lake (Luminant)	2		X		
Martin Lake (Luminant)	3		X		
Monticello (Luminant)	1	X			
Monticello (Luminant)	2	X			
Monticello (Luminant)	3		X		
Newman (El Paso Electric)	2				X
Newman (El Paso Electric)	3				X
Newman (El Paso Electric)	4			X	
O W Sommers (CPS Energy)	1				X
O W Sommers (CPS Energy)	2				X
Stryker Creek (Luminant)	ST2				X
W A Parish (NRG)	WAP4			X	
W A Parish (NRG)	WAP5	X			
W A Parish (NRG)	WAP6	X			
Welsh Power Plant (AEP)	1	X			
Wilkes Power Plant (AEP)	1				X
Wilkes Power Plant (AEP)	2			X	
Wilkes Power Plant (AEP)	3			X	

* The Fayette units have high performing wet Flue Gas Desulfurization scrubbers in place.

For the coal-fired EGUs without an existing scrubber, we have identified four potential control technologies: (1) coal pretreatment, (2) Dry Sorbent Injection (DSI), (3) Spray Dryer Absorber (SDA), and (4) wet Flue Gas Desulfurization (FGD.) For the coal-fired EGUs with an existing underperforming scrubber we will examine whether that scrubber can be upgraded.

Gas-fired EGUs that do not burn oil have inherently very low SO_2 emissions and there are no known SO_2 controls that can be evaluated.

For gas-fired units that occasionally burn fuel oil, we will follow the BART Guidelines recommendations for oil-fired units: "For oil-fired units, regardless of size, you should evaluate limiting the sulfur content of the fuel oil burned to 1 percent or less by weight."[58] In addition, we will also evaluate the potential for post combustion SO_2 controls for these units.

a. Identification of Technically Feasible SO_2 Retrofit Control Technologies for Coal-Fired Units

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.

Coal Pretreatment

Coal pretreatment, or coal 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. Coal pretreatment broadly falls into two categories: coal washing and coal drying.

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).[59] 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

[58] 70 FR 39171 (July 6, 2005) [40 CFR 51, App. Y].
[59] Couch, G. R., "Coal Upgrading to Reduce CO_2 emissions," CCC/67, October 2002, IEA Clean Coal Centre.

matter by this means, except in a few cases.[60] Coal is mechanically sized, then various washing techniques are employed, depending on the particle size, type of coal, and the desired level of preparation.[61] Following the coal washing, the coal is dewatered, and the waste streams are disposed.

Coal washing takes place offsite at large dedicated coal washing facilities, typically located near where the coal is mined. In addition, coal washing carries with it 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,[62] and coal washing slurries are typically stored in impoundments, which can, and have, leaked.[63]

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[60] Ibid.

[61] 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.

[62] "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.

[63] 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.

Because of these issues, we do not consider coal washing as a part of our reasonable set of options for analysis as BART SO_2 control technology.

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 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 unit burning less coal to make the same amount of power.

Coal drying can be performed onsite and so can be considered a potential BART control. Great River Energy has developed a patented process which is being successfully utilized at the Coal Creek facility and is potentially available for installation at other facilities.[64] 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.

Although we view this new patented technology for coal drying onsite as a promising path in the near future 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). We cannot

[64] 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/

assess many of these site-specific issues and we believe that requesting that the facilities in question do so would require detailed engineering analysis and extend our review time greatly. As a result of these issues, we do not further assess coal drying as part of our reasonable set of options for BART analysis. We expect that this technology may have matured enough such that it can be better assessed for the second planning period.

DSI

DSI is performed by injecting a dry reagent into the hot flue gas, which chemically reacts with SO_2 and other gases to form a solid product that is subsequently captured by the particulate control device. A blower delivers 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 are 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. For instance, Luminant states in its response to one of our Section 114(a) letters regarding its Big Brown and Monticello units:[65]

> Luminant commissioned the study of dry sorbent injection ("DSI") at these units in 2011. These studies determined that a very high feed rate (in the range of 20-

[65] Luminant's 6/17/14 response to EPA's 5/20/14 Section 114(a) request for information relating to the Big Brown, Martin Lake, Monticello, and Sandow generating stations.

> 30%) was required to achieve modest SO_2 removal. Further, it was determined that other economic and operational factors make the use of DSI infeasible. For example, sorbent build-up was determined to cause degraded performance of the control equipment over time, as well as significant, repeat down time on a regular basis (i.e., every few days) to remove the buildup. In addition to the high cost of the sorbent required, the disposal and transport of the used sorbent (a Texas Class 1 waste) would result in significant additional cost. Thus, the use of DSI was determined infeasible from both an operational and economic point of view, and further evaluation has been discontinued.

As a consequence of this statement, which is discussed more fully in the CBI material Luminant has submitted and in our TSD, we have concluded that DSI is not a feasible alternative for the Big Brown and Monticello facilities. For all unscrubbed, coal-fired BART-subject units other than the Big Brown and Monticello facilities, although individual installations may present technical difficulties or poor performance due to the suboptimization of one or more of the above factors, we believe that DSI is technically feasible and should be considered as a potential BART control.

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

FGD, and Spray Dry Absorber (SDA). More recently, Circulating Dry Scrubbers (CDS) have been introduced. The EIA reports the following types of flue gas desulfurization systems as being operational in the U.S. for 2015:

Table 8: EIA Reported Desulfurization Systems in 2015

Type	Number of installations
Wet spray tower scrubber	296
Spray dryer absorber	269
Circulating dry scrubber	50
Packed tower wet scrubber	6
Venturi wet scrubber	48
Jet bubbling reactor	31
Tray tower wet scrubber	42
Mechanically aided wet scrubber	4
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.[66] 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%

[66] Trays are often employed in spray type wet scrubbers and EIA lists some of the wet spray tower systems as secondarily including trays.

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.

We consider some of the other scrubber system types (e.g., venturi and packed wet scrubber types) to be older, outdated technologies (that are not existing controls or factor into considerations regarding existing controls) and therefore 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 or their suitability as a retrofit control option. Therefore, they too will not be further considered as part of our reasonable set of options for analysis for BART controls.

In summary, wet FGD and SDA installations account for approximately 81% of all scrubber installations in the U.S. and as such constitute a reasonable set of SO_2 scrubber control options. The vast majority of the wet FGD and SDA installations utilize limestone and lime, respectively as reagents. In addition, these technologies cover the maximum level of SO_2 control available. As described above, these controls are in wide use and have been retrofitted to a variety of boiler types and plant configurations. We therefore see no technical infeasibility issues and believe that limestone wet FGD and lime SDA should be considered as potential BART controls for all of the unscrubbed coal-fired BART-eligible units.

b. Identification of Technically Feasible SO_2 Retrofit Control Technologies for Gas-Fired Units that Burn Oil

Reduction in Fuel Oil Sulfur

A number of the units we proposed in Table 6 as being subject to BART primarily fire gas, but have occasionally fired fuel oil in the past as reported by the EIA databases: EIA-767,

EIA-906/920, and EIA-923,[67] which indicate the historic quantities of fuel oil burned and the type and sulfur content of that fuel oil. These units are identified below in Table 9:

Table 9: Gas Units that Occasionally Burn Oil and are Subject to BART

Facility	Unit(s)	Gas Turbine	Steam Turbine
Graham (Luminant)	2		X
Newman (El Paso Electric)	2, 3		X
O W Sommers (CPS Energy)	1, 2		X
Stryker Creek (Luminant)	ST2		X
Wilkes Power Plant (AEP)	1		X

The BART Guidelines advise that for oil-fired units, regardless of size, limits on fuel oil sulfur content should be considered in the BART evaluation.[68] All of the subject units are limited by permit to burning oil with a sulfur content of no more than 0.7% sulfur by weight.[69] In analyzing the technical feasibility under BART of these facilities burning fuel oils of sulfur contents lower than historically burned, we investigated two issues: (1) Is lower sulfur fuel oil available and what is its cost, and (2) are there any technical issues in burning a lower sulfur fuel oil that could add to the cost of that oil? All of the units have either burned Distillate Fuel Oil (DFO) or have switched between DFO and Residual Fuel Oil (RFO), thus demonstrating the ability to burn DFOs of the type under consideration for SO_2 BART. We therefore conclude that lower sulfur DFOs are a technically feasible retrofit control option under BART. Lower sulfur DFOs carry no capital costs. Any cost increases relate to purchase price differences.

[67] EIA-767: http://www.eia.gov/electricity/data/eia767/. EIA-906/920 and EIA-923: http://www.eia.gov/electricity/data/eia923/
[68] 70 FR at 39171.
[69] In addition, the Newman units 2 and 3 are restricted to burning fuel oil for no more than 10% of their annual operating time.

SO_2 Scrubber Feasibility for Gas/Oil-Fired Boilers

We are aware of instances in which FGDs of various types have been installed or otherwise deemed feasible on a boiler that burns oil.[70] Consequently, we will consider the installation of various types of scrubbers to be technically feasible.

c. Identification of Technically Feasible SO_2 Control Technologies for Scrubber Upgrades

In our recent Texas-Oklahoma FIP,[71] we presented a great deal of information that concluded that the existing scrubbers for a number of facilities could be very cost-effectively upgraded.[72] That information is included in this proposal.[73] It contains a comprehensive survey of available literature concerning the kinds of upgrades that have been performed by industry on scrubber systems similar to the ones installed on the units included in this proposal. We then reviewed all of the information we had at our disposal regarding the status of the existing scrubbers for each unit, including any upgrades the facility may have already installed. We finished by calculating the cost-effectiveness of scrubber upgrades, using the facility's own information, obtained as a result of our Section 114 collection efforts. The companies that supplied this information have asserted a Confidential Business Information (CBI) claim for much of it, as provided in 40 C.F.R. § 2.203(b). We therefore redacted any CBI information we utilize in our analyses, or otherwise disguised it so that it cannot be traced back to its specific

[70] 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."
[71] 81 FR 321.
[72] See information presented in Sections 6 and 7 of the Cost TSD.
[73] That information is included in our BART FIP TSD, Appendix B.

source. Of the facilities we evaluated for scrubber upgrades in that action, Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are subject to BART and are thus a part of this proposal.

2. Step 3: Evaluation of SO_2 Control Effectiveness

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."[74] To calculate a 30-day rolling average based on BOD, 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. In effect, this provides a margin of safety by eliminating spikes that occur at the beginning and end of outages.

a. Evaluation of SO_2 Control Effectiveness for Coal Fired Units

Control Effectiveness of DSI

We lack the site-specific information, which we believe requires an individual performance test, in order to be able to accurately determine the maximum DSI SO_2 removal efficiency for the individual units listed in Table 7. We are aware that a number of the subject-to-BART coal-fired units have conducted such testing. However, although we have examined that

[74] 70 FR 39103, 39172 (July 6, 2005), [40 CFR Part 51, App. Y].

testing, most of the facilities have claimed it as CBI and requested protection from public disclosure as provided by 40 C.F.R. Part 2.

However, we nevertheless must evaluate DSI as a viable, proven method of SO_2 control. We must do the same for SO_2 scrubbing, and in so doing, compare the visibility benefits and costs of each technology in order to inform our proposed BART determinations. We therefore propose the following methodology:

- We will evaluate each unit at its maximum recommended DSI performance level, according to the IPM DSI documentation,[75] assuming milled trona: 80% SO_2 removal for an ESP installation and 90% SO_2 removal for a baghouse installation. This level of control is within the range that can be achieved by SO_2 scrubbers, and thus allows a better comparison of the costs of DSI and scrubbers.

- However, (1) we do not know whether a given 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 all the units at a DSI SO_2 control level of 50%, which we believe is likely achievable for most units.

- We invite comments on whether particular units have performed DSI testing and have concluded they cannot achieve a SO_2 reduction between 50% and 80/90%. Any data to support such a conclusion should be submitted along with those comments.

[75] 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.

Control Effectiveness of Wet FGD and SDA

We 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. As we discuss later in this proposal, we will conduct our wet FGD control cost analysis using the wet FGD cost algorithms, as employed in version 5.13 of our IPM model.[76] 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 established in our Oklahoma FIP,[77] this level of control is achievable with wet FGD. This level of control was also employed in our recent Texas-Oklahoma FIP.[78] We received a comment challenging this level of control and we responded to that comment in our final action on our Texas-Oklahoma FIP and incorporate that response in this proposed action.[79] We continue to conclude that our proposed level of control for wet FGD is reasonable.

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[76] 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.
[77] As discussed previously in our TSD for that action, control efficiencies reasonably achievable by dry scrubbing and wet scrubbing were determined to be 95% and 98% respectively. 76 FR 81742); Oklahoma v. EPA, 723 F.3d 1201 (July 19, 2013), cert. denied (U.S. May 27, 2014).
[78] 81 FR 321.
[79] That information is included in our BART FIP TSD, Appendix A.

As with our Oklahoma FIP, 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 lb/MMBtu, in which case, we assume the percentage of control equal to 0.06 lbs/MMBtu. See our response to comments in our previous Oklahoma FIP.[80] In that FIP, we finalized the same emission limit of 0.06 lbs/MMBtu on a 30 BOD average for 6 coal-fired EGUs. We justified those limits based on the same SDA technology, using a combination of industry publications and real world monitoring data. Much of that information is summarized in our response to a comment to that action[81] and in our TSD. We continue to conclude that our proposed level of control for SDA is reasonable.

b. Evaluation of SO_2 Control Effectiveness for Gas Fired Units

The control effectiveness of switching from a higher sulfur fuel oil to a lower sulfur fuel oil lies in the reduction in sulfur emissions. The emissions reduction depends on the percentage reduction from the sulfur contents of the fuel oil that forms the SO_2 baseline to the replacement fuel oil. Ultimately, the highest level of control would result from a switch from the highest percentage sulfur the units are permitted to burn, 0.7% to the lowest DFO available, ultra-low sulfur diesel, which has a sulfur content of 0.0015%. This would equate to a control effectiveness of 99.8%. Lesser levels of controls are also possible. We will evaluate a range of control effectiveness in switching to lower sulfur fuel oils in the next section.

Because we are unaware of any scrubber installations on oil fired units in the U.S., we have no information on their control effectiveness. However, we see no technical reason why

[80] 76 FR 81728.
[81] 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 comment and response beginning on page 91.

the control effectiveness of FGDs installed on gas-fired units that occasionally burn fuel oil should not be equal to that of FGDs installed on coal-fired units.

3. Step 4: Evaluate Impacts and Document the Results for SO_2

The BART Guidelines offers the following with regard to how Step 4 should be conducted:[82]

> 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.

We evaluate the cost of compliance on a unit-by unit basis, because control cost analysis depends on specific factors that can vary from unit to unit. However, we generally evaluate the energy impacts, non-air quality impacts, and the remaining useful life for all the units in question together because in this instance there are no appreciable differences in these factors from unit to unit.[83]

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[82] 70 FR 39166.

[83] To the extent these factors inform the cost of controls, consistent with the BART Guidelines, they do inform our considerations on a unit-by-unit basis.

In developing our cost estimates for the units in Table 7, we rely on the methods and principles contained within the EPA Air Pollution Control Cost Manual (the Control Cost Manual, or Manual).[84] 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 each of the units listed in Table 7. For the coal units without any SO_2 control, we calculate the cost of installing DSI, a SDA scrubber, and a wet FGD scrubber. For the gas units that burn oil, we evaluate the cost of switching to lower sulfur fuel oils and installing scrubbers.

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 then performed DSI, SDA and wet FGD cost calculations for each unit listed in Table 7 that did not already have SO_2 control.[85] These cost models were based on costs escalated to 2012 dollars.[86] 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).

a. Impact Analysis Part 1: Cost of Compliance for DSI, SDA, and Wet FGD

As we discuss above and in our Cost TSD, we evaluated each unit at its maximum recommended level of control, considering the type of SO_2 control device. Below, we present a

[84] 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.
[85] These spreadsheets are entitled, "DSI Cost IPM 5-13 TX BART.xlsx," "SDA Cost IPM 5-13 TX BART.xlsx," and "Wet FGD Cost IPM 5-13 TX BART.xlsx," and are located in our Docket.
[86] Ibid., p.1: "The data was converted to 2012 dollars based on the Chemical Engineering Plant Index (CEPI) data."

summary of our DSI, SDA, and wet FGD cost analysis[87]:

Table 10. Summary of DSI, SDA, and Wet FGD Cost Analysis

Facility	Unit	Control	Control level (%)	SO_2 reduction (tpy)	2016 Annualized Cost	2016 Cost Effectiveness ($/ton)	2016 Incremental Cost-Effectiveness ($/ton)
Big Brown	1	DSI	50	14,448	$29,468,587	$2,040	
		DSI	90	26,006	$72,131,749	$2,774	$3,691
		SDA	95	27,453	$35,297,532	$1,286	-$25,456
		Wet FGD	98	28,320	$33,673,102	$1,189	-$1,874
	2	DSI	50	15,320	$29,342,350	$1,915	
		DSI	90	27,576	$71,322,593	$2,586	$3,425
		SDA	95	29,108	$35,359,239	$1,215	-$23,475
		Wet FGD	97.9	29,998	$33,817,952	$1,127	-$1,732
Monticello	1	DSI	50	4,787	$11,408,872	$2,383	
		DSI	90	8,617	$25,409,128	$2,949	$3,655
		SDA	95	9,095	$24,294,319	$2,671	-$2,332
		Wet FGD	97	9,286	$25,236,699	$2,718	$4,934
	2	DSI	50	4,129	$9,742,648	$2,360	
		DSI	90	7,431	$21,418,734	$2,882	$3,536
		SDA	95	7,844	$23,126,113	$2,948	$4,134
		Wet FGD	96.8	7,995	$24,233,133	$3,031	$7,331

[87] In this table, the capital cost is the total cost of constructing the facility. The annualized cost is the sum of the annualized capital cost and the annualized operational cost. See our Cost TSD for more information on how these costs were calculated.

Coleto Creek	1	DSI	50	7,376	$16,246,169	$2,203	
		DSI	90	13,277	$34,841,379	$2,624	$3,151
		SDA	92.4	13,632	$29,445,018	$2,160	-$15,201
		Wet FGD	94.9	14,005	$29,786,106	$2,127	$914
Harrington	061B	DSI	50	2,477	$9,187,608	$3,710	
		DSI	80	3,962	$16,073,779	$4,057	$4,637
		SDA	90.2	4,466	$17,455,679	$3,909	$2,742
	062B	DSI	50	2,455	$6,524,937	$2,658	
		DSI	88.9*	4,364	$11,981,111	$2,746	$2,858
		SDA	88.9	4,364	$18,240,127	$4,180	N/A
J T Deely	1	DSI	50	3,072	$8,854,319	$2,883	
		DSI	90	5,529	$18,071,878	$3,269	$3,752
		SDA	91.3	5,609	$21,689,526	$3,867	$45,221
		Wet FGD	94.2	5,787	$22,555,395	$3,898	$4,864
	2	DSI	50	3,222	$9,865,798	$3,062	
		DSI	90	5,800	$20,229,233	$3,488	$4,020
		SDA	91.3	5,884	$21,812,518	$3,707	$18,849
		Wet FGD	94.2	6,070	$22,530,901	$3,712	$3,862
Welsh	1	DSI	50	3,343	$8,963,761	$3,469	
		DSI	87.2*	5,832	$23,090,408	$3,960	$5,676
		SDA	87.2	5,832	$22,697,048	$3,892	N/A
		Wet FGD	91.5	6,116	$23,998,161	$3,924	$4,581
W. A. Parish	5	DSI	50	6,712	$15,002,337	$2,235	
		DSI	90	12,081	$30,865,711	$2,555	$2,955
		SDA	92.1	12,364	$31,195,787	$2,523	$1,166
		Wet FGD	94.7	12,717	$30,735,030	$2,417	-$1,305

	6	DSI	50	7,525	$16,014,988	$2,128	
		DSI	90	13,545	$33,302,528	$2,459	$2,872
		SDA	92.1	13,862	$32,758,784	$2,363	-$1,715
		Wet FGD	94.7	14,258	$32,215,226	$2,259	-$1,373

* DSI control level limited to that of SDA.

b. Impact Analysis Part 1: Cost of Compliance for Scrubber Upgrades

In our BART FIP TSD, we analyze those units listed in Table 7 with an existing SO_2 scrubber in order to determine if cost-effective scrubber upgrades are available. Of our subject-to-BART units, Martin Lake Units 1, 2, 3; Monticello Unit 3, and Fayette Units 1 and 2 are currently equipped with wet FGDs. Of these, all but the Fayette units were analyzed for scrubber upgrades in our Texas-Oklahoma FIP. For all but the Fayette units, we propose to adopt the total annualized cost calculations used to make the cost-effectiveness calculations in our Texas-Oklahoma FIP in this action. We acknowledge that these costs could change slightly, due to changes in the costs of various materials and services. However, these costs were calculated in 2013 dollars. Escalating them to 2015 dollars would result in a reduction in cost, which we conservatively do not take into consideration.[88]

In our Texas-Oklahoma FIP action, after responding to comments we revised our proposed cost-effectiveness basis from where all scrubber upgrades were less than $600/ton, to where all scrubber upgrades ranged from between $368/ton to $910/ton.[89] As with our Texas-Oklahoma FIP, we are limited in what information we can include in this section, because we

[88] The CEPCI for 2013 is 567.3 and that for 2015 is 556.3. Therefore, the costs would be multiplied by a factor of 556.8/567.3, which is approximately 0.98.
[89] 81 FR 318.

used information that was claimed as CBI. This information was submitted in response to our Section 114(a) requests. The following summary is based on information not claimed as CBI.

- The absorber system had either already been upgraded to perform at an SO_2 removal efficiency of at least 95%, or it could be upgraded to perform at that level using proven equipment and techniques.
- The SO_2 scrubber bypass could be eliminated, and the additional flue gas could be treated by the absorber system with at least a 95% removal efficiency.
- Additional modifications necessary to eliminate the bypass, such as adding fan capacity, upgrading the electrical distribution system, and conversion to a wet stack could be performed using proven equipment and techniques.
- The additional SO_2 emission reductions resulting from the scrubber upgrade are substantial, ranging from 68% to 89% reduction from the current emission levels, and are cost-effective.

We now update these calculations for 2011-2015 data.[90] The revised scrubber upgrade results for Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are presented below in Table 11:

Table 11. Summary of Updated Scrubber Upgrade Results

[90] See Coal vs CEM data 2011-2015.xlsx.

Unit	2011-2015 3-yr Avg. SO_2 Emissions (eliminate max and min) (tons)	SO_2 Emissions at 95% Control (tons)	SO_2 Emissions Reduction Due to Scrubber Upgrade (tons)	SO_2 Emission Rate at 95% Control (lbs/MMBtu)
Monticello 3	8,136	1,180	6,956	0.05
Martin Lake 1	19,040	3,208	15,832	0.12
Martin Lake 2	17,973	3,393	14,580	0.12
Martin Lake 3	16,113	2,591	13,522	0.11
Total SO_2 Removed			50,890	

As we note above, we updated the cost-effectiveness for each of these units. Because those calculations depended on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost-effectiveness was $1,156/ton or less. We invite the facilities listed above to make arrangements with us to view our complete updated cost analysis for their units.

The Fayette Units 1 and 2 are currently equipped with high performing wet FGDs. Both units have demonstrated the ability to maintain a SO_2 30 BOD average below 0.04 lbs/MMBtu for years at a time.[91] As we discuss above, we evaluate BART demonstrating that retrofit wet FGDs should be evaluated at 98% control not to go below 0.04 lbs/MMBtu. Because the Fayette units are performing below this level, we propose that no scrubber upgrades are necessary. We propose to find that the Fayette Units 1 and 2 maintain a 30 Boiler Operating Day rolling average SO_2 emission rate of 0.04 lbs/MMBtu based on the actual emissions data we present above. We believe that based on its demonstrated ability to maintain an emission rate below this value on a 30 BOD basis, it can consistently achieve this emission level.

c. Impact Analysis Part 1: Cost of Compliance for Gas Units that Burn Oil

[91] See our BART FIP TSD for graphs of this data.

As we noted in Section III.C.1.b, a number of the units we proposed in Table 9 as being subject to BART primarily fire gas, but have occasionally fired fuel oil in the past as reported by the EIA. These units are limited by their permits to burning oil with a sulfur content of no more than 0.7% sulfur by weight. We proposed to consider both a reduction in fuel oil sulfur and SO_2 scrubbers as potential BART controls. Below we consider the cost of these potential controls.

Reduction in Fuel Oil Sulfur

In order to determine the cost of these facilities switching to lower sulfur content fuel oils, we sent the Graham, Newman, Stryker Creek, and the Wilkes facilities Section 114 letters requesting certain information.[92] We received very limited information in response to one of our questions concerning the present cost of the historic fuel oil burned, and the cost of various lower sulfur replacement fuel oils. Because of this, we were unable to compile facility-specific information on the cost of switching to lower sulfur fuel oils. Consequently, we considered the best available information by consulting more general information from the EIA, which reports the prices for various refinery petroleum products on a monthly and annual basis. Below is a summary of various distillate and residual fuel oil products for 2001 to 2015, averaged across the U.S.[93]

Table 12: Selected EIA Reported Annual Refiner Petroleum Prices

[92] Copies of these letters and the facilities' responses are in our docket. We inadvertently did not send the O W Sommers a letter.
[93] EIA Refiner Petroleum Product Prices by Sales Type, available here: http://www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_a.htm; http://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm

Date	West Texas Intermediate Crude Oil – Cushing Oklahoma ($/bbl)	U.S. No 2 Diesel Wholesale/Resale Price by Refiners ($/Gallon)	U.S. No. 2 Fuel Oil Wholesale/Resale Price by Refiners ($/Gallon)	U.S. No 4 Distillate Wholesale/Resale Price by Refiners ($/Gallon)
2015	48.66	1.667	1.565	1.215
2014	93.17	2.812	2.741	2.333
2013	97.98	3.028	2.966	2.767
2012	94.05	3.109	3.031	
2011	94.88	3.034	2.907	2.801
2010	79.48	2.214	2.147	
2009	61.95	1.713	1.657	1.561
2008	99.67	2.994	2.745	2.157
2007	72.34	2.203	2.072	1.551
2006	66.05	2.012	1.834	1.395
2005	56.64	1.737	1.623	1.377
2004	41.51	1.187	1.125	1.033
2003	31.08	0.883	0.881	0.793
2002	26.18	0.724	0.694	0.663
2001	25.98	0.784	0.756	0.697
2000	30.38	0.898	0.886	0.778

Lacking facility-specific pricing information, for the purposes of calculating the cost of compliance, we make the following assumptions:

- No. 4 distillate is the type of fuel oil currently available that most closely approximates the types of fuel oil that were historically burned by the facilities. It is available in a range of sulfur up to the facilities' permitted maximum of 0.7% sulfur by weight or 7,000 ppm. We will use the cost of this fuel oil in constructing "business as usual" scenarios of the annual cost of fuel oil.
- No. 2 fuel oil is available at approximately 3,000 ppm, which roughly corresponds to the sulfur level present in No. 2 fuel oil prior to our implementation of the Ultra-Low-Sulfur Diesel (ULSD) regulations.[94] We will use the cost of this fuel oil in constructing a

[94] 69 FR 39073: "Both high sulfur No. 2–D and No. 2 fuel oil must contain no more than 5000 ppm sulfur,131 and

"medium control" annual cost of fuel oil.

- No. 2 diesel fuel corresponds to ULSD, with a sulfur content of 15 ppm. We will use the cost of this fuel oil in constructing a "high control" annual cost of fuel oil.

Having identified a reasonable set of historical and lower sulfur fuel oils, we turned to the matter of establishing SO_2 baselines. We would expect that regardless of the baseline selected, a cost-effectiveness calculation that simply depended on differing fuel oil costs and the resulting reductions in SO_2, would result in the same value. In other words, the cost-effectiveness in $/ton is independent of the SO_2 baseline, since *in this case,* it is calculated on a unit basis—the increased cost in burning a unit of fuel divided by the increased reduction in the resulting SO_2. While the above is true, reported data for these units does not match this expectation. This can be illustrated by examining selected EIA and emissions data for the Graham Unit 2:

Table 13: Graham Unit 2 Example Discordance in Fuel Oil Burned and Reported SO_2

Date (month/year)	**Quantity Fuel Oil Burned (bbls)**	**Reported SO_2 for month (tons)**	**Reported EIA sulfur content (wt %)**
Mar-02	9,800	21.614	0.65
Feb-03	8,400	90.389	0.66
Jun-12	18,177	0.064	0.50
Jul-12	5,657	0.07	0.50

As can be seen from the above table, even though the reported sulfur content of the fuel

currently [as of the date of our final rule, 6/29/04] averages 3000 ppm nationwide."

oil in March 2002 and February 2003 was approximately the same, and the quantity burned was fairly close, the reported SO_2 emissions were significantly different. Similarly, although the amount of fuel oil burned in June 2012 was more than three times that burned in July 2012 (at the same sulfur content), the reported SO_2 emissions in June 2012 were less than that in July 2012. Also, although the fuel oil sulfur content in the 2012 examples was only slightly less than that in the 2002/2003 examples, and the amount of fuel oil burned was the same order of magnitude, the resulting reported SO_2 emissions in 2012 were three orders of magnitude less than that in 2002/2003. We conclude that either the values for the EIA fuel quantities, the EIA fuel oil sulfur contents, and/or the reported SO_2 emissions are in error. Further examination of the CAMD emissions data for Graham and Stryker revealed that the data contained a large amount of substitute data for SO_2 emissions and heat input during periods when the units burned fuel oil.

As a consequence of this discordance between the type and amount of fuel oil burned and the reported SO_2 emissions, we cannot rely on historical SO_2 emissions to construct a baseline, because a barrel of fuel oil with a given sulfur content does not result in a consistent reported SO_2 value over time. Instead, we will conduct our cost-effectiveness analysis on the basis of unit values of 1,000 barrels, using the following assumptions:

- Fuel oil costs will be based on the 2015 U.S. average prices as reported in Table 12 for No. 4 distillate at 0.7 wt. % (the permitted maximum for all units) as the current business as usual fuel, No. 2 fuel oil at 0.3wt. % as the moderate control option, and No. 2 diesel at 0.0015% as the high control option.
- The emission factor for calculating the tons of sulfur emitted by the three fuel oils are

taken from AP 42, *Compilation of Air Pollutant Emissions Factors*.[95]

Below is the result of that calculation:

Table 14: Cost Effectiveness of Switching to Lower Sulfur Fuel Oils

Level of Control	Cost for 1,000 barrels baseline ($/yr)	Tons reduced for 1,000 barrels	Cost effectiveness for 1,000 barrels ($/ton)	Incremental Cost-Effectiveness ($/ton)
Business as usual (No. 4 distillate $1.215/gal)	$51,030	N/A	N/A	
Moderate control (No. 2 fuel oil $1.565/gal)	$65,730	1.26	$11,218	
High control (ULSD $1.667/gal)	$70,014	2.20	$8,627	-$2,756

We suspect our price information for ULSD may be high, as the Wilkes facility indicated in its reply to our Section 114 request that its 8/12/16 contract for oil was for ULSD, which had an index price of $1.423/gallon. Assuming this price and retaining the same price for our business as usual No. 4 distillate fuel oil of $1.215/gallon, results in a cost-effectiveness of $3,970/ton—a significant improvement in cost-effectiveness. We invite the affected facilities to provide site-specific information for delivery of ULSD.

Scrubber Retrofits

Elsewhere in our proposal, we conclude that certain types of wet scrubbers were

[95] The emission factor (lb/10^3 gal) used is 150 X S, where S = weight % sulfur, taken from AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.3, Fuel Oil Combustion, available here: https://www3.epa.gov/ttn/chief/ap42/ch01/index.html. Boilers > 100 Million Btu/hr, No. 4 oil fired.

technically feasible as potential control options for gas boilers that occasionally burn oil, similar to the ones under BART review here. Were we to calculate the cost-effectiveness of a wet FGD, similar to those under consideration for the coal units undergoing BART review, we could expect that the capital and operating costs would be on the same order, as displayed in Table 10. It is a straightforward exercise to demonstrate that the installation of such a scrubber on any of the gas-fired units that occasionally burn oil would result in a very high cost-effectiveness value.

For instance, taking the smallest total annualized wet FGD cost in Table 10, corresponding to the Harrington Unit 0161B (approximately the same size as the Graham Unit 2), results in a value of $19,145,500. Assuming a 98% reduction from a baseline equal to the largest annual SO_2 emissions from any of the gas units, 1,287 tons/year (Graham Unit 2, 2001), results in a SO_2 reduction of 1,261 tons/year. The cost-effectiveness is then $15,183/ton, which is very high for a SO_2 scrubber. In addition, the annual SO_2 values for Graham Unit 2 from 2002 to 2015, and the annual SO_2 values for the remaining units, have always been an order of magnitude less than the 2001 Graham Unit 2 value. Although we have not modeled the visibility benefit of installing SO_2 scrubbers on these units, the visibility benefit from scrubbers is estimated to be slightly less than the amount of benefit estimated from switching to ULSD.[96]

4. Impact Analysis Parts 2, 3, and 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

[96] For example, switching from 0.7% sulfur fuel oil to ULSD at 0.0015% sulfur results in a reduction in sulfur emissions of 99.8% compared to an estimated 98% reduction due to the use of a scrubber.

technology results in energy penalties or benefits."[97] 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 all cases. 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[98]:

> 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 the incremental emissions reductions potential of the more stringent control is only marginally greater than the next most-effective option. However, the fact

[97] 70 FR 39103, 39168 (July 6, 2005), [40 CFR Part 51, App. Y.].
[98] 70 FR at 39169 (July 6, 2005), [40 CFR Part 51, App. Y.].

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.

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 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. Consequently, we believe that with one possible exception, any non-air quality environmental impacts have been adequately considered in our analyses. We are aware that the Harrington facility has instituted a water recycling program and obtains some of its water from the City of Amarillo.[99] Due to potential non-air quality concerns, we limit our SO_2 control analysis for Harrington to DSI and dry scrubbers.

Regarding the remaining useful life, the BART Guidelines advise:[100]

You may decide to treat the requirement to consider the source's ''remaining

[99] http://www.powermag.com/xcel-energys-harrington-generating-station-earns-powder-river-basin-coal-users-group-award/.
[100] 70 FR 39103, 39169, [40 CFR Part 51, App. Y.].

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 any of the facilities we have analyzed for BART have entered into an enforceable document to shut down the applicable units earlier than what would occur under our assumed 30-year operational life.[101] As we stated in our Oklahoma FIP,[102] we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be well over 60 years. We identified specific scrubbers installed between 1975 and 1985 that were still in operation. 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. Because none of the facilities involved have entered

[101] We received a November 21, 2016 letter from the source owner regarding Parish Units 5 & 6. The letter, now added to the docket, explains the units have natural gas firing capabilities and expresses interest in obtaining flexibility to avoid BART or obtaining multiple options for complying with BART. While we acknowledge this interest, the letter does not provide or commit to any specifics in furtherance of the BART analysis that EPA is now required to conduct under the BART Guidelines.

[102] 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.

into enforceable documents to shut down the applicable units earlier, we will continue to use a 30-year equipment life for DSI, scrubber retrofits, and scrubber upgrades, as we believe that is proper.

5. Step 5: Evaluate Visibility Impacts

Please see the BART Modeling TSD, where we describe in detail the various modeling runs we conducted, our methodology and selection of emission rates, modeling results, and final modeling analysis that we used to evaluate the benefits of the proposed controls and their associated emission decreases on visibility impairment values. 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.

a. Visibility Benefits of DSI, SDA, and Wet FGD for Coal-Fired Units

We evaluated the visibility benefits of DSI, for the twelve units depicted in Tables 15 and 16 below that currently have no SO_2 control. We evaluated all the units using the control levels we employed in our control cost analyses. In summary, we evaluated these units at a DSI SO_2 control level of 50%, which we believe is likely achievable for any unit. At the lower performance level we assumed, we conclude that the corresponding visibility benefits from DSI in most cases would be close to half of the benefits from scrubbers resulting in the visibility benefits from scrubber retrofits being much more beneficial. We also evaluated the visibility benefits for scrubber retrofits (wet FGD and SDA) for these same units, assuming the same control levels corresponding to SDA and wet FGD that we used in our control cost analyses. For those sources that are within 300 to 400 km of a Class I area, we utilized CALPUFF and CAMx

modeling to assess the visibility benefit of potential controls. For the remaining coal-fired sources (J T Deely, Coleto Creek, Fayette and W A Parish), only CAMx modeling was utilized as these sources are located at much greater distances to the nearest Class I areas. 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.[103] We note that the high control scenario modeling for Fayette units 1 and 2 demonstrate the benefit from existing high performing controls. As discussed elsewhere, we found that for these units no additional controls or upgrades were necessary. For a full discussion of our review of all the modeling results, and factors that we considered in evaluating and weighing all the results, see our BART Modeling TSD. Below, we present a summary of some of those visibility benefits at the Class I areas most impacted by each source:

Table 15: Visibility Benefit of Retrofit Controls: Coal-Fired Units (CAMx modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD(98%)	DSI benefit	WFGD benefit
Big Brown	Source (Unit 1 and 2)	WIMO	Max dv	4.017	2.249	0.474	1.768	3.542
			Days > 0.5 dv	65	33	0	32	65
			Days>1.0 dv	33	13	0	20	33
		CACR	Max dv	3.775	2.539	0.787	1.236	2.988
			Days > 0.5 dv	91	62	4	29	87
			Days>1.0 dv	57	21	0	36	57
	Unit 1	WIMO	Max dv	2.154	1.168	0.245	0.986	1.909
			Days > 0.5 dv	33	13	0	20	33
			Days>1.0 dv	12	1	0	11	12

[103] 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."

		CACR	Max dv	2.016	1.327	0.409	0.688	1.606
			Days > 0.5 dv	58	22	0	36	58
			Days>1.0 dv	17	4	0	13	17
	Unit 2	WIMO	Max dv	2.175	1.181	0.235	0.994	1.940
			Days > 0.5 dv	34	13	0	21	34
			Days>1.0 dv	12	1	0	11	12
		CACR	Max dv	2.033	1.338	0.391	0.695	1.642
			Days > 0.5 dv	58	23	0	35	58
			Days>1.0 dv	17	4	0	13	17
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63
			Days>1.0 dv	40	14	0	26	40
	Unit 1	CACR	Max dv	4.516	3.123	0.733	1.393	3.783
			Days > 0.5 dv	79	43	3	36	76
			Days>1.0 dv	32	16	0	16	32
		WIMO	Max dv	2.241	1.290	0.252	0.951	1.989
			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	8	2	0	6	8
	Unit 2	CACR	Max dv	4.487	3.065	0.563	1.422	3.924
			Days > 0.5 dv	78	42	1	36	77
			Days>1.0 dv	30	13	0	17	30
		WIMO	Max dv	2.189	1.252	0.186	0.937	2.003
			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	6	2	0	4	6
Coleto Creek	Source (Unit 1)	WIMO	Max dv	0.845	0.526	0.176	0.318	0.668
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.791	0.458	0.186	0.333	0.606
			Days > 0.5 dv	5	0	0	5	5
			Days>1.0 dv	0	0	0	0	0
Harrington[1]	Source (Unit 061B & 062B)	SACR	Max dv	5.288	4.287	3.235	1.001	2.053
			Days > 0.5 dv	13	7	3	6	10
			Days>1.0 dv	5	1	1	4	4
		WIMO	Max dv	4.928	4.362	3.798	0.565	1.130
			Days > 0.5 dv	15	11	6	4	9
			Days>1.0 dv	6	5	4	1	2
	Unit 061B	SACR	Max dv	2.908	2.322	1.738	0.586	1.170
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.708	2.382	2.065	0.326	0.643
			Days > 0.5 dv	6	5	4	1	2

			Days>1.0 dv	4	2	1	2	3
	Unit 062B	SACR	Max dv	2.998	2.373	1.719	0.625	1.279
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.770	2.407	2.046	0.363	0.723
			Days > 0.5 dv	6	5	4	1	2
			Days>1.0 dv	4	1	1	3	3
J T Deely	Source (Sommers 1&2, J T Deely 1&2)	WIMO	Max dv	1.513	0.939	0.814	0.574	0.699
			Days > 0.5 dv	47	8	1	39	46
			Days>1.0 dv	6	0	0	6	6
		CACR	Max dv	1.423	1.155	0.905	0.268	0.518
			Days > 0.5 dv	7	3	2	4	5
			Days>1.0 dv	2	1	0	1	2
	J T Deely 1	WIMO	Max dv	0.757	0.449	0.270	0.307	0.487
			Days > 0.5 dv	4	0	0	4	4
			Days>1.0 dv	0	0	0	0	0
		BIBE	Max dv	0.652	0.373	0.069	0.279	0.583
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
	J T Deely 2	WIMO	Max dv	0.632	0.387	0.334	0.245	0.298
			Days > 0.5 dv	3	0	0	3	3
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.604	0.490	0.387	0.114	0.217
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
W.A. Parish	Source (WAP 4,5, &6)	CACR	Max dv	3.177	2.032	0.511	1.145	2.665
			Days > 0.5 dv	54	26	1	28	53
			Days>1.0 dv	22	9	0	13	22
		UPBU	Max dv	1.994	1.215	0.234	0.779	1.760
			Days > 0.5 dv	34	14	0	20	34
			Days>1.0 dv	9	1	0	8	9
	WAP 5	CACR	Max dv	1.698	1.052	0.180	0.646	1.518
			Days > 0.5 dv	22	9	0	13	22
			Days>1.0 dv	8	1	0	7	8
		UPBU	Max dv	1.038	0.613	0.094	0.424	0.943
			Days > 0.5 dv	11	1	0	10	11
			Days>1.0 dv	1	0	0	1	1
	WAP 6	CACR	Max dv	1.648	1.018	0.156	0.630	1.492
			Days > 0.5 dv	22	8	0	14	22
			Days>1.0 dv	6	1	0	5	6
		UPBU	Max dv	1.003	0.591	0.081	0.412	0.922
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	1	0	0	1	1
Welsh[2]	Source (Unit 1 &	CACR	Max dv	4.576		0.822		3.754
			Days > 0.5 dv	92		3		89

	2)							
			Days>1.0 dv	39		0		39
		MING	Max dv	2.544		0.570		1.973
			Days > 0.5 dv	9		1		8
			Days>1.0 dv	3		0		3
	Unit 1	CACR	Max dv	2.343	1.659	0.822	0.684	1.521
			Days > 0.5 dv	37	18	3	19	34
			Days>1.0 dv	8	3	0	5	8
		MING	Max dv	1.150	0.886	0.570	0.264	0.579
			Days > 0.5 dv	2	1	1	1	1
			Days>1.0 dv	1	0	0	1	1
Fayette[2]	Source (Unit 1 & 2)	CACR	Max dv	1.894		0.903		0.991
			Days > 0.5 dv	26		2		24
			Days>1.0 dv	9		0		9
		WIMO	Max dv	1.175		0.580		0.595
			Days > 0.5 dv	19		1		18
			Days>1.0 dv	2		0		2
	Unit 1	CACR	Max dv	1.002		0.480		0.522
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	1		0		1
		WIMO	Max dv	0.609		0.306		0.302
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0
	Unit 2	CACR	Max dv	0.974		0.441		0.534
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	0		0		0
		WIMO	Max dv	0.598		0.282		0.316
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0

[1] Harrington high control scenario for both units is SDA at 95% reduction

[2] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD (wet FGD) installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.

Table 16: Visibility Benefit of Retrofit Controls: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit

Big Brown	Source (Units 1 and 2)	WIMO	Max dv	4.27	2.54	0.43	1.73	3.83
			Days > 0.5 dv Avg.	67.33	43.33	2.67	24.00	64.67
			Days>1.0 dv Avg.	42.00	21.00	1.00	21	41.00
		CACR	Max dv	4.03	2.41	0.47	1.62	3.55
			Days > 0.5 dv Avg.	91.67	64.33	4.67	27.33	87.00
			Days>1.0 dv Avg.	60.33	30.00	0.00	30.33	60.33
Monticello [1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	3.68	1.70	2.89	4.87
			Days > 0.5 dv Avg.	143.67	115.00	62.33	28.67	81.33
			Days>1.0 dv Avg.	113.00	66.33	23.67	46.67	89.33
		UPBU [4]	Max dv	3.45	1.77	0.77	1.68	2.68
			Days > 0.5 dv Avg.	103.00	61.00	13.67	42.00	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60.00	34.67	6.00	25.33	54.00
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67
Harrington [2]	Source (Units 061B & 062B)	SACR	Max dv	1.06	0.86	0.61	0.20	0.45
			Days > 0.5 dv Avg.	21.00	15.33	6.33	5.67	14.67
			Days>1.0 dv Avg.	6.67	3.00	0.67	3.67	6.00
		WIMO	Max dv	1.29	0.97	0.55	0.32	0.74
			Days > 0.5 dv Avg.	26.00	15.33	8.67	10.67	17.33
			Days>1.0 dv Avg.	9.00	4.67	1.33	4.33	7.67
Welsh [3]	Source (Unit 1)	CACR	Max dv	1.44	1.12	0.72	0.32	0.72
			Days > 0.5 dv Avg.	50.33	32.67	12.33	17.67	38

			Days>1.0 dv Avg.	15.33	8.00	2.33	7.33	13.00
		UPBU	Max dv	0.76	0.49	0.22	0.27	0.54
			Days > 0.5 dv Avg.	12.00	4.67	0.33	7.33	11.67
			Days>1.0 dv Avg.	0.67	0.00	0.00	0.67	0.67
		WIMO	Max dv	0.56	0.33	0.15	0.23	0.41
			Days > 0.5 dv Avg.	7.33	2.67	0.33	4.67	7.00
			Days>1.0 dv Avg.	1.33	0.33	0.00	1.00	1.33

[1] Monticello's controlled level is a combination of scrubber upgrades and scrubber install in the facility impact modeling with CALPUFF.

[2] Harrington high control scenario for both units is SDA at 95% reduction

[3] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.

[4] UPBU = Upper Buffalo Wilderness Area.

b. Visibility Benefits of Scrubber Upgrades for Coal-Fired Units

We also modeled the visibility benefits of those same units for which we conducted control cost analysis for upgrading their existing scrubbers. We assumed the same 95% control level we used in our control cost analyses. We also modeled a lower level control at 90%. The visibility benefits from these scrubber upgrades are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits and reduction in number of days impacted.

Table 17: Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CAMx modeling)

Facility	Emission	Class	Metric	Visibility impact	Visibility Benefit

Name	Unit	I area		Baseline	90% Control	95% Control	90% benefit	95% benefit
Martin Lake	Source (Unit 1, 2 & 3)	CACR	Max dv	6.651	4.491	4.321	2.159	2.329
			Days > 0.5 dv	141	75	56	66	85
			Days>1.0 dv	99	31	16	68	83
		UPBU	Max dv	5.803	2.669	2.528	3.134	3.275
			Days > 0.5 dv	99	39	22	60	77
			Days>1.0 dv	67	11	7	56	60
	Unit 1	CACR	Max dv	2.633	1.550	1.468	1.083	1.165
			Days > 0.5 dv	71	17	6	54	65
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.254	0.867	0.805	1.387	1.449
			Days > 0.5 dv	44	6	3	38	41
			Days>1.0 dv	10	0	0	10	10
	Unit 2	CACR	Max dv	2.466	1.882	1.811	0.585	0.655
			Days > 0.5 dv	68	18	9	50	59
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.189	1.077	1.025	1.112	1.164
			Days > 0.5 dv	40	6	5	34	35
			Days>1.0 dv	10	1	1	9	9
	Unit 3	CACR	Max dv	2.755	1.682	1.609	1.074	1.146
			Days > 0.5 dv	76	15	6	61	70
			Days>1.0 dv	29	2	1	27	28
		UPBU	Max dv	2.368	0.942	0.890	1.425	1.478
			Days > 0.5 dv	46	6	4	40	42
			Days>1.0 dv	13	0	0	13	13
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63
			Days>1.0 dv	40	14	0	26	40
	Unit 3	CACR	Max dv	4.632	0.905	0.914	3.728	3.719

			Days > 0.5 dv	79	5	5	74	74
			Days>1.0 dv	32	0	0	32	32
		WIMO	Max dv	2.282	0.462	0.364	1.820	1.918
			Days > 0.5 dv	31	0	0	31	31
			Days>1.0 dv	7	0	0	7	7

Table 18: Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Units 1, 2 & 3)	CACR	Max dv	4.46	2.27	1.86	2.18	2.60
			Days > 0.5 dv Avg.	129.67	77.33	63.00	52.33	66.67
			Days>1.0 dv Avg.	91.33	32.67	22.33	58.67	69.00
		UPBU	Max dv	2.73	1.10	0.85	1.63	1.88
			Days > 0.5 dv Avg.	81.67	30.33	18.67	51.33	63.00
			Days>1.0 dv Avg.	46.67	7.33	3.67	39.33	43.00
Monticello [1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	3.68	1.70	2.89	4.87
			Days > 0.5 dv Avg.	143.67	115	62.33	28.67	81.33
			Days>1.0 dv Avg.	113	66.33	23.67	46.67	89.33
		UPBU	Max dv	3.45	1.77	0.765	1.68	2.68
			Days > 0.5 dv Avg.	103	61	13.67	42	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60	34.67	6	25.33	54
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67

[1] Monticello's controlled level is a combination of scrubber upgrade on Unit 3 and scrubber retrofits on Units 1 and 2 in the facility impact modeling with CALPUFF.

c. Visibility Benefits of Fuel Oil Switching for Gas/Fuel Oil-Fired Units

We also modeled the visibility benefits of those gas/fuel oil-fired units for which we conducted control cost analysis for switching to lower sulfur fuels. We evaluated the visibility benefits of switching to fuel oils corresponding to ultra-low sulfur diesel at 0.0015% sulfur by weight and 0.3% sulfur by weight as we evaluated in our control cost analyses. The visibility benefits from these fuel switches are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits.

Table 19. Visibility Benefits from Lower Sulfur Fuel

Facility Name	Emission Unit	Baseline visibility Impact from Source (most impacted Class I area)	Visibility benefit of 0.3% S fuel oil	Visibility benefit of 0.0015% S fuel oil
Stryker	ST2	CALPUFF 0.65 % S: 0.786 dv @ CACR (Facility)	CALPUFF (0.3 % S) : 0.263 dv @ CACR (Facility)	CALPUFF: 0.522 dv @ CACR (Facility)
Graham	Unit 2	CALPUFF 0.69 % S: 1.228 dv @ WIMO (Facility)	CALPUFF (0.3% S): 0.465 dv @ WIMO (Facility	CALPUFF: 0.851 dv @ WIMO (Facility
Wilkes	Units 1, 2, 3	CALPUFF 0.43 % S: 0.698 dv @ CACR (Facility)	CALPUFF (0.1 % S): 0.029 dv @ CACR (Facility)	CALPUFF: 0.037 dv @ CACR (Facility)
Newman[1]	Unit 2	N/A	N/A	N/A
	Unit 3	N/A	N/A	N/A
	Unit 4	N/A	N/A	N/A
Calaveras	Sommers Unit 1	CAMx: 1.513 dv @ WIMO (Source); 0.106 dv @ CACR (Unit)	0.004 dv @ CACR	0.008 dv @ CACR

	Sommers Unit 2	CAMx: 1.513 dv @ WIMO (Source); 0.180 dv @ CACR (Unit)	0.023 @ CACR	0.047 @ CACR

[1] Newman is on the edge of the CALMET and CALPUFF modeling grids for the database that were used in this action. Since the facility was near the edge, emissions of the facility's impacts could not be adequately modeled since some of the plumes could have gone out of the grid and not be adequately assessed if they come back into the grid and transport to impact a Class I area.

6. BART Analysis for PM

In our recent Texas-Oklahoma FIP, we initially proposed to approve Texas' determination that no PM BART controls were appropriate for its EGUs, based on a screening analysis of the visibility impacts from just PM emissions and the premise that EGU SO_2 and NO_X were covered separately by participation in CSAPR (allowing consideration of PM emissions in isolation). Because of the CSAPR remand and resulting uncertainty regarding SO_2 and NO_X BART for EGUs, we decided not to finalize our proposed approval of Texas' PM BART determination.[104] For reasons earlier stated we are proposing to disapprove the SIP determination regarding PM BART for EGUs. Following from that proposed disapproval, we are proposing a PM BART FIP for those Texas EGUs that are subject to BART.

The BART Guidelines permit us to conduct a streamlined analysis of PM BART in two key ways. First, the Guidelines allow a streamlined analysis for PM sources subject to MACT standards. Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, the Guidelines state it is permissible to rely on MACT standards for purposes of BART.[105]

[104] 81 FR 302 (January 5, 2016).
[105] 70 FR 39163-39164

Second, with respect to gas-fired units, which have inherently low emissions of PM (as well as SO_2), the Regional Haze Rule did not specifically envision new or additional controls or emissions reductions from the PM BART requirement. The BART guidelines preclude us from stating that PM emissions are *de minimis* when plant-wide emissions exceed 15 tons per years. While we must assign PM BART determinations to the gas-firing units, there are no practical add-on controls to consider for setting a more stringent PM BART emissions limit. The Guidelines state that if the most stringent controls are made federally enforceable for BART, then the otherwise required analyses leading up to the BART determination can be skipped.[106]

With this background, we are providing our evaluation along with some supplementary information on the BART sources as divided into two categories: coal-fired EGUs, and gas-fired EGUs.

BART Analysis for PM for Coal-Fired Units

All of the coal-fired EGUs that are subject to BART are currently equipped with either Electrostatic Precipitators (ESPs) or baghouses, or both, as can be seen from Table 20:

Table 20: Current PM Controls for Coal-Fired Units Subject to BART

Facility Name	Unit ID	Fuel Type (Primary)	SO_2 Control(s)	PM Control(s)
Big Brown	1	Coal		Baghouse +Electrostatic Precipitator
Big Brown	2	Coal		Baghouse + Electrostatic Precipitator
Coleto Creek	1	Coal		Baghouse
Harrington Station	061B	Coal		Electrostatic Precipitator

[106] 70 FR 39165 ("…you may skip the remaining analyses in this section, including the visibility analysis…")

Harrington Station	062B	Coal		Baghouse
J T Deely	1	Coal		Baghouse
J T Deely	2	Coal		Baghouse
Martin Lake	1	Coal	Wet Limestone	Electrostatic Precipitator
Martin Lake	2	Coal	Wet Limestone	Electrostatic Precipitator
Martin Lake	3	Coal	Wet Limestone	Electrostatic Precipitator
Monticello	1	Coal		Baghouse + Electrostatic Precipitator
Monticello	2	Coal		Baghouse + Electrostatic Precipitator
Monticello	3	Coal	Wet Limestone	Electrostatic Precipitator
Fayette	1	Coal	Wet Limestone	Electrostatic Precipitator
Fayette	2	Coal	Wet Limestone	Electrostatic Precipitator
W A Parish	WAP5	Coal		Baghouse
W A Parish	WAP6	Coal		Baghouse
Welsh Power Plant	1	Coal		Baghouse (Began Nov 15, 2015) + Electrostatic Precipitator

As an initial matter, we examine the control efficiencies of both baghouses and ESPs. We consider a baghouse, widely reported to be capable of 99.9% control of PM, to be the maximum level control for PM and so the units equipped with a baghouse will not be further analyzed for PM BART. The remaining units are fitted with ESPs.

The particulate matter control efficiency of ESPs varies somewhat with the design, the resistivity of the particulate matter, and the maintenance of the ESP. We do not have any information on the control level efficiency of any of the ESPs for the units in question. However, reported control efficiencies for well-maintained ESPs typically range from greater than 99% to 99.9%.[107] We consider this pertinent in concluding that the potential additional particulate control that a baghouse can offer over an ESP is relatively minimal.[108] In other

[107] EPA, "Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) - Wire Plate Type," EPA-452/F-03-028. Grieco, G., "Particulate Matter Control for Coal-fired Generating Units: Separating Perception from Fact," apcmag.net, February, 2012. Moretti, A. L.; Jones, C. S., "Advanced Emissions Control Technologies for Coal-Fired Power Plants, Babcox and Wilcox Technical Paper BR-1886, Presented at Power-Gen Asia, Bangkok, Thailand, October 3-5, 2012

[108] We do not discount the potential health benefits this additional control can have for ambient PM. However, the regional haze program is only concerned with improving the visibility at Class I areas.

words, if we did obtain control information specific to the ESP units in question, we do not believe that additional information would lead us to a different conclusion.

Nevertheless, we will examine the potential cost of retrofitting a typical 500 MW coal fired unit with a baghouse. Using our baghouse cost algorithms, as employed in version 5.13 of our IPM model,[109] and assuming a conservative air to cloth ratio of 6.0, results in a capital engineering and construction cost of $77,428,000.[110] Applied to the subject units, this cost assumes a retrofit factor of 1.0, and does not consider the demolition of the existing ESP, should it be required in order to make space for the baghouse.

We do not calculate the cost-effectiveness resulting from replacing an ESP with a baghouse. However, we expect that the tons of additional PM removed by a baghouse over an ESP to be very small, which would result in a very high cost-effectiveness figure. Also, we do not model the visibility benefit of replacing an ESP with a baghouse. However, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from replacing an ESP with a baghouse to be a small fraction of that. For instance, our CAMx baseline modeling shows that on a source-wide level, impacts from PM emissions on the maximum impacted days from each source at each Class I area was 3% of the total visibility impairment or less (calculated as percent of total extinction due to the source). Therefore additional PM controls are anticipated to result in very little visibility benefit on the maximum impacted days. Similarly, our CALPUFF modeling indicates that visibility impairment from PM is also a small fraction (typically only a few percent) of the

[109] IPM Model – Updates to Cost and Performance for APC Technologies, Particulate 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 5-7: PM Cost Methodology, downloaded from: https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-7_pm_cost_methodology.pdf

[110] Id. See page 9.

total visibility impairment due to each source.

Adding to the above discussion, we are tasked to assign the enforceable emission limitations that constitute PM BART. We believe a stringent control level that would be met with existing or otherwise-required controls is a filterable PM limit of 0.03 lb/MMBtu for each of the coal-fired units subject to BART. We note that the Mercury and Air Toxics (MATS) Rule establishes an emission standard of 0.03 lb/MMBtu filterable PM (as a surrogate for toxic non-mercury metals) as representing Maximum Achievable Control Technology (MACT) for coal-fired EGUs.[111] This standard derives from the average emission limitation achieved by the best performing 12 percent of existing coal-fired EGUs, as based upon test data used in developing the MATS Rule. We are not familiar with any new technologies subsequent to this standard that could lead to any cost effective increases in the level of control; thus, consistent with the BART Guidelines, we are proposing to rely on this limit for purposes of PM BART for all of the coal-fired units as part of our FIP. We understand the coal-fired units covered by this proposal to be subject to MATS, but to the extent the units may be following alternate limits that differ from the surrogate PM limits found in MATS, we welcome comments on different, appropriately stringent limits reflective of current control capabilities.[112] Because we anticipate that any limit we assign should be achieved by current control capabilities, we propose that compliance can be met at the effective date of the rule. To address periods of startups and shutdowns, we are further proposing that PM BART for these units will additionally be met by following the work practice standards specified in 40 CFR Part 63, subpart UUUUU, Table 3, and using the relevant

[111] 77 FR 9304, 9450, 9458 (February 16, 2012) (codified at 40 CFR 60.42 Da(a), 60.50 Da(b)(1)); 40 CFR Part 63 Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units.

[112] The various limits are provided at 40 CFR Part 63, Subpart UUUUU, Table 2 ("Emission Limits for Existing EGUs")

definitions in 63.10042. We are proposing that the demonstration of compliance can be satisfied by the methods for demonstrating compliance with filterable PM limits that are specified in 40 CFR Part 63, subpart UUUUU, Table 7. However, we would give consideration to commenter-submitted requests for alternate or additional methods of demonstrating compliance.

BART Analysis for PM for Gas-Fired Units

We note that PM emissions for the gas-only fired units that are subject to BART are inherently low.[113] We therefore conclude that PM emissions from natural gas firing is so minimal that the installation of any additional PM controls on the unit would likely achieve very low emissions reductions and have minimal visibility benefits. As there are no appropriate add-on controls and the status quo reflects the most stringent controls, we are proposing to make the requirement to burn pipeline natural gas federally enforceable. We note that in addition to satisfying PM BART, this limitation will also serve to satisfy SO_2 BART for these gas-fired units, as well as the fuel-oil units when they fire natural gas. We are proposing that PM and SO_2 BART for gas fired-units will limit fuel to pipeline natural gas, as defined at 40 CFR 72.2.

The available PM controls for gas units that also burn fuel oil are the same for the coal-fired units. We would expect similar costs for installing a baghouse on a typical gas-fired boiler that occasionally burns fuel oil. Again, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from the installation of a baghouse to be a small fraction on the order of 1-3 % of the visibility impacts from the facility. We are confident that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted

[113] AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.4, Natural Gas Combustion, available here: https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.

with an ESP. We conclude that the cost of a baghouse does not justify the minimal expected improvement in visibility for these units. Accordingly, we are proposing that the fuel content limits for oil burning that we propose to meet SO_2 BART will also satisfy PM BART.

Lastly, should our assumptions regarding the frequency and type of fuel oil burned in these units significantly change, we expect that Texas will address such a change appropriately in its SIP, which we will review in the next planning period.

D. How, If At All, Do Issues of "Grid Reliability" Relate to the Proposed BART Determinations?

On July 15, 2016, a preliminary order of the Fifth Circuit Court of Appeals took the view that EPA's Texas-Oklahoma FIP (81 FR 295, January 5, 2016) gave a "truncated discussion of grid reliability" and additionally stated that "the agency may not have fulfilled its statutory obligation to consider the energy impacts of the FIP." The Court's preliminary ruling made particular reference to "the explicit directive in the [CAA] that implementation plans 'take[] into consideration…the energy…impacts of compliance,' 42 U.S.C. § 7491(g)(1)."[114] Because the BART requirement at issue in this proposal has similar language on *energy impacts of compliance* appearing at 42 U.S.C. § 7491(g)(2), we wish to provide a clear explanation on how grid-related considerations for EGUs could bear on this proposal.

First, the BART factor for *energy impacts of compliance* does not call for the examination of grid reliability considerations from alleged plans to shut down or retire a unit rather than comply with a more stringent emission limit or limits. The language instead calls for

[114]EPA Guidance on this statutory language specifically explains that energy impacts are a matter of whether "energy requirements associated with a control technology result in energy penalties." U.S. EPA, Office of Air Quality Planning and Standards, "Guidance for Setting Reasonable Progress Goals under the Regional Haze Program," (June 1, 2007 rev), at Page 5-2.

consideration of energy impacts from *complying* by installing retrofit controls on a source that continues in operation. In this regard, our proposal follows the required BART Guidelines for EGUs.[115] The Guidelines explain that the energy impacts factor relates to the penalties and benefits that may be associated with the assessment of a control option, e.g., whether (for power penalties) the operation of add-on control technology subtracts from the productive yield of electricity from an EGU (what is sometimes termed an auxiliary or parasitic load).[116] It is also useful to note that the statutory text, while using the word "energy," can apply to sources that do not produce energy or electricity. Thus, the statutory text regarding "energy impacts" of compliance with BART is not confined to the power generating industry and does not dictate that we study grid reliability issues.

We have considered whether this topic has any separate relevance to our proposal. Various court filings, news accounts, and industry market reports suggest that some source operators for some Texas BART units may be contemplating unit retirements. The BART Guidelines directly address such scenarios under the "remaining useful life" factor: "there may be situations where a source operator intends to shut down a source….but wishes to retain the flexibility to continue operating beyond that date in the event, for example, the market conditions change."[117] The Guidelines advise that a source that is willing to assure a permanent stop in operations with a federally- or State-enforceable restriction preventing further operation may obtain a short remaining useful life for BART analysis purposes that could then factor in the

[115] The promulgation of the Guidelines was required by 42 U.S.C. 7491(b)(1). Adherence to the Guidelines is mandatory for fossil-fuel fired generating power plants having total generating capacities "in excess of 750 megawatts."
[116] Other CAA provisions requiring consideration of "energy impacts" or "energy requirements of the control technology" are understood similarly. *See, e.g.,* CAA section 169 (the 1977 "best available control technology" requirement with consideration of "energy…impacts"); *see also* CAA section 108 ("energy requirements…of the emission control technology; "energy…impact of such processes, procedures, and methods [to reduce or control air pollution"); section 111 ("taking into account…energy requirements" of an emission limitation), etc.
[117] *Id.* at 39169-39170.

overall cost analysis.[118] As the Guidelines state, "Where the remaining useful life is less the than the time period for amortizing costs, you should use this shorter period in your cost calculations."[119] We have no information on enforceable restrictions of this type for any of the units that we propose to be subject to BART. Absent that, we must assume that controls installed on the BART units will experience their full useful life. Affected sources are free to submit information as part of their comments containing appropriate enforceable documentation of shorter remaining useful lives.

We note, however, that the Guidelines recognize there may be cases where the installation of controls, even when cost-effective, would "affect the viability of continued plant operations."[120] Under the Guidelines, where there are "unusual circumstances," we are permitted to take into consideration "the conditions of the plant and the economic effects of requiring the use of a control technology."[121] If the effects are judged to have a "severe impact," those effects can be considered in the selection process. In such cases, the Guidelines counsel that any determinations be made with an economic analysis with sufficient detail for public review on the "specific economic effects, parameters, and reasoning."[122] It is recognized, by the language of the Guidelines, that any such review process may entail the use of sensitive business information that may be confidential. The ADDRESSES section of this proposal explains how to submit confidential information with comments, and when claims of confidential business information, or CBI, are asserted with respect to any information that is submitted, the EPA regulations at 40 CFR Part 2, Subpart B-Confidentiality Business Information apply to protect it. All of that said,

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[118] Similar to calculating a mortgage, remaining useful life is used in our cost-effectiveness analysis to calculate the annual cost of a particular control. The longer the remaining useful life, the smaller the total annualized cost, and the more cost-effective the control.
[119] Id. at 39169.
[120] 70 FR 39103, 39171 (July 6, 2005), [40 CFR Part 51, App. Y]
[121] *Id.*
[122] 70 FR at 39171

the Guidelines also advise that we may "consider whether other competing plants in the same industry have been required to install BART controls if this information is available."[123] Because Texas EGUs are among the last to have SO_2 BART determinations, this information is available. It is indeed the case that other similar EGUs have been required to install the same types of SO_2 BART controls that we are proposing as very cost effective.[124]

We have considered the state of available information on whether the proposed controls could affect the viability of continued plant operations. On this point, we note that we are proposing BART determinations for several units where SO_2 control requirements were separately promulgated as part of the Texas-Oklahoma FIP. These under-controlled EGU sources are: Big Brown 1 and 2; Monticello 1, 2 and 3; Martin Lake 1,2 and 3; and Coleto Creek 1. In litigation over the reasonable progress FIP, various declarations were filed on the issues of alleged forced closures and alleged reliability impacts. These declarations have been compiled and added to the docket for this rulemaking. By our review, these declarations do not appropriately inform or substantiate source-specific allegations of "unusual circumstances" that may have a severe impact on plant operations, because they do not offer any site-specific information.[125] Thus, we are unable to conclude that the proposed cost-effective BART controls would severely impact plant operations. Generalized claims of possible retirements and discussions on attributes of the market design of the Electric Reliability Council of Texas (ERCOT) cannot inform the statutorily required, source-specific BART determinations.

As a predicate to studying effects on transmission or reliability as "unusual

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[123] *Id.*

[124] See for instance, the EIA information we present elsewhere in this notice in which we summarize the hundreds of scrubber installations that have been performed on similar EGUs.

[125] Certain statements in declarations from representatives of both Luminant and Coleto Creek, who are the source owners of these facilities, cited compliance planning efforts that would be consistent with continued plant operations.

circumstances," we would require site-specific information from any source that would wish for us to potentially consider "affordability of controls," under the terms specified in the Guidelines. Source owners may submit information, including information claimed to be CBI, for our assessment and consideration to potentially support an economic analysis that might be used in the BART selection process. As suggested by the Guidelines, the information necessary to inform our judgment would likely entail source-specific information on "product prices, the market share, and the profitability of the source." Consideration of such information does not dictate what will be selected as a "best" alternative under the Guidelines, but it will substantiate the likelihood of a retirement scenario that would then give the parameters for: a non-conjectural examination of grid reliability issues; judging the significance or insignificance of such issues; and assessing whether such issues could be avoided through appropriate transmission planning. In sum, unless we are able to substantiate an "affordability of controls" problem for any particular unit and substantiate that a particular unit retirement would not be happening anyway at about the same time, alleged grid reliability impacts are speculative and are not able to inform these required BART determinations. As a final note, we acknowledge Executive Order 13211 ("Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, and Use"). In cases where it does apply, agencies are ordered to prepare a Statement of Energy Effects for submission to the Administrator of the Office of Information and Regulatory Affairs (OIRA), Office of Management and Budget. This EGU BART proposal is not considered a significant regulatory action under Executive Order 12866, so the proposed action cannot be a "significant energy action" for purposes of Executive Order 13211 on that basis. This proposed action has also not been designated a significant energy action by the Administrator of OIRA, so Executive Order 13211 could not apply under that separate basis. With this proposal, there are

no anticipated adverse effects on energy supply, distribution, or use that are meaningful or distinguishable from any other scenario where an EGU is expected to install cost-effective pollution controls required by the CAA.

IV. Our Weighing of the Five BART Factors

Below we present our reasoning for proposing our BART determinations for 29 EGUs in Texas, based on our analysis and weighing of the Five BART Factors. (1) proposed SO_2 and PM BART determinations for 12 coal-fired units with no SO_2 controls, (2) proposed BART SO_2 and PM BART determinations for 6 coal-fired units with existing scrubbers, (3) proposed SO_2 and PM BART determinations 7 gas-fired units that occasionally burn fuel oil, and (4) proposed PM BART determinations for 4 gas-fired units.

In previous sections of this proposal, we have described how we assessed the five BART factors. In no case do we see any instance in which our assessment of energy impacts is a determining factor in assessing BART.[126] Also, in no case do we see any instance in which our assessment of the remaining useful life is a determining factor in assessing BART. Should a facility indicate in comments to us that the remaining useful life is less than the 30 years we have assumed in our control cost analyses, and is willing to enter into an enforceable document to that effect, we will adjust our cost-effectiveness calculation accordingly in making our final decision. In two cases, Harrington units 061B and 062B, we have limited our SO_2 control analysis for Harrington to DSI and dry scrubbers due to potential non-air quality concerns. In all other instances, we conclude that the cost of compliance, and the visibility benefits of controls are the controlling BART factors in our weighing of the five BART factors.

[126] In addition to our assessment of energy impacts, also see our discussion in Section III.D concerning our conclusion that energy impact considerations do not relate to potential electrical grid reliability issues.

In considering cost-effectiveness and visibility benefit, we do not eliminate any controls based solely on the magnitude of the cost-effectiveness value, nor do we use cost-effectiveness as the primary determining factor. Rather, we compare the cost-effectiveness to the anticipated visibility benefit, and we take note of any additional considerations.[127] Also, in judging the visibility benefit we do not simply examine the highest value for a given Class I area, or a group of Class I areas, but we also consider the cumulative visibility benefit for all affected Class I areas, the number of days in a calendar year in which we see significant improvements, and other factors.[128]

First, we note that all of the sources addressed in our proposed BART determinations have already been shown to cause or contribute to visibility impairment at a Class I area as a condition of being subject-to-BART as part of the BART screening analysis. This analysis eliminated any BART-eligible source that emits lower amounts of visibility impacting pollutants, or otherwise impacts any Class I area at less than 0.5 deciviews. In fact, all of the individual units that we are proposing for BART controls exceed 0.5 deciviews on a unit basis, with most exceeding 1.0 deciview impact on a unit basis. As a consequence, all of the units we are proposing for BART controls are among the largest emitters of visibility impacting pollutants in Texas. A number of these units (i.e., Big Brown, Martin Lake, Monticello, and Coleto Creek) were previously determined by us to require the same type and level of controls under the reasonable progress and long-term strategy provisions of the Regional Haze Rule that we are proposing here.[129]

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[127] For instance, as we discuss later in Section IV.C why we believe that there are certain mitigating factors that should be considered when assessing BART for the gas-fired units that occasionally burn fuel oil.
[128] See for example 70 39130: "comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g. the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, a threshold representing an x percent change in improvement, etc.)."
[129] See our recent Texas-Oklahoma FIP, 81 FR 321.

Second, not discounting our approach of considering both cost-effectiveness and visibility benefit in unison, the cost-effectiveness of all of the controls that form the basis of our proposed BART determinations are within a range found to be acceptable in other cases.[130] As we stated in the BART Rule, ''[a] reasonable range would be a range that is consistent with the range of cost effectiveness values used in other similar permit decisions over a period of time.''[131]

A. SO_2 BART for Coal-fired Units with no SO_2 Controls

As we have discussed in this proposal and in our TSD, we have assumed two DSI control levels corresponding to 50% control and either a maximum of 80% or 90% control, depending on the particulate matter control device in use.[132] We did this to address the BART Guidelines directive that in evaluating technically feasible alternatives we "(1) [ensure we] express the degree of control using a metric that ensures an ''apples to apples'' comparison of emissions performance levels among options, and (2) [give] appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels."[133] In most cases, the cost-effectiveness of the higher control level of DSI was higher than either SDA or wet FGD. This was not the case for Monticello Unit 2; Harrington Unit 062B; and J T Deely Units 1 and 2.

However, these maximum DSI control levels are theoretical and we believe that any DSI control level above 50% must be confirmed by onsite testing before we could propose a BART

[130] See for instance 79 FR 5048 (January 30, 2014): Jim Bridger BART determination of LNB/SOFA + SCR on Units 1-4; 77 FR 18070 (March 26, 2012): EPA proposed approval of Colorado's BART determination of SCR for Hayden Unit 2, later finalized at 77 FR 76871 (December 31, 2012).
[131] 70 FR 39168 (July 6, 2005).
[132] Note for Harrington Unit 062B and Welsh 1, we further limited the maximum DSI control level to that of our calculated SDA control level.
[133] 70 FR 39166 (July 6, 2005).

control based on it. As is evident in comparing the 50% control level to the higher control level, the cost-effectiveness of DSI worsens (higher $/ton) as the control level increases, and the certainty of any unit attaining that control level decreases. We therefore regard the cost-effectiveness values of the maximum DSI control levels as being useful in a basic comparison of cost-effectiveness between DSI and scrubbers, but we place much less weight on these values. We therefore conclude that given the uncertainty concerning the maximum control level of DSI, the greater control efficiency and resulting visibility benefit offered by scrubbers overrides any possible advantage DSI may hold in cost-effectiveness. Should the affected facilities provide site-specific information to us in their comments that conflicts with this assumption, we will incorporate it into our final decision on SO_2 BART and potentially re-evaluate DSI.

As we indicate elsewhere in our proposal, both SDA and wet FGD are mature technologies that are in wide use throughout the United States. We are not aware of any unusual circumstances that exist for any of the sources that would serve to indicate they should not be viewed similarly to these hundreds of previous scrubber retrofits. In comparing wet FGD versus SDA we note that in a number of cases the cost-effectiveness of wet FGD is lower than the cost-effectiveness of SDA. In the remaining cases, we conclude that the incremental cost-effectiveness of wet FGD over SDA, which we review in Section III.C.3.a is reasonable, and the improved control and visibility benefit offered by wet FGD overrides the small penalty in cost-effectiveness FGD has in comparison to SDA. We propose that with the exception of the Harrington units, SO_2 BART for all other coal-fired units should be based on the wet FGD control levels we have used in our BART analyses. We propose that SO_2 BART for the Harrington units should be based on the SDA control levels we have used in our BART analyses. Below we discuss our consideration of the cost-effectiveness and anticipated visibility benefits

of controls. See section III.C.5 for additional information on the anticipated visibility benefits from each level of control modeled. See the BART Modeling TSD for a complete summary of our visibility benefit analysis of controls, including modeled benefits and impacts at all Class I areas included in the modeling analyses and additional metrics considered in the assessment of visibility benefits.

CAMx model results shown in the tables below summarize the benefits from the recommended controls at the two Class I areas most impacted by the source or unit in the baseline modeling. The benefit is calculated as the difference between the maximum impact modeled for the baseline and the maximum impact level modeled under the control scenario. 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. The CALPUFF cumulative model results only consider those Class I areas within the typical range of CALPUFF and not all 15 Class I areas included in the CAMx modeling.

1. Big Brown 1 & 2

In reviewing the Big Brown units, we conclude that the installation of wet FGD will result in very significant visibility benefits. We summarize some of these visibility benefits in

the tables below:

Table 21. Wet FGD Visibility Benefits at Big Brown (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Big Brown Units 1 & 2	3.83	3.55	7.38	151.67	101.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek and Wichita Mountains

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek and Wichita Mountains.

In evaluating Big Brown, we note there are two Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results, we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario

subtracted by the cumulative number of days over the threshold for the control scenario. For the two Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate that wet FGD on both units will eliminate 151.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the visibility benefits in terms of dv benefits at the most impacted Class I areas and about 1/3rd to half the cumulative benefits over the class I areas included in the modeling analysis.

Table 22. Wet FGD Visibility Benefits at Big Brown (CAMx)

Unit	Improvement at Wichita mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Big Brown 1	1.909	1.606	12.728	174 / 44	174 / 44
Big Brown 2	1.940	1.642	12.924	175 / 45	175 / 45
Source	3.542	2.988	24.274	372 / 170	362 / 170

[1] 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.

[2] 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.

[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv at all Class I areas on a unit and source-wide basis, and eliminate all but 10 days across the impacted Class I areas where the source-wide impacts exceeds 0.5 dv. At the most impacted Class I area, wet FGD will on each unit result in visibility improvements of 1.9 dv on the most impacted day. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the CAMx modeling.

We also conclude that wet FGD is very cost-effective for both units at less than $1,200/ton and more cost-effective than DSI. Based on this consideration of the BART factors, we propose that SO_2 BART for Big Brown Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

2. Monticello 1 & 2

Similar to the Big Brown units, the installation of wet FGD at Monticello Units 1 and 2 will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 23. Wet FGD Visibility Benefits at Monticello (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	4.87	2.70	10.25	224.67	164.67

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Monticello, we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003

CALPUFF modeling results indicate wet FGD on both units will eliminate 224.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I area and half of the cumulative benefits.

Table 24. Wet FGD Visibility Benefits at Monticello (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 1	3.783	1.989	12.708	197 / 67	191 / 67
Monticello 2	3.924	2.003	13.025	192 / 57	191 / 57
Source (including unit 3)	8.419	4.962	31.553	520 / 293	460 / 278

[1] 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.

[2] 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.

[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv

at all Class I areas on a unit basis, and eliminate all but 15 days across the impacted Class I areas where the source-wide impacts exceeds 1 dv. We note that source-wide modeled benefits include benefits of 95% control scrubber upgrade on Unit 3. At the most impacted Class I area, wet FGD on each unit will each result in visibility improvements of 3.8-3.9 dv on the most impacted day at Caney Creek and 2 dv visibility benefits at Wichita Mountains. DSI operated at 50% control results in less than half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

The wet FGD cost-effectiveness of $2,718/ton and $3,031/ton are higher than those for Big Brown, but these figures remain well within a range that we have previously found to be acceptable for BART, and we consider the very significant visibility benefits that will result justify the cost of wet FGD at the Monticello Units 1 and 2. The 50% control DSI cost-effectiveness is slightly less than that for wet-FGD, but results in much less visibility benefits. Based on our consideration of the BART factors, we therefore propose that SO_2 BART for Monticello Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

3. Coleto Creek 1

In reviewing Coleto Creek Unit 1, we conclude that in comparison with the Monticello units, the installation of a wet FGD is more cost-effective and results in lesser, but still significant visibility benefits. We summarize some of these visibility benefits in the table below:

Table 25. Wet FGD Visibility Benefits at Coleto Creek Unit 1 (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Coleto Creek 1	0.668	0.606	5.233	17 / 0	17 / 0

[1] 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

[2] 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

[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 0.5 dv at all Class I areas. At the most impacted Class I area, wet FGD will result in visibility improvements of 0.6 or more on the most impacted days at both Caney Creek and the Wichita Mountains. In addition, seven other Class I areas are improved by amounts ranging from 0.356 to 0.531 dv on the maximum impacted days with wet FGD. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15class I areas included in the modeling.

We also conclude that wet FGD is very cost-effective at $2,127/ton and well within a range that we have previously found to be acceptable and more cost-effective than DSI. We consider the significant visibility benefits that will result justify the cost of wet FGD at the Coleto Creek Unit 1. We therefore propose that SO_2 BART for Coleto Creek Unit 1 should be

based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

4. Welsh 1

In reviewing Welsh Unit 1, we conclude that the installation of a wet FGD will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 26. Wet FGD Visibility Benefits at Welsh Unit 1 (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Welsh 1	0.72	0.41	1.66	56.67	15

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Welsh we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility

impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 56.67 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

Table 27. Wet FGD Visibility Benefits at Welsh Unit 1 (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Mingo Wilderness (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Welsh 1	1.521	0.579	4.683	65 / 9	60 / 9
Source (Welsh 1 & 2)	3.754	1.973	13.179	211 / 72	206 / 72

[1] 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.

[2] 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.

[3] 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.

CAMx modeling results indicate that wet FGD on unit 1 will eliminate all days impacted by the unit over 1 dv at all Class I areas and all but 5 days impacted over 0.5 dv. At the most impacted Class I area, wet FGD on unit 1 will result in visibility improvements of 1.521 dv on the most impacted days at Caney Creek. In addition to the visibility benefits at Caney Creek and Mingo, visibility benefits at two additional Class I areas exceed 0.5 dv. We note that source-wide benefits shown include the benefits from the shutdown of unit 2. In addition, cumulative benefits from wet FGD on unit 1 over all 15 Class I areas exceeds 4.5 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We conclude that although at $3,824/ton, the cost-effectiveness of wet FGD is higher than for other facilities, it remains within a range that we have previously found to be acceptable. We consider the significant visibility benefits that will result from the installation of wet FGD at Welsh Unit 1 to justify the cost. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for Welsh Unit 1 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

5. Harrington 061B & 062B

In reviewing Harrington, we conclude that the installation of SDA on Units 061B and 062B will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 28. SDA Visibility Benefits at Harrington (CALPUFF)

Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Harrington 061B & 062B	0.45	0.74	2.56	53.67	26

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

In evaluating Harrington we note there are five Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for

each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the five Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 53.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

Table 29. SDA Visibility Benefits at Harrington (CAMx)

Unit	**Improvement at Salt Creek (dv)**	**Improvement at Wichita Mountains (dv)**	**Total Cumulative Visibility Benefit (dv)** [1]	**Baseline Total Cumulative number of days over 0.5/1.0 dv**[2]	**Reduction in number of days above 0.5/1.0 dv**[3]
Harrington 061B	1.170	0.643	4.832	17 / 5	11 / 3
Harrington 062B	1.279	0.723	5.379	17 / 5	11 / 3
Source (061B & 0622B)	2.053	1.130	9.329	51 / 17	37 / 11

[1] 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.

[2] 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.

[3] 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.

CAMx modeling results indicate SDA on these units will eliminate more than half of all days impacted by the units over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, SDA on each unit will each result in visibility improvements of approximately 1.2 dv on the most impacted days at Salt Creek and 0.6 – 0.7 dv at Wichita Mountains, reducing the number of days impacted over 0.5 and 1.0 dv at these Class I areas. In addition, cumulative benefits from SDA on both units over all 15 Class I areas exceeds 9.3 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the SDA visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We also conclude that SDA is cost-effective at $3,904 for Unit 061B and $4,180/ton for Unit 062B and, remains within a range that we have previously found to be acceptable. In contrast to other units we have reviewed, the 50% control DSI cost-effectiveness is much less than that for SDA. However, given the additional large total cumulative visibility benefits that will result from the installation of SDA over DSI at 50% control, we consider SDA to justify the additional cost. We therefore propose that SO_2 BART for Harrington Units 061B and 062B should be based on the installation of SDA at an emission limit of 0.06 lbs/MMBtu based on a 30 BOD.

6. W. A. Parish WAP 5 & 6

In reviewing W A Parish, we conclude that the installation of wet FGD on Units 5 and 6 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 30. Wet FGD Visibility Benefits at W A Parish (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
W A Parish 5	1.518	0.943	8.171	51 / 9	51 / 9
W A Parish 6	1.492	0.922	7.979	48 / 7	48 / 7
Source (WAP 4, 5 & 6)	2.665	1.760	15.301	163 / 49	162 / 49

[1] 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.

[2] 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.

[3] 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.

CAMx modeling results indicate that wet FGD on each of these units will eliminate all days impacted by each unit over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of approximately 1.5

dv on the most impacted days at Caney Creek and 0.9 dv at Upper Buffalo. Nine Class I areas have modeled source-wide baseline impacts over 1 dv, and wet FGD on both units results in source-wide improvements of 1 dv or greater on the maximum impacted days at eight of these Class I areas. In addition, cumulative benefits from wet FGD on both units over all 15 Class I areas exceeds 15 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15class I areas included in the modeling. We note that source-wide modeling includes a small impact from WAP 4. This unit is gas-fired and was modeled at baseline emissions levels for both the baseline and control case scenarios.

We conclude that wet FGD is cost-effective at $2,417/ton for Unit 5 and $2,259/ton for Unit 6, and remains well within a range that we have previously found to be acceptable. DSI at 50% control is approximately the same cost-effectiveness but results in significantly less visibility benefit. We consider the cost of wet FGD at the W A Parish units to be justified by the significant visibility benefits that will result. We therefore propose that SO_2 BART for W A Parish Units 5 and 6 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

7. J T Deely 1 & 2

In reviewing J T Deely, we conclude that the installation of wet FGD on Units 1 and 2 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 31. Wet FGD Visibility Benefits at J T Deely (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
J T Deely 1	0.487	0.283	4.785	10 / 0	10 / 0
J T Deely 2	0.298	0.217	3.650	7 / 0	7 / 0
Source (J T Deely 1 & 2, Sommers 1 & 2)	0.699	0.518	8.943	89 / 13	84 / 13

[1] 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.

[2] 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.

[3] 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.

CAMx modeling results indicate wet FGD on each of these units will eliminate all days impacted by each unit over 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of 0.487 dv and 0.298 dv on the most impacted days at Wichita Mountains and 0.283 dv and 0.217 dv at Caney Creek. Larger visibility improvements on the most impacted days are anticipated at other Class I areas. Benefits from wet FGD on unit 1 are 0.583 dv at Big Bend, 0.511 dv at Salt Creek, 0.449 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.475 dv at White Mountains. Benefits from wet FGD on unit 2 are 0.583 dv at Big Bend, 0.441 dv at Salt Creek, 0.354 dv at Guadalupe

Mountains and Carlsbad Caverns, and 0.375 dv at White Mountains. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 Class I areas included in the modeling. We note that source-wide modeling includes the impact from Sommers units 1 and 2, and as discussed in the BART Modeling TSD, control case scenarios for these units included benefits from switching to lower sulfur fuel oil. However, these modeled improvements are a small fraction of the total visibility benefits from controls at the source.

We conclude that wet FGD is cost-effective at $3,898/ton for Unit 1 and $3,712/ton for Unit 2, and remains within a range that we have previously found to be acceptable. We consider the cost of wet FGD at the J T Deely units to be justified by the significant visibility benefits that will result at a number of impacted Class I areas. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for J T Deely Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.[134]

B. SO_2 BART for Coal-fired Units with Underperforming Scrubbers

The BART Guidelines state that underperforming scrubber systems should be evaluated for upgrades.[135] Other than upgrading the existing scrubbers, all of which are wet FGDs, there are no competing control technologies that could be considered for these units. The CALPUFF modeling generated facility-wide impacts and the benefits of the scrubber upgrade on Monticello Unit 3 and the three Martin Lake facilities are included in Table 17 above. The following is a

[134] We have read reports that CPS Energy, is planning to retire J T Deely Units 1 and 2 by the end of 2018, but we have no enforceable documents to that effect.
[135] 70 FR 39171 (July 6, 2005).

listing of each of the affected units along with the resulting CAMx modeled visibility benefits from upgrading their existing scrubbers:

Table 32. Visibility Benefit for Coal-fired Units with Existing SO_2 Controls (CAMx)

Unit	Improvement at most impacted (dv)	Improvement at 2nd most impacted (dv)	Total Cumulative Visibility Benefit (dv)	Reduction in number of days above 0.5 dv at --------	Reduction in number of days above 1.0 dv at ------
Monticello 3	3.719 (CACR)	1.918 (WIMO)	11.940	200 / 66	188 / 66
Martin Lake 1	1.165 (CACR)	1.449 (UPBU)	7.575	160 / 41	151 / 40
Martin Lake 2	0.655 (CACR)	1.164 (UPBU)	6.199	150 / 41	134 / 39
Martin Lake 3	1.146 (CACR)	1.478 (UPBU)	7.863	173 / 47	163 / 46

As we state elsewhere in this proposal, because our cost-effectiveness calculations depend on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost effectiveness was $1,156/ton or less. We conclude that in all cases, scrubber upgrades are very cost-effective and result in very significant visibility benefits, significantly reducing the impacts from these units and reducing the number of days that Class I areas are impacted over 1.0 dv and 0.5 dv. We propose that SO_2 BART for all other coal-fired units with underperforming scrubbers should be based on the wet FGD upgrade control levels we have used in our BART analyses of them.

C. SO_2 BART for Gas-fired Units that Burn Oil

In analyzing potential controls for those gas-fired units that occasionally burn fuel oil we considered scrubber retrofits and lower sulfur fuel oil. We concluded that the cost-effectiveness of scrubber retrofits for these units were likely very high, and not worth the potential visibility

benefit.

We also concluded that the cost-effectiveness of switching to a No. 2 fuel oil with a sulfur content of 0.3% is $11,218/gallon, and the cost-effectiveness of switching to ULSD with a sulfur content of 0.0015% is $8,627/gallon. We further noted that one facility already had a contract in place for ULSD at a lower price than we assumed, which if used in our analysis would result in a cost effectiveness of $3,970/ton. Although the cost-effectiveness of switching to a lower sulfur oil (assuming our price for ULSD of $1.667/gal) is higher than other controls that we have typically required under BART, we note certain mitigating factors.

For instance, arguing against control, our calculated cost-effectiveness values are high in relation to other BART controls we have required in the past. Also, our visibility modeling necessarily utilized the maximum SO_2 emissions over a 24-hour timeframe,[136] resulting in the configuring of our visibility modeling to analyze the maximum short-term potential impacts that could occur when the unit burns fuel oil. However, as we discuss elsewhere in our proposal, these units are primarily gas-fired, and have only occasionally burned fuel oil. Their most recent practices appear to reinforce this trend.

Arguing for control, unlike the wet FGD and SDA scrubbers we have costed in other sections of this TSD, which have large capital costs, we are unaware of any significant capital costs involved in switching fuels. This means the overall annual costs are relatively minor, if the units in question adhere to their historical usages. Also, because the units in question have only occasionally burned fuel oil, they have the option to avoid the cost of fuel switching entirely by not continuing to burn fuel oil and instead relying solely on their primary fuel of natural gas.

[136] See the BART Guidelines at 70 FR 39162, July 6, 2005: "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."

Lastly, we note that the prevalence of ULSD in the fuel oil market is such that it appears to be gradually replacing most other No. 2 fuel oil applications.[137]

The preamble to the Regional Haze Rule counseled that a one percent sulfur content limitation on fuel oil should be considered as a "starting point,"[138] and the existing sulfur content limits are lower than one percent. Considering all of this information, we propose that SO_2 BART for the gas-fired units that occasionally burn fuel oil should be no further control. In so doing, we acknowledge the data quality issues we have discussed concerning these units and we specifically request comments on all aspects of our proposed BART analysis for these units from all interested parties. Based on the comments we receive, we may either finalize our BART determinations for these units as proposed, or we may revise them without a re-proposal.

D. PM BART

We propose to disapprove the portion of the Texas Regional Haze SIP that sought to address the BART requirement for EGUs for PM. We note that all of the coal-fired units are either currently fitted with a baghouse, an ESP and a polishing baghouse, or an ESP. We conclude that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted with an ESP. Consequently, we propose that PM BART for the coal-fired units is an emission limit of 0.030 lb/MMBtu along with work practice standards. We propose that PM and SO_2 BART for the units that only fire gas be pipeline natural gas. We propose that PM and SO_2 BART for those gas-fired units that occasionally burn fuel oil be the existing permitted fuel oil sulfur content of

[137] http://www.eia.gov/todayinenergy/detail.php?id=5890. http://blogs.platts.com/2014/05/07/heating-oil-new-york-sulfur/. http://oilandenergyonline.com/challenges-to-the-northeast-supply-picture/
[138] 70 FR at 39134

0.7% sulfur by weight or pipeline natural gas.

V. Proposed Actions

A. Regional Haze

We are proposing to disapprove the portion of the Texas Regional Haze SIP that sought to address the BART requirement for EGUs for PM. We are proposing to promulgate a FIP as described in this notice and summarized in this section to satisfy the remaining outstanding regional haze requirements that are unmet by the Texas' regional haze SIP and that we did not take action on in our January 5, 2016 final action.[139] Our proposed FIP includes SO_2 and PM BART emission limits for sources in Texas to reduce emissions that contribute to regional haze in Texas' two Class I areas and other nearby Class I areas and make reasonable progress for the first regional haze planning period for Texas' two Class I areas.

1. NO_X BART

As discussed elsewhere in this proposal, we are proposing a FIP to replace Texas' reliance on CAIR with reliance on CSAPR to address the NO_X BART requirements for EGUs. This portion of our proposal is based on: the recent update to the CSAPR rule[140]; and the EPA's finalization of a separate proposed finding that the 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.[141] We cannot finalize this portion of the proposed FIP unless and until the EPA finalizes

[139] 81 FR 296.
[140] 81 FR 74504.
[141] 81 FR 78954.

the proposed finding that CSAPR continues to be better than BART because finalization of that proposal would allow for reliance on CSAPR participation as an alternative to source-specific EGU BART for NO_X in Texas.

2. SO_2 BART for Coal-fired Units

We propose that SO_2 BART for the coal-fired units be the following SO_2 emission limits to be met on a 30 Boiler Operating Day (BOD) period:

Table 33. Proposed SO_2 BART Emissions Limits for Coal-fired Units

	Unit	Proposed SO_2 emission limit (lbs/MMBtu)
Scrubber Upgrades	Martin Lake 1	0.12
	Martin Lake 2	0.12
	Martin Lake 3	0.11
	Monticello 3	0.05
Scrubber Retrofits	Big Brown 1	0.04
	Big Brown 2	0.04
	Monticello 1	0.04
	Monticello 2	0.04
	Coleto Creek 1	0.04
	Fayette 1	0.04
	Fayette 2	0.04
	Harrington 061B	0.06
	Harrington 062B	0.06
	J T Deely 1	0.04

	J T Deely 2	0.04
	W A Parish 5	0.04
	W A Parish 6	0.04
	Welsh 1	0.04

We propose that compliance with these limits be within five years of the effective date of our final rule for Big Brown Units 1 and 2; Monticello Units 1 and 2; Coleto Creek Unit 1; Harrington Units 061B and 062B; J T Deely Units 1 and 2; W A Parish Units 5 and 6; and Welsh Unit 1. This is the maximum amount of time allowed under the Regional Haze Rule for BART compliance. We based our cost analysis on the installation of wet FGD and SDA scrubbers for these units, and in the past we have typically required that scrubber retrofits under BART be operational within five years.

We propose that compliance with these limits be within three years of the effective date of our final rule for Martin Lake Units 1, 2, and 3; and Monticello Unit 3. We believe that three years is appropriate for these units, as we based our cost analysis on upgrading the existing wet FGD scrubbers of these units, which we believe to be less complex and time consuming that the construction of a new scrubber.

We propose that compliance with these limits be within one year for Fayette Units 1 and 2. We believe that one year is appropriate for these units because the Fayette units have already demonstrated their ability to meet these emission limits.

3. Potential Process for Alternative Scrubber Upgrade Emission Limits

In our BART FIP TSD, we discuss how we calculated the SO_2 removal efficiency of the units we analyzed for scrubber upgrades. We note that due to a number of factors we could not

accurately quantify, our calculations of scrubber efficiency may contain some error. Based on the results of our scrubber upgrade cost analysis, we do not believe that any reasonable error in calculating the true tons of SO_2 removed affects our proposed decision to require emission reductions, as all of the scrubber upgrades we analyzed are cost-effective (low $/ton). In other words, were we to make reasonable adjustments in the tons removed to account for any potential error in our scrubber efficiency calculation, we would still propose to upgrade these SO_2 scrubbers. We believe we have demonstrated that upgrading an underperforming SO_2 scrubber is one of the most cost-effective pollution control upgrades a coal fired power plant can implement to improve the visibility at Class I areas. However, our proposed FIP does specify a SO_2 emission limit that is based on 95% removal in all cases. This is below the upper end of what an upgraded wet SO_2 scrubber can achieve, which is 98–99%, as we have noted in our BART FIP TSD. We believe that a 95% control assumption provides an adequate margin of error for any of the units for which we have proposed scrubber upgrades, such that they should be able to comfortably attain the emission limits we have proposed. However, for the operator of any unit that disagrees with us on this point, we propose the following:

(1) The affected unit should comment why it believes it cannot attain the SO_2 emission limit we have proposed, based on a scrubber upgrade that includes the kinds of improvements (e.g., elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically included in a scrubber upgrade.

(2) After considering those comments, and responding to all relevant comments in a final

rulemaking action, should we still require a scrubber upgrade in our final FIP we will provide the company the following option in the FIP to seek a revised emission limit after taking the following steps:

(a) Install a CEMS at the inlet to the scrubber.

(b) Pre-approval of a scrubber upgrade plan conducted by a third party engineering firm that considers the kinds of improvements (e.g., elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically performed during a scrubber upgrade. The goal of this plan will be to maximize the unit's overall SO_2 removal efficiency.

(c) Installation of the scrubber upgrades.

(d) Pre-approval of a performance testing plan, followed by the performance testing itself.

(e) A pre-approved schedule for 2.a through 2.d.

(f) Should we determine that a revision of the SO_2 emission limit is appropriate, we will have to propose a modification to the BART FIP after it has been promulgated. It should be noted that any proposal to modify the SO_2 emission

limit will be based largely on the performance testing and may result in a proposed increase or decrease of that value.

4. SO_2 BART for Gas-fired Units that Burn Oil

We propose that SO_2 BART for the following gas-fired units that occasionally burn fuel oil be the existing permit limits for the sulfur content of the fuel oil:

Table 34: Proposed BART SO_2 Emission Limits Gas Units that Occasionally Burn Oil

Facility	Fuel Oil Sulfur Content (percent by weight)
Graham 2	0.7
Newman 2*	0.7
Newman 3*	0.7
O W Sommers 1	0.7
O W Sommers 2	0.7
Stryker Creek ST2	0.7
Wilkes 1	0.7

* The Newman Units 2 and 3 are further limited to burning fuel oil for no more than 876 hours per year.

5. PM BART

We propose that PM BART limits for the coal units, Big Brown Units 1 and 2; Monticello Units 1, 2, and 3; Martin Lake Units 1, 2, and 3; Coleto Creek Unit 1; J T Deely Units 1 and 2; W A Parish Units 5 and 6; Welsh Unit 1; Harrington Units 061B and 062B; and Fayette Units 1 and 2 are 0.030 lb/MMBtu and work practice standards, which we present below:

Table 35. PM BART Emissions Standards and Work Practice Standards

Unit Type	PM BART Proposal
Coal-Fired BART Units	0.03 lb/MMBtu filterable PM Table 3 to Subpart UUUUU
Gas-Fired Only BART Units	Pipeline quality natural gas
Oil-Fired BART Units when not firing natural gas	Fuel Content not to exceed 0.7% sulfur by weight (also SO_2 BART)

We propose that compliance with these emissions standards and work practice standards be the effective date of our final rule, as the affected facilities' should already be meeting them.

We propose that PM and SO_2 BART for the units that only fire gas, Newman Unit 4; W A Parish Unit 4; and Wilkes Units 2 and 3 be pipeline natural gas.

We propose that PM and SO_2 BART for those gas-fired units that occasionally burn fuel oil, Newman Unit 2 and 3; O W Sommers Units 1 and 2; Stryker Creek Unit ST2; and Wilkes Unit 1 be the existing permitted fuel oil sulfur content of 0.7% sulfur by weight.

B. Interstate Visibility Transport

We are proposing to disapprove Texas' SIP revisions addressing interstate visibility transport under CAA section 110(a)(2)(D)(i)(II) for six NAAQS. We further are proposing a FIP to fully address Texas' interstate visibility transport obligations for: (1) 1997 8-hour ozone, (2) 1997 $PM_{2.5}$ (annual and 24 hour), (3) 2006 $PM_{2.5}$ (24-hour), (4) 2008 8-hour ozone, (5) 2010 1-hour NO_2 and (6) 2010 1-hour SO_2. The proposed FIP is based on the finding that our proposed action to fully address the Texas Regional Haze BART program is adequate to ensure that

emissions from Texas do not interfere with measures to protect visibility in nearby states in accordance with CAA section 110(a)(2)(D)(i)(II).

VI. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Overview

This proposed action is not a "significant regulatory action" under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011). The proposed FIP would not constitute a rule of general applicability, because it only proposes source specific requirements for particular, identified facilities (8 total).

B. Paperwork Reduction Act

This proposed action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. Section 3501 et seq. Because it does not contain any information collection activities, the Paperwork Reduction Act does not apply. See 5 CFR 1320(c).

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and small governmental jurisdictions. For purposes of assessing the impacts

of today's rule on small entities, small entity is defined as: (1) a small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's proposed rule on small entities, I certify that this action will not have a significant impact on a substantial number of small entities. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule. This rule does not impose any requirements or create impacts on small entities. This proposed FIP action under Section 110 of the CAA will not create any new requirement with which small entities must comply. This action, when finalized, will apply to 14 facilities owned by 8 companies, none of which are small entities. Accordingly, it affords no opportunity for the EPA to fashion for small entities less burdensome compliance or reporting requirements or timetables or exemptions from all or part of the rule. The fact that the CAA prescribes that various consequences (e.g., emission limitations) may or will flow from this action does not mean that the EPA either can or must conduct a regulatory flexibility analysis for this action. We have therefore concluded that, this action will have no net regulatory burden for all directly regulated small entities.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104-4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on state, local, and Tribal governments and the private sector. Under Section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that may result in expenditures to state, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more (adjusted for inflation) in any one year. Before promulgating an EPA rule for which a written statement is needed, Section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of Section 205 of UMRA do not apply when they are inconsistent with applicable law. Moreover, Section 205 of UMRA allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under Section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

EPA has determined that Title II of UMRA does not apply to this proposed rule. In 2 U.S.C. Section 1502(1) all terms in Title II of UMRA have the meanings set forth in 2 U.S.C. Section 658, which further provides that the terms "regulation" and "rule" have the meanings set

forth in 5 U.S.C. Section 601(2). Under 5 U.S.C. Section 601(2), "the term 'rule' does not include a rule of particular applicability relating to . . . facilities." Because this proposed rule is a rule of particular applicability relating to 12 named facilities, EPA has determined that it is not a "rule" for the purposes of Title II of UMRA.

E. Executive Order 13132: Federalism

This proposed action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments

This proposed rule does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments. Thus, Executive Order 13175 does not apply to this rule.

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks[142] applies to any rule that: (1) Is determined to be economically significant as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children. EPA interprets

[142] 62 FR 19885 (Apr. 23, 1997).

EO 13045 as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under Section 5-501 of the EO has the potential to influence the regulation. This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action is not subject to EO 13045 because it implements specific standards established by Congress in statutes. However, to the extent this proposed rule will limit emissions of SO_2, NO_X, and PM, the rule will have a beneficial effect on children's health by reducing air pollution.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This proposed action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12 of the National Technology Transfer and Advancement Act (NTTAA) of 1995 requires Federal agencies to evaluate existing technical standards when developing a new regulation. To comply with NTTAA, EPA must consider and use "voluntary consensus standards" (VCS) if available and applicable when developing programs and policies unless doing so would be inconsistent with applicable law or otherwise impractical. EPA believes that VCS are inapplicable to this action. Today's action does not require the public to perform activities conducive to the use of VCS.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994), establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. We have determined that this proposed rule, if finalized, will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. This proposed federal rule limits emissions of NO_X, SO_2, and PM from 14 facilities in Texas

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxides, Visibility, Interstate transport of pollution, Regional haze, Best available control technology.

Dated: December 9, 2016.

Ron Curry,

Regional Administrator, Region 6.

Title 40, chapter I, of the Code of Federal Regulations is proposed to be amended as follows:

PART 52–APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq*.

Subpart SS – Texas

2. Section 52.2287 is added to read as follows:

§ 52.2287 Best Available Retrofit Requirements (BART) for SO_2 and Particulate Matter and Interstate pollutant transport provisions; What are the FIP requirements for visibility protection?

(a) *Applicability*. The provisions of this section shall apply to each owner or operator, or successive owners or operators, of the coal or natural gas burning equipment designated below.

(b) *Definitions*. All terms used in this part but not defined herein shall have the meaning given them in the CAA and in parts 51 and 60 of this title. For the purposes of this section:

24-hour period means the period of time between 12:01 a.m. and 12 midnight.

Air pollution control equipment includes selective catalytic control units, baghouses, particulate or gaseous scrubbers, and any other apparatus utilized to control emissions of regulated air contaminants that would be emitted to the atmosphere.

Boiler-operating-day means 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.

Daily average means the arithmetic average of the hourly values measured in a 24-hour period.

Heat input means heat derived from combustion of fuel in a unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources. Heat input shall be calculated in accordance with 40 CFR part 75.

Owner or Operator means any person who owns, leases, operates, controls, or supervises any of the coal or natural gas burning equipment designated below.

PM means particulate matter.

Regional Administrator means the Regional Administrator of EPA Region 6 or his/her authorized representative.

Unit means one of the natural gas, gas and/or fuel oil, or coal-fired units covered in this section.

(c) *Emissions limitations and compliance dates for SO_2.* The owner/operator of the units listed below shall not emit or cause to be emitted pollutants in excess of the following limitations from the subject unit. Compliance with the requirements of this section is required as listed below unless otherwise indicated by compliance dates contained in specific provisions.

Unit	Proposed SO_2 emission limit (lbs/MMBtu)	Compliance Date (from the effective date of the final rule)
Martin Lake 1	0.12	3 years
Martin Lake 2	0.12	3 years
Martin Lake 3	0.11	3 years
Monticello 3	0.05	3 years

Big Brown 1	0.04	5 years
Big Brown 2	0.04	5 years
Monticello 1	0.04	5 years
Monticello 2	0.04	5 years
Coleto Creek 1	0.04	5 years
Fayette 1	0.04	1 year
Fayette 2	0.04	1 year
Harrington 061B	0.06	5 years
Harrington 062B	0.06	5 years
J T Deely 1	0.04	5 years
J T Deely 2	0.04	5 years
W A Parish 5	0.04	5 years
W A Parish 6	0.04	5 years
Welsh 1	0.04	5 years

(d) *Emissions limitations and compliance dates for PM*. The owner/operator of the units listed below shall not emit or cause to be emitted pollutants in excess of the following limitations from the subject unit. Compliance with the requirements of this section is required as listed below unless otherwise indicated by compliance dates contained in specific provisions.

(1) Coal-Fired Units at Big Brown Units 1 and 2; Monticello Units 1, 2, and 3; Martin Lake Units 1, 2, and 3; Coleto Creek Unit 1; J T Deely Units 1 and 2; W A Parish Units 5 and 6; Welsh Unit 1; Harrington Units 061B and 062B; and Fayette Units 1 and 2.

(i) Normal operations: Filterable PM limit of 0.030 lb/MMBtu.

(ii) Work practice standards specified in 40 CFR Part 63, subpart UUUUU, Table 3, and using the relevant definitions in 63.10042.

(2) Gas-Fired Units at Newman Unit 4; Wilkes Units 2 and 3; and W A Parish Unit 4 shall

burn only pipeline natural gas, as defined in 40 CFR 72.1

(3) Gas-fired units that also burn fuel oil at Graham Unit 2; Newman Units 2 and 3; O W Sommers Units 1 and 2; Stryker Creek Unit ST2; and Wilkes shall burn 0.7% sulfur content fuel or pipeline natural gas, as defined in 40 CFR 72.1.

(4) Compliance for the units included in Section (d) shall be as of the effective date of the final rule.

(e) *Testing and monitoring*. (1) No later than the compliance date of this regulation, the owner or operator shall install, calibrate, maintain and operate Continuous Emissions Monitoring Systems (CEMS) for SO_2 on the units covered under paragraph (c) of this section. Compliance with the emission limits for SO_2 shall be determined by using data from a CEMS.

(2) Continuous emissions monitoring shall apply during all periods of operation of the coal or natural gas burning equipment, including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments. Continuous monitoring systems for measuring SO_2 and diluent gas shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant in an hour) if data are unavailable as a result of performance of calibration, quality assurance, preventive maintenance activities, or backups of data from data acquisition and handling system, and recertification events. When valid SO_2 pounds per hour, or

SO_2 pounds per million Btu emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks, or zero and span adjustments, emission data must be obtained by using other monitoring systems approved by the EPA to provide emission data for a minimum of 18 hours in each 24 hour period and at least 22 out of 30 successive boiler operating days.

(3) Compliance with the PM emission limits for units in paragraph (d)(1) shall be demonstrated by the filterable PM methods specified in 40 CFR Part 63, subpart UUUUU, Table 7.

(f) *Reporting and recordkeeping requirements*. Unless otherwise stated all requests, reports, submittals, notifications, and other communications to the Regional Administrator required by this section shall be submitted, unless instructed otherwise, to the Director, Multimedia Division, U.S. Environmental Protection Agency, Region 6, to the attention of Mail Code: 6MM, at 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202-2733. For each unit subject to the emissions limitation in this section and upon completion of the installation of CEMS as required in this section, the owner or operator shall comply with the following requirements:

(1) For SO_2 each emissions limit in this section, comply with the notification, reporting, and recordkeeping requirements for CEMS compliance monitoring in 40 CFR 60.7(c) and (d).

(2) For each day, provide the total SO_2 emitted that day by each emission unit. For any hours on any unit where data for hourly pounds or heat input is missing, identify the unit number and monitoring device that did not produce valid data that caused the missing hour.

(3) Records for demonstrating compliance with the SO_2 and PM emission limitations in this section shall be maintained for at least five years.

(g) *Equipment operations*. At all times, including periods of startup, shutdown, and malfunction,

the owner or operator shall, to the extent practicable, maintain and operate the unit including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Regional Administrator which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the unit.

(h) *Enforcement.* (1) Notwithstanding any other provision in this implementation plan, any credible evidence or information relevant as to whether the unit would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed, can be used to establish whether or not the owner or operator has violated or is in violation of any standard or applicable emission limit in the plan.

(2) Emissions in excess of the level of the applicable emission limit or requirement that occur due to a malfunction shall constitute a violation of the applicable emission limit.

3. In § 52.2304, paragraph (f) is added to read as follows:

§ 52.2304 Visibility protection.

* * * * *

(f) *Measures addressing disapproval associated with NO_x, SO_2, and PM.* (1) The deficiencies associated with NO_x identified in EPA's disapproval of the regional haze plan submitted by Texas on March 31, 2009, are satisfied by Section 52.2283.

(2) The deficiencies associated with SO_2 and PM identified in EPA's disapproval of the regional haze plan submitted by Texas on March 31, 2009, are satisfied by Section 52.2287.

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From: Theresa Pella
Sent: Thur 12/22/2016 2:17:36 PM
Subject: TWS Comm Dec. call summary, App W, and NEI comparison tool
Appendix_W-Fact_Sheet.pdf
AppendixW_2016.pdf
16_12_13 TWS Comm call summary_DRAFT.docx

1) Attached find the draft summary of the Dec. 13th call.

2) EPA has finalized the Appendix W rule. Attached is a fact sheet and pre-published version of the rule. Documents should eventually be posted at EPA and in the rule making docket - https://www.regulations.gov/searchResults?rpp=25&po=0&s=EPA-HQ-OAR-2015-0310&fp=true&ns=true

3) If you attended the NOMAD call on Wednesday, you may recall Julie McDill mentioning a comparison tool. The information below will take you to folders containing spreadsheets and maps MARAMA and Georgia developed to help with doing qa work comparing the final 2011 NEI to 2014V1.

The ShareFile site can be accessed at: https://marama.sharefile.com/

Username: @marama.org

Password: ERTACoutr3ach (Please note that the password really has a "3" in it!)

The data is grouped by the 1st four digits of SCCs. There are 4 folders - nonpoint, point, onroad and nonroad (ignore the superseded folder).

There are readme files that should help, but some caveats include: the maps illustrate percentage ranges of emission changes, not tons. They are displayed in color codes, but the codes do not include yellow (means over 50% increase in emissions) nor cyan (means over 50% decrease in emissions). Greenish shades mean 2011 was higher; reddish shades mean 2014 was higher. Gray means few or no reported emissions.

Theresa Pella, Executive Director

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REVISED DRAFT 12/21/16
CenSARA Technical Work Share Committee
Conference Call Summary
December 13, 2016, 10:00 – 11:00 am central

1) Welcome and roll call

Participating organizations included Arkansas DEQ, Iowa DNR, Kansas DHE, Louisiana DEQ, Missouri DNR, Oklahoma DEQ, Texas CEQ, USFS, and EPA Region 6

2) Brief overview of October CMAS conference - https://www.cmascenter.org/conference/2016/agenda.cfm

Shantha Daniel (TCEQ) mentioned presentations included updates/improvements to CMAQ (V5.2), SMOKE emissions processing model and the CAMx model. There were also presentations related to modeling occurring in others parts of the world. She attended the CMAQ sessions, which included overview of work with the model, including modeling NOx from lightning. A highlight from the plenary session is that there is a lot interest in understanding a changing climate on air quality through studying multiple pathways, such as meteorology and impacts on energy. Uncertainties related to modeling were another session with discussion about the high bias of NOx in emission inventories – especially, but not limited to, onroad mobile. EPA and others are working on better understanding NOx budgets and there are field studies underway about how to better constrain NOx for modeling purposes. Another highlighted subject was work underway to understand uncertainties of modeling at varying scales – from global modeling to single source modeling for compliance with App W requirements.

Theresa mentioned she'd heard there was work ongoing to look at the NOx bias for onroad mobile, but the same exists for other source categories? Shantha replied that Heather Simon's (EPA) presentation indicates the issue is for all, with onroad being the largest category at a 30-70% bias. EPA and others are also focusing on EGUs and other point sources.

3) Brief overview of regional/state/local modelers Nov. workshop http://www.cleanairinfo.com/regionalstatelocalmodelingworkshop/archive/2016/agenda.htm

Bret Anderson (USFS) reported that because the Appendix W revisions are not finalized yet, there was little new information disseminated at the workshop. EPA could only go over the plan of action and that was mostly a rehash of information given at previous conferences when the proposed rule came out. EPA is trying to get the final signed this week, so, should see something soon.

Theresa asked if there was an update related to release of the final regional haze rule and guidance. Bret responded that he understood the rule should be coming before the change in administration, if not by the end of the year. The second round of interagency review was

recently completed and the rule should be in signature chain. Michael Feldman (R6) agreed – they're hoping App W revisions are coming very soon and the office heard in the next week or two for the regional haze rule release.

4) Fed/State Technical Work Collaborative Group – overview of Dec. 9th conf call

Theresa updated the committee on the base inventory subgroup activities and asked that if their state had a preference for EPA to use 2015 or 2016 in their next round of national modeling, let Alex Cohan with LADCO know. Even though EPA is developing platforms for each year, they've not made a decision regarding which one to use for a final 2015 Ozone Transport FIP. She also updated the MJO subgroup activities regarding a data "wish" list and the group is talking about a process to efficiently transfer the data to each interested MJO/state. There is a call with Norm Possiel and others from EPA to walk through the list. The goal is that the list and process are ready by the time the NODA is released. Robin Langdon (OAQPS) gave an update on the non-EGU control measures survey – 30 states and some locals responded. EPA is now compiling information –there are about 4,000 records that EPA will update/correct in the 2014 NEIV2 based on the information received. Mark Janssen (LADCO) updated the group on the ERTAC/EPA subgroup - they've worked through issues for the final 2008 Ozone CSAPR rule and will be starting on documentation states can use if they want to use the ERTAC tool for SIPs. Once the NODA for 2015 Ozone CSAPR is released, they will start reviewing IPM data. Finally, Norm is working to get a webinar regarding CMAQ updates pulled together for the week of Jan. 30th, then one with Ramboll Environ to talk about CAMx updates shortly thereafter.

5) E-Enterprise Teams (air quality focus) updates

CAER short-term projects seeking members - QA/AC, GHG, TRI/NEI/SLT Program Crosswalk, Emissions Data Design, and SCC/Emission Factors

EPA held a webinar last week to provide a status of the various projects. The presentation should eventually be on EPA's website. Short-term projects completed to date include a data dictionary and SCC web service that can be used to compare with an individual state's system. See: https://www.epa.gov/e-enterprise/phase-1-short-term-wins

List of other projects still seeking members for are listed above – time commitments and other info is available on the webpage. Kathy Pendleton (TX) added the SCC web service product is an attempt to match up SCCs less of a hassle. She reiterated if interested in any of the groups, let her or Marc. H know.

Joshua Kalfus is a member of the facility ID group and Theresa will ask him to provide an update on the January CenSARA TWS call.

6) EPA/RPO/MJO technical work coordination

a. NOMAD Workgroup and Subcommittees

The group's last call was November 16th. Categories discussed included ag tilling, which EPA is updating for 2014 V2 based on input they received from Iowa and Kansas that fewer passes are occurring than historically. Results will be approximately 20% decrease in PM. Composting is another category Abt continues to work on and have uploaded a first draft of their methodology results on Sharepoint for comments (by the end of December). Part of the challenge in gathering data is

that there is no NAICS code for composting yet. Stacy Allen (MO) added the initial approach is to base emissions on lb/person. She found some information related to locations of composting facilities that was forwarded to EPA to get placement of emissions correct. Marnie Stein (IA) said she was able to get composting tons information from their land division and discovered their state is probably under estimated (EPA has 400 tons; should be closer to 600 tons for VOC). She categorized each location material into yard, trees, animal, or animal bedding. Stacy added that's one reason the lb/person basis probably shouldn't be the default, as it doesn't translate to an animal bedding category. EPA is using California's emission factors, but that may also need to be changed.

b. MJO MOVES Workgroup
Theresa mentioned the next call for the group is Thursday, Dec. 15th.

c. ERTAC EGU
See above.

d. National Oil and Gas Committee (Environ draft memo - https://www.wrapair2.org/NatOilGas.aspx)
The last call was Dec. 8th during which Ramboll-Environ reviewed the draft report from the MJO project. It is now out for state review with a Dec. 30th deadline. Lynn (KS) mentioned it would be helpful if it included analyses for why states are outliers for the various categories. Theresa replied the scope of work did not include that level of work, but as mentioned on the call, the comparison work can be used by individual states to look into why their state is an outlier. For example, she mentioned that Missouri and Nebraska might want to look at Table 2, which has NOx and VOC point source emissions much higher compared to other states. When she asked John Grant (Ramboll-Environ), he said it was because of the NAICS codes they had to use but encouraged her to check in with him. The final report will be used to help the Committee set priorities for 2017 NEI work.

e. 2014 NEI National Fire Emissions Inventory Workgroup – *no update*

f. 2014 NEI Rail Inventory Improvement Group
Theresa mentioned that during the November monthly call, Mark J. (LADCO) gave the heads up there should be line haul and switchyard data ready for states to review by mid-December. The data will be based on updates provided by the railroad companies. For states, a focus on switcher yards may be time better spent than focusing on line haul. The next call is scheduled for Thursday, December 15th.

7) Other topics
Marnie asked if other states have received a letter from EPA that said they fulfilled the NEI requirements, like the one sent for the 2011 NEI. Lynn (KS) replied they had not yet. Stacy (MO) said Marc Houyoux told her because of his assignment to CAER,

the letters were probably not going to happen this round and the survey was intended to be the substitute (though it didn't work out like envisioned).

8) Next call – Tuesday, January 10th, 10:00-11:00 am central time

To: Feldman, Michael[Feldman.Michael@epa.gov]
Cc: Tomasovic, Brian[Tomasovic.Brian@epa.gov]; Kordzi, Joe[Kordzi.Joe@epa.gov]; Imhoff, Robert[imhoff.robert@epa.gov]
From: Snyder, Erik
Sent: Tue 12/20/2016 2:14:29 PM
Subject: TSDs and errata
BART FIP TSD-with errata.docx
Errata - BART FIP TSD.pdf
Errata - BART FIP TSD.docx
BART FIP TSD-with errata.pdf
BART FIP TSD-redline.docx
Errata - BART Modeling TSD.pdf
Errata - BART Modeling TSD.docx
BART Modeling TSD-with errata.docx
BART Modeling TSD-with errata.pdf
BART Modeling TSD-redline.docx

Hi,

Attached are revised TSDs with appropriate changes and the errata sheets for each TSD. The screening TSD was ok as is, so just the Modeling and FIP TSDs. I've also attached the word versions of these documents as well as the redline version (prior to accept changes) for your files. Let me know if you have questions, etc. Working from home about 3 hours this morning and then off for the day. I'll be in the office tomorrow morning. Feel free to call my cell if you need me. 214-207-5125

-Erik

Erik Snyder

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Technical Support Document

for the

Texas Regional Haze BART Federal Implementation Plan
(BART FIP TSD)

Prepared and Reviewed by:

Joe Kordzi
Erik Snyder
Michael Feldman
Robert Imhoff

November 2016
(Revised December 2016, see Errata- BART Modeling TSD for details)

ED_001237_00072752

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Texas Regional Haze BART FIP Technical Support Document

1 Introduction

In our previous action,[1] we determined that due to the CSAPR remand, it was not appropriate to rely on CSAPR as an alternative to SO_2 and NOx BART for Electricity Generating Units (EGUs) in Texas. As a consequence, we took no action on EGU BART.[2] Our proposed FIP would fill that regulatory gap for this requirement by assessing BART for Texas EGUs. This document describes how we propose to accomplish that objective.

2 Our Evaluation of the Texas Infrastructure SIP Submittals for Interstate Visibility Transport

Section 110(a)(2)(D)(i)(II) of the CAA requires that states have a SIP, or submit a SIP revision, containing provisions prohibiting emissions from within a state from interfering with measures required to be included in the implementation plan for any other state under the provisions of Part C of the CAA protecting visibility. To determine whether the CAA Section 110(a)(2)(D)(i) requirement for visibility protection is satisfied, the SIP must address the potential for interference with visibility protection caused by the pollutant (including precursors) to which the new or revised NAAQS applies. Pollutants which could interfere with visibility protection include: (1) SO_2 (which is also a precursor for $PM_{2.5}$), (2) nitrogen oxides (which includes NO_2 and are precursors for ozone and $PM_{2.5}$) and (3) particulate matter.[3] In the infrastructure SIP submittals for the ozone, $PM_{2.5}$, NO_2 and SO_2 NAAQS Texas indicated that the Regional Haze SIP fulfilled its obligation for addressing emissions that would interfere with measures required to be included in the SIP for any other state to protect visibility.

However, we gave limited disapproval to the Texas Regional Haze SIP based on its reliance on CAIR. As explained in our limited disapproval of the Texas regional haze SIP, many states (including Texas) relied on the improvement in visibility expected to result from the implementation of CAIR in developing their long-term strategy.[4] Texas relied on its own CAIR SIP as legal justification for these planned controls and did not include separate enforceable measures in its regional haze SIP to ensure the interstate visibility transport requirements were met. As CAIR has been replaced by CSAPR, we propose to determine that Texas may not rely on its regional haze SIP to ensure that emissions from Texas do not interfere with the measures to protect visibility in nearby states. With respect to interstate transport of air pollution and visibility protection, Texas' SIP submittals for the 1997 $PM_{2.5}$, 2006 $PM_{2.5}$, 1997 ozone, 2008 ozone, 2010 NO_2 and 2010 SO_2 NAAQS are deficient.

We are proposing a FIP to cure the deficiencies in Texas' Regional Haze Program concerning EGU BART. This FIP will replace reliance on CAIR with reliance on CSAPR to meet the requirements for EGU BART for NO_X in Texas. The FIP will address Texas EGU BART for SO_2 and PM on a source-specific basis. With the absence of CSAPR coverage for SO_2, we must

[1] See the discussion beginning on 81 FR 296,301 (January 5, 2016).
[2] Id. at 346.
[3] Section II.A.3 of Appendix Y to Part 51 – Guidelines for BART Determinations Under the Regional Haze Rule and 40 CFR 51.166(b)(i)(b).
[4] 77 FR 33643 (June 7, 2012).

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reevaluate what is needed in Texas to address interstate visibility transport. Our proposed FIP to address Texas EGU BART achieves significant reductions of SO_2, which exceed the reductions initially assumed under either CAIR or CSAPR. Under CAIR projections developed in 2005, Texas SO_2 emissions for 2015 were projected to be 352,000 tpy with CAIR compared to 418,000 tpy without CAIR.[5] Under CSAPR, the Texas SO_2 emission budget for Phase 2 was set at approximately 294,000 tpy with an assurance level of 347,000 tpy.[6] Our proposed FIP to address Texas EGU BART is estimated to reduce annual emissions of SO2 by approximately 194,000 tpy[7], a larger reduction than projected under CAIR or CSAPR.

In addition, our proposed FIP achieves reductions at large sources of SO_2 emissions (e.g., Monticello, Martin Lake and Big Brown), that have significant impacts on Class I areas in nearby states.[8] The BART FIP requires controls on many but not all of the sources that were controlled in our previous partial FIP for Texas Regional Haze. Our EGU BART FIP also includes proposed control requirements at some additional sources not controlled in our previous action on Texas Regional Haze. These include proposed controls for the J T Deely Units 1 and 2, Parish Units 5 and 6, Welsh Unit 1, and Harrington Units 1 and 2.

We are proposing to find that our proposed EGU BART FIP is adequate to prevent interference with measures required to protect visibility in other states for the first planning period.[9] We, therefore, propose a FIP to fully address Texas' interstate visibility transport obligations for the six NAAQS (1997 8-hour ozone, 1997 $PM_{2.5}$, 2006 $PM_{2.5}$, 2008 8-hour ozone, 2010 1-hour NO_2, and 2010 1-hour SO_2) based on the source-specific requirements that will be established by our proposed FIP to address Texas EGU BART for SO_2 and PM. We also propose that reliance on CSAPR for EGU NO_X BART is appropriate to ensure NO_X emissions from Texas EGUs do not interfere with other states' measures to protect visibility. We are proposing this action based on the reasoning that our BART FIP will achieve more emission reductions than projected under CAIR or CASPR and the reductions are occurring at sources that have particularly large impacts on Class I areas outside of Texas.

3 Our Strategy for Assessing BART-eligibility.

Our BART analysis is limited to BART Category 1, fossil-fuel fired steam electric plants of

[5] https://archive.epa.gov/airmarkets/programs/cair/web/html/tx.html; Clean Air Interstate Rule Emissions Inventory Technical Support Document, March 2005 available at: https://archive.epa.gov/airmarkets/programs/cair/web/pdf/finaltech01.pdf

[6] https://www.epa.gov/sites/production/files/2016-02/documents/budgets_annualso2.pdf

[7] Sum of estimated reductions due to all proposed controls calculated from a baseline of the 2011 – 2015 five year average of the SO_2 annual emissions, excluding the maximum and minimum values.

[8] For example, CALPUFF modeling and CAMx modeling estimate that emissions from Monticello can significantly impact visibility at Caney Creek in Arkansas, with many modeled days impacted at levels exceeding 1.0 dv. See BART Screening TSD and BART Modeling TSD for summaries of modeled visibility impacts and visibility benefits from controls for each BART source.

[9] This proposed FIP for interstate visibility transport is premised on the interpretation that this requirement can be addressed even when a Regional Haze SIP is not fully approved and the FIP does not purport to correct all Regional Haze SIP deficiencies. *See e.g.* 76 FR 52388 (August 22, 2011); 76 FR 22036 (April 20, 2011); and 78 FR 14681 (March 7, 2013); *see also*, 2013 i-SIP Guidance, at page 34 (stating that EPA may find it appropriate to supplement the i-SIP Guidance regarding the relationship between Regional Haze SIPs and interstate visibility transport for future planning periods).

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more than 250 million British thermal units (BTU) per hour heat input. All other BART categories were covered in the portion of the Texas Regional Haze SIP we have already approved. We followed the BART Guidelines[10] in analyzing BART for the Texas EGUs covered in this proposal. Our analysis started with the list of BART-eligible sources provided by the Texas Commission on Environmental Quality (TCEQ) in its regional haze SIP.[11] Texas describes how it constructed its BART-eligible list in Section 9 of its SIP, and lists the sources it determined as being BART-eligible in Table 9-2. Unfortunately, Texas only listed these sources by facility and not by unit. Further complicating our analysis, Texas identified each source using its own internal account number and regulated entity number, and the source name was often not descriptive. We contacted the TCEQ in an attempt to determine if a unit-specific listing was available, but were informed that due to its records retention policy, the information was too old to have been retained. That list, filtered to include only EGUs and supplemented with more descriptive names, is shown below. We hereafter refer to this list of thirty-seven EGUs as the "Texas BART list."

Table 1. Texas List of BART-Eligible EGUs

Account	Company	Plant
BC0015L	Lower Colorado River Authority	Lower Colorado River Authority (Sim Gideon)
BG0057U	City Public Service	Sommers Deely Spruce (Calaveras)
BG0186I	City Public Service	V.H. Braunig Plant
CD0013K	AEP Texas Central Company	La Palma Power Station
CI0012D	Texas Genco LP	Cedar Bayou Station
DB0251U	TXU Electric Company	North Lake Steam Electric
EE0029T	El Paso Electric Company	Newman Station
FB0025U	TXU Generation Company LP	Valley Steam Electric
FC0018G	Lower Colorado River Authority	Fayette Power Project
FG0020V	Texas Genco LP	W A Parish Station
FI0020W	TXU Big Brown Company LP	Big Brown
GB0037T	Texas Genco LP	P H Robinson Station
GJ0043K	Southwestern Electric Power	Knox Lee Power Plant
HQ0012T	TXU Generation Company LP	Decordova Steam Electric
JI0030K	AEP Texas North Company	W.T.U.-Ft. Phantom

[10] See Appendix Y to Part 51, published as the "BART Guidelines" and the associated preamble language beginning in 70 FR 39104 (July 6, 2015).
[11] As we discuss later in our BART FIP TSD, we also performed an independent assessment of Texas' BART-eligibility determination.

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LN0081B	Xcel Energy	Jones Station
MB0116C	TXU Generation Company LP	Tradinghouse Steam Electric
ME0006A	Southwestern Electric Power Wilkes	Wilkes Power Plant
MM0023J	TXU Generation Company LP	Sandow Steam Electric
MO0014L	TXU Generation Company LP	Morgan Creek Steam
MQ0009F	Entergy Gulf States Inc	Lewis Creek Plant
NE0024E	AEP Texas Central Company	Barney M Davis Power
NE0025C	Lon C Hill Power	Lon C Hill
NE0026A	AEP Texas Central Company	Nueces Bay Power Station
OC0013O	Entergy Gulf States Inc	Sabine Plant
PG0040T	Southwestern Public Service	Nichols Station
PG0041R	Southwestern Public Service	Harrington Station
RL0020K	TXU Generation Company LP	Martin Lake Electric
TA0352I	TXU Generation Company LP	Eagle Mountain Station
TF0012D	Southwestern Electric Power	Welsh Power Plant
TF0013B	TXU Generation Company LP	Monticello Stm Electric
TG0044C	AEP Texas	San Angelo Power
TH0004D	Electric Utility Dept	Decker Creek Power
VC0003D	Victoria Power	Victoria Power
WC0028Q	TXU Generation Company LP	Permian Basin Steam Electric
WE0005G	Laredo Power	Laredo Power
YB0017V	TXU Generation Company LP	Graham Steam Electric

Our overall strategy for assessing BART-eligibility for Texas EGUs was as follows:

- Convert the Texas BART List to a unit-based list, and supplement it with additional information.
- Update the Texas BART List to account for retirements.
- Conduct a preliminary BART-eligibility assessment based on the Texas BART List.
    - Send letters requesting information (hereinafter, "Section 114(a) letters") from all facilities on the Texas BART List that appeared to be BART-eligible.[12]

[12] Clean Air Section 114(a), 42 U.S.C. § 7414, empowers the EPA, *inter alia*, to require an owner or operator of an emission source to provide information that is reasonably required to carry out any provision of the Clean Air Act (except subchapter II with respect to new motor vehicles or their engines).

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- Follow-up with additional Section 114(a) letters, as needed, requesting additional information or documentation.
- Conduct a supplemental BART-eligibility Assessment, using U.S. Energy Information Administration (EIA) information and data to determine if any additional EGUs should be examined.
  - Send additional Section 114(a) letters to any additional EGUs that appeared to be potentially BART-eligible.
  - Follow-up with additional Section 114(a) letters, as needed, requesting additional documentation.

Below, we discuss how we performed each of those steps.[13]

3.1 Refinement of the Texas BART List

From an investigation of various information sources,[14] we noted that a number of the EGUs on the Texas BART list have since been retired:

Table 2. Known Texas EGU Retirements

Plant	Comments
La Palma Power Station	Shutdown in 2006
North Lake Steam Electric	Shutdown 2008/2009
Valley Steam Electric	Mothballed, retired in 2015
P H Robinson Station	Shutdown 2009
W.T.U.-Ft. Phantom	Shutdown 2004
Tradinghouse Steam Electric	Dismantled 2014
Lon C Hill	Mothballed 2002, shutdown 2006
Eagle Mountain Station	Shutdown 2006
San Angelo Power	Shutdown 2004
Permian Basin Steam Electric	Unit 5 retired 2010, Unit 6 retired 2015
Morgan Creek Steam	Units 2, 3, 4 Retired 2004, demolished In 2011. Units 5 And 6 retired in 2009, demolished 2012
Barney M Davis Power	Unit 2 replaced with 2 combined cycle turbines
Decordova Steam Electric	Unit 1 (Not Ct1) retired 2010, demolished in 2013

[13] The information and analysis discussed in these steps is present in the files, "TCEQ BART Analysis.xlsx," and "EIA Suppl BART Analysis.xlsx."

[14] We conducted Internet searches and consulted ERCOT and Texas PUC documents. These sources are contained within our docket for this action.

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Laredo Power	Units 1, 2, 3 demolished 2008
Nueces Bay Power Steam	Units 5 And 6 retired 2008

We subtracted the retired units from the Texas BART List.[15] We then converted the Texas BART List to a unit-based list. We did this by gathering basic information concerning the configuration of the units and their in-service dates from the Energy Information Administration (EIA)[16].

3.2 Preliminary BART-Eligibility Assessment and First Round 114 Letters

Our goal in conducting a preliminary BART-eligibility assessment was to identify which facilities on the Texas BART List should be required to conduct a BART-eligibility analysis. We first performed a preliminary BART-eligibility assessment in order to identify the units that should be required to undergo a formal BART-eligibility analysis.

The BART Guidelines define a three step test that must be followed in order to determine BART-eligibility:[17]

> Step 1: Identify the emission units in the BART categories,
> Step 2: Identify the start-up dates of those emission units, and
> Step 3: Compare the potential emissions to the 250 ton/yr cutoff.

BART-Eligibility Step 1

As the BART Guidelines note, Step 1 in the BART-eligibility test involves the identification of emission units in the BART categories. Specifically, a facility passes Step 1 of the BART eligibility test if it has at least one unit in one of the 26 BART categories. We consequently filtered our EIA data for facilities that had at least one unit with a steam component, based on the EIA data. This included units listed as "Conventional Steam Coal" Natural Gas Steam Turbine," and "Natural Gas Combined Cycle."

BART-Eligibility Step 2

Step 2 of the BART-eligibility test involves determining whether any of the units identified in Step 1 fall within the BART timeframe. Specifically, a facility passes Step 2 if any of the units identified in Step 1 were "in existence" on August 7, 1977, and began operation after August 7, 1962. The BART Guidelines define "in existence" as[18]:

> [T]he owner or operator has obtained all necessary preconstruction approvals or

[15] The revised Texas BART List appears in Tab "Potential BART-eligible" of the file, "TCEQ BART Analysis.xlsx."
[16] We used 2014 (the latest available as of the time of our assessment) EIA Form 860 data available here: http://www.eia.gov/electricity/data/eia860/index.html.
[17] 70 FR 39103, 39158 (July 6, 2005) [40 CFR Part 51, App. Y].
[18] 70 FR 39103, 39159 (July 6, 2005) [40 CFR Part 51, App. Y].

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> permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time. 40 CFR 51.301.

In order to conservatively identify any units that might satisfy Step 2 in our potentially BART-eligible test, we filtered the units that passed Step 1 for EIA "in-service" dates after 1962 to and including 1982. We went five years beyond the BART timeframe discussed above, in order to identify any units that could have begun construction within the BART timeframe, but did not become operational until afterwards. In so doing, we concluded that a reasonable construction time for a typical EGU was up to five years.

BART-Eligibility Step 3

Step 3 of the BART-eligibility test checks whether the potential emissions from units that passed Steps 1 and 2 exceed 250 ton/yr of any single visibility impairing pollutant. The remaining portions of Section 3 describe how we completed this task.

A unit's potential emissions are only limited by the unit's state air permit. We attempted to locate each unit's air permit, using the TCEQ's online Air Permits Remote Document Server.[19] However, due to the particular limitations of this service, we were unable to efficiently or reliably confirm that we had in fact found the latest version of each unit's permit. Consequently, we were unable to confidently use Texas permitting information to assess the potential emissions from the units in question, and we abandoned this investigative approach. Alternatively, we compiled annual emissions from 2000 to 2015.[20] All of the units in question passed Step 3 of the BART-eligibility test for either SO_2 or NOx (or both).

For any of the units that satisfied both Steps 1 and 2 of our potentially BART-eligible test, we requested certain information under the authority granted to us under Section 114(a) of the Clean Air Act, to assist us in determining which units were in fact BART-eligible.[21] We refer to these initial letters as "First Round 114 Letters," to distinguish them from subsequent rounds of Section 114 letters that were required. These First Round 114 Letters typically requested the following information:

1. If available, furnish copies of all completed surveys calling for information relevant to BART eligibility of the source (and associated documentation) that were previously submitted to the TCEQ in or around 2005. As discussed in Chapter 9 of the Texas Regional Haze SIP, the information that was provided in response to the survey should include, at a minimum:

[19] The TCEQ's Air Permits Remote Document Server is available here: http://www.tceq.state.tx.us/permitting/air/air_permits.html.

[20] Downloaded from the EPA Air Markets Program Data, available here: https://ampd.epa.gov/ampd/. See the tab, "Annl Emissions" in the file, "TCEQ BART Analysis.xlsx."

[21] All the Section 114(a) letters and responses are present in our docket. The pertinent responses are summarized in the file, "114 Letter Response Summary.xlsx."

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a. Your identification of equipment built or reconstructed during the applicable time period for BART-eligibility.
b. Your identification of whether the potential to emit of the site is less than 250 tons per year.
c. Your detailed survey of all operating and idle equipment at the site.
d. Your responses to questions on whether each piece of equipment at the site was built or reconstructed during the applicable time period for BART-eligibility
e. Your response to a question on whether the potential to emit of units from the applicable time period "exceeded the 250 tpy threshold for applicable emissions."

2. State whether past survey responses remain valid for the present equipment and operations of the facility. If any individual responses are no longer accurate, please identify what has changed with a supporting explanation and/or supporting documentation.

3. State the BART-eligibility of any sources under Category 1, Fossil-fuel fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input, for Sulfur Dioxide (SO_2) and Nitrogen Oxides (NOx) with an analysis that applies the steps that are outlined in the BART Guidelines.[22] Specifically address the following steps of the BART Guidelines:

    a. Step 1: Identify Emission Units in the BART Categories.
    b. Step 2: Identify the Start-Up Dates of the Emission Units[23]
    c. Step 3: Compare the Potential Emissions to the 250 Ton/Yr Cutoff.

4. If an EGU has been dismantled, shut down, mothballed, or otherwise is out of service such that it no longer contributes to the source's BART-eligibility under the BART Guidelines, then so state.

5. Provide any information necessary to document all assertions concerning the BART-eligibility of the source under the BART Guidelines.

6. For any EGUs that would be included in any BART-eligible source, please send copies of all of your active and most recently issued (including modifications/alterations) New Source Review (NSR) construction permits. This includes the cover sheet, Special Conditions, and Maximum Allowable Emission Rate Tables. This request includes but is not limited to:

    a. Prevention of Significant Deterioration (PSD) permits.
    b. Nonattainment NSR permits.
    c. Plant wide Applicability Limit (PAL) permits.
    d. Non-SIP and SIP approved flexible permits.
    e. Minor individual NSR permit actions.

[22] See the discussion beginning on 70 FR 39103, 39158 (July 6, 2005).
[23] In particular, see the discussion regarding the meaning of the term "in existence," on 70 FR at 39159.

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f. If any permit by rule (PBR) or qualified facility (or any other minor action) that modifies/alters an individual NSR permit emission limit, and that emission change is not reflected in the individual permit that was modified by the action, please send copies of all those applicable minor actions.
g. Site-wide PBR actions that regulate activities such as coal handling, etc.
h. Permit applications if they contain permit representations that are enforceable and were not reflected in the permit document itself.
i. Copies of your active Title V operating permits.

The following facilities received a First Round 114 Letter based on our preliminary BART-eligibility assessment for the units listed below:

Table 3. Facilities Receiving First Round 114 Letters

Facility Name	Unit ID	Facility Potentially BART Eligible? (satisfies both steam component + date test for at least one unit)	Utility Name
Decker Creek	1	Yes	Austin Energy
Decker Creek	2	Yes	
Decker Creek	GT-1A	No	
Decker Creek	GT-1B	No	
Decker Creek	GT-2A	No	
Decker Creek	GT-2B	No	
Decker Creek	GT-3A	No	
Decker Creek	GT-3B	No	
Decker Creek	GT-4A	No	
Decker Creek	GT-4B	No	
J K Spruce	1	No	City of San Antonio
J K Spruce	2	No	
J T Deely	1	Yes	
J T Deely	2	Yes	
V H Braunig	1	Yes	
V H Braunig	2	Yes	
V H Braunig	3	Yes	
V H Braunig	CGT5	No	
V H Braunig	CGT6	No	
V H Braunig	CGT7	No	
V H Braunig	CGT8	No	
V H Braunig	CT01	No	
V H Braunig	CT02	No	
Newman	1	No	El Paso Electric Co

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Newman	2	Yes	
Newman	3	Yes	
Newman	4	Yes	
Newman	5	No	
Newman	GT-6A	No	
Newman	GT-6B	Yes	
Lewis Creek	1	Yes	Entergy Texas Inc.
Lewis Creek	2	Yes	
Sabine	1	Yes	
Sabine	2	Yes	
Sabine	3	Yes	
Sabine	4	Yes	
Sabine	5	Yes	
Sam Seymour (Fayette)	1	Yes	Lower Colorado River Authority
Sam Seymour (Fayette)	2	Yes	
Sam Seymour (Fayette)	3	No	
Sim Gideon	1	Yes	
Sim Gideon	2	Yes	
Sim Gideon	3	Yes	
Big Brown	1	Yes	Luminant Generation Company LLC
Big Brown	2	Yes	
Decordova	CT1	No	
Decordova	CT2	No	
Decordova	CT3	No	
Decordova	CT4	No	
Graham	1	No	
Graham	2	Yes	
Martin Lake	1	Yes	
Martin Lake	2	Yes	
Martin Lake	3	Yes	
Monticello	1	Yes	
Monticello	2	Yes	
Monticello	3	Yes	
Morgan Creek	CT1	No	
Morgan Creek	CT2	No	
Morgan Creek	CT3	No	
Morgan Creek	CT4	No	
Morgan Creek	CT5	No	
Morgan Creek	CT6	No	
Permian Basin	CT1	No	

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Permian Basin	CT2	No	
Permian Basin	CT3	No	
Permian Basin	CT4	No	
Permian Basin	CT5	No	
Sandow	4	Yes	
Cedar Bayou	CBY1	Yes	NRG Texas Power LLC
Cedar Bayou	CBY2	Yes	
W A Parish	CTSC	Yes	
W A Parish	WAP1	No	
W A Parish	WAP2	No	
W A Parish	WAP3	No	
W A Parish	WAP4	Yes	
W A Parish	WAP5	Yes	
W A Parish	WAP6	Yes	
W A Parish	WAP7	Yes	
W A Parish	WAP8	Yes	
Victoria Power Station	9	Yes	ReNu Power Holdings LLC
Knox Lee Power Plant	2	No	Southwestern Electric Power Co
Knox Lee Power Plant	3	No	
Knox Lee Power Plant	4	No	
Knox Lee Power Plant	5	Yes	
Welsh Power Plant	1	Yes	
Welsh Power Plant	2	Yes	
Welsh Power Plant	3	Yes	
Wilkes Power Plant	1	Yes	
Wilkes Power Plant	2	Yes	
Wilkes Power Plant	3	Yes	
Harrington Station	061B	Yes	Southwestern Public Service Co
Harrington Station	062B	Yes	
Harrington Station	063B	Yes	
Jones Station	1	Yes	
Jones Station	2	Yes	
Jones Station	3	No	
Jones Station	4	No	
Nichols Station	141B	No	
Nichols Station	142B	Yes	
Nichols Station	143B	Yes	
Barney M. Davis	1	Yes	Topaz Power Group LLC
Barney M. Davis	3	No	
Barney M. Davis	4	No	
Laredo	4	No	
Laredo	5	No	
Nueces Bay	8	No	

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Nueces Bay	9	No	

In performing our preliminary BART-eligibility analysis, we inadvertently made two mistakes that we subsequently rectified. First, we mistakenly included the Jones, Nichols, and Harrington Power Plants, owned by Southwestern Public Service Company, in the First Round Section 114 Letter to the Southwestern Electric Power Company. We subsequently sent a separate Section 114(a) letter to the correct owner or operator, i.e., Southwestern Public Service Company, requesting that it perform a BART analysis on those facilities. Second, we mistakenly left the O. W. Sommers Facility, included in the TCEQ's BART List within the "Sommers Deely Spruce" plant off of our refinement of the Texas BART List. We subsequently discovered this during our supplemental BART-eligibility analysis, discussed below, and sent the City of San Antonio, which owns this facility, a Section 114(a) letter requesting that it perform a BART-eligibility analysis. These Section 114 letters are included in our docket.

3.3 First Round Follow-up 114 Letters

Due to inadequately documented or unsupported assertions made by a number of companies in their response to our First Round 114 letters, we found it necessary to request clarification. These "First Round Follow-up 114 Letters" mainly requested documentation to support the "in existence" determinations made by these facilities. Below is a summary of which facilities received these First Round Follow-up 114 Letters for the units listed below:

Table 4. Facilities Receiving First Round Follow-up Section 114(a) Letters

Facility Name	Unit ID	Utility Name
Nichols Station	142B	Xcel Energy
Sabine	1	Entergy Texas Inc.
Sabine	5	
W A Parish	WAP7	NRG Texas Power LLC
W A Parish	WAP 8	
Welsh	3	American Electric Power

3.4 Second Round 114 Letters

After performing our preliminary BART-eligibility assessment, we became aware that some facilities that were potentially BART-eligible and were not on the Texas BART List merited additional investigation. In order to ensure we did not overlook any potentially BART-eligible facilities, we conducted a supplemental BART-eligibility assessment. We did this by examining 2014 EIA Form 860 data for Texas EGUs. We then conducted a similar preliminary BART-eligibility analysis as we did in Section 3.2.

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We addressed Steps 1 and 2 of the BART-eligibility test by filtering the EIA data in the following order:[24]

a) Only show units in Texas.
b) Only show units with operating years from 1962 to 1982, inclusive.
c) Only show units with a sector names of "electric utility," and "IPP Non-CHP," leaving out "Commercial CHP," and "Industrial CHP."
d) Only show units with prime mover names of "CA," "CT," and "ST," leaving out "GT."

As we did in Section 3.2, in filtering step b), we went five years beyond the BART timeframe in order to identify any units that could have begun construction within the BART timeframe, but did not become operational until afterwards. In filtering step c), we examined which units under EIA's sector categorization are in BART Category 1. We note that Combined Heat and Power (CHP) facilities are potentially BART-eligible under BART Category 1, if they "generate electricity for sale."[25] The following units were identified by the EIA data as being either commercial or industrial CHP units:

[24] These filtered units appear in tab "EIA 860 Filtered" in the file, "EIA Suppl BART Analysis.xlsx."
[25] 70 FR 39103, 39159 (July 6, 2005), [40 CFR Part 51, App. Y.].

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Table 5. Commercial CHP and Industrial CHP Units Not Analyzed under BART Category 1

Utility ID	Utility Name	Plant Code	Plant Name	Technology	Sector Name	Generator ID	Operating Month	Operating Year	Prime Mover
14254	Oxy Vinyls LP	50043	Houston Chemical Complex Battleground	Natural Gas Fired Combined Cycle	Industrial CHP	GT1	5	1982	CT
14254	Oxy Vinyls LP	50043	Houston Chemical Complex Battleground	Natural Gas Fired Combined Cycle	Industrial CHP	GT2	6	1982	CT
14254	Oxy Vinyls LP	50043	Houston Chemical Complex Battleground	Natural Gas Fired Combined Cycle	Industrial CHP	ST	8	1982	CA
19537	University of Texas at Austin	50118	Hal C Weaver Power Plant	Natural Gas Fired Combined Cycle	Commercial CHP	GEN7	1	1979	CA
19450	Union Carbide Corp-Seadrift	50150	Union Carbide Seadrift Cogen	Natural Gas Fired Combined Cycle	Industrial CHP	GE10	1	1964	CA
19450	Union Carbide Corp-Seadrift	50150	Union Carbide Seadrift Cogen	Natural Gas Fired Combined Cycle	Industrial CHP	IGT	1	1969	CT
18760	TPC Group, LLC	50229	Texas Petrochemicals	Natural Gas Steam Turbine	Industrial CHP	TG2	6	1972	ST
6090	ExxonMobil Oil Corp	50625	ExxonMobil Beaumont Refinery	Natural Gas Steam Turbine	Industrial CHP	TG22	2	1978	ST
6090	ExxonMobil Oil Corp	50625	ExxonMobil Beaumont Refinery	Natural Gas Steam Turbine	Industrial CHP	TG32	1	1970	ST
6090	ExxonMobil Oil Corp	50625	ExxonMobil Beaumont Refinery	Natural Gas Steam Turbine	Industrial CHP	TG33	1	1966	ST
6090	ExxonMobil Oil Corp	50625	ExxonMobil Beaumont Refinery	Natural Gas Steam Turbine	Industrial CHP	TG34	1	1967	ST
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Natural Gas Fired Combined Cycle	Industrial CHP	GN31	6	1962	CA
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Natural Gas Fired Combined Cycle	Industrial CHP	GN33	6	1978	CA
22337	Alcoa World Alumina LLC	52069	Point Comfort Operations	Natural Gas Steam Turbine	Industrial CHP	GEN4	1	1970	ST

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5338	Dow Chemical Co	5212 0	Dow Chemical Texas Operation	Natural Gas Fired Combined Cycle	Industrial CHP	G-61	10	1982	CT
5338	Dow Chemical Co	5212 0	Dow Chemical Texas Operation	Natural Gas Fired Combined Cycle	Industrial CHP	G-63	8	1982	CT
57445	Pasadena Refining System Inc	5806 9	PRSI FCC Generator	Petroleum Coke	Industrial CHP	55M1	4	1979	ST

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We have no basis of information to believe that any of the above units generate electricity for sale, and thus do not include them in BART Category 1. We invite comment on that conclusion.[26]

In filtering step d), we determined which units under EIA's prime mover categorization are in BART Category 1. EIA uses the following prime mover abbreviations:[27]

Table 6. EIA Prime Mover Abbreviations

BA	Energy Storage, Battery
CE	Energy Storage, Compressed Air
CP	Energy Storage, Concentrated Solar Power
FW	Energy Storage, Flywheel
PS	Energy Storage, Reversible Hydraulic Turbine (Pumped Storage)
ES	Energy Storage, Other (specify in SCHEDULE 7)
ST	**Steam Turbine, including nuclear, geothermal and solar steam (does not include combined cycle)**
GT	**Combustion (Gas) Turbine (does not include the combustion turbine part of a combined cycle; see code CT, below)**
IC	Internal Combustion Engine (diesel, piston, reciprocating)
CA	**Combined Cycle Steam Part**
CT	**Combined Cycle Combustion Turbine Part**
CS	Combined Cycle Single Shaft (combustion turbine and steam turbine share a single generator)
CC	Combined Cycle Total Unit (use only for plants/generators that are in planning stage, for which specific generator details cannot be provided)
HA	Hydrokinetic, Axial Flow Turbine
HB	Hydrokinetic, Wave Buoy
HK	Hydrokinetic, Other (specify in SCHEDULE 7)
HY	Hydroelectric Turbine (includes turbines associated with delivery of water by pipeline)
BT	Turbines Used in a Binary Cycle (including those used for geothermal applications)
PV	Photovoltaic
WT	Wind Turbine, Onshore
WS	Wind Turbine, Offshore
FC	Fuel Cell
OT	Other (specify in SCHEDULE 7)

After the first three filtering steps, only the CA, CT, ST, and GT prime movers were present for further filtering. We eliminated the GT units, since they were not a part of a combined cycle power block and thus had no steam component and are not included in BART Category 1.

[26] As explained in the proposal that this TSD accompanies, we welcome comments on any aspects of our proposal, including all applicable technical support. In this TSD we "invite comment" at several points. These invitations are not necessarily repeated in the proposal itself, and they may concern minor or technical issues.

[27] See the "Reference Tables 1-3" tab of the file, "Layout2014.xlsx" in the 2014 EIA Form 860 data.

We then eliminated those units already covered in our First Round 114 Letter assessment we conducted in Section 3.2. We were left with the following units that were not included in the Texas BART List:[28]

[28] See tab "Suppl BART" in the file, "EIA Suppl BART Analysis.xlsx."

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Table 7. EIA Supplemental BART-eligible Analysis

Utility Name	Plant Code	Plant Name	Generator ID	Technology	Prime Mover	Sector Name	Operating Month	Operating Year
Luminant Generation Company LLC	3452	Lake Hubbard	1	Natural Gas Steam Turbine	ST	IPP Non-CHP	6	1970
Luminant Generation Company LLC	3452	Lake Hubbard	2	Natural Gas Steam Turbine	ST	IPP Non-CHP	11	1973
Exelon Power	3453	Mountain Creek	8	Natural Gas Steam Turbine	ST	IPP Non-CHP	7	1967
NRG Texas Power LLC	3464	Greens Bayou	5	Natural Gas Steam Turbine	ST	IPP Non-CHP	6	1973
NRG Texas Power LLC	3469	T H Wharton	3	Natural Gas Fired Combined Cycle	CA	IPP Non-CHP	8	1974
NRG Texas Power LLC	3469	T H Wharton	31	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	32	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	33	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	34	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	4	Natural Gas Fired Combined Cycle	CA	IPP Non-CHP	8	1974
NRG Texas Power LLC	3469	T H Wharton	41	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	42	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	43	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	8	1974
NRG Texas Power LLC	3469	T H Wharton	44	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	8	1974
Southwestern Public Service Co	3485	Plant X	4	Natural Gas Steam Turbine	ST	Electric Utility	1	1964
Exelon Power	3491	Handley	3	Natural Gas Steam Turbine	ST	IPP Non-CHP	7	1963
Exelon Power	3491	Handley	4	Natural Gas Steam Turbine	ST	IPP Non-CHP	10	1976
Exelon Power	3491	Handley	5	Natural Gas Steam Turbine	ST	IPP Non-CHP	10	1977
Luminant Generation Company LLC	3504	Stryker Creek	ST2	Natural Gas Steam Turbine	ST	IPP Non-CHP	12	1965
Luminant Generation Company LLC	3507	Trinidad (TX)	6	Natural Gas Steam Turbine	ST	IPP Non-CHP	5	1965
City of Garland - (TX)	3576	Ray Olinger	1	Natural Gas Steam Turbine	ST	Electric Utility	7	1967
City of Garland - (TX)	3576	Ray Olinger	2	Natural Gas Steam Turbine	ST	Electric Utility	1	1971
City of Garland - (TX)	3576	Ray Olinger	3	Natural Gas Steam Turbine	ST	Electric Utility	6	1976
City of Lubbock - (TX)	3602	Ty Cooke	1	Natural Gas Steam Turbine	ST	Electric Utility	6	1965
City of Lubbock - (TX)	3602	Ty Cooke	2	Natural Gas Steam Turbine	ST	Electric Utility	6	1978
City of San Antonio - (TX)	3611	O W Sommers	1	Natural Gas Steam Turbine	ST	Electric Utility	4	1972
City of San Antonio - (TX)	3611	O W Sommers	2	Natural Gas Steam Turbine	ST	Electric Utility	1	1974

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Brazos Electric Power Coop Inc	3628	R W Miller	1	Natural Gas Steam Turbine	ST	Electric Utility	10	1968
Brazos Electric Power Coop Inc	3628	R W Miller	2	Natural Gas Steam Turbine	ST	Electric Utility	7	1972
City of Greenville - (TX)	4195	Powerlane Plant	ST1	Natural Gas Steam Turbine	ST	Electric Utility	8	1966
City of Greenville - (TX)	4195	Powerlane Plant	ST2	Natural Gas Steam Turbine	ST	Electric Utility	8	1969
City of Greenville - (TX)	4195	Powerlane Plant	ST3	Natural Gas Steam Turbine	ST	Electric Utility	8	1977
City of Garland - (TX)	4266	Spencer	4	Natural Gas Steam Turbine	ST	Electric Utility	6	1966
City of Garland - (TX)	4266	Spencer	5	Natural Gas Steam Turbine	ST	Electric Utility	5	1973
Coleto Creek Power LP	6178	Coleto Creek	1	Conventional Steam Coal	ST	IPP Non-CHP	6	1980
San Miguel Electric Coop, Inc	6183	San Miguel	1	Conventional Steam Coal	ST	Electric Utility	1	1982
Southwestern Public Service Co	6194	Tolk	1	Conventional Steam Coal	ST	Electric Utility	1	1982
City of Bryan - (TX)	6243	Dansby	1	Natural Gas Steam Turbine	ST	Electric Utility	9	1978

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As was the case with the Preliminary BART-eligibility assessment we performed in Section 3.2, we were unable to confidently use Texas permitting information to assess the potential emissions from the units in question. We therefore similarly examined annual emissions from 2005 to 2015,[29] for these units. However, we were left with mixed results: in some cases, the emissions of either SO_2 or NOx for the units that had passed Steps 1 and 2 of the BART-eligibility test were above 250 tpy, and in some case they were below. Thus, we were not able to use actual emissions to resolve whether the potential emissions test was met, and we had to cast a wider net for the information needed to assess BART-eligibility for these units. Consequently, for each owner of the units present in Table 7, we requested certain information under the authority granted to us under Section 114(a) of the Clean Air Act, to assist us in determining which units were in fact BART-eligible. These "Second Round 114 Letters" were typically similar to the First Round 114 Letters discussed in Section 3.2. [30] The following facilities received these Second Round 114 Letters for the units listed below:

Table 8. Facilities Receiving Second Round Section 114(a) Letters

Facility Name	Unit ID	Utility Name
Lake Hubbard	1	Luminant Generation Company LLC
Lake Hubbard	2	
Stryker Creek	ST2	
Trinidad	6	
Mountain Creek	8	Exelon
Handley	3	
Handley	4	
Handley	5	
Greens Bayou	5	NRG Texas Power LLC
Ty Cooke	1	City of Lubbock
Ty Cooke	2	
R W Miller	1	Brazos Electrical Coop
R W Miller	2	
R W Miller	3	
Powerlane	ST1	City of Greenville
Powerlane	ST2	
Powerlane	ST3	
Spencer	4	City of Garland
Spencer	5	

[29] Downloaded from the EPA Air Markets Program Data, available here: https://ampd.epa.gov/ampd/. See the tab, "Selected Texas Emissions" in the file, "EIA Suppl BART Analysis.xlsx."

[30] All the Section 114(a) letters and responses are present in our docket. The pertinent responses are summarizedin the file, "114 Letter Response Summary.xlsx."

Coleto Creek	1	Engie
San Miguel	1	San Miguel Electrical Coop
Dansby	1	City of Bryan

3.5 Analysis of Section 114(a) Responses.

In a few instances, we exchanged emails with companies in order to clarify the responses we received to our Section 114(a) letters. In most cases, following any follow-up correspondence, we and the companies agreed on the BART-eligibility of the units in question. The following table summarizes: the facilities' determinations of BART-eligibility, whether we agree with that determination, and whether the units in question should be analyzed to determine if they are subject to BART[31]:

Table 9. Summary of BART-Eligibility Analysis

Facility	Unit	Company says BART-eligible?	Does EPA agree with eligibility?	Assess for subject to BART?
Barney M. Davis (Talen/Topaz)	1	Y	Y	Y
Barney M. Davis (Talen/Topaz)	2	N	Y	N
Big Brown (Luminant)	1	Y	Y	Y
Big Brown (Luminant)	2	Y	Y	Y
Cedar Bayou (NRG)	CBY1	Y	Y	Y
Cedar Bayou (NRG)	CBY2	Y	Y	Y
Cedar Bayou (NRG)	CBY3	N	Y	N
Coleto Creek (Engie)	1	N	N	Y
Dansby (City of Bryan)	1	Y	Y	Y
Decker Creek (Austin Energy)	1	Y	Y	Y
Decker Creek (Austin Energy)	2	Y	Y	Y
Decordova (Luminant)	1	N	Y	N
Fayette (LCRA)	1	Y	Y	Y
Fayette (LCRA)	2	Y	Y	Y
Fayette (LCRA)	3	N	Y	N
Graham (Luminant)	1	N	Y	N
Graham (Luminant)	2	Y	Y	Y
Greens Bayou (NRG)	5	Y	Y	Y
Handley (Exelon)	3	Y	Y	Y
Handley (Exelon)	4	Y	Y	Y
Handley (Exelon)	5	Y	Y	Y

[31] We note that the mistaken omission of several EGUs sources from the State's PM BART determinations (and Texas BART list) in its SIP submission would provide another reason why the PM BART component of the SIP, pending action under our proposal, could not be approved.

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Harrington Station (Xcel)	061B	Y	Y	Y
Harrington Station (Xcel)	062B	Y	Y	Y
Harrington Station (Xcel)	063B	N	Y	N
J K Spruce (CPS Energy)	1	N	Y	N
J T Deely (CPS Energy)	1	Y	Y	Y
J T Deely (CPS Energy)	2	Y	Y	Y
Jones Station (Xcel)	151B	Y	Y	Y
Jones Station (Xcel)	152B	Y	Y	Y
Knox Lee Power Plant (AEP)	2	N	Y	N
Knox Lee Power Plant (AEP)	3	N	Y	N
Knox Lee Power Plant (AEP)	4	N	Y	N
Knox Lee Power Plant (AEP)	5	Y	Y	Y
Lake Hubbard (Luminant)	1	Luminant was non-committal		Y
Lake Hubbard (Luminant)	2			Y
Laredo (Talen/Topaz)	1	N	Y	N
Laredo (Talen/Topaz)	2	N	Y	N
Laredo (Talen/Topaz)	3	N	Y	N
Lewis Creek (Entergy)	1	Y	Y	Y
Lewis Creek (Entergy)	2	Y	Y	Y
Martin Lake (Luminant)	1	Y	Y	Y
Martin Lake (Luminant)	2	Y	Y	Y
Martin Lake (Luminant)	3	Y	Y	Y
Monticello (Luminant)	1	Y	Y	Y
Monticello (Luminant)	2	Y	Y	Y
Monticello (Luminant)	3	Y	Y	Y
Morgan Creek (Luminant)	3	N	Y	N
Morgan Creek (Luminant)	4	N	Y	N
Morgan Creek (Luminant)	5	N	Y	N
Morgan Creek (Luminant)	6	N	Y	N
Mountain Creek (Exelon)	8	N	Y	N
Newman (El Paso Electric)	1	N	Y	N
Newman (El Paso Electric)	2	Y	Y	Y
Newman (El Paso Electric)	3	Y	Y	Y
Newman (El Paso Electric)	4	Y	Y	Y
Newman (El Paso Electric)	6	N	Y	N
Nichols Station (Xcel)	141B	N	Y	N
Nichols Station (Xcel)	142B	N	Y	N
Nichols Station (Xcel)	143B	Y	Y	Y
Nueces Bay (Talen/Topaz)	5	N	Y	N
Nueces Bay (Talen/Topaz)	6	N	Y	N
Nueces Bay (Talen/Topaz)	7	N	Y	N
O W Sommers (CPS Energy)	1	Y	Y	Y
O W Sommers (CPS Energy)	2	Y	Y	Y
Permian Basin (Luminant)	5	N	Y	N

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Permian Basin (Luminant)	6	N	Y	N
Plant X (Xcel)	4	Y	Y	Y
Powerlane (City of Greenville)	ST1	Y	Y	Y
Powerlane (City of Greenville)	ST2	Y	Y	Y
Powerlane (City of Greenville)	ST3	Y	Y	Y
R W Miller (Brazos Elec. Coop)	1	Y	Y	Y
R W Miller (Brazos Elec. Coop)	2	Y	Y	Y
R W Miller (Brazos Elec. Coop)	3	Y	Y	Y
Sabine (Entergy)	1	N	Y	N
Sabine (Entergy)	2	Y	Y	Y
Sabine (Entergy)	3	Y	Y	Y
Sabine (Entergy)	4	Y	Y	Y
Sabine (Entergy)	5	Y	Y	Y
San Miguel (San Miguel Elec. Coop)	1	N	Y	N
Sandow-Luminant	4	N	Y	N
Sim Gideon (LCRA)	1	Y	Y	Y
Sim Gideon (LCRA)	2	Y	Y	Y
Sim Gideon (LCRA)	3	Y	Y	Y
Spencer (City of Garland)	4	Y	Y	Y
Spencer (City of Garland)	5	Y	Y	Y
Stryker Creek (Luminant)	ST2	Luminant was non-committal		Y
Tolk (Xcel)	1	N	Y	N
Tolk (Xcel)	2		Tolk (Xcel)	1
Trinidad (Luminant)	6	Luminant was non-committal		Y
Ty Cooke (City of Lubbock)	1	Y	Y	Y
Ty Cooke (City of Lubbock)	2	Y	Y	Y
V H Braunig (CPS Energy)	1	Y	Y	Y
V H Braunig (CPS Energy)	2	Y	Y	Y
V H Braunig (CPS Energy)	3	Y	Y	Y
V H Braunig (CPS Energy)	CT01	N	Y	N
V H Braunig (CPS Energy)	CT02	N	Y	N
Victoria Power Station (Renu)	6	N	Y	N
Victoria Power Station (Renu)	7	N	Y	N
Victoria Power Station (Renu)	8	N	Y	N
Victoria Power Station (Renu)	9	N	Y	N
W A Parish (NRG)	WAP 1	N	Y	N
W A Parish (NRG)	WAP 2	N	Y	N
W A Parish (NRG)	WAP 3	N	Y	N
W A Parish (NRG)	WAP	Y	Y	Y

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	4			
W A Parish (NRG)	WAP 5	Y	Y	Y
W A Parish (NRG)	WAP 6	Y	Y	Y
W A Parish (NRG)	WAP 7	N	Y	N
W A Parish (NRG)	WAP 8	N	Y	N
Welsh Power Plant (AEP)	1	Y	Y	Y
Welsh Power Plant (AEP)	2	Y	Y	Y
Welsh Power Plant (AEP)	3	N	Y	N
Wilkes Power Plant (AEP)	1	Y	Y	Y
Wilkes Power Plant (AEP)	2	Y	Y	Y
Wilkes Power Plant (AEP)	3	Y	Y	Y

The final step in identifying a ''BART-eligible source'' is to use the information from the previous three steps to identify the collection of emissions units that comprise the BART-eligible source.

4 Our Strategy for Assessing which Units are Subject to BART.

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.[32] 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. 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. 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. We employed a four-fold strategy in determining which units should or should not be subject to BART. A flowchart of the analysis along with a detailed discussion of the subject-to-BART screening analysis is provided in the BART Screening TSD.[33] We summarize the methodology and results of this analysis here.

First, we examined whether any of the BART-eligible units should be eliminated from consideration based on the standard model plant exemptions described in the BART Guidelines.[34] Second, we created specific model plants between sources and nearby Class I

[32] *See* 40 C.F.R. Part 51, Appendix Y, III, *How to Identify Sources "Subject to BART"*

[33] See our TSD, "Our Strategy for Assessing which Units are Subject to BART for the Texas Regional Haze BART Federal Implementation Plan (BART Screening TSD)" in our docket.

[34] See the discussion beginning on 70 FR 39104, 39162 (July 6, 2005) [40 CFR Part 51, App. Y].

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areas and conducted CALPUFF modeling to evaluate a number of sources for exemption. . Third, we performed stand-alone source specific CALPUFF modeling on a number of units to determine if their visibility impacts were large enough to identify them as being subject to BART. Fourth, for those remaining units outside of the CALPUFF model's range, we contracted to have CAMx modeling performed to determine if their visibility impacts were large enough to merit their being subject to BART. CAMx results for sources within CALPUFF range are also included to provide additional information supporting the CALPUFF based determinations. These steps and the results of these analyses are described in detail in our BART Screening TSD.[35]

Based on the methodology described above, the BART-eligible sources in the table below have been determined to cause or contribute to visibility impairment at a nearby Class I area and we therefore propose they are Subject-to-BART.

Table 10. Subject-to-BART Sources

Facility	Units
Big Brown	1 & 2
Coleto Creek	1
Fayette Power	1 & 2
Harrington	061B & 062B
Martin Lake	1, 2 & 3
Monticello	1, 2 & 3
Calaveras	Deely 1 & 2, Sommers 1 & 2
W A Parish	WAP4, WAP5 & WAP6
Welsh	1&2*
Stryker	ST2
Graham	2
Wilkes	1, 2 & 3
Newman	2, 3 & 4

* Welsh Unit 2 retired April, 2016.

5 Our BART Five Factor Analyses

In our previous action,[36] we determined that due to the CSAPR remand, it was not appropriate at that time to rely on CSAPR as an alternative to SO_2 and NO_X BART for EGUs in Texas. As a consequence, action to satisfy the overdue requirement to address BART for EGUs in the state of Texas was further delayed.[37] In this proposal, we are proposing that CSAPR, once fully revised to address the D.C. Circuit's remand, provides a basis for satisfying EGU BART obligations for NO_X alone. It remains the case that we cannot rely on CSAPR as an alternative to

[35] Due to the length and complexity of the process we employed in determining which BART-eligible sources are subject-to-BART, we have described it in a separate TSD, entitled, "BART Screening TSD."
[36] See the discussion beginning on 81 FR 301 (January 5, 2016).
[37] Id. at 346.

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SO_2 BART for Texas EGUs as further confirmed by our proposed action to remove Texas from the annual NO_X and SO_2 control programs. Thus, we have the obligation to consider source-specific requirements for Texas EGUs consistent with the BART Guidelines for SO_2 BART.

Because the component of the Texas Regional Haze SIP regarding the PM BART requirement for EGUs has not been acted on, we have the responsibility under CAA section 110(k) to evaluate the submission and take action to approve or disapprove it. The SIP determinations for PM were based on modeling that was conducted by examining visibility impairment due to PM emissions alone, based on the assumption that the state would be participating in CAIR for SO_2 and NO_X and thereby having BART coverage for those pollutants. The Texas Regional Haze SIP had concluded that no PM BART controls for EGUs were appropriate, because modeling assessment of PM impacts alone showed their impacts to be too small for consideration for control. But Texas' screening analysis is no longer reliable or accurate because of the invalid assumption that source-by-source BART for either SO_2 or NO_X would not be required.[38] In order to appropriately evaluate the BART requirements for EGUs, the visibility impacts from all pollutants must be studied, including PM emissions. Texas' PM BART analysis for EGUs does not do this.[39] Considering this, our BART evaluation will evaluate BART for potential SO_2 and PM controls.

All units that are subject to BART must undergo a BART analysis. Regarding this, Section 51.308(e) states:

> The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

This is commonly referred to as the "BART five factor analysis." The BART Guidelines break the analyses of these requirements down into five steps:[40]

> STEP 1—Identify All Available Retrofit Control Technologies,
> STEP 2—Eliminate Technically Infeasible Options,
> STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies,

[38] Additionally, the Texas SIP had mistakenly omitted EGUs from its BART-eligible source list that, by our investigation, should have also been identified as BART-eligible and evaluated for PM BART. Since Texas did not retain underlying records from its survey of BART sources, we are unable to identify what may have led to these omissions.

[39] Texas' Regional Haze SIP determined whether its sources should be subject to review for PM controls by only looking at the impact of PM emissions on visibility. This approach is appropriate, when a State satisfies the requirements for BART for SO_2 and NO_X with an alternative measure. It is not valid under the current facts, as the SIP itself acknowledged. See, e.g., TX Regional Haze SIP Narrative at 9-17 ("Some EGUs may become subject to BART pending resolution of CAIR at the federal level")

[40] 70 FR 39103, 39164 (July 6, 2005) [40 CFR 51, App. Y].

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STEP 4—Evaluate Impacts and Document the Results, and
STEP 5—Evaluate Visibility Impacts.

The following sections treat these steps individually for SO_2. We are combining these steps into one section for PM.

5.1 Steps 1 and 2: Identification of Technically Feasible SO_2 Retrofit Control Technologies

The BART Guidelines state that in identifying all available retrofit control options,

> [Y]ou must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving.[41]

Adhering to this, we will identify a reasonable set of SO_2 control options, including those that cover the maximum level of control each technology is capable of achieving. In the course of that task, we will note whether any of these technologies are technically infeasible.

The subject-to-BART units identified in Table 10, can be organized into four broad categories, based on their fuel type and the potential types of SO_2 controls that could be retrofitted: (1) coal-fired EGUs with no SO_2 scrubber, (2) coal-fired EGUs with underperforming SO_2 scrubbers, (3) gas-fired EGUs that do not burn oil, and (4) gas-fired EGUs that occasionally burn fuel oil. This classification is represented below:

Table 11. Subject to BART Fuel Types and Potential SO2 BART Controls

Facility	Unit	Coal no scrubber	Coal underperforming scrubber	Gas no oil	Gas burns oil
Big Brown (Luminant)	1	X			
Big Brown (Luminant)	2	X			
Coleto Creek (Engie)	1	X			
Fayette (LCRA)*	1				
Fayette (LCRA)*	2				
Graham (Luminant)	2				X
Harrington Station (Xcel)	061B	X			
Harrington Station (Xcel)	062B	X			
J T Deely (CPS Energy)	1	X			
J T Deely (CPS Energy)	2	X			
Martin Lake (Luminant)	1		X		

[41] 70 FR at 39164, fn 12 [40 C.F.R. App. Y]

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Martin Lake (Luminant)	2		X		
Martin Lake (Luminant)	3		X		
Monticello (Luminant)	1	X			
Monticello (Luminant)	2	X			
Monticello (Luminant)	3		X		
Newman (El Paso Electric)	2				X
Newman (El Paso Electric)	3				X
Newman (El Paso Electric)	4			X	
O W Sommers (CPS Energy)	1				X
O W Sommers (CPS Energy)	2				X
Stryker Creek (Luminant)	ST2				X
W A Parish (NRG)	WAP4			X	
W A Parish (NRG)	WAP5	X			
W A Parish (NRG)	WAP6	X			
Welsh Power Plant (AEP)	1	X			
Welsh Power Plant (AEP)	2	X			
Wilkes Power Plant (AEP)	1				X
Wilkes Power Plant (AEP)	2			X	
Wilkes Power Plant (AEP)	3			X	

* The Fayette units have high performing wet FGDs in place.

For the coal-fired EGUs without an existing scrubber, we have identified four potential control technologies: (1) coal pretreatment, (2) Dry Sorbent Injection (DSI), (3) Spray Dryer Absorber (SDA), and (4) wet Flue Gas Desulfurization (FGD). For the coal-fired EGUs with an existing underperforming scrubber we will examine whether that scrubber can be upgraded. Gas-fired EGUs that do not burn oil have inherently low SO_2 emissions and there are no known SO_2 controls that can be evaluated. For gas-fired units that occasionally burn fuel oil, we will follow the BART Guidelines recommendations for oil-fired units: "For oil-fired units, regardless of size, you should evaluate limiting the sulfur content of the fuel oil burned to 1 percent or less by weight."[42] Each of these control technologies are evaluated below.

5.1.1 Identification of Technically Feasible SO_2 Retrofit Control Technologies for Coal Fired Units

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.

5.1.1.1 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 amount of sulfur in the coal burned. Coal pretreatment broadly falls into two categories:

[42] 70 FR 39103, 39171 (July 6, 2005) [40 CFR 51, App. Y].

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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).[43] 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.[44] Coal is mechanically sized, then various washing techniques are employed, depending on the particle size, type of coal, and the desired level of preparation.[45] 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,[46] and coal washing slurries are typically stored in impoundments, which can, and have, leaked.[47]

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 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.

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[43] Couch, G. R., "Coal Upgrading to Reduce CO_2 emissions," CCC/67, October 2002, IEA Clean Coal Centre.
[44] Ibid.
[45] 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.
[46] "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.
[47] 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.

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Coal drying can be performed onsite and so 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.[48] 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). We cannot assess many of these issues and we believe that requesting that the facilities in question do so would require detailed engineering analysis and extend our review time greatly. As a result of these issues, we do not further assess coal drying as a potential BART control.

5.1.1.2 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. For instance, Luminant states in its response to one of our Section 114(a) letters regarding its Big Brown and Monticello units:[49]

> Luminant commissioned the study of dry sorbent injection ("DSI") at these units in 2011. These studies determined that a very high feed rate

[48] 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/

[49] Luminant's 6/17/14 response to EPA's 5/20/14 Section 114(a) request for information relating to the Big Brown, Martin Lake, Monticello, and Sandow generating stations.

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> (in the range of 20-30%) was required to achieve modest SO_2 removal. Further, it was determined that other economic and operational factors make the use of DSI infeasible. For example, sorbent build-up was determined to cause degraded performance of the control equipment over time, as well as significant, repeat down time on a regular basis (i.e., every few days) to remove the buildup. In addition to the high cost of the sorbent required, the disposal and transport of the used sorbent (a Texas Class 1 waste) would result in significant additional cost. Thus, the use of DSI was determined infeasible from both an operational and economic point of view, and further evaluation has been discontinued.

As a consequence of this statement, which is discussed more fully in the CBI material Luminant has submitted, we considered proposing that DSI is not a feasible alternative for the Big Brown and Monticello facilities, and invite the affected facilities to affirm this position in the context of BART. Nevertheless, we included DSI in our BART evaluation for these facilities in order to be conservative. For all other units, although individual installations may present technical difficulties or poor performance due to the suboptimization of one or more of the above factors, we believe that DSI is technically feasible and should be considered as a potential BART control for all of the unscrubbed coal-fired BART-eligible units, with the exception of the Big Brown and Monticello facilities. We invite comments to the contrary.

5.1.1.3 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:[50]

> 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. ·
>
> 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

[50] Babcock and Wilcox. *Steam, Its Generation and Use*. Forty-second edition, 2015. Chapter 34.

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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[51] the following types of flue gas desulfurization systems as being operational in the U.S. for 2015:

Table 12. EIA Reported Desulfurization Systems in 2015

Type	Number of installations
Wet spray tower scrubber	296
Spray dryer absorber	269
Circulating dry scrubber	50
Packed tower wet scrubber	6
Venturi wet scrubber	48
Jet bubbling reactor	31
Tray tower wet scrubber	42
Mechanically aided wet scrubber	4
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.[52] 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.

[51] 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.

[52] 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.

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Therefore, they will not be further considered as BART controls.

In summary, wet FGD and SDA installations account for approximately 81% of all scrubber installations in the U.S. and as such constitute a reasonable set of SO_2 control options. The vast majority of the wet FGD and SDA installations utilize limestone and lime, respectively as reagents. In addition, these technologies cover the maximum level of SO_2 control available. As described above, these controls are in wide use and have been retrofitted to a variety of boiler types and plant configurations. We therefore see no technical infeasibility issues and believe that limestone wet FGD and lime SDA should be considered as potential BART controls for all of the unscrubbed coal-fired BART-eligible units.

5.1.2 Identification of Technically Feasible SO_2 Retrofit Control Technologies for Gas-Fired Units

Four of the units identified in Table 10 as being subject to BART, are only permitted to burn gas: Newman Unit 4, W A Parish Unit 4, and Wilkes Units 2 and 3. These units will not be considered for SO_2 BART.[53]

A number of the units we identified in Table 10 as being subject to BART primarily fire gas, but have occasionally fired fuel oil in the past. These units are identified below in Table 13:

Table 13. Gas Units that Occasionally Burn Oil and are Subject to BART

Facility	Unit(s)	Gas Turbine	Steam Turbine
Graham (Luminant)	2		X
Newman (El Paso Electric)	2, 3		X
O W Sommers (CPS Energy)	1, 2		X
Stryker Creek (Luminant)	ST2		X
Wilkes Power Plant (AEP)	1		X

For the remaining units, we will assess SO_2 BART. To begin, we examine the historical quantity of fuel oil that has been burned by consulting the Energy Information Agency's (EIA) databases: EIA-767, EIA-906/920, and EIA-923.[54] EIA's forms have undergone a number of changes over the years preventing us from presenting an uninterrupted analysis of unit fuel oil usage. For instance, we have been able to collect unit-specific fuel usage data using EIA-767 from 2000-2004. EIA-767 did not collect this type of data in 2005, which was its last date of publication. We therefore turned to EIA-906/920 from 2005-2007, which only collected fuel usage data on a facility basis. However, we were able to access EIA-923 for unit-specific fuel usage from 2008-2015. We present a summary of this information for the units of interest below:

[53] Parish: TCEQ Permit Number 4575, 12/31/2002, general condition 7, "Fuel oil firing is limited to Units 1-3 only…." Newman: TCEQ Permit Number 1467, 5/22/2008, special condition 4.A, "Fuel fired in the gas turbines and duct burners, for Unit 4 shall be natural gas …." Wilkes: TCEQ Permit Number 45435, 11/4/02, general condition 7, "Authorization to fire fuel oil firing is limited to Unit No. 1."

[54] EIA-767: http://www.eia.gov/electricity/data/eia767/. EIA-906/920 and EIA-923: http://www.eia.gov/electricity/data/eia923/

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Table 14. EIA-767 Historical Fuel Usage for Gas Units Subject to BART that Occasionally Burn Oil

				Fuel Oil Usage in Barrels (42 gallons)												
Year	**Plant**	**Boiler Id**	**Fuel Code**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2001	Newman	2	DFO	100							5,000					5,100
2001	Graham	2	DFO	31,500												31,500
2001	O W Sommers	2	DFO	800												800
2001	Wilkes	1	DFO	27,000	4,000											31,000
2002	Graham	2	DFO			9,800										9,800
2002	Stryker Creek	2	RFO			5,000										5,000
2002	Wilkes	1	DFO						1,800							1,800
2003	Graham	2	RFO		8,400	12,000			2,900							23,300
2003	Stryker Creek	2	RFO	22,000	29,200	20,600										71,800
2003	O W Sommers	1	DFO		20,000	20,000			5,000							45,000
2003	O W Sommers	2	DFO		4,000											4,000
2003	Wilkes	1	DFO	400	5,400		2,100								1,900	9,800
2004	Graham	2	DFO												2,200	2,200
2004	Stryker Creek	2	RFO												2,800	2,800
2004	O W Sommers	1	DFO		3,000								700			3,700
2004	Wilkes	1	RFO										2,100			2,100

Table 15. EIA-906/920 Historical Fuel Usage for Gas Units Subject to BART that Occasionally Burn Oil

				Fuel Oil Usage in Barrels (42 gallons)												
Year	**Plant Name**	**Reported Prime Mover**	**Reported Fuel Type Code**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2005	Graham	ST	DFO	0	0	0	0	0	143	1,940	15,345	7,791	0	0	0	25,219
2005	O W Sommers	ST	DFO	90	0	0	0	0	5	62	27	69	67	0	62	382
2005	Wilkes	ST	RFO	0	0	0	0	0	0	0	0	2,538	8,543	0	0	11,081
2006	Graham	ST	DFO	0	0	0	0	0	1,522	7,847	6,198	0	0	0	0	15,567
2006	O W Sommers	ST	DFO	79	37	0	99	75	58	39	0	210	141	0	0	738
2006	Wilkes	ST	RFO	0	8,187	0	9	79	505	46	6,458	0	0	0	0	15,284

2007	Graham	ST	DFO	0	2,254	82	0	4	163	0	464	0	0	0	0	2,967
2007	Graham	ST	RFO	0	0	0	4	0	0	0	0	0	0	0	0	4
2007	O W Sommers	ST	DFO	71	34	25	73	33	30	51	117	112	227	37	0	810
2007	Wilkes	ST	RFO	0	0	404	1,865	0	0	0	0	0	0	0	0	2,269

Table 16. EIA-923 Historical Fuel Usage for Gas Units Subject to BART that Occasionally Burn Oil

				Fuel Oil Usage in Barrels (42 gallons)												
Year	**Plant Name**	**Boiler ID**	**Reported Fuel Type Code**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2008	Graham	2	DFO			303			118							421
2008	Wilkes	1	DFO	18		0	0	0		0	0	0	0	0	0	18
2009	O W Sommers	1	DFO	426	0	0	0	0	0	0	0	0	0	0	0	426
2009	O W Sommers	2	DFO	1,819	0	0	0	0	0	0	0	0	0	0	0	1,819
2009	Stryker Creek	2	DFO	0	24	21	18	0	0	0	0	25	0	0	0	88
2011	Graham	2	DFO	.	.	.	.	.	.	.	.	.	19	.	.	19
2011	O W Sommers	1	DFO	0	2,334	0	0	0	0	0	0	1,049	0	0	0	3,383
2011	O W Sommers	2	DFO	0	26	0	0	0	0	0	0	0	0	0	0	26
2012	Graham	2	RFO	0	0	0	0	2,077	18,177	5,657	0	0	0	0	0	25,911
2012	O W Sommers	1	DFO	0	0	0	0	0	0	0	0	0	495	0	0	495
2012	O W Sommers	2	DFO	0	0	0	0	0	0	0	0	0	87	0	0	87
2013	O W Sommers	2	DFO	0	0	0	0	0	0	0	0	378	0	0	0	378
2014	Newman	2	DFO	.	.	.	.	0	0	0	0	0	115	0	0	115
2014	O W Sommers	1	DFO	0	0	0	0	0	0	0	0	0	35	0	0	35
2014	O W Sommers	2	DFO	0	0	0	0	0	0	0	0	0	23	0	0	23
2014	Wilkes	1	DFO	0	613	0	0	0	0	0	0	0	0	0	.	613
2015	Newman	2	DFO	0	0	0	0	0	0	0	0	0	150	0	0	150
2015	Newman	3	DFO	0	0	0	0	0	0	0	0	0	75	0	0	75
2015	O W Sommers	1	DFO	0	0	0	0	0	0	0	0	0	87	0	0	87
2015	O W Sommers	2	DFO	0	80	0	0	0	0	0	0	0	583	0	0	663
2015	Wilkes	1	DFO	0	0	0	0	0	0	0	0	16	0	0	.	16

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Note in the above tables, DFO = Distillate Fuel Oil and RFO = Residual Fuel Oil. EIA defines DFO as being a general classification for one of the petroleum fractions produced in conventional distillation operations. It includes diesel fuels and fuel oils. Products known as No. 1, No. 2, and No. 4 diesel fuel are used in on-highway diesel engines, such as those in trucks and automobiles, as well as off-highway engines, such as those in railroad locomotives and agricultural machinery. Products known as No. 1, No. 2, and No. 4 fuel oils are used primarily for space heating and electric power generation. EIA defines RFO as being a general classification for the heavier oils, known as No. 5 and No. 6 fuel oils that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations. It conforms to ASTM Specifications D 396 and D 975and Federal Specification VV-F-815C. No. 5, a residual fuel oil of medium viscosity, is also known as Navy Special and is defined in Military Specification MIL-F-859E, including Amendment 2 (NATO Symbol F-770). It is used in steam-powered vessels in government service and inshore power plants. No. 6 fuel oil includes Bunker C fuel oil and is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes.[55]

Note that in the above EIA tables, if a unit or facility is missing for a particular year, it means that unit did not report any fuel oil burning to EIA for that year. Also note that in Table 15, we have not included several entries for Stryker Creek, because these entries refer to prime movers with the "IC" designation, which refers to "Internal Combustion Engine," and the only unit from Stryker Creek that is subject to BART is a Steam Turbine (ST). Similarly, we have not included several entries for Newman, with prime mover designations of "CT" and "CA," which refer to "Combustion Turbine," and the heat recovery portion of a combined cycle turbine, respectively, as the subject-to-BART Newman units are steam turbines.

The amount of fuel oil for the Newman units is fairly minor, and only occurred in years 2001, 2014, and 2015. Also, despite EIA not requiring that unit-specific fuel oil burning be reported from 2005, 2007, we can deduce that during this time period all oil burning for the Wilkes facility can be attributed to Unit 1, as that is the only unit permitted to burn oil. However, although the O W Sommers units 1 and 2 are the only units permitted to burn fuel oil, we cannot determine the amount each unit burned. Lastly, both the Graham Units 1 and 2 are permitted to burn fuel oil so we cannot determine how much can be attributed to Unit 1, the only one of the two units that is subject to BART.

5.1.2.1 Fuel Oil Sulfur Reduction Feasibility for Gas/Oil-Fired Boilers

In analyzing the technical feasibility under BART of these facilities burning fuel oils of sulfur contents lower than historically burned, we investigated two issues: (1) Is lower sulfur fuel oil available and what is its cost, and (2) are there any technical issues in burning a lower sulfur fuel oil that could add to the cost of that oil.

We began by reviewing the permits of the subject facilities. All of the subject units are limited by permit to burning oil with a sulfur content of no more than 0.7% sulfur by weight. In addition, the Newman units 2 and 3 are restricted to burning fuel oil for no more than 10% of their annual operating time. Similar to our summary of the historic volumes of oil burned by

[55] http://www.eia.gov/tools/glossary/

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these facilities, we present the historical sulfur content of the oil burned below:

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Table 17. EIA-767 Historical Fuel Sulfur Content for Gas Units Subject to BART that Occasionally Burn Oil

				Sulfur Content (% by weight)											
Year	**Plant**	**Boiler Id**	**Fuel Code**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2001	Newman	2	DFO	0.2							0.2				
2001	Graham	2	DFO	0.5											
2001	O W Sommers	2	DFO	0.24											
2001	Wilkes	1	DFO	0.11	0.11										
2002	Graham	2	DFO			0.65									
2002	Stryker Creek	2	RFO			0.56									
2002	Wilkes	1	DFO						0.09						
2003	Graham	2	RFO		0.66	0.66			0.66						
2003	Stryker Creek	2	RFO	0.65	0.65	0.65									
2003	O W Sommers	1	DFO		0.19	0.19			0.19						
2003	O W Sommers	2	DFO		0.19										
2003	Wilkes	1	DFO	0.43	0.43		0.42								0.09
2004	Graham	2	DFO												0.69
2004	Stryker Creek	2	RFO												0.64
2004	O W Sommers	1	DFO		0.41								0.37		
2004	Wilkes	1	DFO		0.41								0.37		

Table 18. EIA-923 Historical Fuel Sulfur Content for Gas Units Subject to BART that Occasionally Burn Oil

				Sulfur Content (% by weight)											
Year	**Plant Name**	**Boiler ID**	**Fuel Code**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2008	Graham	2	DFO			0.50			0.50						
2008	Wilkes	1	DFO	0.00		0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00
2009	O W Sommers	1	DFO	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	O W Sommers	2	DFO	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	Stryker Creek	2	DFO	0.00	0.46	0.50	0.41	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.00

2011	Graham	2	DFO	.	.	.	.	.	.	.	.	.	0.01	.	.
2011	O W Sommers	1	DFO	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.00
2011	O W Sommers	2	DFO	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	Graham	2	RFO	0.00	0.00	0.00	0.00	0.50	0.50	0.50	0.00	0.00	0.00	0.00	0.00
2012	O W Sommers	1	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
2012	O W Sommers	2	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
2013	O W Sommers	2	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.00
2014	Newman	2	DFO	.	.	.	.	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2014	O W Sommers	1	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2014	O W Sommers	2	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2014	Wilkes	1	DFO	0.00	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	.
2015	Newman	2	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2015	Newman	3	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2015	O W Sommers	1	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2015	O W Sommers	2	DFO	0.00	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2015	Wilkes	1	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00	.

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Note: In 2008, the Wilkes facility did not report the fuel oil sulfur content, despite reporting that fuel oil was burned. Also note that beginning in 2012, the sulfur content reported is almost uniformly 0.50% (the 0.01% reported by the Graham and O W Sommers facilities is the exception). We suspect that, considering the variation in sulfur contents reported in prior years, this indicates unreliable data. We will examine this further in later sections. Also note that EIA does not report the sulfur content of the fuel oil burned from the 2005-2007 EIA-906/920 forms, so that data is unavailable.

In order to determine the technical feasibility under BART of these facilities burning fuel oils of sulfur contents lower than historically burned, we sent the Graham, Newman, Stryker Creek, and the Wilkes Section 114 letters requesting information on their fuel oil usage and costs.[56] We requested the following information:

1. For each unit, indicate whether that unit is permitted by the State of Texas to burn fuel oil. If so, cite to specific permit language.
2. For *each unit* permitted to burn fuel oil:
    a. Indicate if there are any legal restrictions on how often or how much fuel oil can be burned annually. If such restrictions exist, cite to specific permit language.
    b. Indicate if that unit has any legal restrictions on the sulfur content of the fuel oil that can be burned. If such restrictions exist, cite to specific permit language.
    c. If the restrictions in Questions 2.a and/or 2.b have changed since the period between January 1, 2000 and December 31, 2004, so indicate and cite to the restrictions that were in place during that time period.
    d. If fuel oil was burned between January 1, 2000 and December 31, 2004, indicate the volume burned per month and the sulfur content of that fuel.
    e. If no fuel oil has been burned since January 1, 2000, so indicate.
3. For each unit that is permitted to burn fuel oil, indicate whether the facility is willing to enter into a voluntary, enforceable commitment to remove the ability to burn fuel oil after October 9, 2017 (the projected effective date of our final decision), as a means of addressing BART. If applicable, please state in your response that you request an enforceable restriction prohibiting use of fuel oil at the unit if such unit is determined to be subject to BART for sulfur dioxide. Note that should the unit be determined to be subject to BART, the alternative to this may be a proposal by EPA to limit the sulfur content of the fuel oil burned by this same date.
4. For each unit that is permitted to burn fuel oil and that you wish to retain that ability, provide the following:
    a. For the last delivery of fuel oil, provide the vendor contact information, indicate the date of delivery, the method of delivery (e.g., truck, rail), the cost of the fuel, delivery and unloading charges, the volume of the fuel, the grade of the fuel, and the sulfur content of the fuel.
    b. For any fuel oil delivery over one year old, provide updated pricing for the same delivery method, volume, grade, and sulfur content.
    c. Unless the sulfur content of the fuel oil described in the reply to Question 6.b is already lower, provide updated pricing for an equivalent volume of fuel oil with a

[56] Copies of these letters and the facilities' responses are in our docket. We did not send the O W Sommers a letter due to an oversight on our part.

sulfur content of 0.1% sulfur fuel oil, low sulfur specification fuel oil (approximately 322 ppm sulfur), and ultra-low sulfur specification fuel oil (approximately 15 ppm sulfur).

d. If there are additional costs associated with burning any of the lower sulfur fuels contemplated in Question 4.c, so indicate and estimate those costs.

We received full responses to Questions 1-3. All of the facilities indicated they wished to retain the ability to burn fuel oil.

All facilities have either burned either DFO or have switched between DFO and RFO, thus demonstrating the ability to burn distillate fuel oils of the type under consideration for SO_2 BART. We therefore conclude that lower sulfur DFOs are a technical feasible retrofit control option under BART, and carry no significant capital costs in their use other than their purchase price. We invite comments from the affected facilities concerning this conclusion.

5.1.2.2 SO_2 Scrubber Feasibility for Gas/Oil-Fired Boilers

We began our identification of technically feasible SO_2 retrofit control technologies by conducting a search of our 2015 Air Markets Program Data,[57] supplemented with EIA 860 and 923 data,[58] for any EGUs that primarily fires gas and secondarily fire fuel oil, to determine what, if any, SO_2 controls have been installed for these types of units. The only units with these criteria that indicated any type of SO_2 control are the E W Brown Units 10 and 11, which are simple cycle combustion turbines with nameplate capacities of 126 MW. Our Air Markets Program Data listed the SO_2 control was listed as "Other." We then searched for any EGUs that primarily fired oil for any type of SO_2 control. This resulted in two other units from the E W Brown facility: Units 8 and 9, also listed as 126 MW combustion turbines with the SO_2 control listed as "Other." We must assume this is something other than a scrubber or DSI, as this category lists all known variations of these types of technologies for other types of EGUs. An examination of EIA data did not indicate any type of SO_2 control was present for any of these units. Regardless, these EGUs are combustion turbines and all of the gas-fired units that are under consideration here are steam turbines.

Nevertheless, 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.[59] Consequently, we will consider the installation of various types of scrubbers to be technically feasible.

5.1.3 Identification of Technically Feasible SO_2 Retrofit Control Technologies for Scrubber Upgrades

[57] https://ampd.epa.gov/ampd/

[58] http://www.eia.gov/electricity/data/eia860/index.html, http://www.eia.gov/electricity/data/eia923/

[59] 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."

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In our recent Texas-Oklahoma FIP,[60] we presented a great deal of information that concluded that the existing scrubbers for a number of facilities could be very cost effectively upgraded.[61] That information is attached herein as Appendix B. Of the facilities we evaluated in that action, Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are subject to BART and are thus a part of this proposal.

5.2 Step 3: Evaluation of Control Effectiveness of Remaining Control Technologies

In the following subsections to section 5.2, 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."[62] 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.

5.2.1 Evaluation of Control Effectiveness of DSI

The efficiency of DSI system depends on many factors, such as[63]:

- Sorbent particle size: Finer particles result in better performance.
- 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: [64]

[60] 81 FR 295, 321 (January 5, 2016)
[61] See information presented in Sections 6 and 7 of the Cost TSD.
[62] 70 FR 39103, 39172 (July 6, 2005) [40 CFR 51, App. Y]
[63] Wood, M., Kong, Y., "Dry Sorbent Injection with Trona or Sodium Bicarbonate Meets HCl Limit in Utility MACT, SOLVAir® Solutions, Solvay Chemicals, Inc.
[64] "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.

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Figure 1. Typical Trona SO_2 Removal Rates with ESP or Baghouse Installations

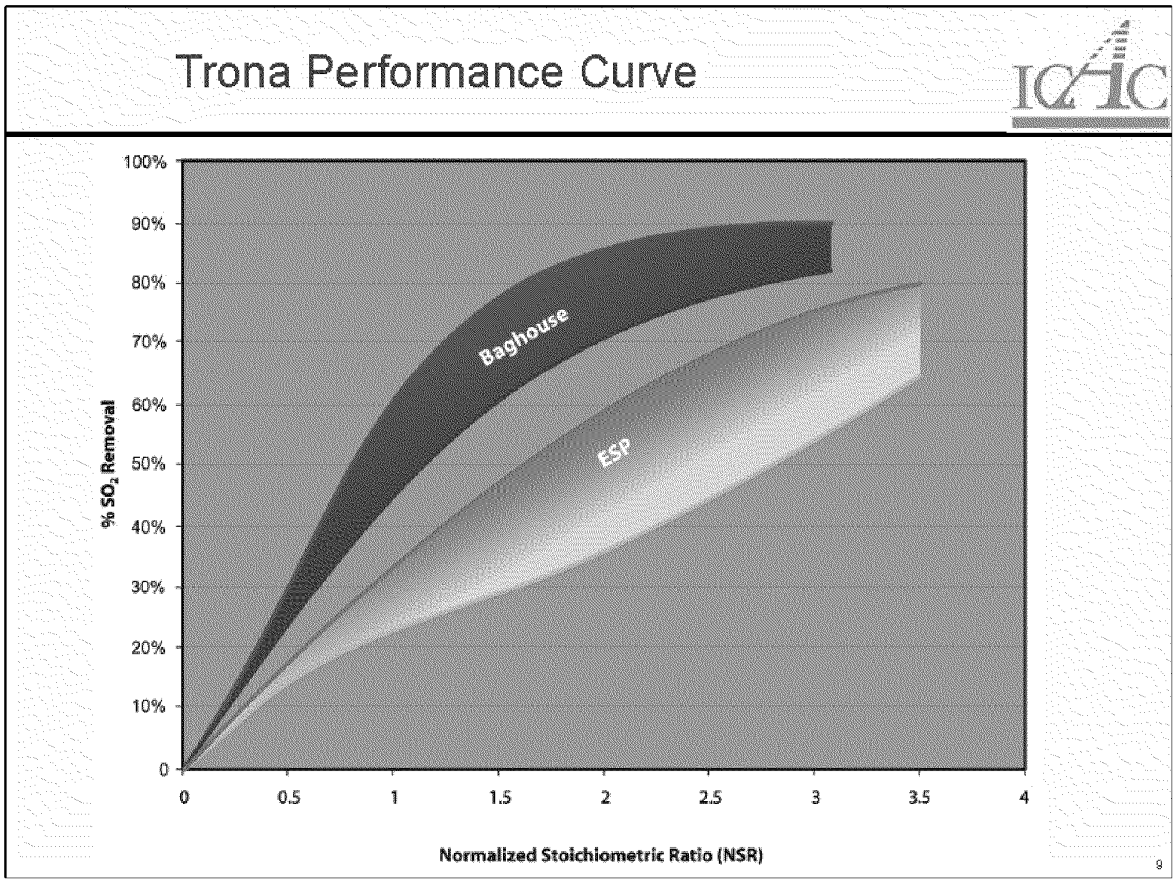

Figure 1 illustrates a number of important concepts concerning the performance potential of DSI:

- 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.

We lack the site specific information, which we believe requires an individual performance test, in order to be able to accurately determine the maximum SO_2 removal efficiency for the coal units listed in Table 10. We are aware that a number of the coal fired units have conducted such testing. However, although we have examined that testing, most of the facilities have claimed it

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as Confidential Business Information (CBI) and requested protection from public disclosure as provided by 40 C.F.R. Part 2.

However, we nevertheless must evaluate DSI as a viable, proven method of SO_2 control. We must do the same for SO_2 scrubbing, and in so doing, compare the visibility benefits and costs of each technology in order to propose which, if either technology, we should propose for installation due to the BART requirements. We therefore propose the following methodology:

- We will evaluate each unit at its maximum recommended DSI performance level, according to the IPM DSI cost model documentation,[65] assuming milled trona: 80% SO_2 removal for an ESP installation and 90% SO_2 removal for a baghouse 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.[66]

- However, (1) we do not know whether a given 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 all the units at a DSI SO_2 control level of 50%, which we believe is likely achievable for most units.

- We invite comments on whether particular units have performed DSI testing and have concluded they cannot achieve a SO_2 reduction between 50% and 80/90%.

5.2.2 Evaluation of Control Effectiveness of Wet FGD and SDA

We 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. As we discuss later in our TSD, we will conduct our wet FGD control cost analysis using the wet FGD cost algorithms, as employed in version 5.13 of our IPM model. [67] The IPM wet FGD

[65] 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.

[66] The exceptions are the Harrington Unit 062B and Welsh Unit 1, for which we limited the upper DSI control to their SDA control efficiencies of 88.9% and 87.2%, respectively. See the discussion in this TSD concerning our evaluation of the control effectiveness of SDA.

[67] 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.

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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 established in our Oklahoma FIP,[68] this level of control is achievable with wet FGD. This level of control was also employed in our recent Texas-Oklahoma FIP.[69] We received a comment challenging this level of control and we reproduce our response to that comment in Appendix A. We continue to conclude that our proposed level of control for wet FGD is reasonable.

As with our Oklahoma BART FIP, 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 lb/MMBtu, in which case, we assume the percentage of control equal to 0.06 lbs/MMBtu. See our response to comments in our previous Oklahoma BART FIP.[70] In that FIP, we finalized the same emission limit of 0.06 lbs/MMBtu on a 30 BOD average for 6 coal fired. We justified those limits based on the same SDA technology, using a combination of industry publications and real world monitoring data. Much of that information is summarized in our response to a comment to that action[71] and in our TSD. We continue to conclude that our proposed level of control for SDA is reasonable.

5.2.3 Evaluation of Control Effectiveness for Gas-Fired Units

The control effectiveness of switching from a higher sulfur fuel oil to a lower sulfur fuel oil lies in the reduction in sulfur. This depends on the percentage reduction from the sulfur contents of the fuel oil that forms the SO_2 baseline to the replacement fuel oil. Ultimately, the highest level of control would result from a switch from the highest percentage sulfur the units are permitted to burn, 0.7% to the lowest DFO available, ultra-low sulfur diesel, which has a sulfur content of 0.0015%. This would equate to a control effectiveness of 99.8%. Lesser levels of controls are also possible. We will evaluate a range of control effectiveness in switching to lower sulfur fuel oils in the next section.

Because we are unaware of any scrubber installations on oil fired units in the U. S., we have no information on their control effectiveness. However, we see no technical reason why the control effectiveness of FGDs installed on gas-fired units that occasionally burn fuel oil should not be equal to that of FGDs installed on coal-fired units.

5.3 Step 4: Evaluate Impacts and Document the Results for SO_2

The BART Guidelines offers the following with regard to how Step 4 should be conducted:[72]

[68] As discussed previously in our TSD for that action, control efficiencies reasonably achievable by dry scrubbing and wet scrubbing were determined to be 95% and 98% respectively. 76 FR 81742); *Oklahoma v. EPA*, 723 F.3d 1201 (July 19, 2013), cert. denied (U.S. May 27, 2014).
[69] 81 FR 295, 321 (January 5, 2016).
[70] 76 FR 81727, 81728 (December 28, 2011).
[71] 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 comment and response beginning on page 91.
[72] 70 FR 39103, 39166 (July 6, 2005) [40 CFR Part 51, App. Y].

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> 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.

We evaluate the cost of compliance on a unit-by unit basis, because control cost analysis depends on specific factors that vary from unit to unit. However, as we discuss later in this TSD, we evaluate the energy impacts. non-air quality impacts, and the remaining useful life for all the units in question together because in this instance there are no appreciable differences in these factors from unit to unit.

In developing our cost estimates for the units in Table 10, we relied on the methods and principles contained within the EPA Air Pollution Control Cost Manual (the Control Cost Manual, or Manual).[73] As we describe in our Oklahoma final action,[74] the Control Cost Manual uses the "overnight" method of cost estimation:

> 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.'' EIA presents all of its projected plant costs in terms of overnight 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

[73] 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.
[74] 76 FR 81727, 81744 (January 27, 2012).

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SO_2 control, if any, for each of the units listed in Table 10. For the coal units without any SO_2 control, we calculate the cost of installing DSI, a SDA scrubber, and a wet FGD scrubber. For the gas units that burn oil, we evaluate the cost of switching to lower sulfur fuel oils and installing scrubbers.

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 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 each unit listed in Table 10 that did not already have SO_2 control.[75] We discuss the inputs and outputs for the DSI, SDA, and wet FGS cost models below. These cost models were based on costs escalated to 2012 dollars.[76] 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 5.3.1, 5.3.2, and 5.3.3.

5.3.1 Impact Analysis Part 1: Cost of Compliance for DSI

Table 19, 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.

[75] These spreadsheets are entitled, "DSI Cost IPM 5-13 TX BART.xlsx," "SDA Cost IPM 5-13 TX BART.xlsx," and "Wet FGD Cost IPM 5-13 TX BART.xlsx," and are located in our Docket.
[76] Ibid., p.1: "The data was converted to 2012 dollars based on the Chemical Engineering Plant Index (CEPI) data."

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Table 19. 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		LIG-PRB Blend	**<---- 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)**	
HHV Lignite		BTU/lb	7,200	**<---- User Input (default is 7,200 Btu/lb if applicable; else no meaning)**	Three year average from 2011-2015, excluding max and min values
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))	example calculated NSRs which differ from those calculated from the formulae here. Per emails from Bill Stevens, the documentation is in
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)	17.05	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	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	($/ton)	170	**<---- User Input**	Based on input from Solvay
Waste Disposal Cost	S	($/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

5.3.1.1 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 individual DSI installations. 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. For example, we designed our cost model based on selecting maximum inputs from 2011 – 2015 for the inlet SO_2 rate, the gross heat rate, and the percentage lignite

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even if these values didn't appear in the same year of data. 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. We therefore invite comments on the accuracy of the values we have used.

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,[77] 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.[78] 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. None of the units we evaluated were affected by this limit, although Big Brown's maximum monthly SO_2 emission rate was right at 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. Therefore, a single coal selection is not appropriate for a few of the facilities for which we are costing DSI and scrubbers, which burn blends of Texas lignite and PRB coals (e.g., Big Brown Units 1, 2 and , Monticello Units 1, 2). In addition, regardless of whether a facility blends coal, we wished to allow 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. We select the maximum percent lignite value from 2011 – 2015. We use the three year average HHV values from 2011 – 2015, eliminating the maximum and minimum values. Our adjusted cost model accounts for this information in the calculation of the VOMW.

[77] http://ampd.epa.gov/ampd/
[78] Ibid.

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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."[79] For those units that use an ESP along with a polishing baghouse, we assumed that the baghouse would have the capacity to handle the additional particulate matter from the trona by itself. Thus, we assumed the trona would be injected downstream of the ESP and upstream of the baghouse and we modeled the DSI cost on the basis of a baghouse. In all cases we assumed the existing particulate control device has the capacity to handle the additional load due to the addition of the trona. We invite comment from the affected facilities as to whether this assumption is valid.

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 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 in all cases.

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."[80] In section 5.2.1, 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.

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[79] 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.
[80] Ibid., p.2.

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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. We invite the affected facilities to inform us whether they would configure DSI in such a manner.

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 in all cases.

Trona Cost. The cost of trona is the largest portion of the variable operating costs. It is partly dependent on the delivery costs. The United States Geological Survey estimates the average 2012 cost of soda ash to be $135/ton F.O.B at the mine or plant.[81] Considering that trona must be delivered from Wyoming to Texas, we contacted Solvay, which is a supplier of Trona, in order to improve this estimate. We were able to get estimated trona costs and some estimated freight delivery costs for various locations:[82]

Table 20. Cost of Trona

Facility	Cost of Trona ($/ton)	Freight by Railroad ($/ton)	Total Cost ($/ton)
Welsh	110.00	87.98	197.98
Fayette	110.00	82.62	192.62
J T Deely	110.00	85.10	195.10
Harrington	110.00	64.90	174.90

We used the Welsh quote to represent the other facilities in east Texas: Big Brown, and Monticello. We used the Fayette quote to represent the W A Parish facility. We used the J T Deely to also represent the Coleto Creek facility. Solvay also indicated that, "if the facilities do not have rail access to accept chemical shipments, the additional fees for running the product through a terminal/transload facility to put the material into bulk trucks would be about $50/ton additional cost. This can vary greatly depending upon volume and location, but this would be an estimated average cost." We have not assumed this additional transportation cost for any facility, but invite clarification from the facilities involved as to whether it should be added.

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

[81] U.S. Department of the Interior U.S. Geological Survey Mineral Commodity Summaries 2016, p. 154. Available at http://minerals.usgs.gov/minerals/pubs/mcs/2016/mcs2016.pdf
[82] Email from Marilyn Treacy to Joe Kordzi, 7-6-2016.

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fly ash and is disposed of separately. We assumed the trona waste and the fly ash were comingled and disposed of together for all cases, and therefore set this value to $50/ton. 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.[83] We invite comments on this issue.

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 information 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.[84] Also, a 7 percent interest rate is recommended by Office of Management and Budget.[85]

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.

Gross Load. The gross load (MW-h) was obtained from emissions data downloaded from our Air Markets Program Data website.[86] 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

[83] 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.'"

[84] 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).

[85] 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

[86] http://ampd.epa.gov/ampd/

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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.[87] 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.

5.3.1.2 DSI Cost Model Output

A sample of the IPM DSI cost model output is depicted below in Table 21. 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."[88] 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.

[87] Ibid.

[88] 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.

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Table 21. 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)	2.87	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not	
VOMP ($/MWh)	0.39	Variable O&M costs for additional auxillary power required (refer to Aux Power % above)	
VOM ($/MWh)	**8.82**	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	$35,260,822	VOM*(Gross Load)	
Fixed operating costs	$404,356	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)	
Total annualized costs	**$37,365,470**		
SO2 emissions reduction (tons)	15,000	H/(100%)*(SO2 emission baseline)	
$/ton	**2,491**		

5.3.1.3 Summary of DSI Cost Model Results

Below in Table 22 is a summary of our DSI cost model results:

Table 22. Summary of DSI Cost Model Results

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Facility	Unit	DSI Control (%)	DSI SO2 Reduction (tpy)	DSI Capital Cost	DSI Annualized Capital Cost	DSI Variable Operating Cost	DSI Fixed Operating Cost	DSI Total Annualized Cost	DSI Cost Effectiveness 2012 ($/ton)	DSI Cost Effectiveness 2016 ($/ton)
Parish	5	50.00	6,712	$15,495,000	$1,248,686	$14,234,884	$267,806	$15,751,376	$2,347	$2,235
		90.00	12,081	$21,266,000	$1,713,750	$30,390,656	$302,372	$32,406,779	$2,682	$2,555
	6	50.00	7,525	$15,986,000	$1,288,254	$15,266,210	$260,123	$16,814,587	$2,234	$2,128
		90.00	13,545	$21,996,000	$1,772,579	$32,897,968	$294,715	$34,965,262	$2,581	$2,459
Welsh	1	50.00	3,343	$12,626,000	$1,017,484	$8,154,876	$238,945	$9,411,305	$2,816	$2,682
		90.00	6,017	$17,373,000	$1,400,028	$15,936,486	$266,062	$17,602,576	$2,926	$2,787
Coleto Creek	1	50.00	7,376	$14,922,000	$1,202,510	$15,507,382	$347,417	$17,057,310	$2,313	$2,203
		90.00	13,277	$20,534,000	$1,654,761	$34,534,592	$391,592	$36,580,945	$2,755	$2,624
J T Deely	1	50.00	3,072	$13,951,000	$1,124,261	$7,963,377	$208,762	$9,296,399	$3,027	$2,883
		90.00	5,529	$19,196,000	$1,546,937	$17,193,108	$234,130	$18,974,174	$3,432	$3,269
	2	50.00	3,222	$13,733,000	$1,106,693	$9,003,561	$248,125	$10,358,379	$3,215	$3,062
		90.00	5,800	$18,898,000	$1,522,922	$19,438,363	$277,956	$21,239,241	$3,662	$3,488
Harrington	061B	50.00	2,477	$14,046,000	$1,131,917	$8,252,558	$261,853	$9,646,328	$3,895	$3,710
		80.00	3,962	$17,828,000	$1,436,694	$15,154,863	$284,755	$16,876,313	$4,259	$4,057
	062B	50.00	2,455	$11,882,000	$957,528	$5,661,879	$231,309	$6,850,715	$2,791	$2,658
		90.00	4,418	$16,348,000	$1,317,427	$11,273,661	$256,449	$12,847,536	$2,908	$2,770
Big Brown	1	50.00	14,448	$19,179,000	$1,545,567	$29,039,816	$354,517	$30,939,899	$2,142	$2,040
		90.00	26,006	$33,862,000	$2,728,817	$72,542,248	$462,091	$75,733,155	$2,912	$2,774
	2	50.00	15,320	$19,035,000	$1,533,962	$28,915,771	$357,627	$30,807,360	$2,011	$1,915
		90.00	27,576	$32,965,000	$2,656,531	$71,766,172	$460,896	$74,883,599	$2,716	$2,586
Monticello	1	50.00	4,787	$17,410,000	$1,403,009	$10,419,393	$156,094	$11,978,496	$2,502	$2,383
		90.00	8,617	$24,083,000	$1,940,762	$24,558,561	$178,436	$26,677,759	$3,096	$2,949
	2	50.00	4,129	$17,057,000	$1,374,562	$8,716,433	$138,086	$10,229,081	$2,478	$2,360
		90.00	7,431	$23,468,000	$1,891,202	$20,439,704	$157,226	$22,488,132	$3,026	$2,882

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.
- For a given level of control, the cost effectiveness of DSI generally improves as the tonnage of SO_2 removal increases.

5.3.2 Impact Analysis Part 1: Cost of Compliance for SDA

Table 23, 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

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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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Table 23. 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**	5 -yr avg. excluding max and min
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

5.3.2.1 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. For instance, simply changing the type of coal from lignite to PRB for Big Brown Unit 1 results in an improvement in the cost effectiveness (lower $/ton) of less than 1%. Therefore, for those facilities that burn a mixture of lignite and PRB, we are simply assuming they burn lignite for the purposes of costing a SDA system.

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

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equipment manufacturers of SDA FGD systems, are 0.06 lb/MMBtu." As we discuss in Section 5.2.2, 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.[89] 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.[90] The USGS estimates the average 2012 cost of quicklime to be $116/ton at the lime plant.[91] Although we do not have lime pricing available for Texas, lime is widely available within the State and we expect delivery charges to be minimal. Consequently, we consider the cost algorithm default cost for delivered lime of $125/ton to be reasonable, and we have adopted it for all cases. We invite the affected facilities to provide comment on this assumption.

Waste Disposal Cost. The waste disposal cost is the second largest portion of the variable operating costs. The cost model default is $30/ton and we have adopted it for all cases.

Elevation Adjustment. The IPM SDA documentation states that the cost methodology is based on a unit located within 500 feet of sea level:[92]

> 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. Consequently, we included this atmospheric pressure adjustment in our SDA cost model by incorporating an atmospheric pressure change with elevation calculation provided by NASA.[93]

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[89] Primex Process Specialists. "Optimizing Scrubber Performance," p. 3. Available at http://www.primexprocess.com/pdf/Paper_4.pdf

[90] IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final, March 2013. Sargent & Lundy, p. 3

[91] 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

[92] IPM SDA documentation, p. 2.

[93] 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).

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In order to utilize this calculation, we constructed Table 24, below, which uses the average of the latitude and longitude of the stack locations. We entered these coordinates into Google Earth Pro,[94] which returns the elevation above sea level.

Table 24. Elevation of Sources undergoing RP and LTS analyses

	Latitude	Longitude	Elevation
Big Brown	31.8200	-96.0552	335
Coleto Creek	28.7108	-97.2139	108
J T Deely	29.3072	-98.3228	498
Monticello	33.0913	-95.0376	384
Harrington	35.2972	-101.7475	3560
W. A. Parish	29.4792	-95.6324	79
Welsh	33.0564	-94.8458	377

As can be seen from the above table, only the Harrington facility is located at an elevation that exceeds 500 feet above sea level, and thus requires an elevation adjustment, which we included in our SDA cost model for this facility. This correction had the effect of worsening the cost effectiveness (increasing the $/ton) for Tolk by approximately 5%.

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. As we state in our Oklahoma FIP,[95] we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be well over 60 years. We identified specific scrubbers installed between 1975 and 1985 that were still in operation. Because none of the facilities involved have entered into or offered to enter into enforceable commitments to shut down the applicable units earlier, we will continue to use a 30 year equipment life for scrubber retrofits and upgrades, as we believe that is proper.

5.3.2.2 SDA Cost Model Output

A sample of the IPM SDA cost model output is depicted below in Table 25. 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.

[94] https://www.google.com/earth/.

[95] 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.

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Table 25. Sample SDA Output

Capital Cost Calculation		Explanation of Calculation	Comments
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit	
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 Capital Recovery factor	$203,640,000 0.0806	Excludes owner's costs and AFUDC	
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**		

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5.3.2.3 Summary of SDA Cost Model Results

Below in Table 26 is a summary of our SDA cost model results:

Table 26. Summary of SDA Cost Model Results

Facility	Unit	SDA Control (%)	SDA SO2 Reduction (tpy)	SDA Capital Cost	SDA Annualized Capital Cost	SDA Variable Operating Cost	SDA Fixed Operating Cost	SDA Total Annualized Cost	SDA Cost Effectiveness 2012 ($/ton)	SDA Cost Effectiveness 2016 ($/ton)
Parish	5	92.11	12,364	$272,260,000	$21,940,454	$7,948,884	$2,863,997	$32,753,335	$2,649	$2,523
	6	92.11	13,862	$285,608,000	$23,016,122	$8,524,785	$2,853,463	$34,394,370	$2,481	$2,363
Welsh	1	87.23	5,832	$210,262,000	$16,944,258	$4,625,309	$2,260,702	$23,830,270	$4,086	$3,892
Coleto Cree	1	92.41	13,632	$230,551,000	$18,579,276	$9,007,945	$3,327,934	$30,915,154	$2,268	$2,160
J T Deely	1	91.30	5,609	$202,172,000	$16,292,314	$4,617,491	$1,862,639	$22,772,444	$4,060	$3,867
	2	91.30	5,884	$192,698,000	$15,528,839	$5,220,370	$2,152,369	$22,901,577	$3,892	$3,707
Harrington	061B	90.16	4,466	$157,015,000	$12,653,274	$3,705,438	$1,968,496	$18,327,209	$4,104	$3,909
	062B	88.89	4,364	$171,141,000	$13,791,638	$3,423,240	$1,935,945	$19,150,823	$4,389	$4,180
Big Brown	1	95.00	27,453	$228,114,000	$18,382,887	$15,603,465	$3,073,521	$37,059,873	$1,350	$1,286
	2	95.00	29,108	$229,544,000	$18,498,125	$15,502,674	$3,123,862	$37,124,661	$1,275	$1,215
Monticello	1	95.00	9,095	$229,711,000	$18,511,583	$5,584,009	$1,411,698	$25,507,290	$2,804	$2,671
	2	95.00	7,844	$227,409,000	$18,326,073	$4,705,402	$1,249,282	$24,280,757	$3,095	$2,948

Some observations are apparent from the SDA cost model results displayed above:

- 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.
- Unlike the cost effectiveness of DSI, the cost effectiveness of SDA improves (lower $/ton) with increasing control levels.

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5.3.3 Impact Analysis Part 1: Cost of Compliance for Wet FGD

Table 27, 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 27. 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
Retrofit Factor	B		1	**<--- User Input (An "average" retrofit has a factor =1.0)**	
Gross Heat Rate	C	(Btu/kWh)	9,500	**<--- User Input**	5 -yr avg. excluding max and min
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

5.3.3.1 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 5.2.2, 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. We note that the cost of limestone is partly dependent on the delivery cost, but limestone is widely available within Texas. Consequently, we consider the cost algorithm default cost for delivered lime of $30/ton to be reasonable, and we have adopted it for all cases.

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. We invite comment from the affected facilities as to whether they believe more extensive wastewater treatment would be required for their facility, and if so, to provide an estimate of that cost.

5.3.3.2 Wet FGD Cost Model Output

A sample of the IPM wet FGD cost model output is depicted below in Table 28. 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.

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Table 28. Sample Wet FGD Output

Capital Cost Calculation		Explanation of Calculation	Comments
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit	
BMR($)	48,869,000	Base absorber island cost	
BMF($)	23,674,000	Base reagent preparation and waste recycle/handling cost	
BMW($)	14,536,000	Base reagent	
BMB($)	89,730,000	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($)	89,730,000	Adjustment to base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.), if elevation is greater than 500 feet. See page 2 of the S&L documentation.	
BM($)	**176,809,000**	Total Base module cost including retrofit factor	
BM($/kW)	354	Base cost per kW	
Total Project Cost			
A1	17,681,000	Engineering and Construction Mnagement costs	
A2	17,681,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.	
A3	17,681,000	Contractor profit and fees.	
CECC ($)	**229,852,000**	Capital, engineering and construction cost subtotal	Excludes Owner's Costs.
CECC($/kW)	**460**	Capital, engineering and construction cost subtotal per kW	Excludes Owner's Costs.
B1	11,493,000	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)	
TPC' ($)	**241,345,000**	Total project cost without AFUDC	Includes Owner's Costs
TPC' ($/kw)	**483**	Total project cost per kW without AFUDC	Includes Owner's Costs
B2	24,135,000	AFUDC (Based on a 3 year engineering and construction cycle)	
TPC ($)	**265,480,000**	Total Project Cost (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
TPC ($/kW)	**531**	Total Project Cost per kW (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
Fixed O&M Cost			additional factors, FOMWW and VOMWW, for a possible future base wastewater treatment facility. They are currently not used, so they are not included here.
FOMO ($/kW-yr)	3.00	Fixed O&M additional operating labor costs. IF MW > 500, then 16 operators, else 12 operators	
FOMM ($/kW-yr)	5.30	Fixed O&M additional maintenance material and labor costs	
FOMA ($/kW-yr)	0.15	Fixed O&M additional administrative labor costs	
FOM ($/kW-yr)	**8.45**	Total Fixed O&M costs	
Variable O&M Cost			
VOMR ($/MWh)	0.73	Variable O&M costs for limestone reagent	
VOMW ($/MWh)	1.31	Variable O&M costs for waste disposal	
VOMP ($/MWh)	0.95	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
VOMM ($/MWh)	0.08	Variable O&M costs for makeup water	
VOM ($/MWh)	**3.07**	Total Variable O&M Costs	
Annualization			
Capital, engineering and construction cost	$229,852,000	Excludes owner's costs and AFUDC	
Capital Recovery factor	0.0806		
Annualized capital costs	$18,522,946		
Variable operating costs	$13,184,075	VOM*(Gross Load)	
Fixed operating costs	$4,144,689	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)	
Total annualized costs	**$35,851,710**		
SO2 emissions reduction	29,061	J/(100%)*(SO2 emission baseline)	
$/ton	**1,234**		

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5.3.3.3 Summary of Wet FGD Cost Model Results

Below in Table 29 is a summary of our SDA cost model results:

Table 29. Summary of Wet FGD Cost Model Results

Facility	Unit	Wet FGD Control (%)	Wet FGD SO_2 Reduction (tpy)	Wet FGD Capital Cost	Wet FGD Annualized Capital Cost	Wet FGD Variable Operating Cost	Wet FGD Fixed Operating Cost	Wet FGD Total Annualized Cost	Wet FGD cost Effectiveness 2012 ($/ton)	Wet FGD cost Effectiveness 2016 ($/ton)
Parish	5	94.7	12,717	$283,182,000	$22,820,619	$5,798,157	$3,650,798	$32,269,573	$2,537	$2,417
	6	94.7	14,258	$297,661,000	$23,987,429	$6,218,236	$3,618,007	$33,823,673	$2,372	$2,259
Welsh	1	91.5	6,116	$230,424,000	$18,569,041	$3,546,457	$3,080,847	$25,196,345	$4,120	$3,924
Coleto Cree	1	94.9	14,005	$251,460,000	$20,264,257	$6,542,816	$4,466,198	$31,273,271	$2,233	$2,127
J T Deely	1	94.2	5,787	$223,325,000	$17,996,959	$3,403,601	$2,280,985	$23,681,544	$4,092	$3,898
	2	94.2	6,070	$212,970,000	$17,162,486	$3,847,988	$2,645,352	$23,655,827	$3,897	$3,712
Harrington	061B	93.4	4,628	$172,845,000	$13,928,957	$2,767,234	$2,449,309	$19,145,500	$4,137	$3,940
	062B	92.6	4,545	$189,971,000	$15,309,080	$2,588,791	$2,405,469	$20,303,340	$4,467	$4,254
Big Brown	1	98.0	28,320	$257,763,000	$20,772,193	$10,364,348	$4,217,796	$35,354,338	$1,248	$1,189
	2	97.9	29,998	$259,141,000	$20,883,241	$10,342,048	$4,281,131	$35,506,420	$1,184	$1,127
Monticello	1	97.0	9,286	$257,182,000	$20,725,372	$3,846,382	$1,924,967	$26,496,721	$2,853	$2,718
	2	96.8	7,995	$254,177,000	$20,483,210	$3,255,811	$1,704,028	$25,443,049	$3,182	$3,031

Some observations are apparent from the wet FDG cost model results displayed above:

- 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.
- As with our SDA cost model, the cost effectiveness of wet FGD improves (lower $/ton) with increasing control levels.

Table 30 compares the capital cost and cost effectiveness of both technologies:

Table 30. Capital cost and cost effectiveness of wet FGD versus SDA

Facility	**Unit**	**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**
Parish	5	$272,260,000	$283,182,000	3.9	$2,523	$2,417	-4.4
	6	$285,608,000	$297,661,000	4.0	$2,363	$2,259	-4.6
Welsh	1	$210,262,000	$230,424,000	8.7	$3,892	$3,924	0.8
Coleto Creek	1	$230,551,000	$251,460,000	8.3	$2,160	$2,127	-1.6

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J T Deely	1	$202,172,000	$223,325,000	9.5	$3,867	$3,898	0.8
	2	$192,698,000	$212,970,000	9.5	$3,707	$3,712	0.1
Harrington	061B	$157,015,000	$186,289,000	15.7	$3,909	$4,185	6.6
	062B	$171,141,000	$189,971,000	9.9	$4,180	$4,254	1.7
Big Brown	1	$228,114,000	$257,763,000	11.5	$1,286	$1,189	-8.1
	2	$229,544,000	$259,141,000	11.4	$1,215	$1,127	-7.8
Monticello	1	$229,711,000	$257,182,000	10.7	$2,671	$2,718	1.7
	2	$227,409,000	$254,177,000	10.5	$2,948	$3,031	2.7

- The capital cost of wet FGD is higher than SDA by approximately 4 – 16%. However, wet FGD delivers a significant improvement in the cost effectiveness for some of the units, increasing as the tonnage of SO_2 removal increases 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.

5.3.4 Impact Analysis Part 1: Cost of Compliance for Upgrading Existing Scrubbers

Of our subject-to-BART units, Martin Lake Units 1, 2, 3; Monticello Unit 3, and Fayette Units 1 and 2 are currently equipped with wet FGDs. Of these, all but the Fayette units were analyzed for scrubber upgrades in our Texas-Oklahoma FIP. As we discussed in that FIP, the cost information we relied upon was based on information claimed as CBI, which was provided to us by the facilities' parent companies. As a consequence, we could only present a summary of the cost-effectiveness. After responding to comments we revised our proposed cost-effectiveness basis from where all scrubber upgrades were less than $600/ton, to where all scrubber upgrades ranged from between $368/ton to $910/ton.[96]

We propose to rely on those total annualized cost calculations used to make the above cost-effectiveness calculations in this action. We acknowledge that these costs could change slightly, due to changes in the costs of various materials and services. However, these costs were calculated in 2013 dollars. Escalating them to 2015 dollars would result in a reduction in cost, which we conservatively ignore.[97]

Using these costs, we propose to update the cost-effectiveness of the scrubber upgrades by retaining the same 95% control level we demonstrated was reasonable, but applying it to updated baseline emissions. For instance, in Table 19 of the Cost TSD in our Texas-Oklahoma FIP, we calculated our SO_2 baseline as being the three year average from 2009-2013 SO_2 annual emissions, excluding the maximum and minimum values. Here we update that baseline to be the

[96] 81 FR 295, 318 (February 4, 2016).
[97] The CEPCI for 2013 is 567.3 and that for 2015 is 556.3. Therefore the costs would be multiplied by a factor of 556.8/567.3, which is approximately 0.98.

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same as we presently use in our DSI, SDA, and wet FGD BART cost analyses— the three year average from 2011-2015 SO_2 annual emissions, excluding the maximum and minimum values.

We will also adopt the same 30 year equipment lifetime as we used in our analysis of scrubber upgrades in our Texas-Oklahoma FIP. As we state in our Oklahoma FIP,[98] we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be well over 60 years. We identified specific scrubbers installed between 1975 and 1985 that were still in operation. Because none of the facilities involved have entered into or offered to enter into enforceable commitments to shut down the applicable units earlier, we will continue to use a 30 year equipment life for scrubber upgrades, as we believe that is proper.

In our Texas-Oklahoma FIP, we also discussed how we calculated the efficiency of the existing SO_2 scrubbers.[99] We noted that in a typical situation in which we would propose that a pollution control device such as an SO_2 scrubber be installed, we would have historical emissions data to use as a baseline. In such an instance, we would apply the control efficiency of the scrubber to the uncontrolled historical SO_2 emissions, and be able to easily propose a controlled SO_2 emission rate that would be appropriate following the installation of the scrubber. However, we faced a more difficult task in analyzing the efficiency of existing SO_2 scrubbers because CEMS data for the inlet of the scrubbers was lacking—we only had CEMS data for the outlet of the scrubbers. We discussed how we used coal quality data to establish the uncontrolled SO_2 emissions.

We calculated the scrubber removal efficiency by utilizing the reported sulfur content and tonnages of the fuels burned and reported to EIA,[100] and the monitored SO_2 scrubber outlet emissions reported to us.[101] We did this by constructing a spreadsheet[102], which among other things, divides the annual SO_2 emissions by the theoretical uncontrolled SO_2 emissions based on coal sulfur content to estimate the percentage of SO_2 in the coal that is emitted. We calculated the theoretical uncontrolled SO_2 emissions from EIA reported coal sulfur data. This calculation is summarized below for a typical unit that burns both lignite and subbituminous coals:

(1)

[98] 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.
[99] See the Cost TSD in our Texas-Oklahoma FIP, Section 6.1. We incorporate the information in this document into our current proposal.
[100] EIA Form 923. Available at http://www.eia.gov/electricity/data/eia923/
[101] EPA Air Markets and Programs Data. Available at http://ampd.epa.gov/ampd/
[102] See "Coal vs CEM data 2009-2013.xlsx," tab "charts," cell H12.

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or, alternatively expressed in tons:

(2)

and the scrubber efficiency is then:

(3)

In equations (1) and (2), the percentage and tonnage values are those reported by the facility to the EIA for each fuel type. In equation (3), the annual EPA reported tons of SO_2 are those reported to us.[103]

We now update these calculations for 2011-2015 data.[104] The revised scrubber upgrade results for Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are presented below in Table 31:

Table 31. Summary of Updated Scrubber Upgrade Results

Unit	2011-2015 3-yr Avg. SO_2 Emissions (eliminate max and min) (tons)	SO_2 Emissions at 95% Control (tons)	SO_2 Emissions Reduction Due to Scrubber Upgrade (tons)	SO_2 Emission Rate at 95% Control (lbs/MMBtu)
Monticello 3	8,136	1,180	6,956	0.05
Martin Lake 1	19,040	3,208	15,832	0.12
Martin Lake 2	17,973	3,393	14,580	0.12
Martin Lake 3	16,113	2,591	13,522	0.11
Total SO_2 Removed			50,890	

As we note above, we updated the cost effectiveness for each of these units. Because those calculations depended on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost effectiveness was $1,156/ton or less. We invite the facilities listed above to make arrangements with us to view our complete updated cost analysis for their units.

[103] EPA Air Markets and Programs Data. Available at http://ampd.epa.gov/ampd/
[104] See "Coal vs CEM data 2011-2015.xlsx.

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The Fayette (Sam Seymour) Units 1 and 2 are currently equipped with high performing wet FGDs. This can be seen from an examination of Figures 2 and 3 below:[105]

Figure 2: 30 BOD SO_2 Average for Fayette Unit 1

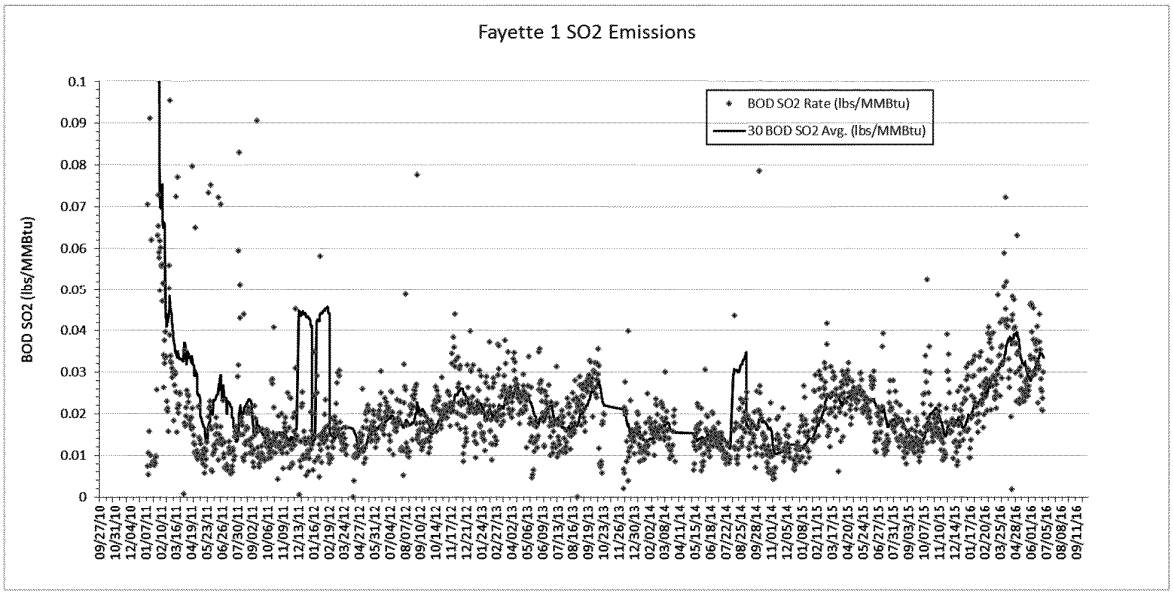
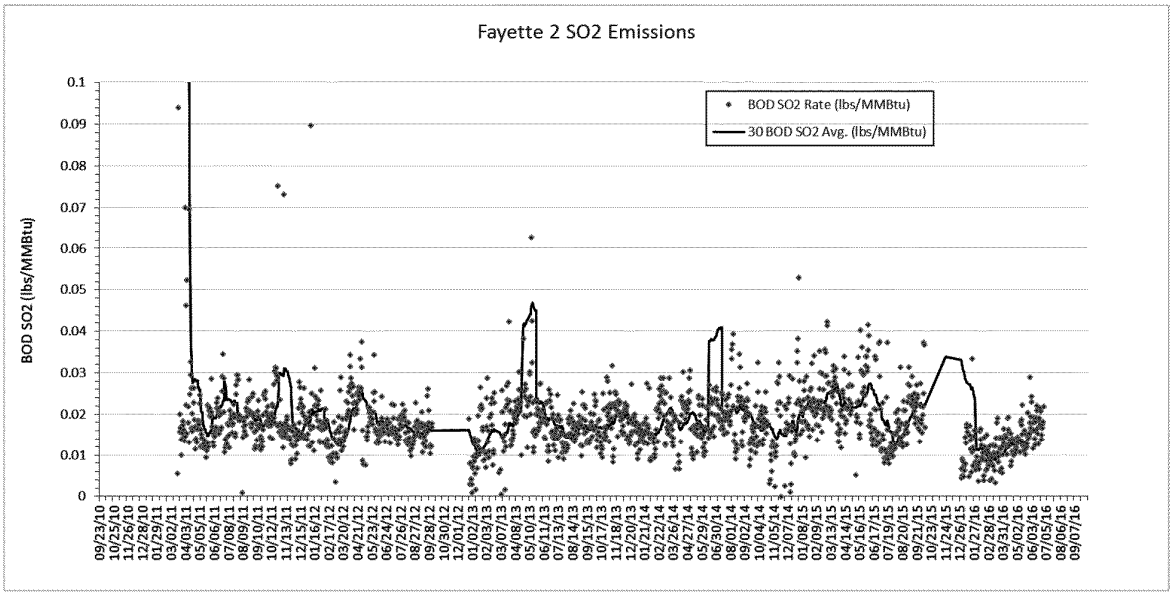


Figure 3: 30 BOD SO_2 Average for Fayette Unit 1



[105] See the file, "Fayette emissions.xlsx."

As can be seen from the above figures, the Fayette Units have both demonstrated the ability to maintain a SO_2 30 BOD average below 0.04 lbs/MMBtu for years at a time. As we discuss above, we evaluate BART demonstrating that retrofit wet FGDs should be evaluated at 98% control not to go below 0.04 lbs/MMBtu. Because the Fayette units are performing below this level, we propose that no scrubber upgrades are necessary. We propose to find that the Fayette Units 1 and 2 maintain a 30 Boiler Operating Day rolling average SO_2 emission rate of 0.04 lbs/MMBtu based on the actual emissions data we present above. We believe, based on its demonstrated ability to maintain an emission rate below this value on a 30 BOD basis, it can consistently achieve this emission level.

5.3.5 Impact Analysis Part 1 Cost of Compliance for Switching to a Lower Sulfur Fuel Oil for Gas-Fired Units

In section 5.1.2.1, we discussed the Section 114 letters we sent to a number of gas-fired facilities. Question 4 requested information on the cost of lower sulfur fuel oil. We received very limited information in response to Question 4. Because of this, we were unable to compile facility-specific information on the technical feasibility under BART of these facilities burning fuel oils of sulfur contents lower than historically burned.

However, information from the EIA indicates that fuel oil of varying sulfur contents is widely available across the U.S. EIA reports the prices for various refinery petroleum products on a monthly and annual basis. Below is summary of various distillate and residual fuel oil products for 2001 to 2015, averaged across the U.S."[106]

Table 32. Selected EIA Reported Annual Refiner Petroleum Prices

Date	West Texas Intermediate Crude Oil – Cushing Oklahoma ($/bbl)	U.S. No 2 Diesel Wholesale/Resale Price by Refiners ($/Gallon)	U.S. No. 2 Fuel Oil Wholesale/Resale Price by Refiners ($/Gallon)	U.S. No 4 Distillate Wholesale/Resale Price by Refiners ($/Gallon)
2015	48.66	1.667	1.565	1.215
2014	93.17	2.812	2.741	2.333
2013	97.98	3.028	2.966	2.767
2012	94.05	3.109	3.031	
2011	94.88	3.034	2.907	2.801
2010	79.48	2.214	2.147	
2009	61.95	1.713	1.657	1.561
2008	99.67	2.994	2.745	2.157
2007	72.34	2.203	2.072	1.551
2006	66.05	2.012	1.834	1.395

[106] EIA Refiner Petroleum Product Prices by Sales Type, available here: http://www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_a.htm; http://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm

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2005	56.64	1.737	1.623	1.377
2004	41.51	1.187	1.125	1.033
2003	31.08	0.883	0.881	0.793
2002	26.18	0.724	0.694	0.663
2001	25.98	0.784	0.756	0.697
2000	30.38	0.898	0.886	0.778

As can be seen from the above table, the price of these fuel oils closely tracks the price of crude oil, and are fairly volatile.

Lacking facility-specific pricing information, for the purposes of calculating the cost of compliance, we make the following assumptions:

- No. 4 distillate is the type of fuel oil currently available that most closely approximates the types of fuel oil that were historically burned by the facilities. It is available in a range of sulfur up to the facilities' permitted maximum of 0.7% sulfur by weight or 7,000 ppm. We will use the cost of this fuel oil along with the SO_2 baselines we discuss in the next section in constructing "business as usual" scenarios of the annual cost of fuel oil.
- No. 2 fuel oil is available at approximately 3,000 ppm, which roughly corresponds to the sulfur level present in No. 2 fuel oil prior to our implementation of the Ultra-Low-Sulfur Diesel (ULSD) regulations.[107] We will use the cost of this fuel oil along with the SO_2 baselines we discuss in the next section in constructing a "medium control" annual cost of fuel oil..
- No. 2 diesel fuel corresponds to ULSD, with a sulfur content of 15 ppm. We will use the cost of this fuel oil along with the SO_2 baselines we discuss in the next section in constructing a "high control" annual cost of fuel oil.

5.3.5.1 SO_2 Baseline for Gas-Fired Units that Occasionally Burn Oil

As we discuss in our DSI, SDA, and Wet FGD SO_2 BART analyses, for the coal-fired units we have analyzed under BART, we employed a baseline selected as the 2011 – 2015 five year average of the SO_2 annual emissions, excluding the maximum and minimum values. We do not believe that approach would be reasonable here, due to the unpredictable, random history of oil burning the units in question exhibit. For instance, the historical fuel oil burning practices of the Graham Unit 2 are presented below:[108]

Table 33. Graham Unit 2 Historic Fuel Oil Burning Practices

Year	Barrels of Fuel Oil Burned
2000	0

[107] 69 FR 38957, 39073 (June 29, 2004): "Both high sulfur No. 2–D and No. 2 fuel oil must contain no more than 5000 ppm sulfur,131 and currently [as of the date of our final rule, 6/29/04] averages 3000 ppm nationwide."
[108] This and other baseline and emission data in this section can be found in the file, Gas-fired SO_2 emissions.xlsx" in our docket.

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2001	31,500
2002	9,800
2003	23,300
2004	2,200
2005	25,219
2006	15,567
2007	2,971
2008	421
2009	0
2010	0
2011	19
2012	25,911
2013	0
2014	0
2015	0

Were we to adopt the same baseline calculation methodology we employed in our BART assessment of the coal units we analyzed, we would consider only the SO_2 resulting from the amount of oil burned from 2011 to 2015. We would eliminate the high SO_2 year (2012) and low SO_2 year (2013), and average the SO_2 from the remaining three years (2011, 2014, 2015), resulting in a baseline based on the SO_2 emissions resulting from burning 6.3 barrels of fuel oil. We conclude this result may not capture the BART Guidelines requirement that, "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source."[109] Alternatively, we could examine the effect a range of different SO_2 baselines could have on the cost. For instance, we could evaluate SO_2 baselines based on the following three scenarios:

- The maximum annual SO_2 resulting from fuel oil burned from 2000 to 2015.
- An average of the SO_2 of any years from 2000 to 2015 when any fuel oil was burned.
- An average of the SO_2 from 2011 to 2015.

This information is presented below:

Table 34. SO_2 Baselines for Gas Fired Units that Occasionally Burn Oil

Unit	Max SO_2 tons (2000-2015)	Average SO_2 tons (2000-2015)	Average SO_2 tons (2011-2015)
Graham 2	1287.0	141.5	0.5
Newman 2	1.2	1.0	1.0
Newman 3	1.4	1.4	1.4
O W Sommers 1	54.8	12.3	1.9
O W Sommers 2	6.6	2.8	2.4
Stryker Creek 2	145.5	40.7	0

[109] 70 FR 39104, 39167 (July 6, 2005) [40 CFR Part 51, App. Y].

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Wilkes 1	14.5	5.3	1.3

As can be seen from Table 34, with the exception of Graham Unit 2, the SO_2 emission baselines, regardless of the method employed, are very small. We would expect that regardless of the baseline selected, a cost-effectiveness calculation that simply depended on differing fuel oil costs and the resulting reductions in SO_2, would result in approximately the same value. In other words, the cost-effectiveness in $/ton should be independent of the SO_2 baseline, since *in this case,* it is calculated on a unit basis—the increased cost in burning a unit of fuel divided by the increased reduction in the resulting SO_2. Unfortunately, that does not occur, because we do not see a regular correspondence between the reported amount and sulfur content of the fuel oil burned with the reported SO_2 emissions. In other words, according to the data a barrel of fuel oil burned with about the same sulfur content does not result in the same amount of SO_2 emitted over time, nor does the expected trend always occur in the right direction. This can be illustrated by examining selected EIA and monitoring data for the Graham Unit 2:

Table 35. Graham Unit 2 Example Discordance in Fuel Oil Burned and Reported SO_2

Date (month/year)	**Quantity Fuel Oil Burned (bbls)**	**Reported SO_2 emissions for month (tons)**	**Reported EIA sulfur content (wt%)**
Mar-02	9,800	21.614	0.65
Feb-03	8,400	90.389	0.66
Jun-12	18,177	0.064	0.50
Jul-12	5,657	0.07	0.50

As can be seen from the above table, even though the reported sulfur content of the fuel oil in March, 2002 and February 2003 was approximately the same, and the quantity burned was fairly close, the resulting reported SO_2 was significantly different. Similarly, although the amount of fuel oil burned in June, 2012 was more than three times that burned in July 2012 (at the same sulfur content), the reported SO_2 in June 2012 was less than that in July 2012. Also, although the fuel oil sulfur content in the 2012 examples was only slightly less than that in the 2002/2003 examples, and the amount of fuel oil burned was the same order of magnitude, the resulting reported SO_2 in 2012 was three orders of magnitude less than that in 2002/2003. Further examination of the CAMD emissions data for Graham and Stryker revealed that the data contained a large amount of substitute data for SO_2 emissions and heat input during periods when the units burned fuel oil. Some of these substitute values were much higher than the maximum potential emissions from the units.[110] As a result of these issues, we cannot construct reasonable SO_2 baselines for the gas fired units that occasionally burn fuel oil. This impacts both the visibility modeling and the control cost analyses we perform on these units causing us to adopt alternative approaches.

5.3.5.2 Cost Analysis for Gas-Fired Units that Occasionally Burn Oil

[110] See the file, "Gas-fired SO2 emissions comparison and calcs.xlsx," in our docket for emission data.

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As a consequence of this discordance between the reported type and amount of fuel oil burned and the reported SO_2, we cannot rely on historical SO_2 emissions to construct a baseline, because a barrel of fuel oil with a given reported sulfur content does not result in a consistent reported SO_2 value over time. Instead, we will conduct our cost-effectiveness analysis on the basis of unit values of 1,000 barrels, using the following assumptions:

- Fuel oil costs can be based on the 2015 U.S. average prices as reported in Table 32 for No. 4 distillate at 0.7 wt. % (the permitted maximum for all units) as the current business as usual fuel, No. 2 fuel oil at 0.3wt. % as the moderate control option, and No. 2 diesel at 0.0015% as the high control option.
- The emission factor for calculating the tons of sulfur emitted by the three fuel oils can be taken from AP 42.[111]

Below is the result of that calculation:

Table 36. Cost Effectiveness of Switching to Lower Sulfur Fuel Oils

	Cost for 1,000 barrels baseline ($/yr)	**Tons reduced for 1,000 barrels**	**Cost effectiveness for 1,000 barrels ($/ton)**
Business as usual (No. 4 distillate $1.215/gal)	$51,030	N/A	N/A
Moderate control (No. 2 fuel oil $1.565/gal)	$65,730	1.26	$11,218
High control (ULSD $1.667/gal)	$70,014	2.20	$8,627

Although the cost-effectiveness of switching to a lower sulfur oil is less attractive (higher $/ton) than other controls we have typically required under BART, we note certain mitigating factors. For instance, unlike the wet FGD and SDA scrubbers we have costed in other sections of this TSD, which have large capital costs, we are unaware of any significant capital costs involved in switching fuels. Also, because the units in question have only occasionally burned fuel oil, they have the option to avoid the cost of fuel switching entirely by not continuing to burn fuel oil and instead relying on their primary fuel of natural gas. Lastly, we note that the prevalence of ULSD in the fuel oil market is such that it appears to be gradually replacing most other No. 2 fuel oil applications.[112] In fact, in responding to our Section 114 letter, the Wilkes facility stated that its current contract was for ULSD.

In Section 5.1.2.1, we concluded that certain types of wet scrubbers were technically feasible as potential control options for gas boilers that occasionally burn oil, similar to the ones under BART review here. Were we to calculate the cost effectiveness of a wet FGD, similar to those under consideration for the coal units undergoing BART review, we could expect that the capital

[111] The emission factor used is 150 X S, where S = weight % sulfur, taken from AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.3, Fuel Oil Combustion, available here: https://www3.epa.gov/ttn/chief/ap42/ch01/index.html. Boilers > 100 Million Btu/hr,, No. 4 oil fired.
[112] http://www.eia.gov/todayinenergy/detail.php?id=5890. http://blogs.platts.com/2014/05/07/heating-oil-new-york-sulfur/. http://oilandenergyonline.com/challenges-to-the-northeast-supply-picture/

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and operating costs would minimally be on the same order, as displayed in Table 29. It is a straightforward exercise to demonstrate that the installation of such a scrubber on any of the gas-fired units that occasionally burn oil is not cost-effective.

For instance, taking the smallest total annualized cost in Table 29, corresponding to the Harrington Unit 0161B (approximately the same size as the Graham Unit 2), results in a value of $19,145,500. Assuming a 98% reduction from a baseline equal to the largest annual SO_2 emissions from any of the gas units, 1,287 tons/year (Graham Unit 2, 2001), results in a SO_2 reduction of 1,261 tons/year. The cost-effectiveness is then $15,183/ton. We do not consider this to be cost effective. In addition, the annual SO_2 values for Graham Unit 2 from 2002 to 2015, and the annual SO_2 values for the remaining units, have always been an order of magnitude less than the 2001 Graham Unit 2 value. Indeed, as we discuss above, we suspect that the Graham Unit 2's reported SO_2 tonnage from 2001 is incorrect.

5.3.6 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 BART analyses in the following manner:

- For all uncontrolled coal-fired units undergoing SO_2 BART analysis, we have calculated the incremental cost-effectiveness of DSI_{50} to $DSI_{80/90}$, $DSI_{80/90}$ to SDA, and SDA to wet FGD.
- For all gas-fired units that occasionally burn oil, we have calculated the incremental cost-effectiveness of burning fuel oil with a sulfur content of 0.3% to a fuel oil with a sulfur content of 0.0015%.

This information is presented below:

Table 37. Summary of Coal-Fired EGU SO_2 BART Incremental Cost-Effectiveness

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Facility	Unit	Control	Control level (%)	SO_2 reduction (tpy)	2016 Annualized Cost	2016 Cost Effectiveness ($/ton)	2016 Incremental Cost-Effectiveness ($/ton)
Big Brown	1	DSI	50	14,448	$29,468,587	$2,040	
		DSI	90	26,006	$72,131,749	$2,774	$3,691
		SDA	95	27,453	$35,297,532	$1,286	-$25,456
		Wet FGD	98	28,320	$33,673,102	$1,189	-$1,874
	2	DSI	50	15,320	$29,342,350	$1,915	
		DSI	90	27,576	$71,322,593	$2,586	$3,425
		SDA	95	29,108	$35,359,239	$1,215	-$23,475
		Wet FGD	97.9	29,998	$33,817,952	$1,127	-$1,732
Monticello	1	DSI	50	4,787	$11,408,872	$2,383	
		DSI	90	8,617	$25,409,128	$2,949	$3,655
		SDA	95	9,095	$24,294,319	$2,671	-$2,332
		Wet FGD	97	9,286	$25,236,699	$2,718	$4,934
	2	DSI	50	4,129	$9,742,648	$2,360	
		DSI	90	7,431	$21,418,734	$2,882	$3,536
		SDA	95	7,844	$23,126,113	$2,948	$4,134
		Wet FGD	96.8	7,995	$24,233,133	$3,031	$7,331
Coleto Creek	1	DSI	50	7,376	$16,246,169	$2,203	
		DSI	90	13,277	$34,841,379	$2,624	$3,151
		SDA	92.4	13,632	$29,445,018	$2,160	-$15,201
		Wet FGD	94.9	14,005	$29,786,106	$2,127	$914
Harrington	061	DSI	50	2,477	$9,187,608	$3,710	

	B						
		DSI	80	3,962	$16,073,779	$4,057	$4,637
		SDA	90.2	4,466	$17,455,679	$3,909	$2,742
	062 B	DSI	50	2,455	$6,524,937	$2,658	
		DSI	**88.9**	4,364	$11,981,111	$2,746	$2,858
		SDA	88.9	4,364	$18,240,127	$4,180	N/A
J T Deely	1	DSI	50	3,072	$8,854,319	$2,883	
		DSI	90	5,529	$18,071,878	$3,269	$3,752
		SDA	91.3	5,609	$21,689,526	$3,867	$45,221
		Wet FGD	94.2	5,787	$22,555,395	$3,898	$4,864
	2	DSI	50	3,222	$9,865,798	$3,062	
		DSI	90	5,800	$20,229,233	$3,488	$4,020
		SDA	91.3	5,884	$21,812,518	$3,707	$18,849
		Wet FGD	94.2	6,070	$22,530,901	$3,712	$3,862
Welsh	1	DSI	50	3,343	$8,963,761	$3,469	
		DSI	**87.2**	5,832	$23,090,408	$3,960	$5,676
		SDA	87.2	5,832	$22,697,048	$3,892	N/A
		Wet FGD	91.5	6,116	$23,998,161	$3,924	$4,581
W. A. Parish	5	DSI	50	6,712	$15,002,337	$2,235	
		DSI	90	12,081	$30,865,711	$2,555	$2,955
		SDA	92.1	12,364	$31,195,787	$2,523	$1,166
		Wet FGD	94.7	12,717	$30,735,030	$2,417	-$1,305
	6	DSI	50	7,525	$16,014,988	$2,128	
		DSI	90	13,545	$33,302,528	$2,459	$2,872
		SDA	92.1	13,862	$32,758,784	$2,363	-$1,715

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		Wet FGD	94.7	14,258	$32,215,226	$2,259	-$1,373

Table 38. Summary of Oil-Fired EGU SO_2 BART Incremental Cost-Effectiveness

	Cost for 1,000 barrels baseline ($/yr)	**Tons reduced for 1,000 barrels**	**Cost effectiveness for 1,000 barrels ($/ton)**	**Incremental Cost-Effectiveness ($/ton)**
Business as usual (No. 4 distillate $1.215/gal)	$51,030	N/A	N/A	
Moderate control (No. 2 fuel oil $1.565/gal)	$65,730	1.26	$11,218	
High control (ULSD $1.667/gal)	$70,014	2.20	$8,627	-$2,756

5.3.7 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."[113] 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 all cases. 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:[114]

> 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 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

[113] 70 FR 39104, 39168 (July 6, 2005) [40 CFR Part 51, App. Y].
[114] *Id.* At 39169.

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> 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.

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 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. Consequently, we believe that with one possible exception, any non-air quality environmental impacts have been adequately considered in our analyses. We are aware that the Harrington facility has instituted a water recycling program and obtains some of its water from the City of Amarillo.[115] Due to potential non-air quality concerns, we limit our SO_2 control analysis for Harrington to DSI and dry scrubbers.

Regarding the remaining useful life, the BART Guidelines advise:[116]

> 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 any of the facilities we have analyzed for BART have entered into or offered to enter into enforceable commitments to shut down the applicable units 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 proper.

5.4 BART Five Factor Analysis for PM

In our recent Texas-Oklahoma FIP, we initially proposed to approve Texas' determination that no PM BART controls were appropriate for its EGUs, based on a screening analysis of the visibility impacts from just PM emissions and the premise that EGU SO_2 and NO_X were covered separately by participation in CSAPR (allowing consideration of PM emissions in isolation).

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[115] http://www.powermag.com/xcel-energys-harrington-generating-station-earns-powder-river-basin-coal-users-group-award/.

[116] 70 FR 39104, 39169 (July 6, 2005) [40 CFR Part 51, App. Y].

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Because of the CSAPR remand and resulting uncertainty regarding SO_2 and NO_X BART for EGUs, we decided not to finalize our proposed approval of Texas' PM BART determination.[117] For reasons earlier stated we are proposing to disapprove the SIP determination regarding PM BART for EGUs. Following from that proposed disapproval, we are proposing a PM BART FIP for those Texas EGUs that are subject to BART.

The BART Guidelines permit us to conduct a streamlined analysis of PM BART in two key ways. First, the Guidelines allow a streamlined analysis for PM sources subject to MACT standards. Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, the Guidelines state it is permissible to rely on MACT standards for purposes of BART.[118]

Second, with respect to gas-fired units, which have inherently low emissions of PM (as well as SO_2), the Regional Haze Rule did not specifically envision new or additional controls or emissions reductions from the PM BART requirement. The BART guidelines preclude us from stating that PM emissions are *de minimis* when plant-wide emissions exceed 15 tons per years. While we must assign PM BART determinations to the gas-firing units, there are no practical add-on controls to consider for setting a more stringent PM BART emissions limit. The Guidelines state that if the most stringent controls are made federally enforceable for BART, then the otherwise required analyses leading up to the BART determination can be skipped.[119]

With this background, we are providing our evaluation along with some supplementary information on the BART sources as divided into two categories: coal-fired EGUs, and gas-fired EGUs.

5.4.1 BART Five Factor Analysis for PM for Coal-Fired Units

All of the coal-fired EGUs that are subject to BART are currently equipped with either Electrostatic Precipitators (ESPs) or baghouses, or both as can be seen from Table 39:

Table 39. Current PM Controls for Coal-Fired Units Subject to BART

Facility Name	Unit ID	Fuel Type (Primary)	SO_2 Control(s)	PM Control(s)
Big Brown	1	Coal		Baghouse +Electrostatic Precipitator
Big Brown	2	Coal		Baghouse + Electrostatic Precipitator
Coleto Creek	1	Coal		Baghouse
Harrington Station	061B	Coal		Electrostatic Precipitator
Harrington Station	062B	Coal		Baghouse
J T Deely	1	Coal		Baghouse

[117] 81 FR 302 (January 5, 2016).
[118] 70 FR 39163-39164
[119] 70 FR 39165 ("…you may skip the remaining analyses in this section, including the visibility analysis…")

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J T Deely	2	Coal		Baghouse
Martin Lake	1	Coal	Wet Limestone	Electrostatic Precipitator
Martin Lake	2	Coal	Wet Limestone	Electrostatic Precipitator
Martin Lake	3	Coal	Wet Limestone	Electrostatic Precipitator
Monticello	1	Coal		Baghouse + Electrostatic Precipitator
Monticello	2	Coal		Baghouse + Electrostatic Precipitator
Monticello	3	Coal	Wet Limestone	Electrostatic Precipitator
Fayette	1	Coal	Wet Limestone	Electrostatic Precipitator
Fayette	2	Coal	Wet Limestone	Electrostatic Precipitator
W A Parish	WAP5	Coal		Baghouse
W A Parish	WAP6	Coal		Baghouse
Welsh Power Plant	1	Coal		Baghouse (Began Nov 15, 2015) + Electrostatic Precipitator

As an initial matter, we examine the control efficiencies of both baghouses and ESPs. We consider a baghouse, widely reported to be capable of 99.9% control of PM, to be a BART-level control for PM and so the units equipped with a baghouse will not be further analyzed for PM BART. The remaining units are fitted with ESPs.

The particulate matter control efficiency of ESPs varies somewhat with the design, the resistivity of the particulate matter, and the maintenance of the ESP. We do not have any information on the control level efficiency of any of the ESPs for the units in question. However, reported control efficiencies for well-maintained ESPs typically range from greater than 99% to 99.9%.[120] We conclude that the potential additional particulate control that a baghouse can offer over an ESP is relatively minimal.[121]

Nevertheless, we will examine the potential cost of retrofitting a typical 500 MW coal fired unit. Using our baghouse cost algorithms, as employed in version 5.13 of our IPM model,[122] and assuming a conservative air to cloth ration of 6.0, results in a capital engineering and

[120] EPA, "Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) - Wire Plate Type," EPA-452/F-03-028. Grieco, G., "Particulate Matter Control for Coal-fired Generating Units: Separating Perception from Fact," apcmag.net, February, 2012. Moretti, A. L.; Jones, C. S., "Advanced Emissions Control Technologies for Coal-Fired Power Plants, Babcox and Wilcox Technical Paper BR-1886, Presented at Power-Gen Asia, Bangkok, Thailand, October 3-5, 2012

[121] We do not discount the potential health benefits this additional control can have for ambient PM. However, the regional haze program is only concerned with improving the visibility at Class I areas.

[122] IPM Model – Updates to Cost and Performance for APC Technologies, Particulate 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 5-7: PM Cost Methodology, downloaded from: https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-7_pm_cost_methodology.pdf

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construction cost of $77,428,000.[123] Applied to the subject units, this cost assumes a retrofit factor of 1.0, and does not consider the demolition of the existing ESP, should it be required in order to make space for the baghouse.

We do not calculate the cost-effectiveness resulting from replacing an ESP with a baghouse. However, we expect that the tons of additional PM removed by a baghouse over an ESP to be very small, which would result in a very high cost-effectiveness figure. Also, we do not model the visibility benefit of replacing an ESP with a baghouse. However, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from replacing an ESP with a baghouse to be a small fraction of that. For instance, our CAMx baseline modeling shows that on a source-wide level, impacts from PM emissions on the maximum impacted days from each source at each Class I area was 3% of the total visibility impairment or less (calculated as percent of total extinction due to the source). Therefore, additional PM controls are anticipated to result in very little visibility benefit on the maximum impacted days. Similarly, our CALPUFF modeling indicates that visibility impairment from PM is also a small fraction (typically only a few percent) of the total visibility impairment due to each source.

Adding to the above discussion, we are tasked to assign the enforceable emission limitations that constitute PM BART. We believe a stringent control level that would be met with existing or otherwise-required controls is a filterable PM limit of 0.03 lb/MMBtu for each of the coal-fired units subject to BART. We note that the Mercury and Air Toxics (MATS) Rule establishes an emission standard of 0.03 lb/MMBtu filterable PM (as a surrogate for toxic non-mercury metals) as representing Maximum Achievable Control Technology (MACT) for coal-fired EGUs.[124] This standard derives from the average emission limitation achieved by the best performing 12 percent of existing coal-fired EGUs, as based upon test data used in developing the MATS Rule. We are not familiar with any new technologies subsequent to this standard that could lead to any cost effective increases in the level of control; thus, consistent with the BART Guidelines, we are proposing to rely on this limit for purposes of PM BART for all of the coal-fired units as part of our FIP. We understand the coal-fired units covered by this proposal to be subject to MATS, but to the extent the units may be following alternate limits that differ from the surrogate PM limits found in MATS, we welcome comments on different, appropriately stringent limits reflective of current control capabilities.[125] Because we anticipate that any limit we assign should be achieved by current control capabilities, we propose that compliance can be met at the effective date of the rule. To address periods of startups and shutdowns, we are further proposing that PM BART for these units will additionally be met by following the work practice standards specified in 40 CFR Part 63, subpart UUUUU, Table 3, and using the relevant definitions in 63.10042. We are proposing that the demonstration of compliance can be satisfied by the methods for demonstrating compliance with filterable PM limits that are specified in 40 CFR Part 63, subpart UUUUU, Table 7. However, we would give consideration to commenter-submitted requests for alternate or additional methods of demonstrating compliance.

[123] Id. See page 9.

[124] 77 FR 9304, 9450, 9458 (February 16, 2012) (codified at 40 CFR 60.42 Da(a), 60.50 Da(b)(1)); 40 CFR Part 63 Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units.

[125] The various limits are provided at 40 CFR Part 63, Subpart UUUUU, Table 2 ("Emission Limits for Existing EGUs")

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5.4.2 BART Five Factor Analysis for PM for Gas-Fired Units

In Section 5.1.2, we noted that four of the units identified in Table 10 as being subject to BART, are only permitted to burn gas: Newman Unit 4, W A Parish Unit 4, and Wilkes Units 2 and 3. We note that PM emissions for the gas-only fired units that are subject to BART are inherently low.[126] We therefore conclude that PM emissions from natural gas firing is so minimal that the installation of any additional PM controls on the unit would likely achieve very low emissions reductions and have minimal visibility benefits. As there are no appropriate add-on controls and the status quo reflects the most stringent controls, we are proposing to make the requirement to burn pipeline natural gas federally enforceable. We note that in addition to satisfying PM BART, this limitation will also serve to satisfy SO_2 BART for these gas-fired units, as well as the fuel-oil units when they fire natural gas. We are proposing that PM and SO_2 BART for gas fired-units will limit fuel to pipeline natural gas, as defined at 40 CFR 72.2.

The available PM controls for gas units that also burn fuel oil are the same for the coal-fired units. We would expect similar costs for installing a baghouse on a typical gas-fired boiler that occasionally burns fuel oil. Again, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from the installation of a baghouse to be a small fraction on the order of 1-3 % of the visibility impacts from the facility. We are confident that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted with an ESP. We conclude that the cost of a baghouse does not justify the minimal expected improvement in visibility for these units. Accordingly, we are proposing that the fuel content limits for oil burning that we propose to meet SO_2 BART will also satisfy PM BART.

Lastly, should our assumptions regarding the frequency and type of fuel oil burned in these units significantly change, we expect that Texas will address such a change appropriately in its SIP, which we will review in the next planning period.

5.5 Step 5: Evaluate Visibility Impacts

Please see the BART Modeling TSD, where we describe in detail the various modeling runs we conducted, our methodology and selection of emission rates, modeling results, and final modeling analysis that we used to evaluate the benefits of the proposed controls and their associated emission decreases on visibility impairment values. 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.

5.5.1 Visibility Benefits of DSI, SDA, and Wet FGD for Coal-Fired Units

We evaluated the visibility benefits of DSI, for the twelve units depicted in Tables 40 and 41 below that currently have no SO_2 control. We evaluated all the units using the control levels we employed in our control cost analyses. In summary, we evaluated these units at a DSI SO_2

[126] AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.4, Natural Gas Combustion, available here: https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.

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control level of 50%, which we believe is likely achievable for any unit. At the lower performance level we assumed, we conclude that the corresponding visibility benefits from DSI in most cases would be close to half of the benefits from scrubbers resulting in the visibility benefits from scrubber retrofits being much more beneficial. We also evaluated the visibility benefits for scrubber retrofits (wet FGD and SDA) for these same units, assuming the same control levels corresponding to SDA and wet FGD that we used in our control cost analyses. For those sources that are within 50 to 400 km of a Class I area, we utilized CALPUFF modeling and supplemented our analysis with CAMx modeling to assess the visibility benefit of potential controls. For the remaining coal-fired sources (J T Deely, Coleto Creek, Fayette and W A Parish), only CAMx modeling was utilized as these sources are located at much greater distances to the nearest Class I areas. 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.[127] We note that high control scenario modeling for Fayette units 1 and 2 demonstrate the benefit from existing high performing controls. As discussed elsewhere, we found that for these units no additional controls or upgrades were necessary. For a full discussion of our review of all the modeling results, and factors that we considered in evaluating and weighing all the results, see our BART Modeling TSD. Below, we present a summary of some of those visibility benefits at the Class I areas most impacted by each source:

Table 40. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CAMx modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD(98%)	DSI benefit	WFGD benefit
Big Brown	Source (Unit 1 and 2)	WIMO	Max dv	4.017	2.249	0.474	1.768	3.542
			Days > 0.5 dv	65	33	0	32	65
			Days>1.0 dv	33	13	0	20	33
		CACR	Max dv	3.775	2.539	0.787	1.236	2.988
			Days > 0.5 dv	91	62	4	29	87
			Days>1.0 dv	57	21	0	36	57
	Unit 1	WIMO	Max dv	2.154	1.168	0.245	0.986	1.909
			Days > 0.5 dv	33	13	0	20	33
			Days>1.0 dv	12	1	0	11	12
		CACR	Max dv	2.016	1.327	0.409	0.688	1.606
			Days > 0.5 dv	58	22	0	36	58
			Days>1.0 dv	17	4	0	13	17
	Unit 2	WIMO	Max dv	2.175	1.181	0.235	0.994	1.940
			Days > 0.5 dv	34	13	0	21	34
			Days>1.0 dv	12	1	0	11	12
		CACR	Max dv	2.033	1.338	0.391	0.695	1.642
			Days > 0.5 dv	58	23	0	35	58

[127] 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."

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			Days>1.0 dv	17	4	0	13	17
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63
			Days>1.0 dv	40	14	0	26	40
	Unit 1	CACR	Max dv	4.516	3.123	0.733	1.393	3.783
			Days > 0.5 dv	79	43	3	36	76
			Days>1.0 dv	32	16	0	16	32
		WIMO	Max dv	2.241	1.290	0.252	0.951	1.989
			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	8	2	0	6	8
	Unit 2	CACR	Max dv	4.487	3.065	0.563	1.422	3.924
			Days > 0.5 dv	78	42	1	36	77
			Days>1.0 dv	30	13	0	17	30
		WIMO	Max dv	2.189	1.252	0.186	0.937	2.003
			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	6	2	0	4	6
Coleto Creek	Source (Unit 1)	WIMO	Max dv	0.845	0.526	0.176	0.318	0.668
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.791	0.458	0.186	0.333	0.606
			Days > 0.5 dv	5	0	0	5	5
			Days>1.0 dv	0	0	0	0	0
Harrington[1]	Source (Unit 061B & 062B)	SACR	Max dv	5.288	4.287	3.235	1.001	2.053
			Days > 0.5 dv	13	7	3	6	10
			Days>1.0 dv	5	1	1	4	4
		WIMO	Max dv	4.928	4.362	3.798	0.565	1.130
			Days > 0.5 dv	15	11	6	4	9
			Days>1.0 dv	6	5	4	1	2
	Unit 061B	SACR	Max dv	2.908	2.322	1.738	0.586	1.170
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.708	2.382	2.065	0.326	0.643
			Days > 0.5 dv	6	5	4	1	2
			Days>1.0 dv	4	2	1	2	3
	Unit 062B	SACR	Max dv	2.998	2.373	1.719	0.625	1.279
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.770	2.407	2.046	0.363	0.723
			Days > 0.5 dv	6	5	4	1	2
			Days>1.0 dv	4	1	1	3	3
J T Deely	Source (Sommers	WIMO	Max dv	1.513	0.939	0.814	0.574	0.699
			Days > 0.5 dv	47	8	1	39	46

	1&2, J T Deely 1&2)							
			Days>1.0 dv	6	0	0	6	6
		CACR	Max dv	1.423	1.155	0.905	0.268	0.518
			Days > 0.5 dv	7	3	2	4	5
			Days>1.0 dv	2	1	0	1	2
	J T Deely 1	WIMO	Max dv	0.757	0.449	0.270	0.307	0.487
			Days > 0.5 dv	4	0	0	4	4
			Days>1.0 dv	0	0	0	0	0
		BIBE	Max dv	0.652	0.373	0.069	0.279	0.583
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
	J T Deely 2	WIMO	Max dv	0.632	0.387	0.334	0.245	0.298
			Days > 0.5 dv	3	0	0	3	3
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.604	0.490	0.387	0.114	0.217
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
W.A. Parish	Source (WAP 4,5, &6)	CACR	Max dv	3.177	2.032	0.511	1.145	2.665
			Days > 0.5 dv	54	26	1	28	53
			Days>1.0 dv	22	9	0	13	22
		UPBU	Max dv	1.994	1.215	0.234	0.779	1.760
			Days > 0.5 dv	34	14	0	20	34
			Days>1.0 dv	9	1	0	8	9
	WAP 5	CACR	Max dv	1.698	1.052	0.180	0.646	1.518
			Days > 0.5 dv	22	9	0	13	22
			Days>1.0 dv	8	1	0	7	8
		UPBU	Max dv	1.038	0.613	0.094	0.424	0.943
			Days > 0.5 dv	11	1	0	10	11
			Days>1.0 dv	1	0	0	1	1
	WAP 6	CACR	Max dv	1.648	1.018	0.156	0.630	1.492
			Days > 0.5 dv	22	8	0	14	22
			Days>1.0 dv	6	1	0	5	6
		UPBU	Max dv	1.003	0.591	0.081	0.412	0.922
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	1	0	0	1	1
Welsh[2]	Source (Unit 1 & 2)	CACR	Max dv	4.576		0.822		3.754
			Days > 0.5 dv	92		3		89
			Days>1.0 dv	39		0		39
		MING	Max dv	2.544		0.570		1.973
			Days > 0.5 dv	9		1		8
			Days>1.0 dv	3		0		3
	Unit 1	CACR	Max dv	2.343	1.659	0.822	0.684	1.521
			Days > 0.5 dv	37	18	3	19	34
			Days>1.0 dv	8	3	0	5	8

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		MING	Max dv	1.150	0.886	0.570	0.264	0.579
			Days > 0.5 dv	2	1	1	1	1
			Days>1.0 dv	1	0	0	1	1
Fayette[2]	Source (Unit 1 & 2)	CACR	Max dv	1.894		0.903		0.991
			Days > 0.5 dv	26		2		24
			Days>1.0 dv	9		0		9
		WIMO	Max dv	1.175		0.580		0.595
			Days > 0.5 dv	19		1		18
			Days>1.0 dv	2		0		2
	Unit 1	CACR	Max dv	1.002		0.480		0.522
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	1		0		1
		WIMO	Max dv	0.609		0.306		0.302
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0
	Unit 2	CACR	Max dv	0.974		0.441		0.534
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	0		0		0
		WIMO	Max dv	0.598		0.282		0.316
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0

[1] Harrington high control scenario for both units is SDA at 95% reduction

[2] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD (wet FGD) installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.

Table 41. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Units 1 and 2)	WIMO	Max dv	4.27	2.54	0.43	1.73	3.83
			Days > 0.5 dv Avg.	67.33	43.33	2.67	24.00	64.67
			Days>1.0 dv Avg.	42.00	21.00	1.00	21.00	41.00
		CACR	Max dv	4.03	2.41	0.47	1.62	3.55
			Days > 0.5 dv Avg.	67	64.33	4.67	27.33	87.00
			Days>1.0 dv Avg.	60.33	30.00	0.00	30.33	60.33
Monticello[1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	3.68	1.70	4.16	4.87
			Days > 0.5 dv Avg.	143.67	115.00	62.33	28.67	81.33

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			Days>1.0 dv Avg.	113.00	66.33	23.67	46.67	89.33
		UPBU [4]	Max dv	3.45	1.77	0.77	1.68	2.68
			Days > 0.5 dv Avg.	103.00	61.00	13.67	42.00	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60.00	34.67	6.00	25.33	54.00
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67
Harrington [2]	Source (Units 061B & 062B)	SACR	Max dv	1.06	0.86	0.61	0.20	0.45
			Days > 0.5 dv Avg.	21.00	15.33	6.33	5.67	14.67
			Days>1.0 dv Avg.	6.67	3.00	0.67	3.67	6.00
		WIMO	Max dv	1.29	0.97	0.55	0.32	0.74
			Days > 0.5 dv Avg.	26.00	15.33	8.67	10.67	17.33
			Days>1.0 dv Avg.	9.00	4.67	1.33	4.33	7.67
Welsh[3]	Source (Unit 1)	CACR	Max dv	1.44	1.12	0.72	0.32	0.72
			Days > 0.5 dv Avg.	50.33	32.67	12.33	17.67	38
			Days>1.0 dv Avg.	15.33	8.00	2.33	7.33	13.00
		UPBU	Max dv	0.76	0.49	0.22	0.27	0.54
			Days > 0.5 dv Avg.	12.00	4.67	0.33	7.33	11.67
			Days>1.0 dv Avg.	0.67	0.00	0.00	0.67	0.67
		WIMO	Max dv	0.56	0.33	0.15	0.23	0.41
			Days > 0.5 dv Avg.	7.33	2.67	0.33	4.67	7.00
			Days>1.0 dv Avg.	1.33	0.33	0.00	1.00	1.33

[1] Monticello's controlled level is a combination of scrubber upgrades and scrubber install in the facility impact modeling with CALPUFF.
[2] Harrington high control scenario for both units is SDA at 95% reduction
[3] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and

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Fayette units have WFGD installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.
[4] UPBU = Upper Buffalo Wilderness Area.

5.5.2 Visibility Benefits of Scrubber Upgrades for Coal-Fired Units

We also modeled the visibility benefits of those same units for which we conducted control cost analysis for upgrading their existing scrubbers. We assumed the same 95% control level we used in our control cost analyses. We also modeled a lower level control at 90%. The visibility benefits from these scrubber upgrades are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits and reduction in number of days impacted.

Table 42. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CAMx modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	90% Control	95% Control	90% benefit	95% benefit
Martin Lake	Source (Unit 1, 2 & 3)	CACR	Max dv	6.651	4.491	4.321	2.159	2.329
			Days > 0.5 dv	141	75	56	66	85
			Days>1.0 dv	99	31	16	68	83
		UPBU	Max dv	5.803	2.669	2.528	3.134	3.275
			Days > 0.5 dv	99	39	22	60	77
			Days>1.0 dv	67	11	7	56	60
	Unit 1	CACR	Max dv	2.633	1.550	1.468	1.083	1.165
			Days > 0.5 dv	71	17	6	54	65
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.254	0.867	0.805	1.387	1.449
			Days > 0.5 dv	44	6	3	38	41
			Days>1.0 dv	10	0	0	10	10
	Unit 2	CACR	Max dv	2.466	1.882	1.811	0.585	0.655
			Days > 0.5 dv	68	18	9	50	59
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.189	1.077	1.025	1.112	1.164
			Days > 0.5 dv	40	6	5	34	35
			Days>1.0 dv	10	1	1	9	9
	Unit 3	CACR	Max dv	2.755	1.682	1.609	1.074	1.146
			Days > 0.5 dv	76	15	6	61	70
			Days>1.0 dv	29	2	1	27	28
		UPBU	Max dv	2.368	0.942	0.890	1.425	1.478
			Days > 0.5 dv	46	6	4	40	42
			Days>1.0 dv	13	0	0	13	13
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63

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			Days>1.0 dv	40	14	0	26	40
	Unit 3	CACR	Max dv	4.632	0.905	0.914	3.728	3.719
			Days > 0.5 dv	79	5	5	74	74
			Days>1.0 dv	32	0	0	32	32
		WIMO	Max dv	2.282	0.462	0.364	1.820	1.918
			Days > 0.5 dv	31	0	0	31	31
			Days>1.0 dv	7	0	0	7	7

Table 43. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Units 1, 2 & 3)	CACR	Max dv	4.46	2.27	1.86	2.18	2.60
			Days > 0.5 dv Avg.	129.67	77.33	63.00	52.33	66.67
			Days>1.0 dv Avg.	91.33	32.67	22.33	58.67	69.00
		UPBU	Max dv	2.73	1.10	0.85	1.63	1.88
			Days > 0.5 dv Avg.	81.67	30.33	18.67	51.33	63.00
			Days>1.0 dv Avg.	46.67	7.33	3.67	39.33	43.00
Monticello [1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	3.68	1.70	2.89	4.87
			Days > 0.5 dv Avg.	143.67	115	62.33	28.67	81.33
			Days>1.0 dv Avg.	113	66.33	23.67	46.67	89.33
		UPBU	Max dv	3.45	1.77	0.765	1.68	2.68
			Days > 0.5 dv Avg.	103	61	13.67	42	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60	34.67	6	25.33	54
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67

[1] Monticello's controlled level is a combination of scrubber upgrade on Unit 3 and scrubber retrofits on Units 1 and 2 in the facility impact modeling with CALPUFF.

5.5.3 Visibility Benefits of Fuel Oil Switching for Gas/Fuel Oil-Fired Units

We also modeled the visibility benefits of those gas/fuel oil-fired units for which we conducted control cost analysis for switching to lower sulfur fuels. We evaluated the visibility benefits of

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switching to fuel oils corresponding to ultra-low sulfur diesel at 0.0015% sulfur by weight and 0.3% sulfur by weight as we evaluated in our control cost analyses. The visibility benefits from these fuel switches are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits.

Table 44. Visibility Benefits from Lower Sulfur Fuel

Facility Name	Emission Unit	Baseline visibility Impact from Source (most impacted Class I area)	Visibility benefit of 0.3% S fuel oil	Visibility benefit of 0.0015% S fuel oil
Stryker	ST2	CALPUFF 0.65 % S: 0.786 dv @ CACR (Facility)	CALPUFF (0.3 % S) : 0.263 dv @ CACR (Facility)	CALPUFF: 0.522 dv @ CACR (Facility)
Graham	Unit 2	CALPUFF 0.69 % S: 1.228 dv @ WIMO (Facility)	CALPUFF (0.3% S): 0.465 dv @ WIMO (Facility	CALPUFF: 0.851 dv @ WIMO (Facility
Wilkes	Units 1, 2, 3	CALPUFF 0.43 % S: 0.698 dv @ CACR (Facility)	CALPUFF (0.1 % S): 0.029 dv @ CACR (Facility)	CALPUFF: 0.037 dv @ CACR (Facility)
Newman[1]	Unit 2	N/A	N/A	N/A
	Unit 3	N/A	N/A	N/A
	Unit 4	N/A	N/A	N/A
Calaveras	Sommers Unit 1	CAMx: 1.513 dv @ WIMO (Source); 0.106 dv @ CACR (Unit)	0.004 dv @ CACR	0.008 dv @ CACR
	Sommers Unit 2	CAMx: 1.513 dv @ WIMO (Source); 0.180 dv @ CACR (Unit)	0.023 @ CACR	0.047 @ CACR

[1] EPA initially considered evaluating with CALPUFF databases, but Newman is located near the edge of the CALMET modeling domain. There are a number of Class I areas that Newman could potentially impact (Gila, Bosque del Apache, Mount Baldy, Chiricahua, White Mountain, etc) and due to the size of the CALMET grid we cannot determine if Newman's impacts are below 0.5 dv at all Class I areas or determine the potential benefits from controls. Since plumes could transport out of the modeling domain and there is no way within the CALPUFF model to account for mass that transports out of the domain that may come back into the domain, the CALPUFF modeling databases cannot be relied on to conclusively assess visibility impacts from the Newman facility.

5.6 How, if at all, Do Issues of "Grid Reliability" Relate to the Proposed BART Determinations?

On July 15, 2016, a preliminary order of the Fifth Circuit Court of Appeals took the view that EPA's Texas-Oklahoma FIP (81 FR 295, January 5, 2016) gave a "truncated discussion of grid reliability" and additionally stated that "the agency may not have fulfilled its statutory obligation to consider the energy impacts of the FIP." The Court's preliminary ruling made particular reference to "the explicit directive in the [CAA] that implementation plans 'take[] into consideration…the energy…impacts of compliance,' 42 U.S.C. § 7491(g)(1)."[128] Because the

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BART requirement at issue in this proposal has similar language on *energy impacts of compliance* appearing at 42 U.S.C. § 7491(g)(2), we wish to provide a clear explanation on how grid-related considerations for EGUs could bear on this proposal.

First, the BART factor for *energy impacts of compliance* does not call for the examination of grid reliability considerations from alleged plans to shut down or retire a unit rather than comply with a more stringent emission limit or limits. The language instead calls for consideration of energy impacts from *complying* by installing retrofit controls on a source that continues in operation. In this regard, our proposal follows the required BART Guidelines for EGUs.[129] The Guidelines explain that the energy impacts factor relates to the penalties and benefits that may be associated with the assessment of a control option, e.g., whether (for power penalties) the operation of add-on control technology subtracts from the productive yield of electricity from an EGU (what is sometimes termed an auxiliary or parasitic load).[130] It is also useful to note that the statutory text, while using the word "energy," can apply to sources that do not produce energy or electricity. Thus, the statutory text regarding "energy impacts" of compliance with BART is not confined to the power generating industry and does not dictate that we study grid reliability issues.

We have considered whether this topic has any separate relevance to our proposal. Various court filings, news accounts, and industry market reports suggest that some source operators for some Texas BART units may be contemplating unit retirements. The BART Guidelines directly address such scenarios under the "remaining useful life" factor: "there may be situations where a source operator intends to shut down a source….but wishes to retain the flexibility to continue operating beyond that date in the event, for example, the market conditions change."[131] The Guidelines advise that a source that is willing to assure a permanent stop in operations with a federally- or State-enforceable restriction preventing further operation may obtain a short remaining useful life for BART analysis purposes that could then factor in the overall cost analysis.[132] As the Guidelines state, "Where the remaining useful life is less the than the time period for amortizing costs, you should use this shorter period in your cost calculations."[133] We have no information on enforceable restrictions of this type for any of the units that we propose to be subject to BART. Absent that, we must assume that controls installed on the BART units

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[128]EPA Guidance on this statutory language specifically explains that energy impacts are a matter of whether "energy requirements associated with a control technology result in energy penalties." U.S. EPA, Office of Air Quality Planning and Standards, "Guidance for Setting Reasonable Progress Goals under the Regional Haze Program," (June 1, 2007 rev), at Page 5-2.

[129] The promulgation of the Guidelines was required by 42 U.S.C. 7491(b)(1). Adherence to the Guidelines is mandatory for fossil-fuel fired generating power plants having total generating capacities "in excess of 750 megawatts."

[130] Other CAA provisions requiring consideration of "energy impacts" or "energy requirements of the control technology" are understood similarly. *See, e.g.,* CAA section 169 (the 1977 "best available control technology" requirement with consideration of "energy…impacts"); *see also* CAA section 108 ("energy requirements…of the emission control technology; "energy…impact of such processes, procedures, and methods [to reduce or control air pollution"); section 111 ("taking into account…energy requirements" of an emission limitation), etc.

[131] *Id.* at 39169-39170.

[132] Similar to calculating a mortgage, remaining useful life is used in our cost-effectiveness analysis to calculate the annual cost of a particular control. The longer the remaining useful life, the smaller the total annualized cost, and the more cost-effective the control.

[133] Id. at 39169.

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will experience their full useful life. Affected sources are free to submit information as part of their comments containing appropriate enforceable documentation of shorter remaining useful lives.

We note, however, that the Guidelines recognize there may be cases where the installation of controls, even when cost-effective, would "affect the viability of continued plant operations."[134] Under the Guidelines, where there are "unusual circumstances," we are permitted to take into consideration "the conditions of the plant and the economic effects of requiring the use of a control technology."[135] If the effects are judged to have a "severe impact," those effects can be considered in the selection process. In such cases, the Guidelines counsel that any determinations be made with an economic analysis with sufficient detail for public review on the "specific economic effects, parameters, and reasoning."[136] It is recognized, by the language of the Guidelines, that any such review process may entail the use of sensitive business information that may be confidential. The ADDRESSES section of this proposal explains how to submit confidential information with comments, and when claims of confidential business information, or CBI, are asserted with respect to any information that is submitted, the EPA regulations at 40 CFR Part 2, Subpart B-Confidentiality Business Information apply to protect it. All of that said, the Guidelines also advise that we may "consider whether other competing plants in the same industry have been required to install BART controls if this information is available."[137] Because Texas EGUs are among the last to have SO_2 BART determinations, this information is available. It is indeed the case that other similar EGUs have been required to install the same types of SO_2 BART controls that we are proposing as very cost effective.[138]

We have considered the state of available information on whether the proposed controls could affect the viability of continued plant operations. On this point, we note that we are proposing BART determinations for several units where SO_2 control requirements were separately promulgated as part of the Texas-Oklahoma FIP. These under-controlled EGU sources are: Big Brown 1 and 2; Monticello 1, 2 and 3; Martin Lake 1,2 and 3; and Coleto Creek 1. In litigation over the reasonable progress FIP, various declarations were filed on the issues of alleged forced closures and alleged reliability impacts. These declarations have been compiled and added to the docket for this rulemaking. By our review, these declarations do not appropriately inform or substantiate source-specific allegations of "unusual circumstances" that may have a severe impact on plant operations, because they do not offer any site-specific information.[139] Here is a summary of relevant points:

- A declaration by a Coleto Creek Plant manager discussed the timelines and commitments to comply with the January 5, 2016 final rulemaking, indicating that efforts to comply would be carried out. The declaration states "alternatively" that the source owner could make an eventual decision to discontinue operations.

[134] 70 FR 39103, 39171 (July 6, 2005), [40 CFR Part 51, App. Y]
[135] *Id.*
[136] 70 FR at 39171
[137] *Id.*
[138] See for instance, the EIA information we present elsewhere in this notice in which we summarize the hundreds of scrubber installations that have been performed on similar EGUs.
[139] Certain statements in declarations from representatives of both Luminant and Coleto Creek, who are the source owners of these facilities, cited compliance planning efforts that would be consistent with continued plant operations.

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- A declaration by a vice president of construction management at Luminant stated, in relevant part, Luminant was "planning for installation of four new scrubbers at Big Brown and Monticello" and "planning for the scrubber upgrades at…Martin Lake, and Monticello."
- Somewhat differently, a declaration by the CFO of Luminant Generating Company LLC stated the January 5, 2016 rulemaking was "likely to force the closure of the Big Brown and Monticello plants" and cites a Form 10-K from March 1, 2016 that similarly states "new scrubbers at the Big Brown and Monticello units…along with the existence of low wholesale power prices in ERCOT, would likely challenge the long-term economic viability of those units." The declaration states that other Clean Air Act regulatory requirements would also threaten the viability of Big Brown and Monticello units. The declaration does not mention Martin Lake.
- A declaration from the Executive Director of the Public Utility Commission of Texas, dated April 18, 2016, stated it was "simply not possible at this point to know the precise units that may retire." Notably, the declarant also disclaimed any argument that unit retirements would occasion an "ERCOT-wide generation capacity shortfall." Instead and only, the declarant cited the potential for "local reliability impacts."
- A declaration from the Director of System Planning for the Electric Reliability Council of Texas (ERCOT) stated that retirement plans "are unknown to ERCOT and the market until formal notification is made." It continued: "ERCOT does not know at this time which units may be retired as a result of the Regional Haze FIP."

In sum, several months after the finalization of the January 5, 2016, final rulemaking representatives for the source owners provided multiple court statements that would appear to contradict or at least equivocate on the matter of whether those FIP controls could be put in place. Meanwhile, declarations submitted by certain public authorities knowledgeable in grid resource planning disclaimed knowledge on severe impacts on any source-specific basis. Thus, we are unable to conclude from any of this information that the proposed cost-effective BART controls would severely impact plant operations. Generalized claims of possible retirements and discussions on attributes of the market design of the Electric Reliability Council of Texas (ERCOT) cannot inform the statutorily required, source-specific BART determinations, and some aspects of these declarations could undermine our ability to determine "unusual circumstances" in the meaning of the BART Guidelines, as to these facilities.

As a predicate to studying effects on transmission or reliability as "unusual circumstances," we would require site-specific information from any source that would wish for us to potentially consider "affordability of controls," under the terms specified in the Guidelines. Source owners may submit information, including information claimed to be CBI, for our assessment and consideration to potentially support an economic analysis that might be used in the BART selection process. As suggested by the Guidelines, the information necessary to inform our judgment would likely entail source-specific information on "product prices, the market share, and the profitability of the source." Consideration of such information does not dictate what will be selected as a "best" alternative under the Guidelines, but it will substantiate the likelihood of a retirement scenario that would then give the parameters for: a non-conjectural examination of grid reliability issues; judging the significance or insignificance of such issues; and assessing whether such issues could be avoided through appropriate transmission planning. In sum, unless we are able to substantiate an "affordability of controls" problem for any particular unit and

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substantiate that a particular unit retirement would not be happening anyway at about the same time, alleged grid reliability impacts are speculative and are not able to inform these required BART determinations. As a final note, we acknowledge Executive Order 13211 ("Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, and Use"). In cases where it does apply, agencies are ordered to prepare a Statement of Energy Effects for submission to the Administrator of the Office of Information and Regulatory Affairs (OIRA), Office of Management and Budget. This EGU BART proposal is not considered a significant regulatory action under Executive Order 12866, so the proposed action cannot be a "significant energy action" for purposes of Executive Order 13211 on that basis. This proposed action has also not been designated a significant energy action by the Administrator of OIRA, so Executive Order 13211 could not apply under that separate basis. With this proposal, there are no anticipated adverse effects on energy supply, distribution, or use that are meaningful or distinguishable from any other scenario where an EGU is expected to install cost-effective pollution controls required by the CAA.

6 Our Proposed BART Determinations

In Section 5, above, we have analyzed the BART five factors for all the units we have identified as being subject to BART. Below we present our reasoning for proposing our BART determinations for 29 EGUs in Texas, based on our analysis and weighing of the Five BART Factors. (1) proposed SO_2 and PM BART determinations for 12 coal-fired units with no SO_2 controls, (2) proposed BART SO_2 and PM BART determinations for 6 coal-fired units with existing scrubbers, (3) proposed SO_2 and PM BART determinations 7 gas-fired units that occasionally burn fuel oil, and (4) proposed PM BART determinations for 4 gas-fired units.

In previous sections of this proposal, we have described how we assessed the five BART factors. In no case do we see any instance in which our assessment of energy impacts is a determining factor in assessing BART.[140] Also, in no case do we see any instance in which our assessment of the remaining useful life is a determining factor in assessing BART. Should a facility determine in comments to us that the remaining useful life is less than the 30 years we have assumed in our control cost analyses, and is willing to enter into an enforceable document to that effect, we will adjust our cost-effectiveness calculation accordingly in making our final decision. In two cases, Harrington units 061B and 062B, we have limited our SO_2 control analysis for Harrington to DSI and dry scrubbers due to potential non-air quality concerns. In all other instances, we conclude that the cost of compliance, and the visibility benefits of controls are the controlling BART factors in our weighing of the five BART factors.

In considering cost-effectiveness and visibility benefit, we do not eliminate any controls based solely on the magnitude of the cost-effectiveness value, nor do we use cost-effectiveness as the primary determining factor. Rather, we compare the cost-effectiveness to the anticipated visibility benefit, and we take note of any additional considerations.[141] Also, in judging the visibility benefit we do not simply examine the highest value for a given Class I area, or a group

[140] In addition to our assessment of energy impacts, also see our discussion in Section 5.6 concerning our conclusion that energy impact considerations do not relate to potential electrical grid reliability issues.
[141] For instance, as we discuss later in Section 5.3.5.2 why we believe that there are certain mitigating factors that should be considered when assessing BART for the gas-fired units that occasionally burn fuel oil.

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of Class I areas, but we also consider the cumulative visibility benefit for all affected Class I areas, the number of days in a calendar year in which we see significant improvements, and other factors.[142] See the BART Modeling TSD for a complete description and summary of our analysis of visibility benefits of potential control options.

First, we note that all of the sources addressed in our proposed BART determinations have already been shown to cause or contribute to visibility impairment at a Class I area as a condition of being subject-to-BART as part of the BART screening analysis. This analysis eliminated any BART-eligible source that emits lower amounts of visibility impacting pollutants, or otherwise impacts any Class I area at less than 0.5 deciviews. In fact, all of the individual units that we are proposing for BART controls exceed 0.5 deciviews on a unit basis, with most exceeding 1.0 deciview impact on a unit basis. As a consequence, all of the units we are proposing for BART controls are among the largest emitters of visibility impacting pollutants in Texas. A number of these units (i.e., Big Brown, Martin Lake, Monticello, and Coleto Creek) were previously determined by us to require the same type and level of controls under the reasonable progress and long-term strategy provisions of the Regional Haze Rule that we are proposing here.[143]

Second, not discounting our approach of considering both cost-effectiveness and visibility benefit in unison, the cost-effectiveness of all of the controls that form the basis of our proposed BART determinations are within a range found to be acceptable in other cases.[144] As we stated in the BART Rule, ''[a] reasonable range would be a range that is consistent with the range of cost effectiveness values used in other similar permit decisions over a period of time.''[145]

6.1 SO_2 BART for Coal-fired Units with no SO_2 Controls

As we have discussed in this proposal and in our TSD, we have assumed two DSI control levels corresponding to 50% control and either a maximum of 80% or 90% control, depending on the particulate matter control device in use.[146] We did this to address the BART Guidelines directive that in evaluating technically feasible alternatives we "(1) [ensure we] express the degree of control using a metric that ensures an ''apples to apples'' comparison of emissions performance levels among options, and (2) [give] appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels."[147] In most cases, the cost-effectiveness of the higher control level of DSI was higher than either SDA or wet FGD. This was not the case for Monticello Unit 2; Harrington Unit 062B; and J T Deely Units 1 and 2.

However, these maximum DSI control levels are theoretical and we believe that any DSI control

[142] See for example 70 39130: "comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g. the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, a threshold representing an x percent change in improvement, etc.)."
[143] See our recent Texas-Oklahoma FIP, 81 FR 321.
[144] See for instance 79 FR 5048 (January 30, 2014): Jim Bridger BART determination of LNB/SOFA + SCR on Units 1-4; 77 FR 18070 (March 26, 2012): EPA proposed approval of Colorado's BART determination of SCR for Hayden Unit 2, later finalized at 77 FR 76871 (December 31, 2012).
[145] 70 FR 39168 (July 6, 2005).
[146] Note for Harrington Unit 062B and Welsh 1, we further limited the maximum DSI control level to that of our calculated SDA control level.
[147] 70 FR 39166 (July 6, 2005).

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level above 50% must be confirmed by onsite testing before we could propose a BART control based on it. As is evident in comparing the 50% control level to the higher control level, the cost-effectiveness of DSI worsens (higher $/ton) as the control level increases, and the certainty of any unit attaining that control level decreases. We therefore regard the cost-effectiveness values of the maximum DSI control levels as being useful in a basic comparison of cost-effectiveness between DSI and scrubbers, but we place much less weight on these values. We therefore conclude that given the uncertainty concerning the maximum control level of DSI, the greater control efficiency and resulting visibility benefit offered by scrubbers overrides any possible advantage DSI may hold in cost-effectiveness. Should the affected facilities provide site-specific information to us in their comments that conflicts with this assumption, we will incorporate it into our final decision on SO_2 BART and potentially re-evaluate DSI.

As we indicate elsewhere in our proposal, both SDA and wet FGD are mature technologies that are in wide use throughout the United States. We are not aware of any unusual circumstances that exist for any of the sources that would serve to indicate they should not be viewed similarly to these hundreds of previous scrubber retrofits. In comparing wet FGD versus SDA we note that in a number of cases the cost-effectiveness of wet FGD is lower than the cost-effectiveness of SDA. In the remaining cases, we conclude that the incremental cost-effectiveness of wet FGD over SDA, which we review in Section 5.3.6 is reasonable, and the improved control and visibility benefit offered by wet FGD overrides the small penalty in cost-effectiveness FGD has in comparison to SDA. We propose that with the exception of the Harrington units, SO_2 BART for all other coal-fired units should be based on the wet FGD control levels we have used in our BART analyses. We propose that SO_2 BART for the Harrington units should be based on the SDA control levels we have used in our BART analyses. Below we discuss our consideration of the cost-effectiveness and anticipated visibility benefits of controls. See section 5.5 for additional information on the anticipated visibility benefits from each level of control modeled. See the BART modeling TSD for a complete summary of our visibility benefit analysis of controls, including modeled benefits and impacts at all Class I areas included in the modeling analyses and additional metrics considered in the assessment of visibility benefits.

CAMx model results shown in the tables below summarize the benefits from the recommended controls at the two Class I areas most impacted by the source or unit in the baseline modeling. The benefit is calculated as the difference between the maximum impact modeled for the baseline and the maximum impact level modeled under the control scenario. 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. The CALPUFF cumulative model results only consider those Class I areas within the typical range of CALPUFF and not all 15 Class I areas included in the CAMx modeling.

6.1.1 Big Brown 1 & 2

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In reviewing the Big Brown units, we conclude that the installation of wet FGD will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 45. Wet FGD Visibility Benefits at Big Brown (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Big Brown Units 1 & 2	3.83	3.55	7.38	151.67	101.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek and Wichita Mountains

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek and Wichita Mountains.

In evaluating Big Brown, we note there are two Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results, we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the two Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate that wet FGD on both units will eliminate 151.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the visibility benefits in terms of dv benefits at the most impacted Class I areas and about 1/3rd to half the cumulative benefits over the class I areas included in the modeling analysis.

Table 46. Wet FGD Visibility Benefits at Big Brown (CAMx)

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Unit	Improvement at Wichita mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Big Brown 1	1.909	1.606	12.728	174 / 44	174 / 44
Big Brown 2	1.940	1.642	12.924	175 / 45	175 / 45
Source	3.542	2.988	24.274	372 / 170	362 / 170

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv at all Class I areas on a unit and source-wide basis, and eliminate all but 10 days across the impacted Class I areas where the source-wide impacts exceeds 0.5 dv. At the most impacted Class I area, wet FGD will on each unit result in visibility improvements of 1.9 dv on the most impacted day. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the CAMx modeling.

We also conclude that wet FGD is very cost-effective for both units at less than $1,200/ton and more cost-effective than DSI. Based on this consideration of the BART factors, we propose that SO_2 BART for Big Brown Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

6.1.2 Monticello 1 & 2

Similar to the Big Brown units, the installation of wet FGD at Monticello Units 1 and 2 will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 47. Wet FGD Visibility Benefits at Monticello (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	4.87	2.70	10.25	224.67	164.67

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control

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scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Monticello, we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 224.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I area and half of the cumulative benefits.

Table 48. Wet FGD Visibility Benefits at Monticello (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 1	3.783	1.989	12.708	197 / 67	191 / 67
Monticello 2	3.924	2.003	13.025	192 / 57	191 / 57
Source (including unit 3)	8.419	4.962	31.553	520 / 293	460 / 278

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv at all Class I areas on a unit basis, and eliminate all but 15 days across the impacted Class I areas where the source-wide impacts exceeds 1 dv. We note that source-wide modeled benefits include benefits of 95% control scrubber upgrade on Unit 3. At the most impacted Class I area, wet FGD on each unit will each result in visibility improvements of 3.8-3.9 dv on the most

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impacted day at Caney Creek and 2 dv visibility benefits at Wichita Mountains. DSI operated at 50% control results in less than half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

The wet FGD cost-effectiveness of $2,718/ton and $3,031/ton are higher than those for Big Brown, but these figures remain well within a range that we have previously found to be acceptable for BART, and we consider the very significant visibility benefits that will result justify the cost of wet FGD at the Monticello Units 1 and 2. The 50% control DSI cost-effectiveness is slightly less than that for wet-FGD, but results in much less visibility benefits. Based on our consideration of the BART factors, we therefore propose that SO_2 BART for Monticello Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

6.1.3 Coleto Creek 1

In reviewing Coleto Creek Unit 1, we conclude that in comparison with the Monticello units, the installation of a wet FGD is more cost-effective and results in lesser, but still significant visibility benefits. We summarize some of these visibility benefits in the table below:

Table 49. Wet FGD Visibility Benefits at Coleto Creek Unit 1 (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Coleto Creek 1	0.668	0.606	5.233	17 / 0	17 / 0

[1] 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
[2] 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
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 0.5 dv at all Class I areas. At the most impacted Class I area, wet FGD will result in visibility improvements of 0.6 or more on the most impacted days at both Caney Creek and the Wichita Mountains. In addition, seven other Class I areas are improved by amounts ranging from 0.356 to 0.531 dv on the maximum impacted days with wet FGD. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15class I areas included in the modeling.

We also conclude that wet FGD is very cost-effective at $2,127/ton and well within a range that we have previously found to be acceptable and more cost-effective than DSI. We consider the significant visibility benefits that will result justify the cost of wet FGD at the Coleto Creek Unit 1. We therefore propose that SO_2 BART for Coleto Creek Unit 1 should be

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based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

6.1.4 Welsh 1

In reviewing Welsh Unit 1, we conclude that the installation of a wet FGD will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 50. Wet FGD Visibility Benefits at Welsh Unit 1 (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Welsh 1	0.72	0.41	1.66	56.67	15

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Welsh we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 56.67 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

Table 51. Wet FGD Visibility Benefits at Welsh Unit 1 (CAMx)

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Unit	Improvement at Caney Creek (dv)	Improvement at Mingo Wilderness (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Welsh 1	1.521	0.579	4.683	65 / 9	60 / 9
Source (Welsh 1 & 2)	3.754	1.973	13.179	211 / 72	206 / 72

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD on unit 1 will eliminate all days impacted by the unit over 1 dv at all Class I areas and all but 5 days impacted over 0.5 dv. At the most impacted Class I area, wet FGD on unit 1 will result in visibility improvements of 1.521 dv on the most impacted days at Caney Creek. In addition to the visibility benefits at Caney Creek and Mingo, visibility benefits at two additional Class I areas exceed 0.5 dv. We note that source-wide benefits shown include the benefits from the shutdown of unit 2. In addition, cumulative benefits from wet FGD on unit 1 over all 15 Class I areas exceeds 4.5 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We conclude that although at $3,824/ton, the cost-effectiveness of wet FGD is higher than for other facilities, it remains within a range that we have previously found to be acceptable. We consider the significant visibility benefits that will result from the installation of wet FGD at Welsh Unit 1 to justify the cost. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for Welsh Unit 1 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

6.1.5 Harrington 061B & 062B

In reviewing Harrington, we conclude that the installation of SDA on Units 061B and 062B will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 52. SDA Visibility Benefits at Harrington (CALPUFF)

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Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Harrington 061B & 062B	0.45	0.74	2.56	53.67	26

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

In evaluating Harrington we note there are five Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the five Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate SDA on both units will eliminate 53.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

Table 53. SDA Visibility Benefits at Harrington (CAMx)

Unit	Improvement at Salt Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Harrington 061B	1.170	0.643	4.832	17 / 5	11 / 3
Harrington 062B	1.279	0.723	5.379	17 / 5	11 / 3
Source (061B & 0622B)	2.053	1.130	9.329	51 / 17	37 / 11

[1] 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.

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[2] 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.
[3] 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.

CAMx modeling results indicate SDA on these units will eliminate more than half of all days impacted by the units over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, SDA on each unit will each result in visibility improvements of approximately 1.2 dv on the most impacted days at Salt Creek and 0.6 – 0.7 dv at Wichita Mountains, reducing the number of days impacted over 0.5 and 1.0 dv at these Class I areas. In addition, cumulative benefits from SDA on both units over all 15 Class I areas exceeds 9.3 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the SDA visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We also conclude that SDA is cost-effective at $3,904 for Unit 061B and $4,180/ton for Unit 062B and, remains within a range that we have previously found to be acceptable. In contrast to other units we have reviewed, the 50% control DSI cost-effectiveness is much less than that for SDA. However, given the additional large total cumulative visibility benefits that will result from the installation of SDA over DSI at 50% control, we consider SDA to justify the additional cost. We therefore propose that SO_2 BART for Harrington Units 061B and 062B should be based on the installation of SDA at an emission limit of 0.06 lbs/MMBtu based on a 30 BOD.

6.1.6 W. A. Parish WAP 5 & 6

In reviewing W A Parish, we conclude that the installation of wet FGD on Units 5 and 6 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 54. Wet FGD Visibility Benefits at W A Parish (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
W A Parish 5	1.518	0.943	8.171	51 / 9	51 / 9
W A Parish 6	1.492	0.922	7.979	48 / 7	48 / 7
Source (WAP 4, 5 & 6)	2.665	1.760	15.301	163 / 49	162 / 49

[1] 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.
[2] 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.
[3] 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

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threshold for the control scenario.

CAMx modeling results indicate that wet FGD on each of these units will eliminate all days impacted by each unit over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of approximately 1.5 dv on the most impacted days at Caney Creek and 0.9 dv at Upper Buffalo. Nine Class I areas have modeled source-wide baseline impacts over 1 dv, and wet FGD on both units results in source-wide improvements of 1 dv or greater on the maximum impacted days at eight of these Class I areas. In addition, cumulative benefits from wet FGD on both units over all 15 Class I areas exceeds 15 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15class I areas included in the modeling. We note that source-wide modeling includes a small impact from WAP 4. This unit is gas-fired and was modeled at baseline emissions levels for both the baseline and control case scenarios.

We conclude that wet FGD is cost-effective at $2,417/ton for Unit 5 and $2,259/ton for Unit 6, and remains well within a range that we have previously found to be acceptable. DSI at 50% control is approximately the same cost-effectiveness but results in significantly less visibility benefit. We consider the cost of wet FGD at the W A Parish units to be justified by the significant visibility benefits that will result. We therefore propose that SO_2 BART for W A Parish Units 5 and 6 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

6.1.7 J T Deely 1 & 2

In reviewing J T Deely, we conclude that the installation of wet FGD on Units 1 and 2 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 55. Wet FGD Visibility Benefits at J T Deely (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
J T Deely 1	0.487	0.283	4.785	10 / 0	10 / 0
J T Deely 2	0.298	0.217	3.650	7 / 0	7 / 0
Source (J T Deely 1 & 2, Sommers 1 & 2)	0.699	0.518	8.943	89 / 13	84 / 13

[1] 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.
[2] 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.
[3] 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

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threshold for the control scenario.

CAMx modeling results indicate wet FGD on each of these units will eliminate all days impacted by each unit over 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of 0.487 dv and 0.298 dv on the most impacted days at Wichita Mountains and 0.283 dv and 0.217 dv at Caney Creek. Larger visibility improvements on the most impacted days are anticipated at other Class I areas. Benefits from wet FGD on unit 1 are 0.583 dv at Big Bend, 0.511 dv at Salt Creek, 0.449 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.475 dv at White Mountains. Benefits from wet FGD on unit 2 are 0.583 dv at Big Bend, 0.441 dv at Salt Creek, 0.354 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.375 dv at White Mountains. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 Class I areas included in the modeling. We note that source-wide modeling includes the impact from Sommers units 1 and 2, and as discussed in the BART Modeling TSD, control case scenarios for these units included benefits from switching to lower sulfur fuel oil. However, these modeled improvements are a small fraction of the total visibility benefits from controls at the source.

We conclude that wet FGD is cost-effective at $3,898/ton for Unit 1 and $3,712/ton for Unit 2, and remains within a range that we have previously found to be acceptable. We consider the cost of wet FGD at the J T Deely units to be justified by the significant visibility benefits that will result at a number of impacted Class I areas. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for J T Deely Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.[148]

6.2 SO_2 BART for Coal-fired Units with Underperforming Scrubbers

The BART Guidelines state that underperforming scrubber systems should be evaluated for upgrades.[149] Other than upgrading the existing scrubbers, all of which are wet FGDs, there are no competing control technologies that could be considered for these units. The CALPUFF modeling generated facility-wide impacts and the benefits of the scrubber upgrade on Monticello Unit 3 and the three Martin Lake facilities are included in Table 42 above. The following is a listing of each of the affected units along with the resulting CAMx modeled visibility benefits from upgrading their existing scrubbers:

Table 56. Visibility Benefit for Coal-fired Units with Existing SO_2 Controls (CAMx)

[148] We have read reports that CPS Energy, is planning to retire J T Deely Units 1 and 2 by the end of 2018, but we have no enforceable documents to that effect.
[149] 70 FR 39171 (July 6, 2005).

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Unit	Improvement at most impacted (dv)	Improvement at 2nd most impacted (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 3	3.719 (CACR)	1.918 (WIMO)	11.940	200 / 66	188 / 66
Martin Lake 1	1.165 (CACR)	1.449 (UPBU)	7.575	160 / 41	151 / 40
Martin Lake 2	0.655 (CACR)	1.164 (UPBU)	6.199	150 / 41	134 / 39
Martin Lake 3	1.146 (CACR)	1.478 (UPBU)	7.863	173 / 47	163 / 46

[1] 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.
[2] 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.
[3] 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.

As we state elsewhere in this proposal, because our cost-effectiveness calculations depend on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost effectiveness was $1,156/ton or less. We conclude that in all cases, scrubber upgrades are very cost-effective and result in very significant visibility benefits, significantly reducing the impacts from these units and reducing the number of days that Class I areas are impacted over 1.0 dv and 0.5 dv. We propose that SO_2 BART for all other coal-fired units with underperforming scrubbers should be based on the wet FGD upgrade control levels we have used in our BART analyses of them.

6.2.1 Potential Process for Alternative Scrubber Upgrade Emission Limits

In our BART FIP TSD, we discuss how we calculated the SO_2 removal efficiency of the units we analyzed for scrubber upgrades. We note that due to a number of factors we could not accurately quantify, our calculations of scrubber efficiency may contain some error. Based on the results of our scrubber upgrade cost analysis, we do not believe that any reasonable error in calculating the true tons of SO_2 removed affects our proposed decision to require emission reductions, as all of the scrubber upgrades we analyzed are cost-effective (low $/ton). In other words, were we to make reasonable adjustments in the tons removed to account for any potential error in our scrubber efficiency calculation, we would still propose to upgrade these SO_2 scrubbers. We believe we have demonstrated that upgrading an underperforming SO_2 scrubber is one of the most cost-effective pollution control upgrades a coal fired power plant can implement to improve the visibility at Class I areas. However, our proposed FIP does specify a SO_2 emission limit that is based on 95% removal in all cases. This is below the upper end of what an upgraded wet SO_2 scrubber can achieve, which is 98–99%, as we have noted in our BART FIP TSD. We believe that a 95% control assumption provides an adequate margin of error for any of the units for which we have proposed scrubber upgrades, such that they should be able to comfortably attain the emission limits we have proposed. However, for the operator of any unit that disagrees with us on this point, we propose the following:

(1) The affected unit should comment why it believes it cannot attain the SO_2 emission

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limit we have proposed, based on a scrubber upgrade that includes the kinds of improvements (e.g., elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically included in a scrubber upgrade.

(2) After considering those comments, and responding to all relevant comments in a final rulemaking action, should we still require a scrubber upgrade in our final FIP we will provide the company the following option in the FIP to seek a revised emission limit after taking the following steps:

(a) Install a CEMS at the inlet to the scrubber.

(b) Pre-approval of a scrubber upgrade plan conducted by a third party engineering firm that considers the kinds of improvements (e.g., elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically performed during a scrubber upgrade. The goal of this plan will be to maximize the unit's overall SO_2 removal efficiency.

(c) Installation of the scrubber upgrades.

(d) Pre-approval of a performance testing plan, followed by the performance testing itself.

(e) A pre-approved schedule for 2.a through 2.d.

(f) Should we determine that a revision of the SO_2 emission limit is appropriate, we will have to propose a modification to the BART FIP after it has been promulgated. It should be noted that any proposal to modify the SO_2 emission limit will be based largely on the performance testing and may result in a proposed increase or decrease of that value.

6.3 SO_2 BART for Gas-fired Units that Burn Oil

In analyzing potential controls for those gas-fired units that occasionally burn fuel oil we considered scrubber retrofits and lower sulfur fuel oil. We concluded that the cost-effectiveness of scrubber retrofits for these units were likely very high, and not worth the potential visibility benefit.

We also concluded that the cost-effectiveness of switching to a No. 2 fuel oil with a sulfur content of 0.3% is $11,218/gallon, and the cost-effectiveness of switching to ULSD with a sulfur content of 0.0015% is $8,627/gallon. We further noted that one facility already had a contract in place for ULSD at a lower price than we assumed, which if used in our analysis would result in a cost effectiveness of $3,970/ton. Although the cost-effectiveness of switching to a lower sulfur oil (assuming our price for ULSD of $1.667/gal) is higher than other controls that we have typically required under BART, we note certain mitigating factors.

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For instance, arguing against control, our calculated cost-effectiveness values are high in relation to other BART controls we have required in the past. Also, our visibility modeling necessarily utilized the maximum SO_2 emissions over a 24-hour timeframe,[150] resulting in the configuring of our visibility modeling to analyze the maximum short-term potential impacts that could occur when the unit burns fuel oil. However, as we discuss elsewhere in our proposal, these units are primarily gas-fired, and have only occasionally burned fuel oil. Their most recent practices appear to reinforce this trend.

Arguing for control, unlike the wet FGD and SDA scrubbers we have costed in other sections of this TSD, which have large capital costs, we are unaware of any significant capital costs involved in switching fuels. This means the overall annual costs are relatively minor, if the units in question adhere to their historical usages. Also, because the units in question have only occasionally burned fuel oil, they have the option to avoid the cost of fuel switching entirely by not continuing to burn fuel oil and instead relying solely on their primary fuel of natural gas. Lastly, we note that the prevalence of ULSD in the fuel oil market is such that it appears to be gradually replacing most other No. 2 fuel oil applications.[151]

The preamble to the Regional Haze Rule counseled that a one percent sulfur content limitation on fuel oil should be considered as a "starting point,"[152] and the existing sulfur content limits are lower than one percent. Considering all of this information, we propose that SO_2 BART for the gas-fired units that occasionally burn fuel oil should be no further control. In so doing, we acknowledge the data quality issues we have discussed concerning these units and we specifically request comments on all aspects of our proposed BART analysis for these units from all interested parties. Based on the comments we receive, we may either finalize our BART determinations for these units as proposed, or we may revise them without a re-proposal.

6.4 PM BART

We propose to disapprove the portion of the Texas Regional Haze SIP that sought to address the BART requirement for EGUs for PM. We note that all of the coal-fired units are either currently fitted with a baghouse, an ESP and a polishing baghouse, or an ESP. We conclude that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted with an ESP. Consequently, we propose that PM BART for the coal-fired units is an emission limit of 0.030 lb/MMBtu along with work practice standards. We propose that PM and SO_2 BART for the units that only fire gas be pipeline natural gas. We propose that PM and SO_2 BART for those gas-fired units that occasionally burn fuel oil be the existing permitted fuel oil sulfur content of 0.7% sulfur by weight or pipeline natural gas.

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[150] See the BART Guidelines at 70 FR 39162, July 6, 2005: "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."

[151] http://www.eia.gov/todayinenergy/detail.php?id=5890. http://blogs.platts.com/2014/05/07/heating-oil-new-york-sulfur/. http://oilandenergyonline.com/challenges-to-the-northeast-supply-picture/

[152] 70 FR at 39134

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Appendix A: Comment and Response Summary Concerning Our Wet FGD Control Efficiency Assumption[153]

Comment: Incorrect assumptions for estimating achievable SO_2 emission rates
[Sargent & Lundy (0061) p. 22]

S&L stated that EPA calculated SO_2 emission reductions based on the assumption that a retrofit wet FGD will achieve 98% reduction or a controlled SO_2 emission rate of 0.04 lb/MMBtu. In our experience, this assumption is unrealistic and cannot be sustained on a continuous, long-term basis. As a basis for its assumption, EPA cites the IPM wet FGD cost development document, which 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."[63] However, EPA misinterprets this statement when it uses the guarantee emission rate to calculate long-term SO_2 emissions.

S&L asserted that EPA's proposal is far too stringent to be achievable with the retrofit of an existing unit. EPA's selection of a controlled emission rate of 0.04 lb/MMBtu is more consistent with the lowest achievable emission rate (LAER) applicable to newly-constructed units, rather than an emission rate achievable with retrofit controls installed on existing units. In fact, a controlled emission rate of 0.04 lb/MMBtu is significantly lower than the most aggressive BART SO_2 emission limits imposed by EPA on BART-eligible sources throughout the U.S.

According to S&L, a controlled SO_2 limit of 0.04 lb/MMBtu is not a realistic or sustainable value to maintain on a long-term basis when considering the normal variation in operation that occurs at all coal-fueled facilities. As noted in the IPM wet FGD document, the 0.04 lb/MMBtu emission rate corresponds to the lowest available SO_2 emission guarantees from wet FGD suppliers. Compliance with a vendor's guarantee value is typically demonstrated during very short term testing conducted at ideal operating conditions. Vendor guarantees do not reflect controlled emission rates that may be achievable on a consistent long-term basis as the unit operation varies from design conditions.

S&L noted that wet FGD control systems, like all large air pollution control systems, are not steady state control systems, and controlled SO_2 emissions will continually fluctuate in response to changing operating parameters. Operating parameters that may affect SO_2 emissions include the fuel sulfur content, boiler load, load changes, flue gas flow rate, and flue gas temperatures, all of which continually change during normal operation of the boiler. Figure 1 shows the hourly emissions data for Spruce Unit 1. Spruce Unit 1 is a 550 MW subbituminous coal-fired boiler equipped with wet limestone FGD. The FGD control system was installed in 1992, and upgraded in 2009. Figure 1 shows the normal fluctuation in controlled hourly SO_2 emissions from Spruce Unit 1, which is typical for all wet FGD control systems.

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[153] This comment and response summary is reproduced from our "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." Docket No. EPA-R06-OAR-2014-0754. 12/9/2015

Figure 1: SO_2 Emission Permit Limits for Recent Wet FGD Projects [Figure not excerpted]

According to S&L, between January 1, 2012 and December 31, 2013, Spruce Unit 1 achieved an average controlled SO_2 emission rate of 0.055 lb/MMBtu (2-year average). During that same time period, the standard deviation in its controlled 30-day average SO_2 emission rate was 0.10 lb/MMBtu, approximately 20% greater than the long-term average, and the controlled SO_2 emission rate achieved at a 95% confidence level was 0.075 lb/MMBtu (0.02 lb/MMBtu above the long-term average). Based on our experience with other wet FGD control systems, fluctuations seen in the controlled SO_2 emission rate at Spruce Unit 1 are typical.

S&L stated that projecting future emissions using the anticipated control system vendor guarantee (i.e., 0.04 lb/MMBtu) as EPA did is overly aggressive and provides no margin for normal operating conditions or long-term operation. A reasonable margin between the vendor guarantee value or design target, and the projected actual long-term achievable emission rate is needed to allow for normal fluctuations in the controlled emissions. In S&L's opinion, an operating margin of at least 0.02 lb/MMBtu between the vendor guarantee and projected long-term emission rate is reasonable. In addition, it would be necessary to contact FGD suppliers to provide bids, on a case-by-case basis, that identify what outlet emission rates would be guaranteed on a 30-day rolling average to determine adequate outlet emission rates for compliance, rather than applying the lowest available emission rate guarantee in all cases.

S&L concluded that EPA's approach to estimating controlled SO_2 emissions is incorrect and based on a misunderstanding of the actual performance and operation of wet FGD technology. By using this approach, EPA is overestimating the tons of SO_2 removed and thus overstating the cost-effectiveness of the retrofit FGD control systems.

[Stamper (0068) p.15] Stamper stated that the EPA assumed SO_2 removal efficiencies of up to 98% control in its wet FGD analyses and up to 95% control in its SDA analyses. However, in no case did EPA assume a controlled wet FGD SO_2 rate of less than 0.04 lb/MMBtu or a controlled SDA SO_2 rate of less than 0.06 lb/MMBtu in its cost effectiveness analyses. EPA's rationale was that these were the lowest emission guarantees and this methodology was consistent with EPA's cost effectiveness calculations for the Oklahoma regional haze FIP. Cost TSD at 16, 21-22.

Stamper stated that the EPA's assumptions limiting the SO_2 removal efficiency based on the guaranteed permitted limits of 0.06 lb/MMBtu for an SDA and 0.04 lb/MMBtu for a wet FGD underestimated the actual SO_2 emission reductions that would likely occur with these SO_2 scrubbers. This is primarily a concern for those EGUs that burn or blend with low sulfur Powder River Basin coal (i.e., Coleto Creek 1, Tolk 171B and 172B, WA Parrish 5, 6, and 7, and Welsh 1, 2, and 3). Further, wet FGD systems can achieve greater than 99% SO_2 removal, and dry scrubbers can achieve greater than 95% SO_2 removal efficiency, as discussed further below.

According to Stamper, wet scrubbers are the most effective SO_2 control technology available. State-of-the-art wet scrubbers can achieve 98-99% removal efficiency. A prime example is the Chiyoda CT-121 FGD. Vendor information for this technology indicates that this scrubber has

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achieved 98-99% SO_2 removal even with low sulfur coal.[43] For example, the Chiyoda's bubbling jet reactor has consistently achieved >99% SO_2 removal during long-term operation at the Shinko-Kobe power plant in Japan. This facility consists of two 700-MW coal-fired utility boilers. The wet FGD was designed to achieve 0.014 lb SO_2/MMBtu (9 ppmv at 3% oxygen) on an instantaneous basis and has consistently exceeded this level of control while treating gases with inlet SO_2 concentrations of 1.78 lb/MMBtu.[44] This technology has been guaranteed by Chiyoda to achieve 99% SO_2 removal on three coal-fired boilers in Japan.[45]

Stamper stated that the Chiyoda CT-121 FGD has been demonstrated in the U.S. at the University of Illinois's Abbott power plant, Georgia Power's Plant Yates[46], Dayton Power & Light's Killen Unit 2,[47] and Plant Bowen Unit 3.[48] It has been licensed for installation on several additional units in the U.S., including the other three units at Plant Bowen in Georgia, the other units at Dayton Power & Light's Killen plant, Dayton Power & Light's Stuart plant, and AEP's Big Sandy Unit 2, Conesville Unit 4, Cardinal Units 1 and 2, and Kyger Creek, among others.[49] Black & Veatch and Southern Company are both U.S. licensees. Further, this technology also has shown to be very effective in removing fine particulates, oxidized and elemental mercury, and acid gases, and the technology uses less energy compared to traditional wet scrubbers.

Stamper noted that Mitsubishi, a vendor of scrubber systems, reports it has guaranteed SO_2 removal efficiencies up to 99.8 percent, including for coal-fired boilers.[50,51,52]

Stamper stated that Sargent & Lundy has indicated that the lowest achievable SO_2 emission rate with low sulfur Powder River Basin coal for a limestone forced oxidation (LSFO) wet scrubber would be 0.03-0.06 lb/MMBtu.[53]

Stamper stated that these SO_2 removal efficacy claims for wet scrubbers at coal-fired boilers burning lower sulfur coal have been demonstrated in practice. SO_2 emissions data was compiled for 2009 to 2013 to reflect newly operating and recently retrofitted wet FGD systems at EGUs that burn low sulfur coal. The results are in Table 3 below. All of these units burn Powder River Basin coal and have recently been retrofitted with wet FGD systems. As the table below demonstrates, wet FGDs at EGUs burning Powder River Basin coal can achieve much lower SO_2 emission rates than 0.04 lb/MMBtu.

Table 3. Annual Average SO2 Emission Rates at EGUs Equipped with Wet FGDs that Burn Low Sulfur Coal[54]

Plant	Unit	Annual Average SO2 Rate, lb/MMBtu
Iatan	1	0.007
Iatan	2	0.007
Boswell Energy Center	3	0.009
Muscatine	9	0.013
Pleasant Prairie	1	0.021
Pleasant Prairie	2	0.029

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Thus, Stamper concluded that the EPA's assumption that a wet FGD could not achieve SO_2 rates lower than 0.04 lb/MMBtu is overly conservative, as demonstrated by the data presented above.

In addition, Stamper noted that recently constructed EGUs that burn Powder River Basin coal and that are equipped with SDAs have achieved lower SO_2 emission rates than the minimum 0.06 lb/MMBtu SO_2 rate assumed by EPA in its cost effectiveness analyses. The Newmont Nevada power plant (aka TS Power Plant), equipped with a dry lime FGD system, has achieved an annual average SO_2 rate of 0.037 lb/MMBtu over 2009 to 2013.[55] The Wygen II is also equipped with a dry lime scrubber and burns low sulfur coal, and is achieving annual average SO_2 rates of 0.047 lb/MMBtu.[56] And the Dry Fork Station which began operation in 2011 and is equipped with a dry lime scrubber is achieving an annual average SO_2 rate of 0.044 lb/MMBtu.[57]

Further, Stamper stated that a circulating dry scrubber can achieve even higher levels of SO_2 removal than an SDA and lower SO_2 emission rates. As discussed elsewhere in this document, EPA should have evaluated circulating dry scrubbers in its analyses of reasonable progress measures for the Texas EGUs.

In summary, Stamper contended that the EPA's assumed level of SO_2 control in its cost effectiveness analyses for SO_2 for wet FGD and SDA systems is likely conservative and does not reflect the full extent of SO_2 emission reductions that can be achieved with these control technologies. That means EPA's cost effectiveness calculations should be lower and the visibility improvements higher for several of the EGUs evaluated by EPA for reasonable progress controls.

Footnotes:

[42] *See*, e.g., Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology, March 2013, at 6.

[43] *See* Black & Veatch vendor brochure on CT-121, (Ex. 14).

[44] Yasuhiko Shimogama, Hirokazu Yasuda, Naohiro Kaji, Fumiaki Tanaka, and David K. Harris, Commercial Experience of the CT-121 FGD Plant for 700 MW Shinko-Kobe Electric Power Plant, Paper No. 27, presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003, (Ex. 15).

[45] CT-121 FGD Process – Jet Bubbling Reactor, http://www.bwe.dk/fgd-ct121.html, (Ex. 16).

[46] Emission-control Technologies Continue to Clear the Air, Power, May/June 2002.

[47] *See* Black & Veatch, First Black&Veatch/Chiyoda Wet Flue Gas Desulfurization System in North America Successfully Goes Operational.

[48] Blankinship, Steve, Go Take a Bath, Power Engineering, October 2008, available at http://pepei.pennnet.com/display_article/342997/6/ARTCL/none/none/1/Go-Take-a-Bath/.

[49] Chiyoda Licenses Its Flue Gas Desulfurization Technology in USA Newly for 5 Coal-Fired Generation Units, Press Release, May 2, 2005; Chiyoda Licenses its Flue Gas Desulfurization Process in USA for Georgia Power Owned 4 FGD Units, January 26, 2005.

[50] Jonas S. Klingspor, Kiyoshi Okazoe, Tetsu Ushiku, and George Munson, High Efficiency Double Contact Flow Scrubber for the U.S. FGD Market, Paper No. 135 presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003, p.8, Table 4, (Ex. 17).

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[51] Yoshio Nakayama, Tetsu Ushiku, and Takeo Shinoda, Commercial Experience and Actual-Plant-Scale Test Facility of MHI Single Tower FGD, (Ex. 18).
[52] Mitsubishi High SO_2 Removal Experience, (Ex. 19).
[53] *See* White Bluff Station Units 1 and 2 Evaluation of Wet vs Dry FGD Technologies, Rev. 3, October 28, 2008, prepared by Sargent & Lundy at 3-7. (Ex. 20).

Footnotes:
[63] Sargent & Lundy LLC, *IPM Model – Revisions to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology*, March 2013.

Response: All of the claims in this comment have been previously addressed in confidential expert reports in the Cinergy case[154], including achievable FGD SO_2 removal efficiency and the reliability of vendor guarantees for setting emission limits, based on CEMS data, published works, and deposition testimony of five major scrubber vendors.[155] These reports and SO_2 scrubber vendor depositions conclude that 98% to 99% SO_2 control has been achieved and is routinely achievable. These reports and depositions also conclude that vendor guarantees are a reliable basis for establishing emission limits. We cannot include these expert reports and depositions in our docket, because they are held confidential under a protective court order. However, we do include the testimony of Dr. Phyllis Fox, one of the government expert witnesses, in which she testifies, based on her expert report with Hal Taylor, that the removal efficiency of wet scrubbers can reach 99%. [156] These conclusions were upheld in court rulings in United States v. Cinergy Corp., 618 F. Supp. 2d 942, 947 and 961-962 (S.D. Ind. 2009).

First, this comment argues that a "controlled SO_2 limit of 0.04 lb/MMBtu is not a realistic or sustainable value to maintain on a long term basis when considering the normal variation in operation that occurs at all coal-fired facilities." This is misleading as the proposed limit for retrofits is not "0.04 lb/MMBtu" on an instantaneous basis, as suggested in this comment, but rather is based on a "30-boiler-operating-day" (30-BOD) average.[157] A boiler operating day is 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."[158] As explained in our FIP TSD (p. 31) and

[154] United States and Plaintiff-Intervenors States of New York, New Jersey, and Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, Civil Action No. IP99-1693 C-M/S, United States, et al., v. Cinergy Corp., et al., In the United States District Court for the Southern District of Indiana, Indianapolis Division.
[155] Phyllis Fox and Hal Taylor, Expert Report of Phyllis Fox and Hal W. Taylor. Prepared on Behalf of Plaintiff United States and Plaintiff-Intervenors States of New York, New Jersey, and Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, Civil Action No. IP99-1693 C-M/S, United States, et al., v. Cinergy Corp., et al., In the United States District Court for the Southern District of Indiana, Indianapolis Division, August 29, 2008; Phyllis Fox and Hal Taylor, Expert Rebuttal Report of Phyllis Fox and Hal W. Taylor, Prepared on Behalf of Plaintiff United States and Plaintiff-Intervenors States of New York, New Jersey, and Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, Civil Action No. IP99-1693 C-M/S, United States, et al., v. Cinergy Corp., et al., In the United States District Court for the Southern District of Indiana, Indianapolis Division, October 14, 2008, 2008.
[156] United States and Plaintiff-Intervenors States of New York, New Jersey, and Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, Civil Action No. IP99-1693 C-M/S, United States, et al., v. Cinergy Corp., et al., In the United States District Court for the Southern District of Indiana, Indianapolis Division. Trial Proceedings, Volume 2. Testimony of Dr. Phyllis Fox, beginning on vol. 2-302.
[157] 79 FR 74,822, Table 1; 74,884 (Dec. 16, 2014).
[158] 70 FR 39,172 (July 6, 2005).

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the proposed rulemaking, days are skipped when the unit is down, as for maintenance. This provides a margin of safety by eliminating spikes that occur at the beginning and end of outages, when the scrubber is not operating.[159] Regardless, all major scrubber vendors guarantee 99% SO_2 control and expect routine performance at this level. This level of control is confirmed under vendor guarantees by making simultaneous measurements of SO_2 at the inlet and outlet of the scrubber.

The emission limit that we have proposed for all wet scrubbed units, 0.04 lb/MMBtu, is based on 98% control, unless the resulting controlled limit fell below an outlet SO_2 level of 0.04 lb/MMBtu, in which case, we would have assumed the percentage control equal to 0.04 lb/MMBtu.[160] All of the calculated 98% control levels, except for Big Brown Unit 1, were lower than 0.04 lb/MMBtu, as shown in the following table. Thus, the limits we propose have built in margin.

Calculation of Wet Scrubber Limits

Unit	Proposed SO_2 Limit (lb/MMBtu)	Baseline (lb/MMBtu)	Control Level (%)	Margin (lb/MMBtu)
Big Brown 1	0.04	0.04	98	0
Big Brown 2	0.04	0.0392	97.91	0.00084
Monticello 1	0.04	0.0388	96.99	0.0012
Monticello 2	0.04	0.0387	96.83	0.0013
Coleto Creek 1	0.04	0.0383	95.65	0.0014

Recent operating experience reported by Hitachi confirms that 99% SO_2 control is achievable.[161] Hitachi has guaranteed many units at 99% SO_2 control efficiency.[162] Hitachi has explained that 99% control on an "instantaneous basis" (not even a rolling average) is routinely achieved in Japan, where rolling averages are not allowed, and has stated that Hitachi is "comfortable with 98%" for PRB coals.[163] See also Stamper comment 0068, pp. 15-17. Alstom has guaranteed

[159] 79 FR 74,884 (Dec. 16, 2014).

[160] Cost TSD, p. 21; 79 FR 74,884 (Dec. 16, 2014). The proposed control level was calculated in the wet FGD spreadsheet in cell E13. First, we tested to see if 98% of the uncontrolled SO_2 rate would result in a value less than 0.04 lb/MMBtu. If it did, then a control level was calculated based on a reduction to 0.04. If it didn't, then the control level was set to 98%. The uncontrolled SO_2 rate itself was calculated based on the maximum monthly SO_2 rate from 2009-2014. This was calculated in the "Monthly Emissions" tab of the wet FGD spreadsheet. The maximum monthly value was used to ensure the scrubber was designed to address the dirtiest coal burned in the recent past.

[161] B.C. Studley and others, Recent Operating Results of the Five New Wet FGD Installations for Ameren Corporation, Available at: http://www.psa.mhps.com/supportingdocs/forbus/hpsa/technical_papers/Recent%20Operating%20Results%20of%20the%20Five%20New%20Wet%20FGD%20Installations%20for%20Ameren%202011.pdf.

[162] Hitachi Wet FGD Sample of Recent Installations (showing 99% guarantees at Boswell #3, Coffeen #1,2, Duck Creek #1, Sioux 1,2).

[163] E-mail from Joseph Barba, Hitachi, to Phyllis Fox, January 31, 2007.

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units at 99%, concluding the new Trimble County Unit 2 "can reliably achieve a high efficiency. 99.8% SOx removal could be expected."[164] Advatech, a joint venture of URS and Mitsubishi, likewise has built scrubbers guaranteed at 98% to 99%.[165] Advatech reports its highest SO_2 guarantee is 99.8%. Their experience list includes many units in Japan guaranteed at this level,[166] which must be met on an instantaneous basis.

Second, this comment asserts that vendor guarantees do not reflect controlled emission rates that may be achievable on a consistent long-term basis as the unit operation varies from design conditions." A survey of owners of FGD systems found that "[w]ith regard to FGD reliability, in every case except for one SDA system, performance overall met or exceeded owner expectation. Therefore, there is reason to believe that the FGD systems will perform as expected (albeit, with some specific components that may perform more or less reliably than other components.)."[167] Major scrubber vendors have testified in confidential depositions that they expect their scrubbers to meet guarantees, which typically have a built-in vendor margin of safety.

Further, vendors offer "make-right" guarantees that cover the life of the FGD and all operating conditions. Make-right guarantees restore a malfunctioning FGD to its design basis. Regardless, the vendor must protect its reputation. Scrubber vendors have a vested interest in maintaining their market position and customer base. We are not aware of any vendor that would walk away from an FGD that did not perform according to its guarantee (even after the guarantee period has ended).

Third, this comment argues that using the vendor guaranteed level of 0.04 lb/MMBtu is "overly aggressive and provides no margin for normal operating conditions or long-term operation." Variations in scrubber performance due to changes in coal quality, reagent quality, startups, shutdowns, and malfunctions are normally accommodated in permitting by specifying a sufficiently long averaging time, in this case, the 30-day BOD, which is specifically designed to average out spikes. In general, averaging smooths out fluctuations in data.[168] We built further margin into the 0.04 lb/MMBtu limits, which are based on less than 98% control, except at Big Brown Unit 1, as summarized in –the above table. Finally, margin is built into the guarantee by the vendor.

Fourth, this comment attempts to support these claims by presenting seven years of SO_2 emission data for a single facility, Spruce Unit 1. Spruce Unit 1 is a 585-MW tangentially-fired Combustion Engineering boiler, designed to burn PRB coal, which started up in December 1992.[169]

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[164] Alstom Responses to Questions, Trimble County Unit 2, October 25, 2004, BV-00000171.
[165] Advatech, Double Contact Flow Scrubber, Available at: http://www.advatechllc.com/wp-content/uploads/2013/10/advatech-double-contact-flow-scrubber-brochure.pdf.
[166] Advatech, Advanced Flue Gas Desulfurization, 2005.
[167] James E. Staudt, Sikander R. Khan, and Manuel J. Oliva, Reliability of Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Systems for High Pollutant Removal Efficiencies on Coal Fired Utility Boilers, MEGA Symposium, 2004, p. 17.
[168] Thad Godish, Air Quality, Lewis Publishers, 2nd Ed. , 1991, p. 216, Figure 7.1; Richard W. Boubel, Donald L. Fox, Bruce Turner, and Arthur C. Stern, Fundamentals of Air Pollution, Academic Press, 3rd Ed., 1994, pp. 41 - 43.
[169] R. Peltier, J.K. Spruce Power Plant, Unit 1, San Antonio, Texas, POWER, October 15, 2008, Available at: http://www.powermag.com/j-k-spruce-power-plant-unit-1-san-antonio-texas/?pagenum=1.

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The original SO_2 scrubber, designed for 70% SO_2 control, was started up in 1992 when the boiler came online. The scrubber was upgraded in 2009 by Alstom to achieve 95% SO_2 control at a cost of about $9 million.[170] However, the SO_2 emission limit of 0.04 lb/MMBtu that this comment is critiquing is proposed only for retrofit scrubbers, i.e., new scrubbers on existing boilers, not upgraded scrubbers. Thus, the Spruce data is misleading, as the performance of a scrubber upgrade may not be representative of the performance that can be achieved by a new scrubber retrofit on an existing unit. In fact, we assumed 95% control for our scrubber upgrade analyses, versus 98% control (not to go below 0. 04 lbs/MMBtu) for our scrubber retrofit analyses.

Fifth, the upgraded Spruce Unit 1 scrubber came on line in early 2009, just as the SO_2 allowance market it would have benefited from collapsed, removing the incentive to operate it at its design SO_2 efficiency.[171] As scrubbers are costly to operate (see O&M costs in our Cost TSD), and this unit has very high SO_2 permit limits,[172] CPS Energy has no incentive to operate the upgraded scrubber at its design basis.

The apparent poor performance of Spruce Unit 1 is not due to issues implied in this comment, but rather the lack of any requirement or incentive to do better. The 30-day BOD data demonstrate that in spite of these disincentives, this upgraded scrubber achieved a 30-day BOD emission rate of 0.07 lb/MMBtu, except when the scrubber was offline, from July 16, 2011 to August 26, 2011. The Spruce permit exempts "maintenance, startup, and shutdown periods" from compliance with emission limits.[173] In other words, the boiler can legally continue to operate while the control equipment is shutdown. The 0.07 lb/MMBtu achieved at Spruce Unit 1 when the scrubber was operating is well within the range of our proposed SO_2 limits for scrubber upgrades.

We are not proposing an SO_2 emission rate of 0.04 lb/MMBtu for any scrubber upgrade, as they may be less efficient than a new retrofit scrubber. Rather, we proposed SO_2 emission rates of 0.06 to 0.60 lb/MMBtu for scrubber upgrades. The 0.04 lb/MMBtu limit that is the subject of this comment was only proposed for new scrubbers on existing boilers or "retrofits".[174] Thus, the performance of Spruce Unit 1 is irrelevant for supporting the arguments made in this comment.

Sixth, we note that this comment visually distorts the performance of Spruce 1 by plotting conventional 30-day moving averages, rather than 30-day BOD averages, as proposed in the rulemaking. Further, the graph is plotted on a fine scale to accentuate fluctuations. We replotted

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[170] CPS, Corporate Sustainability Report 2010, p. 57, Available at: https://www.cpsenergy.com/content/dam/corporate/en/Documents/Sustainability_Report_2010.pdf.

[171] C. Hitaj and A. Stocking, Market Efficiency and the U.S. Market for Sulfur Dioxide Allowances, Working Paper 2014-01, Congressional Budget Office, January, 2014. See especially Figure 1. Available at: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CCAQFjAAahUKEwi1w9HwsJDIAhVIJB4KHRAvB2Y&url=https%3A%2F%2Fwww.cbo.gov%2Fsites%2Fdefault%2Ffiles%2F113th-congress-2013-2014%2Fworkingpaper%2F45044-SO_2MarketAnalysis_1.pdf&usg=AFQjCNHYiyaL3lTMimbRvluvI3DVa-T18w&cad=rja.

[172] Spruce Unit 1 Permit, Permit Numbers 18426 and PSDTX742M1, Special Conditions, Condition 8.

[173] Spruce Unit 1 Permit, p. 7, Condition 15.

[174] 79 FR 74,822, Table 1 (Dec. 16, 2014).

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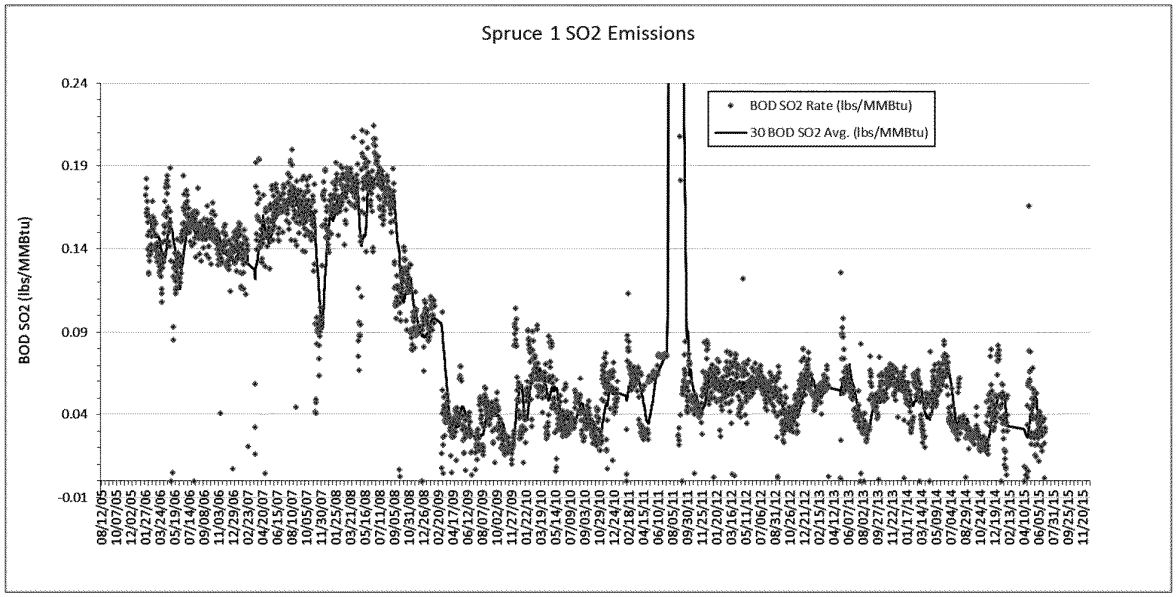
it using a 30-day BOD average and a scale that includes the uncontrolled spike.[175] This analysis is shown in the figure below.



This plot shows that Spruce Unit 1 is achieving a 30-day BOD of 0.07 lb/MMBtu after the upgraded scrubber stabilized, except for the period from July 16, 2011 to August 26, 2011, when the scrubber was off-line, but the boiler continued to operate. This is allowed under Spruce's current permit to operate during "routine maintenance, startup, and shutdown". The EPA recently issued a final rule barring these SSM exemptions in state permits.[176]
Finally, Sargent & Lundy omits that there are units that demonstrate our proposed limits and control efficiencies have been and are being achieved on a routine basis. To demonstrate that the proposed wet scrubber SO_2 emission limits (0.04 lb/MMBtu) are achievable, we reviewed our Clean Air Market Database (CAMD) to identify similar coal-fired boilers that have met a a 30 BOD average SO_2 emission rate of 0.04 lb/MMBtu or better continuously for at least 1 year.

First, we downloaded all annual SO_2 data from 2007-2014, inclusive. This annual data was filtered to select only the units that met the following criteria:

- Electric utility only
- Coal burning only
- Avg. annual SO_2 rate < 0.045 lb/MMBtu
- Wet FGD only
- Operating time > 4,800 hours
- 12 months of reported data only
- Retrofit or upgraded scrubber

[175] See "Selected BOD SO_2 Averages-3.xlsx," Tab "Spruce 1" in our docket.
[176] http://www.epa.gov/airquality/urbanair/sipstatus/emissions.html

We next researched the subset of wet FGDs that met these criteria and eliminated units that used lime wet FGD, as it can achieve a higher SO_2 removal efficiency, but is generally more expensive due to the cost of lime. We only retained one lime FGD, Milton Young 1, as it is the only unit in our dataset that fires lignite coal. We found many units coded as using lime FGD in the CAMD database that in fact used limestone FGD. We also eliminated scrubbers installed on newly built units at the time of initial construction. Most of the scrubbers that met these criteria were retrofits, the target of our analysis, but some upgrades were included. We retained these to compare retrofit with upgrade experience.

We adopted this conservative criteria and methodology in order to quickly and easily demonstrate that in fact there are a number of similar units operating wet scrubbers comfortably below our proposed SO_2 emission limit. In so doing, we note there are a number of additional similarly configured units (e.g., Scherer 1) that have demonstrated their ability to operate for extended periods of time below our proposed control efficiency, but do not meet these criteria. We do not advocate that our criteria and methodology are the only way to demonstrate the operational effectiveness of any particular control, scrubbers or otherwise.

We used EIA information to determine the coal type burned at each facility and eliminated all units that did not burn PRB, lignite, or a blend of PRB or lignite with another coal type, which are the predominate fuels burned by the subject Texas plants. We also researched each plant to confirm the scrubber type, scrubber install date, design control efficiency, and permit limits, where available. The resulting list of plants is:

- Iatan Unit 1[177]
- Boswell Energy Center Unit 3[178]
- James H. Miller Units 1, 2, 3, and 4[179]
- Jeffrey Energy Center Units 1, 2, and 3[180]

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[177] Robert Peltier, Plant of the Year: KCP&L's Iatan 2 Earns POWER's Highest Honor, POWER, August 1, 2011, Available at: http://www.powermag.com/plant-of-the-yearkcpls-iatan-2-earns-powers-highest-honor/.

[178] Retrofitting Boswell Energy Center, Power Engineering, September 1, 2010, Available at: http://www.power-eng.com/articles/print/volume-114/issue-9/Features/retrofitting-boswell-energy-center.html. See also: http://www2.epa.gov/enforcement/minnesota-power-settlement (requiring SO_2 emission rate of no greater than 0.030 lb/MMBtu at Boswell Units 3 and 4) and Consent Decree at http://www2.epa.gov/sites/production/files/2014-07/documents/minnesotapower-cd.pdf ("Minnesota Power shall continuously operate an FGD device at Boswell Unit 3 such that the unit achieves and maintains a 30-day rolling average emission rate for SO_2 no greater than 0.03 lb/MMBtu." and "No later than May 31, 2016, Minnesota Power shall continuously operate a new FGD device at Boswell Unit 4 such that the Unit achieves and maintains a 30-day rolling average emission rate for SO_2 no greater than 0.03 lb/mmBTU."

[179] ADVATECH, Plant Miller – Wet FGD Retrofit Project, Available at: http://www.advatechllc.com/projects/air-quality-control-solutions/acid-gas-control/acid-gas-project-descriptions/southern-company-miller/. Title V Permit at: http://www.jcdh.org/EH/AnR/AnR13.aspx. Consent Decree at: http://www2.epa.gov/enforcement/alabama-power-company-clean-air-act-settlement.

[180] Westar Energy Sulfur Dioxide Removal Project on First of Jeffrey Energy Center's Generating Units Fully Operation, August 11, 2008, Available at: http://www.energycentral.com/generationstorage/fossilandbiomass/news/vpr/5341/WESTAR-ENERGY-SULFUR-DIOXIDE-REMOVAL-PROJECT-ON-FIRST-OF-JEFFREY-ENERGY-CENTER-S-GENERATING-UNITS-FULLY-OPERATIONAL; Gail Reitenbach, WATER AWARDE: Jeffrey Energy Center's Constructed Wetland Treatment System, POWER, August 1, 2014, Available at: http://www.powermag.com/jeffrey-energy-centers-

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- Milton Young Unit B1[181]
- Pleasant Prairie Unit 1 and 2[182]
- Sam Seymore (Fayette) Unit 1, 2,[183]and 3[184]
- Scherer Units 2, 3, and4[185]

We prepared graphs of these units showing the 30-day BOD SO_2 data superimposed on the measured daily data in lb/MMBtu. These graphs are included in our docket in the file "Selected BOD SO_2 Averages-3.xlsx." This file contains tabs corresponding to each of the above units, and a "Read Me" tab that explains our methodology.

The performance of each scrubber in our data set is summarized in the file, "Selected scrubber retrofit efficiencies.xlsx." The "Efficiencies" tab within this file reports vendor guaranteed control efficiency, achieved control efficiency, and the maximum 30-day BOD, excluding shakedown periods following initial startup of scrubber retrofits, and other items. This information supports our proposed SO_2 limits for both retrofits and upgrades. The 13 retrofit units have guaranteed control efficiencies of 95% to 99%, with eight of them guaranteed at 98% to 99%. These eight units are achieving 98% to 99% SO_2 control, with the exception of Scherer Unit 4, when calculated using our very conservative method explained in the "Read Me" tab.

We note that compliance with the vendor guaranteed SO_2 control efficiency is typically determined by simultaneously measuring scrubber inlet and outlet SO_2 emissions. As CAMD does not report and facilities generally do not measure inlet SO_2 CEMS data, our estimated control efficiencies are based on pre-scrubber retrofit SO_2 and post-scrubber retrofit 30-day BOD data, as explained in the "ReadMe" tab noted above. None of the eight units that are achieving 98% to 99% SO_2 control have permit limits that require operation at this level. However, several have entered into consent decrees that do require control efficiencies approaching these values.

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constructed-wetland-treatment-system/?pagenum=1; and Westar Energy, Jeffrey Energy Center Wetlands, Available at: https://www.westarenergy.com/jeffrey-energy-center-wetlands.

[181] Burns & McDonnell, Milton R. Young Units 1 & 2, 2015, Available at: http://www.burnsmcd.com/Resource_/Project/2234/ProjectPdf/Milton-R-Young-Units-1-amp-2.pdf; MET, Wet FGD, Available at: http://www.met.net/wet-fgd-technologies-lime.aspx.

[182] Steven Gebhart and others, Pleasant Prairie Power Plant Air Quality Control Upgrade Project, Pleasant Prairie, Wisconsin, POWER, October 15, 2007, Available at: http://www.powermag.com/pleasant-prairie-power-plant-air-quality-control-upgrade-project-pleasant-prairie-wisconsin/ See also: http://www.pleasantprairieonline.com/services/communitydevelopment/powerplant.asp

[183] C. Frazer and others, Fayette Power Project Unit 3 FGD Upgrade: Design and Performance for More Cost-Effective SO_2 Reduction, Mega Symposium, 2010, Available at: http://www.babcock.com/library/documents/br-1845.pdf; LCRA Adds Scrubbers to Clean Sulfur Dioxide from Plant Emissions, August 1, 2011, Available at: http://www.statesman.com/news/news/local/lcra-adds-scrubbers-to-clean-sulfur-dioxide-from-1/nRc8M/.

[184] Austin City Council, Audit Report, Fayette Power Project Scrubber Costs, October 3, 2006, Available at: Powerplant Upgrades Test New Technology, ENR Texas & Louisiana, April 18, 2011, Available at: https://austintexas.gov/sites/default/files/files/Auditor/au06113.pdf; http://texas.construction.com/texas_construction_projects/2011/0418_powerplantupgrades.asp; Fayette Power Project, Available at: http://www.lcra.org/energy/electric-power/facilities/fayette-power-project/Documents/fayette_power_project_2013_03_22.pdf.

[185] ADVATECH, Plant Scherer – Wet FGD Retrofit Project, Available at: http://www.advatechllc.com/projects/air-quality-control-solutions/acid-gas-control/acid-gas-project-descriptions/southern-company-scherer/; ADVATECH, Double Contact Flow Scrubber, 2011, Available at: http://www.aecomprocesstechnologies.com/wp-content/uploads/2012/03/advatech-dcfs-brochure.pdf

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The maximum 30-day BOD, over the period of record when the scrubbers were operating, excluding scrubber "shakedown" periods, for retrofit FGDs designed to achieve 98% to 99% SO_2 control range from 0.02 lb/MMBtu at Iatan Unit 1 to 0.08 lb/MMBtu at Scherer Unit 3. Three of the units have achieved a maximum 30-day BOD equal to or less than our proposed SO_2 emission limit for scrubber retrofits of 0.04 lb/MMBtu:

- Scherer Unit 2: 0.01 lb/MMBtu based on 485 data points
- Iatan Unit 1: 0.02 lb/MMBtu based on 2,004 data points
- Boswell Energy Center: 0.03 lb/MMBtu based on 1,881 data points

All of these units burn PRB coal and are operating at these levels without permit limits that require compliance at achieved levels. The best performers are discussed below.

Scherer Unit 2

Plant Scherer consists of four 818 MW, Combustion Engineering boilers that became operational in 1982, 1984, 1987, and 1989. All of the units burn PRB coal. All four units were retrofitted with wet scrubbers that became operational in late 2010 to 2014. All of the units have continuously operated below 0.01 lbs/MMBtu for months at a time. The maximum 30-day BOD at Unit 2, after scrubber shakedown, was 0.01 lb/MMBtu, with the majority of the 30-day BOD data points below this level. The compliant data set includes 423 continuous 30-day BOD data points, between March 2014 and June 2015, all less than or equal to 0.01 lb/MMBtu. See the figures below for Unit 2. The second figure shows the period just after the scrubber became operational, plotted on a finer scale to better display the scrubber's performance:

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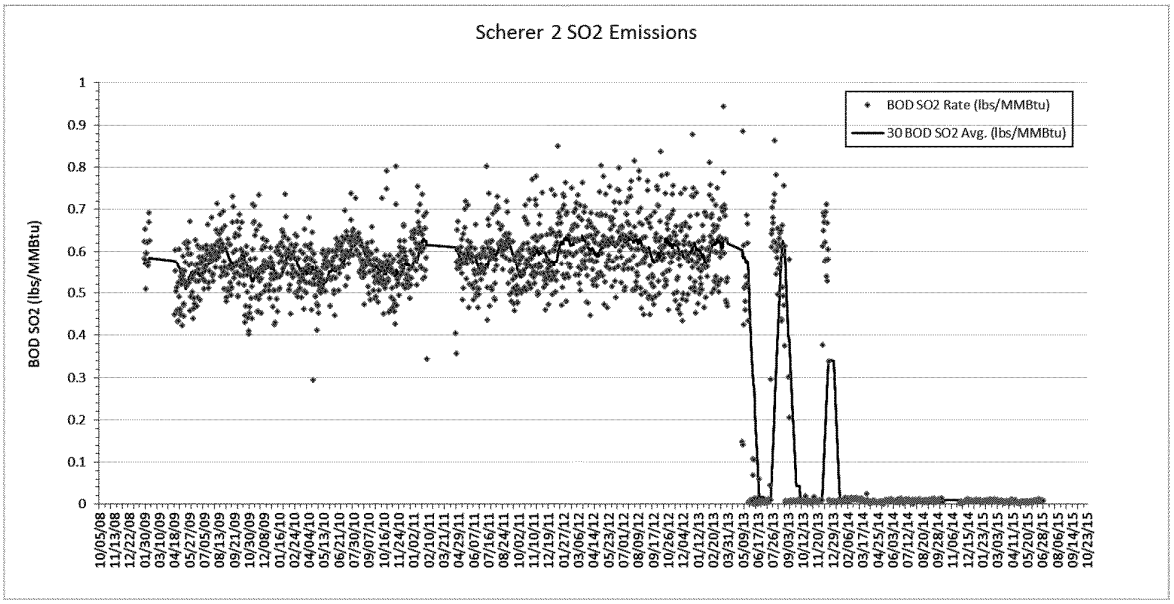
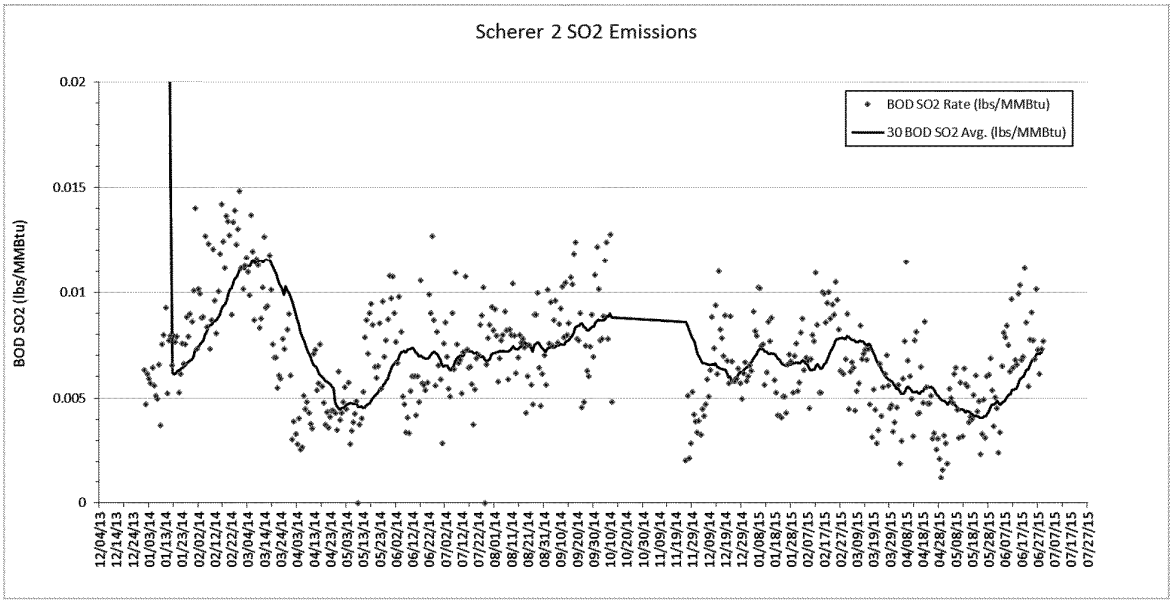




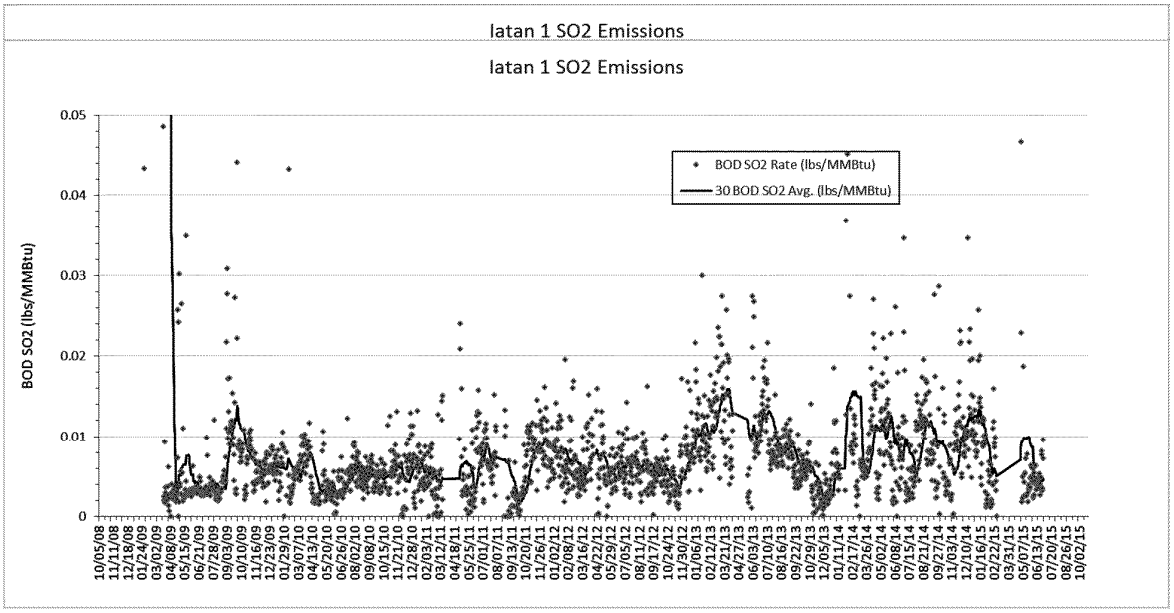
Scherer Units 1, 3, and 4 display similar levels of control capability.

Iatan Unit 1(Retrofit Scrubber)

Iatan Unit 1 is an approximately 700-MW, PRB-fired, Babcock & Wilcox boiler that started up in 1980. This unit was retrofit with a wet scrubber in 2009 at the same time that new Iatan Unit 2 was built. The Iatan Unit 1 scrubber was installed to meet CAIR/CSAPR requirements for SO_2 emissions and as a requirement for the air permit for Iatan 2, under a settlement agreement with the Sierra Club. [186]

The design of the air quality control system for both existing Unit 1 and new Unit 2 was very similar, resulting in similar performance. "The entire post-combustion AQCS [air quality control system] for Iatan 1 is virtually identical to that of the new Iatan 2….The wet FGD systems, using the same size vessel on both units, routinely operate at 99% removal, producing SO_2 levels in the exhaust gas well below the 0.06 lb/MMBtu permit limits. Each vessel is equipped with five recycle pumps but usually runs only three or four, depending on operating conditions." Thus, while the Unit 1 scrubber is a retrofit, its performance is nearly identical to scrubber on new Unit 2.[187]

This is the best performing wet scrubber retrofit in the data set based on 6 years of continuous operation. The maximum 30-day BOD at this unit, after scrubber shakedown, was 0.02 lb/MMBtu, with the majority of the 30-day BOD data points far below this level. The compliant data set includes 2,004 continuous 30-day BOD data points, between April 2009 and June 2015, all less than or equal to 0.02 lb/MMBtu. See the figures below. The second figure shows the period just after the scrubber became operational, plotted on a finer scale to better display the scrubber's performance. This is much better performance than is required by Iatan Unit 1's operating permit, which limits SO_2 emissions to 0.07 lb/MMBtu, based on a conventional 30-day rolling average.[188]

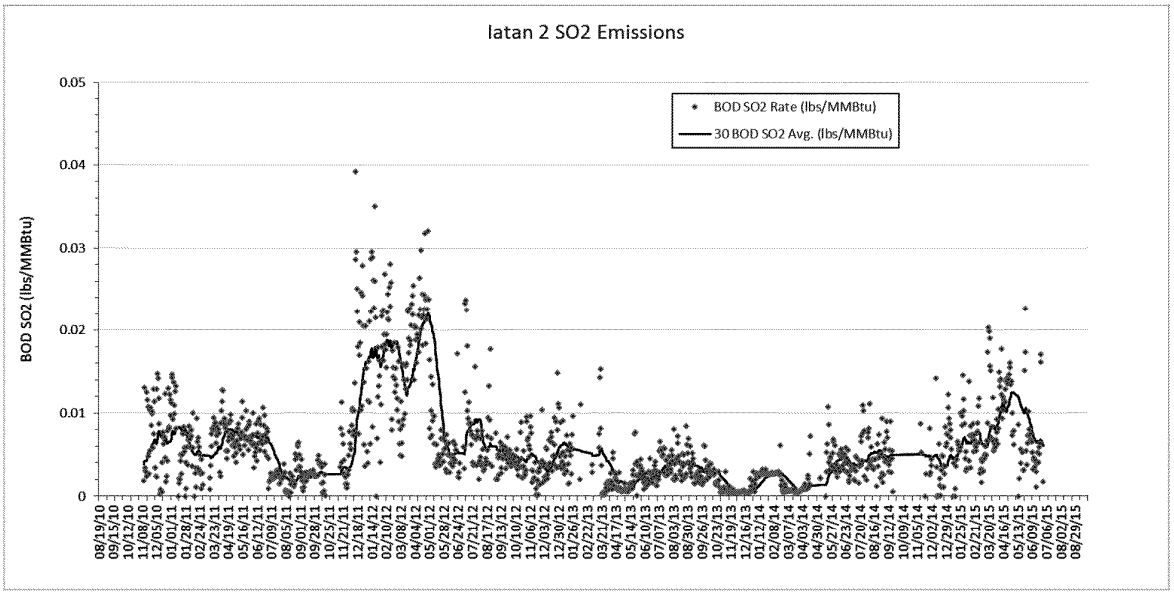


Of note, the 30-day BOD SO_2 data for Iatan Unit 1 does not include the spikes found at some of

[186] Empire District Electric Co – '10-Q' for 3/31/12 – R13, "Compliance Plan" and "SO_2 Emissions." Available at: http://www.secinfo.com/d11MXs.p1Zm2.1s.htm; State of Kansas, Air Quality State Implementation Plan, Regional Haze, October 26, 2009, Available at: http://www.kdheks.gov/bar/reghaze/KDHERegHaze.pdf.
[187] Robert Peltier, Plant of the Year: KCP&L's Iatan 2 Earns POWER's Highest Honor, POWER, August 1, 2011, Available at: http://www.powermag.com/plant-of-the-yearkcpls-iatan-2-earns-powers-highest-honor/.
[188] Kansas City Power & Light, Iatan Generating Station, Permit No. 012006-019B.

the other units we reviewed. Iatan's operating permit does not include any exemptions from permit limits for startups, shutdowns, and malfunctions (SSM), while plants with frequent spikes include this exemption. The Iatan Unit 1 permit limits for all pollutants (except opacity) explicitly "include[ing] periods of start-up, shutdown and malfunction…"[189] Other plants with SSM exemptions in their permits have no obligation to operate their scrubbers during SSM events, resulting in the boiler continuing to run while the scrubber is offline for maintenance, creating spikes that are not related to scrubber performance.

Iatan 2, a new boiler and scrubber, displays a similar level of performance. Because it's scrubber pre-scrubber data is not available:



As can be seen from the above figures, both units have operated for years at a SO_2 emission rate below 0.01 lbs/MMBtu.

Boswell Energy Center Unit 3 (Retrofit Scrubber)

A wet scrubber was retrofit on existing (Clay) Boswell Energy Center Unit 3[190] in November 2009. It was designed by Hitachi to achieve 99% SO_2 control.[191] The existing permit to operate limits SO_2 emissions to 2.97 lb/MMBtu for a 1-hour average and 0.09 lb/MMBtu on a 30-day rolling average basis.[192] The unit has been operating far below these limits.

[189] Iatan Generating Station Permit Number: 012006-019A, July 13, 2007, p. 5, Note to Special Condition 2.E.
[190] Unit 3 is a 365-MW pulverized dry tangential-fired ABB Combustion Engineering boiler that fires PRB coal and started operating in 1973.
[191] Mitsubishi Hitachi Power Systems, Flue Gas Desulfurization, Available at: http://www.psa.mhps.com/products/environmental_products/fgd/.
[192] Minnesota Power Inc – Boswell Energy Center, Air Permit No. 06100004-007, Major Amendment, June 13, 2013, pdf 14.

A subsequent 2014 Consent Decree reduced the Boswell SO_2 limit to 0.03 lb/MMBtu on a 30-day rolling average basis, as of the "date of entry" of the Consent Decree, which was filed on July 16, 2014.[193] This limit has been consistently met since stable scrubber operation began in December 2009. This limit reflects the judgment of EPA that a SO_2 limit of 0.03 lb/MMBtu on a 30-day rolling average basis is achievable.

The Consent Decree limit (0.03 lb/MMBtu 30-day rolling average) is much lower than the SO_2 limit proposed for wet FGD retrofits (0.04 lb/MMBtu 30-day BOD average).[194] A 30-day rolling average is more conservative (i.e., harder to meet) than the 30-day BOD average proposed in this rulemaking. Further, 0.03 is lower than 0.04. Thus, the Boswell Energy Center Consent Decree requires an SO_2 emission limit that is more aggressive than any of the limits proposed by EPA to satisfy reasonable progress. This 0.03 lb/MMBtu 30-day rolling average limit is currently being achieved.

The SO_2 CEMS data for Boswell Unit 3 is shown in the figures below. The second figure shows the period just after the scrubber became operational, plotted on a finer scale to better display the scrubber's performance. These figures demonstrate that the proposed 0.04 lb/MMBtu 30-day BOD for retrofit scrubbers under the Texas FIP has been met with a significant margin at this unit for over five years or for 1,881 individual continuous 30-day BOD data points.

[193] Consent Decree at http://www2.epa.gov/sites/production/files/2014-07/documents/minnesotapower-cd.pdf ("Minnesota Power shall continuously operate an FGD device at Boswell Unit 3 such that the unit achieves and maintains a 30-day rolling average emission rate for SO_2 no greater than 0.03 lb/MMBtu." and "No later than May 31, 2016, Minnesota Power shall continuously operate a new FGD device at Boswell Unit 4 such that the Unit achieves and maintains a 30-day rolling average emission rate for SO_2 no greater than 0.03 lb/mmBTU.")
[194] 79 FR 74,822 (Dec. 16, 2014).

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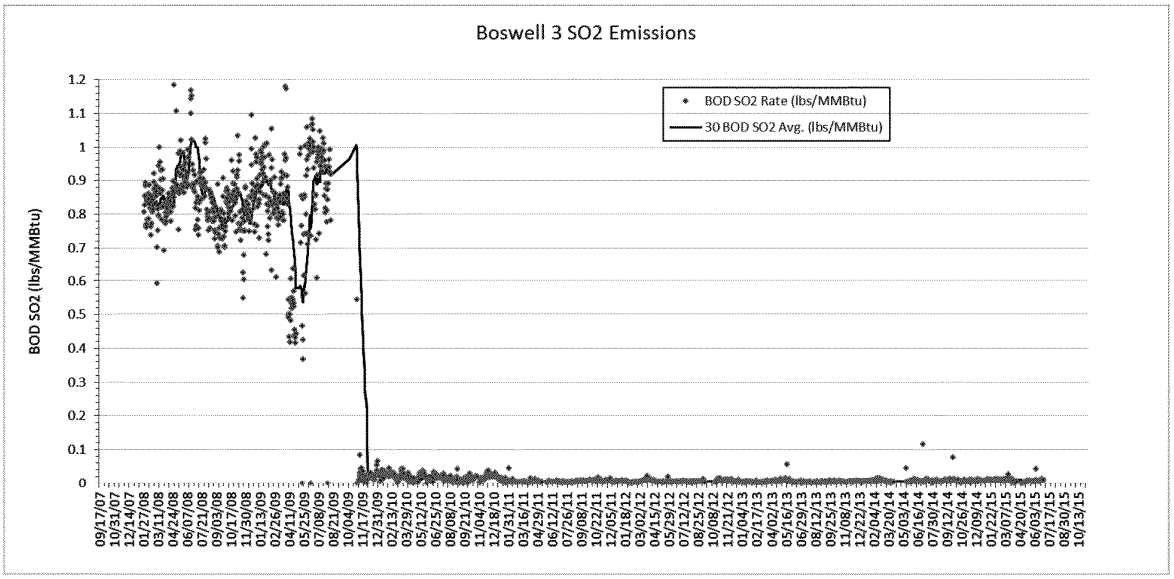

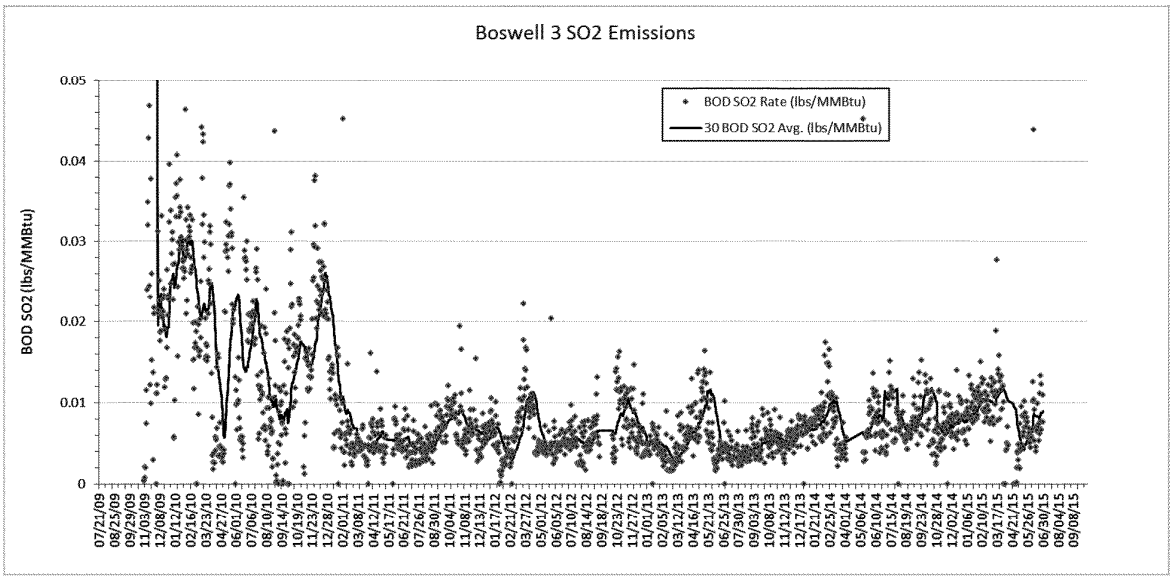

The cluster of spikes between January and December 2010, which are all less than or equal to 0.03 lb/MMBtu, are characteristic of scrubber shakedowns, during which the plant learns how to operate the scrubber and installation issues are resolved. Thereafter, this scrubber has consistently operated at a 30-day BOD of 0.01 lb/MMBtu, four times lower than required in the proposed Texas FIP.

The SO_2 CEMS data for Boswell Unit 3 for the period December 2009 through June 2015 further indicates that this retrofit scrubber has achieved 99% SO_2 reduction, determined from measured SO_2 prior to and after scrubber installation. This is consistent with its 99% SO_2 guarantee.[195]

[195] The guaranteed SO_2 efficiency is calculated from the scrubber inlet and outlet SO_2 concentrations. The CAMD

The maximum 30-day BOD is 0.03 lb/MMBtu since stable operation of the scrubber started in November 2009. This is less than required for retrofit units under the proposed Texas FIP. The majority of the BOD values are substantially lower than this maximum.

Jeffrey Energy Center (Scrubber Upgrade)

Jeffrey Energy Center consists of three 720 to 750 MW, pulverized coal, dry bottom ABB Combustion Engineering boilers that are permitted to combust either liquid and/or solid fossil fuel. The existing wet scrubbers on Jeffrey Energy Center Units 1-3[196] were rebuilt and upgraded in 2008 to 2009 by Burns & McDonnell to achieve a minimum of 95% SO_2 control. The project included replacing the module internals including mist eliminators; adding forced oxidation; eliminating flue gas bypass; increasing limestone grinding capacity; and adding a gypsum dewatering system. Induced draft fans were upgraded and ductwork was replaced. The existing stack was modified for wet-stack operation.[197]

These units are operating under a Consent Decree[198] that requires that they achieve 97% SO_2 reduction and an SO_2 emission limit of 0.07 lb/MMBtu, both on a 30-day rolling average basis. The operating permit also includes an SO_2 limit of 0.8 lb/MMBtu for each unit, no averaging time specified, and no SSM exemptions. As of January 1, 2014, they also must meet a SO_2 emission limit of 0.15 lb/MMBtu as a 30-day rolling average, excluding periods of startup, shutdown and malfunction under a Regional Haze Agreement between Westar Energy, Inc. and KDHE.[199] They are currently meeting the percent reduction requirement.

Nearly five years of continuous operating data demonstrate that these three units have consistently exceeded their 95% SO_2 removal guarantee, achieving 97% to 98% SO_2 control relative to the original scrubber baseline.

The highest 30-day rolling BOD at these units since the upgraded scrubbers achieved stable operation in 2008 to 2009 is 0.06, 0.05, and 0.09 lb/MMBtu, at Units 1, 2, and 3 respectively. This performance is generally better than the proposed SO_2 BART limits for scrubber upgrades (0.06-0.60 lb/MMBtu).[200]

CEMS data is only for the outlet. Thus, we estimated the control efficiency from the average pre-scrubber and post-scrubber emissions, as explained in the "ReadMe" in the file, "Selected scrubber retrofit efficiencies.xlsx" in our docket

[196] Units 1, 2, and 3 are 720 to 750 MW pulverized coal dry bottom ABB Combustion Engineering boilers that started operations in 1978, 1980, and 1983, respectively. They burn PRB coal and were equipped with 60% efficient Combustion Engineering SO_2 scrubbers on startup.

[197] Burns & McDonnell, Jeffrey Energy Center Units 1, 2 & 3 Upgrade Project, 2015, Available at: http://www.burnsmcd.com/Resource_/Project/1244/ProjectPdf/Jeffrey-Energy-Center-Units-1-2-3-Upgrade-Project.pdf.

[198] Consent Decree, United States of America and State of Kansas v. Westar Energy, Inc., U.S. District Court for the District of Kansas, Civil Action No. 09-CV-2059 JAR/DJW, Lodged with federal court: 75 FR 4,847 (January 15, 2010). Available here: http://www2.epa.gov/enforcement/consent-decree-westar-energy-inc-civil-action-no-09-cv-2059-jardjw.

[199] Kansas Department of Health and Environment (KDHE), Air Emission Source Class I Operating Permit, Jeffrey Energy Center, January 28, 2002, p. 25, Condition 6 and p. 28, Condition 14.

[200] 79 FR 74,822, Table 1 (Dec. 16, 2014).

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Startup, Shutdown, and Maintenance Exemptions

Many of the units that we did not specifically discuss, including all of the Miller units, and Scherer units 3 and 4, have large spikes that correspond to periods when the boiler was operating, but the scrubber was off-line. See, for example, "Selected BOD SO_2 Averages-3.xlsx," Tab: Scherer 4, the period 8/15/12 to 9/20/12. These (and other) plants with similar spikes have permits that exempt periods of startup, shutdown, and malfunction (SSM), allowing the boiler to continue to operate when the control equipment is offline.

The Title V Permit for the Scherer units[201] exempts many operating conditions, allowing the control equipment to shutdown while the boilers continue to operate. The Scherer permit limits SO_2 to 95% control on a 30-day rolling average basis, except it allows the boilers to operate without scrubbers during: (1) restarts; (2) periods of startup; (3) periods of shutdown; (4) periods of scheduled and/or preventative maintenance of control technology equipment if such maintenance cannot reasonably be performed during a scheduled outage; (5) periods of malfunction of the EGU or control technology; and (6) during certain testing and research periods. The scrubber on Scherer Unit 2 came on line in January 2014 and has only operated post-shakedown for 485 days. Its performance thus far is spectacular (maximum 30-day BOD = 0.01 lb/MMBtu), indicative of what the other longer-operating Scherer scrubbers could achieve, but for the SSM exemption periods when the scrubbers go offline, and the boilers continue to operate.

The spikes that diminish performance are generally not due to limitations of the scrubbers, but rather the failure of the facility to properly schedule adequate and timely maintenance to limit SO_2 emissions. All scrubbers require periodic maintenance. A facility without SSM exemptions will plan maintenance to avoid scrubber shutdowns during boiler operation, as demonstrated by the performance of Iatan Unit 1, discussed above.

Similarly, the Title V permit for Miller Units 1 - 4[202] limits SO_2 emissions to 1.2 lb/MMBtu (a very high limit, roughly double to its coal sulfur content[203]), with compliance only by stack test. The SO_2 permit condition includes this exception: "The FGD may be placed in bypass mode, provided all SO_2 emissions limitations are met." In other words, it can be turned off at will, as long as it burns low sulfur coal. As the typical coal that is burned at this facility contains about 0.7 lb/MMBtu of SO_2, this condition effectively allows the scrubbers to shutdown while the boilers continue to operate. This pattern is seen in the CEMS data for all four of the Miller units, which have similar SSM exemptions. Thus, we do not report the maximum 30-day BOD for any of these units in the "Efficiencies" tab of "Selected scrubber retrofit efficiencies.xlsx" document,

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[201] Scherer Steam-Electric Generating Plant, Part 70 Operating Permit, Permit Number: 4911-207-0008-V-03-0, May 8, 2012, Condition 3.4.14.

[202] Alabama Power Company, J. H. Miller, Jr. Steam-Electric Generating Plant, Major Source Operating Permit, For Units 1 & 2, p. 16, Condition 2: "The FGD may be placed in bypass mode, provided all SO_2 emissions limitations are met." For Units 3 & 4, p. 23, Condition 2: "The FGD may be placed in bypass mode, provided all SO_2 emissions limitations are met." Permit Available at: http://www.jcdh.org/EH/AnR/AnR13.aspx.

[203] From EIA-923, available here: http://www.eia.gov/electricity/data/eia923/
The 2014 sulfur content ranges from 0.23 to 0.31% and the coal heat content is approx. 17.7 MMBtu/ton. Converting to uncontrolled SO_2: (0.31% sulfur) X (1 ton/17.7 MMBtu) X (2,000 lbs/ton) X (2 molecules SO_2/1 molecule S) X (1/100%) = 0.7 lbs/MMBtu.

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as the CEMS data are not representative of scrubber performance.

The scrubbers on Miller Units 3 and 4 additionally have to meet a 30-day rolling average SO_2 control efficiency of 95%, which drops to 90% if coal with more than 1% sulfur is burned, to comply with a consent decree. However, the 30-day rolling average removal efficiency "shall exclude all emissions that occur during any period of malfunction…".[204] Further the Miller scrubbers are designed to achieve 98% SO_2 control, while the permit only requires that they achieve 90% to 95% SO_2 control, depending upon coal quality. The CEMs data includes many spikes when the boiler is operating but the scrubbers were not. Thus, the apparent poor performance of these scrubbers is not due to poor scrubber performance, but the failure of the permit to adequately limit emissions. The data summarized above indicates that similar scrubbers achieve much better performance when there are no SSM exemptions.

Finally, some of the spikes appear to be due to unspecified errors. For instance, in the Miller 1 data, the daily SO_2 average for 6/22/14 is 3.25 lb/MMBtu. This is likely a bad data point, as it is way above the SO_2 baseline from the PRB coal the Miller units have historically burned. Other graphs have similar spikes that exceed the sulfur content of coal quality.

Thus, we disagree with S&L that our proposed scrubber retrofit SO_2 emission limits are not realistic or maintainable on a long-term basis. We agree with Ms. Stamper that it may be possible that many of the scrubber retrofit units can achieve greater control efficiencies than we proposed. Greater control efficiencies would result in a more favorable cost effectiveness (lower $/ton) and more visibility improvement. This is another area in which we strove to be conservative and demonstrate that even with many conservative cost assumptions, our analyses indicate that the scrubber retrofits we proposed are cost effective.

[204] Miller Permit, pp. 22-23, Conditions 2 and 3.

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Appendix B: Wet FGD Scrubber Upgrade Control Cost Analysis as used in the Texas-Oklahoma FIP[205]

6 Upgrading Existing Scrubber Efficiencies

In Sections 3, 4, and 5, above, for those facilities with no SO_2 control, we contrasted the cost of DSI, SDA, and wet FGD. We then compared those costs to the visibility benefit from those controls from our visibility projection modeling, and we propose a RP and LTS determination. Here, we conduct similar analyses for those units listed in Table 1 with an existing SO_2 scrubber in order to determine if cost effective scrubber upgrades are available. Because all of the scrubber systems we evaluate are wet scrubbers, we limit our analyses of scrubber upgrades to wet scrubbers.

We proceed by first presenting information concerning the kinds of options generally available to facilities for upgrading their existing scrubbers. Following this, to the extent possible, we review all of the information we have at our disposal regarding the status of the existing scrubbers for each unit. This includes any upgrades the facility may have already installed. Although some of this information has been gleaned from public sources of information, much of it was collected as a result of our information collection effort. The companies that have supplied this information have asserted a Confidential Business Information (CBI) claim for much of it, as provided in 40 C.P.R. § 2.203(b). We therefore must redact any CBI information we utilize in our analyses, or otherwise disguise it so that it cannot be traced back to its specific source. Similar to our DSI, SDA, and wet FGD analyses we then contrast the cost of the various options for upgrading those scrubbers. Following this, we compare those costs to the visibility benefit from those controls from our visibility projection modeling, and propose a RP and LTS determination.

We have long recognized that existing underperforming SO_2 scrubbers are likely capable of being upgraded to much higher removal efficiencies. For example, we made this statement in the BART rule:[206]

> For those BART-eligible EGUs with preexisting post-combustion SO_2 controls achieving removal efficiencies of at least 50 percent, your BART determination should consider cost effective scrubber upgrades designed to improve the system's overall SO_2 removal efficiency. There are numerous scrubber enhancements available to upgrade the average removal efficiencies of all types of existing scrubber systems. We recommend that as you evaluate the definition of ''upgrade,'' you evaluate options that not only improve the design removal efficiency of the scrubber vessel itself, but also consider upgrades that can improve the overall SO_2 removal efficiency of the scrubber system. Increasing a scrubber system's reliability, and conversely decreasing its downtime, by way of optimizing operation procedures, improving maintenance practices, adjusting scrubber chemistry, and increasing auxiliary equipment redundancy, are all ways

[205] Reproduced from Sections 6 and 7 of the Cost TSD associated with the Texas-Oklahoma FIP, 81 FR 321.

[206] 70 FR 39171.

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to improve average SO_2 removal efficiencies.

We recommend that as you evaluate the performance of existing wet scrubber systems, you consider some of the following upgrades, in no particular order, as potential scrubber upgrades that have been proven in the industry as cost effective means to increase overall SO_2 removal of wet systems:

(a) Elimination of Bypass Reheat;
(b) Installation of Liquid Distribution Rings;
(c) Installation of Perforated Trays;
(d) Use of Organic Acid Additives;
(e) Improve or Upgrade Scrubber Auxiliary System Equipment;
(f) Redesign Spray Header or Nozzle Configuration.

We recommend that as you evaluate upgrade options for dry scrubber systems, you should consider the following cost effective upgrades, in no particular order:

(a) Use of Performance Additives;
(b) Use of more Reactive Sorbent;
(c) Increase the Pulverization Level of Sorbent;
(d) Engineering redesign of atomizer or slurry injection system.

Industry has also recognized that the efficiency of existing SO_2 scrubbers can and have been upgraded significantly and a number of companies offer scrubber upgrade services. For instance, URS makes this statement in its, "Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants:"[207]

> Upgrades have been performed on a large number of FGD units over the past 15 years and have resulted in increased SO_2 removal performance to levels ranging from 92 – 99%. These have ranged from minor modifications to the internal components of a given unit, to enhance gas-liquid contact, to conversion of some units from one FGD technology to another coupled with the addition or modification of various balance-of-plant equipment or processes.

It is typically much more cost effective to upgrade an existing FGD than to install a completely new scrubber.[208] These existing scrubbers can be upgraded by applying new scrubbing technology[209] to improve their removal efficiency, lower operating costs, and improve operations and reliability for much less than it would cost to replace them with a new scrubber.

A scrubber can be upgraded by reusing as many structural components and equipment in the existing unit as possible, such as existing structural steel and absorber shells, ducts, pumps, and

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[207] Lipinski, George, et al, Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants, URS, April 5, 2011, p. A-5.
[208] Maller et al, p. 5.
[209] See, e.g., Wolfgang Schuettenhelm and others, FGD Technology Developments in Europe and North America, Mega Symposium, 2001, http://www.babcockpower.com/pdf/rst-171.pdf.

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compressors. Scrubber upgrades have been completed on about 50 units in the last 15 years to enhance performance or lower overall operating costs.

As Staudt notes:[210]

> There have been numerous examples of FGD upgrades over the last several years that have improved SO_2 removal efficiencies. For example, the Fayette Station Unit 3, a 470 MW tangentially-fired coal unit in Texas, completed an upgrade to its 1988-vintage scrubber in 2010. The plant's control efficiency was increased from about 84 percent to 99 percent, higher than the guaranteed SO_2 removal efficiency of 95.5 percent. In Kentucky, E.On's Trimble County Generating Station Unit 1, a 550 MW tangentially-fired coal boiler, completed a scrubber upgrade in 2006. Its scrubber, installed in the 1980s, was originally designed for 90 percent removal efficiency. The scrubber system is now able to achieve over 99 percent SO_2 removal efficiency. In Indiana, NiSource upgraded the scrubbers at Schahfer Units 17 and 18 in 2009. The scrubber upgrades increased SO_2 removal efficiency from 91 percent to 97 percent.

Other successful scrubber upgrades include the AEP/SWEPCO Pirkey Unit 1 in Texas,[211] the San Miguel Electric Cooperative Unit 1 in Texas,[212] the Tuscon Electric Power Springerville Units 1 and 2 in Arizona;[213] the Gibbons Creek facility in Texas, the San Juan Generating Station in New Mexico;[214] the Culley Generating Station Units 2 and 3 in Indiana;[215] and the Trimble County Generating Station Unit 1 in Kentucky.[216] These upgrades have increased SO_2 removal to 92% to 99%.[217]

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[210] Staudt, James E., Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants Prepared For: Northeast States for Coordinated Air Use Management 89 South Street, Suite 602, Boston, MA 02111, March 31, 2011, p. 13.

[211] https://www.aeptexas.com/info/news/viewRelease.aspx?releaseID=146: "H. W. Pirkey Plant was equipped with an FGD system when it went into service in 1985. That system consistently removes nearly 80 percent of SO_2. This original equipment will be upgraded to bring its removal rate into the 90-percent range;" Tax Relief For Pollution Control Property Applications Filed for Harrison County 11/1994 & 10/2003. Available at: http://www.tceq.state.tx.us/assets/public/assistance/graphics/Prop2/harrison.pdf

[212] San Miguel Electric Cooperative FGD Upgrade Program Update, URS Corporation, June 30, 2014.

[213] Farber, et al, Results of FGD Upgrade Projects On Low-Rank Coals, Presented at Electric Power 2007 Conference and Exhibition EP-07 Session 12E2007. Covers upgrades to Pirkey Unit 1, San Miguel, and Springerville Units 1 and 2.

[214] Taylor, H., Nischt, W., San Juan Generating Station FGD Retrofit Project Update, Presented to: BR-1667 Power-Gen International '98, December 9-11, 1998, Orlando, Florida.

[215] Quitadamo, M., et al, SO_2 Removal Enhancement to the Vectren Culley Generating Station Units 2&3 Wet Flue Gas Desulfurization System, Babcock Power Technical Publication, Presented at the ICAC Forum 05', March 7-10, 2005, Baltimore, Maryland.

[216] Erickson, Clayton, et al, Wet Flue Gas Desulfurization (WFGD) Upgrade at the Trimble County Generating Station Unit 1, Presented at MEGA Symposium, August 28-31, 2006, Baltimore, Maryland.

[217] URS, 4/5/11, pp. A-5 to A-7; Babcock Power Environmental, Wet Flue Gas Desulfurization Scrubber Upgrades, 2009; Erickson, C., et al, Wet Flue Gas Desulfurization (WFGD) Upgrade at the Trimble County Generating Station Unit 1, Mega Sumposium 2006; Quitadamo, M. et al, SO_2 Removal Enhancement to the Vectren Culley Generating Station Units 2 & 3 Wet Flue Gas Desulfurization System, ICAC Forum 2005; Silva A., and Williams, P., WFGD Case Study – Maximizing SO_2 Removal by Retrofit with Dual Tray Technology, Mega Symposium, 2006; Henry S. Taylor and Walter Nischt, San Juan Generating Station FGD Retrofit Project Update, PowerGen; Maller G., et al, Improving the Performance of Older FGD Systems; B&W, Wet Flue Gas Desulfurization (FGD) Systems Advanced

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As we discussed in Section 5 in our wet scrubber retrofit cost calculations, a typical retrofitted scrubber is capable of 98% removal, down to an effective lower limit of 0.04 lbs/MMBtu. However, we recognize that scrubber upgrades are highly individualistic, depending on the particular equipment in use at the facility. Furthermore, we recognize that a number of the facilities we analyze for scrubber upgrades burn either PRB coals or blends of coals containing a large percentage of PRB coals. Consequently, in our analyses, we assign a presumptive scrubber upgrade target of 95% SO_2 removal, with the understanding that the ultimate individual efficiency will vary depending these factors.

6.1 Calculation of Existing Scrubber Efficiencies

In a typical situation in which we would propose that a pollution control device such as an SO_2 scrubber be installed, we would have historical emissions data to use as a baseline. In such an instance, we would apply the control efficiency of the scrubber to the uncontrolled historical SO_2 emissions, and be able to easily propose a controlled SO_2 emission rate that would be appropriate following the installation of the scrubber. However, we face a more difficult task in analyzing the efficiency of existing SO_2 scrubbers.

As we discussed above, we are confident that any of these existing scrubbers can be upgraded to perform similarly to newly retrofitted scrubbers. If we are to approach the task of calculating the cost of upgrading these scrubbers in a way similar to that of proposing a new scrubber, we must first be able to specify an SO_2 emission rate that would be appropriate following the installation of these scrubber upgrades. Because to our knowledge, none of these units monitors (via CEMS) their emissions before the exhaust gas traverses their existing scrubbers, we do not have CEMS baseline SO_2 emissions. However, we do have coal quality data, which can be used to establish uncontrolled SO_2 emissions.

We calculated the scrubber removal efficiency by utilizing the reported sulfur content and tonnages of the fuels burned and reported to EIA,[218] and the monitored SO_2 scrubber outlet emissions reported to us.[219] We did this by constructing a spreadsheet[220], which among other things, divides the annual SO_2 emissions by the theoretical uncontrolled SO_2 emissions based on coal sulfur content to estimate the percentage of SO_2 in the coal that is emitted by each of the scrubbed facilities in Table 1. We calculated the theoretical uncontrolled SO_2 emissions from EIA reported coal sulfur data. This calculation is summarized below for a typical unit that burns both lignite and subbituminous coals:

(1)

Technology for Maximum SO_2 Removal, 2007 (8,000 MW of non-B&W wet FGD system upgrades by replacing the original absorber internals with tray technology and forced-oxidation conversions).

[218] EIA Form 923. Available at http://www.eia.gov/electricity/data/eia923/

[219] EPA Air Markets and Programs Data. Available at http://ampd.epa.gov/ampd/

[220] See "Coal vs CEM data 2009-2013.xlsx," tab "charts," cell H12.

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or, alternatively expressed in tons:

(2)

and the scrubber efficiency is then:

(3)

In equations (1) and (2), the percentage and tonnage values are those reported by the facility to the EIA for each fuel type. In equation (3), the annual EPA reported tons of SO_2 are those reported to us.[221]

In the following table, we summarize our calculation of the SO_2 removal efficiency for the existing scrubber systems:

[221] EPA Air Markets and Programs Data. Available at http://ampd.epa.gov/ampd/

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Table 14. Efficiency of Units with existing SO_2 scrubbers

Facility	Unit	Scrubbed?	Bypass?	2009-2013 Average SO_2 Removal Efficiency (%)
Sandow 4	1	Y	Y	75.7
Monticello	3	Y	Y	60.0
Martin Lake	1	Y	Y	69.2
Martin Lake	2	Y	Y	71.9
Martin Lake	3	Y	Y	69.8
Limestone	1	Y	Y	78.1
Limestone	2	Y	Y	77.0
San Miguel	1	Y	N	94.0
W. A. Parish	8	Y	Y	84.0

We were interested in gauging the accuracy and precision of our calculations of the theoretical uncontrolled SO_2 emissions, so we compared it to the EPA reported SO_2 emissions for units that do not have scrubbers. The following table presents that information:

Table 15. Comparison of theoretical to monitored SO_2 emissions for unscrubbed units

Unit	2009-2013 average monitored SO_2 emissions (tons)	2009-2013 average theoretical SO_2 emissions (tons)	Percentage theoretical to monitored SO_2 emissions (%)
Big Brown Unit 1	30,606.1	32,489.3	6.2
Big Brown Unit 2	30,638.8	32,048.5	4.6
Coleto Creek	16,665.1	18,771.5	12.6
Monticello Unit 1	16,434.9	18,288.8	11.3
Monticello Unit 2	15,458.0	17,805.3	15.2
Tolk Unit 171B	10,223.9	11,582.1	13.3
Tolk Unit 172B	10,889.4	11,395.4	4.6
W. A. Parish Unit 5	14,295.6	17,480.7	22.3
W. A. Parish Unit 6	15,376.5	17,404.9	13.2
W. A. Parish Unit 7	12,119.3	14,604.6	20.5
Welsh Unit 1	7,956.4	9,618.3	20.9
Welsh Unit 2	8,075.8	9,483.2	17.4
Welsh Unit 3	8,490.6	9,794.1	15.4
Average			13.6

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This table shows that the actual SO_2 emissions as measured by CEMS are about 13.6% lower than the SO_2 estimated from coal quality data. The difference between these two numbers 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. We expect these errors to be compounded for units that blend coals.
- 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.[222]
- Potential effects of NOx and PM pollution control devices. SCRs, which are operating at the Parish units, convert a small amount of SO_2 to SO_3 as a consequence of the catalysts. Low SO_3 conversion SCR catalysts are available, but we do not know if the Parish units employ them. ESPs and baghouses reduce sulfur by removing particulate matter with absorbed SO3. Further, the filter cake in a baghouse absorbs SO_3.[223]
- Losses of sulfur, such as pyrite, when the coal is pulverized or in bottom ash.
- 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.

Therefore, we acknowledge that both our calculations of current SO_2 scrubber efficiency, and our calculations of tons of SO_2 removed once a scrubber upgrade is performed (and hence our cost effectiveness calculations) will have some error. We discuss how we propose to treat this in our Federal Register Notice for our proposed action.

6.2 Historical Scrubber Designs and Upgrades

The scrubber systems we are evaluating were all installed in the late 1970s to mid-1980s as part of the initial design of the facilities. All employ wet limestone, and with one exception – San Miguel – have scrubber bypasses. Scrubbers of this vintage were typically designed to meet the 1971 New Source Performance Standards (NSPS) for EGUs, which required new coal-fired boiler to meet a SO_2 limit of 1.2lb/MMBtu; or the 1979 NSPS, which additionally required 70% control, not to exceed 0.6 lbs/MMBtu unless 90% control was achieved. [224] Compliance usually involved using multiple absorbers with spares.[225]

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[222] Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, Technical Update, EPRI, March 2012.

[223] 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.

[224] Flue Gas Desulfurization Inspection and Performance Evaluation Manual, EPA/625/ 1-85/019, October 1985, Sections 2.1.1.1 and 2.1.1; Farber, et al, p. 18.

[225] Spare scrubber modules allow FGD systems to maintain full or partial operating capability when a primary module fails or is down for service. Early scrubber design commonly included spares due to poor operating experience and the NSPS "emergency condition" provision. See, e.g., William DePriest and Rajendra P. Gaikwad, Economics of Lime and Limestone for Control of Sulfur Dioxide, 2003.

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As Weilert notes,[226] "This is likely due to the requirement of the EPA's new source performance standard (NSPS) for continuous compliance with a 30-day rolling average SO_2 removal, and the provision that stipulates a spare absorber module as a prerequisite to operation during emergency conditions with a malfunctioning FGD system." However, industry gradually recognized that module spares were not required due to advances in scrubber technology, and the proven reliability of single-module FGD systems.[227] Thus, utilization of an existing spare FGD module at one of the facilities we are analyzing (Limestone) potentially represents a cost effective opportunity to increase scrubbing capacity. The following tables summarize the FGD information we have available as a result of mandatory reporting to the EIA via Forms 860 and 923, and from Weilert:[228]

[226] Carl Weilert, FGD Systems Utilizing Single Absorber Modules: The Wave of the Future for New Utility Boilers, Burns & McDonnell Technical Paper.

[227] Bailly Generating Station Advanced Flue Gas Desulfurization System, Final Environmental Information Volume, April 1989; Carl Weilert, Ibid., p. 12: "The available data indicates that single-module FGD systems can be extremely reliable."; Frazer, C., et al, Fayette Power Project Unit 3 FGD Upgrade: Design and Performance for More Cost-Effective SO_2 Reduction, Babcox and Wilcox Technical Paper presented at the EPRI Mega Symposium 2010, p. 3: "Ultimately, the options selected, and discussed above, offer the station the flexibility to permanently remove one of the absorbers from regular service." Taylor et al, Control of SO_2 emissions from power plants: A case of induced technological innovation in the U. S., Technological Forecasting & Social Change 72 (2005) 697 718. …." Page 715: " … according to a study of 111 FGD installations in 1986-1988 that declared that reliability was no longer an issue with FGD. With increased reliability, costly design options such as spare absorber modules were dropped in the 1990s."; Schuettenhelm, W et al, FGD Technology Developments In Europe And North America, Babcock Technical Paper, Presented at the EPA-DOE-EPRI Mega Symposium Arlington Heights, Illinois, August 20-24, 2001, p. 3: "The F. B. Culley FGD (Vectren) system located near Evansville, Indiana … was designed to remove 95% of the SO_2 based on a 10 lb/MMBtu fuel. A unique feature of the project is that it uses one absorber to serve two generating units with no bypasses."

[228] Weilert, C., and Meyer, E., Utility Design Trends, Power Engineering, 8-1-2010; personal communication.

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Table 16. Summary of FGD information[229]

Facility	Units	2011 EIA 860								2012 EIA 923		
		In-service year	Sorbent Type 1	Sorbent Type 2	Bypass?	FGD Trains	FGD Trains at 100% Load	Design Removal Efficiency (%)	Flue Gas Entering FGD (%)	Efficiency at Annual Operating Factor	Tested Efficiency at 100% Load	Date Latest Efficiency Test
Sandow 4	1	1981	LS	DB	Y	3	3	92	83	74.4	74.4	01/1984
Monticello	3	1978	LS	DB	Y	3	3	95	75	55	55	01/2007
Martin Lake	1	1977	LS	DB	Y	4	4	95	95	64.7	64.7	02/1991
Martin Lake	2	1978	LS	DB	Y	4	4	95	95	64.9	64.9	02/1991
Martin Lake	3	1979	LS	DB	Y	4	4	95	95	67.8	67.8	02/1991
Limestone	1	1985	LS	DB	Y	5	4	90	100	77.1	91.5	12/2011
Limestone	2	1986	LS	DB	Y	5	4	90	100	75.8	91.5	12/2011
San Miguel	1	1982	LS		N	4	4	94.2	100	94.1	94.3	05/2010
W. A. Parish	8	1982	LS		Y	3	3	85	82	81.9	73	01/1985

[229] We question the accuracy of some of this information reported to EIA. For instance, the Limestone facility reports that it has a bypass for its scrubbers, yet it reports that 100% of the flue gas enters the scrubber. Also, the Martin Lake facility reports that for Unit 1, 95% of its flue gas enters its FGD and that of that gas, the removal efficiency is 95%. This would result in an overall SO_2 removal efficiency of 90.3% (0.95 X 0.95). However, our own calculations indicate an average removal efficiency of much less. We suspect the EIA scrubber efficiencies are a mixture of supplier guarantees (not counting bypassed flue gas) and actual estimates.

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Table 17. Selected information from Weilert and Meyer

Facility Name[a]	FGD ID[b]	Process Type[a]	Absorber Type I[b]	Sorbent Type[b]	Provision for Bypass[b]	Incorporation of Spare Module[b]	Manufacturer[b]	Material of Construction	Oxidation Mode
Limestone	1	Wet Limestone	SP	LS	Y	Y	AL	NIe	Forced[e]
Limestone	2	Wet Limestone	SP	LS	Y	Y	AL	NIe	Forced[e]
Martin Lake	1	Wet Limestone	TR[m]	LS	Y	N	HRC	FRCS[f]	NR
Martin Lake	2	Wet Limestone	TR[m]	LS	Y	N	HRC	FRCS[f]	NR
Martin Lake	3	Wet Limestone	TR[m]	LS	Y	N	HRC	FRCS[f]	NR
Monticello	3	Wet Limestone	SP	LS	Y	N	MX	FRCS[f]	NR
San Miguel	1	Wet Limestone	TR[m]	LS	N	N	BW	SS[m]	Inhibited[e]
Sandow	4	Wet Limestone	SP	LS	Y	N	AL	SS[e]	NR
W A Parish	8	Wet Limestone[f]	SP	LS	N[230]	N	MX	FRCS[f]	NR

Notation from Weilert and Meyer

a This column is from the 2010 "Emissions" section of EPA's Clean Air Markets Division "Data and Maps" website
b This column is from 2008 EIA-860 data Schedules 6-G & 6-H
c This column is from 2008 EIA-860 data "Annual Electric Generator Report" Generator (Existing) File
d 2009 "Emissions" section of EPA's Clean Air Markets Division "Data and Maps" website
e Information is from respective vendor either from direct correspondence or from their website/publications
f DOE "Utility FGD Survey January - December 1989" Publication Number ORNL/M-2347
g 2008 "Emissions" section of EPA's Clean Air Markets Division "Data and Maps" website
h 2007 "Emissions" section of EPA's Clean Air Markets Division "Data and Maps" website
I 2008 EIA 860 data "Annual Electric Generator Report" Generator (Proposed) File
j Material information from Stebbins Manufacturing Installation List
k Upgrade by BPE according to BPE
l 2005 EIA 767 data Schedule 8 A & 8 B

[230] We note that the Weilert and Meyer data reports that the W A Parish facility does not have a scrubber bypass, yet the EIA data reports that the facility does have a bypass. Examination of aerial photos of Unit 8 seem to confirm the presence of ducting that would serve a bypass.

m Authors' correction based on personal knowledge
n Facility's Utility's website
o EPA's Steam Electric Power Generating Point Source Category: 2007/2008 Detailed Study Report (Online)
p Multiple FGD units are associated with one generator. The value reported is the nameplate capacity for the generator.

General	Absorber Type	Sorbent Type	Material of Construction	Unit Manufacturers
NA Not Applicable	BR Jet Bubbling Reactor	AF Alkaline fly ash	CO Combination	AD Allied
NR Not Reported	CD Circulating Dry Scrubber	LA Lime and alkaline fly ash	CS Carbon Steel	AL Alstom
	DCFS Double Contact Flow Scrubber	LF Limestone and alkaline fly ash	FRCS Flakeglass Reinforced Resin	AM American Air Filter
	DSI Dry Sorbent Injection	LI Lime	Lined Carbon Steel	AP Airpol
	PA Packed	LS Limestone	FRP Fiberglass Reinforced Plastic	AV Advatech
	SD Spray Dryer	MO Magnesium oxide	NI Nickel Alloy	BPE Babcock Power Environmental
	SP Spray	SA Soda ash	RLCS Rubber Lined Carbon Steel	BW Babcock and Wilcox
	TR Tray	SC Sodium carbonate	SS Stainless Steel	CH Chiyoda
	VE Venturi	SL Soda liquid	TL Tile Lined	FMC FMC
				HI Hitachi
				HRC Hamon Research Cottrell
				KE M W Kellogg
				MHI Mitsubishi Heavy Industries
				MX Marsulex
				SHU Saarberg Holter
				SI Siemens
				OT Other

The Instructions for EIA Form 860 indicate the following regarding the fields of interest to us:

Can flue gas bypass the flue gas desulfurization unit? Indicate whether the flue gas can bypass the FGD unit.

What is the total number of flue gas desulfurization unit scrubber trains or modules? Enter the total number of flue gas desulfurization unit scrubber trains or modules operated.

How many flue gas desulfurization unit scrubber trains or modules are operated at 100 percent load? Enter how many flue gas desulfurization unit scrubber trains or modules are operated at 100 percent load.

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What is this unit's design removal efficiency for sulfur dioxide when operating at 100 percent load? Report the design removal efficiency to nearest 0.1 percent by weight of gases removed from the flue gas when operating at 100 percent generator load.

The instructions for EIA Form 923 indicate the following regarding the fields of interest to us:

FGD or FGP Efficiency Rate at Annual Operation Factor (H, K): Enter removal efficiency, based on the annual operating factor. Annual operating factor, as given by the formula below, is defined as the product of design firing rate and hours of operation per year, divided by annual total fuel consumption, expressed as a percentage. If actual data are unavailable, provide estimates, based on equipment design performance specifications.

Annual Operating Factor (AOF) =
*100 * Design Firing Rate (MMBtu/hr) * Hours of Operation (hr) / Total Fuel Consumption (MMBtu)*
*Removal Efficiency at Annual Operating Factor = FGP Removal Efficiency * Average AOF*

FGD or FGP Tested Efficiency Rate (at 100% Load) (I, L): Enter the tested efficiency of the FGD and/or FGP unit for each controlled pollutant. If not tested at 100% load, provide the load at which the test was conducted in a comment on Schedule 9. If an efficiency test has not been conducted, leave field blank and provide a comment.

Test Date (J, M): Enter the date of the latest efficiency test for the FGD and/or FGP unit for each controlled pollutant. If no test was conducted, leave the test date blank.

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These first generation FGD units were typified by multiple absorber modules, SO_2 removal efficiencies between 75% and 90%, and the use of either natural or inhibited oxidation.[231] However, as Staudt notes,[232] "… limestone-forced oxidation (LSFO) wet scrubber technology is [now] the most widely used form of wet FGD and is more widely used on coal-fired power plants than every other form of FGD combined. State-of-the-art LSFO systems are capable of providing very high levels of SO_2 removal – on the order of 98 percent or more." These early units were often designed to operate with a dry stack, which was most often accomplished by bypassing a portion of the flue gas around the scrubber to maintain gas temperatures high enough to prevent condensation and the formation of H_2SO_4 which would erode an unprotected chimney. These older scrubbers represent a significant investment that can be optimized, improved, and/or upgraded to minimize the cost of reducing SO_2 emissions.

These early scrubbers typically employed two scrubbing zones, a venturi section with spray nozzles to enhance gas-liquid mixing and a second spray zone. The second zone sometimes included a tray or packing to enhance gas-liquid contact.[233] They had many operational problems including poor reagent utilization, tray scale, ducting problems, and plugging of nozzles and demisters.[234] Solids deposited on these devices, plugging them, reducing flow and increasing differential pressure, requiring weekly cleanings and driving up O&M costs. The resulting high O&M costs led to replacement of packings and redesign.[235]

We know from our review of the facility's responses to our information collection requests, described in Section 7.1, that many, if not all of these original scrubbers have been modified since their original installations to cure these and other problems. However, there is very little publicly available documentation. A number of key factors have pushed owners to upgrade their scrubbers, often absent any regulatory drivers including: [236]

- Reduction in operating costs
- Reduction in maintenance costs
- Flexibility to burn higher sulfur coals
- Sale of byproduct (upgrade to forced oxidation allowing the sale of gypsum)
- Opportunity to generate excess emissions credits for sale,
- An increase in the SO_2 emission credits price 20
- Reduction in auxiliary power consumption

[231] Farber, et al.
[232] Staudt, James E., Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants Prepared For: Northeast States for Coordinated Air Use Management 89 South Street, Suite 602, Boston, MA 02111, March 31, 2011. p. 10.
[233] Buecker, B., Important Concepts of Wet-Limestone Flue Gas Desulfurization Energy-Tech Magazine, October 2008, http://www.energy-tech.com/article.cfm?id=21789; PEI Associates, 1985.
[234] See, e.g., NERC, Impact of FGD Systems. Availability Losses Experienced by Flue Gas Desulfurization, July 1991, pp. 10, 27; Farber, et al, Ibid.
[235] Buecher, Brad. Ibid.
[236] Klingspor, J., Brown, G., Techniques for Improving FGD System Performance to Achieve Ultra-High SO_2 Removal Efficiencies, URS Technical Paper; Frazer, C., et al, Ibid., p. 8: "The unit also has the option to burn lower-cost, high-sulfur coal, while still maintaining emissions limits;" NERC, Impact of FGD Systems. Availability Losses Experienced by Flue Gas Desulfurization, July 1991; Maller, G., et al; Taylor, H., Nischt, W., p. 5: "This conversion project was justified on the basis of O&M and power/fuel savings."

- Solving process problems that cause high maintenance, reagent, and disposal costs
- Improving reliability (reducing scrubber-related outages)
- Ability to treat a higher volume of flue gas to improve scrubbing efficiency

Analyses of these upgrades reveals that they typically have performed better than guaranteed. Our examination of the facility's responses to our information collection requests, lead us to conclude that some of these existing scrubbers are able to operate at higher removal efficiencies than they currently achieve due to changes in the factors that led to their upgrades. For example, our regulations have been delayed through litigation, SO_2 allowance markets have not materialized or allowance costs have not risen as expected, changes in natural gas pricing, etc. Consequently, we suspect that absent a specific permit limit, other enforceable requirement, or market driver to operate at these higher scrubber efficiencies, some of these facilities may simply choose not to do so for economic reasons. For example, it has been suggested that some facilities owners turn off their scrubbers at peak demand to maximize profits.[237]

6.3 Options for Upgrading SO_2 Scrubbers

The performance of older FGDs is often limited by poor reliability and poor design, resulting in lower SO_2 removal efficiencies and higher operating and maintenance costs than newer FGD systems. The causes for poor performance include the following:[238]

- Bypassing a portion of the flow around the scrubbers
- Unbalanced flow between absorbers
- Poor gas distribution within the absorber
- Poor spray coverage within the absorber
- No droplet-to-droplet interaction within the absorber
- Sneakage along the sides of the absorber
- Poorly designed mist eliminator wash systems
- Inadequate scrubber chemistry

Existing FGD systems can be upgraded by applying new scrubbing technology[239] and improved upon in many instances so that they can operate at performance and reliability levels similar to new systems for much less than it would cost to replace them with a new scrubber.[240] As noted in the BART Rule, "upgrading an existing scrubber system is typically considered more cost

[237] Wynne, H., et al, U.S. Utilities: Can Texas Comply with the Cross-State Air Pollution Rule? Yes, If Existing Scrubbers Are Turned On, Bernstein Research, July 20, 2011, p. 5: "This pattern suggests that generators have sought to avoid the reduction in net generation that results from operating the scrubbers (reflecting the parasitic load of the emissions control equipment) during hours when power prices are highest. Conversations with the investor relations departments of Energy Future Holdings and NRG Energy confirmed that, as long as continuous operation of SO_2 scrubbers is not required to comply with currently prevailing SO_2 emissions limits, generators will avoid operating the scrubbers so as to maximize net power output and revenues, and minimize variable operation and maintenance expense, including the cost of sorbents and water required for the operation of the SO_2 scrubbers."
[238] Klingspor, J., Experience from 52,280 MWs of Wet Flue Gas Desulphurisation System Upgrades, VGD PowerTech, December 2012.
[239] Schuettenhelm, W et al; Maller, G., et al; Klingspor, J.,et al; Farber, P., et al; Klingspor, J., et al.
[240] Maller, G., et al, p. 13.

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effective than constructing a new scrubber system."[241] Dr. Jonas Klingspor, Vice President at URS, a firm that has conducted more than 52,000 MWs of scrubber upgrades, stated that, "a scrubber upgrade is typically about one-third or less than the cost of a new scrubber." This is because a scrubber system can be upgraded by reusing many existing structural components and existing equipment, such as existing structural steel and absorber shells, ducting, pumps, and compressors. Other components can be modified or replaced with new technology. Also according to Klingspor:[242]

> Most wet FGD systems, regardless of initial physical design or chemistry, can be upgraded to achieve above 99% SO_2 removal efficiency and to operate uninterruptedly between scheduled outage cycles.

As described repeatedly in the scrubber upgrade references we provide, a scrubber system can be upgraded by reusing many existing structural components and existing equipment, such as existing structural steel and absorber shells, ducting, pumps, and compressors. There are many viable, cost-effective options to improve SO_2 removal efficiency. These include: [243]

- Removing any existing scrubber bypass;
- Eliminating sneakage of gases down the sides of the absorber bypassing the spray headers, by installing wall baffles or rings within the absorber;
- Improving liquid distribution by installing new spray headers, additional spray levels and/or more efficient nozzles to improve spray coverage in the absorber;
- Improving gas-liquid contact by adding trays within the absorber;
- Increasing the gas-to-liquid ratio by increasing recycle slurry pump flow by, for example, using all available scrubber modules, adding recirculation pump suction line screens or changing pump gear reducers to allow higher impeller speeds, thus producing greater slurry flow on pumps;
- Improving scrubber chemistry by reducing limestone grind size, eliminating limestone blinding, converting to inhibited or forced oxidation, optimizing pH, and using performance additives such as dibasic acid (DBA);
- Redesigning mist eliminators and mist eliminator wash system to handle higher velocities through the absorber;
- Repairing any damaged or worn parts, such as recycle pump impellors; and
- Removing any capacity constraints, such as in the dewatering system or induced draft fan.

We discuss these scrubber upgrade options in the sections that follow. These methods have been used on many vintage scrubbers in the last 20 years to enhance performance and/or to lower

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[241] 70 FR 39133.

[242] Klingspor, J., Experience from 52,280 MWs of Wet Flue Gas Desulphurisation System Upgrades, VGD PowerTech, December 2012.

[243] See for example: Klingspor, J., p. 106; Maller, G., et al; Klingspor, J. and Brown, G; Alstom, Wet Scrubber Upgrade Air Quality Control Systems, http://www.alstom.com/Global/Power/Resources/Documents/Brochures/wet-scrubber-upgrade-datasheet.pdf;
Moretti, A., State-of-the-Art Upgrades to Existing Wet FGD Systems to Improve SO_2 Removal, Reduce Operating Costs and Improve Reliability, Power-Gen Europe, June 3-5, 2014.

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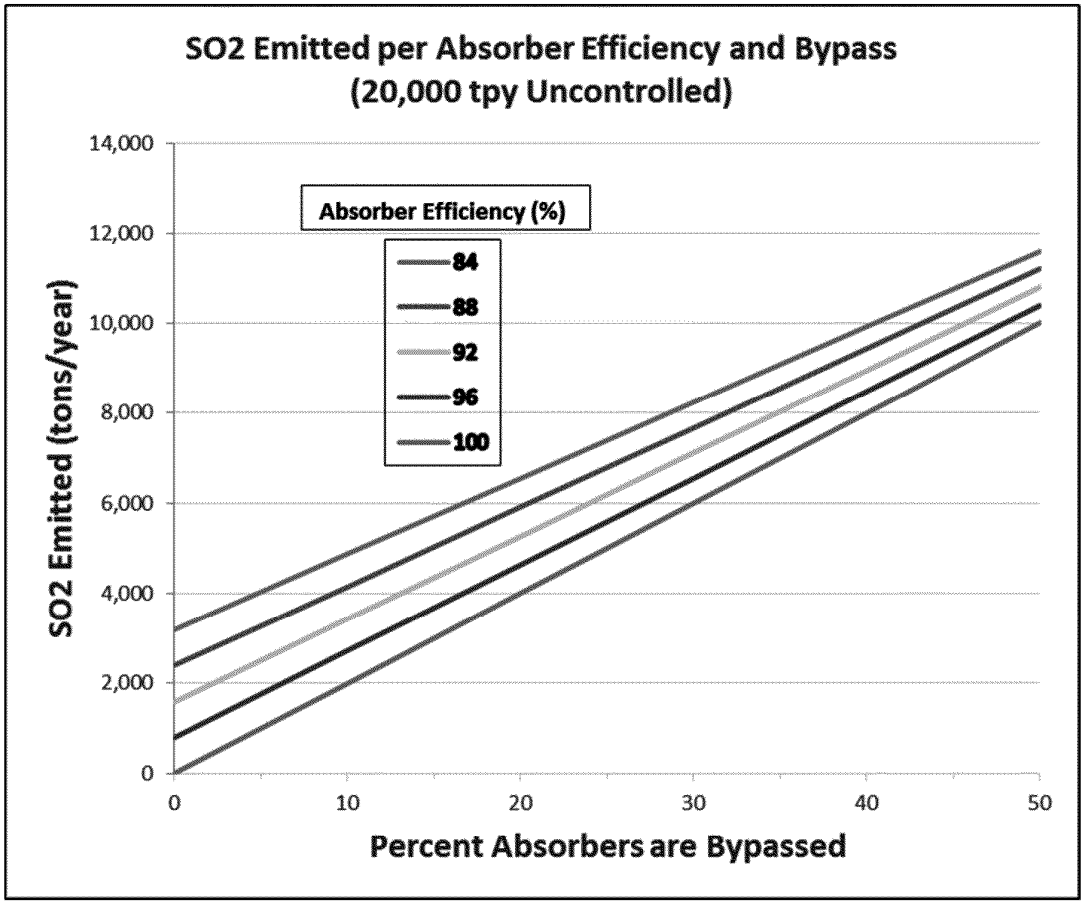
overall operating costs.[244]

6.3.1 Elimination of Scrubber Bypass

As we note above, a flue gas bypass is used on all of the scrubber systems we are investigating for upgrades, except for the San Miguel unit. A bypass allows the facility to route all or a portion of the flue gas around the FGD system for flue gas reheat and/or to improve operating flexibility. Some utilities originally designed the FGD system to scrub only a percentage of the flue gas while others installed bypass capability as a means of providing continuous operating capability, using alternate method for flue gas reheat. Because a bypass can route a large volume of flue gas around the scrubber system, it can have a significant impact on the overall SO_2 removal efficiency of the unit. Below is an example of this:

- Figure 2. Effect of Bypass and Absorber Efficiency on SO_2 Emitted



In the above example for a coal fired power plant that would emit 20,000 tons per year (tpy) if uncontrolled, the difference between no bypass and 20% bypass is significant. For example, if

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the absorbers are 96% efficient, a 20% bypass would mean that 3,840 tpy more is emitted over no bypass.

A wet FGD sprays a limestone-based slurry into the gas stream to remove SO_2. This produces a gas stream that is saturated with water vapor at a temperature of 136-145 F for lignite and sub-bituminous coal. A wet scrubber cools the stack gas and adds moisture to it. The gases are saturated and contain water droplets containing corrosive compounds such as sulfuric acid. If the temperature of the flue gas is blow the dew point, the moisture condenses in the exit ducts, stack walls, etc., corroding downstream equipment. Gasses emitted to the atmosphere can result in liquid fallout, visible steam plumes and plume touchdown, causing high ground-level SO_2 concentrations.[245] Thus, unless corrosive resistant materials are utilized, the temperature of the flue gases exiting the FGD system must be above the dew point to avoid condensation of flue gas and to maintain flue gas velocities in the exit ducts and stack.

At the time the subject scrubbers were installed, this was accomplished by heating the flue gas exiting the FGD system by about 25 to 50°F[246], so it was slightly above the saturation point. This increased the buoyancy of the plume, which reduced ground-level pollutant concentrations; reduced plume visibility by eliminating entrained moisture; and evaporated entrained water droplets, decreasing the potential for corrosion. Four methods were historically used to address this problem:[247]

- In-line reheat, in which the gas is passed through a heat exchanger located in the duct work (20%)
- Indirect hot air injection reheat (15%), in which air is heated in an external heat exchanger and then mixed with the exit flue gas
- Direct combustion reheat (14%), in which hot combustion gases are generated using fuel oil or natural gas and then mixed with the exit flue gas
- Bypassing a portion of the untreated flue gas around the scrubber and then mixing that hotter gas with the scrubbed flue gas (25%)

Bypassing flue gas was the lowest cost approach, followed by in-line reheat system.[248] This is the option used by all of the scrubber systems we are analyzing, with the exception of San Miguel, which does not employ a bypass. This was most commonly accomplished by routing 5%-20% of the flue gas around the scrubbers.[249] A bypass allows the facility to route all or a portion of the flue gas around the FGD system for flue gas reheat and/or to improve operating flexibility. Some utilities originally designed the FGD system to scrub only a percentage of the flue gas while others installed bypass capability as a means of providing continuous operating capability, using alternate methods for flue gas reheat.

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[245] Henzel, D., et al, Limestone FGD Scrubbers: Users Handbook, EPA-600/8-81-017, August 1981, p. 2-27.
[246] Froelich, D., Graves, G., Eliminating Reheat from Existing FGD Systems, A Design and Economic Evaluation, Journal of the Air Pollution Control Association, v. 3 7, no. 3, March 1987, pp. 314 - 321, p. 314
[247] Froelich, D., Graves, G, p. 315. Note percentages refer to FGD systems that used any type of stack gas reheat. Some FGD systems did not employ any stack gas reheat.
[248] Henzel, D., et al, p. 2-28.
[249] Klingspor, J., Brown, G., p. 8; Maller, G, p. 4.

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Many of these early scrubber systems had/have variable bypass capability, including Monticello Unit 3; Martin Lakes 1, 2, and 3; and Sandow 4.[250] Variable bypass is used to adjust for different operating conditions, such as to maintain minimum stack temperature, adjust for variations in coal sulfur levels, and/or to maintain compliance with permits. Variable bypass was accomplished by adjusting the position of louver-type dampers on each scrubber tower, based on measurements of stack temperature, bypass fan parameters, and bypass damper position indicators.

Partially bypassing the scrubber reduces the overall scrubbing efficiency, as not all of the flue gases are treated. Consequently, one way to improve SO_2 removal efficiency is to eliminate the bypass and route 100% of the gases through the scrubber. When the bypass/reheat is eliminated, the amount of gas to be treated increases, the gas velocity decreases, and the gas density increases, resulting in system pressure losses of 5% to 10%, compared to dry operation.[251] This requires that two technical issues be addressed.[252]

First, the scrubber must have adequate capacity to handle the increased gas volume and be able to operate at higher flue gas velocities, which can cause problems with existing equipment such as the mist eliminators and stack. Scrubber capacity is generally not an issue if a scrubber system was designed with a spare absorber or spray level, which was common with many early scrubbers due to uncertainty about performance. This is probably not an issue for one of the subject Texas facilities (Limestone) as it was designed with multiple units plus a spare, which likely provides adequate capacity to handle bypassed gases. Absent a suitable spare, the existing scrubber may have to be modified to accommodate the higher flow, including replacement of the mist eliminators.

Second, existing stacks on currently scrubbed units are designed for hot dry flue gases with a higher gas velocity (~100 ft/sec) in the liner than new wet stacks. The stack downstream of a wet scrubber without bypass or reheat is a "wet stack", which exhausts saturated, scrubbed flue gas that contains droplets from mist-eliminator carryover. Thus, a new or modified mist eliminator and stack are usually required to accommodate the highly corrosive, saturated flue gas. The wet stacks must be designed using corrosion-resistant material and a gas velocity of 55 to 75 ft/sec to prevent condensed moisture from being carried out the top of the stack.[253] As mentioned above, when the bypass is eliminated, corrosive moisture condenses on downstream equipment that was not originally designed for these conditions, including scrubber outlet, ducts, bypass dampers, expansion joints, and the stack.

The cost of converting from dry to wet stack operation depends upon the existing materials used in these components. Moisture condensation within a stack designed for dry use can cause

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[250] Supplied June 17, 2014 by Luminant, in response to request for information under Section 114(a) of the CAA, dated May 20, 2014.6/17/14.
[251] Revised Wet Stack Design Guide, Electric Power Research Institute (EPRI), 2012 Technical Report, Final Report, December 2012, p. 3-2.
[252] Maller, G., et al, p. 4.
[253] DePriest, W., Gaikwad, R., Economics of Lime and Limestone for Control of Sulfur Dioxide, p. 9; Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent and Lundy, p. 25; EPRI 2012, Table 2-1. Froelich, D., Graves. G., p. 317.

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severe damage, as these stacks are typically lined with carbon steel or grouted brick. Considering the latter, moisture migration through the grout would corrode metal liner bands, weakening the stack and eventually resulting in stack failure. An acid-resistant brick liner may require no changes at all, while a carbon steel liner would require an alloy lining or other protection. Only the stack drainage system would likely have to be improved for acid brick lined stacks.[254]

The conversion of a dry stack to wet operation must address several issues that were not present when a bypass or reheat was used. Some of these issues include:[255]

- Stack liquid discharge;
- Plume downwash and icing;
- Corrosion/chemical attack;
- Stack height;
- Stack-liner geometry and material of construction;
- Liner-breach geometry;
- Stack liner geometry and material of construction;
- Gas velocity in the liner; and
- Liquid-collection devices and drainage.

A critical design consideration in converting a dry stack to wet operation is whether the existing liner and ductwork material can withstand the reduced temperatures and wet conditions of wet operation and whether the liner-gas velocity will result in droplet re-entrainment from the stack wall.[256] These issues may be addressed by modifying the existing stack or replacing it with a new "wet" stack. Mist eliminators, designed to reduce liquid carryover and slurry to downstream ductwork and the stack, must often be modified when the bypass is eliminated to facilitate wet stack operation.[257] These issues are further discussed in Section 7 concerning the costs of scrubber upgrades.

Relining a stack has become a common upgrade to power plants. As a general indicator of the scale of stack lining projects, Johnson[258] reports that 126 stack liner projects using Fiberglass Reinforced Plastic (FRP) kicked off in the 2004-2008, inclusive timeframe. This includes a number of facilities in Texas: Fayette Units 1 and 2, J.K. Spruce Unit 2, Sandow Unit 5, and Oak Grove Units 1 and 2. FRP competes with various steel alloys as a stack lining material and thus represents only a portion of the total stack lining projects.

As an alternative to relining an existing dry stack for conversion to wet operation, operators can choose to build a new stack. However, this the most costly of these options.

6.3.2 Optimization of Liquid/Gas Ratio

[254] Maller, G., p. 4; See for example, http://www.hadek.com/project-reports/san-juan-power-station
[255] EPRI, 2012. Ibid., p. 1-2.
[256] EPRI 2012, p.. 1-3.
[257] EPRI, Sec. 2.3.1.
[258] Johnson, T., et al, The Rapid Growth of Fiberglass Reinforced Plastic (FRP) in FGD Systems, 2011, Table 3.

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The liquid-to-gas ratio (L/G ratio) is a sizing criterion for absorbers that compares the slurry recirculation rate to the flue gas flow rate. It is the ratio of the amount of limestone slurry expressed in gallons per minute to the amount of untreated flue gas in thousands (1000s) of actual standard cubic feet per minute (gpm/1000 acfm).[259] Increasing the L/G increases the alkalinity available per pass, which increases the SO_2 removal efficiency. The amount of flue gas is fixed by the boiler, so the L/G ratio is increased by increasing the amount of limestone slurry. This is typically varied by changing the number of operating recycle pumps.

In a conventional scrubber, the amount of slurry is increased by replacing an existing pump with a larger model, increasing the number of slurry recycle pumps and spray headers, upgrading the motors in existing recycle pumps, installing new gear reducers to allow the pumps to operate at higher impeller speed, or reducing the pump head by, for example, replacing high-pressure nozzles with low pressure nozzles.[260]

Sargent & Lundy notes[261] in a wet FGD evaluation that included 2.0 and 4.72 lb/MMBtu SO_2 coals, that most of the scrubbers installed in Phase 1 of the CAA title IV program (1995) were designed for and achieved 95% efficiency with L/Gs of 90-130 and inlet sulfur dioxide up to 8 lb/MMBtu. Demonstrations and testing by the major FGD process developers, including Alstom, Mitsubishi, Babcock & Wilcox, and Wheelabrator, have shown that a 130 L/G is adequate to achieve 98% efficiency in a typical open-spray tower design on the 4.72 lb/MMBtu inlet SO_2 basis (high-sulfur coal case) of this work. This is further verified by recent guarantees offered by FGD vendors for new unit applications.

6.3.3 Gas-Liquid Contact Improvements

SO_2 removal in a wet scrubber is controlled by the amount of SO_2 that can be absorbed per unit volume of recirculated slurry. SO_2 absorption is limited by the amount of solid and liquid phase alkalinity provided in each gallon of slurry. The absorption is also a function of the contact time between slurry and SO_2 as well as the absorber design, which determines the gas-slurry contact area. In a spray tower, the most common type of scrubber, flue gas typically enters horizontally and turns 90 degrees into a vertical open cylindrical vessel with multiple levels of spray headers. The flue gas is first cooled and saturated with slurry. The saturated flue gas then flows upward through the absorber spray zone, where slurry is sprayed countercurrent to the flue gas.

The scale models used to design early scrubbers largely ignored the interaction of flue gas and slurry. The impact of spray nozzles on flue gas distribution was poorly understood and often ignored. Thus, the effect of nozzle spray angle; spray coverage as a function of nozzle size, type, density and pressure; and the impact of wall sneakage were typically not modeled.[262]

Thus, maldistribution of flue gas across the cross section of the absorber is a common cause of

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[259] Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent & Lundy.
[260] Klingspor, J., Brown, G.
[261] Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent and Lundy, p. 10.
[262] Klingspor, J., p. 101.

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poor performance in vintage scrubbers. This is caused by high velocity flue gas entering the absorber, which causes it to hug the walls of the absorber, bypassing the spray headers. This effect is commonly known as "gas sneakage" and can be minimized or eliminated through the installation of various mechanical devices.[263] Gas sneakage also occurs around nozzles inside the absorber.

The skewed flow distribution in the absorber inlet often generates flue gas recirculation zones that cause buildup of solids. Similarly, a skewed flue gas distribution at the absorber outlet duct often leads to excess mist eliminator carryover, scaling of the absorber outlet duct, and stack rain issues.[264] These factors place a limitation on the maximum removal efficiency that can be achieved for a given absorber.

Poor recycle spray header design was another common problem in older FGD systems. The early designs used narrow-angle nozzles and a low nozzle density.[265] This resulted in non-uniform and incomplete spray coverage. Spray towers use several levels of spray nozzles that scrub the flue gas as it moves upward through the absorption tray and spray zone. However, these spray levels are usually not sufficient by themselves to adequately distribute flue gas at the base of the spray zone.[266] There are often significant holes in the spray coverage over the cross-sectional area of the absorber due to a tendency in early scrubbers to use a small number of relatively large spray nozzles. This problem is especially significant along the walls of the absorber as gas flows tend to be higher there, or in the vicinity of internal support members. This results in poor gas-liquid contact because the gas tends to flow where the spray density and gas-side pressure drop are the lowest, contributing to gas sneakage.

Incomplete spray coverage and gas sneakage can be eliminated by improving gas/liquid contact and thus the SO_2 removal efficiency with the goal of achieving a uniform distribution of slurry and gases across the scrubber diameter. Thus, upgrades typically must address uneven flow distribution issues, poor gas-liquid contact, and poor mixing in the reaction tank. This can be achieved by improving flow distribution using turning vanes, perforated plates, and wall rings; improving gas liquid contact using devices such as sieve trays, improved spray nozzle layout, and double hollow cone nozzles; and chemistry modification, including performance additives and conversion to forced oxidation. The specific option depends upon a range of factors such as availability of space for a tray or packing and availability of fan power to overcome additional pressure drop.[267]

Wall Baffles

Wall baffles or liquid distribution rings are widely used to prevent gas sneakage down the sides of the absorber vessels. They are sloped downwards to re-inject wall slurry into the interior of

[263] Klingspor, J., Brown, G.; Maller, G., et al.
[264] Klingspor, J., p. 102.
[265] Klingspor, J. 2012, p. 102 and Figures 2 and 3.
[266] See, for example, Wet Flue Gas Desulfurization (FGD) Systems Advanced Technology for Maximum SO_2 Removal, Babcox and Wilcox, 2007, p. 6.
[267] Klingspor, J., 2012; Klingspor, J., Brown, G.; Maller, G., et al; Moretti, A., State-of-the-Art Upgrades to Existing Wet FGD Systems to Improve SO_2 Removal, Reduce Operating Costs and Improve Reliability, Power-Gen Europe, June 3-5, 2014.

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the absorber where there is a greater chance of interaction with recycle spray droplets. They also promote more thorough mixing of flue gas, ensuring no areas of high SO_2 concentration. These baffles are placed between spray levels. Wall baffles have been used in many scrubber upgrades, including both round and rectangular absorber towers as well as large and small towers. [268] These rings result in improved performance with no increase in power consumption or pressure drop.[269]

Trays

Perforated trays or counter flow trays can be used to improve the gas-liquid contact and distribution of flue gas across the tower. The gases rise through the absorber, contacting a froth of slurry on the tray. This provides increased SO_2 removal by creating additional surface area obtained from liquid holdup on the tray. Trays uniformly distribute gas and create a bubbling zone that improves gas-liquid contact, yielding high SO_2 removals at a lower overall L/G. Adequate space and improved structural support are required to add a tray to an existing open spray scrubber or an additional tray to an existing tray scrubber.[270]

A tray is a much more efficient contact device than a slurry spray.[271] This is because the tray creates more surface area between the slurry and the gas. The limestone dissolution on the tray can be as much as 50% of the dissolution in the entire absorber. The improvement in SO_2 removal by adding a tray is very similar to adding liquid distribution rings or an additional spray level. A tray provides about the same removal efficiency as one spray header without requiring any of the cost and complexity of a recycle pump and spray header system.[272] The benefits of the absorber tray compared to an additional spray level include:

- Reduced liquid to gas ratios
- Increased absorption for the same L/G
- More uniform gas distribution due to back-pressure from tray
- Fewer recirculating pumps
- Fewer spray headers
- Reduced pump maintenance
- Increased particulate removal
- Corrects gas distribution problems in the lower part of the absorber spray zone
- Protects the inlet duct from scaling
- Provides the lowest cost approach to a FGD upgrade
    - Provides a maintenance platform that avoids draining the reaction tank to gain access to the spray headers and mist eliminators.[273]

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[268] Maller, G., et al, Table 1 and pp. 4-5.
[269] Klingspor, J., Brown, G.
[270] Wet Flue Gas Desulfurization (FGD) Systems Advanced Technology for Maximum SO_2 Removal, Babcox and Wilcox, 2007.
Silva, A., et al, WFGD Case Study - Maximizing SO_2 Removal by Retrofit with Dual Tray Technology, Presented to: EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollutant Control Mega Symposium, August 28-31, 2006.
[271] Steam Its Generation and Use, The Babcox & Wilcox Company, Edition 41, 2005, p. 35-6.
[272] Klingspor 2012, p. 104.
[273] Klingspor 2012, p. 104.

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A tray will significantly increase the gas-side pressure drop and thus requires adequate fan capacity. The exact amount is a function of design and operating conditions, but is typically on the order of 1.5 to 2.5 in-wc.[274] However, the additional fan power required from the increased gas-side system pressure drop due to the tray is typically offset by a reduction in pumping power from the lower L/G (i.e., less slurry recycled) required to achieve a given SO_2 removal.[275] The savings in recycle pump power will offset the penalty of increased absorber pressure drop (i.e., pump versus fan power).[276] For moderate SO_2 removal improvements, a tray can allow the use of one less spray level and spray pump per absorber, reducing operating and maintenance costs.[277]

Trays are subject to plugging and scaling if scrubber chemistry is not controlled carefully, and trays are less attractive if absorber gas velocity is increased. However, they are desirable if space is limited, when efficient spray header designs are not present, and to correct skewed gas distribution profiles.[278] More than one tray can be employed to optimize the gas-slurry contact. Babcock and Wilcox, for example, report that scrubber efficiency can be improved by adding a second tray.[279] Adding a second tray increases contact time between SO_2 and slurry, which increases SO_2 removal efficiency.[280]

Spray Headers

The recycle spray header design of many older scrubbers results in incomplete spray coverage, especially near the walls where gas flows tend to be higher. These older designs have gaps or openings in the spray pattern that allow flue gas to bypass the spray zone without contacting the slurry. Many of these gaps are on the outside of the absorber, near the absorber walls and provide a direct path for the flue gas to bypass the slurry spray.[281] This results in poor gas-liquid contact which limits maximum removal efficiency.

The spray headers can be replaced with a high-efficiency spray header that uses a high nozzle density and wide-angle nozzles. The older spray header designs also used a support system that was prone to breakage, resulting in header section failing and falling to the bottom of the absorber. Replacing the headers with a modern, self-supporting design reduces maintenance costs and outage time.[282] A high efficiency spray header in combination with double hollow cone nozzles can substantially improve performance, on average proving about a 40% increase in performance.[283]

Many state-of-the-art nozzle designs are available to upgrade scrubber performance. Bi-

[274] Maller, G., et al, Improving the Performance and Reliability of Older FGD Systems, Mega Symposium, August 2010.
[275] Moretti, A., 2014, p. 4.
[276] Staehle, R., Upgrading Your Wet FGD System, Marsulex, October 2008.
[277] Moretti, A., p. 4.
[278] Maller, G., et al, p. 3.
[279] Silva, A., et al.
[280] Moretti, A., p. 5.
[281] Moretti, A., p. 4, Fig. 4.
[282] Moretti, A., p. 5.
[283] Klingspor, J., 2012, p. 103.

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directional nozzles can be installed regardless of the original design, which provide wider-angle spray cones to provide complete coverage of the spray zone and increased gas-liquid contact. Side-by-side double hollow cone spray nozzles can be used to improve droplet interaction (secondary atomization), thus enhancing removal performance.[284]

These types of changes ensure a high degree of gas-liquid contact with reduced chance for gas sneakage and can significantly improve SO_2 removal efficiency and reduce O&M costs. New spray headers and/or new nozzles have been used in many scrubber upgrades,[285] including Fayette Unit 3.

6.3.4 Improving FGD Chemistry

SO_2 removal can be increased by improving slurry reactivity. There are many ways to do this, including reducing limestone grind size, eliminating limestone blinding, converting to forced oxidation, optimizing operating pH and using performance additives, discussed elsewhere. The easiest way to increase SO_2 removal efficiency in any scrubber is to increase the slurry pH. The SO_2 removal typically responds very quickly to an increase in pH. An increase in slurry pH is typically achieved by increasing the reagent feed rate, which causes limestone utilization to deteriorate. This deterioration can be offset by decreasing grind size, which allows operation at a higher pH while maintaining limestone utilization.[286]

Existing units that use natural or inhibited oxidation can be converted to forced oxidation. This process converts calcium sulfite to calcium sulfate and improves scrubber operating while providing a marketable gypsum byproduct.[287]

Limestone reagent fineness has a significant effect on limestone utilization, which in turn has a significant effect on FGD SO_2 removal efficiency. The finer the grind, the higher the removal efficiency as the fineness of the limestone affects the rate at which it dissolves in the reaction tank.[288] The general rule of thumb today is 95% passing a 325-mesh screen.[289] Increasing the percentage that passes a 325-mesh screen increases the rate of limestone dissolution, which increases the removal efficiency. The majority of the subject FGD systems, those built before about 1995, were designed to produce limestone coarser than this optimum.[290]

Limestone reactivity is also important to scrubber operation. The chemical makeup of the limestone exerts a large influence on scrubber efficiency. In general, limestone with 94% or

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[284] URS, Upgrade of Wet FGD Systems, Available at: http://urs-processtechnologies.com/wp-content/uploads/2013/02/FGD-Upgrade-Final-2_2013.pdf.
[285] See for example, Maller, G., et al, p. 3.
[286] Klingspor, J., Brown, G.
[287] Wet Flue Gas Desulfurization (FGD) Systems Advanced Technology for Maximum SO_2 Removal, Babcox and Wilcox, 2007, p. 4.
[288] Maller, G., Wet FGD Chemistry and Performance Factors, Presented at 2008 Power Gen Conference, December 1, 2008, pdf 48.
[289] LG&E Services Company Contract No. 501654, Mill Creek FGD Performance Upgrade Study, Babcock Power Environmental, February 2011, p. 53.
[290] Seward, R., Brame, K., A Review of Methods for Increasing Limestone Reagent Fineness for Flue Gas Desulfurization, Proceedings Tenths Symposium on Flue Gas Desulfurization, Vol. 1, February 1987.

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more calcium carbonate are very reactive, if properly ground. However, limestone with more than about 10% dolomite ($MgCO_3 \cdot CaCO_3$) are not desirable as the dolomite is rather non-reactive and tends to pass through the FGD untouched and thus does not participate in the chemical reactions that remove SO_2.[291]

6.3.5 Use of Organic Acids to Improve Performance

The use of organic acid additives, such as dibasic acid (DBA) and adipic acid, improves SO_2 removal efficiency by reducing the L/G ratio. Additional benefits of organic acids like DBA (beyond enhanced SO_2 removal efficiency) include reduced power consumption, lower spray pump flow, lower pressure drop, reduced limestone consumption, reduced overall operating costs, and reduced capital costs. They are also used as a backup, to allow a scrubber to be designed without a spare spray header and pump, and to allow increases in coal sulfur content.

The least expensive additives are organic acids that buffer the slurry liquor by acting as an acid or base to help dissolve limestone or to directly neutralize the sulfurous acid formed by the absorption of SO2.[292] Dibasic acid (DBA) is the most economical acid. It is a mixture of succinic, glutaric and adipic acids and is a byproduct in the manufacture of nylon. They can be used continuously or to maintain high SO_2 removal efficiencies if a recycle pump is taken out of service. They work by buffering the pH at the gas-liquid interface, thus reducing back pressure of SO_2 and by lowering the liquid-film resistance to mass transfer. DBA and formate are the most commonly used additives due to cost.[293]

The incorporation of organic acids into an upgrade can significantly reduce the capital, operating, and maintenance cost of the scrubber. This occurs because organic acids increase limestone absorption and stabilize the pH, reducing the liquid-to-gas ratio while maintaining the required SO_2 removal efficiency or increasing the removal efficiency for a given liquid-to-gas ratio. DBA has been reported to provide the equivalent of spraying an extra 20 gpm/1000 cfm of limestone slurry. Thus, increasing SO2 removal from 92% to 95% can either add 25% to the pump energy input or buy an organic chemical.[294]

Their benefit over ultra-fine grind limestone is that the effect is immediate. There is no turnover of a slurry tank prior to the organic acid impacting absorber performance. However, their disadvantages include additional operating cost, uncertainty in long-term supply and pricing of DBA byproducts, possible contamination of gypsum by-product, and increased wastewater treatment cost.[295]

The U.S. Department of Energy and the Electric Power Research Institute conducted full-scale testing, process modeling, and economic evaluations of six utility flue gas desulfurization systems to evaluate low capital cost upgrades for achieving up to 98% SO_2 removal efficiency in

[291] Buecker, B., Important Concepts of Wet-Limestone Flue Gas Desulfurization Energy-Tech Magazine, October 2008, http://www.energy-tech.com/article.cfm?id=21789; PEI Associates, 1985.
[292] Moretti, A., p. 5.
[293] Klingspor, J., and Brown, G.
[294] Invista DBA Will be Available to Improve FGD Efficiency, FGD & DeNOx Newsletter, No. 393, January 2011.
[295] Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent and Lundy. p. 5.

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existing FGD systems. These studies mostly involved using performance additives in the FGD systems, but other low cost options were evaluated using an EPRI model. The tested units are: Big Bend,[296] Merom,[297] Pirkey,[298] Gibson,[299] Elrama, and Kintigh.[300] These tests demonstrated the efficacy of organic acid additives. Many facilities add acid injection systems based on these and other test results, including (can we list the Texas units that use them?)

The addition of an organic acid system to an existing scrubber (that was not designed taking it into consideration) would increase the costs by a very small amount compared to the rest of a scrubber system. For instance, Invista reports the following based on modeling a 566 MW boiler using eastern bituminous high-sulfur coal (3% sulfur, 12,720 BTU/lb heating value) and 90% SO_2-removal efficiency:[301]

> Modeling shows that operational and maintenance costs of a wet limestone scrubber can be reduced by about 2% (about $200,000/year) when using DBA, including the cost of the DBA additive. The increased SO_2 scrubbing efficiency using DBA translates into about a 15% reduction in limestone use, a 1% reduction in steam, a 1% reduction in solid waste disposal costs, and a reduction of about 17% in power usage. Payback time, based on SO_2 credit prices of $200/ton, for the capital required to retrofit an existing wet limestone scrubber for DBA addition (storage tank, pump, piping) ranges from 5 months to about two years, depending on operating strategy (i.e. maintain SO_2 efficiency and reduce operating costs vs. improve SO_2 efficiency and profit from emission credits).

Consequently, the wastewater treatment system is the only item that might increase in capital and operating costs because organic acids increase the Basic Oxygen Demand (BOD) and Chemical Oxygen Demand (COD) of the wastewater, requiring biological treatment.[302] Wastewater treatment is typically a small fraction of the total cost of a scrubber.

6.3.6 Related Capital Improvements

The improvements discussed above generally require modifications to other facility components including the following:

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[296] Radian Corp., Results of High Velocity Tests at Tampa Electric Company's Big Bend 4 FGD System, Topical Report, October 15, 1997.
[297] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, Evaluation of High Efficiency Test Results at Hoosier Energy's Merom Station, April 22, 1996.
[298] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, Results of DBA and Sodium Formate Additive Tests at Southwestern Electric Power Company's Pirkey Station, May 30, 1996.
[299] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, PSI Energy' s Gibson Station High SO_2 Removal Efficiency Test Program, May 20, 1996.
[300] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, Results of Sodium Formate Additive Tests at New York State Electric & Gas Corporation's Kintigh Station, February 14, 1997.
[301] The Role of Dibasic Acid (DBA) in Wet Limestone Flue Gas Desulfurization. Accessed from http://intermediates.invista.com/e-trolley/page_1035/, 7/7/2014.
[302] Riffe, M., et al, Wastewater Treatment for FGD Purge Streams, Paper # 33, Presented at the MEGA Symposium 2008 Baltimore, MD, August 25 – 28, 2008; INVISTA DBA Dibasic Acid For Flue Gas Desulfurization November 17, 2010.

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- A new or modified stack
- A new or modified absorber if the original FGD did not include a spare
- A new or modified limestone slurry preparation system
- A new or modified dewatering system
- Upgraded flue gas system

When SO_2 removal is increased, the amount of wet FGD byproducts will increase. If the upgraded FGD system uses natural oxidation, the disposal pond may reach capacity. This usually requires conversion to forced oxidation to eliminate need for disposal ponds

If limestone consumption is increased to improve SO_2 removal, reagent preparation and dewatering systems may be undersized. In most cases, higher SO_2 removal requires finer grind than delivered by older system. Thus, existing milling systems may have to be upgraded to handle the new quantity and grinding requirements.[303]

Older FGD systems used thickeners for primary dewatering and rotary drum filters for secondary dewatering. Thickeners are prone to maintenance problems. These thickeners are difficult to operate when an FGD is converted to forced oxidation due to rapid settling of gypsum, requiring replacement with hydroclones, which are used in modern FGD systems.[304]

Older FGD systems used thickeners for primary dewatering and rotary drum filters for secondary dewatering. Thickeners are prone to maintenance problems. These thickeners are difficult to operate when an FGD is converted to forced oxidation due to rapid settling of gypsum, requiring replacement with hydroclones, which are used in modern FGD systems. The rotary drum filters also may not have adequate capacity to handle increased SO_2 removal. The capacity constraint can be addressed by increasing the amount of time per day that the rotary drum filter operates; replacing the rotary drum filter with new generation rotary drum technology; or replacing them with vacuum belt filters.[305]

7 Scrubber Upgrade Analyses

We have conducted a cost analysis for upgrading the scrubbers for those facilities listed in Table 1 that currently employ a scrubber. As we discussed above in Section 6.1, we have calculated the SO_2 removal efficiency of these scrubbers as follows:

Table 18. Existing Scrubber SO_2 Removal Efficiencies

[303] Harper, G., Hagan, M.A., Dyer, P., and Breuer, W. J., Increasing Capacity of Existing Limestone Grinding Systems While Reducing Grind Size, Burns & McDonnell Technical Paper, 2006.
[304] Moretti, A., p. 8.
[305] Moretti, A., pp. 10-11.

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Facility	Unit	Bypass?	2009-2013 Average SO_2 Removal Efficiency (%)
Sandow 4	1	Y	75.7
Monticello	3	Y	60.0
Martin Lake	1	Y	69.2
Martin Lake	2	Y	71.9
Martin Lake	3	Y	69.8
Limestone	1	Y	78.1
Limestone	2	Y	77.0
San Miguel	1	N	94.0
W. A. Parish	8	Y	84.0

7.1 Section 114(a) Information Requests

In order to assess the potential range of options available to upgrade the scrubbers in the facilities listed above, we must have an understanding of what upgrades may have already been performed. Most of this information is not available publically. Therefore, for each one of these units, except for San Miguel, we have requested information under authority granted to us under Section 114(a) of the Clean Air Act, which included the following:

a. State whether any of the scrubbers have a bypass.

b. If a unit's scrubber has a bypass, describe whether the percentage of flow going to the scrubber is varied in practice by directly adjusting the bypass or if the bypass is fixed. State how and under what circumstances this is accomplished and monitored.

c. For any scrubber with a bypass, provide the percentage flow that has bypassed the scrubber, based on a monthly average, for the years 2008 through 2013, inclusive.

d. State the maximum SO_2 removal efficiency of each EGU's scrubber system, based on full EGU operating capacity, assuming the optimum amount of reagent usage (including dibasic acid or other organic acids), and the type of coal being burned. Either report this value assuming 100% of each coal type burned, or by the sulfur content of the coal being burned. In reporting this value, do not multiply the efficiency of the scrubber by the percentage of flow going to the scrubber – report only the efficiency of the scrubber.

e. State the maximum percentage of flow at maximum EGU operating capacity that can be directed to the scrubber and treated at the scrubber's maximum efficiency. Either report this value assuming 100% of each coal type burned, or by the sulfur content of the coal being burned.

f. Describe what improvements have been made to the efficiency of the scrubber system since its initial installation, including but not limited to reagent handling and milling, addition of dibasic acid or other organic acids, bypass elimination, absorber (e.g., trays,

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liquid distribution rings, sprayers, recycle pumps, etc), stack lining, etc.

i. Provide the capital costs for these projects and the dates when each upgrade was installed and became operational.

ii. Provide the percentage improvement in the scrubber system for each of these upgrades that were separately installed.

Because the San Miguel facility provided similar information in response to emails and telephone requests, we did not send them a request for information under Section 114(a). All of these units complied with our Section 114(a) requests, but most of the information provided was claimed as Confidential Business Information (CBI) under 40 C.F.R. Part 2, Subpart B. We were able to review and analyze that information to assist us in calculating the costs of upgrading the scrubbers for those units. However, because our analyses largely depends on that information and is thus CBI itself, we can only present a summary of it here. Since the San Miguel facility did not assert any CBI information, our assessment of its scrubber is presented here and the information that San Miguel's provided is in our docket in full.

7.2 Approach to Scrubber Upgrade Cost Analyses

Each of the units listed in Table 18 had contracted with engineering firms (sometimes multiple engineering firms) and conducted multiple SO_2 scrubber upgrade cost analyses, which we were able to review as a result of our Section 114(a) requests. Many of these cost analyses were very detailed. Most of these analyses occurred in the 2004 – 2006 timeframe. They were done because the facilities had concluded that considering the price of SO_2 allowances, upgrading their scrubbers would result in an annual cost savings as they could either stop buying SO_2 allowances, or even sell excess SO_2 allowances. In addition, in a number of cases, the companies had concluded that upgrading various pieces of equipment related to their SO_2 absorbers that either required constant maintenance, or due to their poor initial design caused other problems, would additionally result in annual cost savings.

These scrubber upgrades concentrated on optimizing the unit's total SO_2 removal, with the primary goal being the elimination or minimization of the scrubber bypasses. In most cases, these cost analyses included the following:

- Additional induced draft fan capacity and upgrading of the electrical distribution system to handle the additional load.
- Upgrading of the absorber(s) spray header to more efficient designs.
- Using all available slurry recycle pumps.
- Replacement of the mist eliminators with more efficient designs.
- Use of absorber trays or liquid distribution rings.
- Flow studies to identify flow maldistribution across multiple absorbers and the use of turning vanes (flow straightening baffles used in duct work) to correct this situation.
- Conversion to wet stack operation, which in most cases involved the demolition of the existing stack and the construction of a new wet stack.

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In addition, some of the units' cost analyses included either upgrading or the addition of new DBA systems and forced oxidation systems.

Many units completed some of this work, which usually involved the upgrading of absorber internals (e.g., spray headers, recycle pumps, trays, liquid distribution rings, etc.). Many also partially reduced their scrubber bypasses because upgrading their absorbers allowed them to cost effectively treat more flue gas. None, however, with the exception of San Miguel, totally eliminated their scrubber bypasses.

Our approach to analyzing the cost of a unit's scrubber upgrade was the same in all cases except for San Miguel and consisted of the following basic steps:

- Conduct a literature search of published information from all available non-proprietary sources on any work conducted at the subject facility.
- Review the responses to our Section 114(a) request.
- Construct a timeline of all SO_2 pollution control equipment installations or upgrades, noting what work had already been done so it could be eliminated from our cost analysis.
- Determine what additional equipment is necessary in order to eliminate the SO_2 scrubber bypass and ensure that the unit's overall SO_2 removal efficiency is at least 95%.
- Use the company's scrubber upgrade analyses to estimate the capital and operating costs of eliminating the SO_2 scrubber bypass and ensure that the unit's overall SO_2 removal efficiency is at least 95%.
- Escalate the capital and operating costs to 2013 dollars.
- Annualize the capital and operating costs and calculate the cost effectiveness ($/ton) using the same methodology used in our DSI and scrubber retrofits in Sections 3, 4, and 5, above.
- Weigh the cost of the scrubber upgrades against the visibility improvement at the affected Class I areas.

We discuss how we analyzed San Miguel for potential scrubber upgrades section 7.3.1 below.

7.3 Summary of Scrubber Upgrade Cost Results

With the exception of San Miguel, we are limited in what information we can include in this section, because in developing our scrubber cost estimates we used information that was claimed as CBI. This information was submitted in response to our Section 114(a) requests. We can therefore only present the following summary.

With the exception of San Miguel, we propose to find that for all the units we analyzed:

- The absorber system had either already been upgraded to perform at an SO_2 removal efficiency of at least 95%, or it could be upgraded to perform at that level using proven equipment and techniques.
- The SO_2 scrubber bypass could be eliminated, and the additional flue gas could be treated by the absorber system with at least a 95% removal efficiency.

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- Additional modifications necessary to eliminate the bypass, such as adding fan capacity, upgrading the electrical distribution system, and conversion to a wet stack could be performed using proven equipment and techniques.
- The additional SO_2 emission reductions resulting from the scrubber upgrade are substantial and cost effective.

A summary of our analyses is as follows:

Table 19. Summary of Scrubber Upgrade Results

Unit	2009-2013 3-yr Avg. SO_2 Emissions (eliminate max and min) (tons)	SO_2 Emissions at 95% Control (tons)	SO_2 Emissions Reduction Due to Scrubber Upgrade (tons)	SO_2 Emission Rate at 95% Control (lbs/MMBtu)
W. A. Parish WAP8	2,586	836	1,750	0.04
Monticello 3	13,857	1,571	12,286	0.06
Sandow 4	22,289	4,625	17,664	0.20
Martin Lake 1	24,495	3,706	20,789	0.12
Martin Lake 2	21,580	3,664	17,917	0.12
Martin Lake 3	19,940	3,542	16,389	0.11
Limestone 1	10,913	2,466	8,446	0.08
Limestone 2	11,946	2,615	9,331	0.08
Total SO_2 Removed			**104,572**	

We calculated the cost effectiveness for each of these units. Because those calculations depended on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost effectiveness was less than $600/ton. We invite the facilities listed above to make arrangements with us to view our complete cost analysis for their units.

Appendix C: List of Materials from EPA Docket ID: EPA-R06-OAR-2014-0754

As technical background or added technical support for this proposed rulemaking, this rulemaking record incorporates by reference and considers to be part of this rulemaking the following documents, even as they are not necessarily re-uploaded to the BART rulemaking docket at regulations.gov:

Doc. No. EPA-R06-OAR-2014-0754-0001 through Doc. No. EPA-R06-OAR-2014-0754-0036
Doc. No. EPA-R06-OAR-2014-0754-0087.

This incorporation includes all underlying attachments for these documents. Certain materials claimed as confidential business information (CBI) from the prior rulemaking action are also part of the non-public docket for this rulemaking.

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Technical Support Document

for the

Texas Regional Haze BART Federal Implementation Plan
(BART FIP TSD)

Prepared and Reviewed by:

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(Revised December 2016, see Errata- BART Modeling TSD for details)

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Texas Regional Haze BART FIP Technical Support Document

1 Introduction

In our previous action,[1] we determined that due to the CSAPR remand, it was not appropriate to rely on CSAPR as an alternative to SO_2 and NOx BART for Electricity Generating Units (EGUs) in Texas. As a consequence, we took no action on EGU BART.[2] Our proposed FIP would fill that regulatory gap for this requirement by assessing BART for Texas EGUs. This document describes how we propose to accomplish that objective.

2 Our Evaluation of the Texas Infrastructure SIP Submittals for Interstate Visibility Transport

Section 110(a)(2)(D)(i)(II) of the CAA requires that states have a SIP, or submit a SIP revision, containing provisions prohibiting emissions from within a state from interfering with measures required to be included in the implementation plan for any other state under the provisions of Part C of the CAA protecting visibility. To determine whether the CAA Section 110(a)(2)(D)(i) requirement for visibility protection is satisfied, the SIP must address the potential for interference with visibility protection caused by the pollutant (including precursors) to which the new or revised NAAQS applies. Pollutants which could interfere with visibility protection include: (1) SO_2 (which is also a precursor for $PM_{2.5}$), (2) nitrogen oxides (which includes NO_2 and are precursors for ozone and $PM_{2.5}$) and (3) particulate matter.[3] In the infrastructure SIP submittals for the ozone, $PM_{2.5}$, NO_2 and SO_2 NAAQS Texas indicated that the Regional Haze SIP fulfilled its obligation for addressing emissions that would interfere with measures required to be included in the SIP for any other state to protect visibility.

However, we gave limited disapproval to the Texas Regional Haze SIP based on its reliance on CAIR. As explained in our limited disapproval of the Texas regional haze SIP, many states (including Texas) relied on the improvement in visibility expected to result from the implementation of CAIR in developing their long-term strategy.[4] Texas relied on its own CAIR SIP as legal justification for these planned controls and did not include separate enforceable measures in its regional haze SIP to ensure the interstate visibility transport requirements were met. As CAIR has been replaced by CSAPR, we propose to determine that Texas may not rely on its regional haze SIP to ensure that emissions from Texas do not interfere with the measures to protect visibility in nearby states. With respect to interstate transport of air pollution and visibility protection, Texas' SIP submittals for the 1997 $PM_{2.5}$, 2006 $PM_{2.5}$, 1997 ozone, 2008 ozone, 2010 NO_2 and 2010 SO_2 NAAQS are deficient.

We are proposing a FIP to cure the deficiencies in Texas' Regional Haze Program concerning EGU BART. This FIP will replace reliance on CAIR with reliance on CSAPR to meet the requirements for EGU BART for NO_X in Texas. The FIP will address Texas EGU BART for SO_2 and PM on a source-specific basis. With the absence of CSAPR coverage for SO_2, we must

[1] See the discussion beginning on 81 FR 296,301 (January 5, 2016).
[2] Id. at 346.
[3] Section II.A.3 of Appendix Y to Part 51 – Guidelines for BART Determinations Under the Regional Haze Rule and 40 CFR 51.166(b)(i)(b).
[4] 77 FR 33643 (June 7, 2012).

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reevaluate what is needed in Texas to address interstate visibility transport. Our proposed FIP to address Texas EGU BART achieves significant reductions of SO_2, which exceed the reductions initially assumed under either CAIR or CSAPR. Under CAIR projections developed in 2005, Texas SO_2 emissions for 2015 were projected to be 352,000 tpy with CAIR compared to 418,000 tpy without CAIR.[5] Under CSAPR, the Texas SO_2 emission budget for Phase 2 was set at approximately 294,000 tpy with an assurance level of 347,000 tpy.[6] Our proposed FIP to address Texas EGU BART is estimated to reduce annual emissions of SO2 by approximately 194,000 tpy[7], a larger reduction than projected under CAIR or CSAPR.

In addition, our proposed FIP achieves reductions at large sources of SO_2 emissions (e.g., Monticello, Martin Lake and Big Brown), that have significant impacts on Class I areas in nearby states.[8] The BART FIP requires controls on many but not all of the sources that were controlled in our previous partial FIP for Texas Regional Haze. Our EGU BART FIP also includes proposed control requirements at some additional sources not controlled in our previous action on Texas Regional Haze. These include proposed controls for the J T Deely Units 1 and 2, Parish Units 5 and 6, Welsh Unit 1, and Harrington Units 1 and 2.

We are proposing to find that our proposed EGU BART FIP is adequate to prevent interference with measures required to protect visibility in other states for the first planning period.[9] We, therefore, propose a FIP to fully address Texas' interstate visibility transport obligations for the six NAAQS (1997 8-hour ozone, 1997 $PM_{2.5}$, 2006 $PM_{2.5}$, 2008 8-hour ozone, 2010 1-hour NO_2, and 2010 1-hour SO_2) based on the source-specific requirements that will be established by our proposed FIP to address Texas EGU BART for SO_2 and PM. We also propose that reliance on CSAPR for EGU NO_X BART is appropriate to ensure NO_X emissions from Texas EGUs do not interfere with other states' measures to protect visibility. We are proposing this action based on the reasoning that our BART FIP will achieve more emission reductions than projected under CAIR or CASPR and the reductions are occurring at sources that have particularly large impacts on Class I areas outside of Texas.

3 Our Strategy for Assessing BART-eligibility.

Our BART analysis is limited to BART Category 1, fossil-fuel fired steam electric plants of

[5] https://archive.epa.gov/airmarkets/programs/cair/web/html/tx.html; Clean Air Interstate Rule Emissions Inventory Technical Support Document, March 2005 available at: https://archive.epa.gov/airmarkets/programs/cair/web/pdf/finaltech01.pdf

[6] https://www.epa.gov/sites/production/files/2016-02/documents/budgets_annualso2.pdf

[7] Sum of estimated reductions due to all proposed controls calculated from a baseline of the 2011 – 2015 five year average of the SO_2 annual emissions, excluding the maximum and minimum values.

[8] For example, CALPUFF modeling and CAMx modeling estimate that emissions from Monticello can significantly impact visibility at Caney Creek in Arkansas, with many modeled days impacted at levels exceeding 1.0 dv. See BART Screening TSD and BART Modeling TSD for summaries of modeled visibility impacts and visibility benefits from controls for each BART source.

[9] This proposed FIP for interstate visibility transport is premised on the interpretation that this requirement can be addressed even when a Regional Haze SIP is not fully approved and the FIP does not purport to correct all Regional Haze SIP deficiencies. *See e.g.* 76 FR 52388 (August 22, 2011); 76 FR 22036 (April 20, 2011); and 78 FR 14681 (March 7, 2013); *see also*, 2013 i-SIP Guidance, at page 34 (stating that EPA may find it appropriate to supplement the i-SIP Guidance regarding the relationship between Regional Haze SIPs and interstate visibility transport for future planning periods).

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more than 250 million British thermal units (BTU) per hour heat input. All other BART categories were covered in the portion of the Texas Regional Haze SIP we have already approved. We followed the BART Guidelines[10] in analyzing BART for the Texas EGUs covered in this proposal. Our analysis started with the list of BART-eligible sources provided by the Texas Commission on Environmental Quality (TCEQ) in its regional haze SIP.[11] Texas describes how it constructed its BART-eligible list in Section 9 of its SIP, and lists the sources it determined as being BART-eligible in Table 9-2. Unfortunately, Texas only listed these sources by facility and not by unit. Further complicating our analysis, Texas identified each source using its own internal account number and regulated entity number, and the source name was often not descriptive. We contacted the TCEQ in an attempt to determine if a unit-specific listing was available, but were informed that due to its records retention policy, the information was too old to have been retained. That list, filtered to include only EGUs and supplemented with more descriptive names, is shown below. We hereafter refer to this list of thirty-seven EGUs as the "Texas BART list."

Table 1. Texas List of BART-Eligible EGUs

Account	Company	Plant
BC0015L	Lower Colorado River Authority	Lower Colorado River Authority (Sim Gideon)
BG0057U	City Public Service	Sommers Deely Spruce (Calaveras)
BG0186I	City Public Service	V.H. Braunig Plant
CD0013K	AEP Texas Central Company	La Palma Power Station
CI0012D	Texas Genco LP	Cedar Bayou Station
DB0251U	TXU Electric Company	North Lake Steam Electric
EE0029T	El Paso Electric Company	Newman Station
FB0025U	TXU Generation Company LP	Valley Steam Electric
FC0018G	Lower Colorado River Authority	Fayette Power Project
FG0020V	Texas Genco LP	W A Parish Station
FI0020W	TXU Big Brown Company LP	Big Brown
GB0037T	Texas Genco LP	P H Robinson Station
GJ0043K	Southwestern Electric Power	Knox Lee Power Plant
HQ0012T	TXU Generation Company LP	Decordova Steam Electric
JI0030K	AEP Texas North Company	W.T.U.-Ft. Phantom

[10] See Appendix Y to Part 51, published as the "BART Guidelines" and the associated preamble language beginning in 70 FR 39104 (July 6, 2015).
[11] As we discuss later in our BART FIP TSD, we also performed an independent assessment of Texas' BART-eligibility determination.

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LN0081B	Xcel Energy	Jones Station
MB0116C	TXU Generation Company LP	Tradinghouse Steam Electric
ME0006A	Southwestern Electric Power Wilkes	Wilkes Power Plant
MM0023J	TXU Generation Company LP	Sandow Steam Electric
MO0014L	TXU Generation Company LP	Morgan Creek Steam
MQ0009F	Entergy Gulf States Inc	Lewis Creek Plant
NE0024E	AEP Texas Central Company	Barney M Davis Power
NE0025C	Lon C Hill Power	Lon C Hill
NE0026A	AEP Texas Central Company	Nueces Bay Power Station
OC0013O	Entergy Gulf States Inc	Sabine Plant
PG0040T	Southwestern Public Service	Nichols Station
PG0041R	Southwestern Public Service	Harrington Station
RL0020K	TXU Generation Company LP	Martin Lake Electric
TA0352I	TXU Generation Company LP	Eagle Mountain Station
TF0012D	Southwestern Electric Power	Welsh Power Plant
TF0013B	TXU Generation Company LP	Monticello Stm Electric
TG0044C	AEP Texas	San Angelo Power
TH0004D	Electric Utility Dept	Decker Creek Power
VC0003D	Victoria Power	Victoria Power
WC0028Q	TXU Generation Company LP	Permian Basin Steam Electric
WE0005G	Laredo Power	Laredo Power
YB0017V	TXU Generation Company LP	Graham Steam Electric

Our overall strategy for assessing BART-eligibility for Texas EGUs was as follows:

- Convert the Texas BART List to a unit-based list, and supplement it with additional information.
- Update the Texas BART List to account for retirements.
- Conduct a preliminary BART-eligibility assessment based on the Texas BART List.
    - Send letters requesting information (hereinafter, "Section 114(a) letters") from all facilities on the Texas BART List that appeared to be BART-eligible.[12]

[12] Clean Air Section 114(a), 42 U.S.C. § 7414, empowers the EPA, *inter alia*, to require an owner or operator of an emission source to provide information that is reasonably required to carry out any provision of the Clean Air Act (except subchapter II with respect to new motor vehicles or their engines).

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    - Follow-up with additional Section 114(a) letters, as needed, requesting additional information or documentation.
- Conduct a supplemental BART-eligibility Assessment, using U.S. Energy Information Administration (EIA) information and data to determine if any additional EGUs should be examined.
    - Send additional Section 114(a) letters to any additional EGUs that appeared to be potentially BART-eligible.
    - Follow-up with additional Section 114(a) letters, as needed, requesting additional documentation.

Below, we discuss how we performed each of those steps.[13]

3.1 Refinement of the Texas BART List

From an investigation of various information sources,[14] we noted that a number of the EGUs on the Texas BART list have since been retired:

Table 2. Known Texas EGU Retirements

Plant	Comments
La Palma Power Station	Shutdown in 2006
North Lake Steam Electric	Shutdown 2008/2009
Valley Steam Electric	Mothballed, retired in 2015
P H Robinson Station	Shutdown 2009
W.T.U.-Ft. Phantom	Shutdown 2004
Tradinghouse Steam Electric	Dismantled 2014
Lon C Hill	Mothballed 2002, shutdown 2006
Eagle Mountain Station	Shutdown 2006
San Angelo Power	Shutdown 2004
Permian Basin Steam Electric	Unit 5 retired 2010, Unit 6 retired 2015
Morgan Creek Steam	Units 2, 3, 4 Retired 2004, demolished In 2011. Units 5 And 6 retired in 2009, demolished 2012
Barney M Davis Power	Unit 2 replaced with 2 combined cycle turbines
Decordova Steam Electric	Unit 1 (Not Ct1) retired 2010, demolished in 2013

[13] The information and analysis discussed in these steps is present in the files, "TCEQ BART Analysis.xlsx," and "EIA Suppl BART Analysis.xlsx."
[14] We conducted Internet searches and consulted ERCOT and Texas PUC documents. These sources are contained within our docket for this action.

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Laredo Power	Units 1, 2, 3 demolished 2008
Nueces Bay Power Steam	Units 5 And 6 retired 2008

We subtracted the retired units from the Texas BART List.[15] We then converted the Texas BART List to a unit-based list. We did this by gathering basic information concerning the configuration of the units and their in-service dates from the Energy Information Administration (EIA)[16].

3.2 Preliminary BART-Eligibility Assessment and First Round 114 Letters

Our goal in conducting a preliminary BART-eligibility assessment was to identify which facilities on the Texas BART List should be required to conduct a BART-eligibility analysis. We first performed a preliminary BART-eligibility assessment in order to identify the units that should be required to undergo a formal BART-eligibility analysis.

The BART Guidelines define a three step test that must be followed in order to determine BART-eligibility:[17]

> Step 1: Identify the emission units in the BART categories,
> Step 2: Identify the start-up dates of those emission units, and
> Step 3: Compare the potential emissions to the 250 ton/yr cutoff.

BART-Eligibility Step 1

As the BART Guidelines note, Step 1 in the BART-eligibility test involves the identification of emission units in the BART categories. Specifically, a facility passes Step 1 of the BART eligibility test if it has at least one unit in one of the 26 BART categories. We consequently filtered our EIA data for facilities that had at least one unit with a steam component, based on the EIA data. This included units listed as "Conventional Steam Coal" Natural Gas Steam Turbine," and "Natural Gas Combined Cycle."

BART-Eligibility Step 2

Step 2 of the BART-eligibility test involves determining whether any of the units identified in Step 1 fall within the BART timeframe. Specifically, a facility passes Step 2 if any of the units identified in Step 1 were "in existence" on August 7, 1977, and began operation after August 7, 1962. The BART Guidelines define "in existence" as[18]:

> [T]he owner or operator has obtained all necessary preconstruction approvals or

[15] The revised Texas BART List appears in Tab "Potential BART-eligible" of the file, "TCEQ BART Analysis.xlsx."
[16] We used 2014 (the latest available as of the time of our assessment) EIA Form 860 data available here: http://www.eia.gov/electricity/data/eia860/index.html.
[17] 70 FR 39103, 39158 (July 6, 2005) [40 CFR Part 51, App. Y].
[18] 70 FR 39103, 39159 (July 6, 2005) [40 CFR Part 51, App. Y].

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> permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time. 40 CFR 51.301.

In order to conservatively identify any units that might satisfy Step 2 in our potentially BART-eligible test, we filtered the units that passed Step 1 for EIA "in-service" dates after 1962 to and including 1982. We went five years beyond the BART timeframe discussed above, in order to identify any units that could have begun construction within the BART timeframe, but did not become operational until afterwards. In so doing, we concluded that a reasonable construction time for a typical EGU was up to five years.

BART-Eligibility Step 3

Step 3 of the BART-eligibility test checks whether the potential emissions from units that passed Steps 1 and 2 exceed 250 ton/yr of any single visibility impairing pollutant. The remaining portions of Section 3 describe how we completed this task.

A unit's potential emissions are only limited by the unit's state air permit. We attempted to locate each unit's air permit, using the TCEQ's online Air Permits Remote Document Server.[19] However, due to the particular limitations of this service, we were unable to efficiently or reliably confirm that we had in fact found the latest version of each unit's permit. Consequently, we were unable to confidently use Texas permitting information to assess the potential emissions from the units in question, and we abandoned this investigative approach. Alternatively, we compiled annual emissions from 2000 to 2015.[20] All of the units in question passed Step 3 of the BART-eligibility test for either SO_2 or NOx (or both).

For any of the units that satisfied both Steps 1 and 2 of our potentially BART-eligible test, we requested certain information under the authority granted to us under Section 114(a) of the Clean Air Act, to assist us in determining which units were in fact BART-eligible.[21] We refer to these initial letters as "First Round 114 Letters," to distinguish them from subsequent rounds of Section 114 letters that were required. These First Round 114 Letters typically requested the following information:

1. If available, furnish copies of all completed surveys calling for information relevant to BART eligibility of the source (and associated documentation) that were previously submitted to the TCEQ in or around 2005. As discussed in Chapter 9 of the Texas Regional Haze SIP, the information that was provided in response to the survey should include, at a minimum:

[19] The TCEQ's Air Permits Remote Document Server is available here: http://www.tceq.state.tx.us/permitting/air/air_permits.html.

[20] Downloaded from the EPA Air Markets Program Data, available here: https://ampd.epa.gov/ampd/. See the tab, "Annl Emissions" in the file, "TCEQ BART Analysis.xlsx."

[21] All the Section 114(a) letters and responses are present in our docket. The pertinent responses are summarized in the file, "114 Letter Response Summary.xlsx."

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a. Your identification of equipment built or reconstructed during the applicable time period for BART-eligibility.
b. Your identification of whether the potential to emit of the site is less than 250 tons per year.
c. Your detailed survey of all operating and idle equipment at the site.
d. Your responses to questions on whether each piece of equipment at the site was built or reconstructed during the applicable time period for BART-eligibility
e. Your response to a question on whether the potential to emit of units from the applicable time period "exceeded the 250 tpy threshold for applicable emissions."

2. State whether past survey responses remain valid for the present equipment and operations of the facility. If any individual responses are no longer accurate, please identify what has changed with a supporting explanation and/or supporting documentation.

3. State the BART-eligibility of any sources under Category 1, Fossil-fuel fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input, for Sulfur Dioxide (SO_2) and Nitrogen Oxides (NOx) with an analysis that applies the steps that are outlined in the BART Guidelines.[22] Specifically address the following steps of the BART Guidelines:

    a. Step 1: Identify Emission Units in the BART Categories.
    b. Step 2: Identify the Start-Up Dates of the Emission Units[23]
    c. Step 3: Compare the Potential Emissions to the 250 Ton/Yr Cutoff.

4. If an EGU has been dismantled, shut down, mothballed, or otherwise is out of service such that it no longer contributes to the source's BART-eligibility under the BART Guidelines, then so state.

5. Provide any information necessary to document all assertions concerning the BART-eligibility of the source under the BART Guidelines.

6. For any EGUs that would be included in any BART-eligible source, please send copies of all of your active and most recently issued (including modifications/alterations) New Source Review (NSR) construction permits. This includes the cover sheet, Special Conditions, and Maximum Allowable Emission Rate Tables. This request includes but is not limited to:

    a. Prevention of Significant Deterioration (PSD) permits.
    b. Nonattainment NSR permits.
    c. Plant wide Applicability Limit (PAL) permits.
    d. Non-SIP and SIP approved flexible permits.
    e. Minor individual NSR permit actions.

[22] See the discussion beginning on 70 FR 39103, 39158 (July 6, 2005).
[23] In particular, see the discussion regarding the meaning of the term "in existence," on 70 FR at 39159.

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f. If any permit by rule (PBR) or qualified facility (or any other minor action) that modifies/alters an individual NSR permit emission limit, and that emission change is not reflected in the individual permit that was modified by the action, please send copies of all those applicable minor actions.
g. Site-wide PBR actions that regulate activities such as coal handling, etc.
h. Permit applications if they contain permit representations that are enforceable and were not reflected in the permit document itself.
i. Copies of your active Title V operating permits.

The following facilities received a First Round 114 Letter based on our preliminary BART-eligibility assessment for the units listed below:

Table 3. Facilities Receiving First Round 114 Letters

Facility Name	Unit ID	Facility Potentially BART Eligible? (satisfies both steam component + date test for at least one unit)	Utility Name
Decker Creek	1	Yes	Austin Energy
Decker Creek	2	Yes	
Decker Creek	GT-1A	No	
Decker Creek	GT-1B	No	
Decker Creek	GT-2A	No	
Decker Creek	GT-2B	No	
Decker Creek	GT-3A	No	
Decker Creek	GT-3B	No	
Decker Creek	GT-4A	No	
Decker Creek	GT-4B	No	
J K Spruce	1	No	City of San Antonio
J K Spruce	2	No	
J T Deely	1	Yes	
J T Deely	2	Yes	
V H Braunig	1	Yes	
V H Braunig	2	Yes	
V H Braunig	3	Yes	
V H Braunig	CGT5	No	
V H Braunig	CGT6	No	
V H Braunig	CGT7	No	
V H Braunig	CGT8	No	
V H Braunig	CT01	No	
V H Braunig	CT02	No	
Newman	1	No	El Paso Electric Co

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Newman	2	Yes	
Newman	3	Yes	
Newman	4	Yes	
Newman	5	No	
Newman	GT-6A	No	
Newman	GT-6B	Yes	
Lewis Creek	1	Yes	Entergy Texas Inc.
Lewis Creek	2	Yes	
Sabine	1	Yes	
Sabine	2	Yes	
Sabine	3	Yes	
Sabine	4	Yes	
Sabine	5	Yes	
Sam Seymour (Fayette)	1	Yes	Lower Colorado River Authority
Sam Seymour (Fayette)	2	Yes	
Sam Seymour (Fayette)	3	No	
Sim Gideon	1	Yes	
Sim Gideon	2	Yes	
Sim Gideon	3	Yes	
Big Brown	1	Yes	Luminant Generation Company LLC
Big Brown	2	Yes	
Decordova	CT1	No	
Decordova	CT2	No	
Decordova	CT3	No	
Decordova	CT4	No	
Graham	1	No	
Graham	2	Yes	
Martin Lake	1	Yes	
Martin Lake	2	Yes	
Martin Lake	3	Yes	
Monticello	1	Yes	
Monticello	2	Yes	
Monticello	3	Yes	
Morgan Creek	CT1	No	
Morgan Creek	CT2	No	
Morgan Creek	CT3	No	
Morgan Creek	CT4	No	
Morgan Creek	CT5	No	
Morgan Creek	CT6	No	
Permian Basin	CT1	No	

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Permian Basin	CT2	No	
Permian Basin	CT3	No	
Permian Basin	CT4	No	
Permian Basin	CT5	No	
Sandow	4	Yes	
Cedar Bayou	CBY1	Yes	NRG Texas Power LLC
Cedar Bayou	CBY2	Yes	
W A Parish	CTSC	Yes	
W A Parish	WAP1	No	
W A Parish	WAP2	No	
W A Parish	WAP3	No	
W A Parish	WAP4	Yes	
W A Parish	WAP5	Yes	
W A Parish	WAP6	Yes	
W A Parish	WAP7	Yes	
W A Parish	WAP8	Yes	
Victoria Power Station	9	Yes	ReNu Power Holdings LLC
Knox Lee Power Plant	2	No	Southwestern Electric Power Co
Knox Lee Power Plant	3	No	
Knox Lee Power Plant	4	No	
Knox Lee Power Plant	5	Yes	
Welsh Power Plant	1	Yes	
Welsh Power Plant	2	Yes	
Welsh Power Plant	3	Yes	
Wilkes Power Plant	1	Yes	
Wilkes Power Plant	2	Yes	
Wilkes Power Plant	3	Yes	
Harrington Station	061B	Yes	Southwestern Public Service Co
Harrington Station	062B	Yes	
Harrington Station	063B	Yes	
Jones Station	1	Yes	
Jones Station	2	Yes	
Jones Station	3	No	
Jones Station	4	No	
Nichols Station	141B	No	
Nichols Station	142B	Yes	
Nichols Station	143B	Yes	
Barney M. Davis	1	Yes	Topaz Power Group LLC
Barney M. Davis	3	No	
Barney M. Davis	4	No	
Laredo	4	No	
Laredo	5	No	
Nueces Bay	8	No	

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Nueces Bay	9	No	

In performing our preliminary BART-eligibility analysis, we inadvertently made two mistakes that we subsequently rectified. First, we mistakenly included the Jones, Nichols, and Harrington Power Plants, owned by Southwestern Public Service Company, in the First Round Section 114 Letter to the Southwestern Electric Power Company. We subsequently sent a separate Section 114(a) letter to the correct owner or operator, i.e., Southwestern Public Service Company, requesting that it perform a BART analysis on those facilities. Second, we mistakenly left the O. W. Sommers Facility, included in the TCEQ's BART List within the "Sommers Deely Spruce" plant off of our refinement of the Texas BART List. We subsequently discovered this during our supplemental BART-eligibility analysis, discussed below, and sent the City of San Antonio, which owns this facility, a Section 114(a) letter requesting that it perform a BART-eligibility analysis. These Section 114 letters are included in our docket.

3.3 First Round Follow-up 114 Letters

Due to inadequately documented or unsupported assertions made by a number of companies in their response to our First Round 114 letters, we found it necessary to request clarification. These "First Round Follow-up 114 Letters" mainly requested documentation to support the "in existence" determinations made by these facilities. Below is a summary of which facilities received these First Round Follow-up 114 Letters for the units listed below:

Table 4. Facilities Receiving First Round Follow-up Section 114(a) Letters

Facility Name	Unit ID	Utility Name
Nichols Station	142B	Xcel Energy
Sabine	1	Entergy Texas Inc.
Sabine	5	
W A Parish	WAP7	NRG Texas Power LLC
W A Parish	WAP 8	
Welsh	3	American Electric Power

3.4 Second Round 114 Letters

After performing our preliminary BART-eligibility assessment, we became aware that some facilities that were potentially BART-eligible and were not on the Texas BART List merited additional investigation. In order to ensure we did not overlook any potentially BART-eligible facilities, we conducted a supplemental BART-eligibility assessment. We did this by examining 2014 EIA Form 860 data for Texas EGUs. We then conducted a similar preliminary BART-eligibility analysis as we did in Section 3.2.

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We addressed Steps 1 and 2 of the BART-eligibility test by filtering the EIA data in the following order:[24]

a) Only show units in Texas.
b) Only show units with operating years from 1962 to 1982, inclusive.
c) Only show units with a sector names of "electric utility," and "IPP Non-CHP," leaving out "Commercial CHP," and "Industrial CHP."
d) Only show units with prime mover names of "CA," "CT," and "ST," leaving out "GT."

As we did in Section 3.2, in filtering step b), we went five years beyond the BART timeframe in order to identify any units that could have begun construction within the BART timeframe, but did not become operational until afterwards. In filtering step c), we examined which units under EIA's sector categorization are in BART Category 1. We note that Combined Heat and Power (CHP) facilities are potentially BART-eligible under BART Category 1, if they "generate electricity for sale."[25] The following units were identified by the EIA data as being either commercial or industrial CHP units:

[24] These filtered units appear in tab "EIA 860 Filtered" in the file, "EIA Suppl BART Analysis.xlsx."
[25] 70 FR 39103, 39159 (July 6, 2005), [40 CFR Part 51, App. Y.].

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Table 5. Commercial CHP and Industrial CHP Units Not Analyzed under BART Category 1

Utility ID	Utility Name	Plant Code	Plant Name	Technology	Sector Name	Generator ID	Operating Month	Operating Year	Prime Mover
14254	Oxy Vinyls LP	50043	Houston Chemical Complex Battleground	Natural Gas Fired Combined Cycle	Industrial CHP	GT1	5	1982	CT
14254	Oxy Vinyls LP	50043	Houston Chemical Complex Battleground	Natural Gas Fired Combined Cycle	Industrial CHP	GT2	6	1982	CT
14254	Oxy Vinyls LP	50043	Houston Chemical Complex Battleground	Natural Gas Fired Combined Cycle	Industrial CHP	ST	8	1982	CA
19537	University of Texas at Austin	50118	Hal C Weaver Power Plant	Natural Gas Fired Combined Cycle	Commercial CHP	GEN7	1	1979	CA
19450	Union Carbide Corp-Seadrift	50150	Union Carbide Seadrift Cogen	Natural Gas Fired Combined Cycle	Industrial CHP	GE10	1	1964	CA
19450	Union Carbide Corp-Seadrift	50150	Union Carbide Seadrift Cogen	Natural Gas Fired Combined Cycle	Industrial CHP	IGT	1	1969	CT
18760	TPC Group, LLC	50229	Texas Petrochemicals	Natural Gas Steam Turbine	Industrial CHP	TG2	6	1972	ST
6090	ExxonMobil Oil Corp	50625	ExxonMobil Beaumont Refinery	Natural Gas Steam Turbine	Industrial CHP	TG22	2	1978	ST
6090	ExxonMobil Oil Corp	50625	ExxonMobil Beaumont Refinery	Natural Gas Steam Turbine	Industrial CHP	TG32	1	1970	ST
6090	ExxonMobil Oil Corp	50625	ExxonMobil Beaumont Refinery	Natural Gas Steam Turbine	Industrial CHP	TG33	1	1966	ST
6090	ExxonMobil Oil Corp	50625	ExxonMobil Beaumont Refinery	Natural Gas Steam Turbine	Industrial CHP	TG34	1	1967	ST
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Natural Gas Fired Combined Cycle	Industrial CHP	GN31	6	1962	CA
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Natural Gas Fired Combined Cycle	Industrial CHP	GN33	6	1978	CA
22337	Alcoa World Alumina LLC	52069	Point Comfort Operations	Natural Gas Steam Turbine	Industrial CHP	GEN4	1	1970	ST

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5338	Dow Chemical Co	5212 0	Dow Chemical Texas Operation	Natural Gas Fired Combined Cycle	Industrial CHP	G-61	10	1982	CT
5338	Dow Chemical Co	5212 0	Dow Chemical Texas Operation	Natural Gas Fired Combined Cycle	Industrial CHP	G-63	8	1982	CT
57445	Pasadena Refining System Inc	5806 9	PRSI FCC Generator	Petroleum Coke	Industrial CHP	55M1	4	1979	ST

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We have no basis of information to believe that any of the above units generate electricity for sale, and thus do not include them in BART Category 1. We invite comment on that conclusion.[26]

In filtering step d), we determined which units under EIA's prime mover categorization are in BART Category 1. EIA uses the following prime mover abbreviations:[27]

Table 6. EIA Prime Mover Abbreviations

BA	Energy Storage, Battery
CE	Energy Storage, Compressed Air
CP	Energy Storage, Concentrated Solar Power
FW	Energy Storage, Flywheel
PS	Energy Storage, Reversible Hydraulic Turbine (Pumped Storage)
ES	Energy Storage, Other (specify in SCHEDULE 7)
ST	**Steam Turbine, including nuclear, geothermal and solar steam (does not include combined cycle)**
GT	**Combustion (Gas) Turbine (does not include the combustion turbine part of a combined cycle; see code CT, below)**
IC	Internal Combustion Engine (diesel, piston, reciprocating)
CA	**Combined Cycle Steam Part**
CT	**Combined Cycle Combustion Turbine Part**
CS	Combined Cycle Single Shaft (combustion turbine and steam turbine share a single generator)
CC	Combined Cycle Total Unit (use only for plants/generators that are in planning stage, for which specific generator details cannot be provided)
HA	Hydrokinetic, Axial Flow Turbine
HB	Hydrokinetic, Wave Buoy
HK	Hydrokinetic, Other (specify in SCHEDULE 7)
HY	Hydroelectric Turbine (includes turbines associated with delivery of water by pipeline)
BT	Turbines Used in a Binary Cycle (including those used for geothermal applications)
PV	Photovoltaic
WT	Wind Turbine, Onshore
WS	Wind Turbine, Offshore
FC	Fuel Cell
OT	Other (specify in SCHEDULE 7)

After the first three filtering steps, only the CA, CT, ST, and GT prime movers were present for further filtering. We eliminated the GT units, since they were not a part of a combined cycle power block and thus had no steam component and are not included in BART Category 1.

[26] As explained in the proposal that this TSD accompanies, we welcome comments on any aspects of our proposal, including all applicable technical support. In this TSD we "invite comment" at several points. These invitations are not necessarily repeated in the proposal itself, and they may concern minor or technical issues.

[27] See the "Reference Tables 1-3" tab of the file, "Layout2014.xlsx" in the 2014 EIA Form 860 data.

We then eliminated those units already covered in our First Round 114 Letter assessment we conducted in Section 3.2. We were left with the following units that were not included in the Texas BART List:[28]

[28] See tab "Suppl BART" in the file, "EIA Suppl BART Analysis.xlsx."

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Table 7. EIA Supplemental BART-eligible Analysis

Utility Name	Plant Code	Plant Name	Generator ID	Technology	Prime Mover	Sector Name	Operating Month	Operating Year
Luminant Generation Company LLC	3452	Lake Hubbard	1	Natural Gas Steam Turbine	ST	IPP Non-CHP	6	1970
Luminant Generation Company LLC	3452	Lake Hubbard	2	Natural Gas Steam Turbine	ST	IPP Non-CHP	11	1973
Exelon Power	3453	Mountain Creek	8	Natural Gas Steam Turbine	ST	IPP Non-CHP	7	1967
NRG Texas Power LLC	3464	Greens Bayou	5	Natural Gas Steam Turbine	ST	IPP Non-CHP	6	1973
NRG Texas Power LLC	3469	T H Wharton	3	Natural Gas Fired Combined Cycle	CA	IPP Non-CHP	8	1974
NRG Texas Power LLC	3469	T H Wharton	31	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	32	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	33	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	34	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	4	Natural Gas Fired Combined Cycle	CA	IPP Non-CHP	8	1974
NRG Texas Power LLC	3469	T H Wharton	41	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	42	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	43	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	8	1974
NRG Texas Power LLC	3469	T H Wharton	44	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	8	1974
Southwestern Public Service Co	3485	Plant X	4	Natural Gas Steam Turbine	ST	Electric Utility	1	1964
Exelon Power	3491	Handley	3	Natural Gas Steam Turbine	ST	IPP Non-CHP	7	1963
Exelon Power	3491	Handley	4	Natural Gas Steam Turbine	ST	IPP Non-CHP	10	1976
Exelon Power	3491	Handley	5	Natural Gas Steam Turbine	ST	IPP Non-CHP	10	1977
Luminant Generation Company LLC	3504	Stryker Creek	ST2	Natural Gas Steam Turbine	ST	IPP Non-CHP	12	1965
Luminant Generation Company LLC	3507	Trinidad (TX)	6	Natural Gas Steam Turbine	ST	IPP Non-CHP	5	1965
City of Garland - (TX)	3576	Ray Olinger	1	Natural Gas Steam Turbine	ST	Electric Utility	7	1967
City of Garland - (TX)	3576	Ray Olinger	2	Natural Gas Steam Turbine	ST	Electric Utility	1	1971
City of Garland - (TX)	3576	Ray Olinger	3	Natural Gas Steam Turbine	ST	Electric Utility	6	1976
City of Lubbock - (TX)	3602	Ty Cooke	1	Natural Gas Steam Turbine	ST	Electric Utility	6	1965
City of Lubbock - (TX)	3602	Ty Cooke	2	Natural Gas Steam Turbine	ST	Electric Utility	6	1978
City of San Antonio - (TX)	3611	O W Sommers	1	Natural Gas Steam Turbine	ST	Electric Utility	4	1972
City of San Antonio - (TX)	3611	O W Sommers	2	Natural Gas Steam Turbine	ST	Electric Utility	1	1974

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Brazos Electric Power Coop Inc	3628	R W Miller	1	Natural Gas Steam Turbine	ST	Electric Utility	10	1968
Brazos Electric Power Coop Inc	3628	R W Miller	2	Natural Gas Steam Turbine	ST	Electric Utility	7	1972
City of Greenville - (TX)	4195	Powerlane Plant	ST1	Natural Gas Steam Turbine	ST	Electric Utility	8	1966
City of Greenville - (TX)	4195	Powerlane Plant	ST2	Natural Gas Steam Turbine	ST	Electric Utility	8	1969
City of Greenville - (TX)	4195	Powerlane Plant	ST3	Natural Gas Steam Turbine	ST	Electric Utility	8	1977
City of Garland - (TX)	4266	Spencer	4	Natural Gas Steam Turbine	ST	Electric Utility	6	1966
City of Garland - (TX)	4266	Spencer	5	Natural Gas Steam Turbine	ST	Electric Utility	5	1973
Coleto Creek Power LP	6178	Coleto Creek	1	Conventional Steam Coal	ST	IPP Non-CHP	6	1980
San Miguel Electric Coop, Inc	6183	San Miguel	1	Conventional Steam Coal	ST	Electric Utility	1	1982
Southwestern Public Service Co	6194	Tolk	1	Conventional Steam Coal	ST	Electric Utility	1	1982
City of Bryan - (TX)	6243	Dansby	1	Natural Gas Steam Turbine	ST	Electric Utility	9	1978

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As was the case with the Preliminary BART-eligibility assessment we performed in Section 3.2, we were unable to confidently use Texas permitting information to assess the potential emissions from the units in question. We therefore similarly examined annual emissions from 2005 to 2015,[29] for these units. However, we were left with mixed results: in some cases, the emissions of either SO_2 or NOx for the units that had passed Steps 1 and 2 of the BART-eligibility test were above 250 tpy, and in some case they were below. Thus, we were not able to use actual emissions to resolve whether the potential emissions test was met, and we had to cast a wider net for the information needed to assess BART-eligibility for these units. Consequently, for each owner of the units present in Table 7, we requested certain information under the authority granted to us under Section 114(a) of the Clean Air Act, to assist us in determining which units were in fact BART-eligible. These "Second Round 114 Letters" were typically similar to the First Round 114 Letters discussed in Section 3.2. [30] The following facilities received these Second Round 114 Letters for the units listed below:

Table 8. Facilities Receiving Second Round Section 114(a) Letters

Facility Name	Unit ID	Utility Name
Lake Hubbard	1	Luminant Generation Company LLC
Lake Hubbard	2	
Stryker Creek	ST2	
Trinidad	6	
Mountain Creek	8	Exelon
Handley	3	
Handley	4	
Handley	5	
Greens Bayou	5	NRG Texas Power LLC
Ty Cooke	1	City of Lubbock
Ty Cooke	2	
R W Miller	1	Brazos Electrical Coop
R W Miller	2	
R W Miller	3	
Powerlane	ST1	City of Greenville
Powerlane	ST2	
Powerlane	ST3	
Spencer	4	City of Garland
Spencer	5	

[29] Downloaded from the EPA Air Markets Program Data, available here: https://ampd.epa.gov/ampd/. See the tab, "Selected Texas Emissions" in the file, "EIA Suppl BART Analysis.xlsx."

[30] All the Section 114(a) letters and responses are present in our docket. The pertinent responses are summarizedin the file, "114 Letter Response Summary.xlsx."

Coleto Creek	1	Engie
San Miguel	1	San Miguel Electrical Coop
Dansby	1	City of Bryan

3.5 Analysis of Section 114(a) Responses.

In a few instances, we exchanged emails with companies in order to clarify the responses we received to our Section 114(a) letters. In most cases, following any follow-up correspondence, we and the companies agreed on the BART-eligibility of the units in question. The following table summarizes: the facilities' determinations of BART-eligibility, whether we agree with that determination, and whether the units in question should be analyzed to determine if they are subject to BART[31]:

Table 9. Summary of BART-Eligibility Analysis

Facility	Unit	Company says BART-eligible?	Does EPA agree with eligibility?	Assess for subject to BART?
Barney M. Davis (Talen/Topaz)	1	Y	Y	Y
Barney M. Davis (Talen/Topaz)	2	N	Y	N
Big Brown (Luminant)	1	Y	Y	Y
Big Brown (Luminant)	2	Y	Y	Y
Cedar Bayou (NRG)	CBY1	Y	Y	Y
Cedar Bayou (NRG)	CBY2	Y	Y	Y
Cedar Bayou (NRG)	CBY3	N	Y	N
Coleto Creek (Engie)	1	N	N	Y
Dansby (City of Bryan)	1	Y	Y	Y
Decker Creek (Austin Energy)	1	Y	Y	Y
Decker Creek (Austin Energy)	2	Y	Y	Y
Decordova (Luminant)	1	N	Y	N
Fayette (LCRA)	1	Y	Y	Y
Fayette (LCRA)	2	Y	Y	Y
Fayette (LCRA)	3	N	Y	N
Graham (Luminant)	1	N	Y	N
Graham (Luminant)	2	Y	Y	Y
Greens Bayou (NRG)	5	Y	Y	Y
Handley (Exelon)	3	Y	Y	Y
Handley (Exelon)	4	Y	Y	Y
Handley (Exelon)	5	Y	Y	Y

[31] We note that the mistaken omission of several EGUs sources from the State's PM BART determinations (and Texas BART list) in its SIP submission would provide another reason why the PM BART component of the SIP, pending action under our proposal, could not be approved.

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Harrington Station (Xcel)	061B	Y	Y	Y
Harrington Station (Xcel)	062B	Y	Y	Y
Harrington Station (Xcel)	063B	N	Y	N
J K Spruce (CPS Energy)	1	N	Y	N
J T Deely (CPS Energy)	1	Y	Y	Y
J T Deely (CPS Energy)	2	Y	Y	Y
Jones Station (Xcel)	151B	Y	Y	Y
Jones Station (Xcel)	152B	Y	Y	Y
Knox Lee Power Plant (AEP)	2	N	Y	N
Knox Lee Power Plant (AEP)	3	N	Y	N
Knox Lee Power Plant (AEP)	4	N	Y	N
Knox Lee Power Plant (AEP)	5	Y	Y	Y
Lake Hubbard (Luminant)	1	Luminant was non-committal		Y
Lake Hubbard (Luminant)	2			Y
Laredo (Talen/Topaz)	1	N	Y	N
Laredo (Talen/Topaz)	2	N	Y	N
Laredo (Talen/Topaz)	3	N	Y	N
Lewis Creek (Entergy)	1	Y	Y	Y
Lewis Creek (Entergy)	2	Y	Y	Y
Martin Lake (Luminant)	1	Y	Y	Y
Martin Lake (Luminant)	2	Y	Y	Y
Martin Lake (Luminant)	3	Y	Y	Y
Monticello (Luminant)	1	Y	Y	Y
Monticello (Luminant)	2	Y	Y	Y
Monticello (Luminant)	3	Y	Y	Y
Morgan Creek (Luminant)	3	N	Y	N
Morgan Creek (Luminant)	4	N	Y	N
Morgan Creek (Luminant)	5	N	Y	N
Morgan Creek (Luminant)	6	N	Y	N
Mountain Creek (Exelon)	8	N	Y	N
Newman (El Paso Electric)	1	N	Y	N
Newman (El Paso Electric)	2	Y	Y	Y
Newman (El Paso Electric)	3	Y	Y	Y
Newman (El Paso Electric)	4	Y	Y	Y
Newman (El Paso Electric)	6	N	Y	N
Nichols Station (Xcel)	141B	N	Y	N
Nichols Station (Xcel)	142B	N	Y	N
Nichols Station (Xcel)	143B	Y	Y	Y
Nueces Bay (Talen/Topaz)	5	N	Y	N
Nueces Bay (Talen/Topaz)	6	N	Y	N
Nueces Bay (Talen/Topaz)	7	N	Y	N
O W Sommers (CPS Energy)	1	Y	Y	Y
O W Sommers (CPS Energy)	2	Y	Y	Y
Permian Basin (Luminant)	5	N	Y	N

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Permian Basin (Luminant)	6	N	Y	N
Plant X (Xcel)	4	Y	Y	Y
Powerlane (City of Greenville)	ST1	Y	Y	Y
Powerlane (City of Greenville)	ST2	Y	Y	Y
Powerlane (City of Greenville)	ST3	Y	Y	Y
R W Miller (Brazos Elec. Coop)	1	Y	Y	Y
R W Miller (Brazos Elec. Coop)	2	Y	Y	Y
R W Miller (Brazos Elec. Coop)	3	Y	Y	Y
Sabine (Entergy)	1	N	Y	N
Sabine (Entergy)	2	Y	Y	Y
Sabine (Entergy)	3	Y	Y	Y
Sabine (Entergy)	4	Y	Y	Y
Sabine (Entergy)	5	Y	Y	Y
San Miguel (San Miguel Elec. Coop)	1	N	Y	N
Sandow-Luminant	4	N	Y	N
Sim Gideon (LCRA)	1	Y	Y	Y
Sim Gideon (LCRA)	2	Y	Y	Y
Sim Gideon (LCRA)	3	Y	Y	Y
Spencer (City of Garland)	4	Y	Y	Y
Spencer (City of Garland)	5	Y	Y	Y
Stryker Creek (Luminant)	ST2	Luminant was non-committal		Y
Tolk (Xcel)	1	N	Y	N
Tolk (Xcel)	2		Tolk (Xcel)	1
Trinidad (Luminant)	6	Luminant was non-committal		Y
Ty Cooke (City of Lubbock)	1	Y	Y	Y
Ty Cooke (City of Lubbock)	2	Y	Y	Y
V H Braunig (CPS Energy)	1	Y	Y	Y
V H Braunig (CPS Energy)	2	Y	Y	Y
V H Braunig (CPS Energy)	3	Y	Y	Y
V H Braunig (CPS Energy)	CT01	N	Y	N
V H Braunig (CPS Energy)	CT02	N	Y	N
Victoria Power Station (Renu)	6	N	Y	N
Victoria Power Station (Renu)	7	N	Y	N
Victoria Power Station (Renu)	8	N	Y	N
Victoria Power Station (Renu)	9	N	Y	N
W A Parish (NRG)	WAP 1	N	Y	N
W A Parish (NRG)	WAP 2	N	Y	N
W A Parish (NRG)	WAP 3	N	Y	N
W A Parish (NRG)	WAP	Y	Y	Y

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	4			
W A Parish (NRG)	WAP 5	Y	Y	Y
W A Parish (NRG)	WAP 6	Y	Y	Y
W A Parish (NRG)	WAP 7	N	Y	N
W A Parish (NRG)	WAP 8	N	Y	N
Welsh Power Plant (AEP)	1	Y	Y	Y
Welsh Power Plant (AEP)	2	Y	Y	Y
Welsh Power Plant (AEP)	3	N	Y	N
Wilkes Power Plant (AEP)	1	Y	Y	Y
Wilkes Power Plant (AEP)	2	Y	Y	Y
Wilkes Power Plant (AEP)	3	Y	Y	Y

The final step in identifying a ''BART-eligible source'' is to use the information from the previous three steps to identify the collection of emissions units that comprise the BART-eligible source.

4 Our Strategy for Assessing which Units are Subject to BART.

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.[32] 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. 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. 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. We employed a four-fold strategy in determining which units should or should not be subject to BART. A flowchart of the analysis along with a detailed discussion of the subject-to-BART screening analysis is provided in the BART Screening TSD.[33] We summarize the methodology and results of this analysis here.

First, we examined whether any of the BART-eligible units should be eliminated from consideration based on the standard model plant exemptions described in the BART Guidelines.[34] Second, we created specific model plants between sources and nearby Class I

[32] *See* 40 C.F.R. Part 51, Appendix Y, III, *How to Identify Sources "Subject to BART"*

[33] See our TSD, "Our Strategy for Assessing which Units are Subject to BART for the Texas Regional Haze BART Federal Implementation Plan (BART Screening TSD)" in our docket.

[34] See the discussion beginning on 70 FR 39104, 39162 (July 6, 2005) [40 CFR Part 51, App. Y].

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areas and conducted CALPUFF modeling to evaluate a number of sources for exemption. . Third, we performed stand-alone source specific CALPUFF modeling on a number of units to determine if their visibility impacts were large enough to identify them as being subject to BART. Fourth, for those remaining units outside of the CALPUFF model's range, we contracted to have CAMx modeling performed to determine if their visibility impacts were large enough to merit their being subject to BART. CAMx results for sources within CALPUFF range are also included to provide additional information supporting the CALPUFF based determinations. These steps and the results of these analyses are described in detail in our BART Screening TSD.[35]

Based on the methodology described above, the BART-eligible sources in the table below have been determined to cause or contribute to visibility impairment at a nearby Class I area and we therefore propose they are Subject-to-BART.

Table 10. Subject-to-BART Sources

Facility	Units
Big Brown	1 & 2
Coleto Creek	1
Fayette Power	1 & 2
Harrington	061B & 062B
Martin Lake	1, 2 & 3
Monticello	1, 2 & 3
Calaveras	Deely 1 & 2, Sommers 1 & 2
W A Parish	WAP4, WAP5 & WAP6
Welsh	1&2*
Stryker	ST2
Graham	2
Wilkes	1, 2 & 3
Newman	2, 3 & 4

* Welsh Unit 2 retired April, 2016.

5 Our BART Five Factor Analyses

In our previous action,[36] we determined that due to the CSAPR remand, it was not appropriate at that time to rely on CSAPR as an alternative to SO_2 and NO_X BART for EGUs in Texas. As a consequence, action to satisfy the overdue requirement to address BART for EGUs in the state of Texas was further delayed.[37] In this proposal, we are proposing that CSAPR, once fully revised to address the D.C. Circuit's remand, provides a basis for satisfying EGU BART obligations for NO_X alone. It remains the case that we cannot rely on CSAPR as an alternative to

[35] Due to the length and complexity of the process we employed in determining which BART-eligible sources are subject-to-BART, we have described it in a separate TSD, entitled, "BART Screening TSD."
[36] See the discussion beginning on 81 FR 301 (January 5, 2016).
[37] Id. at 346.

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SO_2 BART for Texas EGUs as further confirmed by our proposed action to remove Texas from the annual NO_X and SO_2 control programs. Thus, we have the obligation to consider source-specific requirements for Texas EGUs consistent with the BART Guidelines for SO_2 BART.

Because the component of the Texas Regional Haze SIP regarding the PM BART requirement for EGUs has not been acted on, we have the responsibility under CAA section 110(k) to evaluate the submission and take action to approve or disapprove it. The SIP determinations for PM were based on modeling that was conducted by examining visibility impairment due to PM emissions alone, based on the assumption that the state would be participating in CAIR for SO_2 and NO_X and thereby having BART coverage for those pollutants. The Texas Regional Haze SIP had concluded that no PM BART controls for EGUs were appropriate, because modeling assessment of PM impacts alone showed their impacts to be too small for consideration for control. But Texas' screening analysis is no longer reliable or accurate because of the invalid assumption that source-by-source BART for either SO_2 or NO_X would not be required.[38] In order to appropriately evaluate the BART requirements for EGUs, the visibility impacts from all pollutants must be studied, including PM emissions. Texas' PM BART analysis for EGUs does not do this.[39] Considering this, our BART evaluation will evaluate BART for potential SO_2 and PM controls.

All units that are subject to BART must undergo a BART analysis. Regarding this, Section 51.308(e) states:

> The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

This is commonly referred to as the "BART five factor analysis." The BART Guidelines break the analyses of these requirements down into five steps:[40]

> STEP 1—Identify All Available Retrofit Control Technologies,
> STEP 2—Eliminate Technically Infeasible Options,
> STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies,

[38] Additionally, the Texas SIP had mistakenly omitted EGUs from its BART-eligible source list that, by our investigation, should have also been identified as BART-eligible and evaluated for PM BART. Since Texas did not retain underlying records from its survey of BART sources, we are unable to identify what may have led to these omissions.

[39] Texas' Regional Haze SIP determined whether its sources should be subject to review for PM controls by only looking at the impact of PM emissions on visibility. This approach is appropriate, when a State satisfies the requirements for BART for SO_2 and NO_X with an alternative measure. It is not valid under the current facts, as the SIP itself acknowledged. See, e.g., TX Regional Haze SIP Narrative at 9-17 ("Some EGUs may become subject to BART pending resolution of CAIR at the federal level")

[40] 70 FR 39103, 39164 (July 6, 2005) [40 CFR 51, App. Y].

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STEP 4—Evaluate Impacts and Document the Results, and
STEP 5—Evaluate Visibility Impacts.

The following sections treat these steps individually for SO_2. We are combining these steps into one section for PM.

5.1 Steps 1 and 2: Identification of Technically Feasible SO_2 Retrofit Control Technologies

The BART Guidelines state that in identifying all available retrofit control options,

> [Y]ou must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving.[41]

Adhering to this, we will identify a reasonable set of SO_2 control options, including those that cover the maximum level of control each technology is capable of achieving. In the course of that task, we will note whether any of these technologies are technically infeasible.

The subject-to-BART units identified in Table 10, can be organized into four broad categories, based on their fuel type and the potential types of SO_2 controls that could be retrofitted: (1) coal-fired EGUs with no SO_2 scrubber, (2) coal-fired EGUs with underperforming SO_2 scrubbers, (3) gas-fired EGUs that do not burn oil, and (4) gas-fired EGUs that occasionally burn fuel oil. This classification is represented below:

Table 11. Subject to BART Fuel Types and Potential SO2 BART Controls

Facility	Unit	Coal no scrubber	Coal underperforming scrubber	Gas no oil	Gas burns oil
Big Brown (Luminant)	1	X			
Big Brown (Luminant)	2	X			
Coleto Creek (Engie)	1	X			
Fayette (LCRA)*	1				
Fayette (LCRA)*	2				
Graham (Luminant)	2				X
Harrington Station (Xcel)	061B	X			
Harrington Station (Xcel)	062B	X			
J T Deely (CPS Energy)	1	X			
J T Deely (CPS Energy)	2	X			
Martin Lake (Luminant)	1		X		

[41] 70 FR at 39164, fn 12 [40 C.F.R. App. Y]

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Martin Lake (Luminant)	2		X		
Martin Lake (Luminant)	3		X		
Monticello (Luminant)	1	X			
Monticello (Luminant)	2	X			
Monticello (Luminant)	3		X		
Newman (El Paso Electric)	2				X
Newman (El Paso Electric)	3				X
Newman (El Paso Electric)	4			X	
O W Sommers (CPS Energy)	1				X
O W Sommers (CPS Energy)	2				X
Stryker Creek (Luminant)	ST2				X
W A Parish (NRG)	WAP4			X	
W A Parish (NRG)	WAP5	X			
W A Parish (NRG)	WAP6	X			
Welsh Power Plant (AEP)	1	X			
Welsh Power Plant (AEP)	2	X			
Wilkes Power Plant (AEP)	1				X
Wilkes Power Plant (AEP)	2			X	
Wilkes Power Plant (AEP)	3			X	

* The Fayette units have high performing wet FGDs in place.

For the coal-fired EGUs without an existing scrubber, we have identified four potential control technologies: (1) coal pretreatment, (2) Dry Sorbent Injection (DSI), (3) Spray Dryer Absorber (SDA), and (4) wet Flue Gas Desulfurization (FGD). For the coal-fired EGUs with an existing underperforming scrubber we will examine whether that scrubber can be upgraded. Gas-fired EGUs that do not burn oil have inherently low SO_2 emissions and there are no known SO_2 controls that can be evaluated. For gas-fired units that occasionally burn fuel oil, we will follow the BART Guidelines recommendations for oil-fired units: "For oil-fired units, regardless of size, you should evaluate limiting the sulfur content of the fuel oil burned to 1 percent or less by weight."[42] Each of these control technologies are evaluated below.

5.1.1 Identification of Technically Feasible SO_2 Retrofit Control Technologies for Coal Fired Units

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.

5.1.1.1 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 amount of sulfur in the coal burned. Coal pretreatment broadly falls into two categories:

[42] 70 FR 39103, 39171 (July 6, 2005) [40 CFR 51, App. Y].

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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).[43] 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.[44] Coal is mechanically sized, then various washing techniques are employed, depending on the particle size, type of coal, and the desired level of preparation.[45] 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,[46] and coal washing slurries are typically stored in impoundments, which can, and have, leaked.[47]

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 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.

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[43] Couch, G. R., "Coal Upgrading to Reduce CO_2 emissions," CCC/67, October 2002, IEA Clean Coal Centre.
[44] Ibid.
[45] 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.
[46] "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.
[47] 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.

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Coal drying can be performed onsite and so 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.[48] 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). We cannot assess many of these issues and we believe that requesting that the facilities in question do so would require detailed engineering analysis and extend our review time greatly. As a result of these issues, we do not further assess coal drying as a potential BART control.

5.1.1.2 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. For instance, Luminant states in its response to one of our Section 114(a) letters regarding its Big Brown and Monticello units:[49]

> Luminant commissioned the study of dry sorbent injection ("DSI") at these units in 2011. These studies determined that a very high feed rate

[48] 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/

[49] Luminant's 6/17/14 response to EPA's 5/20/14 Section 114(a) request for information relating to the Big Brown, Martin Lake, Monticello, and Sandow generating stations.

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> (in the range of 20-30%) was required to achieve modest SO_2 removal. Further, it was determined that other economic and operational factors make the use of DSI infeasible. For example, sorbent build-up was determined to cause degraded performance of the control equipment over time, as well as significant, repeat down time on a regular basis (i.e., every few days) to remove the buildup. In addition to the high cost of the sorbent required, the disposal and transport of the used sorbent (a Texas Class 1 waste) would result in significant additional cost. Thus, the use of DSI was determined infeasible from both an operational and economic point of view, and further evaluation has been discontinued.

As a consequence of this statement, which is discussed more fully in the CBI material Luminant has submitted, we considered proposing that DSI is not a feasible alternative for the Big Brown and Monticello facilities, and invite the affected facilities to affirm this position in the context of BART. Nevertheless, we included DSI in our BART evaluation for these facilities in order to be conservative. For all other units, although individual installations may present technical difficulties or poor performance due to the suboptimization of one or more of the above factors, we believe that DSI is technically feasible and should be considered as a potential BART control for all of the unscrubbed coal-fired BART-eligible units, with the exception of the Big Brown and Monticello facilities. We invite comments to the contrary.

5.1.1.3 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:[50]

> 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. ·
>
> 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

[50] Babcock and Wilcox. *Steam, Its Generation and Use*. Forty-second edition, 2015. Chapter 34.

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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[51] the following types of flue gas desulfurization systems as being operational in the U.S. for 2015:

Table 12. EIA Reported Desulfurization Systems in 2015

Type	Number of installations
Wet spray tower scrubber	296
Spray dryer absorber	269
Circulating dry scrubber	50
Packed tower wet scrubber	6
Venturi wet scrubber	48
Jet bubbling reactor	31
Tray tower wet scrubber	42
Mechanically aided wet scrubber	4
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.[52] 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.

[51] 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.

[52] 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.

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Therefore, they will not be further considered as BART controls.

In summary, wet FGD and SDA installations account for approximately 81% of all scrubber installations in the U.S. and as such constitute a reasonable set of SO_2 control options. The vast majority of the wet FGD and SDA installations utilize limestone and lime, respectively as reagents. In addition, these technologies cover the maximum level of SO_2 control available. As described above, these controls are in wide use and have been retrofitted to a variety of boiler types and plant configurations. We therefore see no technical infeasibility issues and believe that limestone wet FGD and lime SDA should be considered as potential BART controls for all of the unscrubbed coal-fired BART-eligible units.

5.1.2 Identification of Technically Feasible SO_2 Retrofit Control Technologies for Gas-Fired Units

Four of the units identified in Table 10 as being subject to BART, are only permitted to burn gas: Newman Unit 4, W A Parish Unit 4, and Wilkes Units 2 and 3. These units will not be considered for SO_2 BART.[53]

A number of the units we identified in Table 10 as being subject to BART primarily fire gas, but have occasionally fired fuel oil in the past. These units are identified below in Table 13:

Table 13. Gas Units that Occasionally Burn Oil and are Subject to BART

Facility	Unit(s)	Gas Turbine	Steam Turbine
Graham (Luminant)	2		X
Newman (El Paso Electric)	2, 3		X
O W Sommers (CPS Energy)	1, 2		X
Stryker Creek (Luminant)	ST2		X
Wilkes Power Plant (AEP)	1		X

For the remaining units, we will assess SO_2 BART. To begin, we examine the historical quantity of fuel oil that has been burned by consulting the Energy Information Agency's (EIA) databases: EIA-767, EIA-906/920, and EIA-923.[54] EIA's forms have undergone a number of changes over the years preventing us from presenting an uninterrupted analysis of unit fuel oil usage. For instance, we have been able to collect unit-specific fuel usage data using EIA-767 from 2000-2004. EIA-767 did not collect this type of data in 2005, which was its last date of publication. We therefore turned to EIA-906/920 from 2005-2007, which only collected fuel usage data on a facility basis. However, we were able to access EIA-923 for unit-specific fuel usage from 2008-2015. We present a summary of this information for the units of interest below:

[53] Parish: TCEQ Permit Number 4575, 12/31/2002, general condition 7, "Fuel oil firing is limited to Units 1-3 only…." Newman: TCEQ Permit Number 1467, 5/22/2008, special condition 4.A, "Fuel fired in the gas turbines and duct burners, for Unit 4 shall be natural gas …." Wilkes: TCEQ Permit Number 45435, 11/4/02, general condition 7, "Authorization to fire fuel oil firing is limited to Unit No. 1."

[54] EIA-767: http://www.eia.gov/electricity/data/eia767/. EIA-906/920 and EIA-923: http://www.eia.gov/electricity/data/eia923/

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Table 14. EIA-767 Historical Fuel Usage for Gas Units Subject to BART that Occasionally Burn Oil

				Fuel Oil Usage in Barrels (42 gallons)												
Year	**Plant**	**Boiler Id**	**Fuel Code**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2001	Newman	2	DFO	100							5,000					5,100
2001	Graham	2	DFO	31,500												31,500
2001	O W Sommers	2	DFO	800												800
2001	Wilkes	1	DFO	27,000	4,000											31,000
2002	Graham	2	DFO			9,800										9,800
2002	Stryker Creek	2	RFO			5,000										5,000
2002	Wilkes	1	DFO						1,800							1,800
2003	Graham	2	RFO		8,400	12,000			2,900							23,300
2003	Stryker Creek	2	RFO	22,000	29,200	20,600										71,800
2003	O W Sommers	1	DFO		20,000	20,000			5,000							45,000
2003	O W Sommers	2	DFO		4,000											4,000
2003	Wilkes	1	DFO	400	5,400		2,100								1,900	9,800
2004	Graham	2	DFO												2,200	2,200
2004	Stryker Creek	2	RFO												2,800	2,800
2004	O W Sommers	1	DFO		3,000								700			3,700
2004	Wilkes	1	RFO										2,100			2,100

Table 15. EIA-906/920 Historical Fuel Usage for Gas Units Subject to BART that Occasionally Burn Oil

				Fuel Oil Usage in Barrels (42 gallons)												
Year	**Plant Name**	**Reported Prime Mover**	**Reported Fuel Type Code**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2005	Graham	ST	DFO	0	0	0	0	0	143	1,940	15,345	7,791	0	0	0	25,219
2005	O W Sommers	ST	DFO	90	0	0	0	0	5	62	27	69	67	0	62	382
2005	Wilkes	ST	RFO	0	0	0	0	0	0	0	0	2,538	8,543	0	0	11,081
2006	Graham	ST	DFO	0	0	0	0	0	1,522	7,847	6,198	0	0	0	0	15,567
2006	O W Sommers	ST	DFO	79	37	0	99	75	58	39	0	210	141	0	0	738
2006	Wilkes	ST	RFO	0	8,187	0	9	79	505	46	6,458	0	0	0	0	15,284

2007	Graham	ST	DFO	0	2,254	82	0	4	163	0	464	0	0	0	0	2,967
2007	Graham	ST	RFO	0	0	0	4	0	0	0	0	0	0	0	0	4
2007	O W Sommers	ST	DFO	71	34	25	73	33	30	51	117	112	227	37	0	810
2007	Wilkes	ST	RFO	0	0	404	1,865	0	0	0	0	0	0	0	0	2,269

Table 16. EIA-923 Historical Fuel Usage for Gas Units Subject to BART that Occasionally Burn Oil

				Fuel Oil Usage in Barrels (42 gallons)												
Year	**Plant Name**	**Boiler ID**	**Reported Fuel Type Code**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2008	Graham	2	DFO			303			118							421
2008	Wilkes	1	DFO	18		0	0	0		0	0	0	0	0	0	18
2009	O W Sommers	1	DFO	426	0	0	0	0	0	0	0	0	0	0	0	426
2009	O W Sommers	2	DFO	1,819	0	0	0	0	0	0	0	0	0	0	0	1,819
2009	Stryker Creek	2	DFO	0	24	21	18	0	0	0	0	25	0	0	0	88
2011	Graham	2	DFO	.	.	.	.	.	.	.	.	.	19	.	.	19
2011	O W Sommers	1	DFO	0	2,334	0	0	0	0	0	0	1,049	0	0	0	3,383
2011	O W Sommers	2	DFO	0	26	0	0	0	0	0	0	0	0	0	0	26
2012	Graham	2	RFO	0	0	0	0	2,077	18,177	5,657	0	0	0	0	0	25,911
2012	O W Sommers	1	DFO	0	0	0	0	0	0	0	0	0	495	0	0	495
2012	O W Sommers	2	DFO	0	0	0	0	0	0	0	0	0	87	0	0	87
2013	O W Sommers	2	DFO	0	0	0	0	0	0	0	0	378	0	0	0	378
2014	Newman	2	DFO	.	.	.	.	0	0	0	0	0	115	0	0	115
2014	O W Sommers	1	DFO	0	0	0	0	0	0	0	0	0	35	0	0	35
2014	O W Sommers	2	DFO	0	0	0	0	0	0	0	0	0	23	0	0	23
2014	Wilkes	1	DFO	0	613	0	0	0	0	0	0	0	0	0	.	613
2015	Newman	2	DFO	0	0	0	0	0	0	0	0	0	150	0	0	150
2015	Newman	3	DFO	0	0	0	0	0	0	0	0	0	75	0	0	75
2015	O W Sommers	1	DFO	0	0	0	0	0	0	0	0	0	87	0	0	87
2015	O W Sommers	2	DFO	0	80	0	0	0	0	0	0	0	583	0	0	663
2015	Wilkes	1	DFO	0	0	0	0	0	0	0	0	16	0	0	.	16

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Note in the above tables, DFO = Distillate Fuel Oil and RFO = Residual Fuel Oil. EIA defines DFO as being a general classification for one of the petroleum fractions produced in conventional distillation operations. It includes diesel fuels and fuel oils. Products known as No. 1, No. 2, and No. 4 diesel fuel are used in on-highway diesel engines, such as those in trucks and automobiles, as well as off-highway engines, such as those in railroad locomotives and agricultural machinery. Products known as No. 1, No. 2, and No. 4 fuel oils are used primarily for space heating and electric power generation. EIA defines RFO as being a general classification for the heavier oils, known as No. 5 and No. 6 fuel oils that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations. It conforms to ASTM Specifications D 396 and D 975and Federal Specification VV-F-815C. No. 5, a residual fuel oil of medium viscosity, is also known as Navy Special and is defined in Military Specification MIL-F-859E, including Amendment 2 (NATO Symbol F-770). It is used in steam-powered vessels in government service and inshore power plants. No. 6 fuel oil includes Bunker C fuel oil and is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes.[55]

Note that in the above EIA tables, if a unit or facility is missing for a particular year, it means that unit did not report any fuel oil burning to EIA for that year. Also note that in Table 15, we have not included several entries for Stryker Creek, because these entries refer to prime movers with the "IC" designation, which refers to "Internal Combustion Engine," and the only unit from Stryker Creek that is subject to BART is a Steam Turbine (ST). Similarly, we have not included several entries for Newman, with prime mover designations of "CT" and "CA," which refer to "Combustion Turbine," and the heat recovery portion of a combined cycle turbine, respectively, as the subject-to-BART Newman units are steam turbines.

The amount of fuel oil for the Newman units is fairly minor, and only occurred in years 2001, 2014, and 2015. Also, despite EIA not requiring that unit-specific fuel oil burning be reported from 2005, 2007, we can deduce that during this time period all oil burning for the Wilkes facility can be attributed to Unit 1, as that is the only unit permitted to burn oil. However, although the O W Sommers units 1 and 2 are the only units permitted to burn fuel oil, we cannot determine the amount each unit burned. Lastly, both the Graham Units 1 and 2 are permitted to burn fuel oil so we cannot determine how much can be attributed to Unit 1, the only one of the two units that is subject to BART.

5.1.2.1 Fuel Oil Sulfur Reduction Feasibility for Gas/Oil-Fired Boilers

In analyzing the technical feasibility under BART of these facilities burning fuel oils of sulfur contents lower than historically burned, we investigated two issues: (1) Is lower sulfur fuel oil available and what is its cost, and (2) are there any technical issues in burning a lower sulfur fuel oil that could add to the cost of that oil.

We began by reviewing the permits of the subject facilities. All of the subject units are limited by permit to burning oil with a sulfur content of no more than 0.7% sulfur by weight. In addition, the Newman units 2 and 3 are restricted to burning fuel oil for no more than 10% of their annual operating time. Similar to our summary of the historic volumes of oil burned by

[55] http://www.eia.gov/tools/glossary/

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these facilities, we present the historical sulfur content of the oil burned below:

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Table 17. EIA-767 Historical Fuel Sulfur Content for Gas Units Subject to BART that Occasionally Burn Oil

				Sulfur Content (% by weight)											
Year	**Plant**	**Boiler Id**	**Fuel Code**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2001	Newman	2	DFO	0.2							0.2				
2001	Graham	2	DFO	0.5											
2001	O W Sommers	2	DFO	0.24											
2001	Wilkes	1	DFO	0.11	0.11										
2002	Graham	2	DFO			0.65									
2002	Stryker Creek	2	RFO			0.56									
2002	Wilkes	1	DFO						0.09						
2003	Graham	2	RFO		0.66	0.66			0.66						
2003	Stryker Creek	2	RFO	0.65	0.65	0.65									
2003	O W Sommers	1	DFO		0.19	0.19			0.19						
2003	O W Sommers	2	DFO		0.19										
2003	Wilkes	1	DFO	0.43	0.43		0.42								0.09
2004	Graham	2	DFO												0.69
2004	Stryker Creek	2	RFO												0.64
2004	O W Sommers	1	DFO		0.41								0.37		
2004	Wilkes	1	DFO		0.41								0.37		

Table 18. EIA-923 Historical Fuel Sulfur Content for Gas Units Subject to BART that Occasionally Burn Oil

				Sulfur Content (% by weight)											
Year	**Plant Name**	**Boiler ID**	**Fuel Code**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2008	Graham	2	DFO			0.50			0.50						
2008	Wilkes	1	DFO	0.00		0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00
2009	O W Sommers	1	DFO	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	O W Sommers	2	DFO	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	Stryker Creek	2	DFO	0.00	0.46	0.50	0.41	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.00

2011	Graham	2	DFO	.	.	.	.	.	.	.	.	.	0.01	.	.
2011	O W Sommers	1	DFO	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.00
2011	O W Sommers	2	DFO	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	Graham	2	RFO	0.00	0.00	0.00	0.00	0.50	0.50	0.50	0.00	0.00	0.00	0.00	0.00
2012	O W Sommers	1	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
2012	O W Sommers	2	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
2013	O W Sommers	2	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.00
2014	Newman	2	DFO	.	.	.	.	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2014	O W Sommers	1	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2014	O W Sommers	2	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2014	Wilkes	1	DFO	0.00	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	.
2015	Newman	2	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2015	Newman	3	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2015	O W Sommers	1	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2015	O W Sommers	2	DFO	0.00	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2015	Wilkes	1	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00	.

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Note: In 2008, the Wilkes facility did not report the fuel oil sulfur content, despite reporting that fuel oil was burned. Also note that beginning in 2012, the sulfur content reported is almost uniformly 0.50% (the 0.01% reported by the Graham and O W Sommers facilities is the exception). We suspect that, considering the variation in sulfur contents reported in prior years, this indicates unreliable data. We will examine this further in later sections. Also note that EIA does not report the sulfur content of the fuel oil burned from the 2005-2007 EIA-906/920 forms, so that data is unavailable.

In order to determine the technical feasibility under BART of these facilities burning fuel oils of sulfur contents lower than historically burned, we sent the Graham, Newman, Stryker Creek, and the Wilkes Section 114 letters requesting information on their fuel oil usage and costs.[56] We requested the following information:

1. For each unit, indicate whether that unit is permitted by the State of Texas to burn fuel oil. If so, cite to specific permit language.
2. For *each unit* permitted to burn fuel oil:
    a. Indicate if there are any legal restrictions on how often or how much fuel oil can be burned annually. If such restrictions exist, cite to specific permit language.
    b. Indicate if that unit has any legal restrictions on the sulfur content of the fuel oil that can be burned. If such restrictions exist, cite to specific permit language.
    c. If the restrictions in Questions 2.a and/or 2.b have changed since the period between January 1, 2000 and December 31, 2004, so indicate and cite to the restrictions that were in place during that time period.
    d. If fuel oil was burned between January 1, 2000 and December 31, 2004, indicate the volume burned per month and the sulfur content of that fuel.
    e. If no fuel oil has been burned since January 1, 2000, so indicate.
3. For each unit that is permitted to burn fuel oil, indicate whether the facility is willing to enter into a voluntary, enforceable commitment to remove the ability to burn fuel oil after October 9, 2017 (the projected effective date of our final decision), as a means of addressing BART. If applicable, please state in your response that you request an enforceable restriction prohibiting use of fuel oil at the unit if such unit is determined to be subject to BART for sulfur dioxide. Note that should the unit be determined to be subject to BART, the alternative to this may be a proposal by EPA to limit the sulfur content of the fuel oil burned by this same date.
4. For each unit that is permitted to burn fuel oil and that you wish to retain that ability, provide the following:
    a. For the last delivery of fuel oil, provide the vendor contact information, indicate the date of delivery, the method of delivery (e.g., truck, rail), the cost of the fuel, delivery and unloading charges, the volume of the fuel, the grade of the fuel, and the sulfur content of the fuel.
    b. For any fuel oil delivery over one year old, provide updated pricing for the same delivery method, volume, grade, and sulfur content.
    c. Unless the sulfur content of the fuel oil described in the reply to Question 6.b is already lower, provide updated pricing for an equivalent volume of fuel oil with a

[56] Copies of these letters and the facilities' responses are in our docket. We did not send the O W Sommers a letter due to an oversight on our part.

sulfur content of 0.1% sulfur fuel oil, low sulfur specification fuel oil (approximately 322 ppm sulfur), and ultra-low sulfur specification fuel oil (approximately 15 ppm sulfur).

d. If there are additional costs associated with burning any of the lower sulfur fuels contemplated in Question 4.c, so indicate and estimate those costs.

We received full responses to Questions 1-3. All of the facilities indicated they wished to retain the ability to burn fuel oil.

All facilities have either burned either DFO or have switched between DFO and RFO, thus demonstrating the ability to burn distillate fuel oils of the type under consideration for SO_2 BART. We therefore conclude that lower sulfur DFOs are a technical feasible retrofit control option under BART, and carry no significant capital costs in their use other than their purchase price. We invite comments from the affected facilities concerning this conclusion.

5.1.2.2 SO_2 Scrubber Feasibility for Gas/Oil-Fired Boilers

We began our identification of technically feasible SO_2 retrofit control technologies by conducting a search of our 2015 Air Markets Program Data,[57] supplemented with EIA 860 and 923 data,[58] for any EGUs that primarily fires gas and secondarily fire fuel oil, to determine what, if any, SO_2 controls have been installed for these types of units. The only units with these criteria that indicated any type of SO_2 control are the E W Brown Units 10 and 11, which are simple cycle combustion turbines with nameplate capacities of 126 MW. Our Air Markets Program Data listed the SO_2 control was listed as "Other." We then searched for any EGUs that primarily fired oil for any type of SO_2 control. This resulted in two other units from the E W Brown facility: Units 8 and 9, also listed as 126 MW combustion turbines with the SO_2 control listed as "Other." We must assume this is something other than a scrubber or DSI, as this category lists all known variations of these types of technologies for other types of EGUs. An examination of EIA data did not indicate any type of SO_2 control was present for any of these units. Regardless, these EGUs are combustion turbines and all of the gas-fired units that are under consideration here are steam turbines.

Nevertheless, 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.[59] Consequently, we will consider the installation of various types of scrubbers to be technically feasible.

5.1.3 Identification of Technically Feasible SO_2 Retrofit Control Technologies for Scrubber Upgrades

[57] https://ampd.epa.gov/ampd/

[58] http://www.eia.gov/electricity/data/eia860/index.html, http://www.eia.gov/electricity/data/eia923/

[59] 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."

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In our recent Texas-Oklahoma FIP,[60] we presented a great deal of information that concluded that the existing scrubbers for a number of facilities could be very cost effectively upgraded.[61] That information is attached herein as Appendix B. Of the facilities we evaluated in that action, Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are subject to BART and are thus a part of this proposal.

5.2 Step 3: Evaluation of Control Effectiveness of Remaining Control Technologies

In the following subsections to section 5.2, 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."[62] 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.

5.2.1 Evaluation of Control Effectiveness of DSI

The efficiency of DSI system depends on many factors, such as[63]:

- Sorbent particle size: Finer particles result in better performance.
- 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: [64]

[60] 81 FR 295, 321 (January 5, 2016)
[61] See information presented in Sections 6 and 7 of the Cost TSD.
[62] 70 FR 39103, 39172 (July 6, 2005) [40 CFR 51, App. Y]
[63] Wood, M., Kong, Y., "Dry Sorbent Injection with Trona or Sodium Bicarbonate Meets HCl Limit in Utility MACT, SOLVAir® Solutions, Solvay Chemicals, Inc.
[64] "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.

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Figure 1. Typical Trona SO_2 Removal Rates with ESP or Baghouse Installations

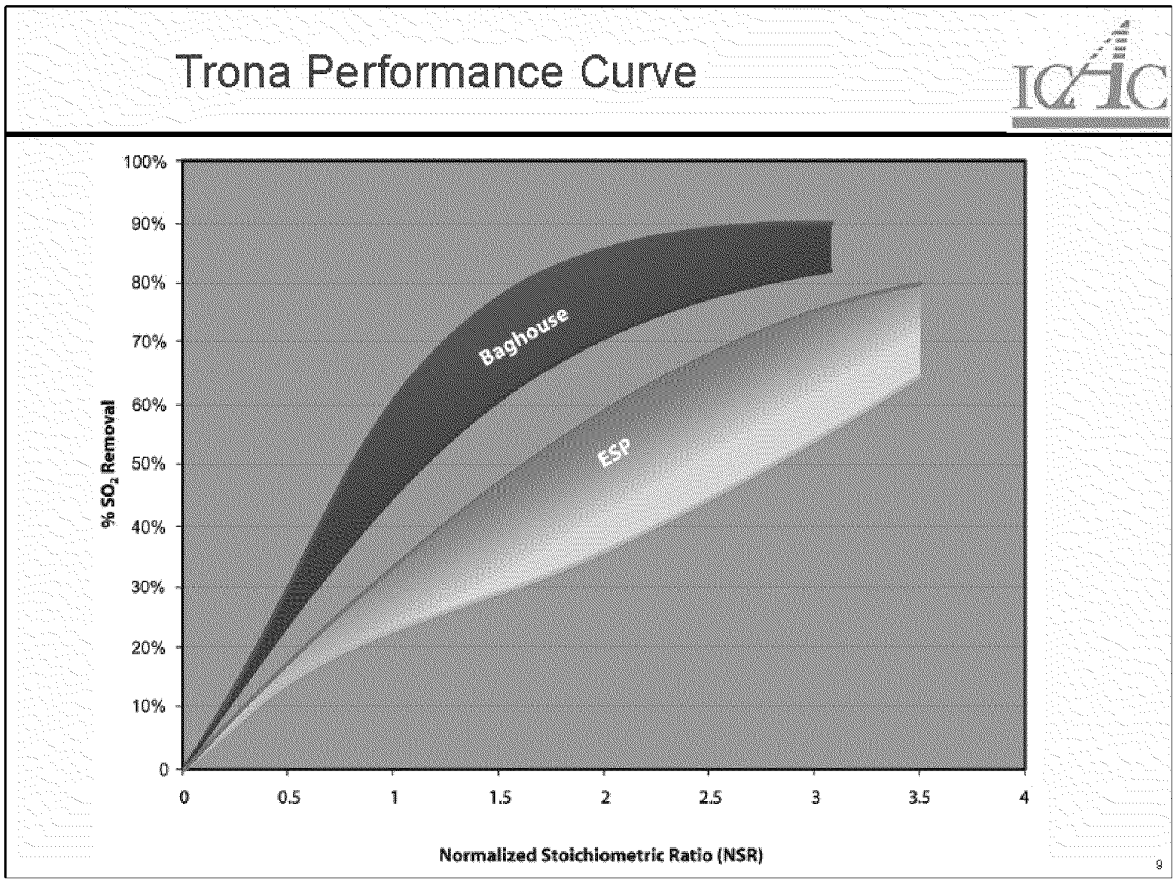

Figure 1 illustrates a number of important concepts concerning the performance potential of DSI:

- 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.

We lack the site specific information, which we believe requires an individual performance test, in order to be able to accurately determine the maximum SO_2 removal efficiency for the coal units listed in Table 10. We are aware that a number of the coal fired units have conducted such testing. However, although we have examined that testing, most of the facilities have claimed it

as Confidential Business Information (CBI) and requested protection from public disclosure as provided by 40 C.F.R. Part 2.

However, we nevertheless must evaluate DSI as a viable, proven method of SO_2 control. We must do the same for SO_2 scrubbing, and in so doing, compare the visibility benefits and costs of each technology in order to propose which, if either technology, we should propose for installation due to the BART requirements. We therefore propose the following methodology:

- We will evaluate each unit at its maximum recommended DSI performance level, according to the IPM DSI cost model documentation,[65] assuming milled trona: 80% SO_2 removal for an ESP installation and 90% SO_2 removal for a baghouse 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.[66]

- However, (1) we do not know whether a given 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 all the units at a DSI SO_2 control level of 50%, which we believe is likely achievable for most units.

- We invite comments on whether particular units have performed DSI testing and have concluded they cannot achieve a SO_2 reduction between 50% and 80/90%.

5.2.2 Evaluation of Control Effectiveness of Wet FGD and SDA

We 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. As we discuss later in our TSD, we will conduct our wet FGD control cost analysis using the wet FGD cost algorithms, as employed in version 5.13 of our IPM model. [67] The IPM wet FGD

[65] 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.

[66] The exceptions are the Harrington Unit 062B and Welsh Unit 1, for which we limited the upper DSI control to their SDA control efficiencies of 88.9% and 87.2%, respectively. See the discussion in this TSD concerning our evaluation of the control effectiveness of SDA.

[67] 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.

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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 established in our Oklahoma FIP,[68] this level of control is achievable with wet FGD. This level of control was also employed in our recent Texas-Oklahoma FIP.[69] We received a comment challenging this level of control and we reproduce our response to that comment in Appendix A. We continue to conclude that our proposed level of control for wet FGD is reasonable.

As with our Oklahoma BART FIP, 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 lb/MMBtu, in which case, we assume the percentage of control equal to 0.06 lbs/MMBtu. See our response to comments in our previous Oklahoma BART FIP.[70] In that FIP, we finalized the same emission limit of 0.06 lbs/MMBtu on a 30 BOD average for 6 coal fired. We justified those limits based on the same SDA technology, using a combination of industry publications and real world monitoring data. Much of that information is summarized in our response to a comment to that action[71] and in our TSD. We continue to conclude that our proposed level of control for SDA is reasonable.

5.2.3 Evaluation of Control Effectiveness for Gas-Fired Units

The control effectiveness of switching from a higher sulfur fuel oil to a lower sulfur fuel oil lies in the reduction in sulfur. This depends on the percentage reduction from the sulfur contents of the fuel oil that forms the SO_2 baseline to the replacement fuel oil. Ultimately, the highest level of control would result from a switch from the highest percentage sulfur the units are permitted to burn, 0.7% to the lowest DFO available, ultra-low sulfur diesel, which has a sulfur content of 0.0015%. This would equate to a control effectiveness of 99.8%. Lesser levels of controls are also possible. We will evaluate a range of control effectiveness in switching to lower sulfur fuel oils in the next section.

Because we are unaware of any scrubber installations on oil fired units in the U. S., we have no information on their control effectiveness. However, we see no technical reason why the control effectiveness of FGDs installed on gas-fired units that occasionally burn fuel oil should not be equal to that of FGDs installed on coal-fired units.

5.3 Step 4: Evaluate Impacts and Document the Results for SO_2

The BART Guidelines offers the following with regard to how Step 4 should be conducted:[72]

[68] As discussed previously in our TSD for that action, control efficiencies reasonably achievable by dry scrubbing and wet scrubbing were determined to be 95% and 98% respectively. 76 FR 81742); *Oklahoma v. EPA*, 723 F.3d 1201 (July 19, 2013), cert. denied (U.S. May 27, 2014).
[69] 81 FR 295, 321 (January 5, 2016).
[70] 76 FR 81727, 81728 (December 28, 2011).
[71] 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 comment and response beginning on page 91.
[72] 70 FR 39103, 39166 (July 6, 2005) [40 CFR Part 51, App. Y].

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> 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.

We evaluate the cost of compliance on a unit-by unit basis, because control cost analysis depends on specific factors that vary from unit to unit. However, as we discuss later in this TSD, we evaluate the energy impacts. non-air quality impacts, and the remaining useful life for all the units in question together because in this instance there are no appreciable differences in these factors from unit to unit.

In developing our cost estimates for the units in Table 10, we relied on the methods and principles contained within the EPA Air Pollution Control Cost Manual (the Control Cost Manual, or Manual).[73] As we describe in our Oklahoma final action,[74] the Control Cost Manual uses the "overnight" method of cost estimation:

> 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.'' EIA presents all of its projected plant costs in terms of overnight 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

[73] 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.
[74] 76 FR 81727, 81744 (January 27, 2012).

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SO_2 control, if any, for each of the units listed in Table 10. For the coal units without any SO_2 control, we calculate the cost of installing DSI, a SDA scrubber, and a wet FGD scrubber. For the gas units that burn oil, we evaluate the cost of switching to lower sulfur fuel oils and installing scrubbers.

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 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 each unit listed in Table 10 that did not already have SO_2 control.[75] We discuss the inputs and outputs for the DSI, SDA, and wet FGS cost models below. These cost models were based on costs escalated to 2012 dollars.[76] 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 5.3.1, 5.3.2, and 5.3.3.

5.3.1 Impact Analysis Part 1: Cost of Compliance for DSI

Table 19, 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.

[75] These spreadsheets are entitled, "DSI Cost IPM 5-13 TX BART.xlsx," "SDA Cost IPM 5-13 TX BART.xlsx," and "Wet FGD Cost IPM 5-13 TX BART.xlsx," and are located in our Docket.
[76] Ibid., p.1: "The data was converted to 2012 dollars based on the Chemical Engineering Plant Index (CEPI) data."

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Table 19. 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		LIG-PRB Blend	**<---- 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)**	
HHV Lignite		BTU/lb	7,200	**<---- User Input (default is 7,200 Btu/lb if applicable; else no meaning)**	Three year average from 2011-2015, excluding max and min values
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))	example calculated NSRs which differ from those calculated from the formulae here. Per emails from Bill Stevens, the documentation is in
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)	17.05	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	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	($/ton)	170	**<---- User Input**	Based on input from Solvay
Waste Disposal Cost	S	($/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

5.3.1.1 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 individual DSI installations. 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. For example, we designed our cost model based on selecting maximum inputs from 2011 – 2015 for the inlet SO_2 rate, the gross heat rate, and the percentage lignite

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even if these values didn't appear in the same year of data. 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. We therefore invite comments on the accuracy of the values we have used.

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,[77] 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.[78] 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. None of the units we evaluated were affected by this limit, although Big Brown's maximum monthly SO_2 emission rate was right at 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. Therefore, a single coal selection is not appropriate for a few of the facilities for which we are costing DSI and scrubbers, which burn blends of Texas lignite and PRB coals (e.g., Big Brown Units 1, 2 and , Monticello Units 1, 2). In addition, regardless of whether a facility blends coal, we wished to allow 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. We select the maximum percent lignite value from 2011 – 2015. We use the three year average HHV values from 2011 – 2015, eliminating the maximum and minimum values. Our adjusted cost model accounts for this information in the calculation of the VOMW.

[77] http://ampd.epa.gov/ampd/
[78] Ibid.

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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."[79] For those units that use an ESP along with a polishing baghouse, we assumed that the baghouse would have the capacity to handle the additional particulate matter from the trona by itself. Thus, we assumed the trona would be injected downstream of the ESP and upstream of the baghouse and we modeled the DSI cost on the basis of a baghouse. In all cases we assumed the existing particulate control device has the capacity to handle the additional load due to the addition of the trona. We invite comment from the affected facilities as to whether this assumption is valid.

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 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 in all cases.

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."[80] In section 5.2.1, 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.

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[79] 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.
[80] Ibid., p.2.

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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. We invite the affected facilities to inform us whether they would configure DSI in such a manner.

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 in all cases.

Trona Cost. The cost of trona is the largest portion of the variable operating costs. It is partly dependent on the delivery costs. The United States Geological Survey estimates the average 2012 cost of soda ash to be $135/ton F.O.B at the mine or plant.[81] Considering that trona must be delivered from Wyoming to Texas, we contacted Solvay, which is a supplier of Trona, in order to improve this estimate. We were able to get estimated trona costs and some estimated freight delivery costs for various locations:[82]

Table 20. Cost of Trona

Facility	Cost of Trona ($/ton)	Freight by Railroad ($/ton)	Total Cost ($/ton)
Welsh	110.00	87.98	197.98
Fayette	110.00	82.62	192.62
J T Deely	110.00	85.10	195.10
Harrington	110.00	64.90	174.90

We used the Welsh quote to represent the other facilities in east Texas: Big Brown, and Monticello. We used the Fayette quote to represent the W A Parish facility. We used the J T Deely to also represent the Coleto Creek facility. Solvay also indicated that, "if the facilities do not have rail access to accept chemical shipments, the additional fees for running the product through a terminal/transload facility to put the material into bulk trucks would be about $50/ton additional cost. This can vary greatly depending upon volume and location, but this would be an estimated average cost." We have not assumed this additional transportation cost for any facility, but invite clarification from the facilities involved as to whether it should be added.

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

[81] U.S. Department of the Interior U.S. Geological Survey Mineral Commodity Summaries 2016, p. 154. Available at http://minerals.usgs.gov/minerals/pubs/mcs/2016/mcs2016.pdf
[82] Email from Marilyn Treacy to Joe Kordzi, 7-6-2016.

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fly ash and is disposed of separately. We assumed the trona waste and the fly ash were comingled and disposed of together for all cases, and therefore set this value to $50/ton. 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.[83] We invite comments on this issue.

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 information 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.[84] Also, a 7 percent interest rate is recommended by Office of Management and Budget.[85]

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.

Gross Load. The gross load (MW-h) was obtained from emissions data downloaded from our Air Markets Program Data website.[86] 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

[83] 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.'"

[84] 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).

[85] 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

[86] http://ampd.epa.gov/ampd/

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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.[87] 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.

5.3.1.2 DSI Cost Model Output

A sample of the IPM DSI cost model output is depicted below in Table 21. 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."[88] 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.

[87] Ibid.

[88] 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.

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Table 21. 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)	2.87	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not	
VOMP ($/MWh)	0.39	Variable O&M costs for additional auxillary power required (refer to Aux Power % above)	
VOM ($/MWh)	**8.82**	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	$35,260,822	VOM*(Gross Load)	
Fixed operating costs	$404,356	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)	
Total annualized costs	**$37,365,470**		
SO2 emissions reduction (tons)	15,000	H/(100%)*(SO2 emission baseline)	
$/ton	**2,491**		

5.3.1.3 Summary of DSI Cost Model Results

Below in Table 22 is a summary of our DSI cost model results:

Table 22. Summary of DSI Cost Model Results

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Facility	Unit	DSI Control (%)	DSI SO2 Reduction (tpy)	DSI Capital Cost	DSI Annualized Capital Cost	DSI Variable Operating Cost	DSI Fixed Operating Cost	DSI Total Annualized Cost	DSI Cost Effectiveness 2012 ($/ton)	DSI Cost Effectiveness 2016 ($/ton)
Parish	5	50.00	6,712	$15,495,000	$1,248,686	$14,234,884	$267,806	$15,751,376	$2,347	$2,235
		90.00	12,081	$21,266,000	$1,713,750	$30,390,656	$302,372	$32,406,779	$2,682	$2,555
	6	50.00	7,525	$15,986,000	$1,288,254	$15,266,210	$260,123	$16,814,587	$2,234	$2,128
		90.00	13,545	$21,996,000	$1,772,579	$32,897,968	$294,715	$34,965,262	$2,581	$2,459
Welsh	1	50.00	3,343	$12,626,000	$1,017,484	$8,154,876	$238,945	$9,411,305	$2,816	$2,682
		90.00	6,017	$17,373,000	$1,400,028	$15,936,486	$266,062	$17,602,576	$2,926	$2,787
Coleto Creek	1	50.00	7,376	$14,922,000	$1,202,510	$15,507,382	$347,417	$17,057,310	$2,313	$2,203
		90.00	13,277	$20,534,000	$1,654,761	$34,534,592	$391,592	$36,580,945	$2,755	$2,624
J T Deely	1	50.00	3,072	$13,951,000	$1,124,261	$7,963,377	$208,762	$9,296,399	$3,027	$2,883
		90.00	5,529	$19,196,000	$1,546,937	$17,193,108	$234,130	$18,974,174	$3,432	$3,269
	2	50.00	3,222	$13,733,000	$1,106,693	$9,003,561	$248,125	$10,358,379	$3,215	$3,062
		90.00	5,800	$18,898,000	$1,522,922	$19,438,363	$277,956	$21,239,241	$3,662	$3,488
Harrington	061B	50.00	2,477	$14,046,000	$1,131,917	$8,252,558	$261,853	$9,646,328	$3,895	$3,710
		80.00	3,962	$17,828,000	$1,436,694	$15,154,863	$284,755	$16,876,313	$4,259	$4,057
	062B	50.00	2,455	$11,882,000	$957,528	$5,661,879	$231,309	$6,850,715	$2,791	$2,658
		90.00	4,418	$16,348,000	$1,317,427	$11,273,661	$256,449	$12,847,536	$2,908	$2,770
Big Brown	1	50.00	14,448	$19,179,000	$1,545,567	$29,039,816	$354,517	$30,939,899	$2,142	$2,040
		90.00	26,006	$33,862,000	$2,728,817	$72,542,248	$462,091	$75,733,155	$2,912	$2,774
	2	50.00	15,320	$19,035,000	$1,533,962	$28,915,771	$357,627	$30,807,360	$2,011	$1,915
		90.00	27,576	$32,965,000	$2,656,531	$71,766,172	$460,896	$74,883,599	$2,716	$2,586
Monticello	1	50.00	4,787	$17,410,000	$1,403,009	$10,419,393	$156,094	$11,978,496	$2,502	$2,383
		90.00	8,617	$24,083,000	$1,940,762	$24,558,561	$178,436	$26,677,759	$3,096	$2,949
	2	50.00	4,129	$17,057,000	$1,374,562	$8,716,433	$138,086	$10,229,081	$2,478	$2,360
		90.00	7,431	$23,468,000	$1,891,202	$20,439,704	$157,226	$22,488,132	$3,026	$2,882

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.
- For a given level of control, the cost effectiveness of DSI generally improves as the tonnage of SO_2 removal increases.

5.3.2 Impact Analysis Part 1: Cost of Compliance for SDA

Table 23, 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

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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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Table 23. 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**	5 -yr avg. excluding max and min
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

5.3.2.1 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. For instance, simply changing the type of coal from lignite to PRB for Big Brown Unit 1 results in an improvement in the cost effectiveness (lower $/ton) of less than 1%. Therefore, for those facilities that burn a mixture of lignite and PRB, we are simply assuming they burn lignite for the purposes of costing a SDA system.

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

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equipment manufacturers of SDA FGD systems, are 0.06 lb/MMBtu." As we discuss in Section 5.2.2, 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.[89] 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.[90] The USGS estimates the average 2012 cost of quicklime to be $116/ton at the lime plant.[91] Although we do not have lime pricing available for Texas, lime is widely available within the State and we expect delivery charges to be minimal. Consequently, we consider the cost algorithm default cost for delivered lime of $125/ton to be reasonable, and we have adopted it for all cases. We invite the affected facilities to provide comment on this assumption.

Waste Disposal Cost. The waste disposal cost is the second largest portion of the variable operating costs. The cost model default is $30/ton and we have adopted it for all cases.

Elevation Adjustment. The IPM SDA documentation states that the cost methodology is based on a unit located within 500 feet of sea level:[92]

> 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. Consequently, we included this atmospheric pressure adjustment in our SDA cost model by incorporating an atmospheric pressure change with elevation calculation provided by NASA.[93]

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[89] Primex Process Specialists. "Optimizing Scrubber Performance," p. 3. Available at http://www.primexprocess.com/pdf/Paper_4.pdf

[90] IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final, March 2013. Sargent & Lundy, p. 3

[91] 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

[92] IPM SDA documentation, p. 2.

[93] 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).

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In order to utilize this calculation, we constructed Table 24, below, which uses the average of the latitude and longitude of the stack locations. We entered these coordinates into Google Earth Pro,[94] which returns the elevation above sea level.

Table 24. Elevation of Sources undergoing RP and LTS analyses

	Latitude	Longitude	Elevation
Big Brown	31.8200	-96.0552	335
Coleto Creek	28.7108	-97.2139	108
J T Deely	29.3072	-98.3228	498
Monticello	33.0913	-95.0376	384
Harrington	35.2972	-101.7475	3560
W. A. Parish	29.4792	-95.6324	79
Welsh	33.0564	-94.8458	377

As can be seen from the above table, only the Harrington facility is located at an elevation that exceeds 500 feet above sea level, and thus requires an elevation adjustment, which we included in our SDA cost model for this facility. This correction had the effect of worsening the cost effectiveness (increasing the $/ton) for Tolk by approximately 5%.

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. As we state in our Oklahoma FIP,[95] we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be well over 60 years. We identified specific scrubbers installed between 1975 and 1985 that were still in operation. Because none of the facilities involved have entered into or offered to enter into enforceable commitments to shut down the applicable units earlier, we will continue to use a 30 year equipment life for scrubber retrofits and upgrades, as we believe that is proper.

5.3.2.2 SDA Cost Model Output

A sample of the IPM SDA cost model output is depicted below in Table 25. 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.

[94] https://www.google.com/earth/.

[95] 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.

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Table 25. Sample SDA Output

Capital Cost Calculation		Explanation of Calculation	Comments
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit	
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 Capital Recovery factor	$203,640,000 0.0806	Excludes owner's costs and AFUDC	
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**		

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5.3.2.3 Summary of SDA Cost Model Results

Below in Table 26 is a summary of our SDA cost model results:

Table 26. Summary of SDA Cost Model Results

Facility	Unit	SDA Control (%)	SDA SO2 Reduction (tpy)	SDA Capital Cost	SDA Annualized Capital Cost	SDA Variable Operating Cost	SDA Fixed Operating Cost	SDA Total Annualized Cost	SDA Cost Effectiveness 2012 ($/ton)	SDA Cost Effectiveness 2016 ($/ton)
Parish	5	92.11	12,364	$272,260,000	$21,940,454	$7,948,884	$2,863,997	$32,753,335	$2,649	$2,523
	6	92.11	13,862	$285,608,000	$23,016,122	$8,524,785	$2,853,463	$34,394,370	$2,481	$2,363
Welsh	1	87.23	5,832	$210,262,000	$16,944,258	$4,625,309	$2,260,702	$23,830,270	$4,086	$3,892
Coleto Cree	1	92.41	13,632	$230,551,000	$18,579,276	$9,007,945	$3,327,934	$30,915,154	$2,268	$2,160
J T Deely	1	91.30	5,609	$202,172,000	$16,292,314	$4,617,491	$1,862,639	$22,772,444	$4,060	$3,867
	2	91.30	5,884	$192,698,000	$15,528,839	$5,220,370	$2,152,369	$22,901,577	$3,892	$3,707
Harrington	061B	90.16	4,466	$157,015,000	$12,653,274	$3,705,438	$1,968,496	$18,327,209	$4,104	$3,909
	062B	88.89	4,364	$171,141,000	$13,791,638	$3,423,240	$1,935,945	$19,150,823	$4,389	$4,180
Big Brown	1	95.00	27,453	$228,114,000	$18,382,887	$15,603,465	$3,073,521	$37,059,873	$1,350	$1,286
	2	95.00	29,108	$229,544,000	$18,498,125	$15,502,674	$3,123,862	$37,124,661	$1,275	$1,215
Monticello	1	95.00	9,095	$229,711,000	$18,511,583	$5,584,009	$1,411,698	$25,507,290	$2,804	$2,671
	2	95.00	7,844	$227,409,000	$18,326,073	$4,705,402	$1,249,282	$24,280,757	$3,095	$2,948

Some observations are apparent from the SDA cost model results displayed above:

- 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.
- Unlike the cost effectiveness of DSI, the cost effectiveness of SDA improves (lower $/ton) with increasing control levels.

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5.3.3 Impact Analysis Part 1: Cost of Compliance for Wet FGD

Table 27, 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 27. 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
Retrofit Factor	B		1	**<--- User Input (An "average" retrofit has a factor =1.0)**	
Gross Heat Rate	C	(Btu/kWh)	9,500	**<--- User Input**	5 -yr avg. excluding max and min
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

5.3.3.1 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.

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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 5.2.2, 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. We note that the cost of limestone is partly dependent on the delivery cost, but limestone is widely available within Texas. Consequently, we consider the cost algorithm default cost for delivered lime of $30/ton to be reasonable, and we have adopted it for all cases.

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. We invite comment from the affected facilities as to whether they believe more extensive wastewater treatment would be required for their facility, and if so, to provide an estimate of that cost.

5.3.3.2 Wet FGD Cost Model Output

A sample of the IPM wet FGD cost model output is depicted below in Table 28. 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.

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Table 28. Sample Wet FGD Output

Capital Cost Calculation		Explanation of Calculation	Comments
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit	
BMR($)	48,869,000	Base absorber island cost	
BMF($)	23,674,000	Base reagent preparation and waste recycle/handling cost	
BMW($)	14,536,000	Base reagent	
BMB($)	89,730,000	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($)	89,730,000	Adjustment to base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.), if elevation is greater than 500 feet. See page 2 of the S&L documentation.	
BM($)	**176,809,000**	Total Base module cost including retrofit factor	
BM($/kW)	354	Base cost per kW	
Total Project Cost			
A1	17,681,000	Engineering and Construction Mnagement costs	
A2	17,681,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.	
A3	17,681,000	Contractor profit and fees.	
CECC ($)	**229,852,000**	Capital, engineering and construction cost subtotal	Excludes Owner's Costs.
CECC($/kW)	**460**	Capital, engineering and construction cost subtotal per kW	Excludes Owner's Costs.
B1	11,493,000	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)	
TPC' ($)	**241,345,000**	Total project cost without AFUDC	Includes Owner's Costs
TPC' ($/kw)	**483**	Total project cost per kW without AFUDC	Includes Owner's Costs
B2	24,135,000	AFUDC (Based on a 3 year engineering and construction cycle)	
TPC ($)	**265,480,000**	Total Project Cost (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
TPC ($/kW)	**531**	Total Project Cost per kW (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
Fixed O&M Cost			additional factors, FOMWW and VOMWW, for a possible future base wastewater treatment facility. They are currently not used, so they are not included here.
FOMO ($/kW-yr)	3.00	Fixed O&M additional operating labor costs. IF MW > 500, then 16 operators, else 12 operators	
FOMM ($/kW-yr)	5.30	Fixed O&M additional maintenance material and labor costs	
FOMA ($/kW-yr)	0.15	Fixed O&M additional administrative labor costs	
FOM ($/kW-yr)	**8.45**	Total Fixed O&M costs	
Variable O&M Cost			
VOMR ($/MWh)	0.73	Variable O&M costs for limestone reagent	
VOMW ($/MWh)	1.31	Variable O&M costs for waste disposal	
VOMP ($/MWh)	0.95	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
VOMM ($/MWh)	0.08	Variable O&M costs for makeup water	
VOM ($/MWh)	**3.07**	Total Variable O&M Costs	
Annualization			
Capital, engineering and construction cost	$229,852,000	Excludes owner's costs and AFUDC	
Capital Recovery factor	0.0806		
Annualized capital costs	$18,522,946		
Variable operating costs	$13,184,075	VOM*(Gross Load)	
Fixed operating costs	$4,144,689	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)	
Total annualized costs	**$35,851,710**		
SO2 emissions reduction	29,061	J/(100%)*(SO2 emission baseline)	
$/ton	**1,234**		

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5.3.3.3 Summary of Wet FGD Cost Model Results

Below in Table 29 is a summary of our SDA cost model results:

Table 29. Summary of Wet FGD Cost Model Results

Facility	Unit	Wet FGD Control (%)	Wet FGD SO_2 Reduction (tpy)	Wet FGD Capital Cost	Wet FGD Annualized Capital Cost	Wet FGD Variable Operating Cost	Wet FGD Fixed Operating Cost	Wet FGD Total Annualized Cost	Wet FGD cost Effectiveness 2012 ($/ton)	Wet FGD cost Effectiveness 2016 ($/ton)
Parish	5	94.7	12,717	$283,182,000	$22,820,619	$5,798,157	$3,650,798	$32,269,573	$2,537	$2,417
	6	94.7	14,258	$297,661,000	$23,987,429	$6,218,236	$3,618,007	$33,823,673	$2,372	$2,259
Welsh	1	91.5	6,116	$230,424,000	$18,569,041	$3,546,457	$3,080,847	$25,196,345	$4,120	$3,924
Coleto Cree	1	94.9	14,005	$251,460,000	$20,264,257	$6,542,816	$4,466,198	$31,273,271	$2,233	$2,127
J T Deely	1	94.2	5,787	$223,325,000	$17,996,959	$3,403,601	$2,280,985	$23,681,544	$4,092	$3,898
	2	94.2	6,070	$212,970,000	$17,162,486	$3,847,988	$2,645,352	$23,655,827	$3,897	$3,712
Harrington	061B	93.4	4,628	$172,845,000	$13,928,957	$2,767,234	$2,449,309	$19,145,500	$4,137	$3,940
	062B	92.6	4,545	$189,971,000	$15,309,080	$2,588,791	$2,405,469	$20,303,340	$4,467	$4,254
Big Brown	1	98.0	28,320	$257,763,000	$20,772,193	$10,364,348	$4,217,796	$35,354,338	$1,248	$1,189
	2	97.9	29,998	$259,141,000	$20,883,241	$10,342,048	$4,281,131	$35,506,420	$1,184	$1,127
Monticello	1	97.0	9,286	$257,182,000	$20,725,372	$3,846,382	$1,924,967	$26,496,721	$2,853	$2,718
	2	96.8	7,995	$254,177,000	$20,483,210	$3,255,811	$1,704,028	$25,443,049	$3,182	$3,031

Some observations are apparent from the wet FDG cost model results displayed above:

- 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.
- As with our SDA cost model, the cost effectiveness of wet FGD improves (lower $/ton) with increasing control levels.

Table 30 compares the capital cost and cost effectiveness of both technologies:

Table 30. Capital cost and cost effectiveness of wet FGD versus SDA

Facility	**Unit**	**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**
Parish	5	$272,260,000	$283,182,000	3.9	$2,523	$2,417	-4.4
	6	$285,608,000	$297,661,000	4.0	$2,363	$2,259	-4.6
Welsh	1	$210,262,000	$230,424,000	8.7	$3,892	$3,924	0.8
Coleto Creek	1	$230,551,000	$251,460,000	8.3	$2,160	$2,127	-1.6

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J T Deely	1	$202,172,000	$223,325,000	9.5	$3,867	$3,898	0.8
	2	$192,698,000	$212,970,000	9.5	$3,707	$3,712	0.1
Harrington	061B	$157,015,000	$186,289,000	15.7	$3,909	$4,185	6.6
	062B	$171,141,000	$189,971,000	9.9	$4,180	$4,254	1.7
Big Brown	1	$228,114,000	$257,763,000	11.5	$1,286	$1,189	-8.1
	2	$229,544,000	$259,141,000	11.4	$1,215	$1,127	-7.8
Monticello	1	$229,711,000	$257,182,000	10.7	$2,671	$2,718	1.7
	2	$227,409,000	$254,177,000	10.5	$2,948	$3,031	2.7

- The capital cost of wet FGD is higher than SDA by approximately 4 – 16%. However, wet FGD delivers a significant improvement in the cost effectiveness for some of the units, increasing as the tonnage of SO_2 removal increases 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.

5.3.4 Impact Analysis Part 1: Cost of Compliance for Upgrading Existing Scrubbers

Of our subject-to-BART units, Martin Lake Units 1, 2, 3; Monticello Unit 3, and Fayette Units 1 and 2 are currently equipped with wet FGDs. Of these, all but the Fayette units were analyzed for scrubber upgrades in our Texas-Oklahoma FIP. As we discussed in that FIP, the cost information we relied upon was based on information claimed as CBI, which was provided to us by the facilities' parent companies. As a consequence, we could only present a summary of the cost-effectiveness. After responding to comments we revised our proposed cost-effectiveness basis from where all scrubber upgrades were less than $600/ton, to where all scrubber upgrades ranged from between $368/ton to $910/ton.[96]

We propose to rely on those total annualized cost calculations used to make the above cost-effectiveness calculations in this action. We acknowledge that these costs could change slightly, due to changes in the costs of various materials and services. However, these costs were calculated in 2013 dollars. Escalating them to 2015 dollars would result in a reduction in cost, which we conservatively ignore.[97]

Using these costs, we propose to update the cost-effectiveness of the scrubber upgrades by retaining the same 95% control level we demonstrated was reasonable, but applying it to updated baseline emissions. For instance, in Table 19 of the Cost TSD in our Texas-Oklahoma FIP, we calculated our SO_2 baseline as being the three year average from 2009-2013 SO_2 annual emissions, excluding the maximum and minimum values. Here we update that baseline to be the

[96] 81 FR 295, 318 (February 4, 2016).
[97] The CEPCI for 2013 is 567.3 and that for 2015 is 556.3. Therefore the costs would be multiplied by a factor of 556.8/567.3, which is approximately 0.98.

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same as we presently use in our DSI, SDA, and wet FGD BART cost analyses— the three year average from 2011-2015 SO_2 annual emissions, excluding the maximum and minimum values.

We will also adopt the same 30 year equipment lifetime as we used in our analysis of scrubber upgrades in our Texas-Oklahoma FIP. As we state in our Oklahoma FIP,[98] we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be well over 60 years. We identified specific scrubbers installed between 1975 and 1985 that were still in operation. Because none of the facilities involved have entered into or offered to enter into enforceable commitments to shut down the applicable units earlier, we will continue to use a 30 year equipment life for scrubber upgrades, as we believe that is proper.

In our Texas-Oklahoma FIP, we also discussed how we calculated the efficiency of the existing SO_2 scrubbers.[99] We noted that in a typical situation in which we would propose that a pollution control device such as an SO_2 scrubber be installed, we would have historical emissions data to use as a baseline. In such an instance, we would apply the control efficiency of the scrubber to the uncontrolled historical SO_2 emissions, and be able to easily propose a controlled SO_2 emission rate that would be appropriate following the installation of the scrubber. However, we faced a more difficult task in analyzing the efficiency of existing SO_2 scrubbers because CEMS data for the inlet of the scrubbers was lacking—we only had CEMS data for the outlet of the scrubbers. We discussed how we used coal quality data to establish the uncontrolled SO_2 emissions.

We calculated the scrubber removal efficiency by utilizing the reported sulfur content and tonnages of the fuels burned and reported to EIA,[100] and the monitored SO_2 scrubber outlet emissions reported to us.[101] We did this by constructing a spreadsheet[102], which among other things, divides the annual SO_2 emissions by the theoretical uncontrolled SO_2 emissions based on coal sulfur content to estimate the percentage of SO_2 in the coal that is emitted. We calculated the theoretical uncontrolled SO_2 emissions from EIA reported coal sulfur data. This calculation is summarized below for a typical unit that burns both lignite and subbituminous coals:

(1)

[98] 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.
[99] See the Cost TSD in our Texas-Oklahoma FIP, Section 6.1. We incorporate the information in this document into our current proposal.
[100] EIA Form 923. Available at http://www.eia.gov/electricity/data/eia923/
[101] EPA Air Markets and Programs Data. Available at http://ampd.epa.gov/ampd/
[102] See "Coal vs CEM data 2009-2013.xlsx," tab "charts," cell H12.

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or, alternatively expressed in tons:

(2)

and the scrubber efficiency is then:

(3)

In equations (1) and (2), the percentage and tonnage values are those reported by the facility to the EIA for each fuel type. In equation (3), the annual EPA reported tons of SO_2 are those reported to us.[103]

We now update these calculations for 2011-2015 data.[104] The revised scrubber upgrade results for Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are presented below in Table 31:

Table 31. Summary of Updated Scrubber Upgrade Results

Unit	2011-2015 3-yr Avg. SO_2 Emissions (eliminate max and min) (tons)	SO_2 Emissions at 95% Control (tons)	SO_2 Emissions Reduction Due to Scrubber Upgrade (tons)	SO_2 Emission Rate at 95% Control (lbs/MMBtu)
Monticello 3	8,136	1,180	6,956	0.05
Martin Lake 1	19,040	3,208	15,832	0.12
Martin Lake 2	17,973	3,393	14,580	0.12
Martin Lake 3	16,113	2,591	13,522	0.11
Total SO_2 Removed			50,890	

As we note above, we updated the cost effectiveness for each of these units. Because those calculations depended on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost effectiveness was $1,156/ton or less. We invite the facilities listed above to make arrangements with us to view our complete updated cost analysis for their units.

[103] EPA Air Markets and Programs Data. Available at http://ampd.epa.gov/ampd/
[104] See "Coal vs CEM data 2011-2015.xlsx.

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The Fayette (Sam Seymour) Units 1 and 2 are currently equipped with high performing wet FGDs. This can be seen from an examination of Figures 2 and 3 below:[105]

Figure 2: 30 BOD SO_2 Average for Fayette Unit 1

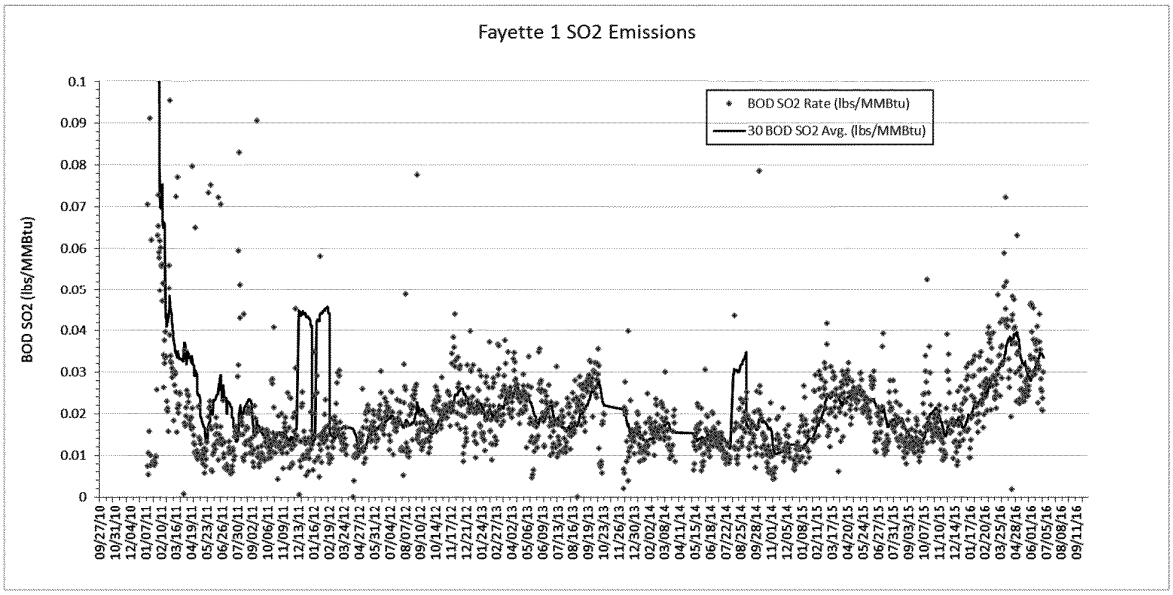
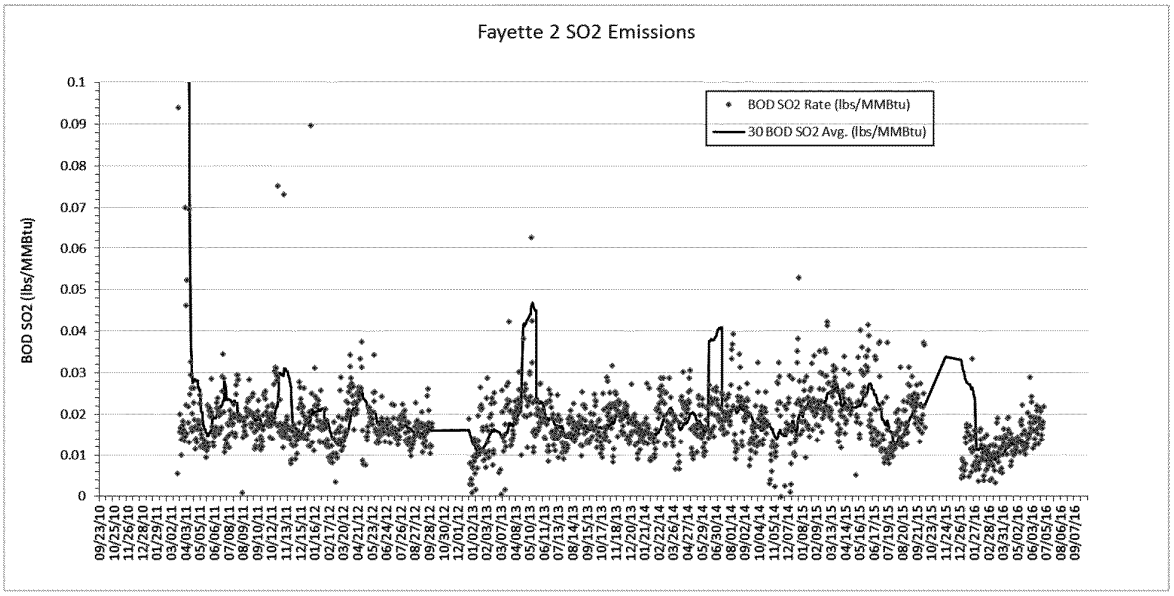


Figure 3: 30 BOD SO_2 Average for Fayette Unit 1



[105] See the file, "Fayette emissions.xlsx."

As can be seen from the above figures, the Fayette Units have both demonstrated the ability to maintain a SO_2 30 BOD average below 0.04 lbs/MMBtu for years at a time. As we discuss above, we evaluate BART demonstrating that retrofit wet FGDs should be evaluated at 98% control not to go below 0.04 lbs/MMBtu. Because the Fayette units are performing below this level, we propose that no scrubber upgrades are necessary. We propose to find that the Fayette Units 1 and 2 maintain a 30 Boiler Operating Day rolling average SO_2 emission rate of 0.04 lbs/MMBtu based on the actual emissions data we present above. We believe, based on its demonstrated ability to maintain an emission rate below this value on a 30 BOD basis, it can consistently achieve this emission level.

5.3.5 Impact Analysis Part 1 Cost of Compliance for Switching to a Lower Sulfur Fuel Oil for Gas-Fired Units

In section 5.1.2.1, we discussed the Section 114 letters we sent to a number of gas-fired facilities. Question 4 requested information on the cost of lower sulfur fuel oil. We received very limited information in response to Question 4. Because of this, we were unable to compile facility-specific information on the technical feasibility under BART of these facilities burning fuel oils of sulfur contents lower than historically burned.

However, information from the EIA indicates that fuel oil of varying sulfur contents is widely available across the U.S. EIA reports the prices for various refinery petroleum products on a monthly and annual basis. Below is summary of various distillate and residual fuel oil products for 2001 to 2015, averaged across the U.S."[106]

Table 32. Selected EIA Reported Annual Refiner Petroleum Prices

Date	West Texas Intermediate Crude Oil – Cushing Oklahoma ($/bbl)	U.S. No 2 Diesel Wholesale/Resale Price by Refiners ($/Gallon)	U.S. No. 2 Fuel Oil Wholesale/Resale Price by Refiners ($/Gallon)	U.S. No 4 Distillate Wholesale/Resale Price by Refiners ($/Gallon)
2015	48.66	1.667	1.565	1.215
2014	93.17	2.812	2.741	2.333
2013	97.98	3.028	2.966	2.767
2012	94.05	3.109	3.031	
2011	94.88	3.034	2.907	2.801
2010	79.48	2.214	2.147	
2009	61.95	1.713	1.657	1.561
2008	99.67	2.994	2.745	2.157
2007	72.34	2.203	2.072	1.551
2006	66.05	2.012	1.834	1.395

[106] EIA Refiner Petroleum Product Prices by Sales Type, available here: http://www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_a.htm; http://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm

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2005	56.64	1.737	1.623	1.377
2004	41.51	1.187	1.125	1.033
2003	31.08	0.883	0.881	0.793
2002	26.18	0.724	0.694	0.663
2001	25.98	0.784	0.756	0.697
2000	30.38	0.898	0.886	0.778

As can be seen from the above table, the price of these fuel oils closely tracks the price of crude oil, and are fairly volatile.

Lacking facility-specific pricing information, for the purposes of calculating the cost of compliance, we make the following assumptions:

- No. 4 distillate is the type of fuel oil currently available that most closely approximates the types of fuel oil that were historically burned by the facilities. It is available in a range of sulfur up to the facilities' permitted maximum of 0.7% sulfur by weight or 7,000 ppm. We will use the cost of this fuel oil along with the SO_2 baselines we discuss in the next section in constructing "business as usual" scenarios of the annual cost of fuel oil.
- No. 2 fuel oil is available at approximately 3,000 ppm, which roughly corresponds to the sulfur level present in No. 2 fuel oil prior to our implementation of the Ultra-Low-Sulfur Diesel (ULSD) regulations.[107] We will use the cost of this fuel oil along with the SO_2 baselines we discuss in the next section in constructing a "medium control" annual cost of fuel oil..
- No. 2 diesel fuel corresponds to ULSD, with a sulfur content of 15 ppm. We will use the cost of this fuel oil along with the SO_2 baselines we discuss in the next section in constructing a "high control" annual cost of fuel oil.

5.3.5.1 SO_2 Baseline for Gas-Fired Units that Occasionally Burn Oil

As we discuss in our DSI, SDA, and Wet FGD SO_2 BART analyses, for the coal-fired units we have analyzed under BART, we employed a baseline selected as the 2011 – 2015 five year average of the SO_2 annual emissions, excluding the maximum and minimum values. We do not believe that approach would be reasonable here, due to the unpredictable, random history of oil burning the units in question exhibit. For instance, the historical fuel oil burning practices of the Graham Unit 2 are presented below:[108]

Table 33. Graham Unit 2 Historic Fuel Oil Burning Practices

Year	Barrels of Fuel Oil Burned
2000	0

[107] 69 FR 38957, 39073 (June 29, 2004): "Both high sulfur No. 2–D and No. 2 fuel oil must contain no more than 5000 ppm sulfur,131 and currently [as of the date of our final rule, 6/29/04] averages 3000 ppm nationwide."
[108] This and other baseline and emission data in this section can be found in the file, Gas-fired SO_2 emissions.xlsx" in our docket.

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2001	31,500
2002	9,800
2003	23,300
2004	2,200
2005	25,219
2006	15,567
2007	2,971
2008	421
2009	0
2010	0
2011	19
2012	25,911
2013	0
2014	0
2015	0

Were we to adopt the same baseline calculation methodology we employed in our BART assessment of the coal units we analyzed, we would consider only the SO_2 resulting from the amount of oil burned from 2011 to 2015. We would eliminate the high SO_2 year (2012) and low SO_2 year (2013), and average the SO_2 from the remaining three years (2011, 2014, 2015), resulting in a baseline based on the SO_2 emissions resulting from burning 6.3 barrels of fuel oil. We conclude this result may not capture the BART Guidelines requirement that, "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source."[109] Alternatively, we could examine the effect a range of different SO_2 baselines could have on the cost. For instance, we could evaluate SO_2 baselines based on the following three scenarios:

- The maximum annual SO_2 resulting from fuel oil burned from 2000 to 2015.
- An average of the SO_2 of any years from 2000 to 2015 when any fuel oil was burned.
- An average of the SO_2 from 2011 to 2015.

This information is presented below:

Table 34. SO_2 Baselines for Gas Fired Units that Occasionally Burn Oil

Unit	Max SO_2 tons (2000-2015)	Average SO_2 tons (2000-2015)	Average SO_2 tons (2011-2015)
Graham 2	1287.0	141.5	0.5
Newman 2	1.2	1.0	1.0
Newman 3	1.4	1.4	1.4
O W Sommers 1	54.8	12.3	1.9
O W Sommers 2	6.6	2.8	2.4
Stryker Creek 2	145.5	40.7	0

[109] 70 FR 39104, 39167 (July 6, 2005) [40 CFR Part 51, App. Y].

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Wilkes 1	14.5	5.3	1.3

As can be seen from Table 34, with the exception of Graham Unit 2, the SO_2 emission baselines, regardless of the method employed, are very small. We would expect that regardless of the baseline selected, a cost-effectiveness calculation that simply depended on differing fuel oil costs and the resulting reductions in SO_2, would result in approximately the same value. In other words, the cost-effectiveness in $/ton should be independent of the SO_2 baseline, since *in this case,* it is calculated on a unit basis—the increased cost in burning a unit of fuel divided by the increased reduction in the resulting SO_2. Unfortunately, that does not occur, because we do not see a regular correspondence between the reported amount and sulfur content of the fuel oil burned with the reported SO_2 emissions. In other words, according to the data a barrel of fuel oil burned with about the same sulfur content does not result in the same amount of SO_2 emitted over time, nor does the expected trend always occur in the right direction. This can be illustrated by examining selected EIA and monitoring data for the Graham Unit 2:

Table 35. Graham Unit 2 Example Discordance in Fuel Oil Burned and Reported SO_2

Date (month/year)	Quantity Fuel Oil Burned (bbls)	Reported SO_2 emissions for month (tons)	Reported EIA sulfur content (wt%)
Mar-02	9,800	21.614	0.65
Feb-03	8,400	90.389	0.66
Jun-12	18,177	0.064	0.50
Jul-12	5,657	0.07	0.50

As can be seen from the above table, even though the reported sulfur content of the fuel oil in March, 2002 and February 2003 was approximately the same, and the quantity burned was fairly close, the resulting reported SO_2 was significantly different. Similarly, although the amount of fuel oil burned in June, 2012 was more than three times that burned in July 2012 (at the same sulfur content), the reported SO_2 in June 2012 was less than that in July 2012. Also, although the fuel oil sulfur content in the 2012 examples was only slightly less than that in the 2002/2003 examples, and the amount of fuel oil burned was the same order of magnitude, the resulting reported SO_2 in 2012 was three orders of magnitude less than that in 2002/2003. Further examination of the CAMD emissions data for Graham and Stryker revealed that the data contained a large amount of substitute data for SO_2 emissions and heat input during periods when the units burned fuel oil. Some of these substitute values were much higher than the maximum potential emissions from the units.[110] As a result of these issues, we cannot construct reasonable SO_2 baselines for the gas fired units that occasionally burn fuel oil. This impacts both the visibility modeling and the control cost analyses we perform on these units causing us to adopt alternative approaches.

5.3.5.2 Cost Analysis for Gas-Fired Units that Occasionally Burn Oil

[110] See the file, "Gas-fired SO2 emissions comparison and calcs.xlsx," in our docket for emission data.

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As a consequence of this discordance between the reported type and amount of fuel oil burned and the reported SO_2, we cannot rely on historical SO_2 emissions to construct a baseline, because a barrel of fuel oil with a given reported sulfur content does not result in a consistent reported SO_2 value over time. Instead, we will conduct our cost-effectiveness analysis on the basis of unit values of 1,000 barrels, using the following assumptions:

- Fuel oil costs can be based on the 2015 U.S. average prices as reported in Table 32 for No. 4 distillate at 0.7 wt. % (the permitted maximum for all units) as the current business as usual fuel, No. 2 fuel oil at 0.3wt. % as the moderate control option, and No. 2 diesel at 0.0015% as the high control option.
- The emission factor for calculating the tons of sulfur emitted by the three fuel oils can be taken from AP 42.[111]

Below is the result of that calculation:

Table 36. Cost Effectiveness of Switching to Lower Sulfur Fuel Oils

	Cost for 1,000 barrels baseline ($/yr)	**Tons reduced for 1,000 barrels**	**Cost effectiveness for 1,000 barrels ($/ton)**
Business as usual (No. 4 distillate $1.215/gal)	$51,030	N/A	N/A
Moderate control (No. 2 fuel oil $1.565/gal)	$65,730	1.26	$11,218
High control (ULSD $1.667/gal)	$70,014	2.20	$8,627

Although the cost-effectiveness of switching to a lower sulfur oil is less attractive (higher $/ton) than other controls we have typically required under BART, we note certain mitigating factors. For instance, unlike the wet FGD and SDA scrubbers we have costed in other sections of this TSD, which have large capital costs, we are unaware of any significant capital costs involved in switching fuels. Also, because the units in question have only occasionally burned fuel oil, they have the option to avoid the cost of fuel switching entirely by not continuing to burn fuel oil and instead relying on their primary fuel of natural gas. Lastly, we note that the prevalence of ULSD in the fuel oil market is such that it appears to be gradually replacing most other No. 2 fuel oil applications.[112] In fact, in responding to our Section 114 letter, the Wilkes facility stated that its current contract was for ULSD.

In Section 5.1.2.1, we concluded that certain types of wet scrubbers were technically feasible as potential control options for gas boilers that occasionally burn oil, similar to the ones under BART review here. Were we to calculate the cost effectiveness of a wet FGD, similar to those under consideration for the coal units undergoing BART review, we could expect that the capital

[111] The emission factor used is 150 X S, where S = weight % sulfur, taken from AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.3, Fuel Oil Combustion, available here: https://www3.epa.gov/ttn/chief/ap42/ch01/index.html. Boilers > 100 Million Btu/hr,, No. 4 oil fired.
[112] http://www.eia.gov/todayinenergy/detail.php?id=5890. http://blogs.platts.com/2014/05/07/heating-oil-new-york-sulfur/. http://oilandenergyonline.com/challenges-to-the-northeast-supply-picture/

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and operating costs would minimally be on the same order, as displayed in Table 29. It is a straightforward exercise to demonstrate that the installation of such a scrubber on any of the gas-fired units that occasionally burn oil is not cost-effective.

For instance, taking the smallest total annualized cost in Table 29, corresponding to the Harrington Unit 0161B (approximately the same size as the Graham Unit 2), results in a value of $19,145,500. Assuming a 98% reduction from a baseline equal to the largest annual SO_2 emissions from any of the gas units, 1,287 tons/year (Graham Unit 2, 2001), results in a SO_2 reduction of 1,261 tons/year. The cost-effectiveness is then $15,183/ton. We do not consider this to be cost effective. In addition, the annual SO_2 values for Graham Unit 2 from 2002 to 2015, and the annual SO_2 values for the remaining units, have always been an order of magnitude less than the 2001 Graham Unit 2 value. Indeed, as we discuss above, we suspect that the Graham Unit 2's reported SO_2 tonnage from 2001 is incorrect.

5.3.6 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 BART analyses in the following manner:

- For all uncontrolled coal-fired units undergoing SO_2 BART analysis, we have calculated the incremental cost-effectiveness of DSI_{50} to $DSI_{80/90}$, $DSI_{80/90}$ to SDA, and SDA to wet FGD.
- For all gas-fired units that occasionally burn oil, we have calculated the incremental cost-effectiveness of burning fuel oil with a sulfur content of 0.3% to a fuel oil with a sulfur content of 0.0015%.

This information is presented below:

Table 37. Summary of Coal-Fired EGU SO_2 BART Incremental Cost-Effectiveness

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Facility	Unit	Control	Control level (%)	SO_2 reduction (tpy)	2016 Annualized Cost	2016 Cost Effectiveness ($/ton)	2016 Incremental Cost-Effectiveness ($/ton)
Big Brown	1	DSI	50	14,448	$29,468,587	$2,040	
		DSI	90	26,006	$72,131,749	$2,774	$3,691
		SDA	95	27,453	$35,297,532	$1,286	-$25,456
		Wet FGD	98	28,320	$33,673,102	$1,189	-$1,874
	2	DSI	50	15,320	$29,342,350	$1,915	
		DSI	90	27,576	$71,322,593	$2,586	$3,425
		SDA	95	29,108	$35,359,239	$1,215	-$23,475
		Wet FGD	97.9	29,998	$33,817,952	$1,127	-$1,732
Monticello	1	DSI	50	4,787	$11,408,872	$2,383	
		DSI	90	8,617	$25,409,128	$2,949	$3,655
		SDA	95	9,095	$24,294,319	$2,671	-$2,332
		Wet FGD	97	9,286	$25,236,699	$2,718	$4,934
	2	DSI	50	4,129	$9,742,648	$2,360	
		DSI	90	7,431	$21,418,734	$2,882	$3,536
		SDA	95	7,844	$23,126,113	$2,948	$4,134
		Wet FGD	96.8	7,995	$24,233,133	$3,031	$7,331
Coleto Creek	1	DSI	50	7,376	$16,246,169	$2,203	
		DSI	90	13,277	$34,841,379	$2,624	$3,151
		SDA	92.4	13,632	$29,445,018	$2,160	-$15,201
		Wet FGD	94.9	14,005	$29,786,106	$2,127	$914
Harrington	061	DSI	50	2,477	$9,187,608	$3,710	

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	B						
		DSI	80	3,962	$16,073,779	$4,057	$4,637
		SDA	90.2	4,466	$17,455,679	$3,909	$2,742
	062 B	DSI	50	2,455	$6,524,937	$2,658	
		DSI	**88.9**	4,364	$11,981,111	$2,746	$2,858
		SDA	88.9	4,364	$18,240,127	$4,180	N/A
J T Deely	1	DSI	50	3,072	$8,854,319	$2,883	
		DSI	90	5,529	$18,071,878	$3,269	$3,752
		SDA	91.3	5,609	$21,689,526	$3,867	$45,221
		Wet FGD	94.2	5,787	$22,555,395	$3,898	$4,864
	2	DSI	50	3,222	$9,865,798	$3,062	
		DSI	90	5,800	$20,229,233	$3,488	$4,020
		SDA	91.3	5,884	$21,812,518	$3,707	$18,849
		Wet FGD	94.2	6,070	$22,530,901	$3,712	$3,862
Welsh	1	DSI	50	3,343	$8,963,761	$3,469	
		DSI	**87.2**	5,832	$23,090,408	$3,960	$5,676
		SDA	87.2	5,832	$22,697,048	$3,892	N/A
		Wet FGD	91.5	6,116	$23,998,161	$3,924	$4,581
W. A. Parish	5	DSI	50	6,712	$15,002,337	$2,235	
		DSI	90	12,081	$30,865,711	$2,555	$2,955
		SDA	92.1	12,364	$31,195,787	$2,523	$1,166
		Wet FGD	94.7	12,717	$30,735,030	$2,417	-$1,305
	6	DSI	50	7,525	$16,014,988	$2,128	
		DSI	90	13,545	$33,302,528	$2,459	$2,872
		SDA	92.1	13,862	$32,758,784	$2,363	-$1,715

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		Wet FGD	94.7	14,258	$32,215,226	$2,259	-$1,373

Table 38. Summary of Oil-Fired EGU SO_2 BART Incremental Cost-Effectiveness

	Cost for 1,000 barrels baseline ($/yr)	**Tons reduced for 1,000 barrels**	**Cost effectiveness for 1,000 barrels ($/ton)**	**Incremental Cost-Effectiveness ($/ton)**
Business as usual (No. 4 distillate $1.215/gal)	$51,030	N/A	N/A	
Moderate control (No. 2 fuel oil $1.565/gal)	$65,730	1.26	$11,218	
High control (ULSD $1.667/gal)	$70,014	2.20	$8,627	-$2,756

5.3.7 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."[113] 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 all cases. 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:[114]

> 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 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

[113] 70 FR 39104, 39168 (July 6, 2005) [40 CFR Part 51, App. Y].
[114] *Id.* At 39169.

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> 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.

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 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. Consequently, we believe that with one possible exception, any non-air quality environmental impacts have been adequately considered in our analyses. We are aware that the Harrington facility has instituted a water recycling program and obtains some of its water from the City of Amarillo.[115] Due to potential non-air quality concerns, we limit our SO_2 control analysis for Harrington to DSI and dry scrubbers.

Regarding the remaining useful life, the BART Guidelines advise:[116]

> 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 any of the facilities we have analyzed for BART have entered into or offered to enter into enforceable commitments to shut down the applicable units 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 proper.

5.4 BART Five Factor Analysis for PM

In our recent Texas-Oklahoma FIP, we initially proposed to approve Texas' determination that no PM BART controls were appropriate for its EGUs, based on a screening analysis of the visibility impacts from just PM emissions and the premise that EGU SO_2 and NO_X were covered separately by participation in CSAPR (allowing consideration of PM emissions in isolation).

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[115] http://www.powermag.com/xcel-energys-harrington-generating-station-earns-powder-river-basin-coal-users-group-award/.

[116] 70 FR 39104, 39169 (July 6, 2005) [40 CFR Part 51, App. Y].

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Because of the CSAPR remand and resulting uncertainty regarding SO_2 and NO_X BART for EGUs, we decided not to finalize our proposed approval of Texas' PM BART determination.[117] For reasons earlier stated we are proposing to disapprove the SIP determination regarding PM BART for EGUs. Following from that proposed disapproval, we are proposing a PM BART FIP for those Texas EGUs that are subject to BART.

The BART Guidelines permit us to conduct a streamlined analysis of PM BART in two key ways. First, the Guidelines allow a streamlined analysis for PM sources subject to MACT standards. Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, the Guidelines state it is permissible to rely on MACT standards for purposes of BART.[118]

Second, with respect to gas-fired units, which have inherently low emissions of PM (as well as SO_2), the Regional Haze Rule did not specifically envision new or additional controls or emissions reductions from the PM BART requirement. The BART guidelines preclude us from stating that PM emissions are *de minimis* when plant-wide emissions exceed 15 tons per years. While we must assign PM BART determinations to the gas-firing units, there are no practical add-on controls to consider for setting a more stringent PM BART emissions limit. The Guidelines state that if the most stringent controls are made federally enforceable for BART, then the otherwise required analyses leading up to the BART determination can be skipped.[119]

With this background, we are providing our evaluation along with some supplementary information on the BART sources as divided into two categories: coal-fired EGUs, and gas-fired EGUs.

5.4.1 BART Five Factor Analysis for PM for Coal-Fired Units

All of the coal-fired EGUs that are subject to BART are currently equipped with either Electrostatic Precipitators (ESPs) or baghouses, or both as can be seen from Table 39:

Table 39. Current PM Controls for Coal-Fired Units Subject to BART

Facility Name	Unit ID	Fuel Type (Primary)	SO_2 Control(s)	PM Control(s)
Big Brown	1	Coal		Baghouse +Electrostatic Precipitator
Big Brown	2	Coal		Baghouse + Electrostatic Precipitator
Coleto Creek	1	Coal		Baghouse
Harrington Station	061B	Coal		Electrostatic Precipitator
Harrington Station	062B	Coal		Baghouse
J T Deely	1	Coal		Baghouse

[117] 81 FR 302 (January 5, 2016).
[118] 70 FR 39163-39164
[119] 70 FR 39165 ("…you may skip the remaining analyses in this section, including the visibility analysis…")

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J T Deely	2	Coal		Baghouse
Martin Lake	1	Coal	Wet Limestone	Electrostatic Precipitator
Martin Lake	2	Coal	Wet Limestone	Electrostatic Precipitator
Martin Lake	3	Coal	Wet Limestone	Electrostatic Precipitator
Monticello	1	Coal		Baghouse + Electrostatic Precipitator
Monticello	2	Coal		Baghouse + Electrostatic Precipitator
Monticello	3	Coal	Wet Limestone	Electrostatic Precipitator
Fayette	1	Coal	Wet Limestone	Electrostatic Precipitator
Fayette	2	Coal	Wet Limestone	Electrostatic Precipitator
W A Parish	WAP5	Coal		Baghouse
W A Parish	WAP6	Coal		Baghouse
Welsh Power Plant	1	Coal		Baghouse (Began Nov 15, 2015) + Electrostatic Precipitator

As an initial matter, we examine the control efficiencies of both baghouses and ESPs. We consider a baghouse, widely reported to be capable of 99.9% control of PM, to be a BART-level control for PM and so the units equipped with a baghouse will not be further analyzed for PM BART. The remaining units are fitted with ESPs.

The particulate matter control efficiency of ESPs varies somewhat with the design, the resistivity of the particulate matter, and the maintenance of the ESP. We do not have any information on the control level efficiency of any of the ESPs for the units in question. However, reported control efficiencies for well-maintained ESPs typically range from greater than 99% to 99.9%.[120] We conclude that the potential additional particulate control that a baghouse can offer over an ESP is relatively minimal.[121]

Nevertheless, we will examine the potential cost of retrofitting a typical 500 MW coal fired unit. Using our baghouse cost algorithms, as employed in version 5.13 of our IPM model,[122] and assuming a conservative air to cloth ration of 6.0, results in a capital engineering and

[120] EPA, "Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) - Wire Plate Type," EPA-452/F-03-028. Grieco, G., "Particulate Matter Control for Coal-fired Generating Units: Separating Perception from Fact," apcmag.net, February, 2012. Moretti, A. L.; Jones, C. S., "Advanced Emissions Control Technologies for Coal-Fired Power Plants, Babcox and Wilcox Technical Paper BR-1886, Presented at Power-Gen Asia, Bangkok, Thailand, October 3-5, 2012

[121] We do not discount the potential health benefits this additional control can have for ambient PM. However, the regional haze program is only concerned with improving the visibility at Class I areas.

[122] IPM Model – Updates to Cost and Performance for APC Technologies, Particulate 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 5-7: PM Cost Methodology, downloaded from: https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-7_pm_cost_methodology.pdf

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construction cost of $77,428,000.[123] Applied to the subject units, this cost assumes a retrofit factor of 1.0, and does not consider the demolition of the existing ESP, should it be required in order to make space for the baghouse.

We do not calculate the cost-effectiveness resulting from replacing an ESP with a baghouse. However, we expect that the tons of additional PM removed by a baghouse over an ESP to be very small, which would result in a very high cost-effectiveness figure. Also, we do not model the visibility benefit of replacing an ESP with a baghouse. However, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from replacing an ESP with a baghouse to be a small fraction of that. For instance, our CAMx baseline modeling shows that on a source-wide level, impacts from PM emissions on the maximum impacted days from each source at each Class I area was 3% of the total visibility impairment or less (calculated as percent of total extinction due to the source). Therefore, additional PM controls are anticipated to result in very little visibility benefit on the maximum impacted days. Similarly, our CALPUFF modeling indicates that visibility impairment from PM is also a small fraction (typically only a few percent) of the total visibility impairment due to each source.

Adding to the above discussion, we are tasked to assign the enforceable emission limitations that constitute PM BART. We believe a stringent control level that would be met with existing or otherwise-required controls is a filterable PM limit of 0.03 lb/MMBtu for each of the coal-fired units subject to BART. We note that the Mercury and Air Toxics (MATS) Rule establishes an emission standard of 0.03 lb/MMBtu filterable PM (as a surrogate for toxic non-mercury metals) as representing Maximum Achievable Control Technology (MACT) for coal-fired EGUs.[124] This standard derives from the average emission limitation achieved by the best performing 12 percent of existing coal-fired EGUs, as based upon test data used in developing the MATS Rule. We are not familiar with any new technologies subsequent to this standard that could lead to any cost effective increases in the level of control; thus, consistent with the BART Guidelines, we are proposing to rely on this limit for purposes of PM BART for all of the coal-fired units as part of our FIP. We understand the coal-fired units covered by this proposal to be subject to MATS, but to the extent the units may be following alternate limits that differ from the surrogate PM limits found in MATS, we welcome comments on different, appropriately stringent limits reflective of current control capabilities.[125] Because we anticipate that any limit we assign should be achieved by current control capabilities, we propose that compliance can be met at the effective date of the rule. To address periods of startups and shutdowns, we are further proposing that PM BART for these units will additionally be met by following the work practice standards specified in 40 CFR Part 63, subpart UUUUU, Table 3, and using the relevant definitions in 63.10042. We are proposing that the demonstration of compliance can be satisfied by the methods for demonstrating compliance with filterable PM limits that are specified in 40 CFR Part 63, subpart UUUUU, Table 7. However, we would give consideration to commenter-submitted requests for alternate or additional methods of demonstrating compliance.

[123] Id. See page 9.

[124] 77 FR 9304, 9450, 9458 (February 16, 2012) (codified at 40 CFR 60.42 Da(a), 60.50 Da(b)(1)); 40 CFR Part 63 Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units.

[125] The various limits are provided at 40 CFR Part 63, Subpart UUUUU, Table 2 ("Emission Limits for Existing EGUs")

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5.4.2 BART Five Factor Analysis for PM for Gas-Fired Units

In Section 5.1.2, we noted that four of the units identified in Table 10 as being subject to BART, are only permitted to burn gas: Newman Unit 4, W A Parish Unit 4, and Wilkes Units 2 and 3. We note that PM emissions for the gas-only fired units that are subject to BART are inherently low.[126] We therefore conclude that PM emissions from natural gas firing is so minimal that the installation of any additional PM controls on the unit would likely achieve very low emissions reductions and have minimal visibility benefits. As there are no appropriate add-on controls and the status quo reflects the most stringent controls, we are proposing to make the requirement to burn pipeline natural gas federally enforceable. We note that in addition to satisfying PM BART, this limitation will also serve to satisfy SO_2 BART for these gas-fired units, as well as the fuel-oil units when they fire natural gas. We are proposing that PM and SO_2 BART for gas fired-units will limit fuel to pipeline natural gas, as defined at 40 CFR 72.2.

The available PM controls for gas units that also burn fuel oil are the same for the coal-fired units. We would expect similar costs for installing a baghouse on a typical gas-fired boiler that occasionally burns fuel oil. Again, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from the installation of a baghouse to be a small fraction on the order of 1-3 % of the visibility impacts from the facility. We are confident that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted with an ESP. We conclude that the cost of a baghouse does not justify the minimal expected improvement in visibility for these units. Accordingly, we are proposing that the fuel content limits for oil burning that we propose to meet SO_2 BART will also satisfy PM BART.

Lastly, should our assumptions regarding the frequency and type of fuel oil burned in these units significantly change, we expect that Texas will address such a change appropriately in its SIP, which we will review in the next planning period.

5.5 Step 5: Evaluate Visibility Impacts

Please see the BART Modeling TSD, where we describe in detail the various modeling runs we conducted, our methodology and selection of emission rates, modeling results, and final modeling analysis that we used to evaluate the benefits of the proposed controls and their associated emission decreases on visibility impairment values. 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.

5.5.1 Visibility Benefits of DSI, SDA, and Wet FGD for Coal-Fired Units

We evaluated the visibility benefits of DSI, for the twelve units depicted in Tables 40 and 41 below that currently have no SO_2 control. We evaluated all the units using the control levels we employed in our control cost analyses. In summary, we evaluated these units at a DSI SO_2

[126] AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.4, Natural Gas Combustion, available here: https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.

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control level of 50%, which we believe is likely achievable for any unit. At the lower performance level we assumed, we conclude that the corresponding visibility benefits from DSI in most cases would be close to half of the benefits from scrubbers resulting in the visibility benefits from scrubber retrofits being much more beneficial. We also evaluated the visibility benefits for scrubber retrofits (wet FGD and SDA) for these same units, assuming the same control levels corresponding to SDA and wet FGD that we used in our control cost analyses. For those sources that are within 50 to 400 km of a Class I area, we utilized CALPUFF modeling and supplemented our analysis with CAMx modeling to assess the visibility benefit of potential controls. For the remaining coal-fired sources (J T Deely, Coleto Creek, Fayette and W A Parish), only CAMx modeling was utilized as these sources are located at much greater distances to the nearest Class I areas. 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.[127] We note that high control scenario modeling for Fayette units 1 and 2 demonstrate the benefit from existing high performing controls. As discussed elsewhere, we found that for these units no additional controls or upgrades were necessary. For a full discussion of our review of all the modeling results, and factors that we considered in evaluating and weighing all the results, see our BART Modeling TSD. Below, we present a summary of some of those visibility benefits at the Class I areas most impacted by each source:

Table 40. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CAMx modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD(98%)	DSI benefit	WFGD benefit
Big Brown	Source (Unit 1 and 2)	WIMO	Max dv	4.017	2.249	0.474	1.768	3.542
			Days > 0.5 dv	65	33	0	32	65
			Days>1.0 dv	33	13	0	20	33
		CACR	Max dv	3.775	2.539	0.787	1.236	2.988
			Days > 0.5 dv	91	62	4	29	87
			Days>1.0 dv	57	21	0	36	57
	Unit 1	WIMO	Max dv	2.154	1.168	0.245	0.986	1.909
			Days > 0.5 dv	33	13	0	20	33
			Days>1.0 dv	12	1	0	11	12
		CACR	Max dv	2.016	1.327	0.409	0.688	1.606
			Days > 0.5 dv	58	22	0	36	58
			Days>1.0 dv	17	4	0	13	17
	Unit 2	WIMO	Max dv	2.175	1.181	0.235	0.994	1.940
			Days > 0.5 dv	34	13	0	21	34
			Days>1.0 dv	12	1	0	11	12
		CACR	Max dv	2.033	1.338	0.391	0.695	1.642
			Days > 0.5 dv	58	23	0	35	58

[127] 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."

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			Days>1.0 dv	17	4	0	13	17
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63
			Days>1.0 dv	40	14	0	26	40
	Unit 1	CACR	Max dv	4.516	3.123	0.733	1.393	3.783
			Days > 0.5 dv	79	43	3	36	76
			Days>1.0 dv	32	16	0	16	32
		WIMO	Max dv	2.241	1.290	0.252	0.951	1.989
			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	8	2	0	6	8
	Unit 2	CACR	Max dv	4.487	3.065	0.563	1.422	3.924
			Days > 0.5 dv	78	42	1	36	77
			Days>1.0 dv	30	13	0	17	30
		WIMO	Max dv	2.189	1.252	0.186	0.937	2.003
			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	6	2	0	4	6
Coleto Creek	Source (Unit 1)	WIMO	Max dv	0.845	0.526	0.176	0.318	0.668
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.791	0.458	0.186	0.333	0.606
			Days > 0.5 dv	5	0	0	5	5
			Days>1.0 dv	0	0	0	0	0
Harrington[1]	Source (Unit 061B & 062B)	SACR	Max dv	5.288	4.287	3.235	1.001	2.053
			Days > 0.5 dv	13	7	3	6	10
			Days>1.0 dv	5	1	1	4	4
		WIMO	Max dv	4.928	4.362	3.798	0.565	1.130
			Days > 0.5 dv	15	11	6	4	9
			Days>1.0 dv	6	5	4	1	2
	Unit 061B	SACR	Max dv	2.908	2.322	1.738	0.586	1.170
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.708	2.382	2.065	0.326	0.643
			Days > 0.5 dv	6	5	4	1	2
			Days>1.0 dv	4	2	1	2	3
	Unit 062B	SACR	Max dv	2.998	2.373	1.719	0.625	1.279
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.770	2.407	2.046	0.363	0.723
			Days > 0.5 dv	6	5	4	1	2
			Days>1.0 dv	4	1	1	3	3
J T Deely	Source (Sommers	WIMO	Max dv	1.513	0.939	0.814	0.574	0.699
			Days > 0.5 dv	47	8	1	39	46

	1&2, J T Deely 1&2)							
			Days>1.0 dv	6	0	0	6	6
		CACR	Max dv	1.423	1.155	0.905	0.268	0.518
			Days > 0.5 dv	7	3	2	4	5
			Days>1.0 dv	2	1	0	1	2
	J T Deely 1	WIMO	Max dv	0.757	0.449	0.270	0.307	0.487
			Days > 0.5 dv	4	0	0	4	4
			Days>1.0 dv	0	0	0	0	0
		BIBE	Max dv	0.652	0.373	0.069	0.279	0.583
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
	J T Deely 2	WIMO	Max dv	0.632	0.387	0.334	0.245	0.298
			Days > 0.5 dv	3	0	0	3	3
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.604	0.490	0.387	0.114	0.217
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
W.A. Parish	Source (WAP 4,5, &6)	CACR	Max dv	3.177	2.032	0.511	1.145	2.665
			Days > 0.5 dv	54	26	1	28	53
			Days>1.0 dv	22	9	0	13	22
		UPBU	Max dv	1.994	1.215	0.234	0.779	1.760
			Days > 0.5 dv	34	14	0	20	34
			Days>1.0 dv	9	1	0	8	9
	WAP 5	CACR	Max dv	1.698	1.052	0.180	0.646	1.518
			Days > 0.5 dv	22	9	0	13	22
			Days>1.0 dv	8	1	0	7	8
		UPBU	Max dv	1.038	0.613	0.094	0.424	0.943
			Days > 0.5 dv	11	1	0	10	11
			Days>1.0 dv	1	0	0	1	1
	WAP 6	CACR	Max dv	1.648	1.018	0.156	0.630	1.492
			Days > 0.5 dv	22	8	0	14	22
			Days>1.0 dv	6	1	0	5	6
		UPBU	Max dv	1.003	0.591	0.081	0.412	0.922
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	1	0	0	1	1
Welsh[2]	Source (Unit 1 & 2)	CACR	Max dv	4.576		0.822		3.754
			Days > 0.5 dv	92		3		89
			Days>1.0 dv	39		0		39
		MING	Max dv	2.544		0.570		1.973
			Days > 0.5 dv	9		1		8
			Days>1.0 dv	3		0		3
	Unit 1	CACR	Max dv	2.343	1.659	0.822	0.684	1.521
			Days > 0.5 dv	37	18	3	19	34
			Days>1.0 dv	8	3	0	5	8

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		MING	Max dv	1.150	0.886	0.570	0.264	0.579
			Days > 0.5 dv	2	1	1	1	1
			Days>1.0 dv	1	0	0	1	1
Fayette[2]	Source (Unit 1 & 2)	CACR	Max dv	1.894		0.903		0.991
			Days > 0.5 dv	26		2		24
			Days>1.0 dv	9		0		9
		WIMO	Max dv	1.175		0.580		0.595
			Days > 0.5 dv	19		1		18
			Days>1.0 dv	2		0		2
	Unit 1	CACR	Max dv	1.002		0.480		0.522
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	1		0		1
		WIMO	Max dv	0.609		0.306		0.302
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0
	Unit 2	CACR	Max dv	0.974		0.441		0.534
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	0		0		0
		WIMO	Max dv	0.598		0.282		0.316
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0

[1] Harrington high control scenario for both units is SDA at 95% reduction

[2] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD (wet FGD) installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.

Table 41. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Units 1 and 2)	WIMO	Max dv	4.27	2.54	0.43	1.73	3.83
			Days > 0.5 dv Avg.	67.33	43.33	2.67	24.00	64.67
			Days>1.0 dv Avg.	42.00	21.00	1.00	21.00	41.00
		CACR	Max dv	4.03	2.41	0.47	1.62	3.55
			Days > 0.5 dv Avg.	67	64.33	4.67	27.33	87.00
			Days>1.0 dv Avg.	60.33	30.00	0.00	30.33	60.33
Monticello[1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	3.68	1.70	4.16	4.87
			Days > 0.5 dv Avg.	143.67	115.00	62.33	28.67	81.33

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			Days>1.0 dv Avg.	113.00	66.33	23.67	46.67	89.33
		UPBU[4]	Max dv	3.45	1.77	0.77	1.68	2.68
			Days > 0.5 dv Avg.	103.00	61.00	13.67	42.00	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60.00	34.67	6.00	25.33	54.00
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67
Harrington[2]	Source (Units 061B & 062B)	SACR	Max dv	1.06	0.86	0.61	0.20	0.45
			Days > 0.5 dv Avg.	21.00	15.33	6.33	5.67	14.67
			Days>1.0 dv Avg.	6.67	3.00	0.67	3.67	6.00
		WIMO	Max dv	1.29	0.97	0.55	0.32	0.74
			Days > 0.5 dv Avg.	26.00	15.33	8.67	10.67	17.33
			Days>1.0 dv Avg.	9.00	4.67	1.33	4.33	7.67
Welsh[3]	Source (Unit 1)	CACR	Max dv	1.44	1.12	0.72	0.32	0.72
			Days > 0.5 dv Avg.	50.33	32.67	12.33	17.67	38
			Days>1.0 dv Avg.	15.33	8.00	2.33	7.33	13.00
		UPBU	Max dv	0.76	0.49	0.22	0.27	0.54
			Days > 0.5 dv Avg.	12.00	4.67	0.33	7.33	11.67
			Days>1.0 dv Avg.	0.67	0.00	0.00	0.67	0.67
		WIMO	Max dv	0.56	0.33	0.15	0.23	0.41
			Days > 0.5 dv Avg.	7.33	2.67	0.33	4.67	7.00
			Days>1.0 dv Avg.	1.33	0.33	0.00	1.00	1.33

[1] Monticello's controlled level is a combination of scrubber upgrades and scrubber install in the facility impact modeling with CALPUFF.
[2] Harrington high control scenario for both units is SDA at 95% reduction
[3] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and

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Fayette units have WFGD installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.
[4] UPBU = Upper Buffalo Wilderness Area.

5.5.2 Visibility Benefits of Scrubber Upgrades for Coal-Fired Units

We also modeled the visibility benefits of those same units for which we conducted control cost analysis for upgrading their existing scrubbers. We assumed the same 95% control level we used in our control cost analyses. We also modeled a lower level control at 90%. The visibility benefits from these scrubber upgrades are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits and reduction in number of days impacted.

Table 42. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CAMx modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	90% Control	95% Control	90% benefit	95% benefit
Martin Lake	Source (Unit 1, 2 & 3)	CACR	Max dv	6.651	4.491	4.321	2.159	2.329
			Days > 0.5 dv	141	75	56	66	85
			Days>1.0 dv	99	31	16	68	83
		UPBU	Max dv	5.803	2.669	2.528	3.134	3.275
			Days > 0.5 dv	99	39	22	60	77
			Days>1.0 dv	67	11	7	56	60
	Unit 1	CACR	Max dv	2.633	1.550	1.468	1.083	1.165
			Days > 0.5 dv	71	17	6	54	65
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.254	0.867	0.805	1.387	1.449
			Days > 0.5 dv	44	6	3	38	41
			Days>1.0 dv	10	0	0	10	10
	Unit 2	CACR	Max dv	2.466	1.882	1.811	0.585	0.655
			Days > 0.5 dv	68	18	9	50	59
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.189	1.077	1.025	1.112	1.164
			Days > 0.5 dv	40	6	5	34	35
			Days>1.0 dv	10	1	1	9	9
	Unit 3	CACR	Max dv	2.755	1.682	1.609	1.074	1.146
			Days > 0.5 dv	76	15	6	61	70
			Days>1.0 dv	29	2	1	27	28
		UPBU	Max dv	2.368	0.942	0.890	1.425	1.478
			Days > 0.5 dv	46	6	4	40	42
			Days>1.0 dv	13	0	0	13	13
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63

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			Days>1.0 dv	40	14	0	26	40
	Unit 3	CACR	Max dv	4.632	0.905	0.914	3.728	3.719
			Days > 0.5 dv	79	5	5	74	74
			Days>1.0 dv	32	0	0	32	32
		WIMO	Max dv	2.282	0.462	0.364	1.820	1.918
			Days > 0.5 dv	31	0	0	31	31
			Days>1.0 dv	7	0	0	7	7

Table 43. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Units 1, 2 & 3)	CACR	Max dv	4.46	2.27	1.86	2.18	2.60
			Days > 0.5 dv Avg.	129.67	77.33	63.00	52.33	66.67
			Days>1.0 dv Avg.	91.33	32.67	22.33	58.67	69.00
		UPBU	Max dv	2.73	1.10	0.85	1.63	1.88
			Days > 0.5 dv Avg.	81.67	30.33	18.67	51.33	63.00
			Days>1.0 dv Avg.	46.67	7.33	3.67	39.33	43.00
Monticello [1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	3.68	1.70	2.89	4.87
			Days > 0.5 dv Avg.	143.67	115	62.33	28.67	81.33
			Days>1.0 dv Avg.	113	66.33	23.67	46.67	89.33
		UPBU	Max dv	3.45	1.77	0.765	1.68	2.68
			Days > 0.5 dv Avg.	103	61	13.67	42	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60	34.67	6	25.33	54
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67

[1] Monticello's controlled level is a combination of scrubber upgrade on Unit 3 and scrubber retrofits on Units 1 and 2 in the facility impact modeling with CALPUFF.

5.5.3 Visibility Benefits of Fuel Oil Switching for Gas/Fuel Oil-Fired Units

We also modeled the visibility benefits of those gas/fuel oil-fired units for which we conducted control cost analysis for switching to lower sulfur fuels. We evaluated the visibility benefits of

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switching to fuel oils corresponding to ultra-low sulfur diesel at 0.0015% sulfur by weight and 0.3% sulfur by weight as we evaluated in our control cost analyses. The visibility benefits from these fuel switches are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits.

Table 44. Visibility Benefits from Lower Sulfur Fuel

Facility Name	Emission Unit	Baseline visibility Impact from Source (most impacted Class I area)	Visibility benefit of 0.3% S fuel oil	Visibility benefit of 0.0015% S fuel oil
Stryker	ST2	CALPUFF 0.65 % S: 0.786 dv @ CACR (Facility)	CALPUFF (0.3 % S) : 0.263 dv @ CACR (Facility)	CALPUFF: 0.522 dv @ CACR (Facility)
Graham	Unit 2	CALPUFF 0.69 % S: 1.228 dv @ WIMO (Facility)	CALPUFF (0.3% S): 0.465 dv @ WIMO (Facility	CALPUFF: 0.851 dv @ WIMO (Facility
Wilkes	Units 1, 2, 3	CALPUFF 0.43 % S: 0.698 dv @ CACR (Facility)	CALPUFF (0.1 % S): 0.029 dv @ CACR (Facility)	CALPUFF: 0.037 dv @ CACR (Facility)
Newman[1]	Unit 2	N/A	N/A	N/A
	Unit 3	N/A	N/A	N/A
	Unit 4	N/A	N/A	N/A
Calaveras	Sommers Unit 1	CAMx: 1.513 dv @ WIMO (Source); 0.106 dv @ CACR (Unit)	0.004 dv @ CACR	0.008 dv @ CACR
	Sommers Unit 2	CAMx: 1.513 dv @ WIMO (Source); 0.180 dv @ CACR (Unit)	0.023 @ CACR	0.047 @ CACR

[1] EPA initially considered evaluating with CALPUFF databases, but Newman is located near the edge of the CALMET modeling domain. There are a number of Class I areas that Newman could potentially impact (Gila, Bosque del Apache, Mount Baldy, Chiricahua, White Mountain, etc) and due to the size of the CALMET grid we cannot determine if Newman's impacts are below 0.5 dv at all Class I areas or determine the potential benefits from controls. Since plumes could transport out of the modeling domain and there is no way within the CALPUFF model to account for mass that transports out of the domain that may come back into the domain, the CALPUFF modeling databases cannot be relied on to conclusively assess visibility impacts from the Newman facility.

5.6 How, if at all, Do Issues of "Grid Reliability" Relate to the Proposed BART Determinations?

On July 15, 2016, a preliminary order of the Fifth Circuit Court of Appeals took the view that EPA's Texas-Oklahoma FIP (81 FR 295, January 5, 2016) gave a "truncated discussion of grid reliability" and additionally stated that "the agency may not have fulfilled its statutory obligation to consider the energy impacts of the FIP." The Court's preliminary ruling made particular reference to "the explicit directive in the [CAA] that implementation plans 'take[] into consideration…the energy…impacts of compliance,' 42 U.S.C. § 7491(g)(1)."[128] Because the

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BART requirement at issue in this proposal has similar language on *energy impacts of compliance* appearing at 42 U.S.C. § 7491(g)(2), we wish to provide a clear explanation on how grid-related considerations for EGUs could bear on this proposal.

First, the BART factor for *energy impacts of compliance* does not call for the examination of grid reliability considerations from alleged plans to shut down or retire a unit rather than comply with a more stringent emission limit or limits. The language instead calls for consideration of energy impacts from *complying* by installing retrofit controls on a source that continues in operation. In this regard, our proposal follows the required BART Guidelines for EGUs.[129] The Guidelines explain that the energy impacts factor relates to the penalties and benefits that may be associated with the assessment of a control option, e.g., whether (for power penalties) the operation of add-on control technology subtracts from the productive yield of electricity from an EGU (what is sometimes termed an auxiliary or parasitic load).[130] It is also useful to note that the statutory text, while using the word "energy," can apply to sources that do not produce energy or electricity. Thus, the statutory text regarding "energy impacts" of compliance with BART is not confined to the power generating industry and does not dictate that we study grid reliability issues.

We have considered whether this topic has any separate relevance to our proposal. Various court filings, news accounts, and industry market reports suggest that some source operators for some Texas BART units may be contemplating unit retirements. The BART Guidelines directly address such scenarios under the "remaining useful life" factor: "there may be situations where a source operator intends to shut down a source….but wishes to retain the flexibility to continue operating beyond that date in the event, for example, the market conditions change."[131] The Guidelines advise that a source that is willing to assure a permanent stop in operations with a federally- or State-enforceable restriction preventing further operation may obtain a short remaining useful life for BART analysis purposes that could then factor in the overall cost analysis.[132] As the Guidelines state, "Where the remaining useful life is less the than the time period for amortizing costs, you should use this shorter period in your cost calculations."[133] We have no information on enforceable restrictions of this type for any of the units that we propose to be subject to BART. Absent that, we must assume that controls installed on the BART units

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[128]EPA Guidance on this statutory language specifically explains that energy impacts are a matter of whether "energy requirements associated with a control technology result in energy penalties." U.S. EPA, Office of Air Quality Planning and Standards, "Guidance for Setting Reasonable Progress Goals under the Regional Haze Program," (June 1, 2007 rev), at Page 5-2.

[129] The promulgation of the Guidelines was required by 42 U.S.C. 7491(b)(1). Adherence to the Guidelines is mandatory for fossil-fuel fired generating power plants having total generating capacities "in excess of 750 megawatts."

[130] Other CAA provisions requiring consideration of "energy impacts" or "energy requirements of the control technology" are understood similarly. *See, e.g.,* CAA section 169 (the 1977 "best available control technology" requirement with consideration of "energy…impacts"); *see also* CAA section 108 ("energy requirements…of the emission control technology; "energy…impact of such processes, procedures, and methods [to reduce or control air pollution"); section 111 ("taking into account…energy requirements" of an emission limitation), etc.

[131] *Id.* at 39169-39170.

[132] Similar to calculating a mortgage, remaining useful life is used in our cost-effectiveness analysis to calculate the annual cost of a particular control. The longer the remaining useful life, the smaller the total annualized cost, and the more cost-effective the control.

[133] Id. at 39169.

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will experience their full useful life. Affected sources are free to submit information as part of their comments containing appropriate enforceable documentation of shorter remaining useful lives.

We note, however, that the Guidelines recognize there may be cases where the installation of controls, even when cost-effective, would "affect the viability of continued plant operations."[134] Under the Guidelines, where there are "unusual circumstances," we are permitted to take into consideration "the conditions of the plant and the economic effects of requiring the use of a control technology."[135] If the effects are judged to have a "severe impact," those effects can be considered in the selection process. In such cases, the Guidelines counsel that any determinations be made with an economic analysis with sufficient detail for public review on the "specific economic effects, parameters, and reasoning."[136] It is recognized, by the language of the Guidelines, that any such review process may entail the use of sensitive business information that may be confidential. The ADDRESSES section of this proposal explains how to submit confidential information with comments, and when claims of confidential business information, or CBI, are asserted with respect to any information that is submitted, the EPA regulations at 40 CFR Part 2, Subpart B-Confidentiality Business Information apply to protect it. All of that said, the Guidelines also advise that we may "consider whether other competing plants in the same industry have been required to install BART controls if this information is available."[137] Because Texas EGUs are among the last to have SO_2 BART determinations, this information is available. It is indeed the case that other similar EGUs have been required to install the same types of SO_2 BART controls that we are proposing as very cost effective.[138]

We have considered the state of available information on whether the proposed controls could affect the viability of continued plant operations. On this point, we note that we are proposing BART determinations for several units where SO_2 control requirements were separately promulgated as part of the Texas-Oklahoma FIP. These under-controlled EGU sources are: Big Brown 1 and 2; Monticello 1, 2 and 3; Martin Lake 1,2 and 3; and Coleto Creek 1. In litigation over the reasonable progress FIP, various declarations were filed on the issues of alleged forced closures and alleged reliability impacts. These declarations have been compiled and added to the docket for this rulemaking. By our review, these declarations do not appropriately inform or substantiate source-specific allegations of "unusual circumstances" that may have a severe impact on plant operations, because they do not offer any site-specific information.[139] Here is a summary of relevant points:

- A declaration by a Coleto Creek Plant manager discussed the timelines and commitments to comply with the January 5, 2016 final rulemaking, indicating that efforts to comply would be carried out. The declaration states "alternatively" that the source owner could make an eventual decision to discontinue operations.

[134] 70 FR 39103, 39171 (July 6, 2005), [40 CFR Part 51, App. Y]
[135] *Id.*
[136] 70 FR at 39171
[137] *Id.*
[138] See for instance, the EIA information we present elsewhere in this notice in which we summarize the hundreds of scrubber installations that have been performed on similar EGUs.
[139] Certain statements in declarations from representatives of both Luminant and Coleto Creek, who are the source owners of these facilities, cited compliance planning efforts that would be consistent with continued plant operations.

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- A declaration by a vice president of construction management at Luminant stated, in relevant part, Luminant was "planning for installation of four new scrubbers at Big Brown and Monticello" and "planning for the scrubber upgrades at…Martin Lake, and Monticello."
- Somewhat differently, a declaration by the CFO of Luminant Generating Company LLC stated the January 5, 2016 rulemaking was "likely to force the closure of the Big Brown and Monticello plants" and cites a Form 10-K from March 1, 2016 that similarly states "new scrubbers at the Big Brown and Monticello units…along with the existence of low wholesale power prices in ERCOT, would likely challenge the long-term economic viability of those units." The declaration states that other Clean Air Act regulatory requirements would also threaten the viability of Big Brown and Monticello units. The declaration does not mention Martin Lake.
- A declaration from the Executive Director of the Public Utility Commission of Texas, dated April 18, 2016, stated it was "simply not possible at this point to know the precise units that may retire." Notably, the declarant also disclaimed any argument that unit retirements would occasion an "ERCOT-wide generation capacity shortfall." Instead and only, the declarant cited the potential for "local reliability impacts."
- A declaration from the Director of System Planning for the Electric Reliability Council of Texas (ERCOT) stated that retirement plans "are unknown to ERCOT and the market until formal notification is made." It continued: "ERCOT does not know at this time which units may be retired as a result of the Regional Haze FIP."

In sum, several months after the finalization of the January 5, 2016, final rulemaking representatives for the source owners provided multiple court statements that would appear to contradict or at least equivocate on the matter of whether those FIP controls could be put in place. Meanwhile, declarations submitted by certain public authorities knowledgeable in grid resource planning disclaimed knowledge on severe impacts on any source-specific basis. Thus, we are unable to conclude from any of this information that the proposed cost-effective BART controls would severely impact plant operations. Generalized claims of possible retirements and discussions on attributes of the market design of the Electric Reliability Council of Texas (ERCOT) cannot inform the statutorily required, source-specific BART determinations, and some aspects of these declarations could undermine our ability to determine "unusual circumstances" in the meaning of the BART Guidelines, as to these facilities.

As a predicate to studying effects on transmission or reliability as "unusual circumstances," we would require site-specific information from any source that would wish for us to potentially consider "affordability of controls," under the terms specified in the Guidelines. Source owners may submit information, including information claimed to be CBI, for our assessment and consideration to potentially support an economic analysis that might be used in the BART selection process. As suggested by the Guidelines, the information necessary to inform our judgment would likely entail source-specific information on "product prices, the market share, and the profitability of the source." Consideration of such information does not dictate what will be selected as a "best" alternative under the Guidelines, but it will substantiate the likelihood of a retirement scenario that would then give the parameters for: a non-conjectural examination of grid reliability issues; judging the significance or insignificance of such issues; and assessing whether such issues could be avoided through appropriate transmission planning. In sum, unless we are able to substantiate an "affordability of controls" problem for any particular unit and

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substantiate that a particular unit retirement would not be happening anyway at about the same time, alleged grid reliability impacts are speculative and are not able to inform these required BART determinations. As a final note, we acknowledge Executive Order 13211 ("Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, and Use"). In cases where it does apply, agencies are ordered to prepare a Statement of Energy Effects for submission to the Administrator of the Office of Information and Regulatory Affairs (OIRA), Office of Management and Budget. This EGU BART proposal is not considered a significant regulatory action under Executive Order 12866, so the proposed action cannot be a "significant energy action" for purposes of Executive Order 13211 on that basis. This proposed action has also not been designated a significant energy action by the Administrator of OIRA, so Executive Order 13211 could not apply under that separate basis. With this proposal, there are no anticipated adverse effects on energy supply, distribution, or use that are meaningful or distinguishable from any other scenario where an EGU is expected to install cost-effective pollution controls required by the CAA.

6 Our Proposed BART Determinations

In Section 5, above, we have analyzed the BART five factors for all the units we have identified as being subject to BART. Below we present our reasoning for proposing our BART determinations for 29 EGUs in Texas, based on our analysis and weighing of the Five BART Factors. (1) proposed SO_2 and PM BART determinations for 12 coal-fired units with no SO_2 controls, (2) proposed BART SO_2 and PM BART determinations for 6 coal-fired units with existing scrubbers, (3) proposed SO_2 and PM BART determinations 7 gas-fired units that occasionally burn fuel oil, and (4) proposed PM BART determinations for 4 gas-fired units.

In previous sections of this proposal, we have described how we assessed the five BART factors. In no case do we see any instance in which our assessment of energy impacts is a determining factor in assessing BART.[140] Also, in no case do we see any instance in which our assessment of the remaining useful life is a determining factor in assessing BART. Should a facility determine in comments to us that the remaining useful life is less than the 30 years we have assumed in our control cost analyses, and is willing to enter into an enforceable document to that effect, we will adjust our cost-effectiveness calculation accordingly in making our final decision. In two cases, Harrington units 061B and 062B, we have limited our SO_2 control analysis for Harrington to DSI and dry scrubbers due to potential non-air quality concerns. In all other instances, we conclude that the cost of compliance, and the visibility benefits of controls are the controlling BART factors in our weighing of the five BART factors.

In considering cost-effectiveness and visibility benefit, we do not eliminate any controls based solely on the magnitude of the cost-effectiveness value, nor do we use cost-effectiveness as the primary determining factor. Rather, we compare the cost-effectiveness to the anticipated visibility benefit, and we take note of any additional considerations.[141] Also, in judging the visibility benefit we do not simply examine the highest value for a given Class I area, or a group

[140] In addition to our assessment of energy impacts, also see our discussion in Section 5.6 concerning our conclusion that energy impact considerations do not relate to potential electrical grid reliability issues.
[141] For instance, as we discuss later in Section 5.3.5.2 why we believe that there are certain mitigating factors that should be considered when assessing BART for the gas-fired units that occasionally burn fuel oil.

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of Class I areas, but we also consider the cumulative visibility benefit for all affected Class I areas, the number of days in a calendar year in which we see significant improvements, and other factors.[142] See the BART Modeling TSD for a complete description and summary of our analysis of visibility benefits of potential control options.

First, we note that all of the sources addressed in our proposed BART determinations have already been shown to cause or contribute to visibility impairment at a Class I area as a condition of being subject-to-BART as part of the BART screening analysis. This analysis eliminated any BART-eligible source that emits lower amounts of visibility impacting pollutants, or otherwise impacts any Class I area at less than 0.5 deciviews. In fact, all of the individual units that we are proposing for BART controls exceed 0.5 deciviews on a unit basis, with most exceeding 1.0 deciview impact on a unit basis. As a consequence, all of the units we are proposing for BART controls are among the largest emitters of visibility impacting pollutants in Texas. A number of these units (i.e., Big Brown, Martin Lake, Monticello, and Coleto Creek) were previously determined by us to require the same type and level of controls under the reasonable progress and long-term strategy provisions of the Regional Haze Rule that we are proposing here.[143]

Second, not discounting our approach of considering both cost-effectiveness and visibility benefit in unison, the cost-effectiveness of all of the controls that form the basis of our proposed BART determinations are within a range found to be acceptable in other cases.[144] As we stated in the BART Rule, ''[a] reasonable range would be a range that is consistent with the range of cost effectiveness values used in other similar permit decisions over a period of time.''[145]

6.1 SO_2 BART for Coal-fired Units with no SO_2 Controls

As we have discussed in this proposal and in our TSD, we have assumed two DSI control levels corresponding to 50% control and either a maximum of 80% or 90% control, depending on the particulate matter control device in use.[146] We did this to address the BART Guidelines directive that in evaluating technically feasible alternatives we "(1) [ensure we] express the degree of control using a metric that ensures an ''apples to apples'' comparison of emissions performance levels among options, and (2) [give] appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels."[147] In most cases, the cost-effectiveness of the higher control level of DSI was higher than either SDA or wet FGD. This was not the case for Monticello Unit 2; Harrington Unit 062B; and J T Deely Units 1 and 2.

However, these maximum DSI control levels are theoretical and we believe that any DSI control

[142] See for example 70 39130: "comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g. the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, a threshold representing an x percent change in improvement, etc.)."
[143] See our recent Texas-Oklahoma FIP, 81 FR 321.
[144] See for instance 79 FR 5048 (January 30, 2014): Jim Bridger BART determination of LNB/SOFA + SCR on Units 1-4; 77 FR 18070 (March 26, 2012): EPA proposed approval of Colorado's BART determination of SCR for Hayden Unit 2, later finalized at 77 FR 76871 (December 31, 2012).
[145] 70 FR 39168 (July 6, 2005).
[146] Note for Harrington Unit 062B and Welsh 1, we further limited the maximum DSI control level to that of our calculated SDA control level.
[147] 70 FR 39166 (July 6, 2005).

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level above 50% must be confirmed by onsite testing before we could propose a BART control based on it. As is evident in comparing the 50% control level to the higher control level, the cost-effectiveness of DSI worsens (higher $/ton) as the control level increases, and the certainty of any unit attaining that control level decreases. We therefore regard the cost-effectiveness values of the maximum DSI control levels as being useful in a basic comparison of cost-effectiveness between DSI and scrubbers, but we place much less weight on these values. We therefore conclude that given the uncertainty concerning the maximum control level of DSI, the greater control efficiency and resulting visibility benefit offered by scrubbers overrides any possible advantage DSI may hold in cost-effectiveness. Should the affected facilities provide site-specific information to us in their comments that conflicts with this assumption, we will incorporate it into our final decision on SO_2 BART and potentially re-evaluate DSI.

As we indicate elsewhere in our proposal, both SDA and wet FGD are mature technologies that are in wide use throughout the United States. We are not aware of any unusual circumstances that exist for any of the sources that would serve to indicate they should not be viewed similarly to these hundreds of previous scrubber retrofits. In comparing wet FGD versus SDA we note that in a number of cases the cost-effectiveness of wet FGD is lower than the cost-effectiveness of SDA. In the remaining cases, we conclude that the incremental cost-effectiveness of wet FGD over SDA, which we review in Section 5.3.6 is reasonable, and the improved control and visibility benefit offered by wet FGD overrides the small penalty in cost-effectiveness FGD has in comparison to SDA. We propose that with the exception of the Harrington units, SO_2 BART for all other coal-fired units should be based on the wet FGD control levels we have used in our BART analyses. We propose that SO_2 BART for the Harrington units should be based on the SDA control levels we have used in our BART analyses. Below we discuss our consideration of the cost-effectiveness and anticipated visibility benefits of controls. See section 5.5 for additional information on the anticipated visibility benefits from each level of control modeled. See the BART modeling TSD for a complete summary of our visibility benefit analysis of controls, including modeled benefits and impacts at all Class I areas included in the modeling analyses and additional metrics considered in the assessment of visibility benefits.

CAMx model results shown in the tables below summarize the benefits from the recommended controls at the two Class I areas most impacted by the source or unit in the baseline modeling. The benefit is calculated as the difference between the maximum impact modeled for the baseline and the maximum impact level modeled under the control scenario. 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. The CALPUFF cumulative model results only consider those Class I areas within the typical range of CALPUFF and not all 15 Class I areas included in the CAMx modeling.

6.1.1 Big Brown 1 & 2

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In reviewing the Big Brown units, we conclude that the installation of wet FGD will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 45. Wet FGD Visibility Benefits at Big Brown (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Big Brown Units 1 & 2	3.83	3.55	7.38	151.67	101.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek and Wichita Mountains
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek and Wichita Mountains.

In evaluating Big Brown, we note there are two Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results, we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the two Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate that wet FGD on both units will eliminate 151.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the visibility benefits in terms of dv benefits at the most impacted Class I areas and about 1/3rd to half the cumulative benefits over the class I areas included in the modeling analysis.

Table 46. Wet FGD Visibility Benefits at Big Brown (CAMx)

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Unit	Improvement at Wichita mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Big Brown 1	1.909	1.606	12.728	174 / 44	174 / 44
Big Brown 2	1.940	1.642	12.924	175 / 45	175 / 45
Source	3.542	2.988	24.274	372 / 170	362 / 170

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv at all Class I areas on a unit and source-wide basis, and eliminate all but 10 days across the impacted Class I areas where the source-wide impacts exceeds 0.5 dv. At the most impacted Class I area, wet FGD will on each unit result in visibility improvements of 1.9 dv on the most impacted day. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the CAMx modeling.

We also conclude that wet FGD is very cost-effective for both units at less than $1,200/ton and more cost-effective than DSI. Based on this consideration of the BART factors, we propose that SO_2 BART for Big Brown Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

6.1.2 Monticello 1 & 2

Similar to the Big Brown units, the installation of wet FGD at Monticello Units 1 and 2 will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 47. Wet FGD Visibility Benefits at Monticello (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	4.87	2.70	10.25	224.67	164.67

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control

scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Monticello, we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 224.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I area and half of the cumulative benefits.

Table 48. Wet FGD Visibility Benefits at Monticello (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 1	3.783	1.989	12.708	197 / 67	191 / 67
Monticello 2	3.924	2.003	13.025	192 / 57	191 / 57
Source (including unit 3)	8.419	4.962	31.553	520 / 293	460 / 278

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv at all Class I areas on a unit basis, and eliminate all but 15 days across the impacted Class I areas where the source-wide impacts exceeds 1 dv. We note that source-wide modeled benefits include benefits of 95% control scrubber upgrade on Unit 3. At the most impacted Class I area, wet FGD on each unit will each result in visibility improvements of 3.8-3.9 dv on the most

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impacted day at Caney Creek and 2 dv visibility benefits at Wichita Mountains. DSI operated at 50% control results in less than half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

The wet FGD cost-effectiveness of $2,718/ton and $3,031/ton are higher than those for Big Brown, but these figures remain well within a range that we have previously found to be acceptable for BART, and we consider the very significant visibility benefits that will result justify the cost of wet FGD at the Monticello Units 1 and 2. The 50% control DSI cost-effectiveness is slightly less than that for wet-FGD, but results in much less visibility benefits. Based on our consideration of the BART factors, we therefore propose that SO_2 BART for Monticello Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

6.1.3 Coleto Creek 1

In reviewing Coleto Creek Unit 1, we conclude that in comparison with the Monticello units, the installation of a wet FGD is more cost-effective and results in lesser, but still significant visibility benefits. We summarize some of these visibility benefits in the table below:

Table 49. Wet FGD Visibility Benefits at Coleto Creek Unit 1 (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Coleto Creek 1	0.668	0.606	5.233	17 / 0	17 / 0

[1] 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
[2] 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
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 0.5 dv at all Class I areas. At the most impacted Class I area, wet FGD will result in visibility improvements of 0.6 or more on the most impacted days at both Caney Creek and the Wichita Mountains. In addition, seven other Class I areas are improved by amounts ranging from 0.356 to 0.531 dv on the maximum impacted days with wet FGD. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15class I areas included in the modeling.

We also conclude that wet FGD is very cost-effective at $2,127/ton and well within a range that we have previously found to be acceptable and more cost-effective than DSI. We consider the significant visibility benefits that will result justify the cost of wet FGD at the Coleto Creek Unit 1. We therefore propose that SO_2 BART for Coleto Creek Unit 1 should be

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based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

6.1.4 Welsh 1

In reviewing Welsh Unit 1, we conclude that the installation of a wet FGD will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 50. Wet FGD Visibility Benefits at Welsh Unit 1 (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Welsh 1	0.72	0.41	1.66	56.67	15

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Welsh we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 56.67 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

Table 51. Wet FGD Visibility Benefits at Welsh Unit 1 (CAMx)

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Unit	Improvement at Caney Creek (dv)	Improvement at Mingo Wilderness (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Welsh 1	1.521	0.579	4.683	65 / 9	60 / 9
Source (Welsh 1 & 2)	3.754	1.973	13.179	211 / 72	206 / 72

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD on unit 1 will eliminate all days impacted by the unit over 1 dv at all Class I areas and all but 5 days impacted over 0.5 dv. At the most impacted Class I area, wet FGD on unit 1 will result in visibility improvements of 1.521 dv on the most impacted days at Caney Creek. In addition to the visibility benefits at Caney Creek and Mingo, visibility benefits at two additional Class I areas exceed 0.5 dv. We note that source-wide benefits shown include the benefits from the shutdown of unit 2. In addition, cumulative benefits from wet FGD on unit 1 over all 15 Class I areas exceeds 4.5 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We conclude that although at $3,824/ton, the cost-effectiveness of wet FGD is higher than for other facilities, it remains within a range that we have previously found to be acceptable. We consider the significant visibility benefits that will result from the installation of wet FGD at Welsh Unit 1 to justify the cost. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for Welsh Unit 1 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

6.1.5 Harrington 061B & 062B

In reviewing Harrington, we conclude that the installation of SDA on Units 061B and 062B will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 52. SDA Visibility Benefits at Harrington (CALPUFF)

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Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Harrington 061B & 062B	0.45	0.74	2.56	53.67	26

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

In evaluating Harrington we note there are five Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the five Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate SDA on both units will eliminate 53.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

Table 53. SDA Visibility Benefits at Harrington (CAMx)

Unit	Improvement at Salt Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Harrington 061B	1.170	0.643	4.832	17 / 5	11 / 3
Harrington 062B	1.279	0.723	5.379	17 / 5	11 / 3
Source (061B & 0622B)	2.053	1.130	9.329	51 / 17	37 / 11

[1] 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.

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[2] 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.
[3] 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.

CAMx modeling results indicate SDA on these units will eliminate more than half of all days impacted by the units over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, SDA on each unit will each result in visibility improvements of approximately 1.2 dv on the most impacted days at Salt Creek and 0.6 – 0.7 dv at Wichita Mountains, reducing the number of days impacted over 0.5 and 1.0 dv at these Class I areas. In addition, cumulative benefits from SDA on both units over all 15 Class I areas exceeds 9.3 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the SDA visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We also conclude that SDA is cost-effective at $3,904 for Unit 061B and $4,180/ton for Unit 062B and, remains within a range that we have previously found to be acceptable. In contrast to other units we have reviewed, the 50% control DSI cost-effectiveness is much less than that for SDA. However, given the additional large total cumulative visibility benefits that will result from the installation of SDA over DSI at 50% control, we consider SDA to justify the additional cost. We therefore propose that SO_2 BART for Harrington Units 061B and 062B should be based on the installation of SDA at an emission limit of 0.06 lbs/MMBtu based on a 30 BOD.

6.1.6 W. A. Parish WAP 5 & 6

In reviewing W A Parish, we conclude that the installation of wet FGD on Units 5 and 6 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 54. Wet FGD Visibility Benefits at W A Parish (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
W A Parish 5	1.518	0.943	8.171	51 / 9	51 / 9
W A Parish 6	1.492	0.922	7.979	48 / 7	48 / 7
Source (WAP 4, 5 & 6)	2.665	1.760	15.301	163 / 49	162 / 49

[1] 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.
[2] 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.
[3] 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

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threshold for the control scenario.

CAMx modeling results indicate that wet FGD on each of these units will eliminate all days impacted by each unit over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of approximately 1.5 dv on the most impacted days at Caney Creek and 0.9 dv at Upper Buffalo. Nine Class I areas have modeled source-wide baseline impacts over 1 dv, and wet FGD on both units results in source-wide improvements of 1 dv or greater on the maximum impacted days at eight of these Class I areas. In addition, cumulative benefits from wet FGD on both units over all 15 Class I areas exceeds 15 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15class I areas included in the modeling. We note that source-wide modeling includes a small impact from WAP 4. This unit is gas-fired and was modeled at baseline emissions levels for both the baseline and control case scenarios.

We conclude that wet FGD is cost-effective at $2,417/ton for Unit 5 and $2,259/ton for Unit 6, and remains well within a range that we have previously found to be acceptable. DSI at 50% control is approximately the same cost-effectiveness but results in significantly less visibility benefit. We consider the cost of wet FGD at the W A Parish units to be justified by the significant visibility benefits that will result. We therefore propose that SO_2 BART for W A Parish Units 5 and 6 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

6.1.7 J T Deely 1 & 2

In reviewing J T Deely, we conclude that the installation of wet FGD on Units 1 and 2 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 55. Wet FGD Visibility Benefits at J T Deely (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
J T Deely 1	0.487	0.283	4.785	10 / 0	10 / 0
J T Deely 2	0.298	0.217	3.650	7 / 0	7 / 0
Source (J T Deely 1 & 2, Sommers 1 & 2)	0.699	0.518	8.943	89 / 13	84 / 13

[1] 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.
[2] 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.
[3] 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

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threshold for the control scenario.

CAMx modeling results indicate wet FGD on each of these units will eliminate all days impacted by each unit over 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of 0.487 dv and 0.298 dv on the most impacted days at Wichita Mountains and 0.283 dv and 0.217 dv at Caney Creek. Larger visibility improvements on the most impacted days are anticipated at other Class I areas. Benefits from wet FGD on unit 1 are 0.583 dv at Big Bend, 0.511 dv at Salt Creek, 0.449 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.475 dv at White Mountains. Benefits from wet FGD on unit 2 are 0.583 dv at Big Bend, 0.441 dv at Salt Creek, 0.354 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.375 dv at White Mountains. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 Class I areas included in the modeling. We note that source-wide modeling includes the impact from Sommers units 1 and 2, and as discussed in the BART Modeling TSD, control case scenarios for these units included benefits from switching to lower sulfur fuel oil. However, these modeled improvements are a small fraction of the total visibility benefits from controls at the source.

We conclude that wet FGD is cost-effective at $3,898/ton for Unit 1 and $3,712/ton for Unit 2, and remains within a range that we have previously found to be acceptable. We consider the cost of wet FGD at the J T Deely units to be justified by the significant visibility benefits that will result at a number of impacted Class I areas. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for J T Deely Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.[148]

6.2 SO_2 BART for Coal-fired Units with Underperforming Scrubbers

The BART Guidelines state that underperforming scrubber systems should be evaluated for upgrades.[149] Other than upgrading the existing scrubbers, all of which are wet FGDs, there are no competing control technologies that could be considered for these units. The CALPUFF modeling generated facility-wide impacts and the benefits of the scrubber upgrade on Monticello Unit 3 and the three Martin Lake facilities are included in Table 42 above. The following is a listing of each of the affected units along with the resulting CAMx modeled visibility benefits from upgrading their existing scrubbers:

Table 56. Visibility Benefit for Coal-fired Units with Existing SO_2 Controls (CAMx)

[148] We have read reports that CPS Energy, is planning to retire J T Deely Units 1 and 2 by the end of 2018, but we have no enforceable documents to that effect.
[149] 70 FR 39171 (July 6, 2005).

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Unit	Improvement at most impacted (dv)	Improvement at 2nd most impacted (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 3	3.719 (CACR)	1.918 (WIMO)	11.940	200 / 66	188 / 66
Martin Lake 1	1.165 (CACR)	1.449 (UPBU)	7.575	160 / 41	151 / 40
Martin Lake 2	0.655 (CACR)	1.164 (UPBU)	6.199	150 / 41	134 / 39
Martin Lake 3	1.146 (CACR)	1.478 (UPBU)	7.863	173 / 47	163 / 46

[1] 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.
[2] 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.
[3] 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.

As we state elsewhere in this proposal, because our cost-effectiveness calculations depend on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost effectiveness was $1,156/ton or less. We conclude that in all cases, scrubber upgrades are very cost-effective and result in very significant visibility benefits, significantly reducing the impacts from these units and reducing the number of days that Class I areas are impacted over 1.0 dv and 0.5 dv. We propose that SO_2 BART for all other coal-fired units with underperforming scrubbers should be based on the wet FGD upgrade control levels we have used in our BART analyses of them.

6.2.1 Potential Process for Alternative Scrubber Upgrade Emission Limits

In our BART FIP TSD, we discuss how we calculated the SO_2 removal efficiency of the units we analyzed for scrubber upgrades. We note that due to a number of factors we could not accurately quantify, our calculations of scrubber efficiency may contain some error. Based on the results of our scrubber upgrade cost analysis, we do not believe that any reasonable error in calculating the true tons of SO_2 removed affects our proposed decision to require emission reductions, as all of the scrubber upgrades we analyzed are cost-effective (low $/ton). In other words, were we to make reasonable adjustments in the tons removed to account for any potential error in our scrubber efficiency calculation, we would still propose to upgrade these SO_2 scrubbers. We believe we have demonstrated that upgrading an underperforming SO_2 scrubber is one of the most cost-effective pollution control upgrades a coal fired power plant can implement to improve the visibility at Class I areas. However, our proposed FIP does specify a SO_2 emission limit that is based on 95% removal in all cases. This is below the upper end of what an upgraded wet SO_2 scrubber can achieve, which is 98–99%, as we have noted in our BART FIP TSD. We believe that a 95% control assumption provides an adequate margin of error for any of the units for which we have proposed scrubber upgrades, such that they should be able to comfortably attain the emission limits we have proposed. However, for the operator of any unit that disagrees with us on this point, we propose the following:

(1) The affected unit should comment why it believes it cannot attain the SO_2 emission

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limit we have proposed, based on a scrubber upgrade that includes the kinds of improvements (e.g., elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically included in a scrubber upgrade.

(2) After considering those comments, and responding to all relevant comments in a final rulemaking action, should we still require a scrubber upgrade in our final FIP we will provide the company the following option in the FIP to seek a revised emission limit after taking the following steps:

(a) Install a CEMS at the inlet to the scrubber.

(b) Pre-approval of a scrubber upgrade plan conducted by a third party engineering firm that considers the kinds of improvements (e.g., elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically performed during a scrubber upgrade. The goal of this plan will be to maximize the unit's overall SO_2 removal efficiency.

(c) Installation of the scrubber upgrades.

(d) Pre-approval of a performance testing plan, followed by the performance testing itself.

(e) A pre-approved schedule for 2.a through 2.d.

(f) Should we determine that a revision of the SO_2 emission limit is appropriate, we will have to propose a modification to the BART FIP after it has been promulgated. It should be noted that any proposal to modify the SO_2 emission limit will be based largely on the performance testing and may result in a proposed increase or decrease of that value.

6.3 SO_2 BART for Gas-fired Units that Burn Oil

In analyzing potential controls for those gas-fired units that occasionally burn fuel oil we considered scrubber retrofits and lower sulfur fuel oil. We concluded that the cost-effectiveness of scrubber retrofits for these units were likely very high, and not worth the potential visibility benefit.

We also concluded that the cost-effectiveness of switching to a No. 2 fuel oil with a sulfur content of 0.3% is $11,218/gallon, and the cost-effectiveness of switching to ULSD with a sulfur content of 0.0015% is $8,627/gallon. We further noted that one facility already had a contract in place for ULSD at a lower price than we assumed, which if used in our analysis would result in a cost effectiveness of $3,970/ton. Although the cost-effectiveness of switching to a lower sulfur oil (assuming our price for ULSD of $1.667/gal) is higher than other controls that we have typically required under BART, we note certain mitigating factors.

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For instance, arguing against control, our calculated cost-effectiveness values are high in relation to other BART controls we have required in the past. Also, our visibility modeling necessarily utilized the maximum SO_2 emissions over a 24-hour timeframe,[150] resulting in the configuring of our visibility modeling to analyze the maximum short-term potential impacts that could occur when the unit burns fuel oil. However, as we discuss elsewhere in our proposal, these units are primarily gas-fired, and have only occasionally burned fuel oil. Their most recent practices appear to reinforce this trend.

Arguing for control, unlike the wet FGD and SDA scrubbers we have costed in other sections of this TSD, which have large capital costs, we are unaware of any significant capital costs involved in switching fuels. This means the overall annual costs are relatively minor, if the units in question adhere to their historical usages. Also, because the units in question have only occasionally burned fuel oil, they have the option to avoid the cost of fuel switching entirely by not continuing to burn fuel oil and instead relying solely on their primary fuel of natural gas. Lastly, we note that the prevalence of ULSD in the fuel oil market is such that it appears to be gradually replacing most other No. 2 fuel oil applications.[151]

The preamble to the Regional Haze Rule counseled that a one percent sulfur content limitation on fuel oil should be considered as a "starting point,"[152] and the existing sulfur content limits are lower than one percent. Considering all of this information, we propose that SO_2 BART for the gas-fired units that occasionally burn fuel oil should be no further control. In so doing, we acknowledge the data quality issues we have discussed concerning these units and we specifically request comments on all aspects of our proposed BART analysis for these units from all interested parties. Based on the comments we receive, we may either finalize our BART determinations for these units as proposed, or we may revise them without a re-proposal.

6.4 PM BART

We propose to disapprove the portion of the Texas Regional Haze SIP that sought to address the BART requirement for EGUs for PM. We note that all of the coal-fired units are either currently fitted with a baghouse, an ESP and a polishing baghouse, or an ESP. We conclude that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted with an ESP. Consequently, we propose that PM BART for the coal-fired units is an emission limit of 0.030 lb/MMBtu along with work practice standards. We propose that PM and SO_2 BART for the units that only fire gas be pipeline natural gas. We propose that PM and SO_2 BART for those gas-fired units that occasionally burn fuel oil be the existing permitted fuel oil sulfur content of 0.7% sulfur by weight or pipeline natural gas.

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[150] See the BART Guidelines at 70 FR 39162, July 6, 2005: "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."

[151] http://www.eia.gov/todayinenergy/detail.php?id=5890. http://blogs.platts.com/2014/05/07/heating-oil-new-york-sulfur/. http://oilandenergyonline.com/challenges-to-the-northeast-supply-picture/

[152] 70 FR at 39134

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Appendix A: Comment and Response Summary Concerning Our Wet FGD Control Efficiency Assumption[153]

Comment: Incorrect assumptions for estimating achievable SO_2 emission rates
[Sargent & Lundy (0061) p. 22]

S&L stated that EPA calculated SO_2 emission reductions based on the assumption that a retrofit wet FGD will achieve 98% reduction or a controlled SO_2 emission rate of 0.04 lb/MMBtu. In our experience, this assumption is unrealistic and cannot be sustained on a continuous, long-term basis. As a basis for its assumption, EPA cites the IPM wet FGD cost development document, which 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."[63] However, EPA misinterprets this statement when it uses the guarantee emission rate to calculate long-term SO_2 emissions.

S&L asserted that EPA's proposal is far too stringent to be achievable with the retrofit of an existing unit. EPA's selection of a controlled emission rate of 0.04 lb/MMBtu is more consistent with the lowest achievable emission rate (LAER) applicable to newly-constructed units, rather than an emission rate achievable with retrofit controls installed on existing units. In fact, a controlled emission rate of 0.04 lb/MMBtu is significantly lower than the most aggressive BART SO_2 emission limits imposed by EPA on BART-eligible sources throughout the U.S.

According to S&L, a controlled SO_2 limit of 0.04 lb/MMBtu is not a realistic or sustainable value to maintain on a long-term basis when considering the normal variation in operation that occurs at all coal-fueled facilities. As noted in the IPM wet FGD document, the 0.04 lb/MMBtu emission rate corresponds to the lowest available SO_2 emission guarantees from wet FGD suppliers. Compliance with a vendor's guarantee value is typically demonstrated during very short term testing conducted at ideal operating conditions. Vendor guarantees do not reflect controlled emission rates that may be achievable on a consistent long-term basis as the unit operation varies from design conditions.

S&L noted that wet FGD control systems, like all large air pollution control systems, are not steady state control systems, and controlled SO_2 emissions will continually fluctuate in response to changing operating parameters. Operating parameters that may affect SO_2 emissions include the fuel sulfur content, boiler load, load changes, flue gas flow rate, and flue gas temperatures, all of which continually change during normal operation of the boiler. Figure 1 shows the hourly emissions data for Spruce Unit 1. Spruce Unit 1 is a 550 MW subbituminous coal-fired boiler equipped with wet limestone FGD. The FGD control system was installed in 1992, and upgraded in 2009. Figure 1 shows the normal fluctuation in controlled hourly SO_2 emissions from Spruce Unit 1, which is typical for all wet FGD control systems.

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[153] This comment and response summary is reproduced from our "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." Docket No. EPA-R06-OAR-2014-0754. 12/9/2015

Figure 1: SO_2 Emission Permit Limits for Recent Wet FGD Projects [Figure not excerpted]

According to S&L, between January 1, 2012 and December 31, 2013, Spruce Unit 1 achieved an average controlled SO_2 emission rate of 0.055 lb/MMBtu (2-year average). During that same time period, the standard deviation in its controlled 30-day average SO_2 emission rate was 0.10 lb/MMBtu, approximately 20% greater than the long-term average, and the controlled SO_2 emission rate achieved at a 95% confidence level was 0.075 lb/MMBtu (0.02 lb/MMBtu above the long-term average). Based on our experience with other wet FGD control systems, fluctuations seen in the controlled SO_2 emission rate at Spruce Unit 1 are typical.

S&L stated that projecting future emissions using the anticipated control system vendor guarantee (i.e., 0.04 lb/MMBtu) as EPA did is overly aggressive and provides no margin for normal operating conditions or long-term operation. A reasonable margin between the vendor guarantee value or design target, and the projected actual long-term achievable emission rate is needed to allow for normal fluctuations in the controlled emissions. In S&L's opinion, an operating margin of at least 0.02 lb/MMBtu between the vendor guarantee and projected long-term emission rate is reasonable. In addition, it would be necessary to contact FGD suppliers to provide bids, on a case-by-case basis, that identify what outlet emission rates would be guaranteed on a 30-day rolling average to determine adequate outlet emission rates for compliance, rather than applying the lowest available emission rate guarantee in all cases.

S&L concluded that EPA's approach to estimating controlled SO_2 emissions is incorrect and based on a misunderstanding of the actual performance and operation of wet FGD technology. By using this approach, EPA is overestimating the tons of SO_2 removed and thus overstating the cost-effectiveness of the retrofit FGD control systems.

[Stamper (0068) p.15] Stamper stated that the EPA assumed SO_2 removal efficiencies of up to 98% control in its wet FGD analyses and up to 95% control in its SDA analyses. However, in no case did EPA assume a controlled wet FGD SO_2 rate of less than 0.04 lb/MMBtu or a controlled SDA SO_2 rate of less than 0.06 lb/MMBtu in its cost effectiveness analyses. EPA's rationale was that these were the lowest emission guarantees and this methodology was consistent with EPA's cost effectiveness calculations for the Oklahoma regional haze FIP. Cost TSD at 16, 21-22.

Stamper stated that the EPA's assumptions limiting the SO_2 removal efficiency based on the guaranteed permitted limits of 0.06 lb/MMBtu for an SDA and 0.04 lb/MMBtu for a wet FGD underestimated the actual SO_2 emission reductions that would likely occur with these SO_2 scrubbers. This is primarily a concern for those EGUs that burn or blend with low sulfur Powder River Basin coal (i.e., Coleto Creek 1, Tolk 171B and 172B, WA Parrish 5, 6, and 7, and Welsh 1, 2, and 3). Further, wet FGD systems can achieve greater than 99% SO_2 removal, and dry scrubbers can achieve greater than 95% SO_2 removal efficiency, as discussed further below.

According to Stamper, wet scrubbers are the most effective SO_2 control technology available. State-of-the-art wet scrubbers can achieve 98-99% removal efficiency. A prime example is the Chiyoda CT-121 FGD. Vendor information for this technology indicates that this scrubber has

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achieved 98-99% SO_2 removal even with low sulfur coal.[43] For example, the Chiyoda's bubbling jet reactor has consistently achieved >99% SO_2 removal during long-term operation at the Shinko-Kobe power plant in Japan. This facility consists of two 700-MW coal-fired utility boilers. The wet FGD was designed to achieve 0.014 lb SO_2/MMBtu (9 ppmv at 3% oxygen) on an instantaneous basis and has consistently exceeded this level of control while treating gases with inlet SO_2 concentrations of 1.78 lb/MMBtu.[44] This technology has been guaranteed by Chiyoda to achieve 99% SO_2 removal on three coal-fired boilers in Japan.[45]

Stamper stated that the Chiyoda CT-121 FGD has been demonstrated in the U.S. at the University of Illinois's Abbott power plant, Georgia Power's Plant Yates[46], Dayton Power & Light's Killen Unit 2,[47] and Plant Bowen Unit 3.[48] It has been licensed for installation on several additional units in the U.S., including the other three units at Plant Bowen in Georgia, the other units at Dayton Power & Light's Killen plant, Dayton Power & Light's Stuart plant, and AEP's Big Sandy Unit 2, Conesville Unit 4, Cardinal Units 1 and 2, and Kyger Creek, among others.[49] Black & Veatch and Southern Company are both U.S. licensees. Further, this technology also has shown to be very effective in removing fine particulates, oxidized and elemental mercury, and acid gases, and the technology uses less energy compared to traditional wet scrubbers.

Stamper noted that Mitsubishi, a vendor of scrubber systems, reports it has guaranteed SO_2 removal efficiencies up to 99.8 percent, including for coal-fired boilers.[50,51,52]

Stamper stated that Sargent & Lundy has indicated that the lowest achievable SO_2 emission rate with low sulfur Powder River Basin coal for a limestone forced oxidation (LSFO) wet scrubber would be 0.03-0.06 lb/MMBtu.[53]

Stamper stated that these SO_2 removal efficacy claims for wet scrubbers at coal-fired boilers burning lower sulfur coal have been demonstrated in practice. SO_2 emissions data was compiled for 2009 to 2013 to reflect newly operating and recently retrofitted wet FGD systems at EGUs that burn low sulfur coal. The results are in Table 3 below. All of these units burn Powder River Basin coal and have recently been retrofitted with wet FGD systems. As the table below demonstrates, wet FGDs at EGUs burning Powder River Basin coal can achieve much lower SO_2 emission rates than 0.04 lb/MMBtu.

Table 3. Annual Average SO2 Emission Rates at EGUs Equipped with Wet FGDs that Burn Low Sulfur Coal[54]

Plant	Unit	Annual Average SO2 Rate, lb/MMBtu
Iatan	1	0.007
Iatan	2	0.007
Boswell Energy Center	3	0.009
Muscatine	9	0.013
Pleasant Prairie	1	0.021
Pleasant Prairie	2	0.029

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Thus, Stamper concluded that the EPA's assumption that a wet FGD could not achieve SO_2 rates lower than 0.04 lb/MMBtu is overly conservative, as demonstrated by the data presented above.

In addition, Stamper noted that recently constructed EGUs that burn Powder River Basin coal and that are equipped with SDAs have achieved lower SO_2 emission rates than the minimum 0.06 lb/MMBtu SO_2 rate assumed by EPA in its cost effectiveness analyses. The Newmont Nevada power plant (aka TS Power Plant), equipped with a dry lime FGD system, has achieved an annual average SO_2 rate of 0.037 lb/MMBtu over 2009 to 2013.[55] The Wygen II is also equipped with a dry lime scrubber and burns low sulfur coal, and is achieving annual average SO_2 rates of 0.047 lb/MMBtu.[56] And the Dry Fork Station which began operation in 2011 and is equipped with a dry lime scrubber is achieving an annual average SO_2 rate of 0.044 lb/MMBtu.[57]

Further, Stamper stated that a circulating dry scrubber can achieve even higher levels of SO_2 removal than an SDA and lower SO_2 emission rates. As discussed elsewhere in this document, EPA should have evaluated circulating dry scrubbers in its analyses of reasonable progress measures for the Texas EGUs.

In summary, Stamper contended that the EPA's assumed level of SO_2 control in its cost effectiveness analyses for SO_2 for wet FGD and SDA systems is likely conservative and does not reflect the full extent of SO_2 emission reductions that can be achieved with these control technologies. That means EPA's cost effectiveness calculations should be lower and the visibility improvements higher for several of the EGUs evaluated by EPA for reasonable progress controls.

Footnotes:

[42] *See*, e.g., Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology, March 2013, at 6.

[43] *See* Black & Veatch vendor brochure on CT-121, (Ex. 14).

[44] Yasuhiko Shimogama, Hirokazu Yasuda, Naohiro Kaji, Fumiaki Tanaka, and David K. Harris, Commercial Experience of the CT-121 FGD Plant for 700 MW Shinko-Kobe Electric Power Plant, Paper No. 27, presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003, (Ex. 15).

[45] CT-121 FGD Process – Jet Bubbling Reactor, http://www.bwe.dk/fgd-ct121.html, (Ex. 16).

[46] Emission-control Technologies Continue to Clear the Air, Power, May/June 2002.

[47] *See* Black & Veatch, First Black&Veatch/Chiyoda Wet Flue Gas Desulfurization System in North America Successfully Goes Operational.

[48] Blankinship, Steve, Go Take a Bath, Power Engineering, October 2008, available at http://pepei.pennnet.com/display_article/342997/6/ARTCL/none/none/1/Go-Take-a-Bath/.

[49] Chiyoda Licenses Its Flue Gas Desulfurization Technology in USA Newly for 5 Coal-Fired Generation Units, Press Release, May 2, 2005; Chiyoda Licenses its Flue Gas Desulfurization Process in USA for Georgia Power Owned 4 FGD Units, January 26, 2005.

[50] Jonas S. Klingspor, Kiyoshi Okazoe, Tetsu Ushiku, and George Munson, High Efficiency Double Contact Flow Scrubber for the U.S. FGD Market, Paper No. 135 presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003, p.8, Table 4, (Ex. 17).

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[51] Yoshio Nakayama, Tetsu Ushiku, and Takeo Shinoda, Commercial Experience and Actual-Plant-Scale Test Facility of MHI Single Tower FGD, (Ex. 18).
[52] Mitsubishi High SO_2 Removal Experience, (Ex. 19).
[53] *See* White Bluff Station Units 1 and 2 Evaluation of Wet vs Dry FGD Technologies, Rev. 3, October 28, 2008, prepared by Sargent & Lundy at 3-7. (Ex. 20).

Footnotes:
[63] Sargent & Lundy LLC, *IPM Model – Revisions to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology*, March 2013.

Response: All of the claims in this comment have been previously addressed in confidential expert reports in the Cinergy case[154], including achievable FGD SO_2 removal efficiency and the reliability of vendor guarantees for setting emission limits, based on CEMS data, published works, and deposition testimony of five major scrubber vendors.[155] These reports and SO_2 scrubber vendor depositions conclude that 98% to 99% SO_2 control has been achieved and is routinely achievable. These reports and depositions also conclude that vendor guarantees are a reliable basis for establishing emission limits. We cannot include these expert reports and depositions in our docket, because they are held confidential under a protective court order. However, we do include the testimony of Dr. Phyllis Fox, one of the government expert witnesses, in which she testifies, based on her expert report with Hal Taylor, that the removal efficiency of wet scrubbers can reach 99%. [156] These conclusions were upheld in court rulings in United States v. Cinergy Corp., 618 F. Supp. 2d 942, 947 and 961-962 (S.D. Ind. 2009).

First, this comment argues that a "controlled SO_2 limit of 0.04 lb/MMBtu is not a realistic or sustainable value to maintain on a long term basis when considering the normal variation in operation that occurs at all coal-fired facilities." This is misleading as the proposed limit for retrofits is not "0.04 lb/MMBtu" on an instantaneous basis, as suggested in this comment, but rather is based on a "30-boiler-operating-day" (30-BOD) average.[157] A boiler operating day is 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."[158] As explained in our FIP TSD (p. 31) and

[154] United States and Plaintiff-Intervenors States of New York, New Jersey, and Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, Civil Action No. IP99-1693 C-M/S, United States, et al., v. Cinergy Corp., et al., In the United States District Court for the Southern District of Indiana, Indianapolis Division.
[155] Phyllis Fox and Hal Taylor, Expert Report of Phyllis Fox and Hal W. Taylor. Prepared on Behalf of Plaintiff United States and Plaintiff-Intervenors States of New York, New Jersey, and Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, Civil Action No. IP99-1693 C-M/S, United States, et al., v. Cinergy Corp., et al., In the United States District Court for the Southern District of Indiana, Indianapolis Division, August 29, 2008; Phyllis Fox and Hal Taylor, Expert Rebuttal Report of Phyllis Fox and Hal W. Taylor, Prepared on Behalf of Plaintiff United States and Plaintiff-Intervenors States of New York, New Jersey, and Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, Civil Action No. IP99-1693 C-M/S, United States, et al., v. Cinergy Corp., et al., In the United States District Court for the Southern District of Indiana, Indianapolis Division, October 14, 2008, 2008.
[156] United States and Plaintiff-Intervenors States of New York, New Jersey, and Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, Civil Action No. IP99-1693 C-M/S, United States, et al., v. Cinergy Corp., et al., In the United States District Court for the Southern District of Indiana, Indianapolis Division. Trial Proceedings, Volume 2. Testimony of Dr. Phyllis Fox, beginning on vol. 2-302.
[157] 79 FR 74,822, Table 1; 74,884 (Dec. 16, 2014).
[158] 70 FR 39,172 (July 6, 2005).

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the proposed rulemaking, days are skipped when the unit is down, as for maintenance. This provides a margin of safety by eliminating spikes that occur at the beginning and end of outages, when the scrubber is not operating.[159] Regardless, all major scrubber vendors guarantee 99% SO_2 control and expect routine performance at this level. This level of control is confirmed under vendor guarantees by making simultaneous measurements of SO_2 at the inlet and outlet of the scrubber.

The emission limit that we have proposed for all wet scrubbed units, 0.04 lb/MMBtu, is based on 98% control, unless the resulting controlled limit fell below an outlet SO_2 level of 0.04 lb/MMBtu, in which case, we would have assumed the percentage control equal to 0.04 lb/MMBtu.[160] All of the calculated 98% control levels, except for Big Brown Unit 1, were lower than 0.04 lb/MMBtu, as shown in the following table. Thus, the limits we propose have built in margin.

Calculation of Wet Scrubber Limits

Unit	Proposed SO_2 Limit (lb/MMBtu)	Baseline (lb/MMBtu)	Control Level (%)	Margin (lb/MMBtu)
Big Brown 1	0.04	0.04	98	0
Big Brown 2	0.04	0.0392	97.91	0.00084
Monticello 1	0.04	0.0388	96.99	0.0012
Monticello 2	0.04	0.0387	96.83	0.0013
Coleto Creek 1	0.04	0.0383	95.65	0.0014

Recent operating experience reported by Hitachi confirms that 99% SO_2 control is achievable.[161] Hitachi has guaranteed many units at 99% SO_2 control efficiency.[162] Hitachi has explained that 99% control on an "instantaneous basis" (not even a rolling average) is routinely achieved in Japan, where rolling averages are not allowed, and has stated that Hitachi is "comfortable with 98%" for PRB coals.[163] See also Stamper comment 0068, pp. 15-17. Alstom has guaranteed

[159] 79 FR 74,884 (Dec. 16, 2014).

[160] Cost TSD, p. 21; 79 FR 74,884 (Dec. 16, 2014). The proposed control level was calculated in the wet FGD spreadsheet in cell E13. First, we tested to see if 98% of the uncontrolled SO_2 rate would result in a value less than 0.04 lb/MMBtu. If it did, then a control level was calculated based on a reduction to 0.04. If it didn't, then the control level was set to 98%. The uncontrolled SO_2 rate itself was calculated based on the maximum monthly SO_2 rate from 2009-2014. This was calculated in the "Monthly Emissions" tab of the wet FGD spreadsheet. The maximum monthly value was used to ensure the scrubber was designed to address the dirtiest coal burned in the recent past.

[161] B.C. Studley and others, Recent Operating Results of the Five New Wet FGD Installations for Ameren Corporation, Available at: http://www.psa.mhps.com/supportingdocs/forbus/hpsa/technical_papers/Recent%20Operating%20Results%20of%20the%20Five%20New%20Wet%20FGD%20Installations%20for%20Ameren%202011.pdf.

[162] Hitachi Wet FGD Sample of Recent Installations (showing 99% guarantees at Boswell #3, Coffeen #1,2, Duck Creek #1, Sioux 1,2).

[163] E-mail from Joseph Barba, Hitachi, to Phyllis Fox, January 31, 2007.

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units at 99%, concluding the new Trimble County Unit 2 "can reliably achieve a high efficiency. 99.8% SOx removal could be expected."[164] Advatech, a joint venture of URS and Mitsubishi, likewise has built scrubbers guaranteed at 98% to 99%.[165] Advatech reports its highest SO_2 guarantee is 99.8%. Their experience list includes many units in Japan guaranteed at this level,[166] which must be met on an instantaneous basis.

Second, this comment asserts that vendor guarantees do not reflect controlled emission rates that may be achievable on a consistent long-term basis as the unit operation varies from design conditions." A survey of owners of FGD systems found that "[w]ith regard to FGD reliability, in every case except for one SDA system, performance overall met or exceeded owner expectation. Therefore, there is reason to believe that the FGD systems will perform as expected (albeit, with some specific components that may perform more or less reliably than other components.)."[167] Major scrubber vendors have testified in confidential depositions that they expect their scrubbers to meet guarantees, which typically have a built-in vendor margin of safety.

Further, vendors offer "make-right" guarantees that cover the life of the FGD and all operating conditions. Make-right guarantees restore a malfunctioning FGD to its design basis. Regardless, the vendor must protect its reputation. Scrubber vendors have a vested interest in maintaining their market position and customer base. We are not aware of any vendor that would walk away from an FGD that did not perform according to its guarantee (even after the guarantee period has ended).

Third, this comment argues that using the vendor guaranteed level of 0.04 lb/MMBtu is "overly aggressive and provides no margin for normal operating conditions or long-term operation." Variations in scrubber performance due to changes in coal quality, reagent quality, startups, shutdowns, and malfunctions are normally accommodated in permitting by specifying a sufficiently long averaging time, in this case, the 30-day BOD, which is specifically designed to average out spikes. In general, averaging smooths out fluctuations in data.[168] We built further margin into the 0.04 lb/MMBtu limits, which are based on less than 98% control, except at Big Brown Unit 1, as summarized in –the above table. Finally, margin is built into the guarantee by the vendor.

Fourth, this comment attempts to support these claims by presenting seven years of SO_2 emission data for a single facility, Spruce Unit 1. Spruce Unit 1 is a 585-MW tangentially-fired Combustion Engineering boiler, designed to burn PRB coal, which started up in December 1992.[169]

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[164] Alstom Responses to Questions, Trimble County Unit 2, October 25, 2004, BV-00000171.
[165] Advatech, Double Contact Flow Scrubber, Available at: http://www.advatechllc.com/wp-content/uploads/2013/10/advatech-double-contact-flow-scrubber-brochure.pdf.
[166] Advatech, Advanced Flue Gas Desulfurization, 2005.
[167] James E. Staudt, Sikander R. Khan, and Manuel J. Oliva, Reliability of Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Systems for High Pollutant Removal Efficiencies on Coal Fired Utility Boilers, MEGA Symposium, 2004, p. 17.
[168] Thad Godish, Air Quality, Lewis Publishers, 2nd Ed. , 1991, p. 216, Figure 7.1; Richard W. Boubel, Donald L. Fox, Bruce Turner, and Arthur C. Stern, Fundamentals of Air Pollution, Academic Press, 3rd Ed., 1994, pp. 41 - 43.
[169] R. Peltier, J.K. Spruce Power Plant, Unit 1, San Antonio, Texas, POWER, October 15, 2008, Available at: http://www.powermag.com/j-k-spruce-power-plant-unit-1-san-antonio-texas/?pagenum=1.

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The original SO_2 scrubber, designed for 70% SO_2 control, was started up in 1992 when the boiler came online. The scrubber was upgraded in 2009 by Alstom to achieve 95% SO_2 control at a cost of about $9 million.[170] However, the SO_2 emission limit of 0.04 lb/MMBtu that this comment is critiquing is proposed only for retrofit scrubbers, i.e., new scrubbers on existing boilers, not upgraded scrubbers. Thus, the Spruce data is misleading, as the performance of a scrubber upgrade may not be representative of the performance that can be achieved by a new scrubber retrofit on an existing unit. In fact, we assumed 95% control for our scrubber upgrade analyses, versus 98% control (not to go below 0. 04 lbs/MMBtu) for our scrubber retrofit analyses.

Fifth, the upgraded Spruce Unit 1 scrubber came on line in early 2009, just as the SO_2 allowance market it would have benefited from collapsed, removing the incentive to operate it at its design SO_2 efficiency.[171] As scrubbers are costly to operate (see O&M costs in our Cost TSD), and this unit has very high SO_2 permit limits,[172] CPS Energy has no incentive to operate the upgraded scrubber at its design basis.

The apparent poor performance of Spruce Unit 1 is not due to issues implied in this comment, but rather the lack of any requirement or incentive to do better. The 30-day BOD data demonstrate that in spite of these disincentives, this upgraded scrubber achieved a 30-day BOD emission rate of 0.07 lb/MMBtu, except when the scrubber was offline, from July 16, 2011 to August 26, 2011. The Spruce permit exempts "maintenance, startup, and shutdown periods" from compliance with emission limits.[173] In other words, the boiler can legally continue to operate while the control equipment is shutdown. The 0.07 lb/MMBtu achieved at Spruce Unit 1 when the scrubber was operating is well within the range of our proposed SO_2 limits for scrubber upgrades.

We are not proposing an SO_2 emission rate of 0.04 lb/MMBtu for any scrubber upgrade, as they may be less efficient than a new retrofit scrubber. Rather, we proposed SO_2 emission rates of 0.06 to 0.60 lb/MMBtu for scrubber upgrades. The 0.04 lb/MMBtu limit that is the subject of this comment was only proposed for new scrubbers on existing boilers or "retrofits".[174] Thus, the performance of Spruce Unit 1 is irrelevant for supporting the arguments made in this comment.

Sixth, we note that this comment visually distorts the performance of Spruce 1 by plotting conventional 30-day moving averages, rather than 30-day BOD averages, as proposed in the rulemaking. Further, the graph is plotted on a fine scale to accentuate fluctuations. We replotted

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[170] CPS, Corporate Sustainability Report 2010, p. 57, Available at: https://www.cpsenergy.com/content/dam/corporate/en/Documents/Sustainability_Report_2010.pdf.

[171] C. Hitaj and A. Stocking, Market Efficiency and the U.S. Market for Sulfur Dioxide Allowances, Working Paper 2014-01, Congressional Budget Office, January, 2014. See especially Figure 1. Available at: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CCAQFjAAahUKEwi1w9HwsJDIAhVIJB4KHRAvB2Y&url=https%3A%2F%2Fwww.cbo.gov%2Fsites%2Fdefault%2Ffiles%2F113th-congress-2013-2014%2Fworkingpaper%2F45044-SO_2MarketAnalysis_1.pdf&usg=AFQjCNHYiyaL3lTMimbRvluvI3DVa-T18w&cad=rja.

[172] Spruce Unit 1 Permit, Permit Numbers 18426 and PSDTX742M1, Special Conditions, Condition 8.

[173] Spruce Unit 1 Permit, p. 7, Condition 15.

[174] 79 FR 74,822, Table 1 (Dec. 16, 2014).

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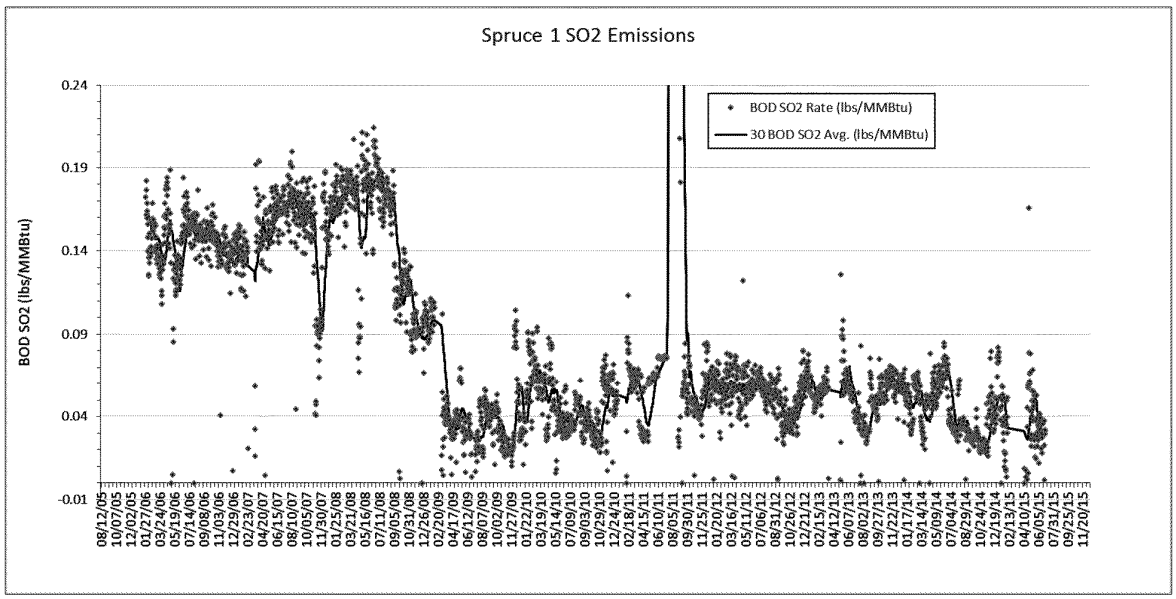
it using a 30-day BOD average and a scale that includes the uncontrolled spike.[175] This analysis is shown in the figure below.



This plot shows that Spruce Unit 1 is achieving a 30-day BOD of 0.07 lb/MMBtu after the upgraded scrubber stabilized, except for the period from July 16, 2011 to August 26, 2011, when the scrubber was off-line, but the boiler continued to operate. This is allowed under Spruce's current permit to operate during "routine maintenance, startup, and shutdown". The EPA recently issued a final rule barring these SSM exemptions in state permits.[176]
Finally, Sargent & Lundy omits that there are units that demonstrate our proposed limits and control efficiencies have been and are being achieved on a routine basis. To demonstrate that the proposed wet scrubber SO_2 emission limits (0.04 lb/MMBtu) are achievable, we reviewed our Clean Air Market Database (CAMD) to identify similar coal-fired boilers that have met a a 30 BOD average SO_2 emission rate of 0.04 lb/MMBtu or better continuously for at least 1 year.

First, we downloaded all annual SO_2 data from 2007-2014, inclusive. This annual data was filtered to select only the units that met the following criteria:

- Electric utility only
- Coal burning only
- Avg. annual SO_2 rate < 0.045 lb/MMBtu
- Wet FGD only
- Operating time > 4,800 hours
- 12 months of reported data only
- Retrofit or upgraded scrubber

[175] See "Selected BOD SO_2 Averages-3.xlsx," Tab "Spruce 1" in our docket.
[176] http://www.epa.gov/airquality/urbanair/sipstatus/emissions.html

We next researched the subset of wet FGDs that met these criteria and eliminated units that used lime wet FGD, as it can achieve a higher SO_2 removal efficiency, but is generally more expensive due to the cost of lime. We only retained one lime FGD, Milton Young 1, as it is the only unit in our dataset that fires lignite coal. We found many units coded as using lime FGD in the CAMD database that in fact used limestone FGD. We also eliminated scrubbers installed on newly built units at the time of initial construction. Most of the scrubbers that met these criteria were retrofits, the target of our analysis, but some upgrades were included. We retained these to compare retrofit with upgrade experience.

We adopted this conservative criteria and methodology in order to quickly and easily demonstrate that in fact there are a number of similar units operating wet scrubbers comfortably below our proposed SO_2 emission limit. In so doing, we note there are a number of additional similarly configured units (e.g., Scherer 1) that have demonstrated their ability to operate for extended periods of time below our proposed control efficiency, but do not meet these criteria. We do not advocate that our criteria and methodology are the only way to demonstrate the operational effectiveness of any particular control, scrubbers or otherwise.

We used EIA information to determine the coal type burned at each facility and eliminated all units that did not burn PRB, lignite, or a blend of PRB or lignite with another coal type, which are the predominate fuels burned by the subject Texas plants. We also researched each plant to confirm the scrubber type, scrubber install date, design control efficiency, and permit limits, where available. The resulting list of plants is:

- Iatan Unit 1[177]
- Boswell Energy Center Unit 3[178]
- James H. Miller Units 1, 2, 3, and 4[179]
- Jeffrey Energy Center Units 1, 2, and 3[180]

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[177] Robert Peltier, Plant of the Year: KCP&L's Iatan 2 Earns POWER's Highest Honor, POWER, August 1, 2011, Available at: http://www.powermag.com/plant-of-the-yearkcpls-iatan-2-earns-powers-highest-honor/.

[178] Retrofitting Boswell Energy Center, Power Engineering, September 1, 2010, Available at: http://www.power-eng.com/articles/print/volume-114/issue-9/Features/retrofitting-boswell-energy-center.html. See also: http://www2.epa.gov/enforcement/minnesota-power-settlement (requiring SO_2 emission rate of no greater than 0.030 lb/MMBtu at Boswell Units 3 and 4) and Consent Decree at http://www2.epa.gov/sites/production/files/2014-07/documents/minnesotapower-cd.pdf ("Minnesota Power shall continuously operate an FGD device at Boswell Unit 3 such that the unit achieves and maintains a 30-day rolling average emission rate for SO_2 no greater than 0.03 lb/MMBtu." and "No later than May 31, 2016, Minnesota Power shall continuously operate a new FGD device at Boswell Unit 4 such that the Unit achieves and maintains a 30-day rolling average emission rate for SO_2 no greater than 0.03 lb/mmBTU."

[179] ADVATECH, Plant Miller – Wet FGD Retrofit Project, Available at: http://www.advatechllc.com/projects/air-quality-control-solutions/acid-gas-control/acid-gas-project-descriptions/southern-company-miller/. Title V Permit at: http://www.jcdh.org/EH/AnR/AnR13.aspx. Consent Decree at: http://www2.epa.gov/enforcement/alabama-power-company-clean-air-act-settlement.

[180] Westar Energy Sulfur Dioxide Removal Project on First of Jeffrey Energy Center's Generating Units Fully Operation, August 11, 2008, Available at: http://www.energycentral.com/generationstorage/fossilandbiomass/news/vpr/5341/WESTAR-ENERGY-SULFUR-DIOXIDE-REMOVAL-PROJECT-ON-FIRST-OF-JEFFREY-ENERGY-CENTER-S-GENERATING-UNITS-FULLY-OPERATIONAL; Gail Reitenbach, WATER AWARDE: Jeffrey Energy Center's Constructed Wetland Treatment System, POWER, August 1, 2014, Available at: http://www.powermag.com/jeffrey-energy-centers-

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- Milton Young Unit B1[181]
- Pleasant Prairie Unit 1 and 2[182]
- Sam Seymore (Fayette) Unit 1, 2,[183]and 3[184]
- Scherer Units 2, 3, and4[185]

We prepared graphs of these units showing the 30-day BOD SO_2 data superimposed on the measured daily data in lb/MMBtu. These graphs are included in our docket in the file "Selected BOD SO_2 Averages-3.xlsx." This file contains tabs corresponding to each of the above units, and a "Read Me" tab that explains our methodology.

The performance of each scrubber in our data set is summarized in the file, "Selected scrubber retrofit efficiencies.xlsx." The "Efficiencies" tab within this file reports vendor guaranteed control efficiency, achieved control efficiency, and the maximum 30-day BOD, excluding shakedown periods following initial startup of scrubber retrofits, and other items. This information supports our proposed SO_2 limits for both retrofits and upgrades. The 13 retrofit units have guaranteed control efficiencies of 95% to 99%, with eight of them guaranteed at 98% to 99%. These eight units are achieving 98% to 99% SO_2 control, with the exception of Scherer Unit 4, when calculated using our very conservative method explained in the "Read Me" tab.

We note that compliance with the vendor guaranteed SO_2 control efficiency is typically determined by simultaneously measuring scrubber inlet and outlet SO_2 emissions. As CAMD does not report and facilities generally do not measure inlet SO_2 CEMS data, our estimated control efficiencies are based on pre-scrubber retrofit SO_2 and post-scrubber retrofit 30-day BOD data, as explained in the "ReadMe" tab noted above. None of the eight units that are achieving 98% to 99% SO_2 control have permit limits that require operation at this level. However, several have entered into consent decrees that do require control efficiencies approaching these values.

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constructed-wetland-treatment-system/?pagenum=1; and Westar Energy, Jeffrey Energy Center Wetlands, Available at: https://www.westarenergy.com/jeffrey-energy-center-wetlands.

[181] Burns & McDonnell, Milton R. Young Units 1 & 2, 2015, Available at: http://www.burnsmcd.com/Resource_/Project/2234/ProjectPdf/Milton-R-Young-Units-1-amp-2.pdf; MET, Wet FGD, Available at: http://www.met.net/wet-fgd-technologies-lime.aspx.

[182] Steven Gebhart and others, Pleasant Prairie Power Plant Air Quality Control Upgrade Project, Pleasant Prairie, Wisconsin, POWER, October 15, 2007, Available at: http://www.powermag.com/pleasant-prairie-power-plant-air-quality-control-upgrade-project-pleasant-prairie-wisconsin/ See also: http://www.pleasantprairieonline.com/services/communitydevelopment/powerplant.asp

[183] C. Frazer and others, Fayette Power Project Unit 3 FGD Upgrade: Design and Performance for More Cost-Effective SO_2 Reduction, Mega Symposium, 2010, Available at: http://www.babcock.com/library/documents/br-1845.pdf; LCRA Adds Scrubbers to Clean Sulfur Dioxide from Plant Emissions, August 1, 2011, Available at: http://www.statesman.com/news/news/local/lcra-adds-scrubbers-to-clean-sulfur-dioxide-from-1/nRc8M/.

[184] Austin City Council, Audit Report, Fayette Power Project Scrubber Costs, October 3, 2006, Available at: Powerplant Upgrades Test New Technology, ENR Texas & Louisiana, April 18, 2011, Available at: https://austintexas.gov/sites/default/files/files/Auditor/au06113.pdf; http://texas.construction.com/texas_construction_projects/2011/0418_powerplantupgrades.asp; Fayette Power Project, Available at: http://www.lcra.org/energy/electric-power/facilities/fayette-power-project/Documents/fayette_power_project_2013_03_22.pdf.

[185] ADVATECH, Plant Scherer – Wet FGD Retrofit Project, Available at: http://www.advatechllc.com/projects/air-quality-control-solutions/acid-gas-control/acid-gas-project-descriptions/southern-company-scherer/; ADVATECH, Double Contact Flow Scrubber, 2011, Available at: http://www.aecomprocesstechnologies.com/wp-content/uploads/2012/03/advatech-dcfs-brochure.pdf

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The maximum 30-day BOD, over the period of record when the scrubbers were operating, excluding scrubber "shakedown" periods, for retrofit FGDs designed to achieve 98% to 99% SO_2 control range from 0.02 lb/MMBtu at Iatan Unit 1 to 0.08 lb/MMBtu at Scherer Unit 3. Three of the units have achieved a maximum 30-day BOD equal to or less than our proposed SO_2 emission limit for scrubber retrofits of 0.04 lb/MMBtu:

- Scherer Unit 2: 0.01 lb/MMBtu based on 485 data points
- Iatan Unit 1: 0.02 lb/MMBtu based on 2,004 data points
- Boswell Energy Center: 0.03 lb/MMBtu based on 1,881 data points

All of these units burn PRB coal and are operating at these levels without permit limits that require compliance at achieved levels. The best performers are discussed below.

Scherer Unit 2

Plant Scherer consists of four 818 MW, Combustion Engineering boilers that became operational in 1982, 1984, 1987, and 1989. All of the units burn PRB coal. All four units were retrofitted with wet scrubbers that became operational in late 2010 to 2014. All of the units have continuously operated below 0.01 lbs/MMBtu for months at a time. The maximum 30-day BOD at Unit 2, after scrubber shakedown, was 0.01 lb/MMBtu, with the majority of the 30-day BOD data points below this level. The compliant data set includes 423 continuous 30-day BOD data points, between March 2014 and June 2015, all less than or equal to 0.01 lb/MMBtu. See the figures below for Unit 2. The second figure shows the period just after the scrubber became operational, plotted on a finer scale to better display the scrubber's performance:

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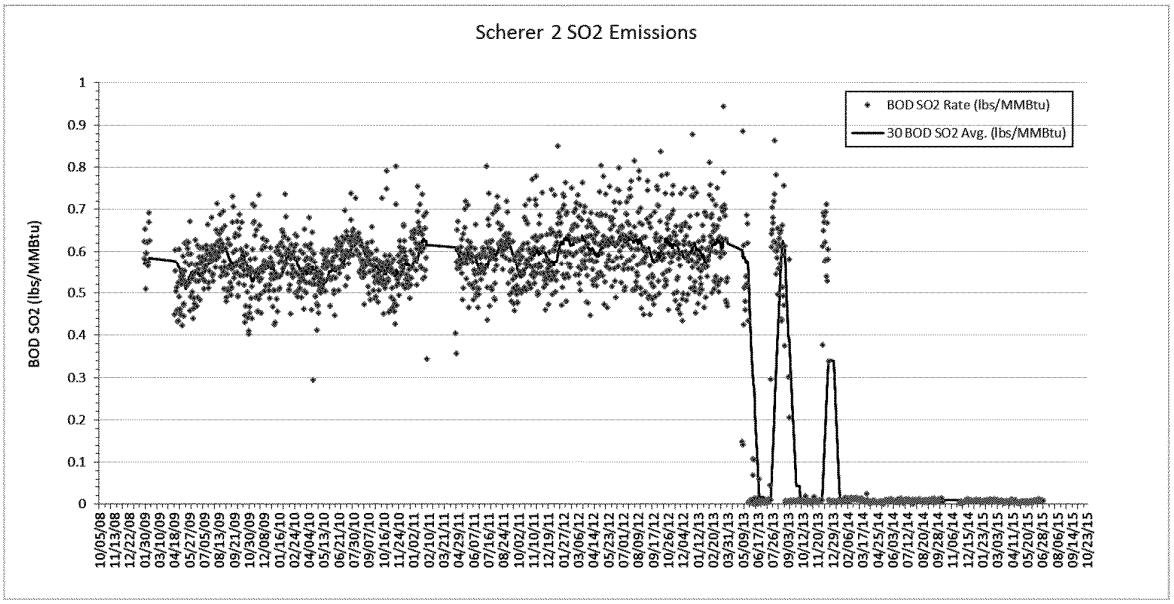
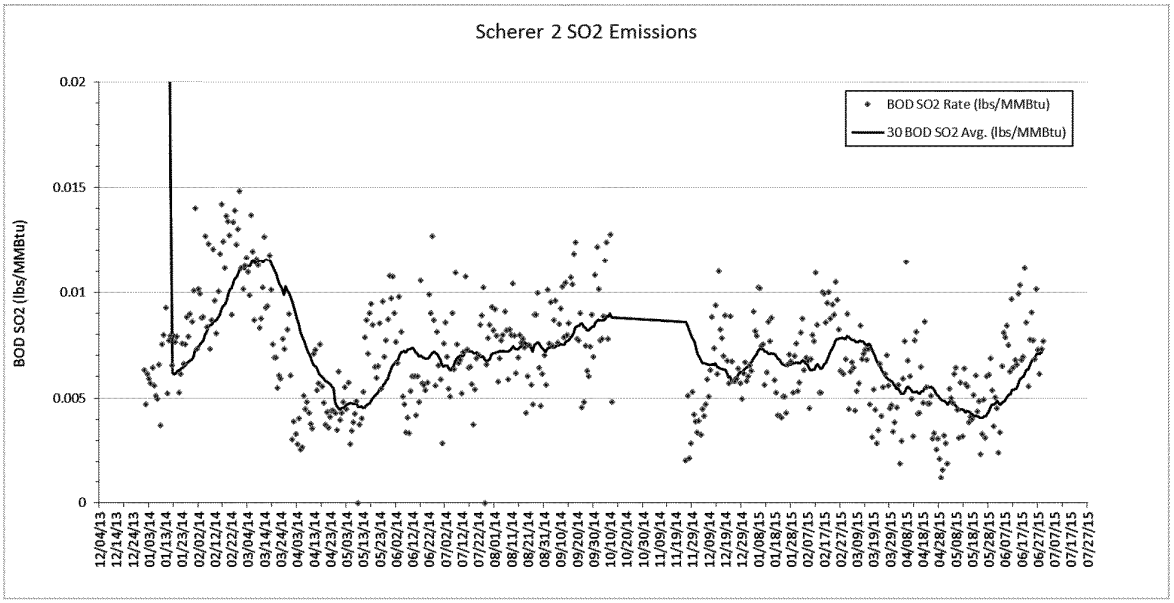




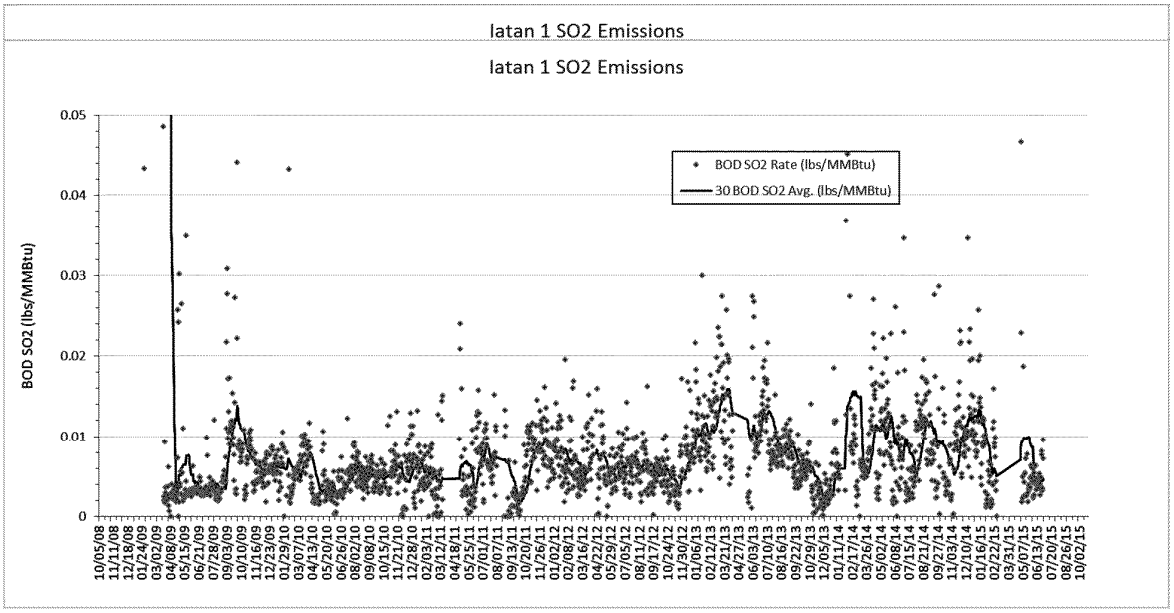
Scherer Units 1, 3, and 4 display similar levels of control capability.

Iatan Unit 1(Retrofit Scrubber)

Iatan Unit 1 is an approximately 700-MW, PRB-fired, Babcock & Wilcox boiler that started up in 1980. This unit was retrofit with a wet scrubber in 2009 at the same time that new Iatan Unit 2 was built. The Iatan Unit 1 scrubber was installed to meet CAIR/CSAPR requirements for SO_2 emissions and as a requirement for the air permit for Iatan 2, under a settlement agreement with the Sierra Club. [186]

The design of the air quality control system for both existing Unit 1 and new Unit 2 was very similar, resulting in similar performance. "The entire post-combustion AQCS [air quality control system] for Iatan 1 is virtually identical to that of the new Iatan 2….The wet FGD systems, using the same size vessel on both units, routinely operate at 99% removal, producing SO_2 levels in the exhaust gas well below the 0.06 lb/MMBtu permit limits. Each vessel is equipped with five recycle pumps but usually runs only three or four, depending on operating conditions." Thus, while the Unit 1 scrubber is a retrofit, its performance is nearly identical to scrubber on new Unit 2.[187]

This is the best performing wet scrubber retrofit in the data set based on 6 years of continuous operation. The maximum 30-day BOD at this unit, after scrubber shakedown, was 0.02 lb/MMBtu, with the majority of the 30-day BOD data points far below this level. The compliant data set includes 2,004 continuous 30-day BOD data points, between April 2009 and June 2015, all less than or equal to 0.02 lb/MMBtu. See the figures below. The second figure shows the period just after the scrubber became operational, plotted on a finer scale to better display the scrubber's performance. This is much better performance than is required by Iatan Unit 1's operating permit, which limits SO_2 emissions to 0.07 lb/MMBtu, based on a conventional 30-day rolling average.[188]

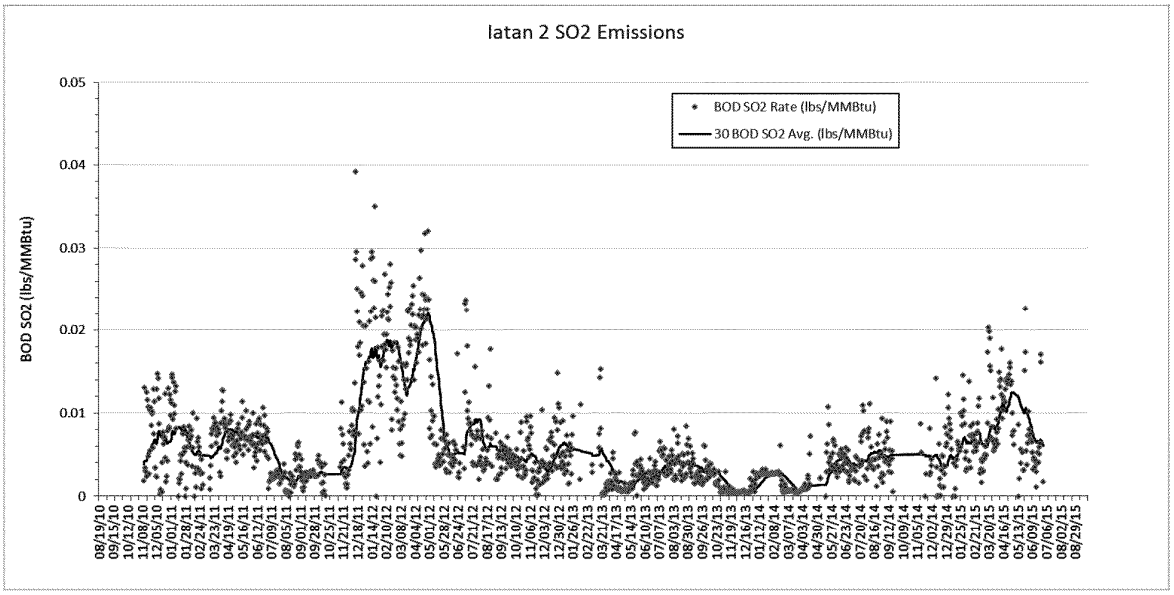


Of note, the 30-day BOD SO_2 data for Iatan Unit 1 does not include the spikes found at some of

[186] Empire District Electric Co – '10-Q' for 3/31/12 – R13, "Compliance Plan" and "SO_2 Emissions." Available at: http://www.secinfo.com/d11MXs.p1Zm2.1s.htm; State of Kansas, Air Quality State Implementation Plan, Regional Haze, October 26, 2009, Available at: http://www.kdheks.gov/bar/reghaze/KDHERegHaze.pdf.
[187] Robert Peltier, Plant of the Year: KCP&L's Iatan 2 Earns POWER's Highest Honor, POWER, August 1, 2011, Available at: http://www.powermag.com/plant-of-the-yearkcpls-iatan-2-earns-powers-highest-honor/.
[188] Kansas City Power & Light, Iatan Generating Station, Permit No. 012006-019B.

the other units we reviewed. Iatan's operating permit does not include any exemptions from permit limits for startups, shutdowns, and malfunctions (SSM), while plants with frequent spikes include this exemption. The Iatan Unit 1 permit limits for all pollutants (except opacity) explicitly "include[ing] periods of start-up, shutdown and malfunction…"[189] Other plants with SSM exemptions in their permits have no obligation to operate their scrubbers during SSM events, resulting in the boiler continuing to run while the scrubber is offline for maintenance, creating spikes that are not related to scrubber performance.

Iatan 2, a new boiler and scrubber, displays a similar level of performance. Because it's scrubber pre-scrubber data is not available:



As can be seen from the above figures, both units have operated for years at a SO_2 emission rate below 0.01 lbs/MMBtu.

Boswell Energy Center Unit 3 (Retrofit Scrubber)

A wet scrubber was retrofit on existing (Clay) Boswell Energy Center Unit 3[190] in November 2009. It was designed by Hitachi to achieve 99% SO_2 control.[191] The existing permit to operate limits SO_2 emissions to 2.97 lb/MMBtu for a 1-hour average and 0.09 lb/MMBtu on a 30-day rolling average basis.[192] The unit has been operating far below these limits.

[189] Iatan Generating Station Permit Number: 012006-019A, July 13, 2007, p. 5, Note to Special Condition 2.E.
[190] Unit 3 is a 365-MW pulverized dry tangential-fired ABB Combustion Engineering boiler that fires PRB coal and started operating in 1973.
[191] Mitsubishi Hitachi Power Systems, Flue Gas Desulfurization, Available at: http://www.psa.mhps.com/products/environmental_products/fgd/.
[192] Minnesota Power Inc – Boswell Energy Center, Air Permit No. 06100004-007, Major Amendment, June 13, 2013, pdf 14.

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A subsequent 2014 Consent Decree reduced the Boswell SO_2 limit to 0.03 lb/MMBtu on a 30-day rolling average basis, as of the "date of entry" of the Consent Decree, which was filed on July 16, 2014.[193] This limit has been consistently met since stable scrubber operation began in December 2009. This limit reflects the judgment of EPA that a SO_2 limit of 0.03 lb/MMBtu on a 30-day rolling average basis is achievable.

The Consent Decree limit (0.03 lb/MMBtu 30-day rolling average) is much lower than the SO_2 limit proposed for wet FGD retrofits (0.04 lb/MMBtu 30-day BOD average).[194] A 30-day rolling average is more conservative (i.e., harder to meet) than the 30-day BOD average proposed in this rulemaking. Further, 0.03 is lower than 0.04. Thus, the Boswell Energy Center Consent Decree requires an SO_2 emission limit that is more aggressive than any of the limits proposed by EPA to satisfy reasonable progress. This 0.03 lb/MMBtu 30-day rolling average limit is currently being achieved.

The SO_2 CEMS data for Boswell Unit 3 is shown in the figures below. The second figure shows the period just after the scrubber became operational, plotted on a finer scale to better display the scrubber's performance. These figures demonstrate that the proposed 0.04 lb/MMBtu 30-day BOD for retrofit scrubbers under the Texas FIP has been met with a significant margin at this unit for over five years or for 1,881 individual continuous 30-day BOD data points.

[193] Consent Decree at http://www2.epa.gov/sites/production/files/2014-07/documents/minnesotapower-cd.pdf ("Minnesota Power shall continuously operate an FGD device at Boswell Unit 3 such that the unit achieves and maintains a 30-day rolling average emission rate for SO_2 no greater than 0.03 lb/MMBtu." and "No later than May 31, 2016, Minnesota Power shall continuously operate a new FGD device at Boswell Unit 4 such that the Unit achieves and maintains a 30-day rolling average emission rate for SO_2 no greater than 0.03 lb/mmBTU.")
[194] 79 FR 74,822 (Dec. 16, 2014).

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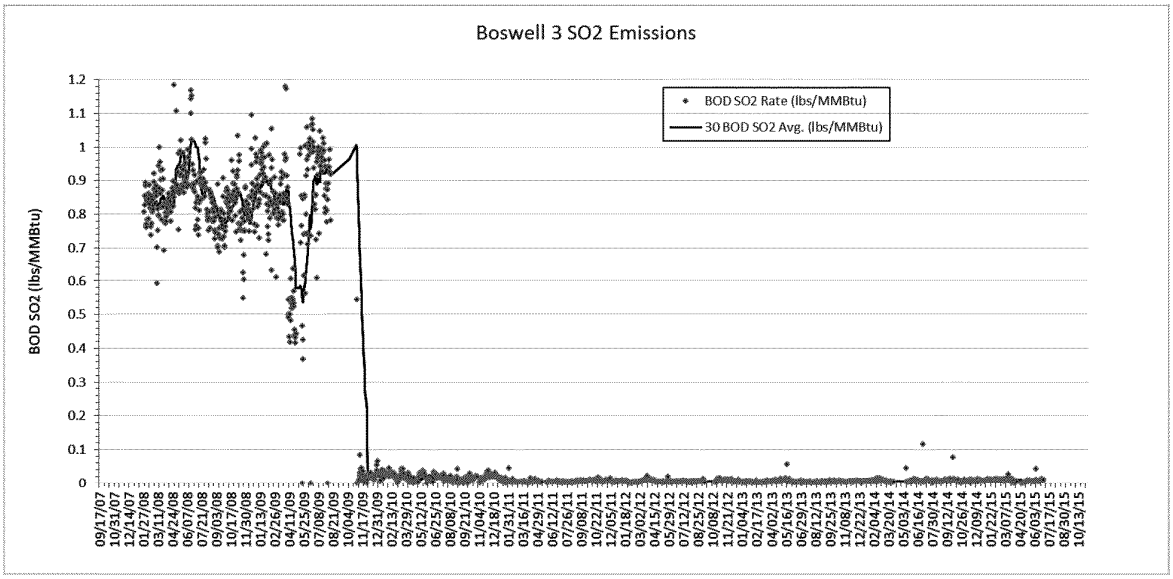

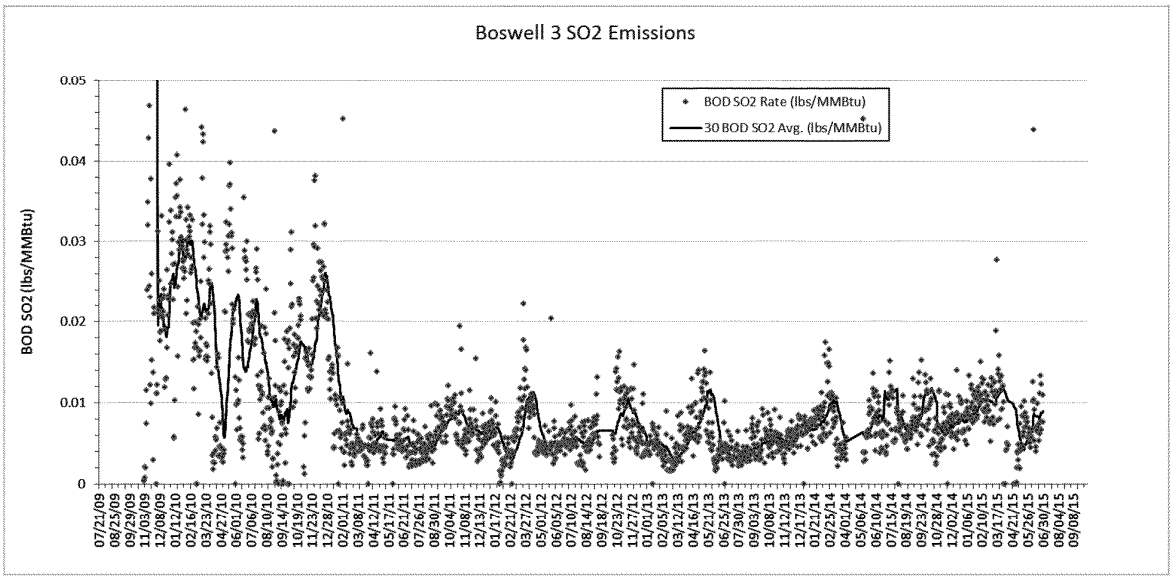

The cluster of spikes between January and December 2010, which are all less than or equal to 0.03 lb/MMBtu, are characteristic of scrubber shakedowns, during which the plant learns how to operate the scrubber and installation issues are resolved. Thereafter, this scrubber has consistently operated at a 30-day BOD of 0.01 lb/MMBtu, four times lower than required in the proposed Texas FIP.

The SO_2 CEMS data for Boswell Unit 3 for the period December 2009 through June 2015 further indicates that this retrofit scrubber has achieved 99% SO_2 reduction, determined from measured SO_2 prior to and after scrubber installation. This is consistent with its 99% SO_2 guarantee.[195]

[195] The guaranteed SO_2 efficiency is calculated from the scrubber inlet and outlet SO_2 concentrations. The CAMD

The maximum 30-day BOD is 0.03 lb/MMBtu since stable operation of the scrubber started in November 2009. This is less than required for retrofit units under the proposed Texas FIP. The majority of the BOD values are substantially lower than this maximum.

Jeffrey Energy Center (Scrubber Upgrade)

Jeffrey Energy Center consists of three 720 to 750 MW, pulverized coal, dry bottom ABB Combustion Engineering boilers that are permitted to combust either liquid and/or solid fossil fuel. The existing wet scrubbers on Jeffrey Energy Center Units 1-3[196] were rebuilt and upgraded in 2008 to 2009 by Burns & McDonnell to achieve a minimum of 95% SO_2 control. The project included replacing the module internals including mist eliminators; adding forced oxidation; eliminating flue gas bypass; increasing limestone grinding capacity; and adding a gypsum dewatering system. Induced draft fans were upgraded and ductwork was replaced. The existing stack was modified for wet-stack operation.[197]

These units are operating under a Consent Decree[198] that requires that they achieve 97% SO_2 reduction and an SO_2 emission limit of 0.07 lb/MMBtu, both on a 30-day rolling average basis. The operating permit also includes an SO_2 limit of 0.8 lb/MMBtu for each unit, no averaging time specified, and no SSM exemptions. As of January 1, 2014, they also must meet a SO_2 emission limit of 0.15 lb/MMBtu as a 30-day rolling average, excluding periods of startup, shutdown and malfunction under a Regional Haze Agreement between Westar Energy, Inc. and KDHE.[199] They are currently meeting the percent reduction requirement.

Nearly five years of continuous operating data demonstrate that these three units have consistently exceeded their 95% SO_2 removal guarantee, achieving 97% to 98% SO_2 control relative to the original scrubber baseline.

The highest 30-day rolling BOD at these units since the upgraded scrubbers achieved stable operation in 2008 to 2009 is 0.06, 0.05, and 0.09 lb/MMBtu, at Units 1, 2, and 3 respectively. This performance is generally better than the proposed SO_2 BART limits for scrubber upgrades (0.06-0.60 lb/MMBtu).[200]

CEMS data is only for the outlet. Thus, we estimated the control efficiency from the average pre-scrubber and post-scrubber emissions, as explained in the "ReadMe" in the file, "Selected scrubber retrofit efficiencies.xlsx" in our docket

[196] Units 1, 2, and 3 are 720 to 750 MW pulverized coal dry bottom ABB Combustion Engineering boilers that started operations in 1978, 1980, and 1983, respectively. They burn PRB coal and were equipped with 60% efficient Combustion Engineering SO_2 scrubbers on startup.

[197] Burns & McDonnell, Jeffrey Energy Center Units 1, 2 & 3 Upgrade Project, 2015, Available at: http://www.burnsmcd.com/Resource_/Project/1244/ProjectPdf/Jeffrey-Energy-Center-Units-1-2-3-Upgrade-Project.pdf.

[198] Consent Decree, United States of America and State of Kansas v. Westar Energy, Inc., U.S. District Court for the District of Kansas, Civil Action No. 09-CV-2059 JAR/DJW, Lodged with federal court: 75 FR 4,847 (January 15, 2010). Available here: http://www2.epa.gov/enforcement/consent-decree-westar-energy-inc-civil-action-no-09-cv-2059-jardjw.

[199] Kansas Department of Health and Environment (KDHE), Air Emission Source Class I Operating Permit, Jeffrey Energy Center, January 28, 2002, p. 25, Condition 6 and p. 28, Condition 14.

[200] 79 FR 74,822, Table 1 (Dec. 16, 2014).

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Startup, Shutdown, and Maintenance Exemptions

Many of the units that we did not specifically discuss, including all of the Miller units, and Scherer units 3 and 4, have large spikes that correspond to periods when the boiler was operating, but the scrubber was off-line. See, for example, "Selected BOD SO_2 Averages-3.xlsx," Tab: Scherer 4, the period 8/15/12 to 9/20/12. These (and other) plants with similar spikes have permits that exempt periods of startup, shutdown, and malfunction (SSM), allowing the boiler to continue to operate when the control equipment is offline.

The Title V Permit for the Scherer units[201] exempts many operating conditions, allowing the control equipment to shutdown while the boilers continue to operate. The Scherer permit limits SO_2 to 95% control on a 30-day rolling average basis, except it allows the boilers to operate without scrubbers during: (1) restarts; (2) periods of startup; (3) periods of shutdown; (4) periods of scheduled and/or preventative maintenance of control technology equipment if such maintenance cannot reasonably be performed during a scheduled outage; (5) periods of malfunction of the EGU or control technology; and (6) during certain testing and research periods. The scrubber on Scherer Unit 2 came on line in January 2014 and has only operated post-shakedown for 485 days. Its performance thus far is spectacular (maximum 30-day BOD = 0.01 lb/MMBtu), indicative of what the other longer-operating Scherer scrubbers could achieve, but for the SSM exemption periods when the scrubbers go offline, and the boilers continue to operate.

The spikes that diminish performance are generally not due to limitations of the scrubbers, but rather the failure of the facility to properly schedule adequate and timely maintenance to limit SO_2 emissions. All scrubbers require periodic maintenance. A facility without SSM exemptions will plan maintenance to avoid scrubber shutdowns during boiler operation, as demonstrated by the performance of Iatan Unit 1, discussed above.

Similarly, the Title V permit for Miller Units 1 - 4[202] limits SO_2 emissions to 1.2 lb/MMBtu (a very high limit, roughly double to its coal sulfur content[203]), with compliance only by stack test. The SO_2 permit condition includes this exception: "The FGD may be placed in bypass mode, provided all SO_2 emissions limitations are met." In other words, it can be turned off at will, as long as it burns low sulfur coal. As the typical coal that is burned at this facility contains about 0.7 lb/MMBtu of SO_2, this condition effectively allows the scrubbers to shutdown while the boilers continue to operate. This pattern is seen in the CEMS data for all four of the Miller units, which have similar SSM exemptions. Thus, we do not report the maximum 30-day BOD for any of these units in the "Efficiencies" tab of "Selected scrubber retrofit efficiencies.xlsx" document,

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[201] Scherer Steam-Electric Generating Plant, Part 70 Operating Permit, Permit Number: 4911-207-0008-V-03-0, May 8, 2012, Condition 3.4.14.

[202] Alabama Power Company, J. H. Miller, Jr. Steam-Electric Generating Plant, Major Source Operating Permit, For Units 1 & 2, p. 16, Condition 2: "The FGD may be placed in bypass mode, provided all SO_2 emissions limitations are met." For Units 3 & 4, p. 23, Condition 2: "The FGD may be placed in bypass mode, provided all SO_2 emissions limitations are met." Permit Available at: http://www.jcdh.org/EH/AnR/AnR13.aspx.

[203] From EIA-923, available here: http://www.eia.gov/electricity/data/eia923/
The 2014 sulfur content ranges from 0.23 to 0.31% and the coal heat content is approx. 17.7 MMBtu/ton. Converting to uncontrolled SO_2: (0.31% sulfur) X (1 ton/17.7 MMBtu) X (2,000 lbs/ton) X (2 molecules SO_2/1 molecule S) X (1/100%) = 0.7 lbs/MMBtu.

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as the CEMS data are not representative of scrubber performance.

The scrubbers on Miller Units 3 and 4 additionally have to meet a 30-day rolling average SO_2 control efficiency of 95%, which drops to 90% if coal with more than 1% sulfur is burned, to comply with a consent decree. However, the 30-day rolling average removal efficiency "shall exclude all emissions that occur during any period of malfunction…".[204] Further the Miller scrubbers are designed to achieve 98% SO_2 control, while the permit only requires that they achieve 90% to 95% SO_2 control, depending upon coal quality. The CEMs data includes many spikes when the boiler is operating but the scrubbers were not. Thus, the apparent poor performance of these scrubbers is not due to poor scrubber performance, but the failure of the permit to adequately limit emissions. The data summarized above indicates that similar scrubbers achieve much better performance when there are no SSM exemptions.

Finally, some of the spikes appear to be due to unspecified errors. For instance, in the Miller 1 data, the daily SO_2 average for 6/22/14 is 3.25 lb/MMBtu. This is likely a bad data point, as it is way above the SO_2 baseline from the PRB coal the Miller units have historically burned. Other graphs have similar spikes that exceed the sulfur content of coal quality.

Thus, we disagree with S&L that our proposed scrubber retrofit SO_2 emission limits are not realistic or maintainable on a long-term basis. We agree with Ms. Stamper that it may be possible that many of the scrubber retrofit units can achieve greater control efficiencies than we proposed. Greater control efficiencies would result in a more favorable cost effectiveness (lower $/ton) and more visibility improvement. This is another area in which we strove to be conservative and demonstrate that even with many conservative cost assumptions, our analyses indicate that the scrubber retrofits we proposed are cost effective.

[204] Miller Permit, pp. 22-23, Conditions 2 and 3.

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Appendix B: Wet FGD Scrubber Upgrade Control Cost Analysis as used in the Texas-Oklahoma FIP[205]

6 Upgrading Existing Scrubber Efficiencies

In Sections 3, 4, and 5, above, for those facilities with no SO_2 control, we contrasted the cost of DSI, SDA, and wet FGD. We then compared those costs to the visibility benefit from those controls from our visibility projection modeling, and we propose a RP and LTS determination. Here, we conduct similar analyses for those units listed in Table 1 with an existing SO_2 scrubber in order to determine if cost effective scrubber upgrades are available. Because all of the scrubber systems we evaluate are wet scrubbers, we limit our analyses of scrubber upgrades to wet scrubbers.

We proceed by first presenting information concerning the kinds of options generally available to facilities for upgrading their existing scrubbers. Following this, to the extent possible, we review all of the information we have at our disposal regarding the status of the existing scrubbers for each unit. This includes any upgrades the facility may have already installed. Although some of this information has been gleaned from public sources of information, much of it was collected as a result of our information collection effort. The companies that have supplied this information have asserted a Confidential Business Information (CBI) claim for much of it, as provided in 40 C.P.R. § 2.203(b). We therefore must redact any CBI information we utilize in our analyses, or otherwise disguise it so that it cannot be traced back to its specific source. Similar to our DSI, SDA, and wet FGD analyses we then contrast the cost of the various options for upgrading those scrubbers. Following this, we compare those costs to the visibility benefit from those controls from our visibility projection modeling, and propose a RP and LTS determination.

We have long recognized that existing underperforming SO_2 scrubbers are likely capable of being upgraded to much higher removal efficiencies. For example, we made this statement in the BART rule:[206]

> For those BART-eligible EGUs with preexisting post-combustion SO_2 controls achieving removal efficiencies of at least 50 percent, your BART determination should consider cost effective scrubber upgrades designed to improve the system's overall SO_2 removal efficiency. There are numerous scrubber enhancements available to upgrade the average removal efficiencies of all types of existing scrubber systems. We recommend that as you evaluate the definition of ''upgrade,'' you evaluate options that not only improve the design removal efficiency of the scrubber vessel itself, but also consider upgrades that can improve the overall SO_2 removal efficiency of the scrubber system. Increasing a scrubber system's reliability, and conversely decreasing its downtime, by way of optimizing operation procedures, improving maintenance practices, adjusting scrubber chemistry, and increasing auxiliary equipment redundancy, are all ways

[205] Reproduced from Sections 6 and 7 of the Cost TSD associated with the Texas-Oklahoma FIP, 81 FR 321.

[206] 70 FR 39171.

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to improve average SO_2 removal efficiencies.

We recommend that as you evaluate the performance of existing wet scrubber systems, you consider some of the following upgrades, in no particular order, as potential scrubber upgrades that have been proven in the industry as cost effective means to increase overall SO_2 removal of wet systems:

(a) Elimination of Bypass Reheat;
(b) Installation of Liquid Distribution Rings;
(c) Installation of Perforated Trays;
(d) Use of Organic Acid Additives;
(e) Improve or Upgrade Scrubber Auxiliary System Equipment;
(f) Redesign Spray Header or Nozzle Configuration.

We recommend that as you evaluate upgrade options for dry scrubber systems, you should consider the following cost effective upgrades, in no particular order:

(a) Use of Performance Additives;
(b) Use of more Reactive Sorbent;
(c) Increase the Pulverization Level of Sorbent;
(d) Engineering redesign of atomizer or slurry injection system.

Industry has also recognized that the efficiency of existing SO_2 scrubbers can and have been upgraded significantly and a number of companies offer scrubber upgrade services. For instance, URS makes this statement in its, "Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants:"[207]

> Upgrades have been performed on a large number of FGD units over the past 15 years and have resulted in increased SO_2 removal performance to levels ranging from 92 – 99%. These have ranged from minor modifications to the internal components of a given unit, to enhance gas-liquid contact, to conversion of some units from one FGD technology to another coupled with the addition or modification of various balance-of-plant equipment or processes.

It is typically much more cost effective to upgrade an existing FGD than to install a completely new scrubber.[208] These existing scrubbers can be upgraded by applying new scrubbing technology[209] to improve their removal efficiency, lower operating costs, and improve operations and reliability for much less than it would cost to replace them with a new scrubber.

A scrubber can be upgraded by reusing as many structural components and equipment in the existing unit as possible, such as existing structural steel and absorber shells, ducts, pumps, and

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[207] Lipinski, George, et al, Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants, URS, April 5, 2011, p. A-5.
[208] Maller et al, p. 5.
[209] See, e.g., Wolfgang Schuettenhelm and others, FGD Technology Developments in Europe and North America, Mega Symposium, 2001, http://www.babcockpower.com/pdf/rst-171.pdf.

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compressors. Scrubber upgrades have been completed on about 50 units in the last 15 years to enhance performance or lower overall operating costs.

As Staudt notes:[210]

> There have been numerous examples of FGD upgrades over the last several years that have improved SO_2 removal efficiencies. For example, the Fayette Station Unit 3, a 470 MW tangentially-fired coal unit in Texas, completed an upgrade to its 1988-vintage scrubber in 2010. The plant's control efficiency was increased from about 84 percent to 99 percent, higher than the guaranteed SO_2 removal efficiency of 95.5 percent. In Kentucky, E.On's Trimble County Generating Station Unit 1, a 550 MW tangentially-fired coal boiler, completed a scrubber upgrade in 2006. Its scrubber, installed in the 1980s, was originally designed for 90 percent removal efficiency. The scrubber system is now able to achieve over 99 percent SO_2 removal efficiency. In Indiana, NiSource upgraded the scrubbers at Schahfer Units 17 and 18 in 2009. The scrubber upgrades increased SO_2 removal efficiency from 91 percent to 97 percent.

Other successful scrubber upgrades include the AEP/SWEPCO Pirkey Unit 1 in Texas,[211] the San Miguel Electric Cooperative Unit 1 in Texas,[212] the Tuscon Electric Power Springerville Units 1 and 2 in Arizona;[213] the Gibbons Creek facility in Texas, the San Juan Generating Station in New Mexico;[214] the Culley Generating Station Units 2 and 3 in Indiana;[215] and the Trimble County Generating Station Unit 1 in Kentucky.[216] These upgrades have increased SO_2 removal to 92% to 99%.[217]

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[210] Staudt, James E., Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants Prepared For: Northeast States for Coordinated Air Use Management 89 South Street, Suite 602, Boston, MA 02111, March 31, 2011, p. 13.

[211] https://www.aeptexas.com/info/news/viewRelease.aspx?releaseID=146: "H. W. Pirkey Plant was equipped with an FGD system when it went into service in 1985. That system consistently removes nearly 80 percent of SO_2. This original equipment will be upgraded to bring its removal rate into the 90-percent range;" Tax Relief For Pollution Control Property Applications Filed for Harrison County 11/1994 & 10/2003. Available at: http://www.tceq.state.tx.us/assets/public/assistance/graphics/Prop2/harrison.pdf

[212] San Miguel Electric Cooperative FGD Upgrade Program Update, URS Corporation, June 30, 2014.

[213] Farber, et al, Results of FGD Upgrade Projects On Low-Rank Coals, Presented at Electric Power 2007 Conference and Exhibition EP-07 Session 12E2007. Covers upgrades to Pirkey Unit 1, San Miguel, and Springerville Units 1 and 2.

[214] Taylor, H., Nischt, W., San Juan Generating Station FGD Retrofit Project Update, Presented to: BR-1667 Power-Gen International '98, December 9-11, 1998, Orlando, Florida.

[215] Quitadamo, M., et al, SO_2 Removal Enhancement to the Vectren Culley Generating Station Units 2&3 Wet Flue Gas Desulfurization System, Babcock Power Technical Publication, Presented at the ICAC Forum 05', March 7-10, 2005, Baltimore, Maryland.

[216] Erickson, Clayton, et al, Wet Flue Gas Desulfurization (WFGD) Upgrade at the Trimble County Generating Station Unit 1, Presented at MEGA Symposium, August 28-31, 2006, Baltimore, Maryland.

[217] URS, 4/5/11, pp. A-5 to A-7; Babcock Power Environmental, Wet Flue Gas Desulfurization Scrubber Upgrades, 2009; Erickson, C., et al, Wet Flue Gas Desulfurization (WFGD) Upgrade at the Trimble County Generating Station Unit 1, Mega Sumposium 2006; Quitadamo, M. et al, SO_2 Removal Enhancement to the Vectren Culley Generating Station Units 2 & 3 Wet Flue Gas Desulfurization System, ICAC Forum 2005; Silva A., and Williams, P., WFGD Case Study – Maximizing SO_2 Removal by Retrofit with Dual Tray Technology, Mega Symposium, 2006; Henry S. Taylor and Walter Nischt, San Juan Generating Station FGD Retrofit Project Update, PowerGen; Maller G., et al, Improving the Performance of Older FGD Systems; B&W, Wet Flue Gas Desulfurization (FGD) Systems Advanced

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As we discussed in Section 5 in our wet scrubber retrofit cost calculations, a typical retrofitted scrubber is capable of 98% removal, down to an effective lower limit of 0.04 lbs/MMBtu. However, we recognize that scrubber upgrades are highly individualistic, depending on the particular equipment in use at the facility. Furthermore, we recognize that a number of the facilities we analyze for scrubber upgrades burn either PRB coals or blends of coals containing a large percentage of PRB coals. Consequently, in our analyses, we assign a presumptive scrubber upgrade target of 95% SO_2 removal, with the understanding that the ultimate individual efficiency will vary depending these factors.

6.1 Calculation of Existing Scrubber Efficiencies

In a typical situation in which we would propose that a pollution control device such as an SO_2 scrubber be installed, we would have historical emissions data to use as a baseline. In such an instance, we would apply the control efficiency of the scrubber to the uncontrolled historical SO_2 emissions, and be able to easily propose a controlled SO_2 emission rate that would be appropriate following the installation of the scrubber. However, we face a more difficult task in analyzing the efficiency of existing SO_2 scrubbers.

As we discussed above, we are confident that any of these existing scrubbers can be upgraded to perform similarly to newly retrofitted scrubbers. If we are to approach the task of calculating the cost of upgrading these scrubbers in a way similar to that of proposing a new scrubber, we must first be able to specify an SO_2 emission rate that would be appropriate following the installation of these scrubber upgrades. Because to our knowledge, none of these units monitors (via CEMS) their emissions before the exhaust gas traverses their existing scrubbers, we do not have CEMS baseline SO_2 emissions. However, we do have coal quality data, which can be used to establish uncontrolled SO_2 emissions.

We calculated the scrubber removal efficiency by utilizing the reported sulfur content and tonnages of the fuels burned and reported to EIA,[218] and the monitored SO_2 scrubber outlet emissions reported to us.[219] We did this by constructing a spreadsheet[220], which among other things, divides the annual SO_2 emissions by the theoretical uncontrolled SO_2 emissions based on coal sulfur content to estimate the percentage of SO_2 in the coal that is emitted by each of the scrubbed facilities in Table 1. We calculated the theoretical uncontrolled SO_2 emissions from EIA reported coal sulfur data. This calculation is summarized below for a typical unit that burns both lignite and subbituminous coals:

(1)

Technology for Maximum SO_2 Removal, 2007 (8,000 MW of non-B&W wet FGD system upgrades by replacing the original absorber internals with tray technology and forced-oxidation conversions).

[218] EIA Form 923. Available at http://www.eia.gov/electricity/data/eia923/

[219] EPA Air Markets and Programs Data. Available at http://ampd.epa.gov/ampd/

[220] See "Coal vs CEM data 2009-2013.xlsx," tab "charts," cell H12.

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or, alternatively expressed in tons:

(2)

and the scrubber efficiency is then:

(3)

In equations (1) and (2), the percentage and tonnage values are those reported by the facility to the EIA for each fuel type. In equation (3), the annual EPA reported tons of SO_2 are those reported to us.[221]

In the following table, we summarize our calculation of the SO_2 removal efficiency for the existing scrubber systems:

[221] EPA Air Markets and Programs Data. Available at http://ampd.epa.gov/ampd/

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Table 14. Efficiency of Units with existing SO_2 scrubbers

Facility	Unit	Scrubbed?	Bypass?	2009-2013 Average SO_2 Removal Efficiency (%)
Sandow 4	1	Y	Y	75.7
Monticello	3	Y	Y	60.0
Martin Lake	1	Y	Y	69.2
Martin Lake	2	Y	Y	71.9
Martin Lake	3	Y	Y	69.8
Limestone	1	Y	Y	78.1
Limestone	2	Y	Y	77.0
San Miguel	1	Y	N	94.0
W. A. Parish	8	Y	Y	84.0

We were interested in gauging the accuracy and precision of our calculations of the theoretical uncontrolled SO_2 emissions, so we compared it to the EPA reported SO_2 emissions for units that do not have scrubbers. The following table presents that information:

Table 15. Comparison of theoretical to monitored SO_2 emissions for unscrubbed units

Unit	2009-2013 average monitored SO_2 emissions (tons)	2009-2013 average theoretical SO_2 emissions (tons)	Percentage theoretical to monitored SO_2 emissions (%)
Big Brown Unit 1	30,606.1	32,489.3	6.2
Big Brown Unit 2	30,638.8	32,048.5	4.6
Coleto Creek	16,665.1	18,771.5	12.6
Monticello Unit 1	16,434.9	18,288.8	11.3
Monticello Unit 2	15,458.0	17,805.3	15.2
Tolk Unit 171B	10,223.9	11,582.1	13.3
Tolk Unit 172B	10,889.4	11,395.4	4.6
W. A. Parish Unit 5	14,295.6	17,480.7	22.3
W. A. Parish Unit 6	15,376.5	17,404.9	13.2
W. A. Parish Unit 7	12,119.3	14,604.6	20.5
Welsh Unit 1	7,956.4	9,618.3	20.9
Welsh Unit 2	8,075.8	9,483.2	17.4
Welsh Unit 3	8,490.6	9,794.1	15.4
Average			13.6

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This table shows that the actual SO_2 emissions as measured by CEMS are about 13.6% lower than the SO_2 estimated from coal quality data. The difference between these two numbers 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. We expect these errors to be compounded for units that blend coals.
- 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.[222]
- Potential effects of NOx and PM pollution control devices. SCRs, which are operating at the Parish units, convert a small amount of SO_2 to SO_3 as a consequence of the catalysts. Low SO_3 conversion SCR catalysts are available, but we do not know if the Parish units employ them. ESPs and baghouses reduce sulfur by removing particulate matter with absorbed SO3. Further, the filter cake in a baghouse absorbs SO_3.[223]
- Losses of sulfur, such as pyrite, when the coal is pulverized or in bottom ash.
- 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.

Therefore, we acknowledge that both our calculations of current SO_2 scrubber efficiency, and our calculations of tons of SO_2 removed once a scrubber upgrade is performed (and hence our cost effectiveness calculations) will have some error. We discuss how we propose to treat this in our Federal Register Notice for our proposed action.

6.2 Historical Scrubber Designs and Upgrades

The scrubber systems we are evaluating were all installed in the late 1970s to mid-1980s as part of the initial design of the facilities. All employ wet limestone, and with one exception – San Miguel – have scrubber bypasses. Scrubbers of this vintage were typically designed to meet the 1971 New Source Performance Standards (NSPS) for EGUs, which required new coal-fired boiler to meet a SO_2 limit of 1.2lb/MMBtu; or the 1979 NSPS, which additionally required 70% control, not to exceed 0.6 lbs/MMBtu unless 90% control was achieved. [224] Compliance usually involved using multiple absorbers with spares.[225]

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[222] Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, Technical Update, EPRI, March 2012.

[223] 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.

[224] Flue Gas Desulfurization Inspection and Performance Evaluation Manual, EPA/625/ 1-85/019, October 1985, Sections 2.1.1.1 and 2.1.1; Farber, et al, p. 18.

[225] Spare scrubber modules allow FGD systems to maintain full or partial operating capability when a primary module fails or is down for service. Early scrubber design commonly included spares due to poor operating experience and the NSPS "emergency condition" provision. See, e.g., William DePriest and Rajendra P. Gaikwad, Economics of Lime and Limestone for Control of Sulfur Dioxide, 2003.

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As Weilert notes,[226] "This is likely due to the requirement of the EPA's new source performance standard (NSPS) for continuous compliance with a 30-day rolling average SO_2 removal, and the provision that stipulates a spare absorber module as a prerequisite to operation during emergency conditions with a malfunctioning FGD system." However, industry gradually recognized that module spares were not required due to advances in scrubber technology, and the proven reliability of single-module FGD systems.[227] Thus, utilization of an existing spare FGD module at one of the facilities we are analyzing (Limestone) potentially represents a cost effective opportunity to increase scrubbing capacity. The following tables summarize the FGD information we have available as a result of mandatory reporting to the EIA via Forms 860 and 923, and from Weilert:[228]

[226] Carl Weilert, FGD Systems Utilizing Single Absorber Modules: The Wave of the Future for New Utility Boilers, Burns & McDonnell Technical Paper.

[227] Bailly Generating Station Advanced Flue Gas Desulfurization System, Final Environmental Information Volume, April 1989; Carl Weilert, Ibid., p. 12: "The available data indicates that single-module FGD systems can be extremely reliable."; Frazer, C., et al, Fayette Power Project Unit 3 FGD Upgrade: Design and Performance for More Cost-Effective SO_2 Reduction, Babcox and Wilcox Technical Paper presented at the EPRI Mega Symposium 2010, p. 3: "Ultimately, the options selected, and discussed above, offer the station the flexibility to permanently remove one of the absorbers from regular service." Taylor et al, Control of SO_2 emissions from power plants: A case of induced technological innovation in the U. S., Technological Forecasting & Social Change 72 (2005) 697 718. …." Page 715: " … according to a study of 111 FGD installations in 1986-1988 that declared that reliability was no longer an issue with FGD. With increased reliability, costly design options such as spare absorber modules were dropped in the 1990s."; Schuettenhelm, W et al, FGD Technology Developments In Europe And North America, Babcock Technical Paper, Presented at the EPA-DOE-EPRI Mega Symposium Arlington Heights, Illinois, August 20-24, 2001, p. 3: "The F. B. Culley FGD (Vectren) system located near Evansville, Indiana … was designed to remove 95% of the SO_2 based on a 10 lb/MMBtu fuel. A unique feature of the project is that it uses one absorber to serve two generating units with no bypasses."

[228] Weilert, C., and Meyer, E., Utility Design Trends, Power Engineering, 8-1-2010; personal communication.

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Table 16. Summary of FGD information[229]

Facility	Units	2011 EIA 860								2012 EIA 923		
		In-service year	Sorbent Type 1	Sorbent Type 2	Bypass?	FGD Trains	FGD Trains at 100% Load	Design Removal Efficiency (%)	Flue Gas Entering FGD (%)	Efficiency at Annual Operating Factor	Tested Efficiency at 100% Load	Date Latest Efficiency Test
Sandow 4	1	1981	LS	DB	Y	3	3	92	83	74.4	74.4	01/1984
Monticello	3	1978	LS	DB	Y	3	3	95	75	55	55	01/2007
Martin Lake	1	1977	LS	DB	Y	4	4	95	95	64.7	64.7	02/1991
Martin Lake	2	1978	LS	DB	Y	4	4	95	95	64.9	64.9	02/1991
Martin Lake	3	1979	LS	DB	Y	4	4	95	95	67.8	67.8	02/1991
Limestone	1	1985	LS	DB	Y	5	4	90	100	77.1	91.5	12/2011
Limestone	2	1986	LS	DB	Y	5	4	90	100	75.8	91.5	12/2011
San Miguel	1	1982	LS		N	4	4	94.2	100	94.1	94.3	05/2010
W. A. Parish	8	1982	LS		Y	3	3	85	82	81.9	73	01/1985

[229] We question the accuracy of some of this information reported to EIA. For instance, the Limestone facility reports that it has a bypass for its scrubbers, yet it reports that 100% of the flue gas enters the scrubber. Also, the Martin Lake facility reports that for Unit 1, 95% of its flue gas enters its FGD and that of that gas, the removal efficiency is 95%. This would result in an overall SO_2 removal efficiency of 90.3% (0.95 X 0.95). However, our own calculations indicate an average removal efficiency of much less. We suspect the EIA scrubber efficiencies are a mixture of supplier guarantees (not counting bypassed flue gas) and actual estimates.

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Table 17. Selected information from Weilert and Meyer

Facility Name[a]	FGD ID[b]	Process Type[a]	Absorber Type I[b]	Sorbent Type[b]	Provision for Bypass[b]	Incorporation of Spare Module[b]	Manufacturer[b]	Material of Construction	Oxidation Mode
Limestone	1	Wet Limestone	SP	LS	Y	Y	AL	NIe	Forced[e]
Limestone	2	Wet Limestone	SP	LS	Y	Y	AL	NIe	Forced[e]
Martin Lake	1	Wet Limestone	TR[m]	LS	Y	N	HRC	FRCS[f]	NR
Martin Lake	2	Wet Limestone	TR[m]	LS	Y	N	HRC	FRCS[f]	NR
Martin Lake	3	Wet Limestone	TR[m]	LS	Y	N	HRC	FRCS[f]	NR
Monticello	3	Wet Limestone	SP	LS	Y	N	MX	FRCS[f]	NR
San Miguel	1	Wet Limestone	TR[m]	LS	N	N	BW	SS[m]	Inhibited[e]
Sandow	4	Wet Limestone	SP	LS	Y	N	AL	SS[e]	NR
W A Parish	8	Wet Limestone[f]	SP	LS	N[230]	N	MX	FRCS[f]	NR

Notation from Weilert and Meyer

a This column is from the 2010 "Emissions" section of EPA's Clean Air Markets Division "Data and Maps" website
b This column is from 2008 EIA-860 data Schedules 6-G & 6-H
c This column is from 2008 EIA-860 data "Annual Electric Generator Report" Generator (Existing) File
d 2009 "Emissions" section of EPA's Clean Air Markets Division "Data and Maps" website
e Information is from respective vendor either from direct correspondence or from their website/publications
f DOE "Utility FGD Survey January - December 1989" Publication Number ORNL/M-2347
g 2008 "Emissions" section of EPA's Clean Air Markets Division "Data and Maps" website
h 2007 "Emissions" section of EPA's Clean Air Markets Division "Data and Maps" website
I 2008 EIA 860 data "Annual Electric Generator Report" Generator (Proposed) File
j Material information from Stebbins Manufacturing Installation List
k Upgrade by BPE according to BPE
l 2005 EIA 767 data Schedule 8 A & 8 B

[230] We note that the Weilert and Meyer data reports that the W A Parish facility does not have a scrubber bypass, yet the EIA data reports that the facility does have a bypass. Examination of aerial photos of Unit 8 seem to confirm the presence of ducting that would serve a bypass.

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m Authors' correction based on personal knowledge
n Facility's Utility's website
o EPA's Steam Electric Power Generating Point Source Category: 2007/2008 Detailed Study Report (Online)
p Multiple FGD units are associated with one generator. The value reported is the nameplate capacity for the generator.

General	Absorber Type	Sorbent Type	Material of Construction	Unit Manufacturers
NA Not Applicable	BR Jet Bubbling Reactor	AF Alkaline fly ash	CO Combination	AD Allied
NR Not Reported	CD Circulating Dry Scrubber	LA Lime and alkaline fly ash	CS Carbon Steel	AL Alstom
	DCFS Double Contact Flow Scrubber	LF Limestone and alkaline fly ash	FRCS Flakeglass Reinforced Resin	AM American Air Filter
	DSI Dry Sorbent Injection	LI Lime	Lined Carbon Steel	AP Airpol
	PA Packed	LS Limestone	FRP Fiberglass Reinforced Plastic	AV Advatech
	SD Spray Dryer	MO Magnesium oxide	NI Nickel Alloy	BPE Babcock Power Environmental
	SP Spray	SA Soda ash	RLCS Rubber Lined Carbon Steel	BW Babcock and Wilcox
	TR Tray	SC Sodium carbonate	SS Stainless Steel	CH Chiyoda
	VE Venturi	SL Soda liquid	TL Tile Lined	FMC FMC
				HI Hitachi
				HRC Hamon Research Cottrell
				KE M W Kellogg
				MHI Mitsubishi Heavy Industries
				MX Marsulex
				SHU Saarberg Holter
				SI Siemens
				OT Other

The Instructions for EIA Form 860 indicate the following regarding the fields of interest to us:

Can flue gas bypass the flue gas desulfurization unit? Indicate whether the flue gas can bypass the FGD unit.

What is the total number of flue gas desulfurization unit scrubber trains or modules? Enter the total number of flue gas desulfurization unit scrubber trains or modules operated.

How many flue gas desulfurization unit scrubber trains or modules are operated at 100 percent load? Enter how many flue gas desulfurization unit scrubber trains or modules are operated at 100 percent load.

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What is this unit's design removal efficiency for sulfur dioxide when operating at 100 percent load? Report the design removal efficiency to nearest 0.1 percent by weight of gases removed from the flue gas when operating at 100 percent generator load.

The instructions for EIA Form 923 indicate the following regarding the fields of interest to us:

FGD or FGP Efficiency Rate at Annual Operation Factor (H, K): Enter removal efficiency, based on the annual operating factor. Annual operating factor, as given by the formula below, is defined as the product of design firing rate and hours of operation per year, divided by annual total fuel consumption, expressed as a percentage. If actual data are unavailable, provide estimates, based on equipment design performance specifications.

Annual Operating Factor (AOF) =
*100 * Design Firing Rate (MMBtu/hr) * Hours of Operation (hr) / Total Fuel Consumption (MMBtu)*
*Removal Efficiency at Annual Operating Factor = FGP Removal Efficiency * Average AOF*

FGD or FGP Tested Efficiency Rate (at 100% Load) (I, L): Enter the tested efficiency of the FGD and/or FGP unit for each controlled pollutant. If not tested at 100% load, provide the load at which the test was conducted in a comment on Schedule 9. If an efficiency test has not been conducted, leave field blank and provide a comment.

Test Date (J, M): Enter the date of the latest efficiency test for the FGD and/or FGP unit for each controlled pollutant. If no test was conducted, leave the test date blank.

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These first generation FGD units were typified by multiple absorber modules, SO_2 removal efficiencies between 75% and 90%, and the use of either natural or inhibited oxidation.[231] However, as Staudt notes,[232] "… limestone-forced oxidation (LSFO) wet scrubber technology is [now] the most widely used form of wet FGD and is more widely used on coal-fired power plants than every other form of FGD combined. State-of-the-art LSFO systems are capable of providing very high levels of SO_2 removal – on the order of 98 percent or more." These early units were often designed to operate with a dry stack, which was most often accomplished by bypassing a portion of the flue gas around the scrubber to maintain gas temperatures high enough to prevent condensation and the formation of H_2SO_4 which would erode an unprotected chimney. These older scrubbers represent a significant investment that can be optimized, improved, and/or upgraded to minimize the cost of reducing SO_2 emissions.

These early scrubbers typically employed two scrubbing zones, a venturi section with spray nozzles to enhance gas-liquid mixing and a second spray zone. The second zone sometimes included a tray or packing to enhance gas-liquid contact.[233] They had many operational problems including poor reagent utilization, tray scale, ducting problems, and plugging of nozzles and demisters.[234] Solids deposited on these devices, plugging them, reducing flow and increasing differential pressure, requiring weekly cleanings and driving up O&M costs. The resulting high O&M costs led to replacement of packings and redesign.[235]

We know from our review of the facility's responses to our information collection requests, described in Section 7.1, that many, if not all of these original scrubbers have been modified since their original installations to cure these and other problems. However, there is very little publicly available documentation. A number of key factors have pushed owners to upgrade their scrubbers, often absent any regulatory drivers including: [236]

- Reduction in operating costs
- Reduction in maintenance costs
- Flexibility to burn higher sulfur coals
- Sale of byproduct (upgrade to forced oxidation allowing the sale of gypsum)
- Opportunity to generate excess emissions credits for sale,
- An increase in the SO_2 emission credits price 20
- Reduction in auxiliary power consumption

[231] Farber, et al.
[232] Staudt, James E., Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants Prepared For: Northeast States for Coordinated Air Use Management 89 South Street, Suite 602, Boston, MA 02111, March 31, 2011. p. 10.
[233] Buecker, B., Important Concepts of Wet-Limestone Flue Gas Desulfurization Energy-Tech Magazine, October 2008, http://www.energy-tech.com/article.cfm?id=21789; PEI Associates, 1985.
[234] See, e.g., NERC, Impact of FGD Systems. Availability Losses Experienced by Flue Gas Desulfurization, July 1991, pp. 10, 27; Farber, et al, Ibid.
[235] Buecher, Brad. Ibid.
[236] Klingspor, J., Brown, G., Techniques for Improving FGD System Performance to Achieve Ultra-High SO_2 Removal Efficiencies, URS Technical Paper; Frazer, C., et al, Ibid., p. 8: "The unit also has the option to burn lower-cost, high-sulfur coal, while still maintaining emissions limits;" NERC, Impact of FGD Systems. Availability Losses Experienced by Flue Gas Desulfurization, July 1991; Maller, G., et al; Taylor, H., Nischt, W., p. 5: "This conversion project was justified on the basis of O&M and power/fuel savings."

- Solving process problems that cause high maintenance, reagent, and disposal costs
- Improving reliability (reducing scrubber-related outages)
- Ability to treat a higher volume of flue gas to improve scrubbing efficiency

Analyses of these upgrades reveals that they typically have performed better than guaranteed. Our examination of the facility's responses to our information collection requests, lead us to conclude that some of these existing scrubbers are able to operate at higher removal efficiencies than they currently achieve due to changes in the factors that led to their upgrades. For example, our regulations have been delayed through litigation, SO_2 allowance markets have not materialized or allowance costs have not risen as expected, changes in natural gas pricing, etc. Consequently, we suspect that absent a specific permit limit, other enforceable requirement, or market driver to operate at these higher scrubber efficiencies, some of these facilities may simply choose not to do so for economic reasons. For example, it has been suggested that some facilities owners turn off their scrubbers at peak demand to maximize profits.[237]

6.3 Options for Upgrading SO_2 Scrubbers

The performance of older FGDs is often limited by poor reliability and poor design, resulting in lower SO_2 removal efficiencies and higher operating and maintenance costs than newer FGD systems. The causes for poor performance include the following:[238]

- Bypassing a portion of the flow around the scrubbers
- Unbalanced flow between absorbers
- Poor gas distribution within the absorber
- Poor spray coverage within the absorber
- No droplet-to-droplet interaction within the absorber
- Sneakage along the sides of the absorber
- Poorly designed mist eliminator wash systems
- Inadequate scrubber chemistry

Existing FGD systems can be upgraded by applying new scrubbing technology[239] and improved upon in many instances so that they can operate at performance and reliability levels similar to new systems for much less than it would cost to replace them with a new scrubber.[240] As noted in the BART Rule, "upgrading an existing scrubber system is typically considered more cost

[237] Wynne, H., et al, U.S. Utilities: Can Texas Comply with the Cross-State Air Pollution Rule? Yes, If Existing Scrubbers Are Turned On, Bernstein Research, July 20, 2011, p. 5: "This pattern suggests that generators have sought to avoid the reduction in net generation that results from operating the scrubbers (reflecting the parasitic load of the emissions control equipment) during hours when power prices are highest. Conversations with the investor relations departments of Energy Future Holdings and NRG Energy confirmed that, as long as continuous operation of SO_2 scrubbers is not required to comply with currently prevailing SO_2 emissions limits, generators will avoid operating the scrubbers so as to maximize net power output and revenues, and minimize variable operation and maintenance expense, including the cost of sorbents and water required for the operation of the SO_2 scrubbers."
[238] Klingspor, J., Experience from 52,280 MWs of Wet Flue Gas Desulphurisation System Upgrades, VGD PowerTech, December 2012.
[239] Schuettenhelm, W et al; Maller, G., et al; Klingspor, J.,et al; Farber, P., et al; Klingspor, J., et al.
[240] Maller, G., et al, p. 13.

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effective than constructing a new scrubber system."[241] Dr. Jonas Klingspor, Vice President at URS, a firm that has conducted more than 52,000 MWs of scrubber upgrades, stated that, "a scrubber upgrade is typically about one-third or less than the cost of a new scrubber." This is because a scrubber system can be upgraded by reusing many existing structural components and existing equipment, such as existing structural steel and absorber shells, ducting, pumps, and compressors. Other components can be modified or replaced with new technology. Also according to Klingspor:[242]

> Most wet FGD systems, regardless of initial physical design or chemistry, can be upgraded to achieve above 99% SO_2 removal efficiency and to operate uninterruptedly between scheduled outage cycles.

As described repeatedly in the scrubber upgrade references we provide, a scrubber system can be upgraded by reusing many existing structural components and existing equipment, such as existing structural steel and absorber shells, ducting, pumps, and compressors. There are many viable, cost-effective options to improve SO_2 removal efficiency. These include:[243]

- Removing any existing scrubber bypass;
- Eliminating sneakage of gases down the sides of the absorber bypassing the spray headers, by installing wall baffles or rings within the absorber;
- Improving liquid distribution by installing new spray headers, additional spray levels and/or more efficient nozzles to improve spray coverage in the absorber;
- Improving gas-liquid contact by adding trays within the absorber;
- Increasing the gas-to-liquid ratio by increasing recycle slurry pump flow by, for example, using all available scrubber modules, adding recirculation pump suction line screens or changing pump gear reducers to allow higher impeller speeds, thus producing greater slurry flow on pumps;
- Improving scrubber chemistry by reducing limestone grind size, eliminating limestone blinding, converting to inhibited or forced oxidation, optimizing pH, and using performance additives such as dibasic acid (DBA);
- Redesigning mist eliminators and mist eliminator wash system to handle higher velocities through the absorber;
- Repairing any damaged or worn parts, such as recycle pump impellors; and
- Removing any capacity constraints, such as in the dewatering system or induced draft fan.

We discuss these scrubber upgrade options in the sections that follow. These methods have been used on many vintage scrubbers in the last 20 years to enhance performance and/or to lower

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[241] 70 FR 39133.

[242] Klingspor, J., Experience from 52,280 MWs of Wet Flue Gas Desulphurisation System Upgrades, VGD PowerTech, December 2012.

[243] See for example: Klingspor, J., p. 106; Maller, G., et al; Klingspor, J. and Brown, G; Alstom, Wet Scrubber Upgrade Air Quality Control Systems, http://www.alstom.com/Global/Power/Resources/Documents/Brochures/wet-scrubber-upgrade-datasheet.pdf;
Moretti, A., State-of-the-Art Upgrades to Existing Wet FGD Systems to Improve SO_2 Removal, Reduce Operating Costs and Improve Reliability, Power-Gen Europe, June 3-5, 2014.

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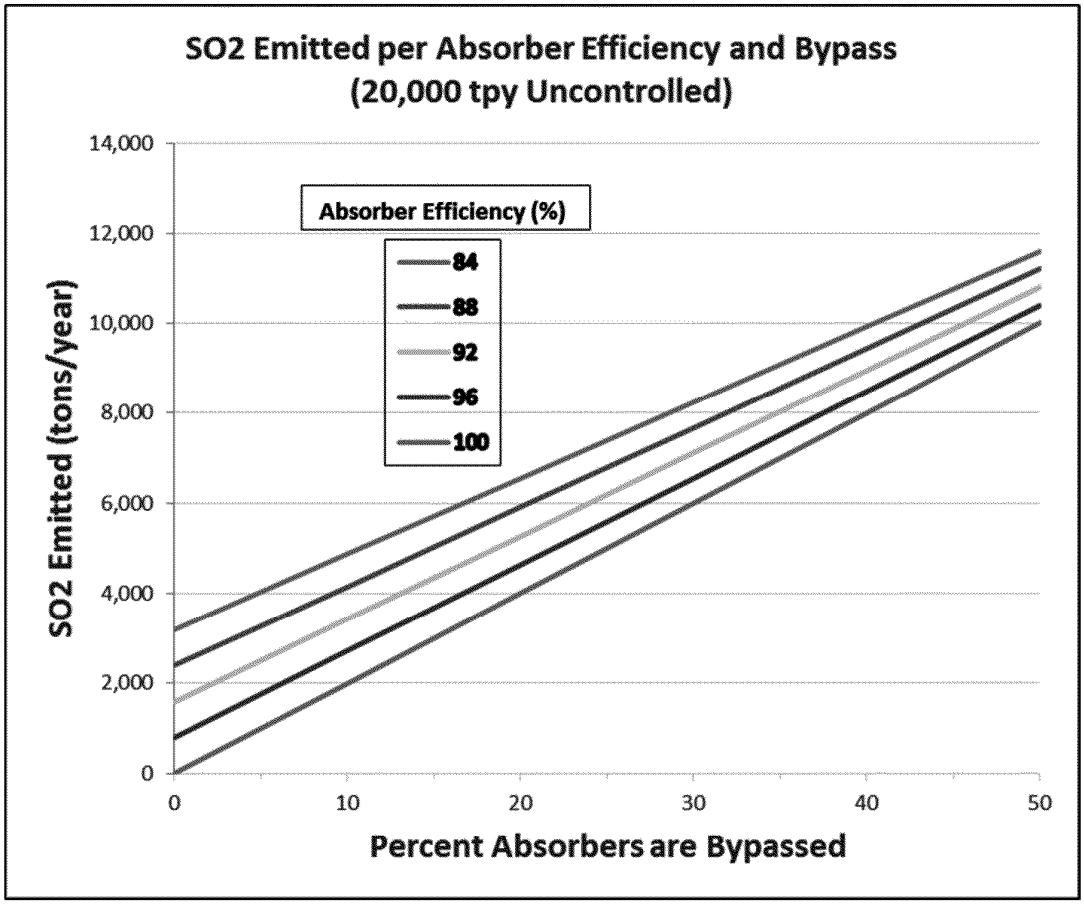
overall operating costs.[244]

6.3.1 Elimination of Scrubber Bypass

As we note above, a flue gas bypass is used on all of the scrubber systems we are investigating for upgrades, except for the San Miguel unit. A bypass allows the facility to route all or a portion of the flue gas around the FGD system for flue gas reheat and/or to improve operating flexibility. Some utilities originally designed the FGD system to scrub only a percentage of the flue gas while others installed bypass capability as a means of providing continuous operating capability, using alternate method for flue gas reheat. Because a bypass can route a large volume of flue gas around the scrubber system, it can have a significant impact on the overall SO_2 removal efficiency of the unit. Below is an example of this:

- Figure 2. Effect of Bypass and Absorber Efficiency on SO_2 Emitted



In the above example for a coal fired power plant that would emit 20,000 tons per year (tpy) if uncontrolled, the difference between no bypass and 20% bypass is significant. For example, if

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the absorbers are 96% efficient, a 20% bypass would mean that 3,840 tpy more is emitted over no bypass.

A wet FGD sprays a limestone-based slurry into the gas stream to remove SO_2. This produces a gas stream that is saturated with water vapor at a temperature of 136-145 F for lignite and sub-bituminous coal. A wet scrubber cools the stack gas and adds moisture to it. The gases are saturated and contain water droplets containing corrosive compounds such as sulfuric acid. If the temperature of the flue gas is blow the dew point, the moisture condenses in the exit ducts, stack walls, etc., corroding downstream equipment. Gasses emitted to the atmosphere can result in liquid fallout, visible steam plumes and plume touchdown, causing high ground-level SO_2 concentrations.[245] Thus, unless corrosive resistant materials are utilized, the temperature of the flue gases exiting the FGD system must be above the dew point to avoid condensation of flue gas and to maintain flue gas velocities in the exit ducts and stack.

At the time the subject scrubbers were installed, this was accomplished by heating the flue gas exiting the FGD system by about 25 to 50°F[246], so it was slightly above the saturation point. This increased the buoyancy of the plume, which reduced ground-level pollutant concentrations; reduced plume visibility by eliminating entrained moisture; and evaporated entrained water droplets, decreasing the potential for corrosion. Four methods were historically used to address this problem:[247]

- In-line reheat, in which the gas is passed through a heat exchanger located in the duct work (20%)
- Indirect hot air injection reheat (15%), in which air is heated in an external heat exchanger and then mixed with the exit flue gas
- Direct combustion reheat (14%), in which hot combustion gases are generated using fuel oil or natural gas and then mixed with the exit flue gas
- Bypassing a portion of the untreated flue gas around the scrubber and then mixing that hotter gas with the scrubbed flue gas (25%)

Bypassing flue gas was the lowest cost approach, followed by in-line reheat system.[248] This is the option used by all of the scrubber systems we are analyzing, with the exception of San Miguel, which does not employ a bypass. This was most commonly accomplished by routing 5%-20% of the flue gas around the scrubbers.[249] A bypass allows the facility to route all or a portion of the flue gas around the FGD system for flue gas reheat and/or to improve operating flexibility. Some utilities originally designed the FGD system to scrub only a percentage of the flue gas while others installed bypass capability as a means of providing continuous operating capability, using alternate methods for flue gas reheat.

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[245] Henzel, D., et al, Limestone FGD Scrubbers: Users Handbook, EPA-600/8-81-017, August 1981, p. 2-27.
[246] Froelich, D., Graves, G., Eliminating Reheat from Existing FGD Systems, A Design and Economic Evaluation, Journal of the Air Pollution Control Association, v. 3 7, no. 3, March 1987, pp. 314 - 321, p. 314
[247] Froelich, D., Graves, G, p. 315. Note percentages refer to FGD systems that used any type of stack gas reheat. Some FGD systems did not employ any stack gas reheat.
[248] Henzel, D., et al, p. 2-28.
[249] Klingspor, J., Brown, G., p. 8; Maller, G, p. 4.

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Many of these early scrubber systems had/have variable bypass capability, including Monticello Unit 3; Martin Lakes 1, 2, and 3; and Sandow 4.[250] Variable bypass is used to adjust for different operating conditions, such as to maintain minimum stack temperature, adjust for variations in coal sulfur levels, and/or to maintain compliance with permits. Variable bypass was accomplished by adjusting the position of louver-type dampers on each scrubber tower, based on measurements of stack temperature, bypass fan parameters, and bypass damper position indicators.

Partially bypassing the scrubber reduces the overall scrubbing efficiency, as not all of the flue gases are treated. Consequently, one way to improve SO_2 removal efficiency is to eliminate the bypass and route 100% of the gases through the scrubber. When the bypass/reheat is eliminated, the amount of gas to be treated increases, the gas velocity decreases, and the gas density increases, resulting in system pressure losses of 5% to 10%, compared to dry operation.[251] This requires that two technical issues be addressed.[252]

First, the scrubber must have adequate capacity to handle the increased gas volume and be able to operate at higher flue gas velocities, which can cause problems with existing equipment such as the mist eliminators and stack. Scrubber capacity is generally not an issue if a scrubber system was designed with a spare absorber or spray level, which was common with many early scrubbers due to uncertainty about performance. This is probably not an issue for one of the subject Texas facilities (Limestone) as it was designed with multiple units plus a spare, which likely provides adequate capacity to handle bypassed gases. Absent a suitable spare, the existing scrubber may have to be modified to accommodate the higher flow, including replacement of the mist eliminators.

Second, existing stacks on currently scrubbed units are designed for hot dry flue gases with a higher gas velocity (~100 ft/sec) in the liner than new wet stacks. The stack downstream of a wet scrubber without bypass or reheat is a "wet stack", which exhausts saturated, scrubbed flue gas that contains droplets from mist-eliminator carryover. Thus, a new or modified mist eliminator and stack are usually required to accommodate the highly corrosive, saturated flue gas. The wet stacks must be designed using corrosion-resistant material and a gas velocity of 55 to 75 ft/sec to prevent condensed moisture from being carried out the top of the stack.[253] As mentioned above, when the bypass is eliminated, corrosive moisture condenses on downstream equipment that was not originally designed for these conditions, including scrubber outlet, ducts, bypass dampers, expansion joints, and the stack.

The cost of converting from dry to wet stack operation depends upon the existing materials used in these components. Moisture condensation within a stack designed for dry use can cause

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[250] Supplied June 17, 2014 by Luminant, in response to request for information under Section 114(a) of the CAA, dated May 20, 2014.6/17/14.
[251] Revised Wet Stack Design Guide, Electric Power Research Institute (EPRI), 2012 Technical Report, Final Report, December 2012, p. 3-2.
[252] Maller, G., et al, p. 4.
[253] DePriest, W., Gaikwad, R., Economics of Lime and Limestone for Control of Sulfur Dioxide, p. 9; Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent and Lundy, p. 25; EPRI 2012, Table 2-1. Froelich, D., Graves. G., p. 317.

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severe damage, as these stacks are typically lined with carbon steel or grouted brick. Considering the latter, moisture migration through the grout would corrode metal liner bands, weakening the stack and eventually resulting in stack failure. An acid-resistant brick liner may require no changes at all, while a carbon steel liner would require an alloy lining or other protection. Only the stack drainage system would likely have to be improved for acid brick lined stacks.[254]

The conversion of a dry stack to wet operation must address several issues that were not present when a bypass or reheat was used. Some of these issues include:[255]

- Stack liquid discharge;
- Plume downwash and icing;
- Corrosion/chemical attack;
- Stack height;
- Stack-liner geometry and material of construction;
- Liner-breach geometry;
- Stack liner geometry and material of construction;
- Gas velocity in the liner; and
- Liquid-collection devices and drainage.

A critical design consideration in converting a dry stack to wet operation is whether the existing liner and ductwork material can withstand the reduced temperatures and wet conditions of wet operation and whether the liner-gas velocity will result in droplet re-entrainment from the stack wall.[256] These issues may be addressed by modifying the existing stack or replacing it with a new "wet" stack. Mist eliminators, designed to reduce liquid carryover and slurry to downstream ductwork and the stack, must often be modified when the bypass is eliminated to facilitate wet stack operation.[257] These issues are further discussed in Section 7 concerning the costs of scrubber upgrades.

Relining a stack has become a common upgrade to power plants. As a general indicator of the scale of stack lining projects, Johnson[258] reports that 126 stack liner projects using Fiberglass Reinforced Plastic (FRP) kicked off in the 2004-2008, inclusive timeframe. This includes a number of facilities in Texas: Fayette Units 1 and 2, J.K. Spruce Unit 2, Sandow Unit 5, and Oak Grove Units 1 and 2. FRP competes with various steel alloys as a stack lining material and thus represents only a portion of the total stack lining projects.

As an alternative to relining an existing dry stack for conversion to wet operation, operators can choose to build a new stack. However, this the most costly of these options.

6.3.2 Optimization of Liquid/Gas Ratio

[254] Maller, G., p. 4; See for example, http://www.hadek.com/project-reports/san-juan-power-station
[255] EPRI, 2012. Ibid., p. 1-2.
[256] EPRI 2012, p.. 1-3.
[257] EPRI, Sec. 2.3.1.
[258] Johnson, T., et al, The Rapid Growth of Fiberglass Reinforced Plastic (FRP) in FGD Systems, 2011, Table 3.

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The liquid-to-gas ratio (L/G ratio) is a sizing criterion for absorbers that compares the slurry recirculation rate to the flue gas flow rate. It is the ratio of the amount of limestone slurry expressed in gallons per minute to the amount of untreated flue gas in thousands (1000s) of actual standard cubic feet per minute (gpm/1000 acfm).[259] Increasing the L/G increases the alkalinity available per pass, which increases the SO_2 removal efficiency. The amount of flue gas is fixed by the boiler, so the L/G ratio is increased by increasing the amount of limestone slurry. This is typically varied by changing the number of operating recycle pumps.

In a conventional scrubber, the amount of slurry is increased by replacing an existing pump with a larger model, increasing the number of slurry recycle pumps and spray headers, upgrading the motors in existing recycle pumps, installing new gear reducers to allow the pumps to operate at higher impeller speed, or reducing the pump head by, for example, replacing high-pressure nozzles with low pressure nozzles.[260]

Sargent & Lundy notes[261] in a wet FGD evaluation that included 2.0 and 4.72 lb/MMBtu SO_2 coals, that most of the scrubbers installed in Phase 1 of the CAA title IV program (1995) were designed for and achieved 95% efficiency with L/Gs of 90-130 and inlet sulfur dioxide up to 8 lb/MMBtu. Demonstrations and testing by the major FGD process developers, including Alstom, Mitsubishi, Babcock & Wilcox, and Wheelabrator, have shown that a 130 L/G is adequate to achieve 98% efficiency in a typical open-spray tower design on the 4.72 lb/MMBtu inlet SO_2 basis (high-sulfur coal case) of this work. This is further verified by recent guarantees offered by FGD vendors for new unit applications.

6.3.3 Gas-Liquid Contact Improvements

SO_2 removal in a wet scrubber is controlled by the amount of SO_2 that can be absorbed per unit volume of recirculated slurry. SO_2 absorption is limited by the amount of solid and liquid phase alkalinity provided in each gallon of slurry. The absorption is also a function of the contact time between slurry and SO_2 as well as the absorber design, which determines the gas-slurry contact area. In a spray tower, the most common type of scrubber, flue gas typically enters horizontally and turns 90 degrees into a vertical open cylindrical vessel with multiple levels of spray headers. The flue gas is first cooled and saturated with slurry. The saturated flue gas then flows upward through the absorber spray zone, where slurry is sprayed countercurrent to the flue gas.

The scale models used to design early scrubbers largely ignored the interaction of flue gas and slurry. The impact of spray nozzles on flue gas distribution was poorly understood and often ignored. Thus, the effect of nozzle spray angle; spray coverage as a function of nozzle size, type, density and pressure; and the impact of wall sneakage were typically not modeled.[262]

Thus, maldistribution of flue gas across the cross section of the absorber is a common cause of

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[259] Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent & Lundy.
[260] Klingspor, J., Brown, G.
[261] Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent and Lundy, p. 10.
[262] Klingspor, J., p. 101.

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poor performance in vintage scrubbers. This is caused by high velocity flue gas entering the absorber, which causes it to hug the walls of the absorber, bypassing the spray headers. This effect is commonly known as "gas sneakage" and can be minimized or eliminated through the installation of various mechanical devices.[263] Gas sneakage also occurs around nozzles inside the absorber.

The skewed flow distribution in the absorber inlet often generates flue gas recirculation zones that cause buildup of solids. Similarly, a skewed flue gas distribution at the absorber outlet duct often leads to excess mist eliminator carryover, scaling of the absorber outlet duct, and stack rain issues.[264] These factors place a limitation on the maximum removal efficiency that can be achieved for a given absorber.

Poor recycle spray header design was another common problem in older FGD systems. The early designs used narrow-angle nozzles and a low nozzle density.[265] This resulted in non-uniform and incomplete spray coverage. Spray towers use several levels of spray nozzles that scrub the flue gas as it moves upward through the absorption tray and spray zone. However, these spray levels are usually not sufficient by themselves to adequately distribute flue gas at the base of the spray zone.[266] There are often significant holes in the spray coverage over the cross-sectional area of the absorber due to a tendency in early scrubbers to use a small number of relatively large spray nozzles. This problem is especially significant along the walls of the absorber as gas flows tend to be higher there, or in the vicinity of internal support members. This results in poor gas-liquid contact because the gas tends to flow where the spray density and gas-side pressure drop are the lowest, contributing to gas sneakage.

Incomplete spray coverage and gas sneakage can be eliminated by improving gas/liquid contact and thus the SO_2 removal efficiency with the goal of achieving a uniform distribution of slurry and gases across the scrubber diameter. Thus, upgrades typically must address uneven flow distribution issues, poor gas-liquid contact, and poor mixing in the reaction tank. This can be achieved by improving flow distribution using turning vanes, perforated plates, and wall rings; improving gas liquid contact using devices such as sieve trays, improved spray nozzle layout, and double hollow cone nozzles; and chemistry modification, including performance additives and conversion to forced oxidation. The specific option depends upon a range of factors such as availability of space for a tray or packing and availability of fan power to overcome additional pressure drop.[267]

Wall Baffles

Wall baffles or liquid distribution rings are widely used to prevent gas sneakage down the sides of the absorber vessels. They are sloped downwards to re-inject wall slurry into the interior of

[263] Klingspor, J., Brown, G.; Maller, G., et al.
[264] Klingspor, J., p. 102.
[265] Klingspor, J. 2012, p. 102 and Figures 2 and 3.
[266] See, for example, Wet Flue Gas Desulfurization (FGD) Systems Advanced Technology for Maximum SO_2 Removal, Babcox and Wilcox, 2007, p. 6.
[267] Klingspor, J., 2012; Klingspor, J., Brown, G.; Maller, G., et al; Moretti, A., State-of-the-Art Upgrades to Existing Wet FGD Systems to Improve SO_2 Removal, Reduce Operating Costs and Improve Reliability, Power-Gen Europe, June 3-5, 2014.

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the absorber where there is a greater chance of interaction with recycle spray droplets. They also promote more thorough mixing of flue gas, ensuring no areas of high SO_2 concentration. These baffles are placed between spray levels. Wall baffles have been used in many scrubber upgrades, including both round and rectangular absorber towers as well as large and small towers. [268] These rings result in improved performance with no increase in power consumption or pressure drop.[269]

Trays

Perforated trays or counter flow trays can be used to improve the gas-liquid contact and distribution of flue gas across the tower. The gases rise through the absorber, contacting a froth of slurry on the tray. This provides increased SO_2 removal by creating additional surface area obtained from liquid holdup on the tray. Trays uniformly distribute gas and create a bubbling zone that improves gas-liquid contact, yielding high SO_2 removals at a lower overall L/G. Adequate space and improved structural support are required to add a tray to an existing open spray scrubber or an additional tray to an existing tray scrubber.[270]

A tray is a much more efficient contact device than a slurry spray.[271] This is because the tray creates more surface area between the slurry and the gas. The limestone dissolution on the tray can be as much as 50% of the dissolution in the entire absorber. The improvement in SO_2 removal by adding a tray is very similar to adding liquid distribution rings or an additional spray level. A tray provides about the same removal efficiency as one spray header without requiring any of the cost and complexity of a recycle pump and spray header system.[272] The benefits of the absorber tray compared to an additional spray level include:

- Reduced liquid to gas ratios
- Increased absorption for the same L/G
- More uniform gas distribution due to back-pressure from tray
- Fewer recirculating pumps
- Fewer spray headers
- Reduced pump maintenance
- Increased particulate removal
- Corrects gas distribution problems in the lower part of the absorber spray zone
- Protects the inlet duct from scaling
- Provides the lowest cost approach to a FGD upgrade
    - Provides a maintenance platform that avoids draining the reaction tank to gain access to the spray headers and mist eliminators.[273]

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[268] Maller, G., et al, Table 1 and pp. 4-5.
[269] Klingspor, J., Brown, G.
[270] Wet Flue Gas Desulfurization (FGD) Systems Advanced Technology for Maximum SO_2 Removal, Babcox and Wilcox, 2007.
Silva, A., et al, WFGD Case Study - Maximizing SO_2 Removal by Retrofit with Dual Tray Technology, Presented to: EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollutant Control Mega Symposium, August 28-31, 2006.
[271] Steam Its Generation and Use, The Babcox & Wilcox Company, Edition 41, 2005, p. 35-6.
[272] Klingspor 2012, p. 104.
[273] Klingspor 2012, p. 104.

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A tray will significantly increase the gas-side pressure drop and thus requires adequate fan capacity. The exact amount is a function of design and operating conditions, but is typically on the order of 1.5 to 2.5 in-wc.[274] However, the additional fan power required from the increased gas-side system pressure drop due to the tray is typically offset by a reduction in pumping power from the lower L/G (i.e., less slurry recycled) required to achieve a given SO_2 removal.[275] The savings in recycle pump power will offset the penalty of increased absorber pressure drop (i.e., pump versus fan power).[276] For moderate SO_2 removal improvements, a tray can allow the use of one less spray level and spray pump per absorber, reducing operating and maintenance costs.[277]

Trays are subject to plugging and scaling if scrubber chemistry is not controlled carefully, and trays are less attractive if absorber gas velocity is increased. However, they are desirable if space is limited, when efficient spray header designs are not present, and to correct skewed gas distribution profiles.[278] More than one tray can be employed to optimize the gas-slurry contact. Babcock and Wilcox, for example, report that scrubber efficiency can be improved by adding a second tray.[279] Adding a second tray increases contact time between SO_2 and slurry, which increases SO_2 removal efficiency.[280]

Spray Headers

The recycle spray header design of many older scrubbers results in incomplete spray coverage, especially near the walls where gas flows tend to be higher. These older designs have gaps or openings in the spray pattern that allow flue gas to bypass the spray zone without contacting the slurry. Many of these gaps are on the outside of the absorber, near the absorber walls and provide a direct path for the flue gas to bypass the slurry spray.[281] This results in poor gas-liquid contact which limits maximum removal efficiency.

The spray headers can be replaced with a high-efficiency spray header that uses a high nozzle density and wide-angle nozzles. The older spray header designs also used a support system that was prone to breakage, resulting in header section failing and falling to the bottom of the absorber. Replacing the headers with a modern, self-supporting design reduces maintenance costs and outage time.[282] A high efficiency spray header in combination with double hollow cone nozzles can substantially improve performance, on average proving about a 40% increase in performance.[283]

Many state-of-the-art nozzle designs are available to upgrade scrubber performance. Bi-

[274] Maller, G., et al, Improving the Performance and Reliability of Older FGD Systems, Mega Symposium, August 2010.
[275] Moretti, A., 2014, p. 4.
[276] Staehle, R., Upgrading Your Wet FGD System, Marsulex, October 2008.
[277] Moretti, A., p. 4.
[278] Maller, G., et al, p. 3.
[279] Silva, A., et al.
[280] Moretti, A., p. 5.
[281] Moretti, A., p. 4, Fig. 4.
[282] Moretti, A., p. 5.
[283] Klingspor, J., 2012, p. 103.

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directional nozzles can be installed regardless of the original design, which provide wider-angle spray cones to provide complete coverage of the spray zone and increased gas-liquid contact. Side-by-side double hollow cone spray nozzles can be used to improve droplet interaction (secondary atomization), thus enhancing removal performance.[284]

These types of changes ensure a high degree of gas-liquid contact with reduced chance for gas sneakage and can significantly improve SO_2 removal efficiency and reduce O&M costs. New spray headers and/or new nozzles have been used in many scrubber upgrades,[285] including Fayette Unit 3.

6.3.4 Improving FGD Chemistry

SO_2 removal can be increased by improving slurry reactivity. There are many ways to do this, including reducing limestone grind size, eliminating limestone blinding, converting to forced oxidation, optimizing operating pH and using performance additives, discussed elsewhere. The easiest way to increase SO_2 removal efficiency in any scrubber is to increase the slurry pH. The SO_2 removal typically responds very quickly to an increase in pH. An increase in slurry pH is typically achieved by increasing the reagent feed rate, which causes limestone utilization to deteriorate. This deterioration can be offset by decreasing grind size, which allows operation at a higher pH while maintaining limestone utilization.[286]

Existing units that use natural or inhibited oxidation can be converted to forced oxidation. This process converts calcium sulfite to calcium sulfate and improves scrubber operating while providing a marketable gypsum byproduct.[287]

Limestone reagent fineness has a significant effect on limestone utilization, which in turn has a significant effect on FGD SO_2 removal efficiency. The finer the grind, the higher the removal efficiency as the fineness of the limestone affects the rate at which it dissolves in the reaction tank.[288] The general rule of thumb today is 95% passing a 325-mesh screen.[289] Increasing the percentage that passes a 325-mesh screen increases the rate of limestone dissolution, which increases the removal efficiency. The majority of the subject FGD systems, those built before about 1995, were designed to produce limestone coarser than this optimum.[290]

Limestone reactivity is also important to scrubber operation. The chemical makeup of the limestone exerts a large influence on scrubber efficiency. In general, limestone with 94% or

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[284] URS, Upgrade of Wet FGD Systems, Available at: http://urs-processtechnologies.com/wp-content/uploads/2013/02/FGD-Upgrade-Final-2_2013.pdf.
[285] See for example, Maller, G., et al, p. 3.
[286] Klingspor, J., Brown, G.
[287] Wet Flue Gas Desulfurization (FGD) Systems Advanced Technology for Maximum SO_2 Removal, Babcox and Wilcox, 2007, p. 4.
[288] Maller, G., Wet FGD Chemistry and Performance Factors, Presented at 2008 Power Gen Conference, December 1, 2008, pdf 48.
[289] LG&E Services Company Contract No. 501654, Mill Creek FGD Performance Upgrade Study, Babcock Power Environmental, February 2011, p. 53.
[290] Seward, R., Brame, K., A Review of Methods for Increasing Limestone Reagent Fineness for Flue Gas Desulfurization, Proceedings Tenths Symposium on Flue Gas Desulfurization, Vol. 1, February 1987.

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more calcium carbonate are very reactive, if properly ground. However, limestone with more than about 10% dolomite ($MgCO_3 \cdot CaCO_3$) are not desirable as the dolomite is rather non-reactive and tends to pass through the FGD untouched and thus does not participate in the chemical reactions that remove SO_2.[291]

6.3.5 Use of Organic Acids to Improve Performance

The use of organic acid additives, such as dibasic acid (DBA) and adipic acid, improves SO_2 removal efficiency by reducing the L/G ratio. Additional benefits of organic acids like DBA (beyond enhanced SO_2 removal efficiency) include reduced power consumption, lower spray pump flow, lower pressure drop, reduced limestone consumption, reduced overall operating costs, and reduced capital costs. They are also used as a backup, to allow a scrubber to be designed without a spare spray header and pump, and to allow increases in coal sulfur content.

The least expensive additives are organic acids that buffer the slurry liquor by acting as an acid or base to help dissolve limestone or to directly neutralize the sulfurous acid formed by the absorption of SO2.[292] Dibasic acid (DBA) is the most economical acid. It is a mixture of succinic, glutaric and adipic acids and is a byproduct in the manufacture of nylon. They can be used continuously or to maintain high SO_2 removal efficiencies if a recycle pump is taken out of service. They work by buffering the pH at the gas-liquid interface, thus reducing back pressure of SO_2 and by lowering the liquid-film resistance to mass transfer. DBA and formate are the most commonly used additives due to cost.[293]

The incorporation of organic acids into an upgrade can significantly reduce the capital, operating, and maintenance cost of the scrubber. This occurs because organic acids increase limestone absorption and stabilize the pH, reducing the liquid-to-gas ratio while maintaining the required SO_2 removal efficiency or increasing the removal efficiency for a given liquid-to-gas ratio. DBA has been reported to provide the equivalent of spraying an extra 20 gpm/1000 cfm of limestone slurry. Thus, increasing SO2 removal from 92% to 95% can either add 25% to the pump energy input or buy an organic chemical.[294]

Their benefit over ultra-fine grind limestone is that the effect is immediate. There is no turnover of a slurry tank prior to the organic acid impacting absorber performance. However, their disadvantages include additional operating cost, uncertainty in long-term supply and pricing of DBA byproducts, possible contamination of gypsum by-product, and increased wastewater treatment cost.[295]

The U.S. Department of Energy and the Electric Power Research Institute conducted full-scale testing, process modeling, and economic evaluations of six utility flue gas desulfurization systems to evaluate low capital cost upgrades for achieving up to 98% SO_2 removal efficiency in

[291] Buecker, B., Important Concepts of Wet-Limestone Flue Gas Desulfurization Energy-Tech Magazine, October 2008, http://www.energy-tech.com/article.cfm?id=21789; PEI Associates, 1985.
[292] Moretti, A., p. 5.
[293] Klingspor, J., and Brown, G.
[294] Invista DBA Will be Available to Improve FGD Efficiency, FGD & DeNOx Newsletter, No. 393, January 2011.
[295] Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent and Lundy. p. 5.

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existing FGD systems. These studies mostly involved using performance additives in the FGD systems, but other low cost options were evaluated using an EPRI model. The tested units are: Big Bend,[296] Merom,[297] Pirkey,[298] Gibson,[299] Elrama, and Kintigh.[300] These tests demonstrated the efficacy of organic acid additives. Many facilities add acid injection systems based on these and other test results, including (can we list the Texas units that use them?)

The addition of an organic acid system to an existing scrubber (that was not designed taking it into consideration) would increase the costs by a very small amount compared to the rest of a scrubber system. For instance, Invista reports the following based on modeling a 566 MW boiler using eastern bituminous high-sulfur coal (3% sulfur, 12,720 BTU/lb heating value) and 90% SO_2-removal efficiency:[301]

> Modeling shows that operational and maintenance costs of a wet limestone scrubber can be reduced by about 2% (about $200,000/year) when using DBA, including the cost of the DBA additive. The increased SO_2 scrubbing efficiency using DBA translates into about a 15% reduction in limestone use, a 1% reduction in steam, a 1% reduction in solid waste disposal costs, and a reduction of about 17% in power usage. Payback time, based on SO_2 credit prices of $200/ton, for the capital required to retrofit an existing wet limestone scrubber for DBA addition (storage tank, pump, piping) ranges from 5 months to about two years, depending on operating strategy (i.e. maintain SO_2 efficiency and reduce operating costs vs. improve SO_2 efficiency and profit from emission credits).

Consequently, the wastewater treatment system is the only item that might increase in capital and operating costs because organic acids increase the Basic Oxygen Demand (BOD) and Chemical Oxygen Demand (COD) of the wastewater, requiring biological treatment.[302] Wastewater treatment is typically a small fraction of the total cost of a scrubber.

6.3.6 Related Capital Improvements

The improvements discussed above generally require modifications to other facility components including the following:

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[296] Radian Corp., Results of High Velocity Tests at Tampa Electric Company's Big Bend 4 FGD System, Topical Report, October 15, 1997.
[297] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, Evaluation of High Efficiency Test Results at Hoosier Energy's Merom Station, April 22, 1996.
[298] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, Results of DBA and Sodium Formate Additive Tests at Southwestern Electric Power Company's Pirkey Station, May 30, 1996.
[299] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, PSI Energy' s Gibson Station High SO_2 Removal Efficiency Test Program, May 20, 1996.
[300] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, Results of Sodium Formate Additive Tests at New York State Electric & Gas Corporation's Kintigh Station, February 14, 1997.
[301] The Role of Dibasic Acid (DBA) in Wet Limestone Flue Gas Desulfurization. Accessed from http://intermediates.invista.com/e-trolley/page_1035/, 7/7/2014.
[302] Riffe, M., et al, Wastewater Treatment for FGD Purge Streams, Paper # 33, Presented at the MEGA Symposium 2008 Baltimore, MD, August 25 – 28, 2008; INVISTA DBA Dibasic Acid For Flue Gas Desulfurization November 17, 2010.

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- A new or modified stack
- A new or modified absorber if the original FGD did not include a spare
- A new or modified limestone slurry preparation system
- A new or modified dewatering system
- Upgraded flue gas system

When SO_2 removal is increased, the amount of wet FGD byproducts will increase. If the upgraded FGD system uses natural oxidation, the disposal pond may reach capacity. This usually requires conversion to forced oxidation to eliminate need for disposal ponds

If limestone consumption is increased to improve SO_2 removal, reagent preparation and dewatering systems may be undersized. In most cases, higher SO_2 removal requires finer grind than delivered by older system. Thus, existing milling systems may have to be upgraded to handle the new quantity and grinding requirements.[303]

Older FGD systems used thickeners for primary dewatering and rotary drum filters for secondary dewatering. Thickeners are prone to maintenance problems. These thickeners are difficult to operate when an FGD is converted to forced oxidation due to rapid settling of gypsum, requiring replacement with hydroclones, which are used in modern FGD systems.[304]

Older FGD systems used thickeners for primary dewatering and rotary drum filters for secondary dewatering. Thickeners are prone to maintenance problems. These thickeners are difficult to operate when an FGD is converted to forced oxidation due to rapid settling of gypsum, requiring replacement with hydroclones, which are used in modern FGD systems. The rotary drum filters also may not have adequate capacity to handle increased SO_2 removal. The capacity constraint can be addressed by increasing the amount of time per day that the rotary drum filter operates; replacing the rotary drum filter with new generation rotary drum technology; or replacing them with vacuum belt filters.[305]

7 Scrubber Upgrade Analyses

We have conducted a cost analysis for upgrading the scrubbers for those facilities listed in Table 1 that currently employ a scrubber. As we discussed above in Section 6.1, we have calculated the SO_2 removal efficiency of these scrubbers as follows:

Table 18. Existing Scrubber SO_2 Removal Efficiencies

[303] Harper, G., Hagan, M.A., Dyer, P., and Breuer, W. J., Increasing Capacity of Existing Limestone Grinding Systems While Reducing Grind Size, Burns & McDonnell Technical Paper, 2006.
[304] Moretti, A., p. 8.
[305] Moretti, A., pp. 10-11.

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Facility	Unit	Bypass?	2009-2013 Average SO_2 Removal Efficiency (%)
Sandow 4	1	Y	75.7
Monticello	3	Y	60.0
Martin Lake	1	Y	69.2
Martin Lake	2	Y	71.9
Martin Lake	3	Y	69.8
Limestone	1	Y	78.1
Limestone	2	Y	77.0
San Miguel	1	N	94.0
W. A. Parish	8	Y	84.0

7.1 Section 114(a) Information Requests

In order to assess the potential range of options available to upgrade the scrubbers in the facilities listed above, we must have an understanding of what upgrades may have already been performed. Most of this information is not available publically. Therefore, for each one of these units, except for San Miguel, we have requested information under authority granted to us under Section 114(a) of the Clean Air Act, which included the following:

a. State whether any of the scrubbers have a bypass.

b. If a unit's scrubber has a bypass, describe whether the percentage of flow going to the scrubber is varied in practice by directly adjusting the bypass or if the bypass is fixed. State how and under what circumstances this is accomplished and monitored.

c. For any scrubber with a bypass, provide the percentage flow that has bypassed the scrubber, based on a monthly average, for the years 2008 through 2013, inclusive.

d. State the maximum SO_2 removal efficiency of each EGU's scrubber system, based on full EGU operating capacity, assuming the optimum amount of reagent usage (including dibasic acid or other organic acids), and the type of coal being burned. Either report this value assuming 100% of each coal type burned, or by the sulfur content of the coal being burned. In reporting this value, do not multiply the efficiency of the scrubber by the percentage of flow going to the scrubber – report only the efficiency of the scrubber.

e. State the maximum percentage of flow at maximum EGU operating capacity that can be directed to the scrubber and treated at the scrubber's maximum efficiency. Either report this value assuming 100% of each coal type burned, or by the sulfur content of the coal being burned.

f. Describe what improvements have been made to the efficiency of the scrubber system since its initial installation, including but not limited to reagent handling and milling, addition of dibasic acid or other organic acids, bypass elimination, absorber (e.g., trays,

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liquid distribution rings, sprayers, recycle pumps, etc), stack lining, etc.

i. Provide the capital costs for these projects and the dates when each upgrade was installed and became operational.

ii. Provide the percentage improvement in the scrubber system for each of these upgrades that were separately installed.

Because the San Miguel facility provided similar information in response to emails and telephone requests, we did not send them a request for information under Section 114(a). All of these units complied with our Section 114(a) requests, but most of the information provided was claimed as Confidential Business Information (CBI) under 40 C.F.R. Part 2, Subpart B. We were able to review and analyze that information to assist us in calculating the costs of upgrading the scrubbers for those units. However, because our analyses largely depends on that information and is thus CBI itself, we can only present a summary of it here. Since the San Miguel facility did not assert any CBI information, our assessment of its scrubber is presented here and the information that San Miguel's provided is in our docket in full.

7.2 Approach to Scrubber Upgrade Cost Analyses

Each of the units listed in Table 18 had contracted with engineering firms (sometimes multiple engineering firms) and conducted multiple SO_2 scrubber upgrade cost analyses, which we were able to review as a result of our Section 114(a) requests. Many of these cost analyses were very detailed. Most of these analyses occurred in the 2004 – 2006 timeframe. They were done because the facilities had concluded that considering the price of SO_2 allowances, upgrading their scrubbers would result in an annual cost savings as they could either stop buying SO_2 allowances, or even sell excess SO_2 allowances. In addition, in a number of cases, the companies had concluded that upgrading various pieces of equipment related to their SO_2 absorbers that either required constant maintenance, or due to their poor initial design caused other problems, would additionally result in annual cost savings.

These scrubber upgrades concentrated on optimizing the unit's total SO_2 removal, with the primary goal being the elimination or minimization of the scrubber bypasses. In most cases, these cost analyses included the following:

- Additional induced draft fan capacity and upgrading of the electrical distribution system to handle the additional load.
- Upgrading of the absorber(s) spray header to more efficient designs.
- Using all available slurry recycle pumps.
- Replacement of the mist eliminators with more efficient designs.
- Use of absorber trays or liquid distribution rings.
- Flow studies to identify flow maldistribution across multiple absorbers and the use of turning vanes (flow straightening baffles used in duct work) to correct this situation.
- Conversion to wet stack operation, which in most cases involved the demolition of the existing stack and the construction of a new wet stack.

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In addition, some of the units' cost analyses included either upgrading or the addition of new DBA systems and forced oxidation systems.

Many units completed some of this work, which usually involved the upgrading of absorber internals (e.g., spray headers, recycle pumps, trays, liquid distribution rings, etc.). Many also partially reduced their scrubber bypasses because upgrading their absorbers allowed them to cost effectively treat more flue gas. None, however, with the exception of San Miguel, totally eliminated their scrubber bypasses.

Our approach to analyzing the cost of a unit's scrubber upgrade was the same in all cases except for San Miguel and consisted of the following basic steps:

- Conduct a literature search of published information from all available non-proprietary sources on any work conducted at the subject facility.
- Review the responses to our Section 114(a) request.
- Construct a timeline of all SO_2 pollution control equipment installations or upgrades, noting what work had already been done so it could be eliminated from our cost analysis.
- Determine what additional equipment is necessary in order to eliminate the SO_2 scrubber bypass and ensure that the unit's overall SO_2 removal efficiency is at least 95%.
- Use the company's scrubber upgrade analyses to estimate the capital and operating costs of eliminating the SO_2 scrubber bypass and ensure that the unit's overall SO_2 removal efficiency is at least 95%.
- Escalate the capital and operating costs to 2013 dollars.
- Annualize the capital and operating costs and calculate the cost effectiveness ($/ton) using the same methodology used in our DSI and scrubber retrofits in Sections 3, 4, and 5, above.
- Weigh the cost of the scrubber upgrades against the visibility improvement at the affected Class I areas.

We discuss how we analyzed San Miguel for potential scrubber upgrades section 7.3.1 below.

7.3 Summary of Scrubber Upgrade Cost Results

With the exception of San Miguel, we are limited in what information we can include in this section, because in developing our scrubber cost estimates we used information that was claimed as CBI. This information was submitted in response to our Section 114(a) requests. We can therefore only present the following summary.

With the exception of San Miguel, we propose to find that for all the units we analyzed:

- The absorber system had either already been upgraded to perform at an SO_2 removal efficiency of at least 95%, or it could be upgraded to perform at that level using proven equipment and techniques.
- The SO_2 scrubber bypass could be eliminated, and the additional flue gas could be treated by the absorber system with at least a 95% removal efficiency.

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- Additional modifications necessary to eliminate the bypass, such as adding fan capacity, upgrading the electrical distribution system, and conversion to a wet stack could be performed using proven equipment and techniques.
- The additional SO_2 emission reductions resulting from the scrubber upgrade are substantial and cost effective.

A summary of our analyses is as follows:

Table 19. Summary of Scrubber Upgrade Results

Unit	2009-2013 3-yr Avg. SO_2 Emissions (eliminate max and min) (tons)	SO_2 Emissions at 95% Control (tons)	SO_2 Emissions Reduction Due to Scrubber Upgrade (tons)	SO_2 Emission Rate at 95% Control (lbs/MMBtu)
W. A. Parish WAP8	2,586	836	1,750	0.04
Monticello 3	13,857	1,571	12,286	0.06
Sandow 4	22,289	4,625	17,664	0.20
Martin Lake 1	24,495	3,706	20,789	0.12
Martin Lake 2	21,580	3,664	17,917	0.12
Martin Lake 3	19,940	3,542	16,389	0.11
Limestone 1	10,913	2,466	8,446	0.08
Limestone 2	11,946	2,615	9,331	0.08
Total SO_2 Removed			**104,572**	

We calculated the cost effectiveness for each of these units. Because those calculations depended on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost effectiveness was less than $600/ton. We invite the facilities listed above to make arrangements with us to view our complete cost analysis for their units.

Appendix C: List of Materials from EPA Docket ID: EPA-R06-OAR-2014-0754

As technical background or added technical support for this proposed rulemaking, this rulemaking record incorporates by reference and considers to be part of this rulemaking the following documents, even as they are not necessarily re-uploaded to the BART rulemaking docket at regulations.gov:

Doc. No. EPA-R06-OAR-2014-0754-0001 through Doc. No. EPA-R06-OAR-2014-0754-0036
Doc. No. EPA-R06-OAR-2014-0754-0087.

This incorporation includes all underlying attachments for these documents. Certain materials claimed as confidential business information (CBI) from the prior rulemaking action are also part of the non-public docket for this rulemaking.

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Technical Support Document

for the

Texas Regional Haze BART Federal Implementation Plan
(BART FIP TSD)

Prepared and Reviewed by:

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(Revised December 2016, see Errata- BART Modeling TSD for details)

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Texas Regional Haze BART FIP Technical Support Document

1 Introduction

In our previous action,[1] we determined that due to the CSAPR remand, it was not appropriate to rely on CSAPR as an alternative to SO_2 and NOx BART for Electricity Generating Units (EGUs) in Texas. As a consequence, we took no action on EGU BART.[2] Our proposed FIP would fill that regulatory gap for this requirement by assessing BART for Texas EGUs. This document describes how we propose to accomplish that objective.

2 Our Evaluation of the Texas Infrastructure SIP Submittals for Interstate Visibility Transport

Section 110(a)(2)(D)(i)(II) of the CAA requires that states have a SIP, or submit a SIP revision, containing provisions prohibiting emissions from within a state from interfering with measures required to be included in the implementation plan for any other state under the provisions of Part C of the CAA protecting visibility. To determine whether the CAA Section 110(a)(2)(D)(i) requirement for visibility protection is satisfied, the SIP must address the potential for interference with visibility protection caused by the pollutant (including precursors) to which the new or revised NAAQS applies. Pollutants which could interfere with visibility protection include: (1) SO_2 (which is also a precursor for $PM_{2.5}$), (2) nitrogen oxides (which includes NO_2 and are precursors for ozone and $PM_{2.5}$) and (3) particulate matter.[3] In the infrastructure SIP submittals for the ozone, $PM_{2.5}$, NO_2 and SO_2 NAAQS Texas indicated that the Regional Haze SIP fulfilled its obligation for addressing emissions that would interfere with measures required to be included in the SIP for any other state to protect visibility.

However, we gave limited disapproval to the Texas Regional Haze SIP based on its reliance on CAIR. As explained in our limited disapproval of the Texas regional haze SIP, many states (including Texas) relied on the improvement in visibility expected to result from the implementation of CAIR in developing their long-term strategy.[4] Texas relied on its own CAIR SIP as legal justification for these planned controls and did not include separate enforceable measures in its regional haze SIP to ensure the interstate visibility transport requirements were met. As CAIR has been replaced by CSAPR, we propose to determine that Texas may not rely on its regional haze SIP to ensure that emissions from Texas do not interfere with the measures to protect visibility in nearby states. With respect to interstate transport of air pollution and visibility protection, Texas' SIP submittals for the 1997 $PM_{2.5}$, 2006 $PM_{2.5}$, 1997 ozone, 2008 ozone, 2010 NO_2 and 2010 SO_2 NAAQS are deficient.

We are proposing a FIP to cure the deficiencies in Texas' Regional Haze Program concerning EGU BART. This FIP will replace reliance on CAIR with reliance on CSAPR to meet the requirements for EGU BART for NO_X in Texas. The FIP will address Texas EGU BART for

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[1] See the discussion beginning on 81 FR 296,301 (January 5, 2016).
[2] Id. at 346.
[3] Section II.A.3 of Appendix Y to Part 51 – Guidelines for BART Determinations Under the Regional Haze Rule and 40 CFR 51.166(b)(i)(b).
[4] 77 FR 33643 (June 7, 2012).

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SO_2 and PM on a source-specific basis. With the absence of CSAPR coverage for SO_2, we must reevaluate what is needed in Texas to address interstate visibility transport. Our proposed FIP to address Texas EGU BART achieves significant reductions of SO_2, which exceed the reductions initially assumed under either CAIR or CSAPR. Under CAIR projections developed in 2005, Texas SO_2 emissions for 2015 were projected to be 352,000 tpy with CAIR compared to 418,000 tpy without CAIR.[5] Under CSAPR, the Texas SO_2 emission budget for Phase 2 was set at approximately 294,000 tpy with an assurance level of 347,000 tpy.[6] Our proposed FIP to address Texas EGU BART is estimated to reduce annual emissions of SO2 by approximately 194,000 tpy[7], a larger reduction than projected under CAIR or CSAPR.

In addition, our proposed FIP achieves reductions at large sources of SO_2 emissions (e.g., Monticello, Martin Lake and Big Brown), that have significant impacts on Class I areas in nearby states.[8] The BART FIP requires controls on many but not all of the sources that were controlled in our previous partial FIP for Texas Regional Haze. Our EGU BART FIP also includes proposed control requirements at some additional sources not controlled in our previous action on Texas Regional Haze. These include proposed controls for the J T Deely Units 1 and 2, Parish Units 5 and 6, Welsh Unit 1, and Harrington Units 1 and 2.

We are proposing to find that our proposed EGU BART FIP is adequate to prevent interference with measures required to protect visibility in other states for the first planning period.[9] We, therefore, propose a FIP to fully address Texas' interstate visibility transport obligations for the six NAAQS (1997 8-hour ozone, 1997 $PM_{2.5}$, 2006 $PM_{2.5}$, 2008 8-hour ozone, 2010 1-hour NO_2, and 2010 1-hour SO_2) based on the source-specific requirements that will be established by our proposed FIP to address Texas EGU BART for SO_2 and PM. We also propose that reliance on CSAPR for EGU NO_X BART is appropriate to ensure NO_X emissions from Texas EGUs do not interfere with other states' measures to protect visibility. We are proposing this action based on the reasoning that our BART FIP will achieve more emission reductions than projected under CAIR or CASPR and the reductions are occurring at sources that have particularly large impacts on Class I areas outside of Texas.

3 Our Strategy for Assessing BART-eligibility.

[5] https://archive.epa.gov/airmarkets/programs/cair/web/html/tx.html; Clean Air Interstate Rule Emissions Inventory Technical Support Document, March 2005 available at: https://archive.epa.gov/airmarkets/programs/cair/web/pdf/finaltech01.pdf

[6] https://www.epa.gov/sites/production/files/2016-02/documents/budgets_annualso2.pdf

[7] Sum of estimated reductions due to all proposed controls calculated from a baseline of the 2011 – 2015 five year average of the SO_2 annual emissions, excluding the maximum and minimum values.

[8] For example, CALPUFF modeling and CAMx modeling estimate that emissions from Monticello can significantly impact visibility at Caney Creek in Arkansas, with many modeled days impacted at levels exceeding 1.0 dv. See BART Screening TSD and BART Modeling TSD for summaries of modeled visibility impacts and visibility benefits from controls for each BART source.

[9] This proposed FIP for interstate visibility transport is premised on the interpretation that this requirement can be addressed even when a Regional Haze SIP is not fully approved and the FIP does not purport to correct all Regional Haze SIP deficiencies. *See e.g.* 76 FR 52388 (August 22, 2011); 76 FR 22036 (April 20, 2011); and 78 FR 14681 (March 7, 2013); *see also*, 2013 i-SIP Guidance, at page 34 (stating that EPA may find it appropriate to supplement the i-SIP Guidance regarding the relationship between Regional Haze SIPs and interstate visibility transport for future planning periods).

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Our BART analysis is limited to BART Category 1, fossil-fuel fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input. All other BART categories were covered in the portion of the Texas Regional Haze SIP we have already approved. We followed the BART Guidelines[10] in analyzing BART for the Texas EGUs covered in this proposal. Our analysis started with the list of BART-eligible sources provided by the Texas Commission on Environmental Quality (TCEQ) in its regional haze SIP.[11] Texas describes how it constructed its BART-eligible list in Section 9 of its SIP, and lists the sources it determined as being BART-eligible in Table 9-2. Unfortunately, Texas only listed these sources by facility and not by unit. Further complicating our analysis, Texas identified each source using its own internal account number and regulated entity number, and the source name was often not descriptive. We contacted the TCEQ in an attempt to determine if a unit-specific listing was available, but were informed that due to its records retention policy, the information was too old to have been retained. That list, filtered to include only EGUs and supplemented with more descriptive names, is shown below. We hereafter refer to this list of thirty-seven EGUs as the "Texas BART list."

Table 1. Texas List of BART-Eligible EGUs

Account	Company	Plant
BC0015L	Lower Colorado River Authority	Lower Colorado River Authority (Sim Gideon)
BG0057U	City Public Service	Sommers Deely Spruce (Calaveras)
BG0186I	City Public Service	V.H. Braunig Plant
CD0013K	AEP Texas Central Company	La Palma Power Station
CI0012D	Texas Genco LP	Cedar Bayou Station
DB0251U	TXU Electric Company	North Lake Steam Electric
EE0029T	El Paso Electric Company	Newman Station
FB0025U	TXU Generation Company LP	Valley Steam Electric
FC0018G	Lower Colorado River Authority	Fayette Power Project
FG0020V	Texas Genco LP	W A Parish Station
FI0020W	TXU Big Brown Company LP	Big Brown
GB0037T	Texas Genco LP	P H Robinson Station
GJ0043K	Southwestern Electric Power	Knox Lee Power Plant

[10] See Appendix Y to Part 51, published as the "BART Guidelines" and the associated preamble language beginning in 70 FR 39104 (July 6, 2015).
[11] As we discuss later in our BART FIP TSD, we also performed an independent assessment of Texas' BART-eligibility determination.

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HQ0012T	TXU Generation Company LP	Decordova Steam Electric
JI0030K	AEP Texas North Company	W.T.U.-Ft. Phantom
LN0081B	Xcel Energy	Jones Station
MB0116C	TXU Generation Company LP	Tradinghouse Steam Electric
ME0006A	Southwestern Electric Power Wilkes	Wilkes Power Plant
MM0023J	TXU Generation Company LP	Sandow Steam Electric
MO0014L	TXU Generation Company LP	Morgan Creek Steam
MQ0009F	Entergy Gulf States Inc	Lewis Creek Plant
NE0024E	AEP Texas Central Company	Barney M Davis Power
NE0025C	Lon C Hill Power	Lon C Hill
NE0026A	AEP Texas Central Company	Nueces Bay Power Station
OC0013O	Entergy Gulf States Inc	Sabine Plant
PG0040T	Southwestern Public Service	Nichols Station
PG0041R	Southwestern Public Service	Harrington Station
RL0020K	TXU Generation Company LP	Martin Lake Electric
TA0352I	TXU Generation Company LP	Eagle Mountain Station
TF0012D	Southwestern Electric Power	Welsh Power Plant
TF0013B	TXU Generation Company LP	Monticello Stm Electric
TG0044C	AEP Texas	San Angelo Power
TH0004D	Electric Utility Dept	Decker Creek Power
VC0003D	Victoria Power	Victoria Power
WC0028Q	TXU Generation Company LP	Permian Basin Steam Electric
WE0005G	Laredo Power	Laredo Power
YB0017V	TXU Generation Company LP	Graham Steam Electric

Our overall strategy for assessing BART-eligibility for Texas EGUs was as follows:

- Convert the Texas BART List to a unit-based list, and supplement it with additional information.
- Update the Texas BART List to account for retirements.
- Conduct a preliminary BART-eligibility assessment based on the Texas BART List.

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- Send letters requesting information (hereinafter, "Section 114(a) letters") from all facilities on the Texas BART List that appeared to be BART-eligible.[12]
- Follow-up with additional Section 114(a) letters, as needed, requesting additional information or documentation.

- Conduct a supplemental BART-eligibility Assessment, using U.S. Energy Information Administration (EIA) information and data to determine if any additional EGUs should be examined.
  - Send additional Section 114(a) letters to any additional EGUs that appeared to be potentially BART-eligible.
  - Follow-up with additional Section 114(a) letters, as needed, requesting additional documentation.

Below, we discuss how we performed each of those steps.[13]

3.1 Refinement of the Texas BART List

From an investigation of various information sources,[14] we noted that a number of the EGUs on the Texas BART list have since been retired:

Table 2. Known Texas EGU Retirements

Plant	Comments
La Palma Power Station	Shutdown in 2006
North Lake Steam Electric	Shutdown 2008/2009
Valley Steam Electric	Mothballed, retired in 2015
P H Robinson Station	Shutdown 2009
W.T.U.-Ft. Phantom	Shutdown 2004
Tradinghouse Steam Electric	Dismantled 2014
Lon C Hill	Mothballed 2002, shutdown 2006
Eagle Mountain Station	Shutdown 2006
San Angelo Power	Shutdown 2004
Permian Basin Steam Electric	Unit 5 retired 2010, Unit 6 retired 2015

[12] Clean Air Section 114(a), 42 U.S.C. § 7414, empowers the EPA, *inter alia*, to require an owner or operator of an emission source to provide information that is reasonably required to carry out any provision of the Clean Air Act (except subchapter II with respect to new motor vehicles or their engines).
[13] The information and analysis discussed in these steps is present in the files, "TCEQ BART Analysis.xlsx," and "EIA Suppl BART Analysis.xlsx."
[14] We conducted Internet searches and consulted ERCOT and Texas PUC documents. These sources are contained within our docket for this action.

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Morgan Creek Steam	Units 2, 3, 4 Retired 2004, demolished In 2011. Units 5 And 6 retired in 2009, demolished 2012
Barney M Davis Power	Unit 2 replaced with 2 combined cycle turbines
Decordova Steam Electric	Unit 1 (Not Ct1) retired 2010, demolished in 2013
Laredo Power	Units 1, 2, 3 demolished 2008
Nueces Bay Power Steam	Units 5 And 6 retired 2008

We subtracted the retired units from the Texas BART List.[15] We then converted the Texas BART List to a unit-based list. We did this by gathering basic information concerning the configuration of the units and their in-service dates from the Energy Information Administration (EIA)[16].

3.2 Preliminary BART-Eligibility Assessment and First Round 114 Letters

Our goal in conducting a preliminary BART-eligibility assessment was to identify which facilities on the Texas BART List should be required to conduct a BART-eligibility analysis. We first performed a preliminary BART-eligibility assessment in order to identify the units that should be required to undergo a formal BART-eligibility analysis.

The BART Guidelines define a three step test that must be followed in order to determine BART-eligibility: [17]

Step 1: Identify the emission units in the BART categories,
Step 2: Identify the start-up dates of those emission units, and
Step 3: Compare the potential emissions to the 250 ton/yr cutoff.

BART-Eligibility Step 1

As the BART Guidelines note, Step 1 in the BART-eligibility test involves the identification of emission units in the BART categories. Specifically, a facility passes Step 1 of the BART eligibility test if it has at least one unit in one of the 26 BART categories. We consequently filtered our EIA data for facilities that had at least one unit with a steam component, based on the EIA data. This included units listed as "Conventional Steam Coal" Natural Gas Steam Turbine," and "Natural Gas Combined Cycle."

BART-Eligibility Step 2

[15] The revised Texas BART List appears in Tab "Potential BART-eligible" of the file, "TCEQ BART Analysis.xlsx."
[16] We used 2014 (the latest available as of the time of our assessment) EIA Form 860 data available here: http://www.eia.gov/electricity/data/eia860/index.html.
[17] 70 FR 39103, 39158 (July 6, 2005) [40 CFR Part 51, App. Y].

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Step 2 of the BART-eligibility test involves determining whether any of the units identified in Step 1 fall within the BART timeframe. Specifically, a facility passes Step 2 if any of the units identified in Step 1 were "in existence" on August 7, 1977, and began operation after August 7, 1962. The BART Guidelines define "in existence" as[18]:

> [T]he owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time. 40 CFR 51.301.

In order to conservatively identify any units that might satisfy Step 2 in our potentially BART-eligible test, we filtered the units that passed Step 1 for EIA "in-service" dates after 1962 to and including 1982. We went five years beyond the BART timeframe discussed above, in order to identify any units that could have begun construction within the BART timeframe, but did not become operational until afterwards. In so doing, we concluded that a reasonable construction time for a typical EGU was up to five years.

BART-Eligibility Step 3

Step 3 of the BART-eligibility test checks whether the potential emissions from units that passed Steps 1 and 2 exceed 250 ton/yr of any single visibility impairing pollutant. The remaining portions of Section 3 describe how we completed this task.

A unit's potential emissions are only limited by the unit's state air permit. We attempted to locate each unit's air permit, using the TCEQ's online Air Permits Remote Document Server.[19] However, due to the particular limitations of this service, we were unable to efficiently or reliably confirm that we had in fact found the latest version of each unit's permit. Consequently, we were unable to confidently use Texas permitting information to assess the potential emissions from the units in question, and we abandoned this investigative approach. Alternatively, we compiled annual emissions from 2000 to 2015.[20] All of the units in question passed Step 3 of the BART-eligibility test for either SO_2 or NOx (or both).

For any of the units that satisfied both Steps 1 and 2 of our potentially BART-eligible test, we requested certain information under the authority granted to us under Section 114(a) of the Clean Air Act, to assist us in determining which units were in fact BART-eligible.[21] We refer to these initial letters as "First Round 114 Letters," to distinguish them from subsequent rounds of

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[18] 70 FR 39103, 39159 (July 6, 2005) [40 CFR Part 51, App. Y].
[19] The TCEQ's Air Permits Remote Document Server is available here: http://www.tceq.state.tx.us/permitting/air/air_permits.html.
[20] Downloaded from the EPA Air Markets Program Data, available here: https://ampd.epa.gov/ampd/. See the tab, "Annl Emissions" in the file, "TCEQ BART Analysis.xlsx."
[21] All the Section 114(a) letters and responses are present in our docket. The pertinent responses are summarized in the file, "114 Letter Response Summary.xlsx."

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Section 114 letters that were required. These First Round 114 Letters typically requested the following information:

1. If available, furnish copies of all completed surveys calling for information relevant to BART eligibility of the source (and associated documentation) that were previously submitted to the TCEQ in or around 2005. As discussed in Chapter 9 of the Texas Regional Haze SIP, the information that was provided in response to the survey should includc, at a minimum:

    a. Your identification of equipment built or reconstructed during the applicable time period for BART-eligibility.
    b. Your identification of whether the potential to emit of the site is less than 250 tons per year.
    c. Your detailed survey of all operating and idle equipment at the site.
    d. Your responses to questions on whether each piece of equipment at the site was built or reconstructed during the applicable time period for BART-eligibility
    e. Your response to a question on whether the potential to emit of units from the applicable time period "exceeded the 250 tpy threshold for applicable emissions."

2. State whether past survey responses remain valid for the present equipment and operations of the facility. If any individual responses are no longer accurate, please identify what has changed with a supporting explanation and/or supporting documentation.

3. State the BART-eligibility of any sources under Category 1, Fossil-fuel fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input, for Sulfur Dioxide (SO_2) and Nitrogen Oxides (NOx) with an analysis that applies the steps that are outlined in the BART Guidelines.[22] Specifically address the following steps of the BART Guidelines:

    a. Step 1: Identify Emission Units in the BART Categories.
    b. Step 2: Identify the Start-Up Dates of the Emission Units[23]
    c. Step 3: Compare the Potential Emissions to the 250 Ton/Yr Cutoff.

4. If an EGU has been dismantled, shut down, mothballed, or otherwise is out of service such that it no longer contributes to the source's BART-eligibility under the BART Guidelines, then so state.

5. Provide any information necessary to document all assertions concerning the BART-eligibility of the source under the BART Guidelines.

6. For any EGUs that would be included in any BART-eligible source, please send copies of all of your active and most recently issued (including modifications/alterations) New Source Review (NSR) construction permits. This includes the cover sheet, Special

[22] See the discussion beginning on 70 FR 39103, 39158 (July 6, 2005).
[23] In particular, see the discussion regarding the meaning of the term "in existence," on 70 FR at 39159.

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Conditions, and Maximum Allowable Emission Rate Tables. This request includes but is not limited to:

a. Prevention of Significant Deterioration (PSD) permits.
b. Nonattainment NSR permits.
c. Plant wide Applicability Limit (PAL) permits.
d. Non-SIP and SIP approved flexible permits.
c. Minor individual NSR permit actions.
f. If any permit by rule (PBR) or qualified facility (or any other minor action) that modifies/alters an individual NSR permit emission limit, and that emission change is not reflected in the individual permit that was modified by the action, please send copies of all those applicable minor actions.
g. Site-wide PBR actions that regulate activities such as coal handling, etc.
h. Permit applications if they contain permit representations that are enforceable and were not reflected in the permit document itself.
i. Copies of your active Title V operating permits.

The following facilities received a First Round 114 Letter based on our preliminary BART-eligibility assessment for the units listed below:

Table 3. Facilities Receiving First Round 114 Letters

Facility Name	Unit ID	Facility Potentially BART Eligible? (satisfies both steam component + date test for at least one unit)	Utility Name
Decker Creek	1	Yes	Austin Energy
Decker Creek	2	Yes	
Decker Creek	GT-1A	No	
Decker Creek	GT-1B	No	
Decker Creek	GT-2A	No	
Decker Creek	GT-2B	No	
Decker Creek	GT-3A	No	
Decker Creek	GT-3B	No	
Decker Creek	GT-4A	No	
Decker Creek	GT-4B	No	
J K Spruce	1	No	City of San Antonio
J K Spruce	2	No	
J T Deely	1	Yes	
J T Deely	2	Yes	
V H Braunig	1	Yes	
V H Braunig	2	Yes	

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V H Braunig	3	Yes	
V H Braunig	CGT5	No	
V H Braunig	CGT6	No	
V H Braunig	CGT7	No	
V H Braunig	CGT8	No	
V H Braunig	CT01	No	
V H Braunig	CT02	No	
Newman	1	No	El Paso Electric Co
Newman	2	Yes	
Newman	3	Yes	
Newman	4	Yes	
Newman	5	No	
Newman	GT-6A	No	
Newman	GT-6B	Yes	
Lewis Creek	1	Yes	Entergy Texas Inc.
Lewis Creek	2	Yes	
Sabine	1	Yes	
Sabine	2	Yes	
Sabine	3	Yes	
Sabine	4	Yes	
Sabine	5	Yes	
Sam Seymour (Fayette)	1	Yes	Lower Colorado River Authority
Sam Seymour (Fayette)	2	Yes	
Sam Seymour (Fayette)	3	No	
Sim Gideon	1	Yes	
Sim Gideon	2	Yes	
Sim Gideon	3	Yes	
Big Brown	1	Yes	Luminant Generation Company LLC
Big Brown	2	Yes	
Decordova	CT1	No	
Decordova	CT2	No	
Decordova	CT3	No	
Decordova	CT4	No	
Graham	1	No	
Graham	2	Yes	
Martin Lake	1	Yes	
Martin Lake	2	Yes	
Martin Lake	3	Yes	
Monticello	1	Yes	
Monticello	2	Yes	
Monticello	3	Yes	

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Morgan Creek	CT1	No	
Morgan Creek	CT2	No	
Morgan Creek	CT3	No	
Morgan Creek	CT4	No	
Morgan Creek	CT5	No	
Morgan Creek	CT6	No	
Permian Basin	CT1	No	
Permian Basin	CT2	No	
Permian Basin	CT3	No	
Permian Basin	CT4	No	
Permian Basin	CT5	No	
Sandow	4	Yes	
Cedar Bayou	CBY1	Yes	NRG Texas Power LLC
Cedar Bayou	CBY2	Yes	
W A Parish	CTSC	Yes	
W A Parish	WAP1	No	
W A Parish	WAP2	No	
W A Parish	WAP3	No	
W A Parish	WAP4	Yes	
W A Parish	WAP5	Yes	
W A Parish	WAP6	Yes	
W A Parish	WAP7	Yes	
W A Parish	WAP8	Yes	
Victoria Power Station	9	Yes	ReNu Power Holdings LLC
Knox Lee Power Plant	2	No	Southwestern Electric Power Co
Knox Lee Power Plant	3	No	
Knox Lee Power Plant	4	No	
Knox Lee Power Plant	5	Yes	
Welsh Power Plant	1	Yes	
Welsh Power Plant	2	Yes	
Welsh Power Plant	3	Yes	
Wilkes Power Plant	1	Yes	
Wilkes Power Plant	2	Yes	
Wilkes Power Plant	3	Yes	
Harrington Station	061B	Yes	Southwestern Public Service Co
Harrington Station	062B	Yes	
Harrington Station	063B	Yes	
Jones Station	1	Yes	
Jones Station	2	Yes	
Jones Station	3	No	
Jones Station	4	No	

Nichols Station	141B	No	
Nichols Station	142B	Yes	
Nichols Station	143B	Yes	
Barney M. Davis	1	Yes	Topaz Power Group LLC
Barney M. Davis	3	No	
Barney M. Davis	4	No	
Laredo	4	No	
Laredo	5	No	
Nueces Bay	8	No	
Nueces Bay	9	No	

In performing our preliminary BART-eligibility analysis, we inadvertently made two mistakes that we subsequently rectified. First, we mistakenly included the Jones, Nichols, and Harrington Power Plants, owned by Southwestern Public Service Company, in the First Round Section 114 Letter to the Southwestern Electric Power Company. We subsequently sent a separate Section 114(a) letter to the correct owner or operator, i.e., Southwestern Public Service Company, requesting that it perform a BART analysis on those facilities. Second, we mistakenly left the O. W. Sommers Facility, included in the TCEQ's BART List within the "Sommers Deely Spruce" plant off of our refinement of the Texas BART List. We subsequently discovered this during our supplemental BART-eligibility analysis, discussed below, and sent the City of San Antonio, which owns this facility, a Section 114(a) letter requesting that it perform a BART-eligibility analysis. These Section 114 letters are included in our docket.

3.3 First Round Follow-up 114 Letters

Due to inadequately documented or unsupported assertions made by a number of companies in their response to our First Round 114 letters, we found it necessary to request clarification. These "First Round Follow-up 114 Letters" mainly requested documentation to support the "in existence" determinations made by these facilities. Below is a summary of which facilities received these First Round Follow-up 114 Letters for the units listed below:

Table 4. Facilities Receiving First Round Follow-up Section 114(a) Letters

Facility Name	Unit ID	Utility Name
Nichols Station	142B	Xcel Energy
Sabine	1	Entergy Texas Inc.
Sabine	5	
W A Parish	WAP7	NRG Texas Power LLC
W A Parish	WAP 8	

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Welsh	3	American Electric Power

3.4 Second Round 114 Letters

After performing our preliminary BART-eligibility assessment, we became aware that some facilities that were potentially BART-eligible and were not on the Texas BART List merited additional investigation. In order to ensure we did not overlook any potentially BART-eligible facilities, we conducted a supplemental BART-eligibility assessment. We did this by examining 2014 EIA Form 860 data for Texas EGUs. We then conducted a similar preliminary BART-eligibility analysis as we did in Section 3.2.

We addressed Steps 1 and 2 of the BART-eligibility test by filtering the EIA data in the following order:[24]

a) Only show units in Texas.
b) Only show units with operating years from 1962 to 1982, inclusive.
c) Only show units with a sector names of "electric utility," and "IPP Non-CHP," leaving out "Commercial CHP," and "Industrial CHP."
d) Only show units with prime mover names of "CA," "CT," and "ST," leaving out "GT."

As we did in Section 3.2, in filtering step b), we went five years beyond the BART timeframe in order to identify any units that could have begun construction within the BART timeframe, but did not become operational until afterwards. In filtering step c), we examined which units under EIA's sector categorization are in BART Category 1. We note that Combined Heat and Power (CHP) facilities are potentially BART-eligible under BART Category 1, if they "generate electricity for sale."[25] The following units were identified by the EIA data as being either commercial or industrial CHP units:

[24] These filtered units appear in tab "EIA 860 Filtered" in the file, "EIA Suppl BART Analysis.xlsx."
[25] 70 FR 39103, 39159 (July 6, 2005), [40 CFR Part 51, App. Y.].

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Table 5. Commercial CHP and Industrial CHP Units Not Analyzed under BART Category 1

Utility ID	Utility Name	Plant Code	Plant Name	Technology	Sector Name	Generator ID	Operating Month	Operating Year	Prime Mover
14254	Oxy Vinyls LP	50043	Houston Chemical Complex Battleground	Natural Gas Fired Combined Cycle	Industrial CHP	GT1	5	1982	CT
14254	Oxy Vinyls LP	50043	Houston Chemical Complex Battleground	Natural Gas Fired Combined Cycle	Industrial CHP	GT2	6	1982	CT
14254	Oxy Vinyls LP	50043	Houston Chemical Complex Battleground	Natural Gas Fired Combined Cycle	Industrial CHP	ST	8	1982	CA
19537	University of Texas at Austin	50118	Hal C Weaver Power Plant	Natural Gas Fired Combined Cycle	Commercial CHP	GEN7	1	1979	CA
19450	Union Carbide Corp-Seadrift	50150	Union Carbide Seadrift Cogen	Natural Gas Fired Combined Cycle	Industrial CHP	GE10	1	1964	CA
19450	Union Carbide Corp-Seadrift	50150	Union Carbide Seadrift Cogen	Natural Gas Fired Combined Cycle	Industrial CHP	IGT	1	1969	CT
18760	TPC Group, LLC	50229	Texas Petrochemicals	Natural Gas Steam Turbine	Industrial CHP	TG2	6	1972	ST
6090	ExxonMobil Oil Corp	50625	ExxonMobil Beaumont Refinery	Natural Gas Steam Turbine	Industrial CHP	TG22	2	1978	ST
6090	ExxonMobil Oil Corp	50625	ExxonMobil Beaumont Refinery	Natural Gas Steam Turbine	Industrial CHP	TG32	1	1970	ST
6090	ExxonMobil Oil Corp	50625	ExxonMobil Beaumont Refinery	Natural Gas Steam Turbine	Industrial CHP	TG33	1	1966	ST
6090	ExxonMobil Oil Corp	50625	ExxonMobil Beaumont Refinery	Natural Gas Steam Turbine	Industrial CHP	TG34	1	1967	ST
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Natural Gas Fired Combined Cycle	Industrial CHP	GN31	6	1962	CA
12981	Motiva Enterprises LLC	50973	Motiva Enterprises Port Arthur Refinery	Natural Gas Fired Combined Cycle	Industrial CHP	GN33	6	1978	CA

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22337	Alcoa World Alumina LLC	52069	Point Comfort Operations	Natural Gas Steam Turbine	Industrial CHP	GEN4	1	1970	ST
5338	Dow Chemical Co	52120	Dow Chemical Texas Operation	Natural Gas Fired Combined Cycle	Industrial CHP	G-61	10	1982	CT
5338	Dow Chemical Co	52120	Dow Chemical Texas Operation	Natural Gas Fired Combined Cycle	Industrial CHP	G-63	8	1982	CT
57445	Pasadena Refining System Inc	58069	PRSI FCC Generator	Petroleum Coke	Industrial CHP	55M1	4	1979	ST

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We have no basis of information to believe that any of the above units generate electricity for sale, and thus do not include them in BART Category 1. We invite comment on that conclusion.[26]

In filtering step d), we determined which units under EIA's prime mover categorization are in BART Category 1. EIA uses the following prime mover abbreviations:[27]

Table 6. EIA Prime Mover Abbreviations

BA	Energy Storage, Battery
CE	Energy Storage, Compressed Air
CP	Energy Storage, Concentrated Solar Power
FW	Energy Storage, Flywheel
PS	Energy Storage, Reversible Hydraulic Turbine (Pumped Storage)
ES	Energy Storage, Other (specify in SCHEDULE 7)
ST	**Steam Turbine, including nuclear, geothermal and solar steam (does not include combined cycle)**
GT	**Combustion (Gas) Turbine (does not include the combustion turbine part of a combined cycle; see code CT, below)**
IC	Internal Combustion Engine (diesel, piston, reciprocating)
CA	**Combined Cycle Steam Part**
CT	**Combined Cycle Combustion Turbine Part**
CS	Combined Cycle Single Shaft (combustion turbine and steam turbine share a single generator)
CC	Combined Cycle Total Unit (use only for plants/generators that are in planning stage, for which specific generator details cannot be provided)
HA	Hydrokinetic, Axial Flow Turbine
HB	Hydrokinetic, Wave Buoy
HK	Hydrokinetic, Other (specify in SCHEDULE 7)
HY	Hydroelectric Turbine (includes turbines associated with delivery of water by pipeline)
BT	Turbines Used in a Binary Cycle (including those used for geothermal applications)
PV	Photovoltaic
WT	Wind Turbine, Onshore
WS	Wind Turbine, Offshore
FC	Fuel Cell
OT	Other (specify in SCHEDULE 7)

[26] As explained in the proposal that this TSD accompanies, we welcome comments on any aspects of our proposal, including all applicable technical support. In this TSD we "invite comment" at several points. These invitations are not necessarily repeated in the proposal itself, and they may concern minor or technical issues.
[27] See the "Reference Tables 1-3" tab of the file, "Layout2014.xlsx" in the 2014 EIA Form 860 data.

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After the first three filtering steps, only the CA, CT, ST, and GT prime movers were present for further filtering. We eliminated the GT units, since they were not a part of a combined cycle power block and thus had no steam component and are not included in BART Category 1.

We then eliminated those units already covered in our First Round 114 Letter assessment we conducted in Section 3.2. We were left with the following units that were not included in the Texas BART List:[28]

[28] See tab "Suppl BART" in the file, "EIA Suppl BART Analysis.xlsx."

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Table 7. EIA Supplemental BART-eligible Analysis

Utility Name	Plant Code	Plant Name	Generator ID	Technology	Prime Mover	Sector Name	Operating Month	Operating Year
Luminant Generation Company LLC	3452	Lake Hubbard	1	Natural Gas Steam Turbine	ST	IPP Non-CHP	6	1970
Luminant Generation Company LLC	3452	Lake Hubbard	2	Natural Gas Steam Turbine	ST	IPP Non-CHP	11	1973
Exelon Power	3453	Mountain Creek	8	Natural Gas Steam Turbine	ST	IPP Non-CHP	7	1967
NRG Texas Power LLC	3464	Greens Bayou	5	Natural Gas Steam Turbine	ST	IPP Non-CHP	6	1973
NRG Texas Power LLC	3469	T H Wharton	3	Natural Gas Fired Combined Cycle	CA	IPP Non-CHP	8	1974
NRG Texas Power LLC	3469	T H Wharton	31	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	32	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	33	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	34	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	4	Natural Gas Fired Combined Cycle	CA	IPP Non-CHP	8	1974
NRG Texas Power LLC	3469	T H Wharton	41	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	42	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	7	1972
NRG Texas Power LLC	3469	T H Wharton	43	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	8	1974
NRG Texas Power LLC	3469	T H Wharton	44	Natural Gas Fired Combined Cycle	CT	IPP Non-CHP	8	1974
Southwestern Public Service Co	3485	Plant X	4	Natural Gas Steam Turbine	ST	Electric Utility	1	1964
Exelon Power	3491	Handley	3	Natural Gas Steam Turbine	ST	IPP Non-CHP	7	1963
Exelon Power	3491	Handley	4	Natural Gas Steam Turbine	ST	IPP Non-CHP	10	1976
Exelon Power	3491	Handley	5	Natural Gas Steam Turbine	ST	IPP Non-CHP	10	1977
Luminant Generation Company LLC	3504	Stryker Creek	ST2	Natural Gas Steam Turbine	ST	IPP Non-CHP	12	1965
Luminant Generation Company LLC	3507	Trinidad (TX)	6	Natural Gas Steam Turbine	ST	IPP Non-CHP	5	1965
City of Garland - (TX)	3576	Ray Olinger	1	Natural Gas Steam Turbine	ST	Electric Utility	7	1967
City of Garland - (TX)	3576	Ray Olinger	2	Natural Gas Steam Turbine	ST	Electric Utility	1	1971
City of Garland - (TX)	3576	Ray Olinger	3	Natural Gas Steam Turbine	ST	Electric Utility	6	1976
City of Lubbock - (TX)	3602	Ty Cooke	1	Natural Gas Steam Turbine	ST	Electric Utility	6	1965
City of Lubbock - (TX)	3602	Ty Cooke	2	Natural Gas Steam Turbine	ST	Electric Utility	6	1978
City of San Antonio - (TX)	3611	O W Sommers	1	Natural Gas Steam Turbine	ST	Electric Utility	4	1972
City of San Antonio - (TX)	3611	O W Sommers	2	Natural Gas Steam Turbine	ST	Electric Utility	1	1974

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Brazos Electric Power Coop Inc	3628	R W Miller	1	Natural Gas Steam Turbine	ST	Electric Utility	10	1968
Brazos Electric Power Coop Inc	3628	R W Miller	2	Natural Gas Steam Turbine	ST	Electric Utility	7	1972
City of Greenville - (TX)	4195	Powerlane Plant	ST1	Natural Gas Steam Turbine	ST	Electric Utility	8	1966
City of Greenville - (TX)	4195	Powerlane Plant	ST2	Natural Gas Steam Turbine	ST	Electric Utility	8	1969
City of Greenville - (TX)	4195	Powerlane Plant	ST3	Natural Gas Steam Turbine	ST	Electric Utility	8	1977
City of Garland - (TX)	4266	Spencer	4	Natural Gas Steam Turbine	ST	Electric Utility	6	1966
City of Garland - (TX)	4266	Spencer	5	Natural Gas Steam Turbine	ST	Electric Utility	5	1973
Coleto Creek Power LP	6178	Coleto Creek	1	Conventional Steam Coal	ST	IPP Non-CHP	6	1980
San Miguel Electric Coop, Inc	6183	San Miguel	1	Conventional Steam Coal	ST	Electric Utility	1	1982
Southwestern Public Service Co	6194	Tolk	1	Conventional Steam Coal	ST	Electric Utility	1	1982
City of Bryan - (TX)	6243	Dansby	1	Natural Gas Steam Turbine	ST	Electric Utility	9	1978

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As was the case with the Preliminary BART-eligibility assessment we performed in Section 3.2, we were unable to confidently use Texas permitting information to assess the potential emissions from the units in question. We therefore similarly examined annual emissions from 2005 to 2015,[29] for these units. However, we were left with mixed results: in some cases, the emissions of either SO_2 or NOx for the units that had passed Steps 1 and 2 of the BART-eligibility test were above 250 tpy, and in some case they were below. Thus, we were not able to use actual emissions to resolve whether the potential emissions test was met, and we had to cast a wider net for the information needed to assess BART-eligibility for these units. Consequently, for each owner of the units present in Table 7, we requested certain information under the authority granted to us under Section 114(a) of the Clean Air Act, to assist us in determining which units were in fact BART-eligible. These "Second Round 114 Letters" were typically similar to the First Round 114 Letters discussed in Section 3.2. [30] The following facilities received these Second Round 114 Letters for the units listed below:

Table 8. Facilities Receiving Second Round Section 114(a) Letters

Facility Name	Unit ID	Utility Name
Lake Hubbard	1	Luminant Generation Company LLC
Lake Hubbard	2	
Stryker Creek	ST2	
Trinidad	6	
Mountain Creek	8	Exelon
Handley	3	
Handley	4	
Handley	5	
Greens Bayou	5	NRG Texas Power LLC
Ty Cooke	1	City of Lubbock
Ty Cooke	2	
R W Miller	1	Brazos Electrical Coop
R W Miller	2	
R W Miller	3	
Powerlane	ST1	City of Greenville
Powerlane	ST2	
Powerlane	ST3	
Spencer	4	City of Garland

[29] Downloaded from the EPA Air Markets Program Data, available here: https://ampd.epa.gov/ampd/. See the tab, "Selected Texas Emissions" in the file, "EIA Suppl BART Analysis.xlsx."

[30] All the Section 114(a) letters and responses are present in our docket. The pertinent responses are summarizedin the file, "114 Letter Response Summary.xlsx."

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Spencer	5	
Coleto Creek	1	Engie
San Miguel	1	San Miguel Electrical Coop
Dansby	1	City of Bryan

3.5 Analysis of Section 114(a) Responses.

In a few instances, we exchanged emails with companies in order to clarify the responses we received to our Section 114(a) letters. In most cases, following any follow-up correspondence, we and the companies agreed on the BART-eligibility of the units in question. The following table summarizes: the facilities' determinations of BART-eligibility, whether we agree with that determination, and whether the units in question should be analyzed to determine if they are subject to BART[31]:

Table 9. Summary of BART-Eligibility Analysis

Facility	Unit	Company says BART-eligible?	Does EPA agree with eligibility?	Assess for subject to BART?
Barney M. Davis (Talen/Topaz)	1	Y	Y	Y
Barney M. Davis (Talen/Topaz)	2	N	Y	N
Big Brown (Luminant)	1	Y	Y	Y
Big Brown (Luminant)	2	Y	Y	Y
Cedar Bayou (NRG)	CBY1	Y	Y	Y
Cedar Bayou (NRG)	CBY2	Y	Y	Y
Cedar Bayou (NRG)	CBY3	N	Y	N
Coleto Creek (Engie)	1	N	N	Y
Dansby (City of Bryan)	1	Y	Y	Y
Decker Creek (Austin Energy)	1	Y	Y	Y
Decker Creek (Austin Energy)	2	Y	Y	Y
Decordova (Luminant)	1	N	Y	N
Fayette (LCRA)	1	Y	Y	Y
Fayette (LCRA)	2	Y	Y	Y
Fayette (LCRA)	3	N	Y	N
Graham (Luminant)	1	N	Y	N
Graham (Luminant)	2	Y	Y	Y
Greens Bayou (NRG)	5	Y	Y	Y
Handley (Exelon)	3	Y	Y	Y
Handley (Exelon)	4	Y	Y	Y

[31] We note that the mistaken omission of several EGUs sources from the State's PM BART determinations (and Texas BART list) in its SIP submission would provide another reason why the PM BART component of the SIP, pending action under our proposal, could not be approved.

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Handley (Exelon)	5	Y	Y	Y
Harrington Station (Xcel)	061B	Y	Y	Y
Harrington Station (Xcel)	062B	Y	Y	Y
Harrington Station (Xcel)	063B	N	Y	N
J K Spruce (CPS Energy)	1	N	Y	N
J T Deely (CPS Energy)	1	Y	Y	Y
J T Deely (CPS Energy)	2	Y	Y	Y
Jones Station (Xcel)	151B	Y	Y	Y
Jones Station (Xcel)	152B	Y	Y	Y
Knox Lee Power Plant (AEP)	2	N	Y	N
Knox Lee Power Plant (AEP)	3	N	Y	N
Knox Lee Power Plant (AEP)	4	N	Y	N
Knox Lee Power Plant (AEP)	5	Y	Y	Y
Lake Hubbard (Luminant)	1	Luminant was non-committal		Y
Lake Hubbard (Luminant)	2			Y
Laredo (Talen/Topaz)	1	N	Y	N
Laredo (Talen/Topaz)	2	N	Y	N
Laredo (Talen/Topaz)	3	N	Y	N
Lewis Creek (Entergy)	1	Y	Y	Y
Lewis Creek (Entergy)	2	Y	Y	Y
Martin Lake (Luminant)	1	Y	Y	Y
Martin Lake (Luminant)	2	Y	Y	Y
Martin Lake (Luminant)	3	Y	Y	Y
Monticello (Luminant)	1	Y	Y	Y
Monticello (Luminant)	2	Y	Y	Y
Monticello (Luminant)	3	Y	Y	Y
Morgan Creek (Luminant)	3	N	Y	N
Morgan Creek (Luminant)	4	N	Y	N
Morgan Creek (Luminant)	5	N	Y	N
Morgan Creek (Luminant)	6	N	Y	N
Mountain Creek (Exelon)	8	N	Y	N
Newman (El Paso Electric)	1	N	Y	N
Newman (El Paso Electric)	2	Y	Y	Y
Newman (El Paso Electric)	3	Y	Y	Y
Newman (El Paso Electric)	4	Y	Y	Y
Newman (El Paso Electric)	6	N	Y	N
Nichols Station (Xcel)	141B	N	Y	N
Nichols Station (Xcel)	142B	N	Y	N
Nichols Station (Xcel)	143B	Y	Y	Y
Nueces Bay (Talen/Topaz)	5	N	Y	N
Nueces Bay (Talen/Topaz)	6	N	Y	N
Nueces Bay (Talen/Topaz)	7	N	Y	N
O W Sommers (CPS Energy)	1	Y	Y	Y

O W Sommers (CPS Energy)	2	Y	Y	Y
Permian Basin (Luminant)	5	N	Y	N
Permian Basin (Luminant)	6	N	Y	N
Plant X (Xcel)	4	Y	Y	Y
Powerlane (City of Greenville)	ST1	Y	Y	Y
Powerlane (City of Greenville)	ST2	Y	Y	Y
Powerlane (City of Greenville)	ST3	Y	Y	Y
R W Miller (Brazos Elec. Coop)	1	Y	Y	Y
R W Miller (Brazos Elec. Coop)	2	Y	Y	Y
R W Miller (Brazos Elec. Coop)	3	Y	Y	Y
Sabine (Entergy)	1	N	Y	N
Sabine (Entergy)	2	Y	Y	Y
Sabine (Entergy)	3	Y	Y	Y
Sabine (Entergy)	4	Y	Y	Y
Sabine (Entergy)	5	Y	Y	Y
San Miguel (San Miguel Elec. Coop)	1	N	Y	N
Sandow-Luminant	4	N	Y	N
Sim Gideon (LCRA)	1	Y	Y	Y
Sim Gideon (LCRA)	2	Y	Y	Y
Sim Gideon (LCRA)	3	Y	Y	Y
Spencer (City of Garland)	4	Y	Y	Y
Spencer (City of Garland)	5	Y	Y	Y
Stryker Creek (Luminant)	ST2	Luminant was non-committal		Y
Tolk (Xcel)	1	N	Y	N
Tolk (Xcel)	2		Tolk (Xcel)	1
Trinidad (Luminant)	6	Luminant was non-committal		Y
Ty Cooke (City of Lubbock)	1	Y	Y	Y
Ty Cooke (City of Lubbock)	2	Y	Y	Y
V H Braunig (CPS Energy)	1	Y	Y	Y
V H Braunig (CPS Energy)	2	Y	Y	Y
V H Braunig (CPS Energy)	3	Y	Y	Y
V H Braunig (CPS Energy)	CT01	N	Y	N
V H Braunig (CPS Energy)	CT02	N	Y	N
Victoria Power Station (Renu)	6	N	Y	N
Victoria Power Station (Renu)	7	N	Y	N
Victoria Power Station (Renu)	8	N	Y	N
Victoria Power Station (Renu)	9	N	Y	N
W A Parish (NRG)	WAP1	N	Y	N
W A Parish (NRG)	WAP2	N	Y	N
W A Parish (NRG)	WAP3	N	Y	N
W A Parish (NRG)	WAP4	Y	Y	Y

W A Parish (NRG)	WAP5	Y	Y	Y
W A Parish (NRG)	WAP6	Y	Y	Y
W A Parish (NRG)	WAP7	N	Y	N
W A Parish (NRG)	WAP8	N	Y	N
Welsh Power Plant (AEP)	1	Y	Y	Y
Welsh Power Plant (AEP)	2	Y	Y	Y
Welsh Power Plant (AEP)	3	N	Y	N
Wilkes Power Plant (AEP)	1	Y	Y	Y
Wilkes Power Plant (AEP)	2	Y	Y	Y
Wilkes Power Plant (AEP)	3	Y	Y	Y

The final step in identifying a ''BART-eligible source'' is to use the information from the previous three steps to identify the collection of emissions units that comprise the BART-eligible source.

4 Our Strategy for Assessing which Units are Subject to BART.

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.[32] 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. 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. 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. We employed a four-fold strategy in determining which units should or should not be subject to BART. A flowchart of the analysis along with a detailed discussion of the subject-to-BART screening analysis is provided in the BART Screening TSD.[33] We summarize the methodology and results of this analysis here.

First, we examined whether any of the BART-eligible units should be eliminated from consideration based on the standard model plant exemptions described in the BART Guidelines.[34] Second, we created specific model plants between sources and nearby Class I areas and conducted CALPUFF modeling to evaluate a number of sources for exemption. . Third, we performed stand-alone source specific CALPUFF modeling on a number of units to determine if their visibility impacts were large enough to identify them as being subject to

[32] *See* 40 C.F.R. Part 51, Appendix Y, III, *How to Identify Sources "Subject to BART"*

[33] See our TSD, "Our Strategy for Assessing which Units are Subject to BART for the Texas Regional Haze BART Federal Implementation Plan (BART Screening TSD)" in our docket.

[34] See the discussion beginning on 70 FR 39104, 39162 (July 6, 2005) [40 CFR Part 51, App. Y].

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BART. Fourth, for those remaining units outside of the CALPUFF model's range, we contracted to have CAMx modeling performed to determine if their visibility impacts were large enough to merit their being subject to BART. CAMx results for sources within CALPUFF range are also included to provide additional information supporting the CALPUFF based determinations. These steps and the results of these analyses are described in detail in our BART Screening TSD.[35]

Based on the methodology described above, the BART-eligible sources in the table below have been determined to cause or contribute to visibility impairment at a nearby Class I area and we therefore propose they are Subject-to-BART.

Table 10. Subject-to-BART Sources

Facility	Units
Big Brown	1 & 2
Coleto Creek	1
Fayette Power	1 & 2
Harrington	061B & 062B
Martin Lake	1, 2 & 3
Monticello	1, 2 & 3
Calaveras	Deely 1 & 2, Sommers 1 & 2
W A Parish	WAP4, WAP5 & WAP6
Welsh	1&2*
Stryker	ST2
Graham	2
Wilkes	1, 2 & 3
Newman	2, 3 & 4

* Welsh Unit 2 retired April, 2016.

5 Our BART Five Factor Analyses

In our previous action,[36] we determined that due to the CSAPR remand, it was not appropriate at that time to rely on CSAPR as an alternative to SO_2 and NO_X BART for EGUs in Texas. As a consequence, action to satisfy the overdue requirement to address BART for EGUs in the state of Texas was further delayed.[37] In this proposal, we are proposing that CSAPR, once fully revised to address the D.C. Circuit's remand, provides a basis for satisfying EGU BART obligations for NO_X alone. It remains the case that we cannot rely on CSAPR as an alternative to SO_2 BART for Texas EGUs as further confirmed by our proposed action to remove Texas from the annual NO_X and SO_2 control programs. Thus, we have the obligation to consider source-specific requirements for Texas EGUs consistent with the BART Guidelines for SO_2 BART.

[35] Due to the length and complexity of the process we employed in determining which BART-eligible sources are subject-to-BART, we have described it in a separate TSD, entitled, "BART Screening TSD."
[36] See the discussion beginning on 81 FR 301 (January 5, 2016).
[37] Id. at 346.

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Because the component of the Texas Regional Haze SIP regarding the PM BART requirement for EGUs has not been acted on, we have the responsibility under CAA section 110(k) to evaluate the submission and take action to approve or disapprove it. The SIP determinations for PM were based on modeling that was conducted by examining visibility impairment due to PM emissions alone, based on the assumption that the state would be participating in CAIR for SO_2 and NO_X and thereby having BART coverage for those pollutants. The Texas Regional Haze SIP had concluded that no PM BART controls for EGUs were appropriate, because modeling assessment of PM impacts alone showed their impacts to be too small for consideration for control. But Texas' screening analysis is no longer reliable or accurate because of the invalid assumption that source-by-source BART for either SO_2 or NO_X would not be required.[38] In order to appropriately evaluate the BART requirements for EGUs, the visibility impacts from all pollutants must be studied, including PM emissions. Texas' PM BART analysis for EGUs does not do this.[39] Considering this, our BART evaluation will evaluate BART for potential SO_2 and PM controls.

All units that are subject to BART must undergo a BART analysis. Regarding this, Section 51.308(e) states:

> The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

This is commonly referred to as the "BART five factor analysis." The BART Guidelines break the analyses of these requirements down into five steps:[40]

> STEP 1—Identify All Available Retrofit Control Technologies,
> STEP 2—Eliminate Technically Infeasible Options,
> STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies,
> STEP 4—Evaluate Impacts and Document the Results, and
> STEP 5—Evaluate Visibility Impacts.

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[38] Additionally, the Texas SIP had mistakenly omitted EGUs from its BART-eligible source list that, by our investigation, should have also been identified as BART-eligible and evaluated for PM BART. Since Texas did not retain underlying records from its survey of BART sources, we are unable to identify what may have led to these omissions.

[39] Texas' Regional Haze SIP determined whether its sources should be subject to review for PM controls by only looking at the impact of PM emissions on visibility. This approach is appropriate, when a State satisfies the requirements for BART for SO_2 and NO_X with an alternative measure. It is not valid under the current facts, as the SIP itself acknowledged. See, e.g., TX Regional Haze SIP Narrative at 9-17 ("Some EGUs may become subject to BART pending resolution of CAIR at the federal level")

[40] 70 FR 39103, 39164 (July 6, 2005) [40 CFR 51, App. Y].

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The following sections treat these steps individually for SO_2. We are combining these steps into one section for PM.

5.1 Steps 1 and 2: Identification of Technically Feasible SO_2 Retrofit Control Technologies

The BART Guidelines state that in identifying all available retrofit control options,

> [Y]ou must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving.[41]

Adhering to this, we will identify a reasonable set of SO_2 control options, including those that cover the maximum level of control each technology is capable of achieving. In the course of that task, we will note whether any of these technologies are technically infeasible.

The subject-to-BART units identified in Table 10, can be organized into four broad categories, based on their fuel type and the potential types of SO_2 controls that could be retrofitted: (1) coal-fired EGUs with no SO_2 scrubber, (2) coal-fired EGUs with underperforming SO_2 scrubbers, (3) gas-fired EGUs that do not burn oil, and (4) gas-fired EGUs that occasionally burn fuel oil. This classification is represented below:

Table 11. Subject to BART Fuel Types and Potential SO2 BART Controls

Facility	Unit	Coal no scrubber	Coal underperforming scrubber	Gas no oil	Gas burns oil
Big Brown (Luminant)	1	X			
Big Brown (Luminant)	2	X			
Coleto Creek (Engie)	1	X			
Fayette (LCRA)*	1				
Fayette (LCRA)*	2				
Graham (Luminant)	2				X
Harrington Station (Xcel)	061B	X			
Harrington Station (Xcel)	062B	X			
J T Deely (CPS Energy)	1	X			
J T Deely (CPS Energy)	2	X			
Martin Lake (Luminant)	1		X		
Martin Lake (Luminant)	2		X		
Martin Lake (Luminant)	3		X		

[41] 70 FR at 39164, fn 12 [40 C.F.R. App. Y]

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Monticello (Luminant)	1	X			
Monticello (Luminant)	2	X			
Monticello (Luminant)	3		X		
Newman (El Paso Electric)	2				X
Newman (El Paso Electric)	3				X
Newman (El Paso Electric)	4			X	
O W Sommers (CPS Energy)	1				X
O W Sommers (CPS Energy)	2				X
Stryker Creek (Luminant)	ST2				X
W A Parish (NRG)	WAP4			X	
W A Parish (NRG)	WAP5	X			
W A Parish (NRG)	WAP6	X			
Welsh Power Plant (AEP)	1	X			
Welsh Power Plant (AEP)	2	X			
Wilkes Power Plant (AEP)	1				X
Wilkes Power Plant (AEP)	2			X	
Wilkes Power Plant (AEP)	3			X	

* The Fayette units have high performing wet FGDs in place.

For the coal-fired EGUs without an existing scrubber, we have identified four potential control technologies: (1) coal pretreatment, (2) Dry Sorbent Injection (DSI), (3) Spray Dryer Absorber (SDA), and (4) wet Flue Gas Desulfurization (FGD). For the coal-fired EGUs with an existing underperforming scrubber we will examine whether that scrubber can be upgraded. Gas-fired EGUs that do not burn oil have inherently low SO_2 emissions and there are no known SO_2 controls that can be evaluated. For gas-fired units that occasionally burn fuel oil, we will follow the BART Guidelines recommendations for oil-fired units: "For oil-fired units, regardless of size, you should evaluate limiting the sulfur content of the fuel oil burned to 1 percent or less by weight."[42] Each of these control technologies are evaluated below.

5.1.1 Identification of Technically Feasible SO_2 Retrofit Control Technologies for Coal Fired Units

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.

5.1.1.1 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 amount of sulfur in the coal burned. Coal pretreatment broadly falls into two categories: coal washing and coal drying.

[42] 70 FR 39103, 39171 (July 6, 2005) [40 CFR 51, App. Y].

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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).[43] 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.[44] Coal is mechanically sized, then various washing techniques are employed, depending on the particle size, type of coal, and the desired level of preparation.[45] 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,[46] and coal washing slurries are typically stored in impoundments, which can, and have, leaked.[47]

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 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.

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[43] Couch, G. R., "Coal Upgrading to Reduce CO_2 emissions," CCC/67, October 2002, IEA Clean Coal Centre.
[44] Ibid.
[45] 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.
[46] "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.
[47] 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.

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Coal drying can be performed onsite and so 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.[48] 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). We cannot assess many of these issues and we believe that requesting that the facilities in question do so would require detailed engineering analysis and extend our review time greatly. As a result of these issues, we do not further assess coal drying as a potential BART control.

5.1.1.2 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. For instance, Luminant states in its response to one of our Section 114(a) letters regarding its Big Brown and Monticello units:[49]

> Luminant commissioned the study of dry sorbent injection ("DSI") at these units in 2011. These studies determined that a very high feed rate

[48] 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/

[49] Luminant's 6/17/14 response to EPA's 5/20/14 Section 114(a) request for information relating to the Big Brown, Martin Lake, Monticello, and Sandow generating stations.

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> (in the range of 20-30%) was required to achieve modest SO_2 removal. Further, it was determined that other economic and operational factors make the use of DSI infeasible. For example, sorbent build-up was determined to cause degraded performance of the control equipment over time, as well as significant, repeat down time on a regular basis (i.e., every few days) to remove the buildup. In addition to the high cost of the sorbent required, the disposal and transport of the used sorbent (a Texas Class 1 waste) would result in significant additional cost. Thus, the use of DSI was determined infeasible from both an operational and economic point of view, and further evaluation has been discontinued.

As a consequence of this statement, which is discussed more fully in the CBI material Luminant has submitted, we considered proposing that DSI is not a feasible alternative for the Big Brown and Monticello facilities, and invite the affected facilities to affirm this position in the context of BART. Nevertheless, we included DSI in our BART evaluation for these facilities in order to be conservative. For all other units, although individual installations may present technical difficulties or poor performance due to the suboptimization of one or more of the above factors, we believe that DSI is technically feasible and should be considered as a potential BART control for all of the unscrubbed coal-fired BART-eligible units, with the exception of the Big Brown and Monticello facilities. We invite comments to the contrary.

5.1.1.3 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: [50]

> 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. ·
>
> 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

[50] Babcock and Wilcox. *Steam, Its Generation and Use*. Forty-second edition, 2015. Chapter 34.

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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[51] the following types of flue gas desulfurization systems as being operational in the U.S. for 2015:

Table 12. EIA Reported Desulfurization Systems in 2015

Type	Number of installations
Wet spray tower scrubber	296
Spray dryer absorber	269
Circulating dry scrubber	50
Packed tower wet scrubber	6
Venturi wet scrubber	48
Jet bubbling reactor	31
Tray tower wet scrubber	42
Mechanically aided wet scrubber	4
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.[52] 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,

[51] 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.

[52] 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.

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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, wet FGD and SDA installations account for approximately 81% of all scrubber installations in the U.S. and as such constitute a reasonable set of SO_2 control options. The vast majority of the wet FGD and SDA installations utilize limestone and lime, respectively as reagents. In addition, these technologies cover the maximum level of SO_2 control available. As described above, these controls are in wide use and have been retrofitted to a variety of boiler types and plant configurations. We therefore see no technical infeasibility issues and believe that limestone wet FGD and lime SDA should be considered as potential BART controls for all of the unscrubbed coal-fired BART-eligible units.

5.1.2 Identification of Technically Feasible SO_2 Retrofit Control Technologies for Gas-Fired Units

Four of the units identified in Table 10 as being subject to BART, are only permitted to burn gas: Newman Unit 4, W A Parish Unit 4, and Wilkes Units 2 and 3. These units will not be considered for SO_2 BART.[53]

A number of the units we identified in Table 10 as being subject to BART primarily fire gas, but have occasionally fired fuel oil in the past. These units are identified below in Table 13:

Table 13. Gas Units that Occasionally Burn Oil and are Subject to BART

Facility	Unit(s)	Gas Turbine	Steam Turbine
Graham (Luminant)	2		X
Newman (El Paso Electric)	2, 3		X
O W Sommers (CPS Energy)	1, 2		X
Stryker Creek (Luminant)	ST2		X
Wilkes Power Plant (AEP)	1		X

For the remaining units, we will assess SO_2 BART. To begin, we examine the historical quantity of fuel oil that has been burned by consulting the Energy Information Agency's (EIA) databases: EIA-767, EIA-906/920, and EIA-923.[54] EIA's forms have undergone a number of changes over the years preventing us from presenting an uninterrupted analysis of unit fuel oil usage. For instance, we have been able to collect unit-specific fuel usage data using EIA-767 from 2000-2004. EIA-767 did not collect this type of data in 2005, which was its last date of publication. We therefore turned to EIA-906/920 from 2005-2007, which only collected fuel usage data on a facility basis. However, we were able to access EIA-923 for unit-specific fuel usage from 2008-2015. We present a summary of this information for the units of interest below:

[53] Parish: TCEQ Permit Number 4575, 12/31/2002, general condition 7, "Fuel oil firing is limited to Units 1-3 only…." Newman: TCEQ Permit Number 1467, 5/22/2008, special condition 4.A, "Fuel fired in the gas turbines and duct burners, for Unit 4 shall be natural gas …." Wilkes: TCEQ Permit Number 45435, 11/4/02, general condition 7, "Authorization to fire fuel oil firing is limited to Unit No. 1."

[54] EIA-767: http://www.eia.gov/electricity/data/eia767/. EIA-906/920 and EIA-923: http://www.eia.gov/electricity/data/eia923/

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Table 14. EIA-767 Historical Fuel Usage for Gas Units Subject to BART that Occasionally Burn Oil

				Fuel Oil Usage in Barrels (42 gallons)												
Year	Plant	Boiler Id	Fuel Code	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2001	Newman	2	DFO	100							5,000					5,100
2001	Graham	2	DFO	31,500												31,500
2001	O W Sommers	2	DFO	800												800
2001	Wilkes	1	DFO	27,000	4,000											31,000
2002	Graham	2	DFO			9,800										9,800
2002	Stryker Creek	2	RFO			5,000										5,000
2002	Wilkes	1	DFO						1,800							1,800
2003	Graham	2	RFO		8,400	12,000			2,900							23,300
2003	Stryker Creek	2	RFO	22,000	29,200	20,600										71,800
2003	O W Sommers	1	DFO		20,000	20,000			5,000							45,000
2003	O W Sommers	2	DFO		4,000											4,000
2003	Wilkes	1	DFO	400	5,400		2,100								1,900	9,800
2004	Graham	2	DFO												2,200	2,200
2004	Stryker Creek	2	RFO												2,800	2,800
2004	O W Sommers	1	DFO		3,000								700			3,700
2004	Wilkes	1	RFO										2,100			2,100

Table 15. EIA-906/920 Historical Fuel Usage for Gas Units Subject to BART that Occasionally Burn Oil

				Fuel Oil Usage in Barrels (42 gallons)												
Year	Plant Name	Reported Prime Mover	Reported Fuel Type Code	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2005	Graham	ST	DFO	0	0	0	0	0	143	1,940	15,345	7,791	0	0	0	25,219
2005	O W Sommers	ST	DFO	90	0	0	0	0	5	62	27	69	67	0	62	382
2005	Wilkes	ST	RFO	0	0	0	0	0	0	0	0	2,538	8,543	0	0	11,081
2006	Graham	ST	DFO	0	0	0	0	0	1,522	7,847	6,198	0	0	0	0	15,567
2006	O W Sommers	ST	DFO	79	37	0	99	75	58	39	0	210	141	0	0	738
2006	Wilkes	ST	RFO	0	8,187	0	9	79	505	46	6,458	0	0	0	0	15,284
2007	Graham	ST	DFO	0	2,254	82	0	4	163	0	464	0	0	0	0	2,967

2007	Graham	ST	RFO	0	0	0	4	0	0	0	0	0	0	0	0	4
2007	O W Sommers	ST	DFO	71	34	25	73	33	30	51	117	112	227	37	0	810
2007	Wilkes	ST	RFO	0	0	404	1,865	0	0	0	0	0	0	0	0	2,269

Table 16. EIA-923 Historical Fuel Usage for Gas Units Subject to BART that Occasionally Burn Oil

				Fuel Oil Usage in Barrels (42 gallons)												
Year	**Plant Name**	**Boiler ID**	**Reported Fuel Type Code**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2008	Graham	2	DFO			303			118							421
2008	Wilkes	1	DFO	18		0	0	0		0	0	0	0	0	0	18
2009	O W Sommers	1	DFO	426	0	0	0	0	0	0	0	0	0	0	0	426
2009	O W Sommers	2	DFO	1,819	0	0	0	0	0	0	0	0	0	0	0	1,819
2009	Stryker Creek	2	DFO	0	24	21	18	0	0	0	0	25	0	0	0	88
2011	Graham	2	DFO	.	.	.	.	.	.	.	.	.	19	.	.	19
2011	O W Sommers	1	DFO	0	2,334	0	0	0	0	0	0	1,049	0	0	0	3,383
2011	O W Sommers	2	DFO	0	26	0	0	0	0	0	0	0	0	0	0	26
2012	Graham	2	RFO	0	0	0	0	2,077	18,177	5,657	0	0	0	0	0	25,911
2012	O W Sommers	1	DFO	0	0	0	0	0	0	0	0	0	495	0	0	495
2012	O W Sommers	2	DFO	0	0	0	0	0	0	0	0	0	87	0	0	87
2013	O W Sommers	2	DFO	0	0	0	0	0	0	0	0	378	0	0	0	378
2014	Newman	2	DFO	.	.	.	.	0	0	0	0	0	115	0	0	115
2014	O W Sommers	1	DFO	0	0	0	0	0	0	0	0	0	35	0	0	35
2014	O W Sommers	2	DFO	0	0	0	0	0	0	0	0	0	23	0	0	23
2014	Wilkes	1	DFO	0	613	0	0	0	0	0	0	0	0	0	.	613
2015	Newman	2	DFO	0	0	0	0	0	0	0	0	0	150	0	0	150
2015	Newman	3	DFO	0	0	0	0	0	0	0	0	0	75	0	0	75
2015	O W Sommers	1	DFO	0	0	0	0	0	0	0	0	0	87	0	0	87
2015	O W Sommers	2	DFO	0	80	0	0	0	0	0	0	0	583	0	0	663
2015	Wilkes	1	DFO	0	0	0	0	0	0	0	0	16	0	0	.	16

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Note in the above tables, DFO = Distillate Fuel Oil and RFO = Residual Fuel Oil. EIA defines DFO as being a general classification for one of the petroleum fractions produced in conventional distillation operations. It includes diesel fuels and fuel oils. Products known as No. 1, No. 2, and No. 4 diesel fuel are used in on-highway diesel engines, such as those in trucks and automobiles, as well as off-highway engines, such as those in railroad locomotives and agricultural machinery. Products known as No. 1, No. 2, and No. 4 fuel oils are used primarily for space heating and electric power generation. EIA defines RFO as being a general classification for the heavier oils, known as No. 5 and No. 6 fuel oils that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations. It conforms to ASTM Specifications D 396 and D 975and Federal Specification VV-F-815C. No. 5, a residual fuel oil of medium viscosity, is also known as Navy Special and is defined in Military Specification MIL-F-859E, including Amendment 2 (NATO Symbol F-770). It is used in steam-powered vessels in government service and inshore power plants. No. 6 fuel oil includes Bunker C fuel oil and is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes.[55]

Note that in the above EIA tables, if a unit or facility is missing for a particular year, it means that unit did not report any fuel oil burning to EIA for that year. Also note that in Table 15, we have not included several entries for Stryker Creek, because these entries refer to prime movers with the "IC" designation, which refers to "Internal Combustion Engine," and the only unit from Stryker Creek that is subject to BART is a Steam Turbine (ST). Similarly, we have not included several entries for Newman, with prime mover designations of "CT" and "CA," which refer to "Combustion Turbine," and the heat recovery portion of a combined cycle turbine, respectively, as the subject-to-BART Newman units are steam turbines.

The amount of fuel oil for the Newman units is fairly minor, and only occurred in years 2001, 2014, and 2015. Also, despite EIA not requiring that unit-specific fuel oil burning be reported from 2005, 2007, we can deduce that during this time period all oil burning for the Wilkes facility can be attributed to Unit 1, as that is the only unit permitted to burn oil. However, although the O W Sommers units 1 and 2 are the only units permitted to burn fuel oil, we cannot determine the amount each unit burned. Lastly, both the Graham Units 1 and 2 are permitted to burn fuel oil so we cannot determine how much can be attributed to Unit 1, the only one of the two units that is subject to BART.

5.1.2.1 Fuel Oil Sulfur Reduction Feasibility for Gas/Oil-Fired Boilers

In analyzing the technical feasibility under BART of these facilities burning fuel oils of sulfur contents lower than historically burned, we investigated two issues: (1) Is lower sulfur fuel oil available and what is its cost, and (2) are there any technical issues in burning a lower sulfur fuel oil that could add to the cost of that oil.

We began by reviewing the permits of the subject facilities. All of the subject units are limited by permit to burning oil with a sulfur content of no more than 0.7% sulfur by weight. In addition, the Newman units 2 and 3 are restricted to burning fuel oil for no more than 10% of

[55] http://www.eia.gov/tools/glossary/

their annual operating time. Similar to our summary of the historic volumes of oil burned by these facilities, we present the historical sulfur content of the oil burned below:

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Table 17. EIA-767 Historical Fuel Sulfur Content for Gas Units Subject to BART that Occasionally Burn Oil

				Sulfur Content (% by weight)											
Year	**Plant**	**Boiler Id**	**Fuel Code**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2001	Newman	2	DFO	0.2							0.2				
2001	Graham	2	DFO	0.5											
2001	O W Sommers	2	DFO	0.24											
2001	Wilkes	1	DFO	0.11	0.11										
2002	Graham	2	DFO			0.65									
2002	Stryker Creek	2	RFO			0.56									
2002	Wilkes	1	DFO						0.09						
2003	Graham	2	RFO		0.66	0.66			0.66						
2003	Stryker Creek	2	RFO	0.65	0.65	0.65									
2003	O W Sommers	1	DFO		0.19	0.19			0.19						
2003	O W Sommers	2	DFO		0.19										
2003	Wilkes	1	DFO	0.43	0.43		0.42								0.09
2004	Graham	2	DFO												0.69
2004	Stryker Creek	2	RFO												0.64
2004	O W Sommers	1	DFO		0.41								0.37		
2004	Wilkes	1	DFO		0.41								0.37		

Table 18. EIA-923 Historical Fuel Sulfur Content for Gas Units Subject to BART that Occasionally Burn Oil

				Sulfur Content (% by weight)											
Year	**Plant Name**	**Boiler ID**	**Fuel Code**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
2008	Graham	2	DFO			0.50			0.50						
2008	Wilkes	1	DFO	0.00		0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00
2009	O W Sommers	1	DFO	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	O W Sommers	2	DFO	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2009	Stryker Creek	2	DFO	0.00	0.46	0.50	0.41	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.00

2011	Graham	2	DFO	.	.	.	.	.	.	.	.	.	0.01	.	.
2011	O W Sommers	1	DFO	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.00
2011	O W Sommers	2	DFO	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2012	Graham	2	RFO	0.00	0.00	0.00	0.00	0.50	0.50	0.50	0.00	0.00	0.00	0.00	0.00
2012	O W Sommers	1	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
2012	O W Sommers	2	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
2013	O W Sommers	2	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00	0.00
2014	Newman	2	DFO	.	.	.	.	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2014	O W Sommers	1	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2014	O W Sommers	2	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2014	Wilkes	1	DFO	0.00	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	.
2015	Newman	2	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2015	Newman	3	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2015	O W Sommers	1	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2015	O W Sommers	2	DFO	0.00	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00
2015	Wilkes	1	DFO	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0.00	0.00	.

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Note: In 2008, the Wilkes facility did not report the fuel oil sulfur content, despite reporting that fuel oil was burned. Also note that beginning in 2012, the sulfur content reported is almost uniformly 0.50% (the 0.01% reported by the Graham and O W Sommers facilities is the exception). We suspect that, considering the variation in sulfur contents reported in prior years, this indicates unreliable data. We will examine this further in later sections. Also note that EIA does not report the sulfur content of the fuel oil burned from the 2005-2007 EIA-906/920 forms, so that data is unavailable.

In order to determine the technical feasibility under BART of these facilities burning fuel oils of sulfur contents lower than historically burned, we sent the Graham, Newman, Stryker Creek, and the Wilkes Section 114 letters requesting information on their fuel oil usage and costs.[56] We requested the following information:

1. For each unit, indicate whether that unit is permitted by the State of Texas to burn fuel oil. If so, cite to specific permit language.
2. For *each unit* permitted to burn fuel oil:
    a. Indicate if there are any legal restrictions on how often or how much fuel oil can be burned annually. If such restrictions exist, cite to specific permit language.
    b. Indicate if that unit has any legal restrictions on the sulfur content of the fuel oil that can be burned. If such restrictions exist, cite to specific permit language.
    c. If the restrictions in Questions 2.a and/or 2.b have changed since the period between January 1, 2000 and December 31, 2004, so indicate and cite to the restrictions that were in place during that time period.
    d. If fuel oil was burned between January 1, 2000 and December 31, 2004, indicate the volume burned per month and the sulfur content of that fuel.
    e. If no fuel oil has been burned since January 1, 2000, so indicate.
3. For each unit that is permitted to burn fuel oil, indicate whether the facility is willing to enter into a voluntary, enforceable commitment to remove the ability to burn fuel oil after October 9, 2017 (the projected effective date of our final decision), as a means of addressing BART. If applicable, please state in your response that you request an enforceable restriction prohibiting use of fuel oil at the unit if such unit is determined to be subject to BART for sulfur dioxide. Note that should the unit be determined to be subject to BART, the alternative to this may be a proposal by EPA to limit the sulfur content of the fuel oil burned by this same date.
4. For each unit that is permitted to burn fuel oil and that you wish to retain that ability, provide the following:
    a. For the last delivery of fuel oil, provide the vendor contact information, indicate the date of delivery, the method of delivery (e.g., truck, rail), the cost of the fuel, delivery and unloading charges, the volume of the fuel, the grade of the fuel, and the sulfur content of the fuel.
    b. For any fuel oil delivery over one year old, provide updated pricing for the same delivery method, volume, grade, and sulfur content.
    c. Unless the sulfur content of the fuel oil described in the reply to Question 6.b is already lower, provide updated pricing for an equivalent volume of fuel oil with a

[56] Copies of these letters and the facilities' responses are in our docket. We did not send the O W Sommers a letter due to an oversight on our part.

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sulfur content of 0.1% sulfur fuel oil, low sulfur specification fuel oil (approximately 322 ppm sulfur), and ultra-low sulfur specification fuel oil (approximately 15 ppm sulfur).

d. If there are additional costs associated with burning any of the lower sulfur fuels contemplated in Question 4.c, so indicate and estimate those costs.

We received full responses to Questions 1-3. All of the facilities indicated they wished to retain the ability to burn fuel oil.

All facilities have either burned either DFO or have switched between DFO and RFO, thus demonstrating the ability to burn distillate fuel oils of the type under consideration for SO_2 BART. We therefore conclude that lower sulfur DFOs are a technical feasible retrofit control option under BART, and carry no significant capital costs in their use other than their purchase price. We invite comments from the affected facilities concerning this conclusion.

5.1.2.2 SO_2 Scrubber Feasibility for Gas/Oil-Fired Boilers

We began our identification of technically feasible SO_2 retrofit control technologies by conducting a search of our 2015 Air Markets Program Data,[57] supplemented with EIA 860 and 923 data,[58] for any EGUs that primarily fires gas and secondarily fire fuel oil, to determine what, if any, SO_2 controls have been installed for these types of units. The only units with these criteria that indicated any type of SO_2 control are the E W Brown Units 10 and 11, which are simple cycle combustion turbines with nameplate capacities of 126 MW. Our Air Markets Program Data listed the SO_2 control was listed as "Other." We then searched for any EGUs that primarily fired oil for any type of SO_2 control. This resulted in two other units from the E W Brown facility: Units 8 and 9, also listed as 126 MW combustion turbines with the SO_2 control listed as "Other." We must assume this is something other than a scrubber or DSI, as this category lists all known variations of these types of technologies for other types of EGUs. An examination of EIA data did not indicate any type of SO_2 control was present for any of these units. Regardless, these EGUs are combustion turbines and all of the gas-fired units that are under consideration here are steam turbines.

Nevertheless, 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.[59] Consequently, we will consider the installation of various types of scrubbers to be technically feasible.

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[57] https://ampd.epa.gov/ampd/

[58] http://www.eia.gov/electricity/data/eia860/index.html, http://www.eia.gov/electricity/data/eia923/

[59] 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."

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5.1.3 Identification of Technically Feasible SO_2 Retrofit Control Technologies for Scrubber Upgrades

In our recent Texas-Oklahoma FIP,[60] we presented a great deal of information that concluded that the existing scrubbers for a number of facilities could be very cost effectively upgraded.[61] That information is attached herein as Appendix B. Of the facilities we evaluated in that action, Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are subject to BART and are thus a part of this proposal.

5.2 Step 3: Evaluation of Control Effectiveness of Remaining Control Technologies

In the following subsections to section 5.2, 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."[62] 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.

5.2.1 Evaluation of Control Effectiveness of DSI

The efficiency of DSI system depends on many factors, such as[63]:

- Sorbent particle size: Finer particles result in better performance.
- 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.

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[60] 81 FR 295, 321 (January 5, 2016)
[61] See information presented in Sections 6 and 7 of the Cost TSD.
[62] 70 FR 39103, 39172 (July 6, 2005) [40 CFR 51, App. Y]
[63] Wood, M., Kong, Y., "Dry Sorbent Injection with Trona or Sodium Bicarbonate Meets HCl Limit in Utility MACT, SOLVAir® Solutions, Solvay Chemicals, Inc.

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Solvay Chemicals, Inc., a manufacturer of DSI sorbents, provides general performance information: [64]

[64] "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.

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Figure 1. Typical Trona SO_2 Removal Rates with ESP or Baghouse Installations

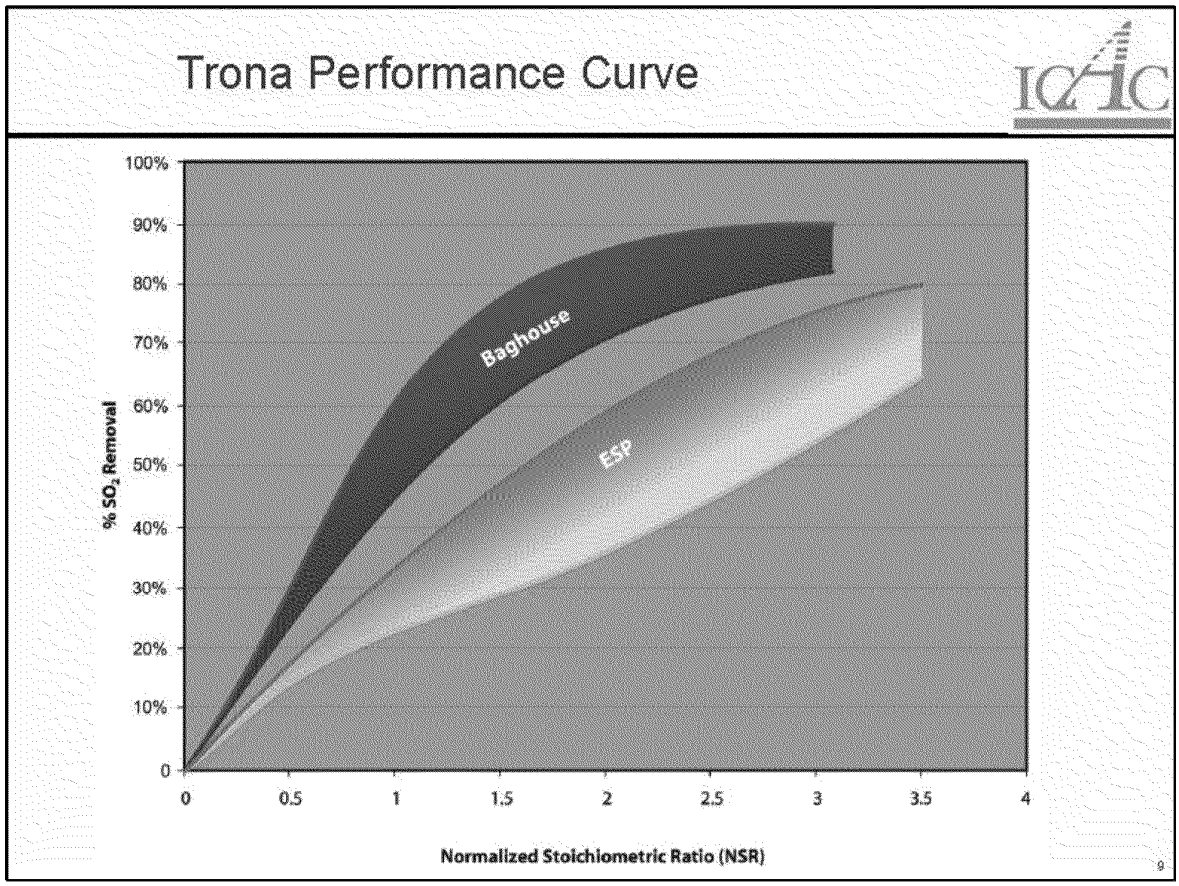

Figure 1 illustrates a number of important concepts concerning the performance potential of DSI:

- 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.

We lack the site specific information, which we believe requires an individual performance test, in order to be able to accurately determine the maximum SO_2 removal efficiency for the coal units listed in Table 10. We are aware that a number of the coal fired units have conducted such testing. However, although we have examined that testing, most of the facilities have claimed it as Confidential Business Information (CBI) and requested protection from public disclosure as provided by 40 C.F.R. Part 2.

However, we nevertheless must evaluate DSI as a viable, proven method of SO_2 control. We must do the same for SO_2 scrubbing, and in so doing, compare the visibility benefits and costs of each technology in order to propose which, if either technology, we should propose for installation due to the BART requirements. We therefore propose the following methodology:

- We will evaluate each unit at its maximum recommended DSI performance level, according to the IPM DSI cost model documentation,[65] assuming milled trona: 80% SO_2 removal for an ESP installation and 90% SO_2 removal for a baghouse 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.[66]

- However, (1) we do not know whether a given 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 all the units at a DSI SO_2 control level of 50%, which we believe is likely achievable for most units.

- We invite comments on whether particular units have performed DSI testing and have concluded they cannot achieve a SO_2 reduction between 50% and 80/90%.

5.2.2 Evaluation of Control Effectiveness of Wet FGD and SDA

We 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. As we discuss later in our TSD, we will conduct our wet FGD control cost analysis using the wet FGD cost algorithms, as employed in version 5.13 of our IPM model. [67] The IPM wet FGD

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[65] 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.

[66] The exceptions are the Harrington Unit 062B and Welsh Unit 1, for which we limited the upper DSI control to their SDA control efficiencies of 88.9% and 87.2%, respectively. See the discussion in this TSD concerning our evaluation of the control effectiveness of SDA.

[67] 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.

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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 established in our Oklahoma FIP,[68] this level of control is achievable with wet FGD. This level of control was also employed in our recent Texas-Oklahoma FIP.[69] We received a comment challenging this level of control and we reproduce our response to that comment in Appendix A. We continue to conclude that our proposed level of control for wet FGD is reasonable.

As with our Oklahoma BART FIP, 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 lb/MMBtu, in which case, we assume the percentage of control equal to 0.06 lbs/MMBtu. See our response to comments in our previous Oklahoma BART FIP.[70] In that FIP, we finalized the same emission limit of 0.06 lbs/MMBtu on a 30 BOD average for 6 coal fired. We justified those limits based on the same SDA technology, using a combination of industry publications and real world monitoring data. Much of that information is summarized in our response to a comment to that action[71] and in our TSD. We continue to conclude that our proposed level of control for SDA is reasonable.

5.2.3 Evaluation of Control Effectiveness for Gas-Fired Units

The control effectiveness of switching from a higher sulfur fuel oil to a lower sulfur fuel oil lies in the reduction in sulfur. This depends on the percentage reduction from the sulfur contents of the fuel oil that forms the SO_2 baseline to the replacement fuel oil. Ultimately, the highest level of control would result from a switch from the highest percentage sulfur the units are permitted to burn, 0.7% to the lowest DFO available, ultra-low sulfur diesel, which has a sulfur content of 0.0015%. This would equate to a control effectiveness of 99.8%. Lesser levels of controls are also possible. We will evaluate a range of control effectiveness in switching to lower sulfur fuel oils in the next section.

Because we are unaware of any scrubber installations on oil fired units in the U. S., we have no information on their control effectiveness. However, we see no technical reason why the control effectiveness of FGDs installed on gas-fired units that occasionally burn fuel oil should not be equal to that of FGDs installed on coal-fired units.

5.3 Step 4: Evaluate Impacts and Document the Results for SO_2

The BART Guidelines offers the following with regard to how Step 4 should be conducted:[72]

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[68] As discussed previously in our TSD for that action, control efficiencies reasonably achievable by dry scrubbing and wet scrubbing were determined to be 95% and 98% respectively. 76 FR 81742); *Oklahoma v. EPA*, 723 F.3d 1201 (July 19, 2013), cert. denied (U.S. May 27, 2014).
[69] 81 FR 295, 321 (January 5, 2016).
[70] 76 FR 81727, 81728 (December 28, 2011).
[71] 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 comment and response beginning on page 91.
[72] 70 FR 39103, 39166 (July 6, 2005) [40 CFR Part 51, App. Y].

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> 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.

We evaluate the cost of compliance on a unit-by unit basis, because control cost analysis depends on specific factors that vary from unit to unit. However, as we discuss later in this TSD, we evaluate the energy impacts. non-air quality impacts, and the remaining useful life for all the units in question together because in this instance there are no appreciable differences in these factors from unit to unit.

In developing our cost estimates for the units in Table 10, we relied on the methods and principles contained within the EPA Air Pollution Control Cost Manual (the Control Cost Manual, or Manual).[73] As we describe in our Oklahoma final action,[74] the Control Cost Manual uses the "overnight" method of cost estimation:

> 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.'' EIA presents all of its projected plant costs in terms of overnight 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.''

[73] 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.
[74] 76 FR 81727, 81744 (January 27, 2012).

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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 each of the units listed in Table 10. For the coal units without any SO_2 control, we calculate the cost of installing DSI, a SDA scrubber, and a wet FGD scrubber. For the gas units that burn oil, we evaluate the cost of switching to lower sulfur fuel oils and installing scrubbers.

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 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 each unit listed in Table 10 that did not already have SO_2 control.[75] We discuss the inputs and outputs for the DSI, SDA, and wet FGS cost models below. These cost models were based on costs escalated to 2012 dollars.[76] 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 5.3.1, 5.3.2, and 5.3.3.

5.3.1 Impact Analysis Part 1: Cost of Compliance for DSI

Table 19, 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.

[75] These spreadsheets are entitled, "DSI Cost IPM 5-13 TX BART.xlsx," "SDA Cost IPM 5-13 TX BART.xlsx," and "Wet FGD Cost IPM 5-13 TX BART.xlsx," and are located in our Docket.
[76] Ibid., p.1: "The data was converted to 2012 dollars based on the Chemical Engineering Plant Index (CEPI) data."

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Table 19. 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		LIG-PRB Blend	<---- 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)	
HHV Lignite		BTU/lb	7,200	<---- User Input (default is 7,200 Btu/lb if applicable; else no meaning)	Three year average from 2011-2015, excluding max and min values
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
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)	17.05	(A*E)*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	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	($/ton)	170	<---- User Input	Based on input from Solvay
Waste Disposal Cost	S	($/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

5.3.1.1 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 individual DSI installations. 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. For example, we designed our cost model based on selecting maximum inputs from 2011 – 2015 for the inlet SO_2 rate, the gross heat rate, and the percentage lignite even if these values didn't appear in the same year of data. We took this approach in order to

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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. We therefore invite comments on the accuracy of the values we have used.

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,[77] 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.[78] 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. None of the units we evaluated were affected by this limit, although Big Brown's maximum monthly SO_2 emission rate was right at 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. Therefore, a single coal selection is not appropriate for a few of the facilities for which we are costing DSI and scrubbers, which burn blends of Texas lignite and PRB coals (e.g., Big Brown Units 1, 2 and , Monticello Units 1, 2). In addition, regardless of whether a facility blends coal, we wished to allow 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. We select the maximum percent lignite value from 2011 – 2015. We use the three year average HHV values from 2011 – 2015, eliminating the maximum and minimum values. Our adjusted cost model accounts for this information in the calculation of the VOMW.

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[77] http://ampd.epa.gov/ampd/
[78] Ibid.

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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."[79] For those units that use an ESP along with a polishing baghouse, we assumed that the baghouse would have the capacity to handle the additional particulate matter from the trona by itself. Thus, we assumed the trona would be injected downstream of the ESP and upstream of the baghouse and we modeled the DSI cost on the basis of a baghouse. In all cases we assumed the existing particulate control device has the capacity to handle the additional load due to the addition of the trona. We invite comment from the affected facilities as to whether this assumption is valid.

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 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 in all cases.

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."[80] In section 5.2.1, 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.

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[79] 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.
[80] Ibid., p.2.

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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. We invite the affected facilities to inform us whether they would configure DSI in such a manner.

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 in all cases.

Trona Cost. The cost of trona is the largest portion of the variable operating costs. It is partly dependent on the delivery costs. The United States Geological Survey estimates the average 2012 cost of soda ash to be $135/ton F.O.B at the mine or plant.[81] Considering that trona must be delivered from Wyoming to Texas, we contacted Solvay, which is a supplier of Trona, in order to improve this estimate. We were able to get estimated trona costs and some estimated freight delivery costs for various locations:[82]

Table 20. Cost of Trona

Facility	Cost of Trona ($/ton)	Freight by Railroad ($/ton)	Total Cost ($/ton)
Welsh	110.00	87.98	197.98
Fayette	110.00	82.62	192.62
J T Deely	110.00	85.10	195.10
Harrington	110.00	64.90	174.90

We used the Welsh quote to represent the other facilities in east Texas: Big Brown, and Monticello. We used the Fayette quote to represent the W A Parish facility. We used the J T Deely to also represent the Coleto Creek facility. Solvay also indicated that, "if the facilities do not have rail access to accept chemical shipments, the additional fees for running the product through a terminal/transload facility to put the material into bulk trucks would be about $50/ton additional cost. This can vary greatly depending upon volume and location, but this would be an estimated average cost." We have not assumed this additional transportation cost for any facility, but invite clarification from the facilities involved as to whether it should be added.

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

[81] U.S. Department of the Interior U.S. Geological Survey Mineral Commodity Summaries 2016, p. 154. Available at http://minerals.usgs.gov/minerals/pubs/mcs/2016/mcs2016.pdf
[82] Email from Marilyn Treacy to Joe Kordzi, 7-6-2016.

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fly ash and is disposed of separately. We assumed the trona waste and the fly ash were comingled and disposed of together for all cases, and therefore set this value to $50/ton. 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.[83] We invite comments on this issue.

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 recoveryfactor, 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 govern ment regulations, an appropriate "social" interest (discount) rate should be used, unless site specific information 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. [84] Also, a 7 percent interest rate is recommended by Office of Management and Budget.[85]

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.

Gross Load. The gross load (MW-h) was obtained from emissions data downloaded from our Air Markets Program Data website.[86] 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

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[83] 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.'"

[84] 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).

[85] 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

[86] http://ampd.epa.gov/ampd/

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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.[87] 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.

5.3.1.2 DSI Cost Model Output

A sample of the IPM DSI cost model output is depicted below in Table 21. 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."[88] 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.

[87] Ibid.

[88] 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.

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Table 21. 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)	2.87	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not	
VOMP ($/MWh)	0.39	Variable O&M costs for additional auxillary power required (refer to Aux Power % above)	
VOM ($/MWh)	**8.82**	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	$35,260,822	VOM*(Gross Load)	
Fixed operating costs	$404,356	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)	
Total annualized costs	**$37,365,470**		
SO2 emissions reduction (tons)	15,000	H/(100%)*(SO2 emission baseline)	
$/ton	**2,491**		

5.3.1.3 Summary of DSI Cost Model Results

Below in Table 22 is a summary of our DSI cost model results:

Table 22. Summary of DSI Cost Model Results

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Facility	Unit	DSI Control (%)	DSI SO2 Reduction (tpy)	DSI Capital Cost	DSI Annualized Capital Cost	DSI Variable Operating Cost	DSI Fixed Operating Cost	DSI Total Annualized Cost	DSI Cost Effectiveness 2012 ($/ton)	DSI Cost Effectiveness 2016 ($/ton)
Parish	5	50.00	6,712	$15,495,000	$1,248,686	$14,234,884	$267,806	$15,751,376	$2,347	$2,235
		90.00	12,081	$21,266,000	$1,713,750	$30,390,656	$302,372	$32,406,779	$2,682	$2,555
	6	50.00	7,525	$15,986,000	$1,288,254	$15,266,210	$260,123	$16,814,587	$2,234	$2,128
		90.00	13,545	$21,996,000	$1,772,579	$32,897,968	$294,715	$34,965,262	$2,581	$2,459
Welsh	1	50.00	3,343	$12,626,000	$1,017,484	$8,154,876	$238,945	$9,411,305	$2,816	$2,682
		90.00	6,017	$17,373,000	$1,400,028	$15,936,486	$266,062	$17,602,576	$2,926	$2,787
Coleto Creek	1	50.00	7,376	$14,922,000	$1,202,510	$15,507,382	$347,417	$17,057,310	$2,313	$2,203
		90.00	13,277	$20,534,000	$1,654,761	$34,534,592	$391,592	$36,580,945	$2,755	$2,624
J T Deely	1	50.00	3,072	$13,951,000	$1,124,261	$7,963,377	$208,762	$9,296,399	$3,027	$2,883
		90.00	5,529	$19,196,000	$1,546,937	$17,193,108	$234,130	$18,974,174	$3,432	$3,269
	2	50.00	3,222	$13,733,000	$1,106,693	$9,003,561	$248,125	$10,358,379	$3,215	$3,062
		90.00	5,800	$18,898,000	$1,522,922	$19,438,363	$277,956	$21,239,241	$3,662	$3,488
Harrington	061B	50.00	2,477	$14,046,000	$1,131,917	$8,252,558	$261,853	$9,646,328	$3,895	$3,710
		80.00	3,962	$17,828,000	$1,436,694	$15,154,863	$284,755	$16,876,313	$4,259	$4,057
	062B	50.00	2,455	$11,882,000	$957,528	$5,661,879	$231,309	$6,850,715	$2,791	$2,658
		90.00	4,418	$16,348,000	$1,317,427	$11,273,661	$256,449	$12,847,536	$2,908	$2,770
Big Brown	1	50.00	14,448	$19,179,000	$1,545,567	$29,039,816	$354,517	$30,939,899	$2,142	$2,040
		90.00	26,006	$33,862,000	$2,728,817	$72,542,248	$462,091	$75,733,155	$2,912	$2,774
	2	50.00	15,320	$19,035,000	$1,533,962	$28,915,771	$357,627	$30,807,360	$2,011	$1,915
		90.00	27,576	$32,965,000	$2,656,531	$71,766,172	$460,896	$74,883,599	$2,716	$2,586
Monticello	1	50.00	4,787	$17,410,000	$1,403,009	$10,419,393	$156,094	$11,978,496	$2,502	$2,383
		90.00	8,617	$24,083,000	$1,940,762	$24,558,561	$178,436	$26,677,759	$3,096	$2,949
	2	50.00	4,129	$17,057,000	$1,374,562	$8,716,433	$138,086	$10,229,081	$2,478	$2,360
		90.00	7,431	$23,468,000	$1,891,202	$20,439,704	$157,226	$22,488,132	$3,026	$2,882

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.
- For a given level of control, the cost effectiveness of DSI generally improves as the tonnage of SO_2 removal increases.

5.3.2 Impact Analysis Part 1: Cost of Compliance for SDA

Table 23, 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

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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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Table 23. 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**	5 -yr avg. excluding max and min
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

5.3.2.1 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. For instance, simply changing the type of coal from lignite to PRB for Big Brown Unit 1 results in an improvement in the cost effectiveness (lower $/ton) of less than 1%. Therefore, for those facilities that burn a mixture of lignite and PRB, we are simply assuming they burn lignite for the purposes of costing a SDA system.

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

5.2.2, 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.[89] 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.[90] The USGS estimates the average 2012 cost of quicklime to be $116/ton at the lime plant.[91] Although we do not have lime pricing available for Texas, lime is widely available within the State and we expect delivery charges to be minimal. Consequently, we consider the cost algorithm default cost for delivered lime of $125/ton to be reasonable, and we have adopted it for all cases. We invite the affected facilities to provide comment on this assumption.

Waste Disposal Cost. The waste disposal cost is the second largest portion of the variable operating costs. The cost model default is $30/ton and we have adopted it for all cases.

Elevation Adjustment. The IPM SDA documentation states that the cost methodology is based on a unit located within 500 feet of sea level:[92]

> 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. Consequently, we included this atmospheric pressure adjustment in our SDA cost model by incorporating an atmospheric pressure change with elevation calculation provided by NASA.[93]

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[89] Primex Process Specialists. "Optimizing Scrubber Performance," p. 3. Available at http://www.primexprocess.com/pdf/Paper_4.pdf

[90] IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final, March 2013. Sargent & Lundy, p. 3

[91] 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

[92] IPM SDA documentation, p. 2.

[93] 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).

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In order to utilize this calculation, we constructed Table 24, below, which uses the average of the latitude and longitude of the stack locations. We entered these coordinates into Google Earth Pro,[94] which returns the elevation above sea level.

Table 24. Elevation of Sources undergoing RP and LTS analyses

	Latitude	Longitude	Elevation
Big Brown	31.8200	-96.0552	335
Coleto Creek	28.7108	-97.2139	108
J T Deely	29.3072	-98.3228	498
Monticello	33.0913	-95.0376	384
Harrington	35.2972	-101.7475	3560
W. A. Parish	29.4792	-95.6324	79
Welsh	33.0564	-94.8458	377

As can be seen from the above table, only the Harrington facility is located at an elevation that exceeds 500 feet above sea level, and thus requires an elevation adjustment, which we included in our SDA cost model for this facility. This correction had the effect of worsening the cost effectiveness (increasing the $/ton) for Tolk by approximately 5%.

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. As we state in our Oklahoma FIP,[95] we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler, which might easily be well over 60 years. We identified specific scrubbers installed between 1975 and 1985 that were still in operation. Because none of the facilities involved have entered into or offered to enter into enforceable commitments to shut down the applicable units earlier, we will continue to use a 30 year equipment life for scrubber retrofits and upgrades, as we believe that is proper.

5.3.2.2 SDA Cost Model Output

A sample of the IPM SDA cost model output is depicted below in Table 25. 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.

[94] https://www.google.com/earth/.

[95] 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.

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Table 25. Sample SDA Output

Capital Cost Calculation		Explanation of Calculation	Comments
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit	
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**		

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5.3.2.3 Summary of SDA Cost Model Results

Below in Table 26 is a summary of our SDA cost model results:

Table 26. Summary of SDA Cost Model Results

Facility	Unit	SDA Control (%)	SDA SO2 Reduction (tpy)	SDA Capital Cost	SDA Annualized Capital Cost	SDA Variable Operating Cost	SDA Fixed Operating Cost	SDA Total Annualized Cost	SDA Cost Effectiveness 2012 ($/ton)	SDA Cost Effectiveness 2016 ($/ton)
Parish	5	92.11	12,364	$272,260,000	$21,940,454	$7,948,884	$2,863,997	$32,753,335	$2,649	$2,523
	6	92.11	13,862	$285,608,000	$23,016,122	$8,524,785	$2,853,463	$34,394,370	$2,481	$2,363
Welsh	1	87.23	5,832	$210,262,000	$16,944,258	$4,625,309	$2,260,702	$23,830,270	$4,086	$3,892
Coleto Creek	1	92.41	13,632	$230,551,000	$18,579,276	$9,007,945	$3,327,934	$30,915,154	$2,268	$2,160
J T Deely	1	91.30	5,609	$202,172,000	$16,292,314	$4,617,491	$1,862,639	$22,772,444	$4,060	$3,867
	2	91.30	5,884	$192,698,000	$15,528,839	$5,220,370	$2,152,369	$22,901,577	$3,892	$3,707
Harrington	061B	90.16	4,466	$157,015,000	$12,653,274	$3,705,438	$1,968,496	$18,327,209	$4,104	$3,909
	062B	88.89	4,364	$171,141,000	$13,791,638	$3,423,240	$1,935,945	$19,150,823	$4,389	$4,180
Big Brown	1	95.00	27,453	$228,114,000	$18,382,887	$15,603,465	$3,073,521	$37,059,873	$1,350	$1,286
	2	95.00	29,108	$229,544,000	$18,498,125	$15,502,674	$3,123,862	$37,124,661	$1,275	$1,215
Monticello	1	95.00	9,095	$229,711,000	$18,511,583	$5,584,009	$1,411,698	$25,507,290	$2,804	$2,671
	2	95.00	7,844	$227,409,000	$18,326,073	$4,705,402	$1,249,282	$24,280,757	$3,095	$2,948

Some observations are apparent from the SDA cost model results displayed above:

- 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.
- Unlike the cost effectiveness of DSI, the cost effectiveness of SDA improves (lower $/ton) with increasing control levels.

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5.3.3 Impact Analysis Part 1: Cost of Compliance for Wet FGD

Table 27, 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 27. 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
Retrofit Factor	B		1	**<--- User Input (An "average" retrofit has a factor =1.0)**	
Gross Heat Rate	C	(Btu/kWh)	9,500	**<--- User Input**	5 -yr avg. excluding max and min
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

5.3.3.1 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.

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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 5.2.2, 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. We note that the cost of limestone is partly dependent on the delivery cost, but limestone is widely available within Texas. Consequently, we consider the cost algorithm default cost for delivered lime of $30/ton to be reasonable, and we have adopted it for all cases.

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. We invite comment from the affected facilities as to whether they believe more extensive wastewater treatment would be required for their facility, and if so, to provide an estimate of that cost.

5.3.3.2 Wet FGD Cost Model Output

A sample of the IPM wet FGD cost model output is depicted below in Table 28. 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.

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Table 28. Sample Wet FGD Output

Capital Cost Calculation		Explanation of Calculation	Comments
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit	
BMR($)	48,869,000	Base absorber island cost	
BMF($)	23,674,000	Base reagent preparation and waste recycle/handling cost	
BMW($)	14,536,000	Base reagent	
BMB($)	89,730,000	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($)	89,730,000	Adjustment to base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.), if elevation is greater than 500 feet. See page 2 of the S&L documentation.	
BM($)	**176,809,000**	Total Base module cost including retrofit factor	
BM($/kW)	354	Base cost per kW	
Total Project Cost			
A1	17,681,000	Engineering and Construction Mnagement costs	
A2	17,681,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.	
A3	17,681,000	Contractor profit and fees.	
CECC ($)	**229,852,000**	Capital, engineering and construction cost subtotal	Excludes Owner's Costs.
CECC($/kW)	**460**	Capital, engineering and construction cost subtotal per kW	Excludes Owner's Costs.
B1	11,493,000	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)	
TPC' ($)	**241,345,000**	Total project cost without AFUDC	Includes Owner's Costs
TPC' ($/kw)	**483**	Total project cost per kW without AFUDC	Includes Owner's Costs
B2	24,135,000	AFUDC (Based on a 3 year engineering and construction cycle)	
TPC ($)	**265,480,000**	Total Project Cost (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
TPC ($/kW)	**531**	Total Project Cost per kW (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
			The cost algorithms present
Fixed O&M Cost			additional factors, FOMWW
			and VOMWW, for a possible
FOMO ($/kW-yr)	3.00	Fixed O&M additional operating labor costs. IF MW > 500, then 16 operators, else 12 operators	future base wastewater treatment facility. They are
FOMM ($/kW-yr)	5.30	Fixed O&M additional maintenance material and labor costs	currently not used, so they are
FOMA ($/kW-yr)	0.15	Fixed O&M additional administrative labor costs	not included here.
FOM ($/kW-yr)	**8.45**	Total Fixed O&M costs	
Variable O&M Cost			
VOMR ($/MWh)	0.73	Variable O&M costs for limestone reagent	
VOMW ($/MWh)	1.31	Variable O&M costs for waste disposal	
VOMP ($/MWh)	0.95	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
VOMM ($/MWh)	0.08	Variable O&M costs for makeup water	
VOM ($/MWh)	**3.07**	Total Variable O&M Costs	
Annualization			
Capital, engineering and construction cost	$229,852,000	Excludes owner's costs and AFUDC	
Capital Recovery factor	0.0806		
Annualized capital costs	$18,522,946		
Variable operating costs	$13,184,075	VOM*(Gross Load)	
Fixed operating costs	$4,144,689	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)	
Total annualized costs	**$35,851,710**		
SO2 emissions reduction	29,061	J/(100%)*(SO2 emission baseline)	
$/ton	**1,234**		

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5.3.3.3 Summary of Wet FGD Cost Model Results

Below in Table 29 is a summary of our SDA cost model results:

Table 29. Summary of Wet FGD Cost Model Results

Facility	Unit	Wet FGD Control (%)	Wet FGD SO_2 Reduction (tpy)	Wet FGD Capital Cost	Wet FGD Annualized Capital Cost	Wet FGD Variable Operating Cost	Wet FGD Fixed Operating Cost	Wet FGD Total Annualized Cost	Wet FGD cost Effectiveness 2012 ($/ton)	Wet FGD cost Effectiveness 2016 ($/ton)
Parish	5	94.7	12,717	$283,182,000	$22,820,619	$5,798,157	$3,650,798	$32,269,573	$2,537	$2,417
	6	94.7	14,258	$297,661,000	$23,987,429	$6,218,236	$3,618,007	$33,823,673	$2,372	$2,259
Welsh	1	91.5	6,116	$230,424,000	$18,569,041	$3,546,457	$3,080,847	$25,196,345	$4,120	$3,924
Coleto Creek	1	94.9	14,005	$251,460,000	$20,264,257	$6,542,816	$4,466,198	$31,273,271	$2,233	$2,127
J T Deely	1	94.2	5,787	$223,325,000	$17,996,959	$3,403,601	$2,280,985	$23,681,544	$4,092	$3,898
	2	94.2	6,070	$212,970,000	$17,162,486	$3,847,988	$2,645,352	$23,655,827	$3,897	$3,712
Harrington	061B	93.4	4,628	$172,845,000	$13,928,957	$2,767,234	$2,449,309	$19,145,500	$4,137	$3,940
	062B	92.6	4,545	$189,971,000	$15,309,080	$2,588,791	$2,405,469	$20,303,340	$4,467	$4,254
Big Brown	1	98.0	28,320	$257,763,000	$20,772,193	$10,364,348	$4,217,796	$35,354,338	$1,248	$1,189
	2	97.9	29,998	$259,141,000	$20,883,241	$10,342,048	$4,281,131	$35,506,420	$1,184	$1,127
Monticello	1	97.0	9,286	$257,182,000	$20,725,372	$3,846,382	$1,924,967	$26,496,721	$2,853	$2,718
	2	96.8	7,995	$254,177,000	$20,483,210	$3,255,811	$1,704,028	$25,443,049	$3,182	$3,031

Some observations are apparent from the wet FDG cost model results displayed above:

- 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.
- As with our SDA cost model, the cost effectiveness of wet FGD improves (lower $/ton) with increasing control levels.

Table 30 compares the capital cost and cost effectiveness of both technologies:

Table 30. Capital cost and cost effectiveness of wet FGD versus SDA

Facility	Unit	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
Parish	5	$272,260,000	$283,182,000	3.9	$2,523	$2,417	-4.4
	6	$285,608,000	$297,661,000	4.0	$2,363	$2,259	-4.6
Welsh	1	$210,262,000	$230,424,000	8.7	$3,892	$3,924	0.8
Coleto Creek	1	$230,551,000	$251,460,000	8.3	$2,160	$2,127	-1.6
J T Deely	1	$202,172,000	$223,325,000	9.5	$3,867	$3,898	0.8
	2	$192,698,000	$212,970,000	9.5	$3,707	$3,712	0.1
Harrington	061B	$157,015,000	$186,289,000	15.7	$3,909	$4,185	6.6

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	062B	$171,141,000	$189,971,000	9.9	$4,180	$4,254	1.7
Big Brown	1	$228,114,000	$257,763,000	11.5	$1,286	$1,189	-8.1
	2	$229,544,000	$259,141,000	11.4	$1,215	$1,127	-7.8
Monticello	1	$229,711,000	$257,182,000	10.7	$2,671	$2,718	1.7
	2	$227,409,000	$254,177,000	10.5	$2,948	$3,031	2.7

- The capital cost of wet FGD is higher than SDA by approximately 4 – 16%. However, wet FGD delivers a significant improvement in the cost effectiveness for some of the units, increasing as the tonnage of SO_2 removal increases 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.

5.3.4 Impact Analysis Part 1: Cost of Compliance for Upgrading Existing Scrubbers

Of our subject-to-BART units, Martin Lake Units 1, 2, 3; Monticello Unit 3, and Fayette Units 1 and 2 are currently equipped with wet FGDs. Of these, all but the Fayette units were analyzed for scrubber upgrades in our Texas-Oklahoma FIP. As we discussed in that FIP, the cost information we relied upon was based on information claimed as CBI, which was provided to us by the facilities' parent companies. As a consequence, we could only present a summary of the cost-effectiveness. After responding to comments we revised our proposed cost-effectiveness basis from where all scrubber upgrades were less than $600/ton, to where all scrubber upgrades ranged from between $368/ton to $910/ton.[96]

We propose to rely on those total annualized cost calculations used to make the above cost-effectiveness calculations in this action. We acknowledge that these costs could change slightly, due to changes in the costs of various materials and services. However, these costs were calculated in 2013 dollars. Escalating them to 2015 dollars would result in a reduction in cost, which we conservatively ignore.[97]

Using these costs, we propose to update the cost-effectiveness of the scrubber upgrades by retaining the same 95% control level we demonstrated was reasonable, but applying it to updated baseline emissions. For instance, in Table 19 of the Cost TSD in our Texas-Oklahoma FIP, we calculated our SO_2 baseline as being the three year average from 2009-2013 SO_2 annual emissions, excluding the maximum and minimum values. Here we update that baseline to be the same as we presently use in our DSI, SDA, and wet FGD BART cost analyses— the three year average from 2011-2015 SO_2 annual emissions, excluding the maximum and minimum values.

We will also adopt the same 30 year equipment lifetime as we used in our analysis of scrubber upgrades in our Texas-Oklahoma FIP. As we state in our Oklahoma FIP,[98] we noted that scrubber vendors indicate that the lifetime of a scrubber is equal to the lifetime of the boiler,

[96] 81 FR 295, 318 (February 4, 2016).
[97] The CEPCI for 2013 is 567.3 and that for 2015 is 556.3. Therefore the costs would be multiplied by a factor of 556.8/567.3, which is approximately 0.98.
[98] 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.

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which might easily be well over 60 years. We identified specific scrubbers installed between 1975 and 1985 that were still in operation. Because none of the facilities involved have entered into or offered to enter into enforceable commitments to shut down the applicable units earlier, we will continue to use a 30 year equipment life for scrubber upgrades, as we believe that is proper.

In our Texas-Oklahoma FIP, we also discussed how we calculated the efficiency of the existing SO_2 scrubbers.[99] We noted that in a typical situation in which we would propose that a pollution control device such as an SO_2 scrubber be installed, we would have historical emissions data to use as a baseline. In such an instance, we would apply the control efficiency of the scrubber to the uncontrolled historical SO_2 emissions, and be able to easily propose a controlled SO_2 emission rate that would be appropriate following the installation of the scrubber. However, we faced a more difficult task in analyzing the efficiency of existing SO_2 scrubbers because CEMS data for the inlet of the scrubbers was lacking—we only had CEMS data for the outlet of the scrubbers. We discussed how we used coal quality data to establish the uncontrolled SO_2 emissions.

We calculated the scrubber removal efficiency by utilizing the reported sulfur content and tonnages of the fuels burned and reported to EIA,[100] and the monitored SO_2 scrubber outlet emissions reported to us.[101] We did this by constructing a spreadsheet[102], which among other things, divides the annual SO_2 emissions by the theoretical uncontrolled SO_2 emissions based on coal sulfur content to estimate the percentage of SO_2 in the coal that is emitted. We calculated the theoretical uncontrolled SO_2 emissions from EIA reported coal sulfur data. This calculation is summarized below for a typical unit that burns both lignite and subbituminous coals:

(1) $\left\{ \frac{\left(\frac{\%\ [illegible]}{100}\ [illegible]\ 2000\ [illegible]\right) + \left(\frac{\%\ [illegible]}{100}\ [illegible]\ 2000\ [illegible]\right)}{\left([illegible] + [illegible]\right)} \right\}\ [illegible]\ \left(\frac{2\ [illegible]}{1\ [illegible]}\right)$

$= \frac{[illegible]\ 2\ [illegible]}{[illegible]}$

or, alternatively expressed in tons:

(2) $\frac{[illegible]\ 2\ [illegible]}{[illegible]}\ [illegible]\ \left(\frac{[illegible]}{[illegible]} + \frac{[illegible]}{[illegible]}\right)$

$= [illegible]\ 2\ [illegible]$

and the scrubber efficiency is then:

[99] See the Cost TSD in our Texas-Oklahoma FIP, Section 6.1. We incorporate the information in this document into our current proposal.
[100] EIA Form 923. Available at http://www.eia.gov/electricity/data/eia923/
[101] EPA Air Markets and Programs Data. Available at http://ampd.epa.gov/ampd/
[102] See "Coal vs CEM data 2009-2013.xlsx," tab "charts," cell H12.

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(3) [illegible] = 1 − ([illegible])

In equations (1) and (2), the percentage and tonnage values are those reported by the facility to the EIA for each fuel type. In equation (3), the annual EPA reported tons of SO_2 are those reported to us.[103]

We now update these calculations for 2011-2015 data.[104] The revised scrubber upgrade results for Martin Lake Units 1, 2, and 3; and Monticello Unit 3 are presented below in Table 31:

Table 31. Summary of Updated Scrubber Upgrade Results

Unit	2011-2015 3-yr Avg. SO_2 Emissions (eliminate max and min) (tons)	SO_2 Emissions at 95% Control (tons)	SO_2 Emissions Reduction Due to Scrubber Upgrade (tons)	SO_2 Emission Rate at 95% Control (lbs/MMBtu)
Monticello 3	8,136	1,180	6,956	0.05
Martin Lake 1	19,040	3,208	15,832	0.12
Martin Lake 2	17,973	3,393	14,580	0.12
Martin Lake 3	16,113	2,591	13,522	0.11
Total SO_2 Removed			50,890	

As we note above, we updated the cost effectiveness for each of these units. Because those calculations depended on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost effectiveness was $1,156/ton or less. We invite the facilities listed above to make arrangements with us to view our complete updated cost analysis for their units.

The Fayette (Sam Seymour) Units 1 and 2 are currently equipped with high performing wet FGDs. This can be seen from an examination of Figures 2 and 3 below:[105]

Figure 2: 30 BOD SO_2 Average for Fayette Unit 1

[103] EPA Air Markets and Programs Data. Available at http://ampd.epa.gov/ampd/
[104] See "Coal vs CEM data 2011-2015.xlsx.
[105] See the file, "Fayette emissions.xlsx."

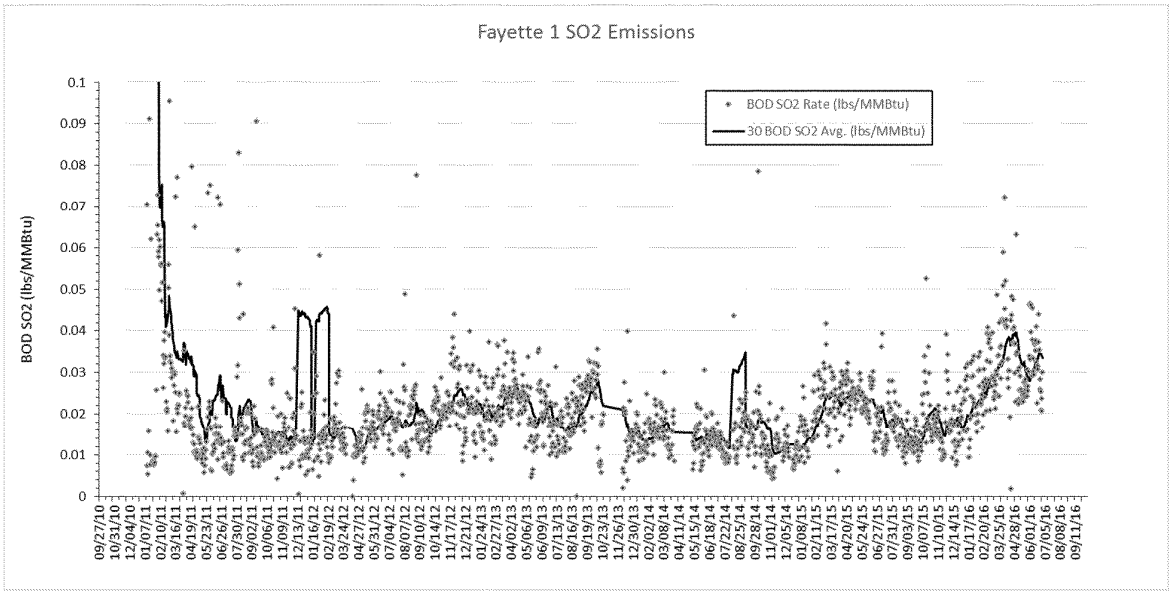
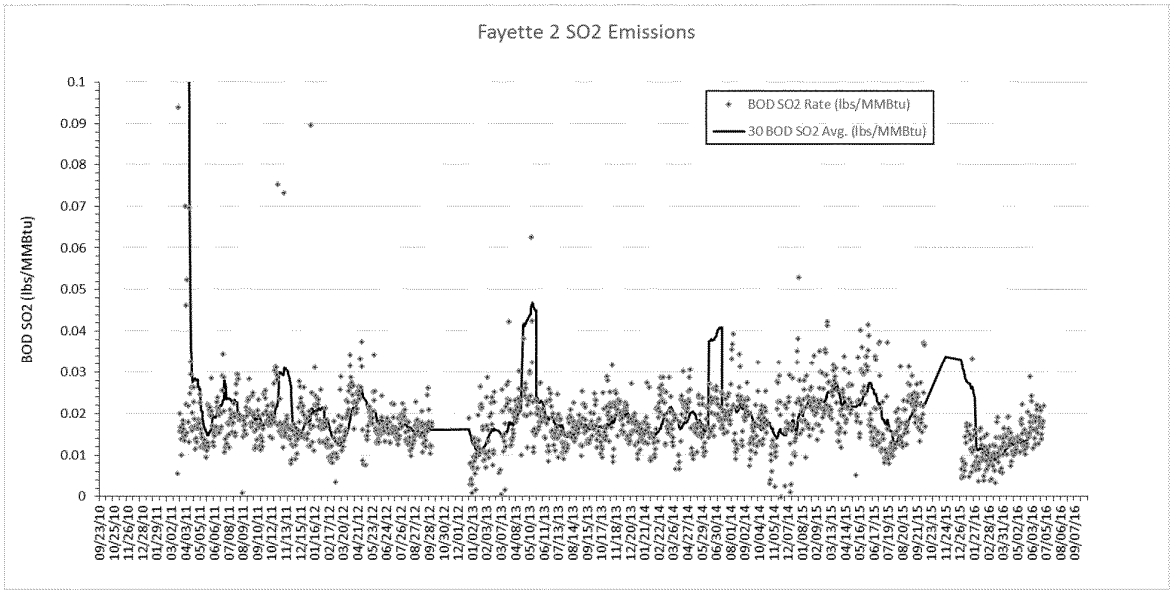


Figure 3: 30 BOD SO_2 Average for Fayette Unit 1



As can be seen from the above figures, the Fayette Units have both demonstrated the ability to maintain a SO_2 30 BOD average below 0.04 lbs/MMBtu for years at a time. As we discuss above, we evaluate BART demonstrating that retrofit wet FGDs should be evaluated at 98% control not to go below 0.04 lbs/MMBtu. Because the Fayette units are performing below this level, we propose that no scrubber upgrades are necessary. We propose to find that the Fayette Units 1 and 2 maintain a 30 Boiler Operating Day rolling average SO_2 emission rate of 0.04

lbs/MMBtu based on the actual emissions data we present above. We believe, based on its demonstrated ability to maintain an emission rate below this value on a 30 BOD basis, it can consistently achieve this emission level.

5.3.5 Impact Analysis Part 1 Cost of Compliance for Switching to a Lower Sulfur Fuel Oil for Gas-Fired Units

In section 5.1.2.1, we discussed the Section 114 letters we sent to a number of gas-fired facilities. Question 4 requested information on the cost of lower sulfur fuel oil. We received very limited information in response to Question 4. Because of this, we were unable to compile facility-specific information on the technical feasibility under BART of these facilities burning fuel oils of sulfur contents lower than historically burned.

However, information from the EIA indicates that fuel oil of varying sulfur contents is widely available across the U.S. EIA reports the prices for various refinery petroleum products on a monthly and annual basis. Below is summary of various distillate and residual fuel oil products for 2001 to 2015, averaged across the U.S."[106]

Table 32. Selected EIA Reported Annual Refiner Petroleum Prices

Date	West Texas Intermediate Crude Oil – Cushing Oklahoma ($/bbl)	U.S. No 2 Diesel Wholesale/Resale Price by Refiners ($/Gallon)	U.S. No. 2 Fuel Oil Wholesale/Resale Price by Refiners ($/Gallon)	U.S. No 4 Distillate Wholesale/Resale Price by Refiners ($/Gallon)
2015	48.66	1.667	1.565	1.215
2014	93.17	2.812	2.741	2.333
2013	97.98	3.028	2.966	2.767
2012	94.05	3.109	3.031	
2011	94.88	3.034	2.907	2.801
2010	79.48	2.214	2.147	
2009	61.95	1.713	1.657	1.561
2008	99.67	2.994	2.745	2.157
2007	72.34	2.203	2.072	1.551
2006	66.05	2.012	1.834	1.395
2005	56.64	1.737	1.623	1.377
2004	41.51	1.187	1.125	1.033
2003	31.08	0.883	0.881	0.793
2002	26.18	0.724	0.694	0.663
2001	25.98	0.784	0.756	0.697
2000	30.38	0.898	0.886	0.778

[106] EIA Refiner Petroleum Product Prices by Sales Type, available here: http://www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_a.htm; http://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm

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As can be seen from the above table, the price of these fuel oils closely tracks the price of crude oil, and are fairly volatile.

Lacking facility-specific pricing information, for the purposes of calculating the cost of compliance, we make the following assumptions:

- No. 4 distillate is the type of fuel oil currently available that most closely approximates the types of fuel oil that were historically burned by the facilities. It is available in a range of sulfur up to the facilities' permitted maximum of 0.7% sulfur by weight or 7,000 ppm. We will use the cost of this fuel oil along with the SO_2 baselines we discuss in the next section in constructing "business as usual" scenarios of the annual cost of fuel oil.
- No. 2 fuel oil is available at approximately 3,000 ppm, which roughly corresponds to the sulfur level present in No. 2 fuel oil prior to our implementation of the Ultra-Low-Sulfur Diesel (ULSD) regulations.[107] We will use the cost of this fuel oil along with the SO_2 baselines we discuss in the next section in constructing a "medium control" annual cost of fuel oil..
- No. 2 diesel fuel corresponds to ULSD, with a sulfur content of 15 ppm. We will use the cost of this fuel oil along with the SO_2 baselines we discuss in the next section in constructing a "high control" annual cost of fuel oil.

5.3.5.1 SO_2 Baseline for Gas-Fired Units that Occasionally Burn Oil

As we discuss in our DSI, SDA, and Wet FGD SO_2 BART analyses, for the coal-fired units we have analyzed under BART, we employed a baseline selected as the 2011 – 2015 five year average of the SO_2 annual emissions, excluding the maximum and minimum values. We do not believe that approach would be reasonable here, due to the unpredictable, random history of oil burning the units in question exhibit. For instance, the historical fuel oil burning practices of the Graham Unit 2 are presented below:[108]

Table 33. Graham Unit 2 Historic Fuel Oil Burning Practices

Year	Barrels of Fuel Oil Burned
2000	0
2001	31,500
2002	9,800
2003	23,300
2004	2,200
2005	25,219
2006	15,567
2007	2,971

[107] 69 FR 38957, 39073 (June 29, 2004): "Both high sulfur No. 2–D and No. 2 fuel oil must contain no more than 5000 ppm sulfur,131 and currently [as of the date of our final rule, 6/29/04] averages 3000 ppm nationwide."
[108] This and other baseline and emission data in this section can be found in the file, Gas-fired SO_2 emissions.xlsx" in our docket.

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2008	421
2009	0
2010	0
2011	19
2012	25,911
2013	0
2014	0
2015	0

Were we to adopt the same baseline calculation methodology we employed in our BART assessment of the coal units we analyzed, we would consider only the SO_2 resulting from the amount of oil burned from 2011 to 2015. We would eliminate the high SO_2 year (2012) and low SO_2 year (2013), and average the SO_2 from the remaining three years (2011, 2014, 2015), resulting in a baseline based on the SO_2 emissions resulting from burning 6.3 barrels of fuel oil. We conclude this result may not capture the BART Guidelines requirement that, "The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source."[109] Alternatively, we could examine the effect a range of different SO_2 baselines could have on the cost. For instance, we could evaluate SO_2 baselines based on the following three scenarios:

- The maximum annual SO_2 resulting from fuel oil burned from 2000 to 2015.
- An average of the SO_2 of any years from 2000 to 2015 when any fuel oil was burned.
- An average of the SO_2 from 2011 to 2015.

This information is presented below:

Table 34. SO_2 Baselines for Gas Fired Units that Occasionally Burn Oil

Unit	Max SO_2 tons (2000-2015)	Average SO_2 tons (2000-2015)	Average SO_2 tons (2011-2015)
Graham 2	1287.0	141.5	0.5
Newman 2	1.2	1.0	1.0
Newman 3	1.4	1.4	1.4
O W Sommers 1	54.8	12.3	1.9
O W Sommers 2	6.6	2.8	2.4
Stryker Creek 2	145.5	40.7	0
Wilkes 1	14.5	5.3	1.3

As can be seen from Table 34, with the exception of Graham Unit 2, the SO_2 emission baselines, regardless of the method employed, are very small. We would expect that regardless of the baseline selected, a cost-effectiveness calculation that simply depended on differing fuel oil costs and the resulting reductions in SO_2, would result in approximately the same value. In other words, the cost-effectiveness in $/ton should be independent of the SO_2 baseline, since *in this*

[109] 70 FR 39104, 39167 (July 6, 2005) [40 CFR Part 51, App. Y].

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case, it is calculated on a unit basis—the increased cost in burning a unit of fuel divided by the increased reduction in the resulting SO_2. Unfortunately, that does not occur, because we do not see a regular correspondence between the reported amount and sulfur content of the fuel oil burned with the reported SO_2 emissions. In other words, according to the data a barrel of fuel oil burned with about the same sulfur content does not result in the same amount of SO_2 emitted over time, nor does the expected trend always occur in the right direction. This can be illustrated by examining selected EIA and monitoring data for the Graham Unit 2:

Table 35. Graham Unit 2 Example Discordance in Fuel Oil Burned and Reported SO_2

Date (month/year)	Quantity Fuel Oil Burned (bbls)	Reported SO_2 emissions for month (tons)	Reported EIA sulfur content (wt%)
Mar-02	9,800	21.614	0.65
Feb-03	8,400	90.389	0.66
Jun-12	18,177	0.064	0.50
Jul-12	5,657	0.07	0.50

As can be seen from the above table, even though the reported sulfur content of the fuel oil in March, 2002 and February 2003 was approximately the same, and the quantity burned was fairly close, the resulting reported SO_2 was significantly different. Similarly, although the amount of fuel oil burned in June, 2012 was more than three times that burned in July 2012 (at the same sulfur content), the reported SO_2 in June 2012 was less than that in July 2012. Also, although the fuel oil sulfur content in the 2012 examples was only slightly less than that in the 2002/2003 examples, and the amount of fuel oil burned was the same order of magnitude, the resulting reported SO_2 in 2012 was three orders of magnitude less than that in 2002/2003. Further examination of the CAMD emissions data for Graham and Stryker revealed that the data contained a large amount of substitute data for SO_2 emissions and heat input during periods when the units burned fuel oil. Some of these substitute values were much higher than the maximum potential emissions from the units.[110] As a result of these issues, we cannot construct reasonable SO_2 baselines for the gas fired units that occasionally burn fuel oil. This impacts both the visibility modeling and the control cost analyses we perform on these units causing us to adopt alternative approaches.

5.3.5.2 Cost Analysis for Gas-Fired Units that Occasionally Burn Oil

As a consequence of this discordance between the reported type and amount of fuel oil burned and the reported SO_2, we cannot rely on historical SO_2 emissions to construct a baseline, because a barrel of fuel oil with a given reported sulfur content does not result in a consistent reported SO_2 value over time. Instead, we will conduct our cost-effectiveness analysis on the basis of unit values of 1,000 barrels, using the following assumptions:

- Fuel oil costs can be based on the 2015 U.S. average prices as reported in Table 32 for No. 4 distillate at 0.7 wt. % (the permitted maximum for all units) as the current business

[110] See the file, "Gas-fired SO2 emissions comparison and calcs.xlsx," in our docket for emission data.

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as usual fuel, No. 2 fuel oil at 0.3wt. % as the moderate control option, and No. 2 diesel at 0.0015% as the high control option.

- The emission factor for calculating the tons of sulfur emitted by the three fuel oils can be taken from AP 42.[111]

Below is the result of that calculation:

Table 36. Cost Effectiveness of Switching to Lower Sulfur Fuel Oils

	Cost for 1,000 barrels baseline ($/yr)	**Tons reduced for 1,000 barrels**	**Cost effectiveness for 1,000 barrels ($/ton)**
Business as usual (No. 4 distillate $1.215/gal)	$51,030	N/A	N/A
Moderate control (No. 2 fuel oil $1.565/gal)	$65,730	1.26	$11,218
High control (ULSD $1.667/gal)	$70,014	2.20	$8,627

Although the cost-effectiveness of switching to a lower sulfur oil is less attractive (higher $/ton) than other controls we have typically required under BART, we note certain mitigating factors. For instance, unlike the wet FGD and SDA scrubbers we have costed in other sections of this TSD, which have large capital costs, we are unaware of any significant capital costs involved in switching fuels. Also, because the units in question have only occasionally burned fuel oil, they have the option to avoid the cost of fuel switching entirely by not continuing to burn fuel oil and instead relying on their primary fuel of natural gas. Lastly, we note that the prevalence of ULSD in the fuel oil market is such that it appears to be gradually replacing most other No. 2 fuel oil applications.[112] In fact, in responding to our Section 114 letter, the Wilkes facility stated that its current contract was for ULSD.

In Section 5.1.2.1, we concluded that certain types of wet scrubbers were technically feasible as potential control options for gas boilers that occasionally burn oil, similar to the ones under BART review here. Were we to calculate the cost effectiveness of a wet FGD, similar to those under consideration for the coal units undergoing BART review, we could expect that the capital and operating costs would minimally be on the same order, as displayed in Table 29. It is a straightforward exercise to demonstrate that the installation of such a scrubber on any of the gas-fired units that occasionally burn oil is not cost-effective.

For instance, taking the smallest total annualized cost in Table 29, corresponding to the Harrington Unit 0161B (approximately the same size as the Graham Unit 2), results in a value of $19,145,500. Assuming a 98% reduction from a baseline equal to the largest annual SO_2 emissions from any of the gas units, 1,287 tons/year (Graham Unit 2, 2001), results in a SO_2

[111] The emission factor used is 150 X S, where S = weight % sulfur, taken from AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.3, Fuel Oil Combustion, available here: https://www3.epa.gov/ttn/chief/ap42/ch01/index.html. Boilers > 100 Million Btu/hr,, No. 4 oil fired.
[112] http://www.eia.gov/todayinenergy/detail.php?id=5890. http://blogs.platts.com/2014/05/07/heating-oil-new-york-sulfur/. http://oilandenergyonline.com/challenges-to-the-northeast-supply-picture/

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reduction of 1,261 tons/year. The cost-effectiveness is then $15,183/ton. We do not consider this to be cost effective. In addition, the annual SO_2 values for Graham Unit 2 from 2002 to 2015, and the annual SO_2 values for the remaining units, have always been an order of magnitude less than the 2001 Graham Unit 2 value. Indeed, as we discuss above, we suspect that the Graham Unit 2's reported SO_2 tonnage from 2001 is incorrect.

5.3.6 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 BART analyses in the following manner:

- For all uncontrolled coal-fired units undergoing SO_2 BART analysis, we have calculated the incremental cost-effectiveness of DSI_{50} to $DSI_{80/90}$, $DSI_{80/90}$ to SDA, and SDA to wet FGD.
- For all gas-fired units that occasionally burn oil, we have calculated the incremental cost-effectiveness of burning fuel oil with a sulfur content of 0.3% to a fuel oil with a sulfur content of 0.0015%.

This information is presented below:

Table 37. Summary of Coal-Fired EGU SO_2 BART Incremental Cost-Effectiveness

Facility	Unit	Control	Control level (%)	SO_2 reduction (tpy)	2016 Annualized Cost	2016 Cost Effectiveness ($/ton)	2016 Incremental Cost-Effectiveness ($/ton)
Big Brown	1	DSI	50	14,448	$29,468,587	$2,040	
		DSI	90	26,006	$72,131,749	$2,774	$3,691
		SDA	95	27,453	$35,297,532	$1,286	-$25,456
		Wet FGD	98	28,320	$33,673,102	$1,189	-$1,874
	2	DSI	50	15,320	$29,342,350	$1,915	

		DSI	90	27,576	$71,322,593	$2,586	$3,425
		SDA	95	29,108	$35,359,239	$1,215	-$23,475
		Wet FGD	97.9	29,998	$33,817,952	$1,127	-$1,732
Monticello	1	DSI	50	4,787	$11,408,872	$2,383	
		DSI	90	8,617	$25,409,128	$2,949	$3,655
		SDA	95	9,095	$24,294,319	$2,671	-$2,332
		Wet FGD	97	9,286	$25,236,699	$2,718	$4,934
	2	DSI	50	4,129	$9,742,648	$2,360	
		DSI	90	7,431	$21,418,734	$2,882	$3,536
		SDA	95	7,844	$23,126,113	$2,948	$4,134
		Wet FGD	96.8	7,995	$24,233,133	$3,031	$7,331
Coleto Creek	1	DSI	50	7,376	$16,246,169	$2,203	
		DSI	90	13,277	$34,841,379	$2,624	$3,151
		SDA	92.4	13,632	$29,445,018	$2,160	-$15,201
		Wet FGD	94.9	14,005	$29,786,106	$2,127	$914
Harrington	061 B	DSI	50	2,477	$9,187,608	$3,710	
		DSI	80	3,962	$16,073,779	$4,057	$4,637
		SDA	90.2	4,466	$17,455,679	$3,909	$2,742
	062 B	DSI	50	2,455	$6,524,937	$2,658	
		DSI	**88.9**	4,364	$11,981,111	$2,746	$2,858
		SDA	88.9	4,364	$18,240,127	$4,180	N/A
J T Deely	1	DSI	50	3,072	$8,854,319	$2,883	
		DSI	90	5,529	$18,071,878	$3,269	$3,752
		SDA	91.3	5,609	$21,689,526	$3,867	$45,221
		Wet FGD	94.2	5,787	$22,555,395	$3,898	$4,864
	2	DSI	50	3,222	$9,865,798	$3,062	
		DSI	90	5,800	$20,229,233	$3,488	$4,020
		SDA	91.3	5,884	$21,812,518	$3,707	$18,849
		Wet FGD	94.2	6,070	$22,530,901	$3,712	$3,862
Welsh	1	DSI	50	3,343	$8,963,761	$3,469	
		DSI	**87.2**	5,832	$23,090,408	$3,960	$5,676
		SDA	87.2	5,832	$22,697,048	$3,892	N/A
		Wet FGD	91.5	6,116	$23,998,161	$3,924	$4,581
W. A. Parish	5	DSI	50	6,712	$15,002,337	$2,235	
		DSI	90	12,081	$30,865,711	$2,555	$2,955
		SDA	92.1	12,364	$31,195,787	$2,523	$1,166
		Wet FGD	94.7	12,717	$30,735,030	$2,417	-$1,305
	6	DSI	50	7,525	$16,014,988	$2,128	
		DSI	90	13,545	$33,302,528	$2,459	$2,872
		SDA	92.1	13,862	$32,758,784	$2,363	-$1,715
		Wet FGD	94.7	14,258	$32,215,226	$2,259	-$1,373

Table 38. Summary of Oil-Fired EGU SO_2 BART Incremental Cost-Effectiveness

	Cost for 1,000 barrels baseline ($/yr)	Tons reduced for 1,000 barrels	Cost effectiveness for 1,000 barrels ($/ton)	Incremental Cost-Effectiveness ($/ton)
Business as usual (No. 4 distillate $1.215/gal)	$51,030	N/A	N/A	
Moderate control (No. 2 fuel oil $1.565/gal)	$65,730	1.26	$11,218	
High control (ULSD $1.667/gal)	$70,014	2.20	$8,627	-$2,756

5.3.7 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."[113] 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 all cases. 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:[114]

> 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 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

[113] 70 FR 39104, 39168 (July 6, 2005) [40 CFR Part 51, App. Y].
[114] *Id.* At 39169.

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> create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control alternative as BART.

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 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. Consequently, we believe that with one possible exception, any non-air quality environmental impacts have been adequately considered in our analyses. We are aware that the Harrington facility has instituted a water recycling program and obtains some of its water from the City of Amarillo.[115] Due to potential non-air quality concerns, we limit our SO_2 control analysis for Harrington to DSI and dry scrubbers.

Regarding the remaining useful life, the BART Guidelines advise:[116]

> 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 any of the facilities we have analyzed for BART have entered into or offered to enter into enforceable commitments to shut down the applicable units 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 proper.

5.4 BART Five Factor Analysis for PM

In our recent Texas-Oklahoma FIP, we initially proposed to approve Texas' determination that no PM BART controls were appropriate for its EGUs, based on a screening analysis of the visibility impacts from just PM emissions and the premise that EGU SO_2 and NO_X were covered separately by participation in CSAPR (allowing consideration of PM emissions in isolation). Because of the CSAPR remand and resulting uncertainty regarding SO_2 and NO_X BART for EGUs, we decided not to finalize our proposed approval of Texas' PM BART determination.[117]

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[115] http://www.powermag.com/xcel-energys-harrington-generating-station-earns-powder-river-basin-coal-users-group-award/.
[116] 70 FR 39104, 39169 (July 6, 2005) [40 CFR Part 51, App. Y].
[117] 81 FR 302 (January 5, 2016).

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For reasons earlier stated we are proposing to disapprove the SIP determination regarding PM BART for EGUs. Following from that proposed disapproval, we are proposing a PM BART FIP for those Texas EGUs that are subject to BART.

The BART Guidelines permit us to conduct a streamlined analysis of PM BART in two key ways. First, the Guidelines allow a streamlined analysis for PM sources subject to MACT standards. Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, the Guidelines state it is permissible to rely on MACT standards for purposes of BART.[118]

Second, with respect to gas-fired units, which have inherently low emissions of PM (as well as SO_2), the Regional Haze Rule did not specifically envision new or additional controls or emissions reductions from the PM BART requirement. The BART guidelines preclude us from stating that PM emissions are *de minimis* when plant-wide emissions exceed 15 tons per years. While we must assign PM BART determinations to the gas-firing units, there are no practical add-on controls to consider for setting a more stringent PM BART emissions limit. The Guidelines state that if the most stringent controls are made federally enforceable for BART, then the otherwise required analyses leading up to the BART determination can be skipped.[119]

With this background, we are providing our evaluation along with some supplementary information on the BART sources as divided into two categories: coal-fired EGUs, and gas-fired EGUs.

5.4.1 BART Five Factor Analysis for PM for Coal-Fired Units

All of the coal-fired EGUs that are subject to BART are currently equipped with either Electrostatic Precipitators (ESPs) or baghouses, or both as can be seen from Table 39:

Table 39. Current PM Controls for Coal-Fired Units Subject to BART

Facility Name	Unit ID	Fuel Type (Primary)	SO_2 Control(s)	PM Control(s)
Big Brown	1	Coal		Baghouse +Electrostatic Precipitator
Big Brown	2	Coal		Baghouse + Electrostatic Precipitator
Coleto Creek	1	Coal		Baghouse
Harrington Station	061B	Coal		Electrostatic Precipitator
Harrington Station	062B	Coal		Baghouse
J T Deely	1	Coal		Baghouse
J T Deely	2	Coal		Baghouse

[118] 70 FR 39163-39164
[119] 70 FR 39165 ("…you may skip the remaining analyses in this section, including the visibility analysis…")

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Martin Lake	1	Coal	Wet Limestone	Electrostatic Precipitator
Martin Lake	2	Coal	Wet Limestone	Electrostatic Precipitator
Martin Lake	3	Coal	Wet Limestone	Electrostatic Precipitator
Monticello	1	Coal		Baghouse + Electrostatic Precipitator
Monticello	2	Coal		Baghouse + Electrostatic Precipitator
Monticello	3	Coal	Wet Limestone	Electrostatic Precipitator
Fayette	1	Coal	Wet Limestone	Electrostatic Precipitator
Fayette	2	Coal	Wet Limestone	Electrostatic Precipitator
W A Parish	WAP5	Coal		Baghouse
W A Parish	WAP6	Coal		Baghouse
Welsh Power Plant	1	Coal		Baghouse (Began Nov 15, 2015) + Electrostatic Precipitator

As an initial matter, we examine the control efficiencies of both baghouses and ESPs. We consider a baghouse, widely reported to be capable of 99.9% control of PM, to be a BART-level control for PM and so the units equipped with a baghouse will not be further analyzed for PM BART. The remaining units are fitted with ESPs.

The particulate matter control efficiency of ESPs varies somewhat with the design, the resistivity of the particulate matter, and the maintenance of the ESP. We do not have any information on the control level efficiency of any of the ESPs for the units in question. However, reported control efficiencies for well-maintained ESPs typically range from greater than 99% to 99.9%.[120] We conclude that the potential additional particulate control that a baghouse can offer over an ESP is relatively minimal.[121]

Nevertheless, we will examine the potential cost of retrofitting a typical 500 MW coal fired unit. Using our baghouse cost algorithms, as employed in version 5.13 of our IPM model,[122] and

[120] EPA, "Air Pollution Control Technology Fact Sheet: Dry Electrostatic Precipitator (ESP) - Wire Plate Type," EPA-452/F-03-028. Grieco, G., "Particulate Matter Control for Coal-fired Generating Units: Separating Perception from Fact," apcmag.net, February, 2012. Moretti, A. L.; Jones, C. S., "Advanced Emissions Control Technologies for Coal-Fired Power Plants, Babcox and Wilcox Technical Paper BR-1886, Presented at Power-Gen Asia, Bangkok, Thailand, October 3-5, 2012

[121] We do not discount the potential health benefits this additional control can have for ambient PM. However, the regional haze program is only concerned with improving the visibility at Class I areas.

[122] IPM Model – Updates to Cost and Performance for APC Technologies, Particulate 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 5-7: PM Cost Methodology, downloaded from: https://www.epa.gov/sites/production/files/2015-08/documents/attachment_5-7_pm_cost_methodology.pdf

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assuming a conservative air to cloth ration of 6.0, results in a capital engineering and construction cost of $77,428,000.[123] Applied to the subject units, this cost assumes a retrofit factor of 1.0, and does not consider the demolition of the existing ESP, should it be required in order to make space for the baghouse.

We do not calculate the cost-effectiveness resulting from replacing an ESP with a baghouse. However, we expect that the tons of additional PM removed by a baghouse over an ESP to be very small, which would result in a very high cost-effectiveness figure. Also, we do not model the visibility benefit of replacing an ESP with a baghouse. However, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from replacing an ESP with a baghouse to be a small fraction of that. For instance, our CAMx baseline modeling shows that on a source-wide level, impacts from PM emissions on the maximum impacted days from each source at each Class I area was 3% of the total visibility impairment or less (calculated as percent of total extinction due to the source). Therefore, additional PM controls are anticipated to result in very little visibility benefit on the maximum impacted days. Similarly, our CALPUFF modeling indicates that visibility impairment from PM is also a small fraction (typically only a few percent) of the total visibility impairment due to each source.

Adding to the above discussion, we are tasked to assign the enforceable emission limitations that constitute PM BART. We believe a stringent control level that would be met with existing or otherwise-required controls is a filterable PM limit of 0.03 lb/MMBtu for each of the coal-fired units subject to BART. We note that the Mercury and Air Toxics (MATS) Rule establishes an emission standard of 0.03 lb/MMBtu filterable PM (as a surrogate for toxic non-mercury metals) as representing Maximum Achievable Control Technology (MACT) for coal-fired EGUs.[124] This standard derives from the average emission limitation achieved by the best performing 12 percent of existing coal-fired EGUs, as based upon test data used in developing the MATS Rule. We are not familiar with any new technologies subsequent to this standard that could lead to any cost effective increases in the level of control; thus, consistent with the BART Guidelines, we are proposing to rely on this limit for purposes of PM BART for all of the coal-fired units as part of our FIP. We understand the coal-fired units covered by this proposal to be subject to MATS, but to the extent the units may be following alternate limits that differ from the surrogate PM limits found in MATS, we welcome comments on different, appropriately stringent limits reflective of current control capabilities.[125] Because we anticipate that any limit we assign should be achieved by current control capabilities, we propose that compliance can be met at the effective date of the rule. To address periods of startups and shutdowns, we are further proposing that PM BART for these units will additionally be met by following the work practice standards specified in 40 CFR Part 63, subpart UUUUU, Table 3, and using the relevant definitions in 63.10042. We are proposing that the demonstration of compliance can be satisfied by the methods for demonstrating compliance with filterable PM limits that are specified in 40 CFR Part 63, subpart

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[123] Id. See page 9.

[124] 77 FR 9304, 9450, 9458 (February 16, 2012) (codified at 40 CFR 60.42 Da(a), 60.50 Da(b)(1)); 40 CFR Part 63 Subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units.

[125] The various limits are provided at 40 CFR Part 63, Subpart UUUUU, Table 2 ("Emission Limits for Existing EGUs")

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UUUUU, Table 7. However, we would give consideration to commenter-submitted requests for alternate or additional methods of demonstrating compliance.

5.4.2 BART Five Factor Analysis for PM for Gas-Fired Units

In Section 5.1.2, we noted that four of the units identified in Table 10 as being subject to BART, are only permitted to burn gas: Newman Unit 4, W A Parish Unit 4, and Wilkes Units 2 and 3. We note that PM emissions for the gas-only fired units that are subject to BART are inherently low.[126] We therefore conclude that PM emissions from natural gas firing is so minimal that the installation of any additional PM controls on the unit would likely achieve very low emissions reductions and have minimal visibility benefits. As there are no appropriate add-on controls and the status quo reflects the most stringent controls, we are proposing to make the requirement to burn pipeline natural gas federally enforceable. We note that in addition to satisfying PM BART, this limitation will also serve to satisfy SO_2 BART for these gas-fired units, as well as the fuel-oil units when they fire natural gas. We are proposing that PM and SO_2 BART for gas fired-units will limit fuel to pipeline natural gas, as defined at 40 CFR 72.2.

The available PM controls for gas units that also burn fuel oil are the same for the coal-fired units. We would expect similar costs for installing a baghouse on a typical gas-fired boiler that occasionally burns fuel oil. Again, our visibility impact modeling indicates that the baseline PM emissions of these units are very small, so we expect that the visibility improvement from the installation of a baghouse to be a small fraction on the order of 1-3 % of the visibility impacts from the facility. We are confident that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted with an ESP. We conclude that the cost of a baghouse does not justify the minimal expected improvement in visibility for these units. Accordingly, we are proposing that the fuel content limits for oil burning that we propose to meet SO_2 BART will also satisfy PM BART.

Lastly, should our assumptions regarding the frequency and type of fuel oil burned in these units significantly change, we expect that Texas will address such a change appropriately in its SIP, which we will review in the next planning period.

5.5 Step 5: Evaluate Visibility Impacts

Please see the BART Modeling TSD, where we describe in detail the various modeling runs we conducted, our methodology and selection of emission rates, modeling results, and final modeling analysis that we used to evaluate the benefits of the proposed controls and their associated emission decreases on visibility impairment values. 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.

5.5.1 Visibility Benefits of DSI, SDA, and Wet FGD for Coal-Fired Units

We evaluated the visibility benefits of DSI, for the twelve units depicted in Tables 40 and 41

[126] AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.4, Natural Gas Combustion, available here: https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.

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below that currently have no SO_2 control. We evaluated all the units using the control levels we employed in our control cost analyses. In summary, we evaluated these units at a DSI SO_2 control level of 50%, which we believe is likely achievable for any unit. At the lower performance level we assumed, we conclude that the corresponding visibility benefits from DSI in most cases would be close to half of the benefits from scrubbers resulting in the visibility benefits from scrubber retrofits being much more beneficial. We also evaluated the visibility benefits for scrubber retrofits (wet FGD and SDA) for these same units, assuming the same control levels corresponding to SDA and wet FGD that we used in our control cost analyses. For those sources that are within 50 to 400 km of a Class I area, we utilized CALPUFF modeling and supplemented our analysis with CAMx modeling to assess the visibility benefit of potential controls. For the remaining coal-fired sources (J T Deely, Coleto Creek, Fayette and W A Parish), only CAMx modeling was utilized as these sources are located at much greater distances to the nearest Class I areas. 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.[127] We note that high control scenario modeling for Fayette units 1 and 2 demonstrate the benefit from existing high performing controls. As discussed elsewhere, we found that for these units no additional controls or upgrades were necessary. For a full discussion of our review of all the modeling results, and factors that we considered in evaluating and weighing all the results, see our BART Modeling TSD. Below, we present a summary of some of those visibility benefits at the Class I areas most impacted by each source:

Table 40. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CAMx modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD(98%)	DSI benefit	WFGD benefit
Big Brown	Source (Unit 1 and 2)	WIMO	Max dv	4.017	2.249	0.474	1.768	3.542
			Days > 0.5 dv	65	33	0	32	65
			Days>1.0 dv	33	13	0	20	33
		CACR	Max dv	3.775	2.539	0.787	1.236	2.988
			Days > 0.5 dv	91	62	4	29	87
			Days>1.0 dv	57	21	0	36	57
	Unit 1	WIMO	Max dv	2.154	1.168	0.245	0.986	1.909
			Days > 0.5 dv	33	13	0	20	33
			Days>1.0 dv	12	1	0	11	12
		CACR	Max dv	2.016	1.327	0.409	0.688	1.606
			Days > 0.5 dv	58	22	0	36	58
			Days>1.0 dv	17	4	0	13	17
	Unit 2	WIMO	Max dv	2.175	1.181	0.235	0.994	1.940
			Days > 0.5 dv	34	13	0	21	34
			Days>1.0 dv	12	1	0	11	12

[127] 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."

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		CACR	Max dv	2.033	1.338	0.391	0.695	1.642
			Days > 0.5 dv	58	23	0	35	58
			Days>1.0 dv	17	4	0	13	17
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63
			Days>1.0 dv	40	14	0	26	40
	Unit 1	CACR	Max dv	4.516	3.123	0.733	1.393	3.783
			Days > 0.5 dv	79	43	3	36	76
			Days>1.0 dv	32	16	0	16	32
		WIMO	Max dv	2.241	1.290	0.252	0.951	1.989
			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	8	2	0	6	8
	Unit 2	CACR	Max dv	4.487	3.065	0.563	1.422	3.924
			Days > 0.5 dv	78	42	1	36	77
			Days>1.0 dv	30	13	0	17	30
		WIMO	Max dv	2.189	1.252	0.186	0.937	2.003
			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	6	2	0	4	6
Coleto Creek	Source (Unit 1)	WIMO	Max dv	0.845	0.526	0.176	0.318	0.668
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.791	0.458	0.186	0.333	0.606
			Days > 0.5 dv	5	0	0	5	5
			Days>1.0 dv	0	0	0	0	0
Harrington[1]	Source (Unit 061B & 062B)	SACR	Max dv	5.288	4.287	3.235	1.001	2.053
			Days > 0.5 dv	13	7	3	6	10
			Days>1.0 dv	5	1	1	4	4
		WIMO	Max dv	4.928	4.362	3.798	0.565	1.130
			Days > 0.5 dv	15	11	6	4	9
			Days>1.0 dv	6	5	4	1	2
	Unit 061B	SACR	Max dv	2.908	2.322	1.738	0.586	1.170
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.708	2.382	2.065	0.326	0.643
			Days > 0.5 dv	6	5	4	1	2
			Days>1.0 dv	4	2	1	2	3
	Unit 062B	SACR	Max dv	2.998	2.373	1.719	0.625	1.279
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.770	2.407	2.046	0.363	0.723

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			Days > 0.5 dv	6	5	4	1	2
			Days>1.0 dv	4	1	1	3	3
J T Deely	Source (Sommers 1&2, J T Deely 1&2)	WIMO	Max dv	1.513	0.939	0.814	0.574	0.699
			Days > 0.5 dv	47	8	1	39	46
			Days>1.0 dv	6	0	0	6	6
		CACR	Max dv	1.423	1.155	0.905	0.268	0.518
			Days > 0.5 dv	7	3	2	4	5
			Days>1.0 dv	2	1	0	1	2
	J T Deely 1	WIMO	Max dv	0.757	0.449	0.270	0.307	0.487
			Days > 0.5 dv	4	0	0	4	4
			Days>1.0 dv	0	0	0	0	0
		BIBE	Max dv	0.652	0.373	0.069	0.279	0.583
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
	J T Deely 2	WIMO	Max dv	0.632	0.387	0.334	0.245	0.298
			Days > 0.5 dv	3	0	0	3	3
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.604	0.490	0.387	0.114	0.217
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
W.A. Parish	Source (WAP 4,5, &6)	CACR	Max dv	3.177	2.032	0.511	1.145	2.665
			Days > 0.5 dv	54	26	1	28	53
			Days>1.0 dv	22	9	0	13	22
		UPBU	Max dv	1.994	1.215	0.234	0.779	1.760
			Days > 0.5 dv	34	14	0	20	34
			Days>1.0 dv	9	1	0	8	9
	WAP 5	CACR	Max dv	1.698	1.052	0.180	0.646	1.518
			Days > 0.5 dv	22	9	0	13	22
			Days>1.0 dv	8	1	0	7	8
		UPBU	Max dv	1.038	0.613	0.094	0.424	0.943
			Days > 0.5 dv	11	1	0	10	11
			Days>1.0 dv	1	0	0	1	1
	WAP 6	CACR	Max dv	1.648	1.018	0.156	0.630	1.492
			Days > 0.5 dv	22	8	0	14	22
			Days>1.0 dv	6	1	0	5	6
		UPBU	Max dv	1.003	0.591	0.081	0.412	0.922
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	1	0	0	1	1
Welsh[2]	Source (Unit 1 & 2)	CACR	Max dv	4.576		0.822		3.754
			Days > 0.5 dv	92		3		89
			Days>1.0 dv	39		0		39
		MING	Max dv	2.544		0.570		1.973
			Days > 0.5 dv	9		1		8

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			Days>1.0 dv	3		0		3
	Unit 1	CACR	Max dv	2.343	1.659	0.822	0.684	1.521
			Days > 0.5 dv	37	18	3	19	34
			Days>1.0 dv	8	3	0	5	8
		MING	Max dv	1.150	0.886	0.570	0.264	0.579
			Days > 0.5 dv	2	1	1	1	1
			Days>1.0 dv	1	0	0	1	1
Fayette[2]	Source (Unit 1 & 2)	CACR	Max dv	1.894		0.903		0.991
			Days > 0.5 dv	26		2		24
			Days>1.0 dv	9		0		9
		WIMO	Max dv	1.175		0.580		0.595
			Days > 0.5 dv	19		1		18
			Days>1.0 dv	2		0		2
	Unit 1	CACR	Max dv	1.002		0.480		0.522
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	1		0		1
		WIMO	Max dv	0.609		0.306		0.302
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0
	Unit 2	CACR	Max dv	0.974		0.441		0.534
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	0		0		0
		WIMO	Max dv	0.598		0.282		0.316
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0

[1] Harrington high control scenario for both units is SDA at 95% reduction

[2] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD (wet FGD) installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.

Table 41. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Units 1 and 2)	WIMO	Max dv	4.27	2.54	0.43	1.73	3.83
			Days > 0.5 dv Avg.	67.33	43.33	2.67	24.00	64.67
			Days>1.0 dv Avg.	42.00	21.00	1.00	21.00	41.00
		CACR	Max dv	4.03	2.41	0.47	1.62	3.55
			Days > 0.5 dv Avg.	67	64.33	4.67	27.33	87.00

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			Days>1.0 dv Avg.	60.33	30.00	0.00	30.33	60.33
Monticello[1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	3.68	1.70	4.16	4.87
			Days > 0.5 dv Avg.	143.67	115.00	62.33	28.67	81.33
			Days>1.0 dv Avg.	113.00	66.33	23.67	46.67	89.33
		UPBU[4]	Max dv	3.45	1.77	0.77	1.68	2.68
			Days > 0.5 dv Avg.	103.00	61.00	13.67	42.00	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60.00	34.67	6.00	25.33	54.00
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67
Harrington[2]	Source (Units 061B & 062B)	SACR	Max dv	1.06	0.86	0.61	0.20	0.45
			Days > 0.5 dv Avg.	21.00	15.33	6.33	5.67	14.67
			Days>1.0 dv Avg.	6.67	3.00	0.67	3.67	6.00
		WIMO	Max dv	1.29	0.97	0.55	0.32	0.74
			Days > 0.5 dv Avg.	26.00	15.33	8.67	10.67	17.33
			Days>1.0 dv Avg.	9.00	4.67	1.33	4.33	7.67
Welsh[3]	Source (Unit 1)	CACR	Max dv	1.44	1.12	0.72	0.32	0.72
			Days > 0.5 dv Avg.	50.33	32.67	12.33	17.67	38
			Days>1.0 dv Avg.	15.33	8.00	2.33	7.33	13.00
		UPBU	Max dv	0.76	0.49	0.22	0.27	0.54
			Days > 0.5 dv Avg.	12.00	4.67	0.33	7.33	11.67
			Days>1.0 dv Avg.	0.67	0.00	0.00	0.67	0.67
		WIMO	Max dv	0.56	0.33	0.15	0.23	0.41

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			Days > 0.5 dv Avg.	7.33	2.67	0.33	4.67	7.00
			Days>1.0 dv Avg.	1.33	0.33	0.00	1.00	1.33

[1] Monticello's controlled level is a combination of scrubber upgrades and scrubber install in the facility impact modeling with CALPUFF.
[2] Harrington high control scenario for both units is SDA at 95% reduction
[3] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.
[4] UPBU = Upper Buffalo Wilderness Area.

5.5.2 Visibility Benefits of Scrubber Upgrades for Coal-Fired Units

We also modeled the visibility benefits of those same units for which we conducted control cost analysis for upgrading their existing scrubbers. We assumed the same 95% control level we used in our control cost analyses. We also modeled a lower level control at 90%. The visibility benefits from these scrubber upgrades are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits and reduction in number of days impacted.

Table 42. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CAMx modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	90% Control	95% Control	90% benefit	95% benefit
Martin Lake	Source (Unit 1, 2 & 3)	CACR	Max dv	6.651	4.491	4.321	2.159	2.329
			Days > 0.5 dv	141	75	56	66	85
			Days>1.0 dv	99	31	16	68	83
		UPBU	Max dv	5.803	2.669	2.528	3.134	3.275
			Days > 0.5 dv	99	39	22	60	77
			Days>1.0 dv	67	11	7	56	60
	Unit 1	CACR	Max dv	2.633	1.550	1.468	1.083	1.165
			Days > 0.5 dv	71	17	6	54	65
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.254	0.867	0.805	1.387	1.449
			Days > 0.5 dv	44	6	3	38	41
			Days>1.0 dv	10	0	0	10	10
	Unit 2	CACR	Max dv	2.466	1.882	1.811	0.585	0.655
			Days > 0.5 dv	68	18	9	50	59
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.189	1.077	1.025	1.112	1.164
			Days > 0.5 dv	40	6	5	34	35
			Days>1.0 dv	10	1	1	9	9
	Unit 3	CACR	Max dv	2.755	1.682	1.609	1.074	1.146
			Days > 0.5 dv	76	15	6	61	70
			Days>1.0 dv	29	2	1	27	28

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		UPBU	Max dv	2.368	0.942	0.890	1.425	1.478
			Days > 0.5 dv	46	6	4	40	42
			Days>1.0 dv	13	0	0	13	13
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63
			Days>1.0 dv	40	14	0	26	40
	Unit 3	CACR	Max dv	4.632	0.905	0.914	3.728	3.719
			Days > 0.5 dv	79	5	5	74	74
			Days>1.0 dv	32	0	0	32	32
		WIMO	Max dv	2.282	0.462	0.364	1.820	1.918
			Days > 0.5 dv	31	0	0	31	31
			Days>1.0 dv	7	0	0	7	7

Table 43. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Units 1, 2 & 3)	CACR	Max dv	4.46	2.27	1.86	2.18	2.60
			Days > 0.5 dv Avg.	129.67	77.33	63.00	52.33	66.67
			Days>1.0 dv Avg.	91.33	32.67	22.33	58.67	69.00
		UPBU	Max dv	2.73	1.10	0.85	1.63	1.88
			Days > 0.5 dv Avg.	81.67	30.33	18.67	51.33	63.00
			Days>1.0 dv Avg.	46.67	7.33	3.67	39.33	43.00
Monticello [1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	3.68	1.70	2.89	4.87
			Days > 0.5 dv Avg.	143.67	115	62.33	28.67	81.33
			Days>1.0 dv Avg.	113	66.33	23.67	46.67	89.33
		UPBU	Max dv	3.45	1.77	0.765	1.68	2.68
			Days > 0.5 dv Avg.	103	61	13.67	42	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60	34.67	6	25.33	54

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			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67

[1] Monticello's controlled level is a combination of scrubber upgrade on Unit 3 and scrubber retrofits on Units 1 and 2 in the facility impact modeling with CALPUFF.

5.5.3 Visibility Benefits of Fuel Oil Switching for Gas/Fuel Oil-Fired Units

We also modeled the visibility benefits of those gas/fuel oil-fired units for which we conducted control cost analysis for switching to lower sulfur fuels. We evaluated the visibility benefits of switching to fuel oils corresponding to ultra-low sulfur diesel at 0.0015% sulfur by weight and 0.3% sulfur by weight as we evaluated in our control cost analyses. The visibility benefits from these fuel switches are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits.

Table 44. Visibility Benefits from Lower Sulfur Fuel

Facility Name	Emission Unit	Baseline visibility Impact from Source (most impacted Class I area)	Visibility benefit of 0.3% S fuel oil	Visibility benefit of 0.0015% S fuel oil
Stryker	ST2	CALPUFF 0.65 % S: 0.786 dv @ CACR (Facility)	CALPUFF (0.3 % S) : 0.263 dv @ CACR (Facility)	CALPUFF: 0.522 dv @ CACR (Facility)
Graham	Unit 2	CALPUFF 0.69 % S: 1.228 dv @ WIMO (Facility)	CALPUFF (0.3% S): 0.465 dv @ WIMO (Facility	CALPUFF: 0.851 dv @ WIMO (Facility
Wilkes	Units 1, 2, 3	CALPUFF 0.43 % S: 0.698 dv @ CACR (Facility)	CALPUFF (0.1 % S): 0.029 dv @ CACR (Facility)	CALPUFF: 0.037 dv @ CACR (Facility)
Newman[1]	Unit 2	N/A	N/A	N/A
	Unit 3	N/A	N/A	N/A
	Unit 4	N/A	N/A	N/A
Calaveras	Sommers Unit 1	CAMx: 1.513 dv @ WIMO (Source); 0.106 dv @ CACR (Unit)	0.004 dv @ CACR	0.008 dv @ CACR
	Sommers Unit 2	CAMx: 1.513 dv @ WIMO (Source); 0.180 dv @ CACR (Unit)	0.023 @ CACR	0.047 @ CACR

[1] EPA initially considered evaluating with CALPUFF databases, but Newman is located near the edge of the CALMET modeling domain. There are a number of Class I areas that Newman could potentially impact (Gila, Bosque del Apache, Mount Baldy, Chiricahua, White Mountain, etc) and due to the size of the CALMET grid we cannot determine if Newman's impacts are below 0.5 dv at all Class I areas or determine the potential benefits from controls. Since plumes could transport out of the modeling domain and there is no way within the CALPUFF model to account for mass that transports out of the domain that may come back into the domain, the CALPUFF modeling databases cannot be relied on to conclusively assess visibility impacts from the Newman facility.

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5.6 How, if at all, Do Issues of "Grid Reliability" Relate to the Proposed BART Determinations?

On July 15, 2016, a preliminary order of the Fifth Circuit Court of Appeals took the view that EPA's Texas-Oklahoma FIP (81 FR 295, January 5, 2016) gave a "truncated discussion of grid reliability" and additionally stated that "the agency may not have fulfilled its statutory obligation to consider the energy impacts of the FIP." The Court's preliminary ruling made particular reference to "the explicit directive in the [CAA] that implementation plans 'take[] into consideration…the energy…impacts of compliance,' 42 U.S.C. § 7491(g)(1)."[128] Because the BART requirement at issue in this proposal has similar language on *energy impacts of compliance* appearing at 42 U.S.C. § 7491(g)(2), we wish to provide a clear explanation on how grid-related considerations for EGUs could bear on this proposal.

First, the BART factor for *energy impacts of compliance* does not call for the examination of grid reliability considerations from alleged plans to shut down or retire a unit rather than comply with a more stringent emission limit or limits. The language instead calls for consideration of energy impacts from *complying* by installing retrofit controls on a source that continues in operation. In this regard, our proposal follows the required BART Guidelines for EGUs.[129] The Guidelines explain that the energy impacts factor relates to the penalties and benefits that may be associated with the assessment of a control option, e.g., whether (for power penalties) the operation of add-on control technology subtracts from the productive yield of electricity from an EGU (what is sometimes termed an auxiliary or parasitic load).[130] It is also useful to note that the statutory text, while using the word "energy," can apply to sources that do not produce energy or electricity. Thus, the statutory text regarding "energy impacts" of compliance with BART is not confined to the power generating industry and does not dictate that we study grid reliability issues.

We have considered whether this topic has any separate relevance to our proposal. Various court filings, news accounts, and industry market reports suggest that some source operators for some Texas BART units may be contemplating unit retirements. The BART Guidelines directly address such scenarios under the "remaining useful life" factor: "there may be situations where a source operator intends to shut down a source….but wishes to retain the flexibility to continue operating beyond that date in the event, for example, the market conditions change."[131] The Guidelines advise that a source that is willing to assure a permanent stop in operations with a

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[128]EPA Guidance on this statutory language specifically explains that energy impacts are a matter of whether "energy requirements associated with a control technology result in energy penalties." U.S. EPA, Office of Air Quality Planning and Standards, "Guidance for Setting Reasonable Progress Goals under the Regional Haze Program," (June 1, 2007 rev), at Page 5-2.

[129] The promulgation of the Guidelines was required by 42 U.S.C. 7491(b)(1). Adherence to the Guidelines is mandatory for fossil-fuel fired generating power plants having total generating capacities "in excess of 750 megawatts."

[130] Other CAA provisions requiring consideration of "energy impacts" or "energy requirements of the control technology" are understood similarly. *See, e.g.,* CAA section 169 (the 1977 "best available control technology" requirement with consideration of "energy…impacts"); *see also* CAA section 108 ("energy requirements…of the emission control technology; "energy…impact of such processes, procedures, and methods [to reduce or control air pollution"); section 111 ("taking into account…energy requirements" of an emission limitation), etc.

[131] *Id.* at 39169-39170.

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federally- or State-enforceable restriction preventing further operation may obtain a short remaining useful life for BART analysis purposes that could then factor in the overall cost analysis.[132] As the Guidelines state, "Where the remaining useful life is less the than the time period for amortizing costs, you should use this shorter period in your cost calculations."[133] We have no information on enforceable restrictions of this type for any of the units that we propose to be subject to BART. Absent that, we must assume that controls installed on the BART units will experience their full useful life. Affected sources are free to submit information as part of their comments containing appropriate enforceable documentation of shorter remaining useful lives.

We note, however, that the Guidelines recognize there may be cases where the installation of controls, even when cost-effective, would "affect the viability of continued plant operations."[134] Under the Guidelines, where there are "unusual circumstances," we are permitted to take into consideration "the conditions of the plant and the economic effects of requiring the use of a control technology."[135] If the effects are judged to have a "severe impact," those effects can be considered in the selection process. In such cases, the Guidelines counsel that any determinations be made with an economic analysis with sufficient detail for public review on the "specific economic effects, parameters, and reasoning."[136] It is recognized, by the language of the Guidelines, that any such review process may entail the use of sensitive business information that may be confidential. The ADDRESSES section of this proposal explains how to submit confidential information with comments, and when claims of confidential business information, or CBI, are asserted with respect to any information that is submitted, the EPA regulations at 40 CFR Part 2, Subpart B-Confidentiality Business Information apply to protect it. All of that said, the Guidelines also advise that we may "consider whether other competing plants in the same industry have been required to install BART controls if this information is available."[137] Because Texas EGUs are among the last to have SO_2 BART determinations, this information is available. It is indeed the case that other similar EGUs have been required to install the same types of SO_2 BART controls that we are proposing as very cost effective.[138]

We have considered the state of available information on whether the proposed controls could affect the viability of continued plant operations. On this point, we note that we are proposing BART determinations for several units where SO_2 control requirements were separately promulgated as part of the Texas-Oklahoma FIP. These under-controlled EGU sources are: Big Brown 1 and 2; Monticello 1, 2 and 3; Martin Lake 1,2 and 3; and Coleto Creek 1. In litigation over the reasonable progress FIP, various declarations were filed on the issues of alleged forced closures and alleged reliability impacts. These declarations have been compiled and added to the

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[132] Similar to calculating a mortgage, remaining useful life is used in our cost-effectiveness analysis to calculate the annual cost of a particular control. The longer the remaining useful life, the smaller the total annualized cost, and the more cost-effective the control.
[133] Id. at 39169.
[134] 70 FR 39103, 39171 (July 6, 2005), [40 CFR Part 51, App. Y]
[135] *Id.*
[136] 70 FR at 39171
[137] *Id.*
[138] See for instance, the EIA information we present elsewhere in this notice in which we summarize the hundreds of scrubber installations that have been performed on similar EGUs.

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docket for this rulemaking. By our review, these declarations do not appropriately inform or substantiate source-specific allegations of "unusual circumstances" that may have a severe impact on plant operations, because they do not offer any site-specific information.[139] Here is a summary of relevant points:

- A declaration by a Coleto Creek Plant manager discussed the timelines and commitments to comply with the January 5, 2016 final rulemaking, indicating that efforts to comply would be carried out. The declaration states "alternatively" that the source owner could make an eventual decision to discontinue operations.
- A declaration by a vice president of construction management at Luminant stated, in relevant part, Luminant was "planning for installation of four new scrubbers at Big Brown and Monticello" and "planning for the scrubber upgrades at…Martin Lake, and Monticello."
- Somewhat differently, a declaration by the CFO of Luminant Generating Company LLC stated the January 5, 2016 rulemaking was "likely to force the closure of the Big Brown and Monticello plants" and cites a Form 10-K from March 1, 2016 that similarly states "new scrubbers at the Big Brown and Monticello units…along with the existence of low wholesale power prices in ERCOT, would likely challenge the long-term economic viability of those units." The declaration states that other Clean Air Act regulatory requirements would also threaten the viability of Big Brown and Monticello units. The declaration does not mention Martin Lake.
- A declaration from the Executive Director of the Public Utility Commission of Texas, dated April 18, 2016, stated it was "simply not possible at this point to know the precise units that may retire." Notably, the declarant also disclaimed any argument that unit retirements would occasion an "ERCOT-wide generation capacity shortfall." Instead and only, the declarant cited the potential for "local reliability impacts."
- A declaration from the Director of System Planning for the Electric Reliability Council of Texas (ERCOT) stated that retirement plans "are unknown to ERCOT and the market until formal notification is made." It continued: "ERCOT does not know at this time which units may be retired as a result of the Regional Haze FIP."

In sum, several months after the finalization of the January 5, 2016, final rulemaking representatives for the source owners provided multiple court statements that would appear to contradict or at least equivocate on the matter of whether those FIP controls could be put in place. Meanwhile, declarations submitted by certain public authorities knowledgeable in grid resource planning disclaimed knowledge on severe impacts on any source-specific basis. Thus, we are unable to conclude from any of this information that the proposed cost-effective BART controls would severely impact plant operations. Generalized claims of possible retirements and discussions on attributes of the market design of the Electric Reliability Council of Texas (ERCOT) cannot inform the statutorily required, source-specific BART determinations, and some aspects of these declarations could undermine our ability to determine "unusual circumstances" in the meaning of the BART Guidelines, as to these facilities.

As a predicate to studying effects on transmission or reliability as "unusual circumstances," we would require site-specific information from any source that would wish for us to potentially

[139] Certain statements in declarations from representatives of both Luminant and Coleto Creek, who are the source owners of these facilities, cited compliance planning efforts that would be consistent with continued plant operations.

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consider "affordability of controls," under the terms specified in the Guidelines. Source owners may submit information, including information claimed to be CBI, for our assessment and consideration to potentially support an economic analysis that might be used in the BART selection process. As suggested by the Guidelines, the information necessary to inform our judgment would likely entail source-specific information on "product prices, the market share, and the profitability of the source." Consideration of such information does not dictate what will be selected as a "best" alternative under the Guidelines, but it will substantiate the likelihood of a retirement scenario that would then give the parameters for: a non-conjectural examination of grid reliability issues; judging the significance or insignificance of such issues; and assessing whether such issues could be avoided through appropriate transmission planning. In sum, unless we are able to substantiate an "affordability of controls" problem for any particular unit and substantiate that a particular unit retirement would not be happening anyway at about the same time, alleged grid reliability impacts are speculative and are not able to inform these required BART determinations. As a final note, we acknowledge Executive Order 13211 ("Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, and Use"). In cases where it does apply, agencies are ordered to prepare a Statement of Energy Effects for submission to the Administrator of the Office of Information and Regulatory Affairs (OIRA), Office of Management and Budget. This EGU BART proposal is not considered a significant regulatory action under Executive Order 12866, so the proposed action cannot be a "significant energy action" for purposes of Executive Order 13211 on that basis. This proposed action has also not been designated a significant energy action by the Administrator of OIRA, so Executive Order 13211 could not apply under that separate basis. With this proposal, there are no anticipated adverse effects on energy supply, distribution, or use that are meaningful or distinguishable from any other scenario where an EGU is expected to install cost-effective pollution controls required by the CAA.

6 Our Proposed BART Determinations

In Section 5, above, we have analyzed the BART five factors for all the units we have identified as being subject to BART. Below we present our reasoning for proposing our BART determinations for 29 EGUs in Texas, based on our analysis and weighing of the Five BART Factors. (1) proposed SO_2 and PM BART determinations for 12 coal-fired units with no SO_2 controls, (2) proposed BART SO_2 and PM BART determinations for 6 coal-fired units with existing scrubbers, (3) proposed SO_2 and PM BART determinations 7 gas-fired units that occasionally burn fuel oil, and (4) proposed PM BART determinations for 4 gas-fired units.

In previous sections of this proposal, we have described how we assessed the five BART factors. In no case do we see any instance in which our assessment of energy impacts is a determining factor in assessing BART.[140] Also, in no case do we see any instance in which our assessment of the remaining useful life is a determining factor in assessing BART. Should a facility determine in comments to us that the remaining useful life is less than the 30 years we have assumed in our control cost analyses, and is willing to enter into an enforceable document to that effect, we will adjust our cost-effectiveness calculation accordingly in making our final decision. In two cases, Harrington units 061B and 062B, we have limited our SO_2 control analysis for

[140] In addition to our assessment of energy impacts, also see our discussion in Section 5.6 concerning our conclusion that energy impact considerations do not relate to potential electrical grid reliability issues.

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Harrington to DSI and dry scrubbers due to potential non-air quality concerns. In all other instances, we conclude that the cost of compliance, and the visibility benefits of controls are the controlling BART factors in our weighing of the five BART factors.

In considering cost-effectiveness and visibility benefit, we do not eliminate any controls based solely on the magnitude of the cost-effectiveness value, nor do we use cost-effectiveness as the primary determining factor. Rather, we compare the cost-effectiveness to the anticipated visibility benefit, and we take note of any additional considerations.[141] Also, in judging the visibility benefit we do not simply examine the highest value for a given Class I area, or a group of Class I areas, but we also consider the cumulative visibility benefit for all affected Class I areas, the number of days in a calendar year in which we see significant improvements, and other factors.[142] See the BART Modeling TSD for a complete description and summary of our analysis of visibility benefits of potential control options.

First, we note that all of the sources addressed in our proposed BART determinations have already been shown to cause or contribute to visibility impairment at a Class I area as a condition of being subject-to-BART as part of the BART screening analysis. This analysis eliminated any BART-eligible source that emits lower amounts of visibility impacting pollutants, or otherwise impacts any Class I area at less than 0.5 deciviews. In fact, all of the individual units that we are proposing for BART controls exceed 0.5 deciviews on a unit basis, with most exceeding 1.0 deciview impact on a unit basis. As a consequence, all of the units we are proposing for BART controls are among the largest emitters of visibility impacting pollutants in Texas. A number of these units (i.e., Big Brown, Martin Lake, Monticello, and Coleto Creek) were previously determined by us to require the same type and level of controls under the reasonable progress and long-term strategy provisions of the Regional Haze Rule that we are proposing here.[143]

Second, not discounting our approach of considering both cost-effectiveness and visibility benefit in unison, the cost-effectiveness of all of the controls that form the basis of our proposed BART determinations are within a range found to be acceptable in other cases.[144] As we stated in the BART Rule, ''[a] reasonable range would be a range that is consistent with the range of cost effectiveness values used in other similar permit decisions over a period of time.''[145]

6.1 SO_2 BART for Coal-fired Units with no SO_2 Controls

As we have discussed in this proposal and in our TSD, we have assumed two DSI control levels corresponding to 50% control and either a maximum of 80% or 90% control, depending on the

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[141] For instance, as we discuss later in Section 5.3.5.2 why we believe that there are certain mitigating factors that should be considered when assessing BART for the gas-fired units that occasionally burn fuel oil.
[142] See for example 70 39130: "comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g. the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, a threshold representing an x percent change in improvement, etc.)."
[143] See our recent Texas-Oklahoma FIP, 81 FR 321.
[144] See for instance 79 FR 5048 (January 30, 2014): Jim Bridger BART determination of LNB/SOFA + SCR on Units 1-4; 77 FR 18070 (March 26, 2012): EPA proposed approval of Colorado's BART determination of SCR for Hayden Unit 2, later finalized at 77 FR 76871 (December 31, 2012).
[145] 70 FR 39168 (July 6, 2005).

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particulate matter control device in use.[146] We did this to address the BART Guidelines directive that in evaluating technically feasible alternatives we "(1) [ensure we] express the degree of control using a metric that ensures an ''apples to apples'' comparison of emissions performance levels among options, and (2) [give] appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels."[147] In most cases, the cost-effectiveness of the higher control level of DSI was higher than either SDA or wet FGD. This was not the case for Monticello Unit 2; Harrington Unit 062B; and J T Deely Units 1 and 2.

However, these maximum DSI control levels are theoretical and we believe that any DSI control level above 50% must be confirmed by onsite testing before we could propose a BART control based on it. As is evident in comparing the 50% control level to the higher control level, the cost-effectiveness of DSI worsens (higher $/ton) as the control level increases, and the certainty of any unit attaining that control level decreases. We therefore regard the cost-effectiveness values of the maximum DSI control levels as being useful in a basic comparison of cost-effectiveness between DSI and scrubbers, but we place much less weight on these values. We therefore conclude that given the uncertainty concerning the maximum control level of DSI, the greater control efficiency and resulting visibility benefit offered by scrubbers overrides any possible advantage DSI may hold in cost-effectiveness. Should the affected facilities provide site-specific information to us in their comments that conflicts with this assumption, we will incorporate it into our final decision on SO_2 BART and potentially re-evaluate DSI.

As we indicate elsewhere in our proposal, both SDA and wet FGD are mature technologies that are in wide use throughout the United States. We are not aware of any unusual circumstances that exist for any of the sources that would serve to indicate they should not be viewed similarly to these hundreds of previous scrubber retrofits. In comparing wet FGD versus SDA we note that in a number of cases the cost-effectiveness of wet FGD is lower than the cost-effectiveness of SDA. In the remaining cases, we conclude that the incremental cost-effectiveness of wet FGD over SDA, which we review in Section 5.3.6 is reasonable, and the improved control and visibility benefit offered by wet FGD overrides the small penalty in cost-effectiveness FGD has in comparison to SDA. We propose that with the exception of the Harrington units, SO_2 BART for all other coal-fired units should be based on the wet FGD control levels we have used in our BART analyses. We propose that SO_2 BART for the Harrington units should be based on the SDA control levels we have used in our BART analyses. Below we discuss our consideration of the cost-effectiveness and anticipated visibility benefits of controls. See section 5.5 for additional information on the anticipated visibility benefits from each level of control modeled. See the BART modeling TSD for a complete summary of our visibility benefit analysis of controls, including modeled benefits and impacts at all Class I areas included in the modeling analyses and additional metrics considered in the assessment of visibility benefits.

CAMx model results shown in the tables below summarize the benefits from the recommended controls at the two Class I areas most impacted by the source or unit in the baseline modeling. The benefit is calculated as the difference between the maximum impact modeled for the baseline and the maximum impact level modeled under the control scenario. Also summarized

[146] Note for Harrington Unit 062B and Welsh 1, we further limited the maximum DSI control level to that of our calculated SDA control level.
[147] 70 FR 39166 (July 6, 2005).

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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. The CALPUFF cumulative model results only consider those Class I areas within the typical range of CALPUFF and not all 15 Class I areas included in the CAMx modeling.

6.1.1 Big Brown 1 & 2

In reviewing the Big Brown units, we conclude that the installation of wet FGD will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 45. Wet FGD Visibility Benefits at Big Brown (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Big Brown Units 1 & 2	3.83	3.55	7.38	151.67	101.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek and Wichita Mountains

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek and Wichita Mountains.

In evaluating Big Brown, we note there are two Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results, we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the two Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate that wet FGD on both units will eliminate 151.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the visibility benefits in terms of dv benefits at the

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most impacted Class I areas and about 1/3rd to half the cumulative benefits over the class I areas included in the modeling analysis.

Table 46. Wet FGD Visibility Benefits at Big Brown (CAMx)

Unit	Improvement at Wichita mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Big Brown 1	1.909	1.606	12.728	174 / 44	174 / 44
Big Brown 2	1.940	1.642	12.924	175 / 45	175 / 45
Source	3.542	2.988	24.274	372 / 170	362 / 170

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv at all Class I areas on a unit and source-wide basis, and eliminate all but 10 days across the impacted Class I areas where the source-wide impacts exceeds 0.5 dv. At the most impacted Class I area, wet FGD will on each unit result in visibility improvements of 1.9 dv on the most impacted day. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the CAMx modeling.

We also conclude that wet FGD is very cost-effective for both units at less than $1,200/ton and more cost-effective than DSI. Based on this consideration of the BART factors, we propose that SO_2 BART for Big Brown Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

6.1.2 Monticello 1 & 2

Similar to the Big Brown units, the installation of wet FGD at Monticello Units 1 and 2 will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 47. Wet FGD Visibility Benefits at Monticello (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit	Baseline Total Cumulative number of	Cumulative Reduction in number of days

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			(dv)[1]	days over 0.5/1.0 dv[2]	above 1.0 dv[2]
Monticello Units 1, 2 & 3	4.87	2.70	10.25	224.67	164.67

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Monticello, we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 224.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I area and half of the cumulative benefits.

Table 48. Wet FGD Visibility Benefits at Monticello (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 1	3.783	1.989	12.708	197 / 67	191 / 67
Monticello 2	3.924	2.003	13.025	192 / 57	191 / 57
Source (including unit 3)	8.419	4.962	31.553	520 / 293	460 / 278

[1] 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.
[2] 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.
[3] 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.

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CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv at all Class I areas on a unit basis, and eliminate all but 15 days across the impacted Class I areas where the source-wide impacts exceeds 1 dv. We note that source-wide modeled benefits include benefits of 95% control scrubber upgrade on Unit 3. At the most impacted Class I area, wet FGD on each unit will each result in visibility improvements of 3.8-3.9 dv on the most impacted day at Caney Creek and 2 dv visibility benefits at Wichita Mountains. DSI operated at 50% control results in less than half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

The wet FGD cost-effectiveness of $2,718/ton and $3,031/ton are higher than those for Big Brown, but these figures remain well within a range that we have previously found to be acceptable for BART, and we consider the very significant visibility benefits that will result justify the cost of wet FGD at the Monticello Units 1 and 2. The 50% control DSI cost-effectiveness is slightly less than that for wet-FGD, but results in much less visibility benefits. Based on our consideration of the BART factors, we therefore propose that SO_2 BART for Monticello Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

6.1.3 Coleto Creek 1

In reviewing Coleto Creek Unit 1, we conclude that in comparison with the Monticello units, the installation of a wet FGD is more cost-effective and results in lesser, but still significant visibility benefits. We summarize some of these visibility benefits in the table below:

Table 49. Wet FGD Visibility Benefits at Coleto Creek Unit 1 (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Coleto Creek 1	0.668	0.606	5.233	17 / 0	17 / 0

[1] 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
[2] 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
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 0.5 dv at all Class I areas. At the most impacted Class I area, wet FGD will result in visibility improvements of 0.6 or more on the most impacted days at both Caney Creek and the Wichita Mountains. In addition, seven other Class I areas are improved by amounts ranging from 0.356 to 0.531 dv on the maximum impacted days with wet FGD. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15class I areas included in the modeling.

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We also conclude that wet FGD is very cost-effective at $2,127/ton and well within a range that we have previously found to be acceptable and more cost-effective than DSI. We consider the significant visibility benefits that will result justify the cost of wet FGD at the Coleto Creek Unit 1. We therefore propose that SO_2 BART for Coleto Creek Unit 1 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

6.1.4 Welsh 1

In reviewing Welsh Unit 1, we conclude that the installation of a wet FGD will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 50. Wet FGD Visibility Benefits at Welsh Unit 1 (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Welsh 1	0.72	0.41	1.66	56.67	15

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Welsh we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 56.67 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

Table 51. Wet FGD Visibility Benefits at Welsh Unit 1 (CAMx)

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Unit	Improvement at Caney Creek (dv)	Improvement at Mingo Wilderness (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Welsh 1	1.521	0.579	4.683	65 / 9	60 / 9
Source (Welsh 1 & 2)	3.754	1.973	13.179	211 / 72	206 / 72

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD on unit 1 will eliminate all days impacted by the unit over 1 dv at all Class I areas and all but 5 days impacted over 0.5 dv. At the most impacted Class I area, wet FGD on unit 1 will result in visibility improvements of 1.521 dv on the most impacted days at Caney Creek. In addition to the visibility benefits at Caney Creek and Mingo, visibility benefits at two additional Class I areas exceed 0.5 dv. We note that source-wide benefits shown include the benefits from the shutdown of unit 2. In addition, cumulative benefits from wet FGD on unit 1 over all 15 Class I areas exceeds 4.5 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We conclude that although at $3,824/ton, the cost-effectiveness of wet FGD is higher than for other facilities, it remains within a range that we have previously found to be acceptable. We consider the significant visibility benefits that will result from the installation of wet FGD at Welsh Unit 1 to justify the cost. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for Welsh Unit 1 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

6.1.5 Harrington 061B & 062B

In reviewing Harrington, we conclude that the installation of SDA on Units 061B and 062B will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 52. SDA Visibility Benefits at Harrington (CALPUFF)

Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility	Cumulative Reduction in number of	Cumulative Reduction in number

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			Benefit (dv)[1]	days above 0.5 dv[2]	of days above 1.0 dv[2]
Harrington 061B & 062B	0.45	0.74	2.56	53.67	26

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

In evaluating Harrington we note there are five Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the five Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate SDA on both units will eliminate 53.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

Table 53. SDA Visibility Benefits at Harrington (CAMx)

Unit	Improvement at Salt Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Harrington 061B	1.170	0.643	4.832	17 / 5	11 / 3
Harrington 062B	1.279	0.723	5.379	17 / 5	11 / 3
Source (061B & 0622B)	2.053	1.130	9.329	51 / 17	37 / 11

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate SDA on these units will eliminate more than half of all days

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impacted by the units over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, SDA on each unit will each result in visibility improvements of approximately 1.2 dv on the most impacted days at Salt Creek and 0.6 – 0.7 dv at Wichita Mountains, reducing the number of days impacted over 0.5 and 1.0 dv at these Class I areas. In addition, cumulative benefits from SDA on both units over all 15 Class I areas exceeds 9.3 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the SDA visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling.

We also conclude that SDA is cost-effective at $3,904 for Unit 061B and $4,180/ton for Unit 062B and, remains within a range that we have previously found to be acceptable. In contrast to other units we have reviewed, the 50% control DSI cost-effectiveness is much less than that for SDA. However, given the additional large total cumulative visibility benefits that will result from the installation of SDA over DSI at 50% control, we consider SDA to justify the additional cost. We therefore propose that SO_2 BART for Harrington Units 061B and 062B should be based on the installation of SDA at an emission limit of 0.06 lbs/MMBtu based on a 30 BOD.

6.1.6 W. A. Parish WAP 5 & 6

In reviewing W A Parish, we conclude that the installation of wet FGD on Units 5 and 6 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 54. Wet FGD Visibility Benefits at W A Parish (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
W A Parish 5	1.518	0.943	8.171	51 / 9	51 / 9
W A Parish 6	1.492	0.922	7.979	48 / 7	48 / 7
Source (WAP 4, 5 & 6)	2.665	1.760	15.301	163 / 49	162 / 49

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD on each of these units will eliminate all days impacted by each unit over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of approximately 1.5 dv on the most impacted days at Caney Creek and 0.9 dv at Upper Buffalo. Nine Class I areas have

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modeled source-wide baseline impacts over 1 dv, and wet FGD on both units results in source-wide improvements of 1 dv or greater on the maximum impacted days at eight of these Class I areas. In addition, cumulative benefits from wet FGD on both units over all 15 Class I areas exceeds 15 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15class I areas included in the modeling. We note that source-wide modeling includes a small impact from WAP 4. This unit is gas-fired and was modeled at baseline emissions levels for both the baseline and control case scenarios.

We conclude that wet FGD is cost-effective at $2,417/ton for Unit 5 and $2,259/ton for Unit 6, and remains well within a range that we have previously found to be acceptable. DSI at 50% control is approximately the same cost-effectiveness but results in significantly less visibility benefit. We consider the cost of wet FGD at the W A Parish units to be justified by the significant visibility benefits that will result. We therefore propose that SO_2 BART for W A Parish Units 5 and 6 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.

6.1.7 J T Deely 1 & 2

In reviewing J T Deely, we conclude that the installation of wet FGD on Units 1 and 2 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 55. Wet FGD Visibility Benefits at J T Deely (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
J T Deely 1	0.487	0.283	4.785	10 / 0	10 / 0
J T Deely 2	0.298	0.217	3.650	7 / 0	7 / 0
Source (J T Deely 1 & 2, Sommers 1 & 2)	0.699	0.518	8.943	89 / 13	84 / 13

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate wet FGD on each of these units will eliminate all days impacted by each unit over 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of 0.487 dv and 0.298 dv on the most impacted days at Wichita Mountains and 0.283 dv and 0.217 dv at Caney Creek. Larger visibility improvements on the most impacted days are anticipated at other Class I areas.

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Benefits from wet FGD on unit 1 are 0.583 dv at Big Bend, 0.511 dv at Salt Creek, 0.449 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.475 dv at White Mountains. Benefits from wet FGD on unit 2 are 0.583 dv at Big Bend, 0.441 dv at Salt Creek, 0.354 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.375 dv at White Mountains. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits at the most impacted Class I areas and half of the cumulative benefits over the 15 Class I areas included in the modeling. We note that source-wide modeling includes the impact from Sommers units 1 and 2, and as discussed in the BART Modeling TSD, control case scenarios for these units included benefits from switching to lower sulfur fuel oil. However, these modeled improvements are a small fraction of the total visibility benefits from controls at the source.

We conclude that wet FGD is cost-effective at $3,898/ton for Unit 1 and $3,712/ton for Unit 2, and remains within a range that we have previously found to be acceptable. We consider the cost of wet FGD at the J T Deely units to be justified by the significant visibility benefits that will result at a number of impacted Class I areas. DSI at 50% control is slightly more cost-effective but results in much less visibility benefit. We therefore propose that SO_2 BART for J T Deely Units 1 and 2 should be based on the installation of wet FGD at an emission limit of 0.04 lbs/MMBtu based on a 30 BOD.[148]

6.2 SO_2 BART for Coal-fired Units with Underperforming Scrubbers

The BART Guidelines state that underperforming scrubber systems should be evaluated for upgrades.[149] Other than upgrading the existing scrubbers, all of which are wet FGDs, there are no competing control technologies that could be considered for these units. The CALPUFF modeling generated facility-wide impacts and the benefits of the scrubber upgrade on Monticello Unit 3 and the three Martin Lake facilities are included in Table 42 above. The following is a listing of each of the affected units along with the resulting CAMx modeled visibility benefits from upgrading their existing scrubbers:

Table 56. Visibility Benefit for Coal-fired Units with Existing SO_2 Controls (CAMx)

Unit	Improvement at most impacted (dv)	Improvement at 2nd most impacted (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 3	3.719 (CACR)	1.918 (WIMO)	11.940	200 / 66	188 / 66
Martin Lake 1	1.165 (CACR)	1.449 (UPBU)	7.575	160 / 41	151 / 40
Martin Lake 2	0.655 (CACR)	1.164 (UPBU)	6.199	150 / 41	134 / 39
Martin Lake 3	1.146 (CACR)	1.478 (UPBU)	7.863	173 / 47	163 / 46

[1] 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.

[148] We have read reports that CPS Energy, is planning to retire J T Deely Units 1 and 2 by the end of 2018, but we have no enforceable documents to that effect.
[149] 70 FR 39171 (July 6, 2005).

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[2] 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.
[3] 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.

As we state elsewhere in this proposal, because our cost-effectiveness calculations depend on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost effectiveness was $1,156/ton or less. We conclude that in all cases, scrubber upgrades are very cost-effective and result in very significant visibility benefits, significantly reducing the impacts from these units and reducing the number of days that Class I areas are impacted over 1.0 dv and 0.5 dv. We propose that SO_2 BART for all other coal-fired units with underperforming scrubbers should be based on the wet FGD upgrade control levels we have used in our BART analyses of them.

6.2.1 Potential Process for Alternative Scrubber Upgrade Emission Limits

In our BART FIP TSD, we discuss how we calculated the SO_2 removal efficiency of the units we analyzed for scrubber upgrades. We note that due to a number of factors we could not accurately quantify, our calculations of scrubber efficiency may contain some error. Based on the results of our scrubber upgrade cost analysis, we do not believe that any reasonable error in calculating the true tons of SO_2 removed affects our proposed decision to require emission reductions, as all of the scrubber upgrades we analyzed are cost-effective (low $/ton). In other words, were we to make reasonable adjustments in the tons removed to account for any potential error in our scrubber efficiency calculation, we would still propose to upgrade these SO_2 scrubbers. We believe we have demonstrated that upgrading an underperforming SO_2 scrubber is one of the most cost-effective pollution control upgrades a coal fired power plant can implement to improve the visibility at Class I areas. However, our proposed FIP does specify a SO_2 emission limit that is based on 95% removal in all cases. This is below the upper end of what an upgraded wet SO_2 scrubber can achieve, which is 98–99%, as we have noted in our BART FIP TSD. We believe that a 95% control assumption provides an adequate margin of error for any of the units for which we have proposed scrubber upgrades, such that they should be able to comfortably attain the emission limits we have proposed. However, for the operator of any unit that disagrees with us on this point, we propose the following:

(1) The affected unit should comment why it believes it cannot attain the SO_2 emission limit we have proposed, based on a scrubber upgrade that includes the kinds of improvements (e.g., elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically included in a scrubber upgrade.

(2) After considering those comments, and responding to all relevant comments in a final rulemaking action, should we still require a scrubber upgrade in our final FIP we will provide the company the following option in the FIP to seek a revised emission limit after taking the following steps:

(a) Install a CEMS at the inlet to the scrubber.

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(b) Pre-approval of a scrubber upgrade plan conducted by a third party engineering firm that considers the kinds of improvements (e.g., elimination of bypass, wet stack conversion, installation of trays or rings, upgraded spray headers, upgraded ID fans, using all recycle pumps, etc.) typically performed during a scrubber upgrade. The goal of this plan will be to maximize the unit's overall SO_2 removal efficiency.

(c) Installation of the scrubber upgrades.

(d) Pre-approval of a performance testing plan, followed by the performance testing itself.

(e) A pre-approved schedule for 2.a through 2.d.

(f) Should we determine that a revision of the SO_2 emission limit is appropriate, we will have to propose a modification to the BART FIP after it has been promulgated. It should be noted that any proposal to modify the SO_2 emission limit will be based largely on the performance testing and may result in a proposed increase or decrease of that value.

6.3 SO_2 BART for Gas-fired Units that Burn Oil

In analyzing potential controls for those gas-fired units that occasionally burn fuel oil we considered scrubber retrofits and lower sulfur fuel oil. We concluded that the cost-effectiveness of scrubber retrofits for these units were likely very high, and not worth the potential visibility benefit.

We also concluded that the cost-effectiveness of switching to a No. 2 fuel oil with a sulfur content of 0.3% is $11,218/gallon, and the cost-effectiveness of switching to ULSD with a sulfur content of 0.0015% is $8,627/gallon. We further noted that one facility already had a contract in place for ULSD at a lower price than we assumed, which if used in our analysis would result in a cost effectiveness of $3,970/ton. Although the cost-effectiveness of switching to a lower sulfur oil (assuming our price for ULSD of $1.667/gal) is higher than other controls that we have typically required under BART, we note certain mitigating factors.

For instance, arguing against control, our calculated cost-effectiveness values are high in relation to other BART controls we have required in the past. Also, our visibility modeling necessarily utilized the maximum SO_2 emissions over a 24-hour timeframe,[150] resulting in the configuring of our visibility modeling to analyze the maximum short-term potential impacts that could occur when the unit burns fuel oil. However, as we discuss elsewhere in our proposal, these units are primarily gas-fired, and have only occasionally burned fuel oil. Their most recent practices appear to reinforce this trend.

[150] See the BART Guidelines at 70 FR 39162, July 6, 2005: "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."

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Arguing for control, unlike the wet FGD and SDA scrubbers we have costed in other sections of this TSD, which have large capital costs, we are unaware of any significant capital costs involved in switching fuels. This means the overall annual costs are relatively minor, if the units in question adhere to their historical usages. Also, because the units in question have only occasionally burned fuel oil, they have the option to avoid the cost of fuel switching entirely by not continuing to burn fuel oil and instead relying solely on their primary fuel of natural gas. Lastly, we note that the prevalence of ULSD in the fuel oil market is such that it appears to be gradually replacing most other No. 2 fuel oil applications.[151]

The preamble to the Regional Haze Rule counseled that a one percent sulfur content limitation on fuel oil should be considered as a "starting point,"[152] and the existing sulfur content limits are lower than one percent. Considering all of this information, we propose that SO_2 BART for the gas-fired units that occasionally burn fuel oil should be no further control. In so doing, we acknowledge the data quality issues we have discussed concerning these units and we specifically request comments on all aspects of our proposed BART analysis for these units from all interested parties. Based on the comments we receive, we may either finalize our BART determinations for these units as proposed, or we may revise them without a re-proposal.

6.4 PM BART

We propose to disapprove the portion of the Texas Regional Haze SIP that sought to address the BART requirement for EGUs for PM. We note that all of the coal-fired units are either currently fitted with a baghouse, an ESP and a polishing baghouse, or an ESP. We conclude that the cost of retrofitting the subject units with a baghouse would be extremely high compared to the visibility benefit for any of the units currently fitted with an ESP. Consequently, we propose that PM BART for the coal-fired units is an emission limit of 0.030 lb/MMBtu along with work practice standards. We propose that PM and SO_2 BART for the units that only fire gas be pipeline natural gas. We propose that PM and SO_2 BART for those gas-fired units that occasionally burn fuel oil be the existing permitted fuel oil sulfur content of 0.7% sulfur by weight or pipeline natural gas.

[151] http://www.eia.gov/todayinenergy/detail.php?id=5890. http://blogs.platts.com/2014/05/07/heating-oil-new-york-sulfur/. http://oilandenergyonline.com/challenges-to-the-northeast-supply-picture/
[152] 70 FR at 39134

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Appendix A: Comment and Response Summary Concerning Our Wet FGD Control Efficiency Assumption[153]

Comment: Incorrect assumptions for estimating achievable SO_2 emission rates
[Sargent & Lundy (0061) p. 22]

S&L stated that EPA calculated SO_2 emission reductions based on the assumption that a retrofit wet FGD will achieve 98% reduction or a controlled SO_2 emission rate of 0.04 lb/MMBtu. In our experience, this assumption is unrealistic and cannot be sustained on a continuous, long-term basis. As a basis for its assumption, EPA cites the IPM wet FGD cost development document, which 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."[63] However, EPA misinterprets this statement when it uses the guarantee emission rate to calculate long-term SO_2 emissions.

S&L asserted that EPA's proposal is far too stringent to be achievable with the retrofit of an existing unit. EPA's selection of a controlled emission rate of 0.04 lb/MMBtu is more consistent with the lowest achievable emission rate (LAER) applicable to newly-constructed units, rather than an emission rate achievable with retrofit controls installed on existing units. In fact, a controlled emission rate of 0.04 lb/MMBtu is significantly lower than the most aggressive BART SO_2 emission limits imposed by EPA on BART-eligible sources throughout the U.S.

According to S&L, a controlled SO_2 limit of 0.04 lb/MMBtu is not a realistic or sustainable value to maintain on a long-term basis when considering the normal variation in operation that occurs at all coal-fueled facilities. As noted in the IPM wet FGD document, the 0.04 lb/MMBtu emission rate corresponds to the lowest available SO_2 emission guarantees from wet FGD suppliers. Compliance with a vendor's guarantee value is typically demonstrated during very short term testing conducted at ideal operating conditions. Vendor guarantees do not reflect controlled emission rates that may be achievable on a consistent long-term basis as the unit operation varies from design conditions.

S&L noted that wet FGD control systems, like all large air pollution control systems, are not steady state control systems, and controlled SO_2 emissions will continually fluctuate in response to changing operating parameters. Operating parameters that may affect SO_2 emissions include the fuel sulfur content, boiler load, load changes, flue gas flow rate, and flue gas temperatures, all of which continually change during normal operation of the boiler. Figure 1 shows the hourly emissions data for Spruce Unit 1. Spruce Unit 1 is a 550 MW subbituminous coal-fired boiler equipped with wet limestone FGD. The FGD control system was installed in 1992, and upgraded in 2009. Figure 1 shows the normal fluctuation in controlled hourly SO_2 emissions from Spruce Unit 1, which is typical for all wet FGD control systems.

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[153] This comment and response summary is reproduced from our "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." Docket No. EPA-R06-OAR-2014-0754. 12/9/2015

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Figure 1: SO_2 Emission Permit Limits for Recent Wet FGD Projects [Figure not excerpted]

According to S&L, between January 1, 2012 and December 31, 2013, Spruce Unit 1 achieved an average controlled SO_2 emission rate of 0.055 lb/MMBtu (2-year average). During that same time period, the standard deviation in its controlled 30-day average SO_2 emission rate was 0.10 lb/MMBtu, approximately 20% greater than the long-term average, and the controlled SO_2 emission rate achieved at a 95% confidence level was 0.075 lb/MMBtu (0.02 lb/MMBtu above the long-term average). Based on our experience with other wet FGD control systems, fluctuations seen in the controlled SO_2 emission rate at Spruce Unit 1 are typical.

S&L stated that projecting future emissions using the anticipated control system vendor guarantee (i.e., 0.04 lb/MMBtu) as EPA did is overly aggressive and provides no margin for normal operating conditions or long-term operation. A reasonable margin between the vendor guarantee value or design target, and the projected actual long-term achievable emission rate is needed to allow for normal fluctuations in the controlled emissions. In S&L's opinion, an operating margin of at least 0.02 lb/MMBtu between the vendor guarantee and projected long-term emission rate is reasonable. In addition, it would be necessary to contact FGD suppliers to provide bids, on a case-by-case basis, that identify what outlet emission rates would be guaranteed on a 30-day rolling average to determine adequate outlet emission rates for compliance, rather than applying the lowest available emission rate guarantee in all cases.

S&L concluded that EPA's approach to estimating controlled SO_2 emissions is incorrect and based on a misunderstanding of the actual performance and operation of wet FGD technology. By using this approach, EPA is overestimating the tons of SO_2 removed and thus overstating the cost-effectiveness of the retrofit FGD control systems.

[Stamper (0068) p.15] Stamper stated that the EPA assumed SO_2 removal efficiencies of up to 98% control in its wet FGD analyses and up to 95% control in its SDA analyses. However, in no case did EPA assume a controlled wet FGD SO_2 rate of less than 0.04 lb/MMBtu or a controlled SDA SO_2 rate of less than 0.06 lb/MMBtu in its cost effectiveness analyses. EPA's rationale was that these were the lowest emission guarantees and this methodology was consistent with EPA's cost effectiveness calculations for the Oklahoma regional haze FIP. Cost TSD at 16, 21-22.

Stamper stated that the EPA's assumptions limiting the SO_2 removal efficiency based on the guaranteed permitted limits of 0.06 lb/MMBtu for an SDA and 0.04 lb/MMBtu for a wet FGD underestimated the actual SO_2 emission reductions that would likely occur with these SO_2 scrubbers. This is primarily a concern for those EGUs that burn or blend with low sulfur Powder River Basin coal (i.e., Coleto Creek 1, Tolk 171B and 172B, WA Parrish 5, 6, and 7, and Welsh 1, 2, and 3). Further, wet FGD systems can achieve greater than 99% SO_2 removal, and dry scrubbers can achieve greater than 95% SO_2 removal efficiency, as discussed further below.

According to Stamper, wet scrubbers are the most effective SO_2 control technology available. State-of-the-art wet scrubbers can achieve 98-99% removal efficiency. A prime example is the Chiyoda CT-121 FGD. Vendor information for this technology indicates that this scrubber has

achieved 98-99% SO_2 removal even with low sulfur coal.[43] For example, the Chiyoda's bubbling jet reactor has consistently achieved >99% SO_2 removal during long-term operation at the Shinko-Kobe power plant in Japan. This facility consists of two 700-MW coal-fired utility boilers. The wet FGD was designed to achieve 0.014 lb SO_2/MMBtu (9 ppmv at 3% oxygen) on an instantaneous basis and has consistently exceeded this level of control while treating gases with inlet SO_2 concentrations of 1.78 lb/MMBtu.[44] This technology has been guaranteed by Chiyoda to achieve 99% SO_2 removal on three coal-fired boilers in Japan.[45]

Stamper stated that the Chiyoda CT-121 FGD has been demonstrated in the U.S. at the University of Illinois's Abbott power plant, Georgia Power's Plant Yates[46], Dayton Power & Light's Killen Unit 2,[47] and Plant Bowen Unit 3.[48] It has been licensed for installation on several additional units in the U.S., including the other three units at Plant Bowen in Georgia, the other units at Dayton Power & Light's Killen plant, Dayton Power & Light's Stuart plant, and AEP's Big Sandy Unit 2, Conesville Unit 4, Cardinal Units 1 and 2, and Kyger Creek, among others.[49] Black & Veatch and Southern Company are both U.S. licensees. Further, this technology also has shown to be very effective in removing fine particulates, oxidized and elemental mercury, and acid gases, and the technology uses less energy compared to traditional wet scrubbers.

Stamper noted that Mitsubishi, a vendor of scrubber systems, reports it has guaranteed SO_2 removal efficiencies up to 99.8 percent, including for coal-fired boilers.[50,51,52]

Stamper stated that Sargent & Lundy has indicated that the lowest achievable SO_2 emission rate with low sulfur Powder River Basin coal for a limestone forced oxidation (LSFO) wet scrubber would be 0.03-0.06 lb/MMBtu.[53]

Stamper stated that these SO_2 removal efficacy claims for wet scrubbers at coal-fired boilers burning lower sulfur coal have been demonstrated in practice. SO_2 emissions data was compiled for 2009 to 2013 to reflect newly operating and recently retrofitted wet FGD systems at EGUs that burn low sulfur coal. The results are in Table 3 below. All of these units burn Powder River Basin coal and have recently been retrofitted with wet FGD systems. As the table below demonstrates, wet FGDs at EGUs burning Powder River Basin coal can achieve much lower SO_2 emission rates than 0.04 lb/MMBtu.

Table 3. Annual Average SO2 Emission Rates at EGUs Equipped with Wet FGDs that Burn Low Sulfur Coal[54]

Plant	Unit	Annual Average SO2 Rate, lb/MMBtu
Iatan	1	0.007
Iatan	2	0.007
Boswell Energy Center	3	0.009
Muscatine	9	0.013
Pleasant Prairie	1	0.021
Pleasant Prairie	2	0.029

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Thus, Stamper concluded that the EPA's assumption that a wet FGD could not achieve SO_2 rates lower than 0.04 lb/MMBtu is overly conservative, as demonstrated by the data presented above.

In addition, Stamper noted that recently constructed EGUs that burn Powder River Basin coal and that are equipped with SDAs have achieved lower SO_2 emission rates than the minimum 0.06 lb/MMBtu SO_2 rate assumed by EPA in its cost effectiveness analyses. The Newmont Nevada power plant (aka TS Power Plant), equipped with a dry lime FGD system, has achieved an annual average SO_2 rate of 0.037 lb/MMBtu over 2009 to 2013.[55] The Wygen II is also equipped with a dry lime scrubber and burns low sulfur coal, and is achieving annual average SO_2 rates of 0.047 lb/MMBtu.[56] And the Dry Fork Station which began operation in 2011 and is equipped with a dry lime scrubber is achieving an annual average SO_2 rate of 0.044 lb/MMBtu.[57]

Further, Stamper stated that a circulating dry scrubber can achieve even higher levels of SO_2 removal than an SDA and lower SO_2 emission rates. As discussed elsewhere in this document, EPA should have evaluated circulating dry scrubbers in its analyses of reasonable progress measures for the Texas EGUs.

In summary, Stamper contended that the EPA's assumed level of SO_2 control in its cost effectiveness analyses for SO_2 for wet FGD and SDA systems is likely conservative and does not reflect the full extent of SO_2 emission reductions that can be achieved with these control technologies. That means EPA's cost effectiveness calculations should be lower and the visibility improvements higher for several of the EGUs evaluated by EPA for reasonable progress controls.

Footnotes:

[42] *See*, e.g., Sargent & Lundy, IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology, March 2013, at 6.

[43] *See* Black & Veatch vendor brochure on CT-121, (Ex. 14).

[44] Yasuhiko Shimogama, Hirokazu Yasuda, Naohiro Kaji, Fumiaki Tanaka, and David K. Harris, Commercial Experience of the CT-121 FGD Plant for 700 MW Shinko-Kobe Electric Power Plant, Paper No. 27, presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003, (Ex. 15).

[45] CT-121 FGD Process – Jet Bubbling Reactor, http://www.bwe.dk/fgd-ct121.html, (Ex. 16).

[46] Emission-control Technologies Continue to Clear the Air, Power, May/June 2002.

[47] *See* Black & Veatch, First Black&Veatch/Chiyoda Wet Flue Gas Desulfurization System in North America Successfully Goes Operational.

[48] Blankinship, Steve, Go Take a Bath, Power Engineering, October 2008, available at http://pepei.pennnet.com/display_article/342997/6/ARTCL/none/none/1/Go-Take-a-Bath/.

[49] Chiyoda Licenses Its Flue Gas Desulfurization Technology in USA Newly for 5 Coal-Fired Generation Units, Press Release, May 2, 2005; Chiyoda Licenses its Flue Gas Desulfurization Process in USA for Georgia Power Owned 4 FGD Units, January 26, 2005.

[50] Jonas S. Klingspor, Kiyoshi Okazoe, Tetsu Ushiku, and George Munson, High Efficiency Double Contact Flow Scrubber for the U.S. FGD Market, Paper No. 135 presented at MEGA Symposium, Air & Waste Management Association, May 19-22, 2003, p.8, Table 4, (Ex. 17).

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[51] Yoshio Nakayama, Tetsu Ushiku, and Takeo Shinoda, Commercial Experience and Actual-Plant-Scale Test Facility of MHI Single Tower FGD, (Ex. 18).
[52] Mitsubishi High SO_2 Removal Experience, (Ex. 19).
[53] *See* White Bluff Station Units 1 and 2 Evaluation of Wet vs Dry FGD Technologies, Rev. 3, October 28, 2008, prepared by Sargent & Lundy at 3-7. (Ex. 20).

Footnotes:
[63] Sargent & Lundy LLC, *IPM Model – Revisions to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology*, March 2013.

Response: All of the claims in this comment have been previously addressed in confidential expert reports in the Cinergy case[154], including achievable FGD SO_2 removal efficiency and the reliability of vendor guarantees for setting emission limits, based on CEMS data, published works, and deposition testimony of five major scrubber vendors.[155] These reports and SO_2 scrubber vendor depositions conclude that 98% to 99% SO_2 control has been achieved and is routinely achievable. These reports and depositions also conclude that vendor guarantees are a reliable basis for establishing emission limits. We cannot include these expert reports and depositions in our docket, because they are held confidential under a protective court order. However, we do include the testimony of Dr. Phyllis Fox, one of the government expert witnesses, in which she testifies, based on her expert report with Hal Taylor, that the removal efficiency of wet scrubbers can reach 99%. [156] These conclusions were upheld in court rulings in United States v. Cinergy Corp., 618 F. Supp. 2d 942, 947 and 961-962 (S.D. Ind. 2009).

First, this comment argues that a "controlled SO_2 limit of 0.04 lb/MMBtu is not a realistic or sustainable value to maintain on a long term basis when considering the normal variation in operation that occurs at all coal-fired facilities." This is misleading as the proposed limit for retrofits is not "0.04 lb/MMBtu" on an instantaneous basis, as suggested in this comment, but rather is based on a "30-boiler-operating-day" (30-BOD) average.[157] A boiler operating day is any 24-hour period between 12:00 midnight and the following midnight during which any fuel is

[154] United States and Plaintiff-Intervenors States of New York, New Jersey, and Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, Civil Action No. IP99-1693 C-M/S, United States, et al., v. Cinergy Corp., et al., In the United States District Court for the Southern District of Indiana, Indianapolis Division.
[155] Phyllis Fox and Hal Taylor, Expert Report of Phyllis Fox and Hal W. Taylor. Prepared on Behalf of Plaintiff United States and Plaintiff-Intervenors States of New York, New Jersey, and Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, Civil Action No. IP99-1693 C-M/S, United States, et al., v. Cinergy Corp., et al., In the United States District Court for the Southern District of Indiana, Indianapolis Division, August 29, 2008; Phyllis Fox and Hal Taylor, Expert Rebuttal Report of Phyllis Fox and Hal W. Taylor, Prepared on Behalf of Plaintiff United States and Plaintiff-Intervenors States of New York, New Jersey, and Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, Civil Action No. IP99-1693 C-M/S, United States, et al., v. Cinergy Corp., et al., In the United States District Court for the Southern District of Indiana, Indianapolis Division, October 14, 2008, 2008.
[156] United States and Plaintiff-Intervenors States of New York, New Jersey, and Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, Civil Action No. IP99-1693 C-M/S, United States, et al., v. Cinergy Corp., et al., In the United States District Court for the Southern District of Indiana, Indianapolis Division. Trial Proceedings, Volume 2. Testimony of Dr. Phyllis Fox, beginning on vol. 2-302.
[157] 79 FR 74,822, Table 1; 74,884 (Dec. 16, 2014).

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combusted at any time at the steam generating unit."[158] As explained in our FIP TSD (p. 31) and the proposed rulemaking, days are skipped when the unit is down, as for maintenance. This provides a margin of safety by eliminating spikes that occur at the beginning and end of outages, when the scrubber is not operating.[159] Regardless, all major scrubber vendors guarantee 99% SO_2 control and expect routine performance at this level. This level of control is confirmed under vendor guarantees by making simultaneous measurements of SO_2 at the inlet and outlet of the scrubber.

The emission limit that we have proposed for all wet scrubbed units, 0.04 lb/MMBtu, is based on 98% control, unless the resulting controlled limit fell below an outlet SO_2 level of 0.04 lb/MMBtu, in which case, we would have assumed the percentage control equal to 0.04 lb/MMBtu.[160] All of the calculated 98% control levels, except for Big Brown Unit 1, were lower than 0.04 lb/MMBtu, as shown in the following table. Thus, the limits we propose have built in margin.

Calculation of Wet Scrubber Limits

Unit	Proposed SO_2 Limit (lb/MMBtu)	Baseline (lb/MMBtu)	Control Level (%)	Margin (lb/MMBtu)
Big Brown 1	0.04	0.04	98	0
Big Brown 2	0.04	0.0392	97.91	0.00084
Monticello 1	0.04	0.0388	96.99	0.0012
Monticello 2	0.04	0.0387	96.83	0.0013
Coleto Creek 1	0.04	0.0383	95.65	0.0014

Recent operating experience reported by Hitachi confirms that 99% SO_2 control is achievable.[161] Hitachi has guaranteed many units at 99% SO_2 control efficiency.[162] Hitachi has explained that 99% control on an "instantaneous basis" (not even a rolling average) is routinely achieved in Japan, where rolling averages are not allowed, and has stated that Hitachi is "comfortable with

[158] 70 FR 39,172 (July 6, 2005).
[159] 79 FR 74,884 (Dec. 16, 2014).
[160] Cost TSD, p. 21; 79 FR 74,884 (Dec. 16, 2014). The proposed control level was calculated in the wet FGD spreadsheet in cell E13. First, we tested to see if 98% of the uncontrolled SO_2 rate would result in a value less than 0.04 lb/MMBtu. If it did, then a control level was calculated based on a reduction to 0.04. If it didn't, then the control level was set to 98%. The uncontrolled SO_2 rate itself was calculated based on the maximum monthly SO_2 rate from 2009-2014. This was calculated in the "Monthly Emissions" tab of the wet FGD spreadsheet. The maximum monthly value was used to ensure the scrubber was designed to address the dirtiest coal burned in the recent past.
[161] B.C. Studley and others, Recent Operating Results of the Five New Wet FGD Installations for Ameren Corporation, Available at: http://www.psa.mhps.com/supportingdocs/forbus/hpsa/technical_papers/Recent%20Operating%20Results%20of%20the%20Five%20New%20Wet%20FGD%20Installations%20for%20Ameren%202011.pdf.
[162] Hitachi Wet FGD Sample of Recent Installations (showing 99% guarantees at Boswell #3, Coffeen #1,2, Duck Creek #1, Sioux 1,2).

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98%" for PRB coals.[163] See also Stamper comment 0068, pp. 15-17. Alstom has guaranteed units at 99%, concluding the new Trimble County Unit 2 "can reliably achieve a high efficiency. 99.8% SOx removal could be expected."[164] Advatech, a joint venture of URS and Mitsubishi, likewise has built scrubbers guaranteed at 98% to 99%.[165] Advatech reports its highest SO_2 guarantee is 99.8%. Their experience list includes many units in Japan guaranteed at this level,[166] which must be met on an instantaneous basis.

Second, this comment asserts that vendor guarantees do not reflect controlled emission rates that may be achievable on a consistent long-term basis as the unit operation varies from design conditions." A survey of owners of FGD systems found that "[w]ith regard to FGD reliability, in every case except for one SDA system, performance overall met or exceeded owner expectation. Therefore, there is reason to believe that the FGD systems will perform as expected (albeit, with some specific components that may perform more or less reliably than other components.)."[167] Major scrubber vendors have testified in confidential depositions that they expect their scrubbers to meet guarantees, which typically have a built-in vendor margin of safety.

Further, vendors offer "make-right" guarantees that cover the life of the FGD and all operating conditions. Make-right guarantees restore a malfunctioning FGD to its design basis. Regardless, the vendor must protect its reputation. Scrubber vendors have a vested interest in maintaining their market position and customer base. We are not aware of any vendor that would walk away from an FGD that did not perform according to its guarantee (even after the guarantee period has ended).

Third, this comment argues that using the vendor guaranteed level of 0.04 lb/MMBtu is "overly aggressive and provides no margin for normal operating conditions or long-term operation." Variations in scrubber performance due to changes in coal quality, reagent quality, startups, shutdowns, and malfunctions are normally accommodated in permitting by specifying a sufficiently long averaging time, in this case, the 30-day BOD, which is specifically designed to average out spikes. In general, averaging smooths out fluctuations in data.[168] We built further margin into the 0.04 lb/MMBtu limits, which are based on less than 98% control, except at Big Brown Unit 1, as summarized in –the above table. Finally, margin is built into the guarantee by the vendor.

Fourth, this comment attempts to support these claims by presenting seven years of SO_2 emission data for a single facility, Spruce Unit 1. Spruce Unit 1 is a 585-MW tangentially-fired

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[163] E-mail from Joseph Barba, Hitachi, to Phyllis Fox, January 31, 2007.
[164] Alstom Responses to Questions, Trimble County Unit 2, October 25, 2004, BV-00000171.
[165] Advatech, Double Contact Flow Scrubber, Available at: http://www.advatechllc.com/wp-content/uploads/2013/10/advatech-double-contact-flow-scrubber-brochure.pdf.
[166] Advatech, Advanced Flue Gas Desulfurization, 2005.
[167] James E. Staudt, Sikander R. Khan, and Manuel J. Oliva, Reliability of Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Systems for High Pollutant Removal Efficiencies on Coal Fired Utility Boilers, MEGA Symposium, 2004, p. 17.
[168] Thad Godish, Air Quality, Lewis Publishers, 2nd Ed. , 1991, p. 216, Figure 7.1; Richard W. Boubel, Donald L. Fox, Bruce Turner, and Arthur C. Stern, Fundamentals of Air Pollution, Academic Press, 3rd Ed., 1994, pp. 41 - 43.

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Combustion Engineering boiler, designed to burn PRB coal, which started up in December 1992.[169]

The original SO_2 scrubber, designed for 70% SO_2 control, was started up in 1992 when the boiler came online. The scrubber was upgraded in 2009 by Alstom to achieve 95% SO_2 control at a cost of about $9 million.[170] However, the SO_2 emission limit of 0.04 lb/MMBtu that this comment is critiquing is proposed only for retrofit scrubbers, i.e., new scrubbers on existing boilers, not upgraded scrubbers. Thus, the Spruce data is misleading, as the performance of a scrubber upgrade may not be representative of the performance that can be achieved by a new scrubber retrofit on an existing unit. In fact, we assumed 95% control for our scrubber upgrade analyses, versus 98% control (not to go below 0. 04 lbs/MMBtu) for our scrubber retrofit analyses.

Fifth, the upgraded Spruce Unit 1 scrubber came on line in early 2009, just as the SO_2 allowance market it would have benefited from collapsed, removing the incentive to operate it at its design SO_2 efficiency.[171] As scrubbers are costly to operate (see O&M costs in our Cost TSD), and this unit has very high SO_2 permit limits,[172] CPS Energy has no incentive to operate the upgraded scrubber at its design basis.

The apparent poor performance of Spruce Unit 1 is not due to issues implied in this comment, but rather the lack of any requirement or incentive to do better. The 30-day BOD data demonstrate that in spite of these disincentives, this upgraded scrubber achieved a 30-day BOD emission rate of 0.07 lb/MMBtu, except when the scrubber was offline, from July 16, 2011 to August 26, 2011. The Spruce permit exempts "maintenance, startup, and shutdown periods" from compliance with emission limits.[173] In other words, the boiler can legally continue to operate while the control equipment is shutdown. The 0.07 lb/MMBtu achieved at Spruce Unit 1 when the scrubber was operating is well within the range of our proposed SO_2 limits for scrubber upgrades.

We are not proposing an SO_2 emission rate of 0.04 lb/MMBtu for any scrubber upgrade, as they may be less efficient than a new retrofit scrubber. Rather, we proposed SO_2 emission rates of 0.06 to 0.60 lb/MMBtu for scrubber upgrades. The 0.04 lb/MMBtu limit that is the subject of this comment was only proposed for new scrubbers on existing boilers or "retrofits".[174] Thus,

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[169] R. Peltier, J.K. Spruce Power Plant, Unit 1, San Antonio, Texas, POWER, October 15, 2008, Available at: http://www.powermag.com/j-k-spruce-power-plant-unit-1-san-antonio-texas/?pagenum=1.
[170] CPS, Corporate Sustainability Report 2010, p. 57, Available at: https://www.cpsenergy.com/content/dam/corporate/en/Documents/Sustainability_Report_2010.pdf.
[171] C. Hitaj and A. Stocking, Market Efficiency and the U.S. Market for Sulfur Dioxide Allowances, Working Paper 2014-01, Congressional Budget Office, January, 2014. See especially Figure 1. Available at: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0CCAQFjAAahUKEwi1w9HwsJDIAhVIJB4KHRAvB2Y&url=https%3A%2F%2Fwww.cbo.gov%2Fsites%2Fdefault%2Ffiles%2F113th-congress-2013-2014%2Fworkingpaper%2F45044-SO_2MarketAnalysis_1.pdf&usg=AFQjCNHYiyaL3lTMimbRvluvI3DVa-T18w&cad=rja.
[172] Spruce Unit 1 Permit, Permit Numbers 18426 and PSDTX742M1, Special Conditions, Condition 8.
[173] Spruce Unit 1 Permit, p. 7, Condition 15.
[174] 79 FR 74,822, Table 1 (Dec. 16, 2014).

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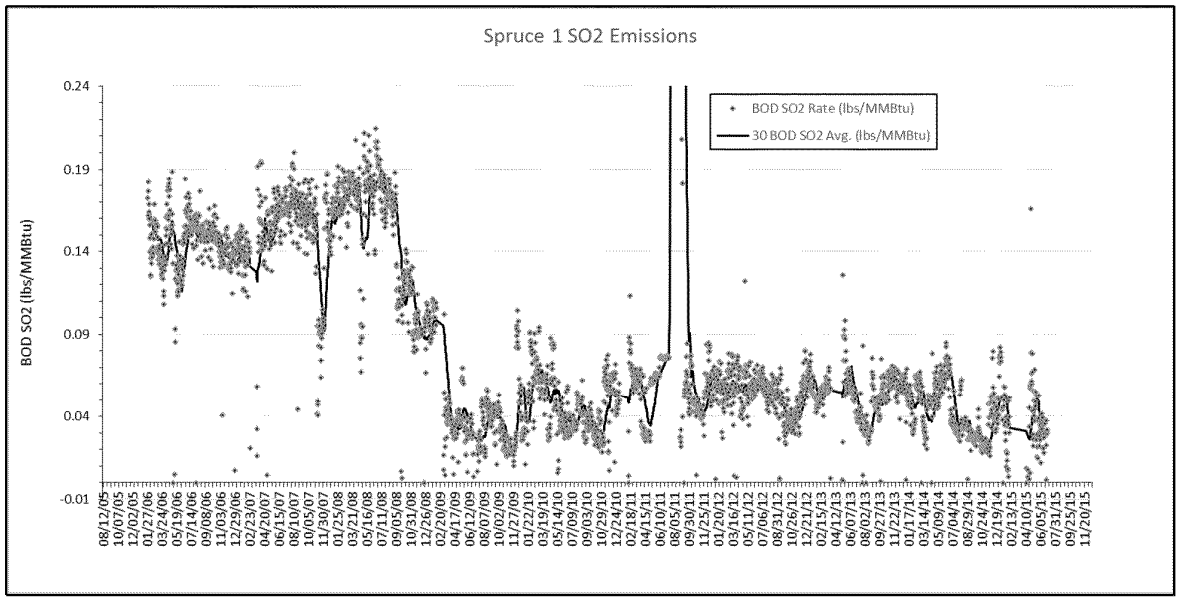
the performance of Spruce Unit 1 is irrelevant for supporting the arguments made in this comment.

Sixth, we note that this comment visually distorts the performance of Spruce 1 by plotting conventional 30-day moving averages, rather than 30-day BOD averages, as proposed in the rulemaking. Further, the graph is plotted on a fine scale to accentuate fluctuations. We replotted it using a 30-day BOD average and a scale that includes the uncontrolled spike.[175] This analysis is shown in the figure below.



This plot shows that Spruce Unit 1 is achieving a 30-day BOD of 0.07 lb/MMBtu after the upgraded scrubber stabilized, except for the period from July 16, 2011 to August 26, 2011, when the scrubber was off-line, but the boiler continued to operate. This is allowed under Spruce's current permit to operate during "routine maintenance, startup, and shutdown". The EPA recently issued a final rule barring these SSM exemptions in state permits.[176]
Finally, Sargent & Lundy omits that there are units that demonstrate our proposed limits and control efficiencies have been and are being achieved on a routine basis. To demonstrate that the proposed wet scrubber SO_2 emission limits (0.04 lb/MMBtu) are achievable, we reviewed our Clean Air Market Database (CAMD) to identify similar coal-fired boilers that have met a a 30 BOD average SO_2 emission rate of 0.04 lb/MMBtu or better continuously for at least 1 year.

First, we downloaded all annual SO_2 data from 2007-2014, inclusive. This annual data was filtered to select only the units that met the following criteria:

- Electric utility only
- Coal burning only

[175] See "Selected BOD SO_2 Averages-3.xlsx," Tab "Spruce 1" in our docket.
[176] http://www.epa.gov/airquality/urbanair/sipstatus/emissions.html

- Avg. annual SO_2 rate < 0.045 lb/MMBtu
- Wet FGD only
- Operating time > 4,800 hours
- 12 months of reported data only
- Retrofit or upgraded scrubber

We next researched the subset of wet FGDs that met these criteria and eliminated units that used lime wet FGD, as it can achieve a higher SO_2 removal efficiency, but is generally more expensive due to the cost of lime. We only retained one lime FGD, Milton Young 1, as it is the only unit in our dataset that fires lignite coal. We found many units coded as using lime FGD in the CAMD database that in fact used limestone FGD. We also eliminated scrubbers installed on newly built units at the time of initial construction. Most of the scrubbers that met these criteria were retrofits, the target of our analysis, but some upgrades were included. We retained these to compare retrofit with upgrade experience.

We adopted this conservative criteria and methodology in order to quickly and easily demonstrate that in fact there are a number of similar units operating wet scrubbers comfortably below our proposed SO_2 emission limit. In so doing, we note there are a number of additional similarly configured units (e.g., Scherer 1) that have demonstrated their ability to operate for extended periods of time below our proposed control efficiency, but do not meet these criteria. We do not advocate that our criteria and methodology are the only way to demonstrate the operational effectiveness of any particular control, scrubbers or otherwise.

We used EIA information to determine the coal type burned at each facility and eliminated all units that did not burn PRB, lignite, or a blend of PRB or lignite with another coal type, which are the predominate fuels burned by the subject Texas plants. We also researched each plant to confirm the scrubber type, scrubber install date, design control efficiency, and permit limits, where available. The resulting list of plants is:

- Iatan Unit 1[177]
- Boswell Energy Center Unit 3[178]
- James H. Miller Units 1, 2, 3, and 4[179]

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[177] Robert Peltier, Plant of the Year: KCP&L's Iatan 2 Earns POWER's Highest Honor, POWER, August 1, 2011, Available at: http://www.powermag.com/plant-of-the-yearkcpls-iatan-2-earns-powers-highest-honor/.

[178] Retrofitting Boswell Energy Center, Power Engineering, September 1, 2010, Available at: http://www.power-eng.com/articles/print/volume-114/issue-9/Features/retrofitting-boswell-energy-center.html. See also: http://www2.epa.gov/enforcement/minnesota-power-settlement (requiring SO_2 emission rate of no greater than 0.030 lb/MMBtu at Boswell Units 3 and 4) and Consent Decree at http://www2.epa.gov/sites/production/files/2014-07/documents/minnesotapower-cd.pdf ("Minnesota Power shall continuously operate an FGD device at Boswell Unit 3 such that the unit achieves and maintains a 30-day rolling average emission rate for SO_2 no greater than 0.03 lb/MMBtu." and "No later than May 31, 2016, Minnesota Power shall continuously operate a new FGD device at Boswell Unit 4 such that the Unit achieves and maintains a 30-day rolling average emission rate for SO_2 no greater than 0.03 lb/mmBTU."

[179] ADVATECH, Plant Miller – Wet FGD Retrofit Project, Available at: http://www.advatechllc.com/projects/air-quality-control-solutions/acid-gas-control/acid-gas-project-descriptions/southern-company-miller/. Title V Permit

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- Jeffrey Energy Center Units 1, 2, and 3[180]
- Milton Young Unit B1[181]
- Pleasant Prairie Unit 1 and 2[182]
- Sam Seymore (Fayette) Unit 1, 2,[183]and 3[184]
- Scherer Units 2, 3, and4[185]

We prepared graphs of these units showing the 30-day BOD SO_2 data superimposed on the measured daily data in lb/MMBtu. These graphs are included in our docket in the file "Selected BOD SO_2 Averages-3.xlsx." This file contains tabs corresponding to each of the above units, and a "Read Me" tab that explains our methodology.

The performance of each scrubber in our data set is summarized in the file, "Selected scrubber retrofit efficiencies.xlsx." The "Efficiencies" tab within this file reports vendor guaranteed control efficiency, achieved control efficiency, and the maximum 30-day BOD, excluding shakedown periods following initial startup of scrubber retrofits, and other items. This information supports our proposed SO_2 limits for both retrofits and upgrades. The 13 retrofit units have guaranteed control efficiencies of 95% to 99%, with eight of them guaranteed at 98% to 99%. These eight units are achieving 98% to 99% SO_2 control, with the exception of Scherer Unit 4, when calculated using our very conservative method explained in the "Read Me" tab.

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at: http://www.jcdh.org/EH/AnR/AnR13.aspx. Consent Decree at: http://www2.epa.gov/enforcement/alabama-power-company-clean-air-act-settlement.

[180] Westar Energy Sulfur Dioxide Removal Project on First of Jeffrey Energy Center's Generating Units Fully Operation, August 11, 2008, Available at: http://www.energycentral.com/generationstorage/fossilandbiomass/news/vpr/5341/WESTAR-ENERGY-SULFUR-DIOXIDE-REMOVAL-PROJECT-ON-FIRST-OF-JEFFREY-ENERGY-CENTER-S-GENERATING-UNITS-FULLY-OPERATIONAL; Gail Reitenbach, WATER AWARDE: Jeffrey Energy Center's Constructed Wetland Treatment System, POWER, August 1, 2014, Available at: http://www.powermag.com/jeffrey-energy-centers-constructed-wetland-treatment-system/?pagenum=1; and Westar Energy, Jeffrey Energy Center Wetlands, Available at: https://www.westarenergy.com/jeffrey-energy-center-wetlands.

[181] Burns & McDonnell, Milton R. Young Units 1 & 2, 2015, Available at: http://www.burnsmcd.com/Resource_/Project/2234/ProjectPdf/Milton-R-Young-Units-1-amp-2.pdf; MET, Wet FGD, Available at: http://www.met.net/wet-fgd-technologies-lime.aspx.

[182] Steven Gebhart and others, Pleasant Prairie Power Plant Air Quality Control Upgrade Project, Pleasant Prairie, Wisconsin, POWER, October 15, 2007, Available at: http://www.powermag.com/pleasant-prairie-power-plant-air-quality-control-upgrade-project-pleasant-prairie-wisconsin/ See also: http://www.pleasantprairieonline.com/services/communitydevelopment/powerplant.asp

[183] C. Frazer and others, Fayette Power Project Unit 3 FGD Upgrade: Design and Performance for More Cost-Effective SO_2 Reduction, Mega Symposium, 2010, Available at: http://www.babcock.com/library/documents/br-1845.pdf; LCRA Adds Scrubbers to Clean Sulfur Dioxide from Plant Emissions, August 1, 2011, Available at: http://www.statesman.com/news/news/local/lcra-adds-scrubbers-to-clean-sulfur-dioxide-from-1/nRc8M/.

[184] Austin City Council, Audit Report, Fayette Power Project Scrubber Costs, October 3, 2006, Available at: Powerplant Upgrades Test New Technology, ENR Texas & Louisiana, April 18, 2011, Available at: https://austintexas.gov/sites/default/files/files/Auditor/au06113.pdf; http://texas.construction.com/texas_construction_projects/2011/0418_powerplantupgrades.asp; Fayette Power Project, Available at: http://www.lcra.org/energy/electric-power/facilities/fayette-power-project/Documents/fayette_power_project_2013_03_22.pdf.

[185] ADVATECH, Plant Scherer – Wet FGD Retrofit Project, Available at: http://www.advatechllc.com/projects/air-quality-control-solutions/acid-gas-control/acid-gas-project-descriptions/southern-company-scherer/; ADVATECH, Double Contact Flow Scrubber, 2011, Available at: http://www.aecomprocesstechnologies.com/wp-content/uploads/2012/03/advatech-dcfs-brochure.pdf

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We note that compliance with the vendor guaranteed SO_2 control efficiency is typically determined by simultaneously measuring scrubber inlet and outlet SO_2 emissions. As CAMD does not report and facilities generally do not measure inlet SO_2 CEMS data, our estimated control efficiencies are based on pre-scrubber retrofit SO_2 and post-scrubber retrofit 30-day BOD data, as explained in the "ReadMe" tab noted above. None of the eight units that are achieving 98% to 99% SO_2 control have permit limits that require operation at this level. However, several have entered into consent decrees that do require control efficiencies approaching these values.

The maximum 30-day BOD, over the period of record when the scrubbers were operating, excluding scrubber "shakedown" periods, for retrofit FGDs designed to achieve 98% to 99% SO_2 control range from 0.02 lb/MMBtu at Iatan Unit 1 to 0.08 lb/MMBtu at Scherer Unit 3. Three of the units have achieved a maximum 30-day BOD equal to or less than our proposed SO_2 emission limit for scrubber retrofits of 0.04 lb/MMBtu:

- Scherer Unit 2: 0.01 lb/MMBtu based on 485 data points
- Iatan Unit 1: 0.02 lb/MMBtu based on 2,004 data points
- Boswell Energy Center: 0.03 lb/MMBtu based on 1,881 data points

All of these units burn PRB coal and are operating at these levels without permit limits that require compliance at achieved levels. The best performers are discussed below.

Scherer Unit 2

Plant Scherer consists of four 818 MW, Combustion Engineering boilers that became operational in 1982, 1984, 1987, and 1989. All of the units burn PRB coal. All four units were retrofitted with wet scrubbers that became operational in late 2010 to 2014. All of the units have continuously operated below 0.01 lbs/MMBtu for months at a time. The maximum 30-day BOD at Unit 2, after scrubber shakedown, was 0.01 lb/MMBtu, with the majority of the 30-day BOD data points below this level. The compliant data set includes 423 continuous 30-day BOD data points, between March 2014 and June 2015, all less than or equal to 0.01 lb/MMBtu. See the figures below for Unit 2. The second figure shows the period just after the scrubber became operational, plotted on a finer scale to better display the scrubber's performance:

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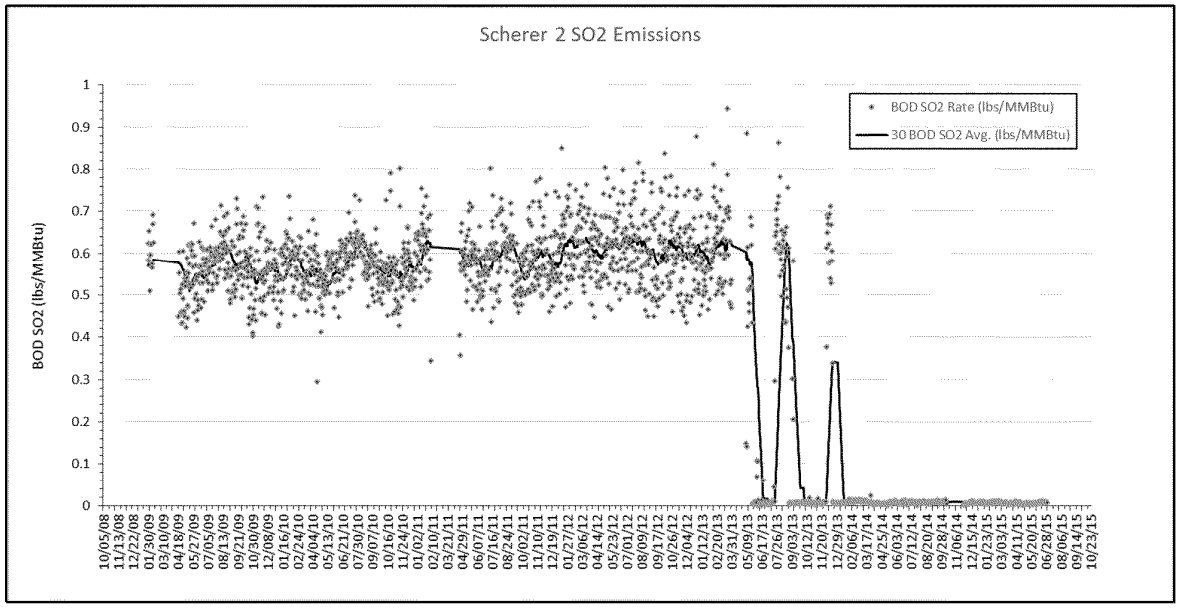
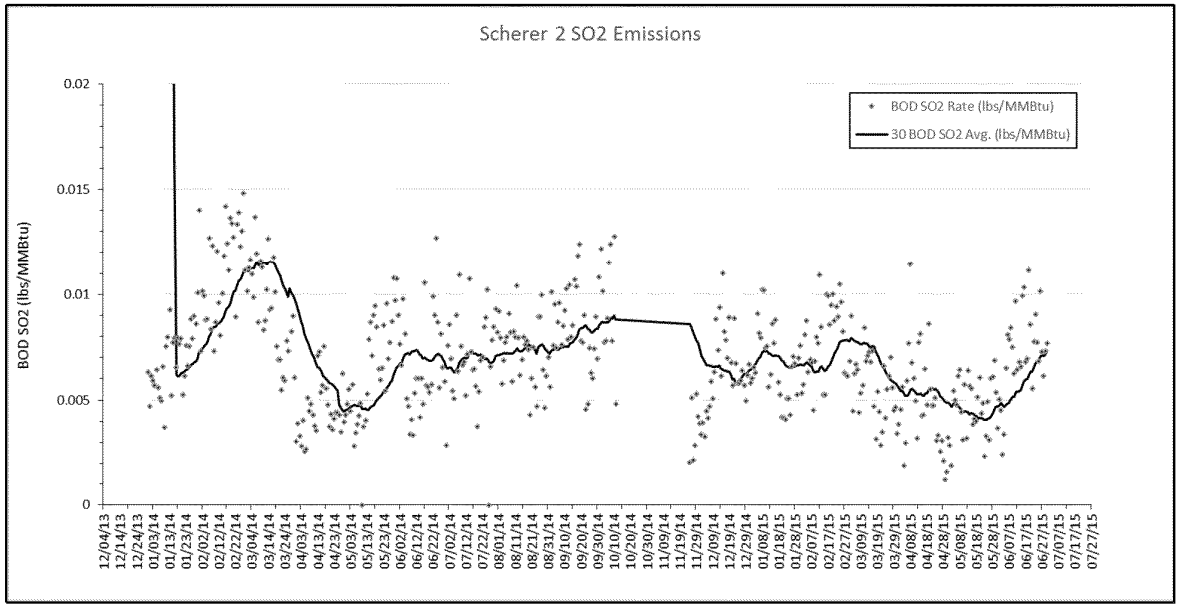




Scherer Units 1, 3, and 4 display similar levels of control capability.

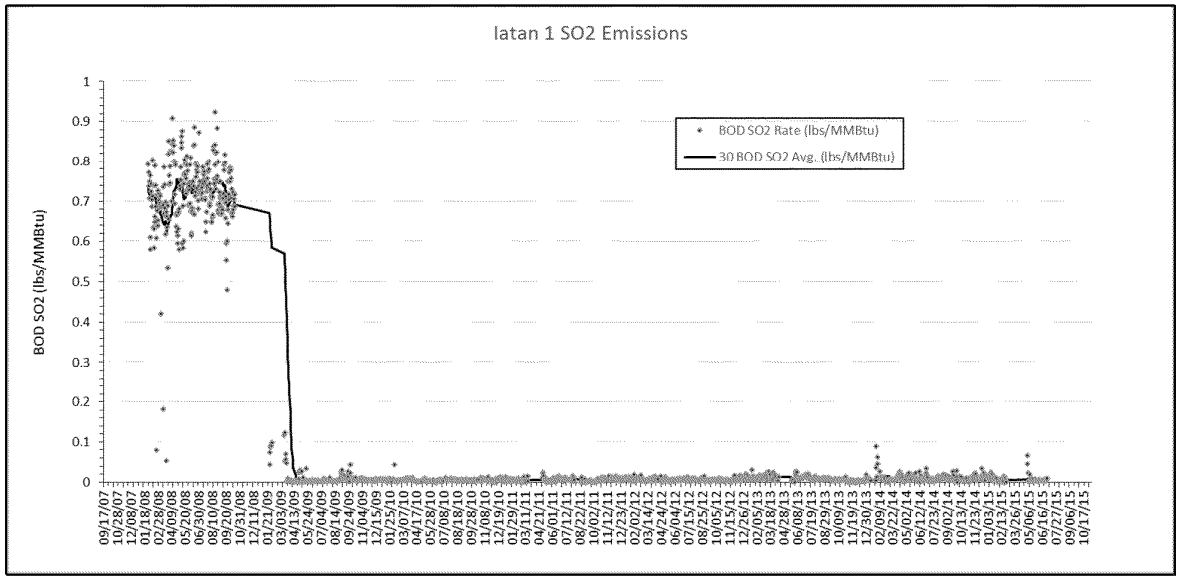
Iatan Unit 1(Retrofit Scrubber)

Iatan Unit 1 is an approximately 700-MW, PRB-fired, Babcock & Wilcox boiler that started up in 1980. This unit was retrofit with a wet scrubber in 2009 at the same time that new Iatan Unit 2 was built. The Iatan Unit 1 scrubber was installed to meet CAIR/CSAPR requirements for SO_2

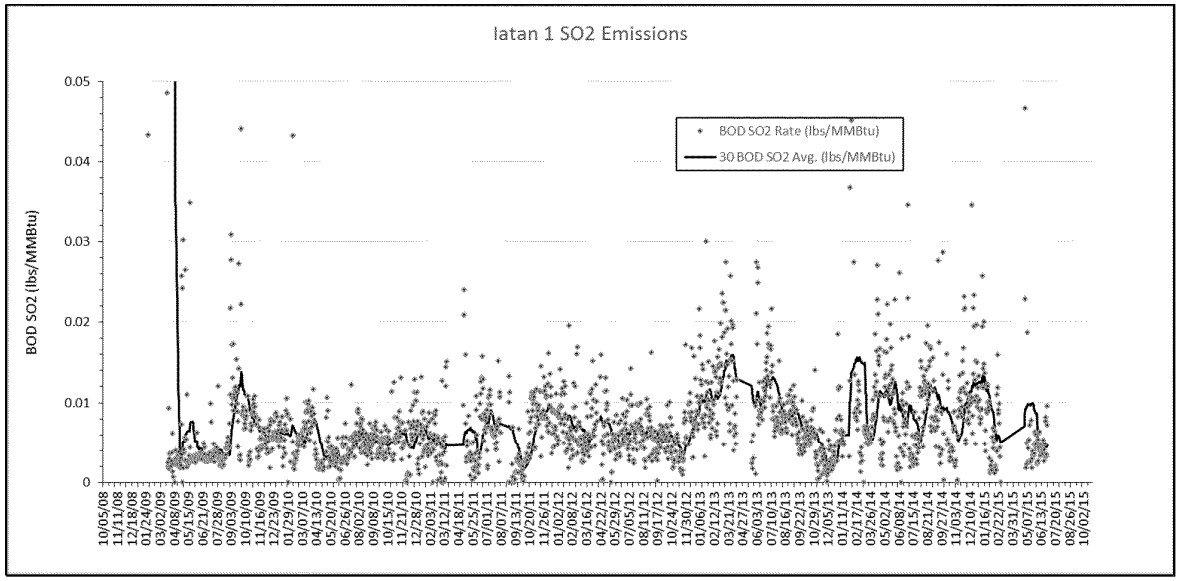
emissions and as a requirement for the air permit for Iatan 2, under a settlement agreement with the Sierra Club. [186]

The design of the air quality control system for both existing Unit 1 and new Unit 2 was very similar, resulting in similar performance. "The entire post-combustion AQCS [air quality control system] for Iatan 1 is virtually identical to that of the new Iatan 2….The wet FGD systems, using the same size vessel on both units, routinely operate at 99% removal, producing SO_2 levels in the exhaust gas well below the 0.06 lb/MMBtu permit limits. Each vessel is equipped with five recycle pumps but usually runs only three or four, depending on operating conditions." Thus, while the Unit 1 scrubber is a retrofit, its performance is nearly identical to scrubber on new Unit 2.[187]

This is the best performing wet scrubber retrofit in the data set based on 6 years of continuous operation. The maximum 30-day BOD at this unit, after scrubber shakedown, was 0.02 lb/MMBtu, with the majority of the 30-day BOD data points far below this level. The compliant data set includes 2,004 continuous 30-day BOD data points, between April 2009 and June 2015, all less than or equal to 0.02 lb/MMBtu. See the figures below. The second figure shows the period just after the scrubber became operational, plotted on a finer scale to better display the scrubber's performance. This is much better performance than is required by Iatan Unit 1's operating permit, which limits SO_2 emissions to 0.07 lb/MMBtu, based on a conventional 30-day rolling average.[188]



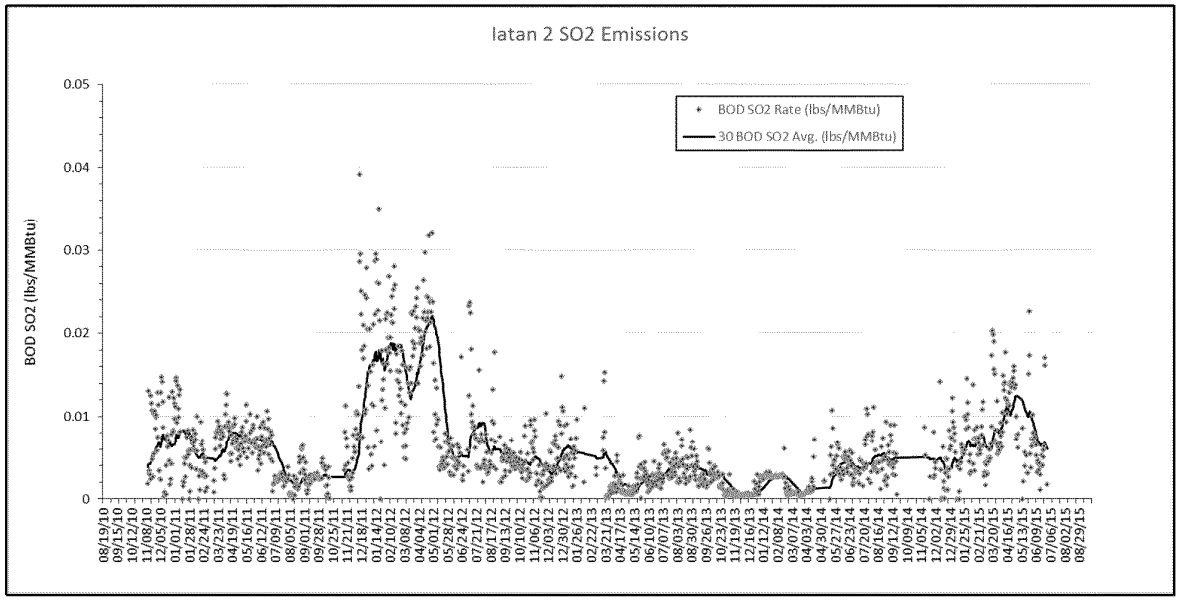
[186] Empire District Electric Co – '10-Q' for 3/31/12 – R13, "Compliance Plan" and "SO_2 Emissions." Available at: http://www.secinfo.com/d11MXs.p1Zm2.1s.htm; State of Kansas, Air Quality State Implementation Plan, Regional Haze, October 26, 2009, Available at: http://www.kdheks.gov/bar/reghaze/KDHERegHaze.pdf.
[187] Robert Peltier, Plant of the Year: KCP&L's Iatan 2 Earns POWER's Highest Honor, POWER, August 1, 2011, Available at: http://www.powermag.com/plant-of-the-yearkcpls-iatan-2-earns-powers-highest-honor/.
[188] Kansas City Power & Light, Iatan Generating Station, Permit No. 012006-019B.



Of note, the 30-day BOD SO_2 data for Iatan Unit 1 does not include the spikes found at some of the other units we reviewed. Iatan's operating permit does not include any exemptions from permit limits for startups, shutdowns, and malfunctions (SSM), while plants with frequent spikes include this exemption. The Iatan Unit 1 permit limits for all pollutants (except opacity) explicitly "include[ing] periods of start-up, shutdown and malfunction…"[189] Other plants with SSM exemptions in their permits have no obligation to operate their scrubbers during SSM events, resulting in the boiler continuing to run while the scrubber is offline for maintenance, creating spikes that are not related to scrubber performance.

Iatan 2, a new boiler and scrubber, displays a similar level of performance. Because it's scrubber pre-scrubber data is not available:

[189] Iatan Generating Station Permit Number: 012006-019A, July 13, 2007, p. 5, Note to Special Condition 2.E.



As can be seen from the above figures, both units have operated for years at a SO_2 emission rate below 0.01 lbs/MMBtu.

Boswell Energy Center Unit 3 (Retrofit Scrubber)

A wet scrubber was retrofit on existing (Clay) Boswell Energy Center Unit 3[190] in November 2009. It was designed by Hitachi to achieve 99% SO_2 control.[191] The existing permit to operate limits SO_2 emissions to 2.97 lb/MMBtu for a 1-hour average and 0.09 lb/MMBtu on a 30-day rolling average basis.[192] The unit has been operating far below these limits.

A subsequent 2014 Consent Decree reduced the Boswell SO_2 limit to 0.03 lb/MMBtu on a 30-day rolling average basis, as of the "date of entry" of the Consent Decree, which was filed on July 16, 2014.[193] This limit has been consistently met since stable scrubber operation began in December 2009. This limit reflects the judgment of EPA that a SO_2 limit of 0.03 lb/MMBtu on a 30-day rolling average basis is achievable.

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[190] Unit 3 is a 365-MW pulverized dry tangential-fired ABB Combustion Engineering boiler that fires PRB coal and started operating in 1973.

[191] Mitsubishi Hitachi Power Systems, Flue Gas Desulfurization, Available at: http://www.psa.mhps.com/products/environmental_products/fgd/.

[192] Minnesota Power Inc – Boswell Energy Center, Air Permit No. 06100004-007, Major Amendment, June 13, 2013, pdf 14.

[193] Consent Decree at http://www2.epa.gov/sites/production/files/2014-07/documents/minnesotapower-cd.pdf ("Minnesota Power shall continuously operate an FGD device at Boswell Unit 3 such that the unit achieves and maintains a 30-day rolling average emission rate for SO_2 no greater than 0.03 lb/MMBtu." and "No later than May 31, 2016, Minnesota Power shall continuously operate a new FGD device at Boswell Unit 4 such that the Unit achieves and maintains a 30-day rolling average emission rate for SO_2 no greater than 0.03 lb/mmBTU.")

The Consent Decree limit (0.03 lb/MMBtu 30-day rolling average) is much lower than the SO_2 limit proposed for wet FGD retrofits (0.04 lb/MMBtu 30-day BOD average).[194] A 30-day rolling average is more conservative (i.e., harder to meet) than the 30-day BOD average proposed in this rulemaking. Further, 0.03 is lower than 0.04. Thus, the Boswell Energy Center Consent Decree requires an SO_2 emission limit that is more aggressive than any of the limits proposed by EPA to satisfy reasonable progress. This 0.03 lb/MMBtu 30-day rolling average limit is currently being achieved.

The SO_2 CEMS data for Boswell Unit 3 is shown in the figures below. The second figure shows the period just after the scrubber became operational, plotted on a finer scale to better display the scrubber's performance. These figures demonstrate that the proposed 0.04 lb/MMBtu 30-day BOD for retrofit scrubbers under the Texas FIP has been met with a significant margin at this unit for over five years or for 1,881 individual continuous 30-day BOD data points.

[194] 79 FR 74,822 (Dec. 16, 2014).

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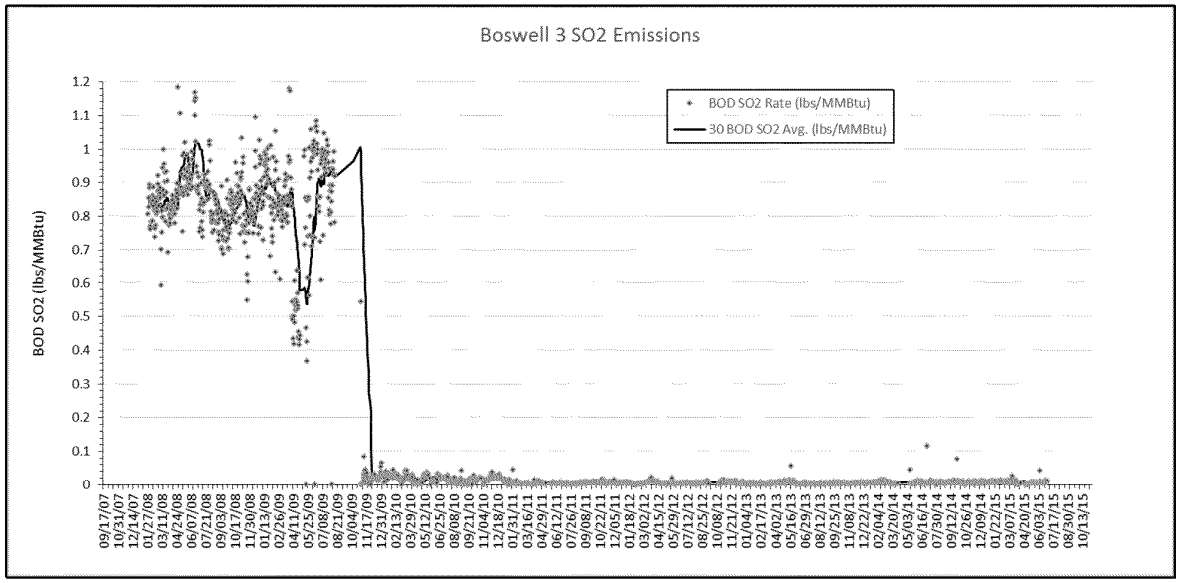

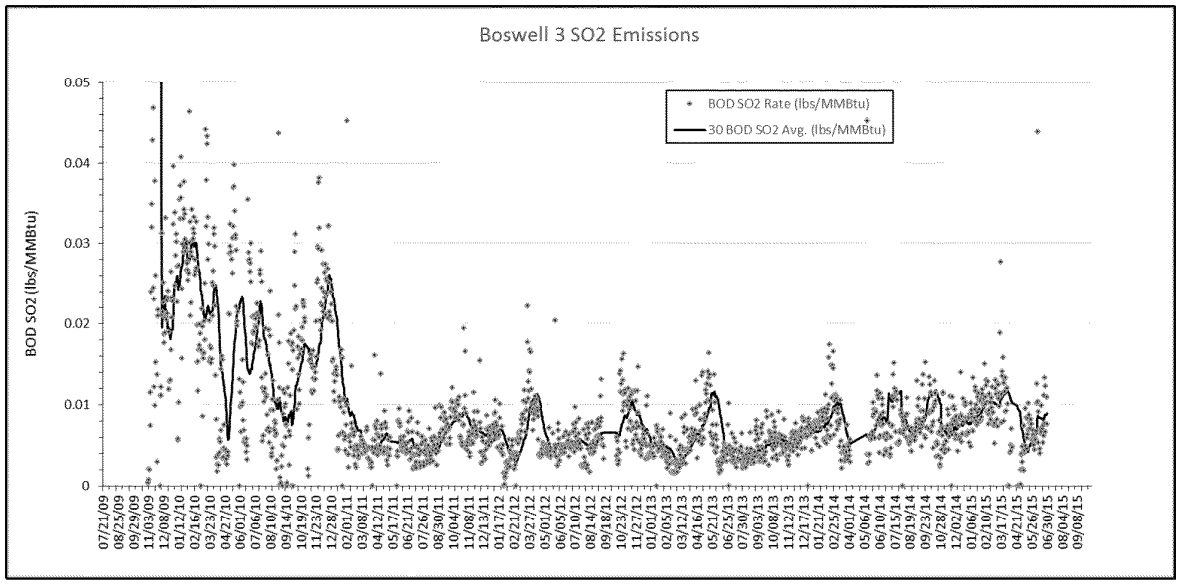

The cluster of spikes between January and December 2010, which are all less than or equal to 0.03 lb/MMBtu, are characteristic of scrubber shakedowns, during which the plant learns how to operate the scrubber and installation issues are resolved. Thereafter, this scrubber has consistently operated at a 30-day BOD of 0.01 lb/MMBtu, four times lower than required in the proposed Texas FIP.

The SO_2 CEMS data for Boswell Unit 3 for the period December 2009 through June 2015 further indicates that this retrofit scrubber has achieved 99% SO_2 reduction, determined from measured

SO_2 prior to and after scrubber installation. This is consistent with its 99% SO_2 guarantee.[195] The maximum 30-day BOD is 0.03 lb/MMBtu since stable operation of the scrubber started in November 2009. This is less than required for retrofit units under the proposed Texas FIP. The majority of the BOD values are substantially lower than this maximum.

Jeffrey Energy Center (Scrubber Upgrade)

Jeffrey Energy Center consists of three 720 to 750 MW, pulverized coal, dry bottom ABB Combustion Engineering boilers that are permitted to combust either liquid and/or solid fossil fuel. The existing wet scrubbers on Jeffrey Energy Center Units 1-3[196] were rebuilt and upgraded in 2008 to 2009 by Burns & McDonnell to achieve a minimum of 95% SO_2 control. The project included replacing the module internals including mist eliminators; adding forced oxidation; eliminating flue gas bypass; increasing limestone grinding capacity; and adding a gypsum dewatering system. Induced draft fans were upgraded and ductwork was replaced. The existing stack was modified for wet-stack operation.[197]

These units are operating under a Consent Decree[198] that requires that they achieve 97% SO_2 reduction and an SO_2 emission limit of 0.07 lb/MMBtu, both on a 30-day rolling average basis. The operating permit also includes an SO_2 limit of 0.8 lb/MMBtu for each unit, no averaging time specified, and no SSM exemptions. As of January 1, 2014, they also must meet a SO_2 emission limit of 0.15 lb/MMBtu as a 30-day rolling average, excluding periods of startup, shutdown and malfunction under a Regional Haze Agreement between Westar Energy, Inc. and KDHE.[199] They are currently meeting the percent reduction requirement.

Nearly five years of continuous operating data demonstrate that these three units have consistently exceeded their 95% SO_2 removal guarantee, achieving 97% to 98% SO_2 control relative to the original scrubber baseline.

The highest 30-day rolling BOD at these units since the upgraded scrubbers achieved stable operation in 2008 to 2009 is 0.06, 0.05, and 0.09 lb/MMBtu, at Units 1, 2, and 3 respectively.

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[195] The guaranteed SO_2 efficiency is calculated from the scrubber inlet and outlet SO_2 concentrations. The CAMD CEMS data is only for the outlet. Thus, we estimated the control efficiency from the average pre-scrubber and post-scrubber emissions, as explained in the "ReadMe" in the file, "Selected scrubber retrofit efficiencies.xlsx" in our docket

[196] Units 1, 2, and 3 are 720 to 750 MW pulverized coal dry bottom ABB Combustion Engineering boilers that started operations in 1978, 1980, and 1983, respectively. They burn PRB coal and were equipped with 60% efficient Combustion Engineering SO_2 scrubbers on startup.

[197] Burns & McDonnell, Jeffrey Energy Center Units 1, 2 & 3 Upgrade Project, 2015, Available at: http://www.burnsmcd.com/Resource_/Project/1244/ProjectPdf/Jeffrey-Energy-Center-Units-1-2-3-Upgrade-Project.pdf.

[198] Consent Decree, United States of America and State of Kansas v. Westar Energy, Inc., U.S. District Court for the District of Kansas, Civil Action No. 09-CV-2059 JAR/DJW, Lodged with federal court: 75 FR 4,847 (January 15, 2010). Available here: http://www2.epa.gov/enforcement/consent-decree-westar-energy-inc-civil-action-no-09-cv-2059-jardjw.

[199] Kansas Department of Health and Environment (KDHE), Air Emission Source Class I Operating Permit, Jeffrey Energy Center, January 28, 2002, p. 25, Condition 6 and p. 28, Condition 14.

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This performance is generally better than the proposed SO_2 BART limits for scrubber upgrades (0.06-0.60 lb/MMBtu).[200]

Startup, Shutdown, and Maintenance Exemptions

Many of the units that we did not specifically discuss, including all of the Miller units, and Scherer units 3 and 4, have large spikes that correspond to periods when the boiler was operating, but the scrubber was off-line. See, for example, "Selected BOD SO_2 Averages-3.xlsx," Tab: Scherer 4, the period 8/15/12 to 9/20/12. These (and other) plants with similar spikes have permits that exempt periods of startup, shutdown, and malfunction (SSM), allowing the boiler to continue to operate when the control equipment is offline.

The Title V Permit for the Scherer units[201] exempts many operating conditions, allowing the control equipment to shutdown while the boilers continue to operate. The Scherer permit limits SO_2 to 95% control on a 30-day rolling average basis, except it allows the boilers to operate without scrubbers during: (1) restarts; (2) periods of startup; (3) periods of shutdown; (4) periods of scheduled and/or preventative maintenance of control technology equipment if such maintenance cannot reasonably be performed during a scheduled outage; (5) periods of malfunction of the EGU or control technology; and (6) during certain testing and research periods. The scrubber on Scherer Unit 2 came on line in January 2014 and has only operated post-shakedown for 485 days. Its performance thus far is spectacular (maximum 30-day BOD = 0.01 lb/MMBtu), indicative of what the other longer-operating Scherer scrubbers could achieve, but for the SSM exemption periods when the scrubbers go offline, and the boilers continue to operate.

The spikes that diminish performance are generally not due to limitations of the scrubbers, but rather the failure of the facility to properly schedule adequate and timely maintenance to limit SO_2 emissions. All scrubbers require periodic maintenance. A facility without SSM exemptions will plan maintenance to avoid scrubber shutdowns during boiler operation, as demonstrated by the performance of Iatan Unit 1, discussed above.

Similarly, the Title V permit for Miller Units 1 - 4[202] limits SO_2 emissions to 1.2 lb/MMBtu (a very high limit, roughly double to its coal sulfur content[203]), with compliance only by stack test. The SO_2 permit condition includes this exception: "The FGD may be placed in bypass mode, provided all SO_2 emissions limitations are met." In other words, it can be turned off at will, as

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[200] 79 FR 74,822, Table 1 (Dec. 16, 2014).

[201] Scherer Steam-Electric Generating Plant, Part 70 Operating Permit, Permit Number: 4911-207-0008-V-03-0, May 8, 2012, Condition 3.4.14.

[202] Alabama Power Company, J. H. Miller, Jr. Steam-Electric Generating Plant, Major Source Operating Permit, For Units 1 & 2, p. 16, Condition 2: "The FGD may be placed in bypass mode, provided all SO_2 emissions limitations are met." For Units 3 & 4, p. 23, Condition 2: "The FGD may be placed in bypass mode, provided all SO_2 emissions limitations are met." Permit Available at: http://www.jcdh.org/EH/AnR/AnR13.aspx.

[203] From EIA-923, available here: http://www.eia.gov/electricity/data/eia923/
The 2014 sulfur content ranges from 0.23 to 0.31% and the coal heat content is approx. 17.7 MMBtu/ton. Converting to uncontrolled SO_2: (0.31% sulfur) X (1 ton/17.7 MMBtu) X (2,000 lbs/ton) X (2 molecules SO_2/1 molecule S) X (1/100%) = 0.7 lbs/MMBtu.

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long as it burns low sulfur coal. As the typical coal that is burned at this facility contains about 0.7 lb/MMBtu of SO_2, this condition effectively allows the scrubbers to shutdown while the boilers continue to operate. This pattern is seen in the CEMS data for all four of the Miller units, which have similar SSM exemptions. Thus, we do not report the maximum 30-day BOD for any of these units in the "Efficiencies" tab of "Selected scrubber retrofit efficiencies.xlsx" document, as the CEMS data are not representative of scrubber performance.

The scrubbers on Miller Units 3 and 4 additionally have to meet a 30-day rolling average SO_2 control efficiency of 95%, which drops to 90% if coal with more than 1% sulfur is burned, to comply with a consent decree. However, the 30-day rolling average removal efficiency "shall exclude all emissions that occur during any period of malfunction…".[204] Further the Miller scrubbers are designed to achieve 98% SO_2 control, while the permit only requires that they achieve 90% to 95% SO_2 control, depending upon coal quality. The CEMs data includes many spikes when the boiler is operating but the scrubbers were not. Thus, the apparent poor performance of these scrubbers is not due to poor scrubber performance, but the failure of the permit to adequately limit emissions. The data summarized above indicates that similar scrubbers achieve much better performance when there are no SSM exemptions.

Finally, some of the spikes appear to be due to unspecified errors. For instance, in the Miller 1 data, the daily SO_2 average for 6/22/14 is 3.25 lb/MMBtu. This is likely a bad data point, as it is way above the SO_2 baseline from the PRB coal the Miller units have historically burned. Other graphs have similar spikes that exceed the sulfur content of coal quality.

Thus, we disagree with S&L that our proposed scrubber retrofit SO_2 emission limits are not realistic or maintainable on a long-term basis. We agree with Ms. Stamper that it may be possible that many of the scrubber retrofit units can achieve greater control efficiencies than we proposed. Greater control efficiencies would result in a more favorable cost effectiveness (lower $/ton) and more visibility improvement. This is another area in which we strove to be conservative and demonstrate that even with many conservative cost assumptions, our analyses indicate that the scrubber retrofits we proposed are cost effective.

[204] Miller Permit, pp. 22-23, Conditions 2 and 3.

Appendix B: Wet FGD Scrubber Upgrade Control Cost Analysis as used in the Texas-Oklahoma FIP[205]

6 Upgrading Existing Scrubber Efficiencies

In Sections 3, 4, and 5, above, for those facilities with no SO_2 control, we contrasted the cost of DSI, SDA, and wet FGD. We then compared those costs to the visibility benefit from those controls from our visibility projection modeling, and we propose a RP and LTS determination. Here, we conduct similar analyses for those units listed in Table 1 with an existing SO_2 scrubber in order to determine if cost effective scrubber upgrades are available. Because all of the scrubber systems we evaluate are wet scrubbers, we limit our analyses of scrubber upgrades to wet scrubbers.

We proceed by first presenting information concerning the kinds of options generally available to facilities for upgrading their existing scrubbers. Following this, to the extent possible, we review all of the information we have at our disposal regarding the status of the existing scrubbers for each unit. This includes any upgrades the facility may have already installed. Although some of this information has been gleaned from public sources of information, much of it was collected as a result of our information collection effort. The companies that have supplied this information have asserted a Confidential Business Information (CBI) claim for much of it, as provided in 40 C.P.R. § 2.203(b). We therefore must redact any CBI information we utilize in our analyses, or otherwise disguise it so that it cannot be traced back to its specific source. Similar to our DSI, SDA, and wet FGD analyses we then contrast the cost of the various options for upgrading those scrubbers. Following this, we compare those costs to the visibility benefit from those controls from our visibility projection modeling, and propose a RP and LTS determination.

We have long recognized that existing underperforming SO_2 scrubbers are likely capable of being upgraded to much higher removal efficiencies. For example, we made this statement in the BART rule:[206]

> For those BART-eligible EGUs with preexisting post-combustion SO_2 controls achieving removal efficiencies of at least 50 percent, your BART determination should consider cost effective scrubber upgrades designed to improve the system's overall SO_2 removal efficiency. There are numerous scrubber enhancements available to upgrade the average removal efficiencies of all types of existing scrubber systems. We recommend that as you evaluate the definition of ''upgrade,'' you evaluate options that not only improve the design removal efficiency of the scrubber vessel itself, but also consider upgrades that can improve the overall SO_2 removal efficiency of the scrubber system. Increasing a scrubber system's reliability, and conversely decreasing its downtime, by way of optimizing operation procedures, improving maintenance practices, adjusting

[205] Reproduced from Sections 6 and 7 of the Cost TSD associated with the Texas-Oklahoma FIP, 81 FR 321.

[206] 70 FR 39171.

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scrubber chemistry, and increasing auxiliary equipment redundancy, are all ways to improve average SO_2 removal efficiencies.

We recommend that as you evaluate the performance of existing wet scrubber systems, you consider some of the following upgrades, in no particular order, as potential scrubber upgrades that have been proven in the industry as cost effective means to increase overall SO_2 removal of wet systems:

(a) Elimination of Bypass Reheat;
(b) Installation of Liquid Distribution Rings;
(c) Installation of Perforated Trays;
(d) Use of Organic Acid Additives;
(e) Improve or Upgrade Scrubber Auxiliary System Equipment;
(f) Redesign Spray Header or Nozzle Configuration.

We recommend that as you evaluate upgrade options for dry scrubber systems, you should consider the following cost effective upgrades, in no particular order:

(a) Use of Performance Additives;
(b) Use of more Reactive Sorbent;
(c) Increase the Pulverization Level of Sorbent;
(d) Engineering redesign of atomizer or slurry injection system.

Industry has also recognized that the efficiency of existing SO_2 scrubbers can and have been upgraded significantly and a number of companies offer scrubber upgrade services. For instance, URS makes this statement in its, "Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants:"[207]

> Upgrades have been performed on a large number of FGD units over the past 15 years and have resulted in increased SO_2 removal performance to levels ranging from 92 – 99%. These have ranged from minor modifications to the internal components of a given unit, to enhance gas-liquid contact, to conversion of some units from one FGD technology to another coupled with the addition or modification of various balance-of-plant equipment or processes.

It is typically much more cost effective to upgrade an existing FGD than to install a completely new scrubber.[208] These existing scrubbers can be upgraded by applying new scrubbing technology[209] to improve their removal efficiency, lower operating costs, and improve operations and reliability for much less than it would cost to replace them with a new scrubber.

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[207] Lipinski, George, et al, Assessment of Technology Options Available to Achieve Reductions of Hazardous Air Pollutants, URS, April 5, 2011, p. A-5.
[208] Maller et al, p. 5.
[209] See, e.g., Wolfgang Schuettenhelm and others, FGD Technology Developments in Europe and North America, Mega Symposium, 2001, http://www.babcockpower.com/pdf/rst-171.pdf.

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A scrubber can be upgraded by reusing as many structural components and equipment in the existing unit as possible, such as existing structural steel and absorber shells, ducts, pumps, and compressors. Scrubber upgrades have been completed on about 50 units in the last 15 years to enhance performance or lower overall operating costs.

As Staudt notes:[210]

> There have been numerous examples of FGD upgrades over the last several years that have improved SO_2 removal efficiencies. For example, the Fayette Station Unit 3, a 470 MW tangentially-fired coal unit in Texas, completed an upgrade to its 1988-vintage scrubber in 2010. The plant's control efficiency was increased from about 84 percent to 99 percent, higher than the guaranteed SO_2 removal efficiency of 95.5 percent. In Kentucky, E.On's Trimble County Generating Station Unit 1, a 550 MW tangentially-fired coal boiler, completed a scrubber upgrade in 2006. Its scrubber, installed in the 1980s, was originally designed for 90 percent removal efficiency. The scrubber system is now able to achieve over 99 percent SO_2 removal efficiency. In Indiana, NiSource upgraded the scrubbers at Schahfer Units 17 and 18 in 2009. The scrubber upgrades increased SO_2 removal efficiency from 91 percent to 97 percent.

Other successful scrubber upgrades include the AEP/SWEPCO Pirkey Unit 1 in Texas,[211] the San Miguel Electric Cooperative Unit 1 in Texas,[212] the Tuscon Electric Power Springerville Units 1 and 2 in Arizona;[213] the Gibbons Creek facility in Texas, the San Juan Generating Station in New Mexico;[214] the Culley Generating Station Units 2 and 3 in Indiana;[215] and the Trimble County Generating Station Unit 1 in Kentucky.[216] These upgrades have increased SO_2 removal to 92% to 99%.[217]

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[210] Staudt, James E., Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants Prepared For: Northeast States for Coordinated Air Use Management 89 South Street, Suite 602, Boston, MA 02111, March 31, 2011, p. 13.

[211] https://www.aeptexas.com/info/news/viewRelease.aspx?releaseID=146: "H. W. Pirkey Plant was equipped with an FGD system when it went into service in 1985. That system consistently removes nearly 80 percent of SO_2. This original equipment will be upgraded to bring its removal rate into the 90-percent range;" Tax Relief For Pollution Control Property Applications Filed for Harrison County 11/1994 & 10/2003. Available at: http://www.tceq.state.tx.us/assets/public/assistance/graphics/Prop2/harrison.pdf

[212] San Miguel Electric Cooperative FGD Upgrade Program Update, URS Corporation, June 30, 2014.

[213] Farber, et al, Results of FGD Upgrade Projects On Low-Rank Coals, Presented at Electric Power 2007 Conference and Exhibition EP-07 Session 12E2007. Covers upgrades to Pirkey Unit 1, San Miguel, and Springerville Units 1 and 2.

[214] Taylor, H., Nischt, W., San Juan Generating Station FGD Retrofit Project Update, Presented to: BR-1667 Power-Gen International '98, December 9-11, 1998, Orlando, Florida.

[215] Quitadamo, M., et al, SO_2 Removal Enhancement to the Vectren Culley Generating Station Units 2&3 Wet Flue Gas Desulfurization System, Babcock Power Technical Publication, Presented at the ICAC Forum 05', March 7-10, 2005, Baltimore, Maryland.

[216] Erickson, Clayton, et al, Wet Flue Gas Desulfurization (WFGD) Upgrade at the Trimble County Generating Station Unit 1, Presented at MEGA Symposium, August 28-31, 2006, Baltimore, Maryland.

[217] URS, 4/5/11, pp. A-5 to A-7; Babcock Power Environmental, Wet Flue Gas Desulfurization Scrubber Upgrades, 2009; Erickson, C., et al, Wet Flue Gas Desulfurization (WFGD) Upgrade at the Trimble County Generating Station Unit 1, Mega Sumposium 2006; Quitadamo, M. et al, SO_2 Removal Enhancement to the Vectren Culley Generating

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As we discussed in Section 5 in our wet scrubber retrofit cost calculations, a typical retrofitted scrubber is capable of 98% removal, down to an effective lower limit of 0.04 lbs/MMBtu. However, we recognize that scrubber upgrades are highly individualistic, depending on the particular equipment in use at the facility. Furthermore, we recognize that a number of the facilities we analyze for scrubber upgrades burn either PRB coals or blends of coals containing a large percentage of PRB coals. Consequently, in our analyses, we assign a presumptive scrubber upgrade target of 95% SO_2 removal, with the understanding that the ultimate individual efficiency will vary depending these factors.

6.1 Calculation of Existing Scrubber Efficiencies

In a typical situation in which we would propose that a pollution control device such as an SO_2 scrubber be installed, we would have historical emissions data to use as a baseline. In such an instance, we would apply the control efficiency of the scrubber to the uncontrolled historical SO_2 emissions, and be able to easily propose a controlled SO_2 emission rate that would be appropriate following the installation of the scrubber. However, we face a more difficult task in analyzing the efficiency of existing SO_2 scrubbers.

As we discussed above, we are confident that any of these existing scrubbers can be upgraded to perform similarly to newly retrofitted scrubbers. If we are to approach the task of calculating the cost of upgrading these scrubbers in a way similar to that of proposing a new scrubber, we must first be able to specify an SO_2 emission rate that would be appropriate following the installation of these scrubber upgrades. Because to our knowledge, none of these units monitors (via CEMS) their emissions before the exhaust gas traverses their existing scrubbers, we do not have CEMS baseline SO_2 emissions. However, we do have coal quality data, which can be used to establish uncontrolled SO_2 emissions.

We calculated the scrubber removal efficiency by utilizing the reported sulfur content and tonnages of the fuels burned and reported to EIA,[218] and the monitored SO_2 scrubber outlet emissions reported to us.[219] We did this by constructing a spreadsheet[220], which among other things, divides the annual SO_2 emissions by the theoretical uncontrolled SO_2 emissions based on coal sulfur content to estimate the percentage of SO_2 in the coal that is emitted by each of the scrubbed facilities in Table 1. We calculated the theoretical uncontrolled SO_2 emissions from EIA reported coal sulfur data. This calculation is summarized below for a typical unit that burns both lignite and subbituminous coals:

Station Units 2 & 3 Wet Flue Gas Desulfurization System, ICAC Forum 2005; Silva A., and Williams, P., WFGD Case Study – Maximizing SO_2 Removal by Retrofit with Dual Tray Technology, Mega Symposium, 2006; Henry S. Taylor and Walter Nischt, San Juan Generating Station FGD Retrofit Project Update, PowerGen; Maller G., et al, Improving the Performance of Older FGD Systems; B&W, Wet Flue Gas Desulfurization (FGD) Systems Advanced Technology for Maximum SO_2 Removal, 2007 (8,000 MW of non-B&W wet FGD system upgrades by replacing the original absorber internals with tray technology and forced-oxidation conversions).

[218] EIA Form 923. Available at http://www.eia.gov/electricity/data/eia923/

[219] EPA Air Markets and Programs Data. Available at http://ampd.epa.gov/ampd/

[220] See "Coal vs CEM data 2009-2013.xlsx," tab "charts," cell H12.

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$$(1)\ \left\{\frac{\left(\frac{\%}{100}\ \text{[illegible]}\ \frac{2000}{\text{[illegible]}}\right)+\left(\frac{\%}{100}\ \text{[illegible]}\ \frac{2000}{\text{[illegible]}}\right)}{\left(\frac{\text{[illegible]}}{\text{[illegible]}}+\frac{\text{[illegible]}}{\text{[illegible]}}\right)}\right\}\ \text{[illegible]}\ \left(\frac{2\ \text{[illegible]}\ 2}{1\ \text{[illegible]}}\right)$$

$$=\frac{\text{[illegible]}\ 2\ \text{[illegible]}}{\text{[illegible]}}$$

or, alternatively expressed in tons:

$$(2)\ \frac{\text{[illegible]}\ 2\ \text{[illegible]}}{\text{[illegible]}}\ \text{[illegible]}\ \left(\frac{\text{[illegible]}}{\text{[illegible]}}+\frac{\text{[illegible]}}{\text{[illegible]}}\right)$$

$$=\text{[illegible]}\ 2\ \text{[illegible]}$$

and the scrubber efficiency is then:

$$(3)\ \text{[illegible]}=1-\left(\frac{\text{[illegible]}\ 2\ \text{[illegible]}}{\text{[illegible]}\ 2\ \text{[illegible]}}\right)$$

In equations (1) and (2), the percentage and tonnage values are those reported by the facility to the EIA for each fuel type. In equation (3), the annual EPA reported tons of SO_2 are those reported to us.[221]

In the following table, we summarize our calculation of the SO_2 removal efficiency for the existing scrubber systems:

[221] EPA Air Markets and Programs Data. Available at http://ampd.epa.gov/ampd/

Table 14. Efficiency of Units with existing SO_2 scrubbers

Facility	Unit	Scrubbed?	Bypass?	2009-2013 Average SO_2 Removal Efficiency (%)
Sandow 4	1	Y	Y	75.7
Monticello	3	Y	Y	60.0
Martin Lake	1	Y	Y	69.2
Martin Lake	2	Y	Y	71.9
Martin Lake	3	Y	Y	69.8
Limestone	1	Y	Y	78.1
Limestone	2	Y	Y	77.0
San Miguel	1	Y	N	94.0
W. A. Parish	8	Y	Y	84.0

We were interested in gauging the accuracy and precision of our calculations of the theoretical uncontrolled SO_2 emissions, so we compared it to the EPA reported SO_2 emissions for units that do not have scrubbers. The following table presents that information:

Table 15. Comparison of theoretical to monitored SO_2 emissions for unscrubbed units

Unit	2009-2013 average monitored SO_2 emissions (tons)	2009-2013 average theoretical SO_2 emissions (tons)	Percentage theoretical to monitored SO_2 emissions (%)
Big Brown Unit 1	30,606.1	32,489.3	6.2
Big Brown Unit 2	30,638.8	32,048.5	4.6
Coleto Creek	16,665.1	18,771.5	12.6
Monticello Unit 1	16,434.9	18,288.8	11.3
Monticello Unit 2	15,458.0	17,805.3	15.2
Tolk Unit 171B	10,223.9	11,582.1	13.3
Tolk Unit 172B	10,889.4	11,395.4	4.6
W. A. Parish Unit 5	14,295.6	17,480.7	22.3
W. A. Parish Unit 6	15,376.5	17,404.9	13.2
W. A. Parish Unit 7	12,119.3	14,604.6	20.5
Welsh Unit 1	7,956.4	9,618.3	20.9
Welsh Unit 2	8,075.8	9,483.2	17.4
Welsh Unit 3	8,490.6	9,794.1	15.4
Average			13.6

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This table shows that the actual SO_2 emissions as measured by CEMS are about 13.6% lower than the SO_2 estimated from coal quality data. The difference between these two numbers 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. We expect these errors to be compounded for units that blend coals.
- 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.[222]
- Potential effects of NOx and PM pollution control devices. SCRs, which are operating at the Parish units, convert a small amount of SO_2 to SO_3 as a consequence of the catalysts. Low SO_3 conversion SCR catalysts are available, but we do not know if the Parish units employ them. ESPs and baghouses reduce sulfur by removing particulate matter with absorbed SO3. Further, the filter cake in a baghouse absorbs SO_3.[223]
- Losses of sulfur, such as pyrite, when the coal is pulverized or in bottom ash.
- 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.

Therefore, we acknowledge that both our calculations of current SO_2 scrubber efficiency, and our calculations of tons of SO_2 removed once a scrubber upgrade is performed (and hence our cost effectiveness calculations) will have some error. We discuss how we propose to treat this in our Federal Register Notice for our proposed action.

6.2 Historical Scrubber Designs and Upgrades

The scrubber systems we are evaluating were all installed in the late 1970s to mid-1980s as part of the initial design of the facilities. All employ wet limestone, and with one exception – San Miguel – have scrubber bypasses. Scrubbers of this vintage were typically designed to meet the 1971 New Source Performance Standards (NSPS) for EGUs, which required new coal-fired boiler to meet a SO_2 limit of 1.2lb/MMBtu; or the 1979 NSPS, which additionally required 70% control, not to exceed 0.6 lbs/MMBtu unless 90% control was achieved. [224] Compliance usually involved using multiple absorbers with spares.[225]

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[222] Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, Technical Update, EPRI, March 2012.

[223] 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.

[224] Flue Gas Desulfurization Inspection and Performance Evaluation Manual, EPA/625/ 1-85/019, October 1985, Sections 2.1.1.1 and 2.1.1; Farber, et al, p. 18.

[225] Spare scrubber modules allow FGD systems to maintain full or partial operating capability when a primary module fails or is down for service. Early scrubber design commonly included spares due to poor operating experience and the NSPS "emergency condition" provision. See, e.g., William DePriest and Rajendra P. Gaikwad, Economics of Lime and Limestone for Control of Sulfur Dioxide, 2003.

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As Weilert notes,[226] "This is likely due to the requirement of the EPA's new source performance standard (NSPS) for continuous compliance with a 30-day rolling average SO_2 removal, and the provision that stipulates a spare absorber module as a prerequisite to operation during emergency conditions with a malfunctioning FGD system." However, industry gradually recognized that module spares were not required due to advances in scrubber technology, and the proven reliability of single-module FGD systems.[227] Thus, utilization of an existing spare FGD module at one of the facilities we are analyzing (Limestone) potentially represents a cost effective opportunity to increase scrubbing capacity. The following tables summarize the FGD information we have available as a result of mandatory reporting to the EIA via Forms 860 and 923, and from Weilert:[228]

[226] Carl Weilert, FGD Systems Utilizing Single Absorber Modules: The Wave of the Future for New Utility Boilers, Burns & McDonnell Technical Paper.

[227] Bailly Generating Station Advanced Flue Gas Desulfurization System, Final Environmental Information Volume, April 1989; Carl Weilert, Ibid., p. 12: "The available data indicates that single-module FGD systems can be extremely reliable."; Frazer, C., et al, Fayette Power Project Unit 3 FGD Upgrade: Design and Performance for More Cost-Effective SO_2 Reduction, Babcox and Wilcox Technical Paper presented at the EPRI Mega Symposium 2010, p. 3: "Ultimately, the options selected, and discussed above, offer the station the flexibility to permanently remove one of the absorbers from regular service." Taylor et al, Control of SO_2 emissions from power plants: A case of induced technological innovation in the U. S., Technological Forecasting & Social Change 72 (2005) 697 718. …." Page 715: " … according to a study of 111 FGD installations in 1986-1988 that declared that reliability was no longer an issue with FGD. With increased reliability, costly design options such as spare absorber modules were dropped in the 1990s."; Schuettenhelm, W et al, FGD Technology Developments In Europe And North America, Babcock Technical Paper, Presented at the EPA-DOE-EPRI Mega Symposium Arlington Heights, Illinois, August 20-24, 2001, p. 3: "The F. B. Culley FGD (Vectren) system located near Evansville, Indiana … was designed to remove 95% of the SO_2 based on a 10 lb/MMBtu fuel. A unique feature of the project is that it uses one absorber to serve two generating units with no bypasses."

[228] Weilert, C., and Meyer, E., Utility Design Trends, Power Engineering, 8-1-2010; personal communication.

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Table 16. Summary of FGD information[229]

Facility	Units	2011 EIA 860								2012 EIA 923		
		In-service year	Sorbent Type 1	Sorbent Type 2	Bypass?	FGD Trains	FGD Trains at 100% Load	Design Removal Efficiency (%)	Flue Gas Entering FGD (%)	Efficiency at Annual Operating Factor	Tested Efficiency at 100% Load	Date Latest Efficiency Test
Sandow 4	1	1981	LS	DB	Y	3	3	92	83	74.4	74.4	01/1984
Monticello	3	1978	LS	DB	Y	3	3	95	75	55	55	01/2007
Martin Lake	1	1977	LS	DB	Y	4	4	95	95	64.7	64.7	02/1991
Martin Lake	2	1978	LS	DB	Y	4	4	95	95	64.9	64.9	02/1991
Martin Lake	3	1979	LS	DB	Y	4	4	95	95	67.8	67.8	02/1991
Limestone	1	1985	LS	DB	Y	5	4	90	100	77.1	91.5	12/2011
Limestone	2	1986	LS	DB	Y	5	4	90	100	75.8	91.5	12/2011
San Miguel	1	1982	LS		N	4	4	94.2	100	94.1	94.3	05/2010
W. A. Parish	8	1982	LS		Y	3	3	85	82	81.9	73	01/1985

[229] We question the accuracy of some of this information reported to EIA. For instance, the Limestone facility reports that it has a bypass for its scrubbers, yet it reports that 100% of the flue gas enters the scrubber. Also, the Martin Lake facility reports that for Unit 1, 95% of its flue gas enters its FGD and that of that gas, the removal efficiency is 95%. This would result in an overall SO_2 removal efficiency of 90.3% (0.95 X 0.95). However, our own calculations indicate an average removal efficiency of much less. We suspect the EIA scrubber efficiencies are a mixture of supplier guarantees (not counting bypassed flue gas) and actual estimates.

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Table 17. Selected information from Weilert and Meyer

Facility Name[a]	FGD ID[b]	Process Type[a]	Absorber Type I[b]	Sorbent Type[b]	Provision for Bypass[b]	Incorporation of Spare Module[b]	Manufacturer[b]	Material of Construction	Oxidation Mode
Limestone	1	Wet Limestone	SP	LS	Y	Y	AL	NIe	Forced[e]
Limestone	2	Wet Limestone	SP	LS	Y	Y	AL	NIe	Forced[e]
Martin Lake	1	Wet Limestone	TR[m]	LS	Y	N	HRC	FRCS[f]	NR
Martin Lake	2	Wet Limestone	TR[m]	LS	Y	N	HRC	FRCS[f]	NR
Martin Lake	3	Wet Limestone	TR[m]	LS	Y	N	HRC	FRCS[f]	NR
Monticello	3	Wet Limestone	SP	LS	Y	N	MX	FRCS[f]	NR
San Miguel	1	Wet Limestone	TR[m]	LS	N	N	BW	SS[m]	Inhibited[e]
Sandow	4	Wet Limestone	SP	LS	Y	N	AL	SS[e]	NR
W A Parish	8	Wet Limestone[f]	SP	LS	N[230]	N	MX	FRCS[f]	NR

Notation from Weilert and Meyer

a This column is from the 2010 "Emissions" section of EPA's Clean Air Markets Division "Data and Maps" website
b This column is from 2008 EIA-860 data Schedules 6-G & 6-H
c This column is from 2008 EIA-860 data "Annual Electric Generator Report" Generator (Existing) File
d 2009 "Emissions" section of EPA's Clean Air Markets Division "Data and Maps" website
e Information is from respective vendor either from direct correspondence or from their website/publications
f DOE "Utility FGD Survey January - December 1989" Publication Number ORNL/M-2347
g 2008 "Emissions" section of EPA's Clean Air Markets Division "Data and Maps" website
h 2007 "Emissions" section of EPA's Clean Air Markets Division "Data and Maps" website
I 2008 EIA 860 data "Annual Electric Generator Report" Generator (Proposed) File
j Material information from Stebbins Manufacturing Installation List
k Upgrade by BPE according to BPE
l 2005 EIA 767 data Schedule 8 A & 8 B

[230] We note that the Weilert and Meyer data reports that the W A Parish facility does not have a scrubber bypass, yet the EIA data reports that the facility does have a bypass. Examination of aerial photos of Unit 8 seem to confirm the presence of ducting that would serve a bypass.

m Authors' correction based on personal knowledge
n Facility's Utility's website
o EPA's Steam Electric Power Generating Point Source Category: 2007/2008 Detailed Study Report (Online)
p Multiple FGD units are associated with one generator. The value reported is the nameplate capacity for the generator.

General	Absorber Type	Sorbent Type	Material of Construction	Unit Manufacturers
NA Not Applicable	BR Jet Bubbling Reactor	AF Alkaline fly ash	CO Combination	AD Allied
NR Not Reported	CD Circulating Dry Scrubber	LA Lime and alkaline fly ash	CS Carbon Steel	AL Alstom
	DCFS Double Contact Flow Scrubber	LF Limestone and alkaline fly ash	FRCS Flakeglass Reinforced Resin	AM American Air Filter
	DSI Dry Sorbent Injection	LI Lime	Lined Carbon Steel	AP Airpol
	PA Packed	LS Limestone	FRP Fiberglass Reinforced Plastic	AV Advatech
	SD Spray Dryer	MO Magnesium oxide	NI Nickel Alloy	BPE Babcock Power Environmental
	SP Spray	SA Soda ash	RLCS Rubber Lined Carbon Steel	BW Babcock and Wilcox
	TR Tray	SC Sodium carbonate	SS Stainless Steel	CH Chiyoda
	VE Venturi	SL Soda liquid	TL Tile Lined	FMC FMC
				HI Hitachi
				HRC Hamon Research Cottrell
				KE M W Kellogg
				MHI Mitsubishi Heavy Industries
				MX Marsulex
				SHU Saarberg Holter
				SI Siemens
				OT Other

The Instructions for EIA Form 860 indicate the following regarding the fields of interest to us:

Can flue gas bypass the flue gas desulfurization unit? Indicate whether the flue gas can bypass the FGD unit.

What is the total number of flue gas desulfurization unit scrubber trains or modules? Enter the total number of flue gas desulfurization unit scrubber trains or modules operated.

How many flue gas desulfurization unit scrubber trains or modules are operated at 100 percent load? Enter how many flue gas desulfurization unit scrubber trains or modules are operated at 100 percent load.

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What is this unit's design removal efficiency for sulfur dioxide when operating at 100 percent load? Report the design removal efficiency to nearest 0.1 percent by weight of gases removed from the flue gas when operating at 100 percent generator load.

The instructions for EIA Form 923 indicate the following regarding the fields of interest to us:

FGD or FGP Efficiency Rate at Annual Operation Factor (H, K): Enter removal efficiency, based on the annual operating factor. Annual operating factor, as given by the formula below, is defined as the product of design firing rate and hours of operation per year, divided by annual total fuel consumption, expressed as a percentage. If actual data are unavailable, provide estimates, based on equipment design performance specifications.

Annual Operating Factor (AOF) =
*100 * Design Firing Rate (MMBtu/hr) * Hours of Operation (hr) / Total Fuel Consumption (MMBtu)*
*Removal Efficiency at Annual Operating Factor = FGP Removal Efficiency * Average AOF*

FGD or FGP Tested Efficiency Rate (at 100% Load) (I, L): Enter the tested efficiency of the FGD and/or FGP unit for each controlled pollutant. If not tested at 100% load, provide the load at which the test was conducted in a comment on Schedule 9. If an efficiency test has not been conducted, leave field blank and provide a comment.

Test Date (J, M): Enter the date of the latest efficiency test for the FGD and/or FGP unit for each controlled pollutant. If no test was conducted, leave the test date blank.

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These first generation FGD units were typified by multiple absorber modules, SO_2 removal efficiencies between 75% and 90%, and the use of either natural or inhibited oxidation.[231] However, as Staudt notes,[232] "… limestone-forced oxidation (LSFO) wet scrubber technology is [now] the most widely used form of wet FGD and is more widely used on coal-fired power plants than every other form of FGD combined. State-of-the-art LSFO systems are capable of providing very high levels of SO_2 removal – on the order of 98 percent or more." These early units were often designed to operate with a dry stack, which was most often accomplished by bypassing a portion of the flue gas around the scrubber to maintain gas temperatures high enough to prevent condensation and the formation of H_2SO_4 which would erode an unprotected chimney. These older scrubbers represent a significant investment that can be optimized, improved, and/or upgraded to minimize the cost of reducing SO_2 emissions.

These early scrubbers typically employed two scrubbing zones, a venturi section with spray nozzles to enhance gas-liquid mixing and a second spray zone. The second zone sometimes included a tray or packing to enhance gas-liquid contact.[233] They had many operational problems including poor reagent utilization, tray scale, ducting problems, and plugging of nozzles and demisters.[234] Solids deposited on these devices, plugging them, reducing flow and increasing differential pressure, requiring weekly cleanings and driving up O&M costs. The resulting high O&M costs led to replacement of packings and redesign.[235]

We know from our review of the facility's responses to our information collection requests, described in Section 7.1, that many, if not all of these original scrubbers have been modified since their original installations to cure these and other problems. However, there is very little publicly available documentation. A number of key factors have pushed owners to upgrade their scrubbers, often absent any regulatory drivers including: [236]

- Reduction in operating costs
- Reduction in maintenance costs
- Flexibility to burn higher sulfur coals
- Sale of byproduct (upgrade to forced oxidation allowing the sale of gypsum)
- Opportunity to generate excess emissions credits for sale,
- An increase in the SO_2 emission credits price 20
- Reduction in auxiliary power consumption

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[231] Farber, et al.

[232] Staudt, James E., Control Technologies to Reduce Conventional and Hazardous Air Pollutants from Coal-Fired Power Plants Prepared For: Northeast States for Coordinated Air Use Management 89 South Street, Suite 602, Boston, MA 02111, March 31, 2011. p. 10.

[233] Buecker, B., Important Concepts of Wet-Limestone Flue Gas Desulfurization Energy-Tech Magazine, October 2008, http://www.energy-tech.com/article.cfm?id=21789; PEI Associates, 1985.

[234] See, e.g., NERC, Impact of FGD Systems. Availability Losses Experienced by Flue Gas Desulfurization, July 1991, pp. 10, 27; Farber, et al, Ibid.

[235] Buecher, Brad. Ibid.

[236] Klingspor, J., Brown, G., Techniques for Improving FGD System Performance to Achieve Ultra-High SO_2 Removal Efficiencies, URS Technical Paper; Frazer, C., et al, Ibid., p. 8: "The unit also has the option to burn lower-cost, high-sulfur coal, while still maintaining emissions limits;" NERC, Impact of FGD Systems. Availability Losses Experienced by Flue Gas Desulfurization, July 1991; Maller, G., et al; Taylor, H., Nischt, W., p. 5: "This conversion project was justified on the basis of O&M and power/fuel savings."

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- Solving process problems that cause high maintenance, reagent, and disposal costs
- Improving reliability (reducing scrubber-related outages)
- Ability to treat a higher volume of flue gas to improve scrubbing efficiency

Analyses of these upgrades reveals that they typically have performed better than guaranteed. Our examination of the facility's responses to our information collection requests, lead us to conclude that some of these existing scrubbers are able to operate at higher removal efficiencies than they currently achieve due to changes in the factors that led to their upgrades. For example, our regulations have been delayed through litigation, SO_2 allowance markets have not materialized or allowance costs have not risen as expected, changes in natural gas pricing, etc. Consequently, we suspect that absent a specific permit limit, other enforceable requirement, or market driver to operate at these higher scrubber efficiencies, some of these facilities may simply choose not to do so for economic reasons. For example, it has been suggested that some facilities owners turn off their scrubbers at peak demand to maximize profits.[237]

6.3 Options for Upgrading SO_2 Scrubbers

The performance of older FGDs is often limited by poor reliability and poor design, resulting in lower SO_2 removal efficiencies and higher operating and maintenance costs than newer FGD systems. The causes for poor performance include the following:[238]

- Bypassing a portion of the flow around the scrubbers
- Unbalanced flow between absorbers
- Poor gas distribution within the absorber
- Poor spray coverage within the absorber
- No droplet-to-droplet interaction within the absorber
- Sneakage along the sides of the absorber
- Poorly designed mist eliminator wash systems
- Inadequate scrubber chemistry

Existing FGD systems can be upgraded by applying new scrubbing technology[239] and improved upon in many instances so that they can operate at performance and reliability levels similar to new systems for much less than it would cost to replace them with a new scrubber.[240] As noted in the BART Rule, "upgrading an existing scrubber system is typically considered more cost

[237] Wynne, H., et al, U.S. Utilities: Can Texas Comply with the Cross-State Air Pollution Rule? Yes, If Existing Scrubbers Are Turned On, Bernstein Research, July 20, 2011, p. 5: "This pattern suggests that generators have sought to avoid the reduction in net generation that results from operating the scrubbers (reflecting the parasitic load of the emissions control equipment) during hours when power prices are highest. Conversations with the investor relations departments of Energy Future Holdings and NRG Energy confirmed that, as long as continuous operation of SO_2 scrubbers is not required to comply with currently prevailing SO_2 emissions limits, generators will avoid operating the scrubbers so as to maximize net power output and revenues, and minimize variable operation and maintenance expense, including the cost of sorbents and water required for the operation of the SO_2 scrubbers."
[238] Klingspor, J., Experience from 52,280 MWs of Wet Flue Gas Desulphurisation System Upgrades, VGD PowerTech, December 2012.
[239] Schuettenhelm, W et al; Maller, G., et al; Klingspor, J.,et al; Farber, P., et al; Klingspor, J., et al.
[240] Maller, G., et al, p. 13.

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effective than constructing a new scrubber system."[241] Dr. Jonas Klingspor, Vice President at URS, a firm that has conducted more than 52,000 MWs of scrubber upgrades, stated that, "a scrubber upgrade is typically about one-third or less than the cost of a new scrubber." This is because a scrubber system can be upgraded by reusing many existing structural components and existing equipment, such as existing structural steel and absorber shells, ducting, pumps, and compressors. Other components can be modified or replaced with new technology. Also according to Klingspor:[242]

> Most wet FGD systems, regardless of initial physical design or chemistry, can be upgraded to achieve above 99% SO_2 removal efficiency and to operate uninterruptedly between scheduled outage cycles.

As described repeatedly in the scrubber upgrade references we provide, a scrubber system can be upgraded by reusing many existing structural components and existing equipment, such as existing structural steel and absorber shells, ducting, pumps, and compressors. There are many viable, cost-effective options to improve SO_2 removal efficiency. These include: [243]

- Removing any existing scrubber bypass;
- Eliminating sneakage of gases down the sides of the absorber bypassing the spray headers, by installing wall baffles or rings within the absorber;
- Improving liquid distribution by installing new spray headers, additional spray levels and/or more efficient nozzles to improve spray coverage in the absorber;
- Improving gas-liquid contact by adding trays within the absorber;
- Increasing the gas-to-liquid ratio by increasing recycle slurry pump flow by, for example, using all available scrubber modules, adding recirculation pump suction line screens or changing pump gear reducers to allow higher impeller speeds, thus producing greater slurry flow on pumps;
- Improving scrubber chemistry by reducing limestone grind size, eliminating limestone blinding, converting to inhibited or forced oxidation, optimizing pH, and using performance additives such as dibasic acid (DBA);
- Redesigning mist eliminators and mist eliminator wash system to handle higher velocities through the absorber;
- Repairing any damaged or worn parts, such as recycle pump impellors; and
- Removing any capacity constraints, such as in the dewatering system or induced draft fan.

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[241] 70 FR 39133.

[242] Klingspor, J., Experience from 52,280 MWs of Wet Flue Gas Desulphurisation System Upgrades, VGD PowerTech, December 2012.

[243] See for example: Klingspor, J., p. 106; Maller, G., et al; Klingspor, J. and Brown, G; Alstom, Wet Scrubber Upgrade Air Quality Control Systems, http://www.alstom.com/Global/Power/Resources/Documents/Brochures/wet-scrubber-upgrade-datasheet.pdf;
Moretti, A., State-of-the-Art Upgrades to Existing Wet FGD Systems to Improve SO_2 Removal, Reduce Operating Costs and Improve Reliability, Power-Gen Europe, June 3-5, 2014.

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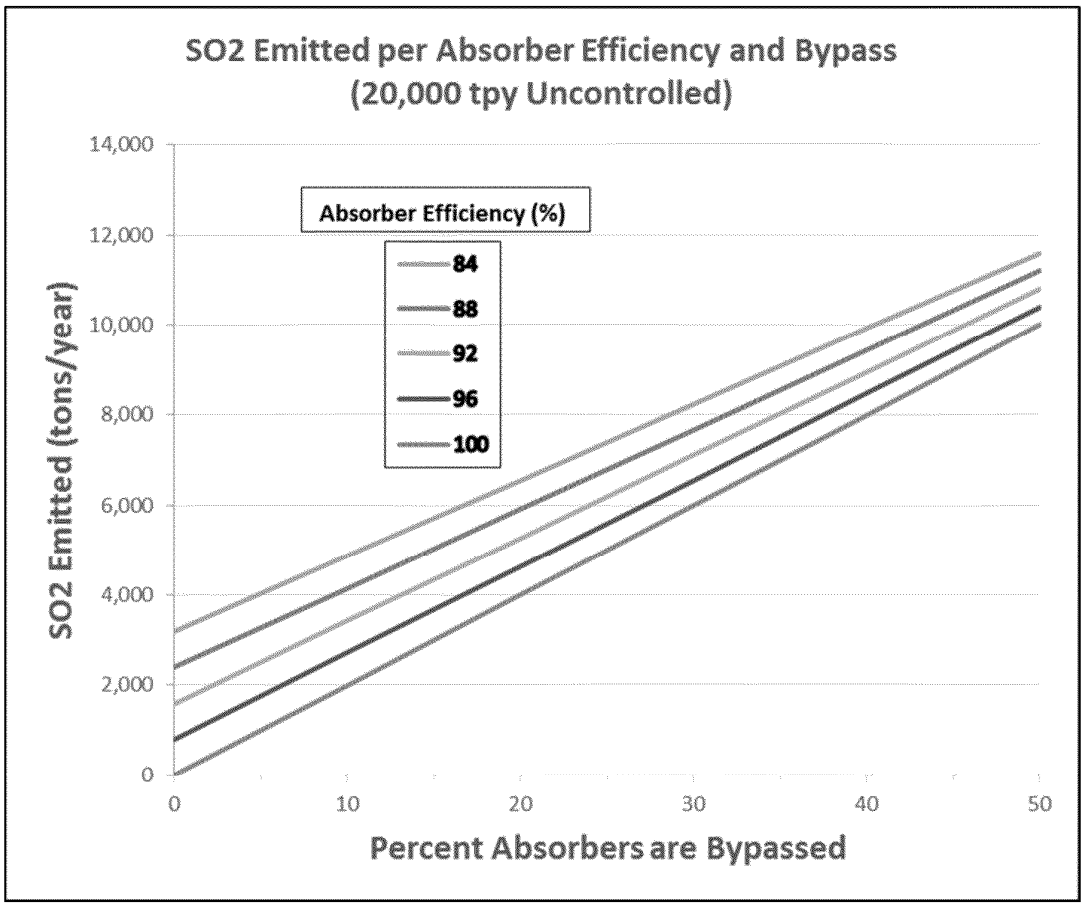
We discuss these scrubber upgrade options in the sections that follow. These methods have been used on many vintage scrubbers in the last 20 years to enhance performance and/or to lower overall operating costs.[244]

6.3.1 Elimination of Scrubber Bypass

As we note above, a flue gas bypass is used on all of the scrubber systems we are investigating for upgrades, except for the San Miguel unit. A bypass allows the facility to route all or a portion of the flue gas around the FGD system for flue gas reheat and/or to improve operating flexibility. Some utilities originally designed the FGD system to scrub only a percentage of the flue gas while others installed bypass capability as a means of providing continuous operating capability, using alternate method for flue gas reheat. Because a bypass can route a large volume of flue gas around the scrubber system, it can have a significant impact on the overall SO_2 removal efficiency of the unit. Below is an example of this:

- Figure 2. Effect of Bypass and Absorber Efficiency on SO_2 Emitted



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In the above example for a coal fired power plant that would emit 20,000 tons per year (tpy) if uncontrolled, the difference between no bypass and 20% bypass is significant. For example, if the absorbers are 96% efficient, a 20% bypass would mean that 3,840 tpy more is emitted over no bypass.

A wet FGD sprays a limestone-based slurry into the gas stream to remove SO_2. This produces a gas stream that is saturated with water vapor at a temperature of 136-145 F for lignite and sub-bituminous coal. A wet scrubber cools the stack gas and adds moisture to it. The gases are saturated and contain water droplets containing corrosive compounds such as sulfuric acid. If the temperature of the flue gas is blow the dew point, the moisture condenses in the exit ducts, stack walls, etc., corroding downstream equipment. Gasses emitted to the atmosphere can result in liquid fallout, visible steam plumes and plume touchdown, causing high ground-level SO_2 concentrations.[245] Thus, unless corrosive resistant materials are utilized, the temperature of the flue gases exiting the FGD system must be above the dew point to avoid condensation of flue gas and to maintain flue gas velocities in the exit ducts and stack.

At the time the subject scrubbers were installed, this was accomplished by heating the flue gas exiting the FGD system by about 25 to 50°F[246], so it was slightly above the saturation point. This increased the buoyancy of the plume, which reduced ground-level pollutant concentrations; reduced plume visibility by eliminating entrained moisture; and evaporated entrained water droplets, decreasing the potential for corrosion. Four methods were historically used to address this problem:[247]

- In-line reheat, in which the gas is passed through a heat exchanger located in the duct work (20%)
- Indirect hot air injection reheat (15%), in which air is heated in an external heat exchanger and then mixed with the exit flue gas
- Direct combustion reheat (14%), in which hot combustion gases are generated using fuel oil or natural gas and then mixed with the exit flue gas
- Bypassing a portion of the untreated flue gas around the scrubber and then mixing that hotter gas with the scrubbed flue gas (25%)

Bypassing flue gas was the lowest cost approach, followed by in-line reheat system.[248] This is the option used by all of the scrubber systems we are analyzing, with the exception of San Miguel, which does not employ a bypass. This was most commonly accomplished by routing 5%-20% of the flue gas around the scrubbers.[249] A bypass allows the facility to route all or a portion of the flue gas around the FGD system for flue gas reheat and/or to improve operating flexibility. Some utilities originally designed the FGD system to scrub only a percentage of the

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[245] Henzel, D., et al, Limestone FGD Scrubbers: Users Handbook, EPA-600/8-81-017, August 1981, p. 2-27.
[246] Froelich, D., Graves, G., Eliminating Reheat from Existing FGD Systems, A Design and Economic Evaluation, Journal of the Air Pollution Control Association, v. 3 7, no. 3, March 1987, pp. 314 - 321, p. 314
[247] Froelich, D., Graves, G, p. 315. Note percentages refer to FGD systems that used any type of stack gas reheat. Some FGD systems did not employ any stack gas reheat.
[248] Henzel, D., et al, p. 2-28.
[249] Klingspor, J., Brown, G., p. 8; Maller, G, p. 4.

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flue gas while others installed bypass capability as a means of providing continuous operating capability, using alternate methods for flue gas reheat.

Many of these early scrubber systems had/have variable bypass capability, including Monticello Unit 3; Martin Lakes 1, 2, and 3; and Sandow 4.[250] Variable bypass is used to adjust for different operating conditions, such as to maintain minimum stack temperature, adjust for variations in coal sulfur levels, and/or to maintain compliance with permits. Variable bypass was accomplished by adjusting the position of louver-type dampers on each scrubber tower, based on measurements of stack temperature, bypass fan parameters, and bypass damper position indicators.

Partially bypassing the scrubber reduces the overall scrubbing efficiency, as not all of the flue gases are treated. Consequently, one way to improve SO_2 removal efficiency is to eliminate the bypass and route 100% of the gases through the scrubber. When the bypass/reheat is eliminated, the amount of gas to be treated increases, the gas velocity decreases, and the gas density increases, resulting in system pressure losses of 5% to 10%, compared to dry operation.[251] This requires that two technical issues be addressed.[252]

First, the scrubber must have adequate capacity to handle the increased gas volume and be able to operate at higher flue gas velocities, which can cause problems with existing equipment such as the mist eliminators and stack. Scrubber capacity is generally not an issue if a scrubber system was designed with a spare absorber or spray level, which was common with many early scrubbers due to uncertainty about performance. This is probably not an issue for one of the subject Texas facilities (Limestone) as it was designed with multiple units plus a spare, which likely provides adequate capacity to handle bypassed gases. Absent a suitable spare, the existing scrubber may have to be modified to accommodate the higher flow, including replacement of the mist eliminators.

Second, existing stacks on currently scrubbed units are designed for hot dry flue gases with a higher gas velocity (~100 ft/sec) in the liner than new wet stacks. The stack downstream of a wet scrubber without bypass or reheat is a "wet stack", which exhausts saturated, scrubbed flue gas that contains droplets from mist-eliminator carryover. Thus, a new or modified mist eliminator and stack are usually required to accommodate the highly corrosive, saturated flue gas. The wet stacks must be designed using corrosion-resistant material and a gas velocity of 55 to 75 ft/sec to prevent condensed moisture from being carried out the top of the stack.[253] As mentioned above, when the bypass is eliminated, corrosive moisture condenses on downstream equipment that was not originally designed for these conditions, including scrubber outlet, ducts, bypass dampers, expansion joints, and the stack.

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[250] Supplied June 17, 2014 by Luminant, in response to request for information under Section 114(a) of the CAA, dated May 20, 2014.6/17/14.
[251] Revised Wet Stack Design Guide, Electric Power Research Institute (EPRI), 2012 Technical Report, Final Report, December 2012, p. 3-2.
[252] Maller, G., et al, p. 4.
[253] DePriest, W., Gaikwad, R., Economics of Lime and Limestone for Control of Sulfur Dioxide, p. 9; Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent and Lundy, p. 25; EPRI 2012, Table 2-1. Froelich, D., Graves. G., p. 317.

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The cost of converting from dry to wet stack operation depends upon the existing materials used in these components. Moisture condensation within a stack designed for dry use can cause severe damage, as these stacks are typically lined with carbon steel or grouted brick. Considering the latter, moisture migration through the grout would corrode metal liner bands, weakening the stack and eventually resulting in stack failure. An acid-resistant brick liner may require no changes at all, while a carbon steel liner would require an alloy lining or other protection. Only the stack drainage system would likely have to be improved for acid brick lined stacks.[254]

The conversion of a dry stack to wet operation must address several issues that were not present when a bypass or reheat was used. Some of these issues include:[255]

- Stack liquid discharge;
- Plume downwash and icing;
- Corrosion/chemical attack;
- Stack height;
- Stack-liner geometry and material of construction;
- Liner-breach geometry;
- Stack liner geometry and material of construction;
- Gas velocity in the liner; and
- Liquid-collection devices and drainage.

A critical design consideration in converting a dry stack to wet operation is whether the existing liner and ductwork material can withstand the reduced temperatures and wet conditions of wet operation and whether the liner-gas velocity will result in droplet re-entrainment from the stack wall.[256] These issues may be addressed by modifying the existing stack or replacing it with a new "wet" stack. Mist eliminators, designed to reduce liquid carryover and slurry to downstream ductwork and the stack, must often be modified when the bypass is eliminated to facilitate wet stack operation.[257] These issues are further discussed in Section 7 concerning the costs of scrubber upgrades.

Relining a stack has become a common upgrade to power plants. As a general indicator of the scale of stack lining projects, Johnson[258] reports that 126 stack liner projects using Fiberglass Reinforced Plastic (FRP) kicked off in the 2004-2008, inclusive timeframe. This includes a number of facilities in Texas: Fayette Units 1 and 2, J.K. Spruce Unit 2, Sandow Unit 5, and Oak Grove Units 1 and 2. FRP competes with various steel alloys as a stack lining material and thus represents only a portion of the total stack lining projects.

As an alternative to relining an existing dry stack for conversion to wet operation, operators can choose to build a new stack. However, this the most costly of these options.

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[254] Maller, G., p. 4; See for example, http://www.hadek.com/project-reports/san-juan-power-station
[255] EPRI, 2012. Ibid., p. 1-2.
[256] EPRI 2012, p.. 1-3.
[257] EPRI, Sec. 2.3.1.
[258] Johnson, T., et al, The Rapid Growth of Fiberglass Reinforced Plastic (FRP) in FGD Systems, 2011, Table 3.

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6.3.2 Optimization of Liquid/Gas Ratio

The liquid-to-gas ratio (L/G ratio) is a sizing criterion for absorbers that compares the slurry recirculation rate to the flue gas flow rate. It is the ratio of the amount of limestone slurry expressed in gallons per minute to the amount of untreated flue gas in thousands (1000s) of actual standard cubic feet per minute (gpm/1000 acfm).[259] Increasing the L/G increases the alkalinity available per pass, which increases the SO_2 removal efficiency. The amount of flue gas is fixed by the boiler, so the L/G ratio is increased by increasing the amount of limestone slurry. This is typically varied by changing the number of operating recycle pumps.

In a conventional scrubber, the amount of slurry is increased by replacing an existing pump with a larger model, increasing the number of slurry recycle pumps and spray headers, upgrading the motors in existing recycle pumps, installing new gear reducers to allow the pumps to operate at higher impeller speed, or reducing the pump head by, for example, replacing high-pressure nozzles with low pressure nozzles.[260]

Sargent & Lundy notes[261] in a wet FGD evaluation that included 2.0 and 4.72 lb/MMBtu SO_2 coals, that most of the scrubbers installed in Phase 1 of the CAA title IV program (1995) were designed for and achieved 95% efficiency with L/Gs of 90-130 and inlet sulfur dioxide up to 8 lb/MMBtu. Demonstrations and testing by the major FGD process developers, including Alstom, Mitsubishi, Babcock & Wilcox, and Wheelabrator, have shown that a 130 L/G is adequate to achieve 98% efficiency in a typical open-spray tower design on the 4.72 lb/MMBtu inlet SO_2 basis (high-sulfur coal case) of this work. This is further verified by recent guarantees offered by FGD vendors for new unit applications.

6.3.3 Gas-Liquid Contact Improvements

SO_2 removal in a wet scrubber is controlled by the amount of SO_2 that can be absorbed per unit volume of recirculated slurry. SO_2 absorption is limited by the amount of solid and liquid phase alkalinity provided in each gallon of slurry. The absorption is also a function of the contact time between slurry and SO_2 as well as the absorber design, which determines the gas-slurry contact area. In a spray tower, the most common type of scrubber, flue gas typically enters horizontally and turns 90 degrees into a vertical open cylindrical vessel with multiple levels of spray headers. The flue gas is first cooled and saturated with slurry. The saturated flue gas then flows upward through the absorber spray zone, where slurry is sprayed countercurrent to the flue gas.

The scale models used to design early scrubbers largely ignored the interaction of flue gas and slurry. The impact of spray nozzles on flue gas distribution was poorly understood and often

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[259] Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent & Lundy.
[260] Klingspor, J., Brown, G.
[261] Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent and Lundy, p. 10.

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ignored. Thus, the effect of nozzle spray angle; spray coverage as a function of nozzle size, type, density and pressure; and the impact of wall sneakage were typically not modeled.[262]

Thus, maldistribution of flue gas across the cross section of the absorber is a common cause of poor performance in vintage scrubbers. This is caused by high velocity flue gas entering the absorber, which causes it to hug the walls of the absorber, bypassing the spray headers. This effect is commonly known as "gas sneakage" and can be minimized or eliminated through the installation of various mechanical devices.[263] Gas sneakage also occurs around nozzles inside the absorber.

The skewed flow distribution in the absorber inlet often generates flue gas recirculation zones that cause buildup of solids. Similarly, a skewed flue gas distribution at the absorber outlet duct often leads to excess mist eliminator carryover, scaling of the absorber outlet duct, and stack rain issues.[264] These factors place a limitation on the maximum removal efficiency that can be achieved for a given absorber.

Poor recycle spray header design was another common problem in older FGD systems. The early designs used narrow-angle nozzles and a low nozzle density.[265] This resulted in non-uniform and incomplete spray coverage. Spray towers use several levels of spray nozzles that scrub the flue gas as it moves upward through the absorption tray and spray zone. However, these spray levels are usually not sufficient by themselves to adequately distribute flue gas at the base of the spray zone.[266] There are often significant holes in the spray coverage over the cross-sectional area of the absorber due to a tendency in early scrubbers to use a small number of relatively large spray nozzles. This problem is especially significant along the walls of the absorber as gas flows tend to be higher there, or in the vicinity of internal support members. This results in poor gas-liquid contact because the gas tends to flow where the spray density and gas-side pressure drop are the lowest, contributing to gas sneakage.

Incomplete spray coverage and gas sneakage can be eliminated by improving gas/liquid contact and thus the SO_2 removal efficiency with the goal of achieving a uniform distribution of slurry and gases across the scrubber diameter. Thus, upgrades typically must address uneven flow distribution issues, poor gas-liquid contact, and poor mixing in the reaction tank. This can be achieved by improving flow distribution using turning vanes, perforated plates, and wall rings; improving gas liquid contact using devices such as sieve trays, improved spray nozzle layout, and double hollow cone nozzles; and chemistry modification, including performance additives and conversion to forced oxidation. The specific option depends upon a range of factors such as availability of space for a tray or packing and availability of fan power to overcome additional pressure drop.[267]

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[262] Klingspor, J., p. 101.
[263] Klingspor, J., Brown, G.; Maller, G., et al.
[264] Klingspor, J., p. 102.
[265] Klingspor, J. 2012, p. 102 and Figures 2 and 3.
[266] See, for example, Wet Flue Gas Desulfurization (FGD) Systems Advanced Technology for Maximum SO_2 Removal, Babcox and Wilcox, 2007, p. 6.
[267] Klingspor, J., 2012; Klingspor, J., Brown, G.; Maller, G., et al; Moretti, A., State-of-the-Art Upgrades to Existing Wet FGD Systems to Improve SO_2 Removal, Reduce Operating Costs and Improve Reliability, Power-Gen Europe, June 3-5, 2014.

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Wall Baffles

Wall baffles or liquid distribution rings are widely used to prevent gas sneakage down the sides of the absorber vessels. They are sloped downwards to re-inject wall slurry into the interior of the absorber where there is a greater chance of interaction with recycle spray droplets. They also promote more thorough mixing of flue gas, ensuring no areas of high SO_2 concentration. These baffles are placed between spray levels. Wall baffles have been used in many scrubber upgrades, including both round and rectangular absorber towers as well as large and small towers. [268] These rings result in improved performance with no increase in power consumption or pressure drop.[269]

Trays

Perforated trays or counter flow trays can be used to improve the gas-liquid contact and distribution of flue gas across the tower. The gases rise through the absorber, contacting a froth of slurry on the tray. This provides increased SO_2 removal by creating additional surface area obtained from liquid holdup on the tray. Trays uniformly distribute gas and create a bubbling zone that improves gas-liquid contact, yielding high SO_2 removals at a lower overall L/G. Adequate space and improved structural support are required to add a tray to an existing open spray scrubber or an additional tray to an existing tray scrubber.[270]

A tray is a much more efficient contact device than a slurry spray.[271] This is because the tray creates more surface area between the slurry and the gas. The limestone dissolution on the tray can be as much as 50% of the dissolution in the entire absorber. The improvement in SO_2 removal by adding a tray is very similar to adding liquid distribution rings or an additional spray level. A tray provides about the same removal efficiency as one spray header without requiring any of the cost and complexity of a recycle pump and spray header system.[272] The benefits of the absorber tray compared to an additional spray level include:

- Reduced liquid to gas ratios
- Increased absorption for the same L/G
- More uniform gas distribution due to back-pressure from tray
- Fewer recirculating pumps
- Fewer spray headers
- Reduced pump maintenance
- Increased particulate removal

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[268] Maller, G., et al, Table 1 and pp. 4-5.
[269] Klingspor, J., Brown, G.
[270] Wet Flue Gas Desulfurization (FGD) Systems Advanced Technology for Maximum SO_2 Removal, Babcox and Wilcox, 2007.
Silva, A., et al, WFGD Case Study - Maximizing SO_2 Removal by Retrofit with Dual Tray Technology, Presented to: EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollutant Control Mega Symposium, August 28-31, 2006.
[271] Steam Its Generation and Use, The Babcox & Wilcox Company, Edition 41, 2005, p. 35-6.
[272] Klingspor 2012, p. 104.

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- Corrects gas distribution problems in the lower part of the absorber spray zone
- Protects the inlet duct from scaling
- Provides the lowest cost approach to a FGD upgrade
    - Provides a maintenance platform that avoids draining the reaction tank to gain access to the spray headers and mist eliminators.[273]

A tray will significantly increase the gas-side pressure drop and thus requires adequate fan capacity. The exact amount is a function of design and operating conditions, but is typically on the order of 1.5 to 2.5 in-wc.[274] However, the additional fan power required from the increased gas-side system pressure drop due to the tray is typically offset by a reduction in pumping power from the lower L/G (i.e., less slurry recycled) required to achieve a given SO_2 removal.[275] The savings in recycle pump power will offset the penalty of increased absorber pressure drop (i.e., pump versus fan power).[276] For moderate SO_2 removal improvements, a tray can allow the use of one less spray level and spray pump per absorber, reducing operating and maintenance costs.[277]

Trays are subject to plugging and scaling if scrubber chemistry is not controlled carefully, and trays are less attractive if absorber gas velocity is increased. However, they are desirable if space is limited, when efficient spray header designs are not present, and to correct skewed gas distribution profiles.[278] More than one tray can be employed to optimize the gas-slurry contact. Babcock and Wilcox, for example, report that scrubber efficiency can be improved by adding a second tray.[279] Adding a second tray increases contact time between SO_2 and slurry, which increases SO_2 removal efficiency.[280]

Spray Headers

The recycle spray header design of many older scrubbers results in incomplete spray coverage, especially near the walls where gas flows tend to be higher. These older designs have gaps or openings in the spray pattern that allow flue gas to bypass the spray zone without contacting the slurry. Many of these gaps are on the outside of the absorber, near the absorber walls and provide a direct path for the flue gas to bypass the slurry spray.[281] This results in poor gas-liquid contact which limits maximum removal efficiency.

The spray headers can be replaced with a high-efficiency spray header that uses a high nozzle density and wide-angle nozzles. The older spray header designs also used a support system that was prone to breakage, resulting in header section failing and falling to the bottom of the

[273] Klingspor 2012, p. 104.
[274] Maller, G., et al, Improving the Performance and Reliability of Older FGD Systems, Mega Symposium, August 2010.
[275] Moretti, A., 2014, p. 4.
[276] Staehle, R., Upgrading Your Wet FGD System, Marsulex, October 2008.
[277] Moretti, A., p. 4.
[278] Maller, G., et al, p. 3.
[279] Silva, A., et al.
[280] Moretti, A., p. 5.
[281] Moretti, A., p. 4, Fig. 4.

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absorber. Replacing the headers with a modern, self-supporting design reduces maintenance costs and outage time.[282] A high efficiency spray header in combination with double hollow cone nozzles can substantially improve performance, on average proving about a 40% increase in performance.[283]

Many state-of-the-art nozzle designs are available to upgrade scrubber performance. Bi-directional nozzles can be installed regardless of the original design, which provide wider-angle spray cones to provide complete coverage of the spray zone and increased gas-liquid contact. Side-by-side double hollow cone spray nozzles can be used to improve droplet interaction (secondary atomization), thus enhancing removal performance.[284]

These types of changes ensure a high degree of gas-liquid contact with reduced chance for gas sneakage and can significantly improve SO_2 removal efficiency and reduce O&M costs. New spray headers and/or new nozzles have been used in many scrubber upgrades,[285] including Fayette Unit 3.

6.3.4 Improving FGD Chemistry

SO_2 removal can be increased by improving slurry reactivity. There are many ways to do this, including reducing limestone grind size, eliminating limestone blinding, converting to forced oxidation, optimizing operating pH and using performance additives, discussed elsewhere. The easiest way to increase SO_2 removal efficiency in any scrubber is to increase the slurry pH. The SO_2 removal typically responds very quickly to an increase in pH. An increase in slurry pH is typically achieved by increasing the reagent feed rate, which causes limestone utilization to deteriorate. This deterioration can be offset by decreasing grind size, which allows operation at a higher pH while maintaining limestone utilization.[286]

Existing units that use natural or inhibited oxidation can be converted to forced oxidation. This process converts calcium sulfite to calcium sulfate and improves scrubber operating while providing a marketable gypsum byproduct.[287]

Limestone reagent fineness has a significant effect on limestone utilization, which in turn has a significant effect on FGD SO_2 removal efficiency. The finer the grind, the higher the removal efficiency as the fineness of the limestone affects the rate at which it dissolves in the reaction

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[282] Moretti, A., p. 5.
[283] Klingspor, J., 2012, p. 103.
[284] URS, Upgrade of Wet FGD Systems, Available at: http://urs-processtechnologies.com/wp-content/uploads/2013/02/FGD-Upgrade-Final-2_2013.pdf.
[285] See for example, Maller, G., et al, p. 3.
[286] Klingspor, J., Brown, G.
[287] Wet Flue Gas Desulfurization (FGD) Systems Advanced Technology for Maximum SO_2 Removal, Babcox and Wilcox, 2007, p. 4.

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tank.[288] The general rule of thumb today is 95% passing a 325-mesh screen.[289] Increasing the percentage that passes a 325-mesh screen increases the rate of limestone dissolution, which increases the removal efficiency. The majority of the subject FGD systems, those built before about 1995, were designed to produce limestone coarser than this optimum.[290]

Limestone reactivity is also important to scrubber operation. The chemical makeup of the limestone exerts a large influence on scrubber efficiency. In general, limestone with 94% or more calcium carbonate are very reactive, if properly ground. However, limestone with more than about 10% dolomite ($MgCO_3 \cdot CaCO_3$) are not desirable as the dolomite is rather non-reactive and tends to pass through the FGD untouched and thus does not participate in the chemical reactions that remove SO_2.[291]

6.3.5 Use of Organic Acids to Improve Performance

The use of organic acid additives, such as dibasic acid (DBA) and adipic acid, improves SO_2 removal efficiency by reducing the L/G ratio. Additional benefits of organic acids like DBA (beyond enhanced SO_2 removal efficiency) include reduced power consumption, lower spray pump flow, lower pressure drop, reduced limestone consumption, reduced overall operating costs, and reduced capital costs. They are also used as a backup, to allow a scrubber to be designed without a spare spray header and pump, and to allow increases in coal sulfur content.

The least expensive additives are organic acids that buffer the slurry liquor by acting as an acid or base to help dissolve limestone or to directly neutralize the sulfurous acid formed by the absorption of SO2.[292] Dibasic acid (DBA) is the most economical acid. It is a mixture of succinic, glutaric and adipic acids and is a byproduct in the manufacture of nylon. They can be used continuously or to maintain high SO_2 removal efficiencies if a recycle pump is taken out of service. They work by buffering the pH at the gas-liquid interface, thus reducing back pressure of SO_2 and by lowering the liquid-film resistance to mass transfer. DBA and formate are the most commonly used additives due to cost.[293]

The incorporation of organic acids into an upgrade can significantly reduce the capital, operating, and maintenance cost of the scrubber. This occurs because organic acids increase limestone absorption and stabilize the pH, reducing the liquid-to-gas ratio while maintaining the required SO_2 removal efficiency or increasing the removal efficiency for a given liquid-to-gas ratio. DBA has been reported to provide the equivalent of spraying an extra 20 gpm/1000 cfm of

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[288] Maller, G., Wet FGD Chemistry and Performance Factors, Presented at 2008 Power Gen Conference, December 1, 2008, pdf 48.
[289] LG&E Services Company Contract No. 501654, Mill Creek FGD Performance Upgrade Study, Babcock Power Environmental, February 2011, p. 53.
[290] Seward, R., Brame, K., A Review of Methods for Increasing Limestone Reagent Fineness for Flue Gas Desulfurization, Proceedings Tenths Symposium on Flue Gas Desulfurization, Vol. 1, February 1987.
[291] Buecker, B., Important Concepts of Wet-Limestone Flue Gas Desulfurization Energy-Tech Magazine, October 2008, http://www.energy-tech.com/article.cfm?id=21789; PEI Associates, 1985.
[292] Moretti, A., p. 5.
[293] Klingspor, J., and Brown, G.

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limestone slurry. Thus, increasing SO2 removal from 92% to 95% can either add 25% to the pump energy input or buy an organic chemical.[294]

Their benefit over ultra-fine grind limestone is that the effect is immediate. There is no turnover of a slurry tank prior to the organic acid impacting absorber performance. However, their disadvantages include additional operating cost, uncertainty in long-term supply and pricing of DBA byproducts, possible contamination of gypsum by-product, and increased wastewater treatment cost.[295]

The U.S. Department of Energy and the Electric Power Research Institute conducted full-scale testing, process modeling, and economic evaluations of six utility flue gas desulfurization systems to evaluate low capital cost upgrades for achieving up to 98% SO_2 removal efficiency in existing FGD systems. These studies mostly involved using performance additives in the FGD systems, but other low cost options were evaluated using an EPRI model. The tested units are: Big Bend,[296] Merom,[297] Pirkey,[298] Gibson,[299] Elrama, and Kintigh.[300] These tests demonstrated the efficacy of organic acid additives. Many facilities add acid injection systems based on these and other test results, including (can we list the Texas units that use them?)

The addition of an organic acid system to an existing scrubber (that was not designed taking it into consideration) would increase the costs by a very small amount compared to the rest of a scrubber system. For instance, Invista reports the following based on modeling a 566 MW boiler using eastern bituminous high-sulfur coal (3% sulfur, 12,720 BTU/lb heating value) and 90% SO_2-removal efficiency:[301]

> Modeling shows that operational and maintenance costs of a wet limestone scrubber can be reduced by about 2% (about $200,000/year) when using DBA, including the cost of the DBA additive. The increased SO_2 scrubbing efficiency using DBA translates into about a 15% reduction in limestone use, a 1% reduction in steam, a 1% reduction in solid waste disposal costs, and a reduction of about 17% in power usage. Payback time, based on SO_2 credit prices of $200/ton, for the capital required to retrofit an existing wet limestone scrubber for DBA addition (storage tank, pump, piping) ranges from 5 months to about two years,

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[294] Invista DBA Will be Available to Improve FGD Efficiency, FGD & DeNOx Newsletter, No. 393, January 2011.
[295] Wet Flue Gas Desulfurization Technology Evaluation, Project Number 11311-000, Prepared For National Lime Association, January 2003, Prepared by Sargent and Lundy. p. 5.
[296] Radian Corp., Results of High Velocity Tests at Tampa Electric Company's Big Bend 4 FGD System, Topical Report, October 15, 1997.
[297] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, Evaluation of High Efficiency Test Results at Hoosier Energy's Merom Station, April 22, 1996.
[298] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, Results of DBA and Sodium Formate Additive Tests at Southwestern Electric Power Company's Pirkey Station, May 30, 1996.
[299] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, PSI Energy' s Gibson Station High SO_2 Removal Efficiency Test Program, May 20, 1996.
[300] Radian Corp., High SO_2 Removal Efficiency Testing, Topical Report, Results of Sodium Formate Additive Tests at New York State Electric & Gas Corporation's Kintigh Station, February 14, 1997.
[301] The Role of Dibasic Acid (DBA) in Wet Limestone Flue Gas Desulfurization. Accessed from http://intermediates.invista.com/e-trolley/page_1035/, 7/7/2014.

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depending on operating strategy (i.e. maintain SO_2 efficiency and reduce operating costs vs. improve SO_2 efficiency and profit from emission credits).

Consequently, the wastewater treatment system is the only item that might increase in capital and operating costs because organic acids increase the Basic Oxygen Demand (BOD) and Chemical Oxygen Demand (COD) of the wastewater, requiring biological treatment.[302] Wastewater treatment is typically a small fraction of the total cost of a scrubber.

6.3.6 Related Capital Improvements

The improvements discussed above generally require modifications to other facility components including the following:

- A new or modified stack
- A new or modified absorber if the original FGD did not include a spare
- A new or modified limestone slurry preparation system
- A new or modified dewatering system
- Upgraded flue gas system

When SO_2 removal is increased, the amount of wet FGD byproducts will increase. If the upgraded FGD system uses natural oxidation, the disposal pond may reach capacity. This usually requires conversion to forced oxidation to eliminate need for disposal ponds

If limestone consumption is increased to improve SO_2 removal, reagent preparation and dewatering systems may be undersized. In most cases, higher SO_2 removal requires finer grind than delivered by older system. Thus, existing milling systems may have to be upgraded to handle the new quantity and grinding requirements.[303]

Older FGD systems used thickeners for primary dewatering and rotary drum filters for secondary dewatering. Thickeners are prone to maintenance problems. These thickeners are difficult to operate when an FGD is converted to forced oxidation due to rapid settling of gypsum, requiring replacement with hydroclones, which are used in modern FGD systems.[304]

Older FGD systems used thickeners for primary dewatering and rotary drum filters for secondary dewatering. Thickeners are prone to maintenance problems. These thickeners are difficult to operate when an FGD is converted to forced oxidation due to rapid settling of gypsum, requiring replacement with hydroclones, which are used in modern FGD systems. The rotary drum filters

[302] Riffe, M., et al, Wastewater Treatment for FGD Purge Streams, Paper # 33, Presented at the MEGA Symposium 2008 Baltimore, MD, August 25 – 28, 2008; INVISTA DBA Dibasic Acid For Flue Gas Desulfurization November 17, 2010.
[303] Harper, G., Hagan, M.A., Dyer, P., and Breuer, W. J., Increasing Capacity of Existing Limestone Grinding Systems While Reducing Grind Size, Burns & McDonnell Technical Paper, 2006.
[304] Moretti, A., p. 8.

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also may not have adequate capacity to handle increased SO_2 removal. The capacity constraint can be addressed by increasing the amount of time per day that the rotary drum filter operates; replacing the rotary drum filter with new generation rotary drum technology; or replacing them with vacuum belt filters.[305]

7 Scrubber Upgrade Analyses

We have conducted a cost analysis for upgrading the scrubbers for those facilities listed in Table 1 that currently employ a scrubber. As we discussed above in Section 6.1, we have calculated the SO_2 removal efficiency of these scrubbers as follows:

Table 18. Existing Scrubber SO_2 Removal Efficiencies

Facility	Unit	Bypass?	2009-2013 Average SO_2 Removal Efficiency (%)
Sandow 4	1	Y	75.7
Monticello	3	Y	60.0
Martin Lake	1	Y	69.2
Martin Lake	2	Y	71.9
Martin Lake	3	Y	69.8
Limestone	1	Y	78.1
Limestone	2	Y	77.0
San Miguel	1	N	94.0
W. A. Parish	8	Y	84.0

7.1 Section 114(a) Information Requests

In order to assess the potential range of options available to upgrade the scrubbers in the facilities listed above, we must have an understanding of what upgrades may have already been performed. Most of this information is not available publically. Therefore, for each one of these units, except for San Miguel, we have requested information under authority granted to us under Section 114(a) of the Clean Air Act, which included the following:

a. State whether any of the scrubbers have a bypass.

b. If a unit's scrubber has a bypass, describe whether the percentage of flow going to the scrubber is varied in practice by directly adjusting the bypass or if the bypass is fixed. State how and under what circumstances this is accomplished and monitored.

c. For any scrubber with a bypass, provide the percentage flow that has bypassed the scrubber, based on a monthly average, for the years 2008 through 2013, inclusive.

[305] Moretti, A., pp. 10-11.

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d. State the maximum SO_2 removal efficiency of each EGU's scrubber system, based on full EGU operating capacity, assuming the optimum amount of reagent usage (including dibasic acid or other organic acids), and the type of coal being burned. Either report this value assuming 100% of each coal type burned, or by the sulfur content of the coal being burned. In reporting this value, do not multiply the efficiency of the scrubber by the percentage of flow going to the scrubber – report only the efficiency of the scrubber.

e. State the maximum percentage of flow at maximum EGU operating capacity that can be directed to the scrubber and treated at the scrubber's maximum efficiency. Either report this value assuming 100% of each coal type burned, or by the sulfur content of the coal being burned.

f. Describe what improvements have been made to the efficiency of the scrubber system since its initial installation, including but not limited to reagent handling and milling, addition of dibasic acid or other organic acids, bypass elimination, absorber (e.g., trays, liquid distribution rings, sprayers, recycle pumps, etc), stack lining, etc.

    i. Provide the capital costs for these projects and the dates when each upgrade was installed and became operational.

    ii. Provide the percentage improvement in the scrubber system for each of these upgrades that were separately installed.

Because the San Miguel facility provided similar information in response to emails and telephone requests, we did not send them a request for information under Section 114(a). All of these units complied with our Section 114(a) requests, but most of the information provided was claimed as Confidential Business Information (CBI) under 40 C.F.R. Part 2, Subpart B. We were able to review and analyze that information to assist us in calculating the costs of upgrading the scrubbers for those units. However, because our analyses largely depends on that information and is thus CBI itself, we can only present a summary of it here. Since the San Miguel facility did not assert any CBI information, our assessment of its scrubber is presented here and the information that San Miguel's provided is in our docket in full.

7.2 Approach to Scrubber Upgrade Cost Analyses

Each of the units listed in Table 18 had contracted with engineering firms (sometimes multiple engineering firms) and conducted multiple SO_2 scrubber upgrade cost analyses, which we were able to review as a result of our Section 114(a) requests. Many of these cost analyses were very detailed. Most of these analyses occurred in the 2004 – 2006 timeframe. They were done because the facilities had concluded that considering the price of SO_2 allowances, upgrading their scrubbers would result in an annual cost savings as they could either stop buying SO_2 allowances, or even sell excess SO_2 allowances. In addition, in a number of cases, the companies had concluded that upgrading various pieces of equipment related to their SO_2 absorbers that either required constant maintenance, or due to their poor initial design caused other problems, would additionally result in annual cost savings.

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These scrubber upgrades concentrated on optimizing the unit's total SO_2 removal, with the primary goal being the elimination or minimization of the scrubber bypasses. In most cases, these cost analyses included the following:

- Additional induced draft fan capacity and upgrading of the electrical distribution system to handle the additional load.
- Upgrading of the absorber(s) spray header to more efficient designs.
- Using all available slurry recycle pumps.
- Replacement of the mist eliminators with more efficient designs.
- Use of absorber trays or liquid distribution rings.
- Flow studies to identify flow maldistribution across multiple absorbers and the use of turning vanes (flow straightening baffles used in duct work) to correct this situation.
- Conversion to wet stack operation, which in most cases involved the demolition of the existing stack and the construction of a new wet stack.

In addition, some of the units' cost analyses included either upgrading or the addition of new DBA systems and forced oxidation systems.

Many units completed some of this work, which usually involved the upgrading of absorber internals (e.g., spray headers, recycle pumps, trays, liquid distribution rings, etc.). Many also partially reduced their scrubber bypasses because upgrading their absorbers allowed them to cost effectively treat more flue gas. None, however, with the exception of San Miguel, totally eliminated their scrubber bypasses.

Our approach to analyzing the cost of a unit's scrubber upgrade was the same in all cases except for San Miguel and consisted of the following basic steps:

- Conduct a literature search of published information from all available non-proprietary sources on any work conducted at the subject facility.
- Review the responses to our Section 114(a) request.
- Construct a timeline of all SO_2 pollution control equipment installations or upgrades, noting what work had already been done so it could be eliminated from our cost analysis.
- Determine what additional equipment is necessary in order to eliminate the SO_2 scrubber bypass and ensure that the unit's overall SO_2 removal efficiency is at least 95%.
- Use the company's scrubber upgrade analyses to estimate the capital and operating costs of eliminating the SO_2 scrubber bypass and ensure that the unit's overall SO_2 removal efficiency is at least 95%.
- Escalate the capital and operating costs to 2013 dollars.
- Annualize the capital and operating costs and calculate the cost effectiveness ($/ton) using the same methodology used in our DSI and scrubber retrofits in Sections 3, 4, and 5, above.
- Weigh the cost of the scrubber upgrades against the visibility improvement at the affected Class I areas.

We discuss how we analyzed San Miguel for potential scrubber upgrades section 7.3.1 below.

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7.3 Summary of Scrubber Upgrade Cost Results

With the exception of San Miguel, we are limited in what information we can include in this section, because in developing our scrubber cost estimates we used information that was claimed as CBI. This information was submitted in response to our Section 114(a) requests. We can therefore only present the following summary.

With the exception of San Miguel, we propose to find that for all the units we analyzed:

- The absorber system had either already been upgraded to perform at an SO_2 removal efficiency of at least 95%, or it could be upgraded to perform at that level using proven equipment and techniques.
- The SO_2 scrubber bypass could be eliminated, and the additional flue gas could be treated by the absorber system with at least a 95% removal efficiency.
- Additional modifications necessary to eliminate the bypass, such as adding fan capacity, upgrading the electrical distribution system, and conversion to a wet stack could be performed using proven equipment and techniques.
- The additional SO_2 emission reductions resulting from the scrubber upgrade are substantial and cost effective.

A summary of our analyses is as follows:

Table 19. Summary of Scrubber Upgrade Results

Unit	2009-2013 3-yr Avg. SO_2 Emissions (eliminate max and min) (tons)	SO_2 Emissions at 95% Control (tons)	SO_2 Emissions Reduction Due to Scrubber Upgrade (tons)	SO_2 Emission Rate at 95% Control (lbs/MMBtu)
W. A. Parish WAP8	2,586	836	1,750	0.04
Monticello 3	13,857	1,571	12,286	0.06
Sandow 4	22,289	4,625	17,664	0.20
Martin Lake 1	24,495	3,706	20,789	0.12
Martin Lake 2	21,580	3,664	17,917	0.12
Martin Lake 3	19,940	3,542	16,389	0.11
Limestone 1	10,913	2,466	8,446	0.08
Limestone 2	11,946	2,615	9,331	0.08
Total SO_2 Removed			**104,572**	

We calculated the cost effectiveness for each of these units. Because those calculations depended on information claimed by the companies as CBI we cannot present it here, except to note that in all cases, the cost effectiveness was less than $600/ton. We invite the facilities listed above to make arrangements with us to view our complete cost analysis for their units.

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Appendix C: List of Materials from EPA Docket ID: EPA-R06-OAR-2014-0754

As technical background or added technical support for this proposed rulemaking, this rulemaking record incorporates by reference and considers to be part of this rulemaking the following documents, even as they are not necessarily re-uploaded to the BART rulemaking docket at regulations.gov:

Doc. No. EPA-R06-OAR-2014-0754-0001 through Doc. No. EPA-R06-OAR-2014-0754-0036
Doc. No. EPA-R06-OAR-2014-0754-0087.

This incorporation includes all underlying attachments for these documents. Certain materials claimed as confidential business information (CBI) from the prior rulemaking action are also part of the non-public docket for this rulemaking.

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Technical Support Document

Our Visibility Analysis of Potential Controls for Subject to BART sources for the Texas Regional Haze BART Federal Implementation Plan

(BART Modeling TSD)

Prepared and Reviewed by:

Erik Snyder
Michael Feldman
Robert Imhoff
Joe Kordzi

November 2016

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Preparation of Emissions Scenarios for Potential Controls - Additional visibility Modeling

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.

1. Background and Introduction

We 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.[1] 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 BART Screening TSD.

Some of the subject-to-BART sources in Texas are very far away from a Class I area yet have high enough emissions that they significantly impact visibility at Class I areas in Texas 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-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 the large emission sources. The CAMx modeling protocol followed is described in detail in the BART Screening TSD. See the UNC-IE memorandum that documents these additional CAMx runs.[2]

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[1] 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.

[2] "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"

Regarding how to use modeling to assess visibility benefits from controls, the BART guidelines state: [3]

- 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. 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.

2. Emission Calculation Methodology

See Appendix A (CAMx) and Appendix B (CALPUFF) for a full summary of emissions modeled for the visibility benefit analysis of controls. Below we describe the methodology applied to estimate the emission reductions anticipated from controls used for visibility modeling.

2.1. SO_2 emissions

As explained below and in more detail in the BART FIP 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 50% control efficiency and modeled SO_2 emissions at 50% of the baseline actual 24-hr maximum emission level obtained from 2000-2004 CAMD data. 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 24-hr heat input (MMBtu/hr) reported in

[3] 40 CFR part 51 Appendix Y Section IV.D.5

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the CAMD data for 2000-2004.

We noted that some of the units we were evaluating were already equipped with older underperforming scrubbers, most of which were partially bypassed. For the units with scrubber bypasses, we lacked information on scrubber absorber efficiencies represented by the recent actual emission levels and the amount of bypass that has occurred. This made it impossible to estimate the current base control efficiency and the amount of additional reductions that would occur if the unit was further controlled based solely on the actual emissions data. Therefore, as is described in our BART TSD, we used Coal Data from EIA Form 923. This information enabled us to assess the total sulfur levels coming into a unit, to determine an uncontrolled baseline, and then estimate the achievable emission rates for the low and high control scenarios, to cover the potential range of upgraded scrubber control efficiencies. The high control emissions were estimated based on 95% control efficiency and the maximum 24-hr heat input (MMBtu/hr) reported in the CAMD data for 2000-2004. The low control scenario for these units was estimated by doubling the high control emission rate to estimate a 90% control efficiency. The table below summarizes the SO_2 emissions modeled with CALPUFF. In addition to these runs, we also performed CALPUFF modeling with an alternative baseline for these units, as explained in more detail later in this TSD. For units evaluated with WFGD level controls in the high control scenario, an additional model run with SDA level controls was also performed. See appendix B for a full list of modeled emissions for all scenarios.

Table 2.1-1. 2000-2004 Baseline CALPUFF Modeled SO_2 emissions: Coal-fired Units

Source	Unit	High Control efficiency	Maximum Heat Input (2000-2004)	SO_2 Emissions (lb/hr)		
				Baseline (2000-2004)	High Control Scenario	Low Control Scenario
Big Brown	1	0.04	7121	16591.25	284.84	8295.63
Big Brown	2	0.04	7306	16756.08	292.24	8378.04
Harrington	061B	0.06	4953	3337.17	297.18	1668.58
Harrington	062B	0.06	4491	3562.42	269.46	1781.21
Martin Lake	1	0.12	9370	9880.75	1124.4	2248.80
Martin Lake	2	0.12	8887	9144.67	1066.44	2132.88
Martin Lake	3	0.11	9343	10365.00	1027.73	2055.46
Monticello	1	0.04	6635	11892.83	265.4	5946.42
Monticello	2	0.04	6735	11663.50	269.4	5831.75
Monticello	3	0.06	9521	11734.58	571.26	1142.52
Welsh	1	0.04	6513	4656.83	260.52	2328.42
Welsh [1]	2	0.04	6126	5264.50	0	0

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[1]We did some initial baseline/screening modeling with Welsh 2 included, but we also did CALPUFF runs with Welsh 2 at zero emissions for baseline and control case modeling for Welsh to reflect the recent shutdown of this unit and isolate the visibility benefits from controlling Welsh unit 1

For the coal-fired EGUs evaluated with CALPUFF, we also evaluated maximum 24-hour NOx and SO_2 from a more recent baseline period (2011-2015) using the 2001-2003 CALMET data since some controls or reductions in emissions may have occurred due to federal rules and we wanted to provide additional information as part of the visibility benefit analysis. For High Control we used the recent Maximum Heat Input and High Control Efficiency to calculate the controlled emission rate. For the Low Control we used a 50% reduction of recent emissions for the units currently unscrubbed. For the units that have underperforming scrubbers, we used the High control emission rate and doubled to estimate a lower scrubbed control.

Table 2.1-2. 2011-2015 Recent NOx and SO_2 Emissions (RNS) CALPUFF Modeled SO_2 emissions: Coal-fired Units

Source	Unit	High Control efficiency	Maximum Heat Input (2011-2015)	SO_2 Emissions (lb/hr)		
				Recent Emissions (2011-2015)	High Control Scenario	Low Control Scenario
Big Brown	1	0.04	6301	12939.17	252.04	8295.63
Big Brown	2	0.04	6355	14045	254.21	8378.04
Harrington	061B	0.06	3858	2725.25	231.49	1668.58
Harrington	062B	0.06	4780	2759	286.80	1781.21
Martin Lake	1	0.12	9137	9275.42	1096.4	2192.8
Martin Lake	2	0.12	8820	8635	1058.42	2116.8
Martin Lake	3	0.11	9051	8243.75	995.65	1991.3
Monticello	1	0.04	6311	7663.75	252.45	3832
Monticello	2	0.04	6541	7875	261.63	3937.3
Monticello	3	0.06	8661	7900.42	519.63	1039.3
Welsh	1	0.04	5515	2922.5	220.61	1461
Welsh [1]	2	0.04	5606	0	0	0

UNC-IE assisted EPA in conducting two additional CAMx runs, with one run being based on

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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 units with existing scrubbers, the low control case assumed scrubber upgrades achieving 90% control efficiency and the high control case assumed scrubber upgrades achieving 95% control efficiency. 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.

W.A. Parish unit 4 and Sommers units 1 and 2 are primarily gas-fired units. Parish unit 4 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 this unit were held at baseline levels for the two control scenarios. The Sommers units burned fuel oil during the baseline period. EIA form 767 data shows that Sommers reported burning 0.19% sulfur fuel oil during 2003 when the maximum 24-hr baseline emissions occurred. High and low control scenario emissions were estimated based on a reduction to ultra-low sulfur diesel (ULSD) at 0.0015% and 0.01% sulfur fuel oil.

Table 2.1-3. CAMx modeled SO_2 emission rates

Source	**Unit**	SO_2 **(tons/day)**		
		Base case (2000-2004)	**Low control**	**High Control**
Big Brown (Luminant)	1	199.095	99.5475	3.41808
Big Brown (Luminant)	2	201.073	100.5365	3.50688
Coleto Creek (Engie)	1	67.83	33.915	3.21264
Fayette (LCRA)	1	61.388	61.388*	3.07056
Fayette (LCRA)	2	61.909	61.909*	3.3096
Harrington Station (Xcel)	061B	40.046	20.023	3.56616
Harrington Station (Xcel)	062B	42.749	21.3745	3.23352
J T Deely (CPS Energy)	1	65.542	32.771	3.17328
J T Deely (CPS Energy)	2	52.262	26.131	3.192
Martin Lake (Luminant)	1	118.569	26.9856	13.4928
Martin Lake (Luminant)	2	109.736	25.59456	12.79728
Martin Lake (Luminant)	3	124.38	24.66552	12.33276
Monticello (Luminant)	1	142.714	71.357	3.1848
Monticello (Luminant)	2	139.962	69.981	3.2328
Monticello (Luminant)	3	140.815	13.71024	6.85512
O W Sommers (CPS				

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Energy)				
O W Sommers (CPS Energy)	2	2.011	1.058421053	0.015876
W A Parish (NRG)	WAP4	0.033	0.033	0.033
W A Parish (NRG)	WAP5	97.654	48.827	4.6536
W A Parish (NRG)	WAP6	94.288	47.144	3.8928
Welsh Power Plant (AEP)	1	55.882	27.941	3.12624
Welsh Power Plant (AEP)	2	63.174	63.174*	0

*Modeled at the baseline rate in the low control scenario. Fayette units already have scrubber installed and Welsh 2 is shut down. No need to examine a low control scenario for these units.

2.2. NOx, PM and Sulfuric Acid Emissions

NOx emissions were held constant at baseline emission levels for all emission units in order to isolate visibility improvements due to SO_2 reductions from any visibility benefits that would result from reductions in NOx emissions.

For the coal-fired EGUs evaluated with CALPUFF, we also evaluated a more recent baseline period (2011-2015) using the 2001-2003 CALMET data since some controls or reductions in emissions may have occurred due to federal rules and we wanted to provide additional information as part of the visibility benefit analysis. In these RNS (Recent NOx and SO2) CALPUFF runs, we used the recent maximum NOx emissions and held the NOx emissions constant for all runs to isolate visibility improvements due to SO_2 reductions from any visibility benefits that would result from reductions in NOx emissions.

For the high control scenarios for dry scrubbing and wet scrubbing retrofits, 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.

Speciated PM emissions for CALPUFF modeling were calculated using the National Park Service (NPS) speciation worksheets corresponding to dry bottom boilers and the emission control equipment present in each modeling scenario for the coal-fired boilers. PM speciation in the NPS worksheets is based on AP-42 Tables 1.1-5 and 1-1.6 (for dry-bottom boilers) and depends on the type of emission control equipment and the coal's sulfur and ash content. PM coarse, PM fine, soil, elemental carbon and SOA emissions were input into CALPUFF. See Appendix E of the BART Screening TSD for summary of coal properties utilized in these calculations.

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Consistent with the methodology used to estimate baseline sulfuric acid emissions for CALPUFF modeling described in the BART Screening TSD, control scenario estimates of H_2SO_4 emissions from the coal-fired units are based on the best current information available from 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 the Electric Power Research Institute (EPRI). 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. For further information about the baseline and control scenario H_2SO_4 emission rates used for CALPUFF modeling see Appendix D of this TSD.

For the RNS CALPUFF runs we adjusted the NOx and SO_2 to reflect more recent maximum emission rates for the recent baseline. We used the same speciated PM and sulfuric acid emission rates as the 2001-2004 baseline and the two control case scenarios. NOx emissions were held constant at the more recent baseline rate. For the actual emission rates used in the RNS baseline and two control scenarios see Appendix C.

2.3. Emissions reductions from Fuel Oil Switching

To evaluate the visibility benefit of switching to lower sulfur fuel oil for those subject-to-BART gas/fuel oil-fired units, we modeled estimated emissions for switching to 0.3% sulfur fuel oil and 0.0015% S fuel oil (ULSD). SO_2 emissions were calculated by multiplying the baseline rate by the ratio of control scenario sulfur content to baseline sulfur content of the fuel oil burned. NOx and PM emissions were held constant at baseline levels. We note that PM emissions from lower sulfur fuel oils are anticipated to be less than baseline levels but visibility impact from direct PM emissions are a very small portion of the overall visibility impact due to the sources emissions. Reducing the PM emissions for the control scenarios would result in slightly greater visibility benefits from fuel switching.[4] See the BART Screening TSD for additional information on estimates of maximum emissions for Stryker and Graham units used for baseline emissions for these units.

Table 2.3-1. CALPUFF Modeled SO_2 emissions: Gas/Fuel-fired Units

Source	Unit	Baseline Fuel oil Sulfur Content (%)[5]	SO_2 Emissions (lb/hr)		
			Baseline	High Control Scenario (0.0015% S)	Low Control Scenario (0.3% S)
Graham	2	0.69	3727.5	7.67	1620.65
Stryker	ST2	0.65	3604.9	7.88	1663.78

[4] See "gas-fired SO_2 emissions comparison and calcs.xlsx" for detailed emission calculations and BART FIP TSD for a summary of EIA data.
[5] Maximum reported fuel oil sulfur content from EIA-767 data for 2001-2004

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Wilkes	1	0.43	323.5	1.13	75.23*
Wilkes	2	NA	1.92	1.92	1.92
Wilkes	3	NA	1.83	1.83	1.83

*Modeled at 0.1% S fuel oil

3. Visibility Benefits of DSI, SDA, and Wet FGD for Coal-Fired Units

We evaluated the visibility benefits of DSI, for the twelve units below that currently have no SO_2 control. We evaluated all the units using the control levels we employed in our control cost analyses. In summary, we evaluated these units at a DSI SO_2 control level of 50%, which we believe is likely achievable for any unit. At the lower performance level we assumed, we conclude that the corresponding visibility benefits from DSI in most cases would be close to half of the benefits from scrubbers resulting in the visibility benefits from scrubber retrofits being much more beneficial. We also evaluated the visibility benefits for scrubber retrofits (wet FGD and SDA) for these same units, assuming the same control levels corresponding to SDA and wet FGD that we used in our control cost analyses. For those sources that are within 50 to 400 km of a Class I area, we utilized CALPUFF modeling and supplemented our analysis with CAMx modeling to assess the visibility benefit of potential controls. For the remaining coal-fired sources (J T Deely, Coleto Creek, Fayette and W A Parish), only CAMx modeling was utilized as these sources are located at much greater distances to the nearest Class I areas. 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.[6] We note that high control scenario modeling for Fayette units 1 and 2 demonstrate the benefit from existing high performing controls. As discussed elsewhere, we found that for these units no additional controls or upgrades were necessary. For a full discussion of our review of all the modeling results, and factors that we considered in evaluating and weighing all the results, see the following sections of this TSD. Below, we present a summary of some of those visibility benefits at the Class I areas most impacted by each source:

Table 3-1. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CAMx modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Unit 1 and 2)	WIMO	Max dv	4.017	2.249	0.474	1.768	3.542
			Days > 0.5 dv	65	33	0	32	65
			Days>1.0 dv	33	13	0	20	33

[6] 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."

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		CACR	Max dv	3.775	2.539	0.787	1.236	2.988
			Days > 0.5 dv	91	62	4	29	87
			Days>1.0 dv	57	21	0	36	57
	Unit 1	WIMO	Max dv	2.154	1.168	0.245	0.986	1.909
			Days > 0.5 dv	33	13	0	20	33
			Days>1.0 dv	12	1	0	11	12
		CACR	Max dv	2.016	1.327	0.409	0.688	1.606
			Days > 0.5 dv	58	22	0	36	58
			Days>1.0 dv	17	4	0	13	17
	Unit 2	WIMO	Max dv	2.175	1.181	0.235	0.994	1.940
			Days > 0.5 dv	34	13	0	21	34
			Days>1.0 dv	12	1	0	11	12
		CACR	Max dv	2.033	1.338	0.391	0.695	1.642
			Days > 0.5 dv	58	23	0	35	58
			Days>1.0 dv	17	4	0	13	17
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63
			Days>1.0 dv	40	14	0	26	40
	Unit 1	CACR	Max dv	4.516	3.123	0.733	1.393	3.783
			Days > 0.5 dv	79	43	3	36	76
			Days>1.0 dv	32	16	0	16	32
		WIMO	Max dv	2.241	1.290	0.252	0.951	1.989
			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	8	2	0	6	8
	Unit 2	CACR	Max dv	4.487	3.065	0.563	1.422	3.924

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			Days > 0.5 dv	78	42	1	36	77
			Days>1.0 dv	30	13	0	17	30
		WIM O	Max dv	2.189	1.252	0.186	0.937	2.003
			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	6	2	0	4	6
Coleto Creek	Source (Unit 1)	WIM O	Max dv	0.845	0.526	0.176	0.318	0.668
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.791	0.458	0.186	0.333	0.606
			Days > 0.5 dv	5	0	0	5	5
			Days>1.0 dv	0	0	0	0	0
Harrington	Source (Unit 061B & 062B)	SACR	Max dv	5.288	4.287	3.235	1.001	2.053
			Days > 0.5 dv	13	7	3	6	10
			Days>1.0 dv	5	1	1	4	4
		WIM O	Max dv	4.928	4.362	3.798	0.565	1.130
			Days > 0.5 dv	15	11	6	4	9
			Days>1.0 dv	6	5	4	1	2
	Unit 061B	SACR	Max dv	2.908	2.322	1.738	0.586	1.170
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIM O	Max dv	2.708	2.382	2.065	0.326	0.643
			Days > 0.5 dv	6	5	4	1	2
			Days>1.0 dv	4	2	1	2	3
	Unit 062B	SACR	Max dv	2.998	2.373	1.719	0.625	1.279
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIM O	Max dv	2.770	2.407	2.046	0.363	0.723

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			Days > 0.5 dv	6	5	4	1	2
			Days>1.0 dv	4	1	1	3	3
JT Deely	Source (Sommers 1&2, JTDeely 1&2)	WIMO	Max dv	1.513	0.939	0.814	0.574	0.699
			Days > 0.5 dv	47	8	1	39	46
			Days>1.0 dv	6	0	0	6	6
		CACR	Max dv	1.423	1.155	0.905	0.268	0.518
			Days > 0.5 dv	7	3	2	4	5
			Days>1.0 dv	2	1	0	1	2
	JT Deely 1	WIMO	Max dv	0.757	0.449	0.270	0.307	0.487
			Days > 0.5 dv	4	0	0	4	4
			Days>1.0 dv	0	0	0	0	0
		BIBE	Max dv	0.652	0.373	0.069	0.279	0.583
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
	JT Deely 2	WIMO	Max dv	0.632	0.387	0.334	0.245	0.298
			Days > 0.5 dv	3	0	0	3	3
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.604	0.490	0.387	0.114	0.217
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
W.A. Parish	Source (WAP 4,5, &6)	CACR	Max dv	3.177	2.032	0.511	1.145	2.665
			Days > 0.5 dv	54	26	1	28	53
			Days>1.0 dv	22	9	0	13	22
		UPBU	Max dv	1.994	1.215	0.234	0.779	1.760
			Days > 0.5 dv	34	14	0	20	34
			Days>1.0 dv	9	1	0	8	9
	WAP 5	CACR	Max dv	1.698	1.052	0.180	0.646	1.518

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			Days > 0.5 dv	22	9	0	13	22
			Days>1.0 dv	8	1	0	7	8
		UPBU	Max dv	1.038	0.613	0.094	0.424	0.943
			Days > 0.5 dv	11	1	0	10	11
			Days>1.0 dv	1	0	0	1	1
	WAP 6	CACR	Max dv	1.648	1.018	0.156	0.630	1.492
			Days > 0.5 dv	22	8	0	14	22
			Days>1.0 dv	6	1	0	5	6
		UPBU	Max dv	1.003	0.591	0.081	0.412	0.922
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	1	0	0	1	1
Welsh	Source (Unit 1 & 2)	CACR	Max dv	4.576		0.822		3.754
			Days > 0.5 dv	92		3		89
			Days>1.0 dv	39		0		39
		MING	Max dv	2.544		0.570		1.973
			Days > 0.5 dv	9		1		8
			Days>1.0 dv	3		0		3
	Unit 1	CACR	Max dv	2.343	1.659	0.822	0.684	1.521
			Days > 0.5 dv	37	18	3	19	34
			Days>1.0 dv	8	3	0	5	8
		MING	Max dv	1.150	0.886	0.570	0.264	0.579
			Days > 0.5 dv	2	1	1	1	1
			Days>1.0 dv	1	0	0	1	1
Fayette	Source (Unit 1 & 2)	CACR	Max dv	1.894		0.903		0.991
			Days > 0.5 dv	26		2		24
			Days>1.0 dv	9		0		9
		WIMO	Max dv	1.175		0.580		0.595

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			Days > 0.5 dv	19		1		18
			Days>1.0 dv	2		0		2
	Unit 1	CACR	Max dv	1.002		0.480		0.522
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	1		0		1
		WIM O	Max dv	0.609		0.306		0.302
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0
	Unit 2	CACR	Max dv	0.974		0.441		0.534
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	0		0		0
		WIM O	Max dv	0.598		0.282		0.316
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0

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Table 3-2. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Units 1 and 2)	WIMO	Max dv	4.27	2.54	0.43	1.73	3.83
			Days > 0.5 dv Avg.	67.33	43.33	2.67	24.00	64.67
			Days>1.0 dv Avg.	42.00	21.00	1.00	21.00	41.00
		CACR	Max dv	4.03	2.41	0.47	1.62	3.55
			Days > 0.5 dv Avg.	91.67	64.33	4.67	27.33	87.00
			Days>1.0 dv Avg.	60.33	30.00	0.00	30.33	60.33
Monticello [1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	3.68	1.70	4.16	4.87
			Days > 0.5 dv Avg.	143.67	115.00	62.33	28.67	81.33
			Days>1.0 dv Avg.	113.00	66.33	23.67	46.67	89.33
		UPBU [4]	Max dv	3.45	1.77	0.77	1.68	2.68
			Days > 0.5 dv Avg.	103.00	61.00	13.67	42.00	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60.00	34.67	6.00	25.33	54.00
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67
Harrington [2]	Source (Units 061B & 062B)	SACR	Max dv	1.06	0.86	0.61	0.20	0.45
			Days > 0.5 dv Avg.	21.00	15.33	6.33	5.67	14.67
			Days>1.0 dv Avg.	6.67	3.00	0.67	3.67	6.00
		WIMO	Max dv	1.29	0.97	0.55	0.32	0.74
			Days > 0.5 dv Avg.	26.00	15.33	8.67	10.67	17.33
			Days>1.0 dv Avg.	9.00	4.67	1.33	4.33	7.67

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Welsh[3]	Source (Unit 1)	CACR	Max dv	1.44	1.12	0.72	0.32	0.72
			Days > 0.5 dv Avg.	50.33	32.67	12.33	17.67	38
			Days>1.0 dv Avg.	15.33	8.00	2.33	7.33	13.00
		UPBU	Max dv	0.76	0.49	0.22	0.27	0.54
			Days > 0.5 dv Avg.	12.00	4.67	0.33	7.33	11.67
			Days>1.0 dv Avg.	0.67	0.00	0.00	0.67	0.67
		WIMO	Max dv	0.56	0.33	0.15	0.23	0.41
			Days > 0.5 dv Avg.	7.33	2.67	0.33	4.67	7.00
			Days>1.0 dv Avg.	1.33	0.33	0.00	1.00	1.33

[1] Monticello's controlled level is a combination of scrubber upgrades and scrubber install in the facility impact modeling with CALPUFF.
[2] Harrington high control scenario for both units is SDA at 95% reduction
[3] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.
[4] UPBU = Upper Buffalo Wilderness Area.

Based on the information presented here, we find that installing either wet FGD or SDA scrubbers on these units would yield significant visibility improvements. Below we provide additional analysis of visibility modeling results for each unit.

4. Visibility Benefit Analysis of DSI, SDA, and wet FGD

CALPUFF[7] and CAMx model results[8,9] shown in the tables below summarize the benefits from the recommended controls at the two Class I areas most impacted by the source or unit in the baseline modeling. As previously discussed and also in the BART Screening TSD, we have utilized CALPUFF for sources within the typical range of CALPUFF. We conducted CALPUFF and CAMx modeling to evaluate the visibility benefits for DSI, SDA, and WFGD but are only explicitly reporting the visibility benefits for the proposed BART level in this TSD. For the visibility benefits for the other potential emission rate/control levels not proposed for BART modeled with CALPUFF, see the spreadsheets that include CALPUFF results listed in the footnotes for this paragraph. For the visibility benefits for the other potential emission

[7] See spreadsheets: "TX_CALPOST_coal_all.xlsx", "TX_CALPOST_coal_RNS_all.xlsx", and "TX_CALPOST_NG-FO_all.xlsx" in the docket for this action for these and additional model results.
[8] See spreadsheet: "summary CAMx vis daily.xlsx" in the docket for this action for these and additional model results.
[9] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for summary of base case model results, including species specific 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.

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rate/control levels not proposed for BART modeled with CAMx, see the figures in the following sections, Appendix E and F, and the spreadsheets that include CAMx results listed in the footnotes for this paragraph.

For the CALPUFF and CAMx modeling, the benefit is calculated as the difference between the maximum impact modeled for the baseline and the maximum impact level modeled under the control scenario and provided in tables for each facility/subsection below. Also summarized are the cumulative benefit and the number of days impacted over 0.5 and 1.0 dv (CALPUFF and CAMx). 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 E for CAMx modeled maximum impact at each Class I area for each model scenario. See Appendix F for CAMx modeled number of days over 0.5 and 1.0 dv at each Class I area for each model scenario.

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 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. The figures in each subsection below show unit-level model results for the base case (Run 1) and the two control scenarios (Run 3 and Run 4) modeled for all unscrubbed units. The low control scenario (Run 4) estimates the visibility impacts and benefits from DSI level controls at 50% for unscrubbed units. The high control scenario (Run 3) estimates visibility impacts and benefits for WFGD/SDA level controls at unscrubbed units. For each unscrubbed unit, there are four figures. The first figure shows the maximum CAMx modeled impact at each Class I area for each modeled scenario, consistent with the data in the tables above. The second figure provides 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. The third figure provides an assessment of 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.[10] Finally, the fourth figure shows the contribution to extinction from the unit due to each

[10] See spreadsheet: "summary CAMx vis daily.xlsx" in the docket for this action for these and additional model

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visibility impairing species[11] 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.[12]

4.1. Big Brown 1 & 2

In reviewing the Big Brown units, we conclude that the installation of wet FGD will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.1-1a. Wet FGD Visibility Benefits at Big Brown (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Big Brown Units 1 & 2	3.83	3.55	7.38	151.67	101.33

Table 4.1-1b. Wet FGD Visibility Benefits at Big Brown RNS {2011-2015} (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Big Brown Units 1 & 2	3.205	2.97	6.175	138.33	83

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek and Wichita Mountains
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek and Wichita Mountains.

results.
[11] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)
[12] 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.

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In evaluating Big Brown, we note there are two Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results, we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the two Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate that wet FGD on both units will eliminate 151.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the visibility benefits in terms of dv benefits at the most impacted Class I areas and about 1/3rd to half the cumulative benefits over the class I areas included in the modeling analysis. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to wet FGD levels.

Table 4.1-2. Wet FGD Visibility Benefits at Big Brown (CAMx)

Unit	Improvement at Wichita mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Big Brown 1	1.909	1.606	12.728	174 / 44	174 / 44
Big Brown 2	1.940	1.642	12.924	175 / 45	175 / 45
Source	3.542	2.988	24.274	372 / 170	362 / 170

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv at all Class I areas on a unit- and source-wide basis, and eliminate all but 10 days across the impacted Class I areas where the source-wide impacts exceeds 0.5 dv. At the most impacted Class I area, wet FGD on each unit result in visibility improvements of 1.9 dv each on the most impacted day. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the CAMx modeling. Figures 4.1-1 (unit 1) and 4.1-5 (unit 2) below show the

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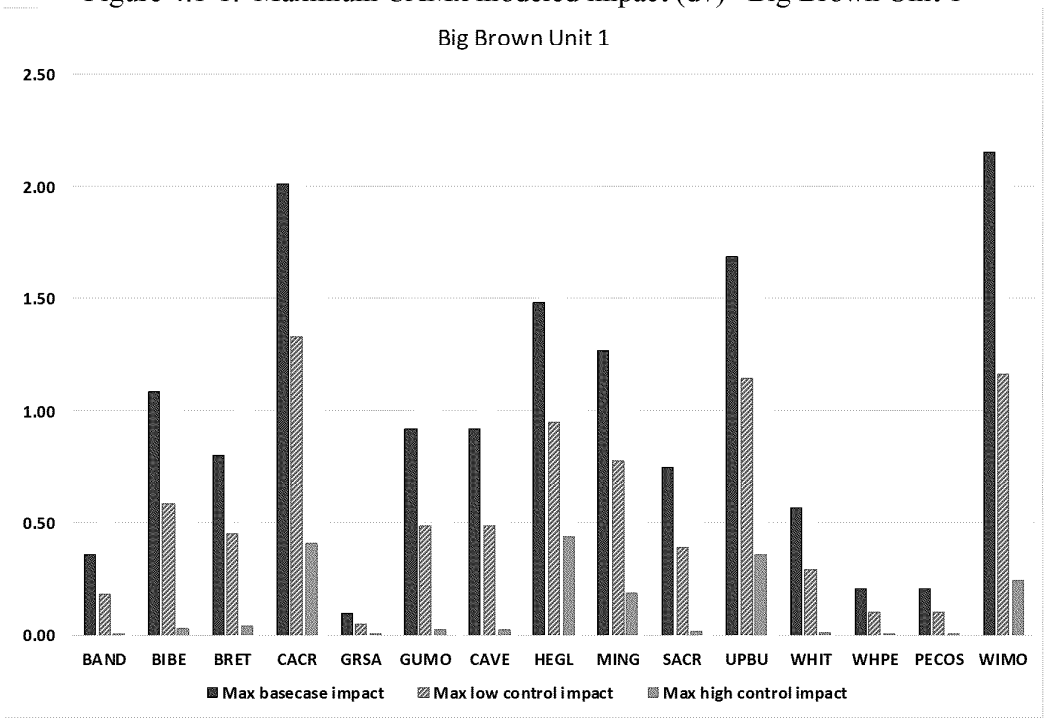
maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figures 4.1-2 and 4.1-6). At the most impacted Class I area, wet FGD on each unit results in visibility improvements of 1.4 dv on average across the top ten most impacted days, and approximately 1.3 dv at the second most impacted Class I area for each unit. Figures 4.1-3 and 4.1-7 show an assessment of the annual average impacts and benefits under the control scenarios.[13] Wet FGD reduces annual average base case impacts from each unit at each Class I area by over 90% while DSI reduces annual average impacts at each Class I area by 50% or less. On average across all Class I areas, Wet FGD results in a 95% reduction in annual average visibility impacts from each unit. Figures 4.1-4 and 4.1-8 show the contribution to extinction from the units due to each visibility impairing species[14] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Wichita Mountains and Caney Creek) for the base case modeling scenario.[15] These figures show that the impacts from the Big Brown units on these days are primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to these units.

Figure 4.1-1. Maximum CAMx modeled impact (dv)– Big Brown Unit 1



[13] 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 at each Class I area with impacts greater than 0.1 dv.

[14] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[15] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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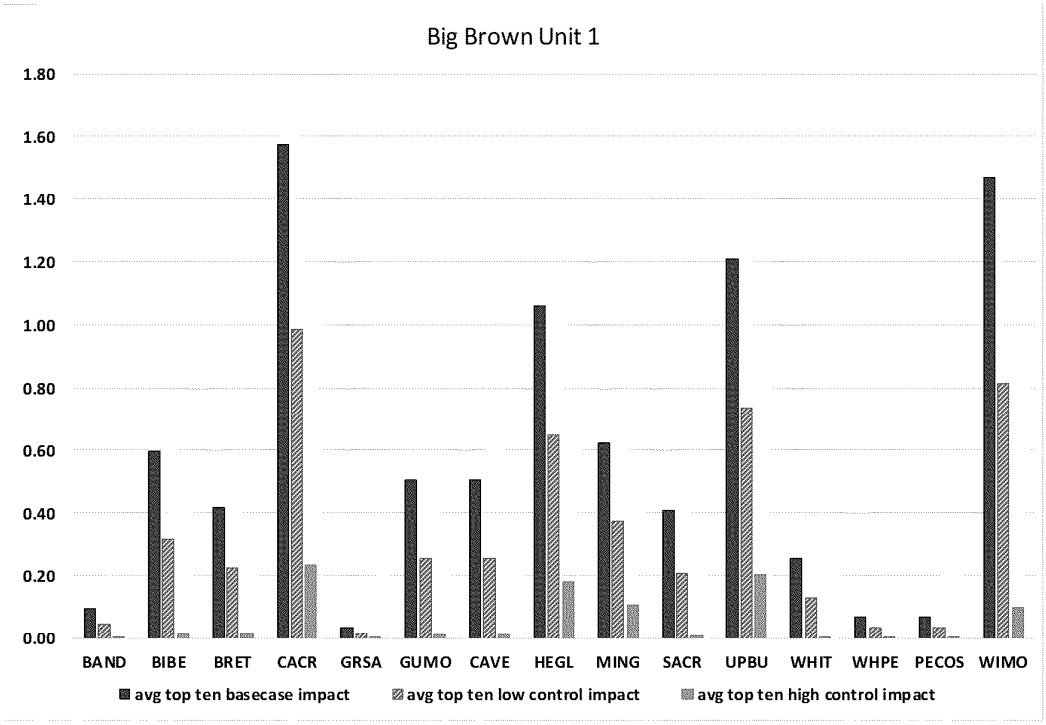

Figure 4.1-2. Average of top ten CAMx modeled impact (dv) – Big Brown Unit 1

Figure 4.1-3. Annual Average CAMx modeled impact (dv) excluding baseline days impacted less than 0.1 dv – Big Brown Unit 1

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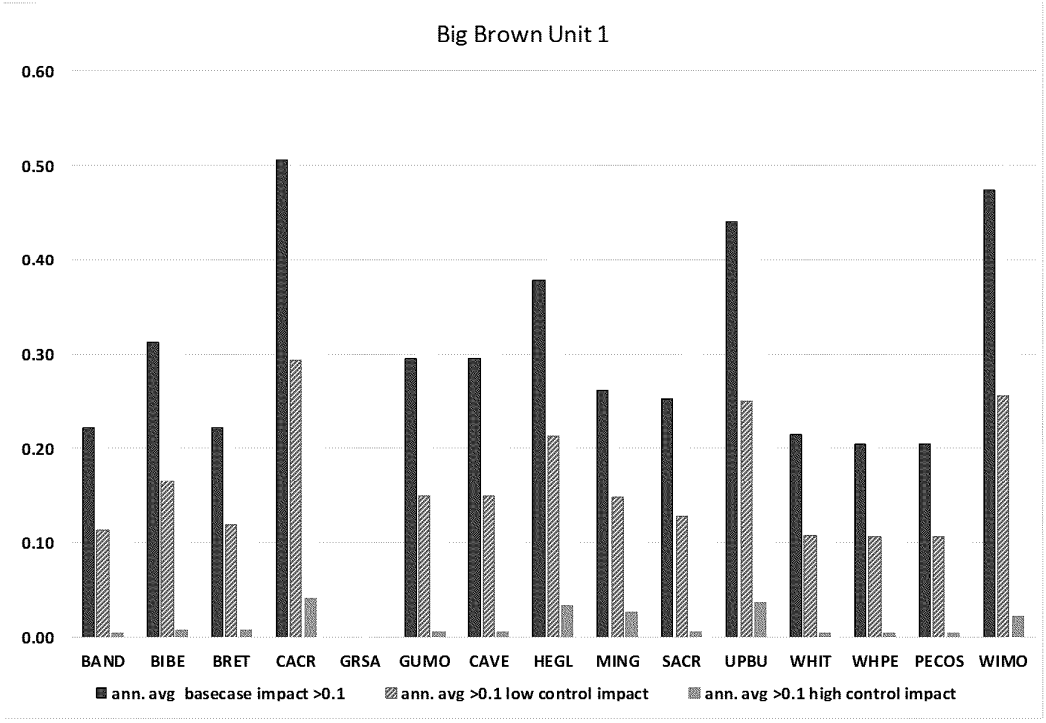


Figure 4.1-4. Species Contribution (Mm-1) on ten highest impact days (base case) at two most impacted Class I areas – Big Brown Unit 1

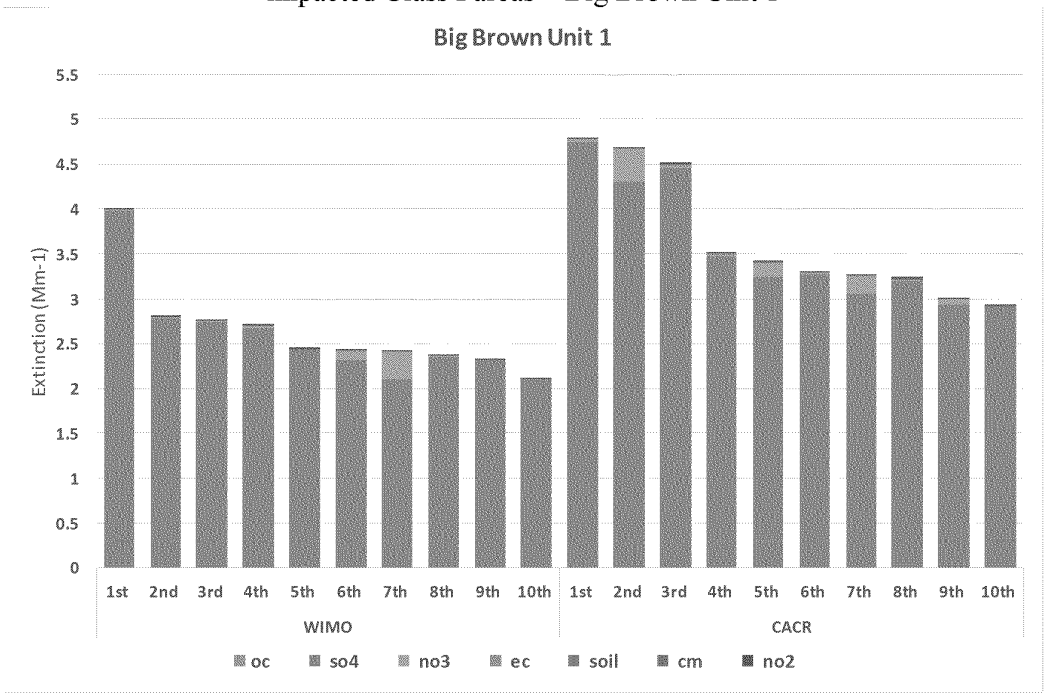


Figure 4.1-5. Maximum CAMx modeled impact (dv) – Big Brown Unit 2

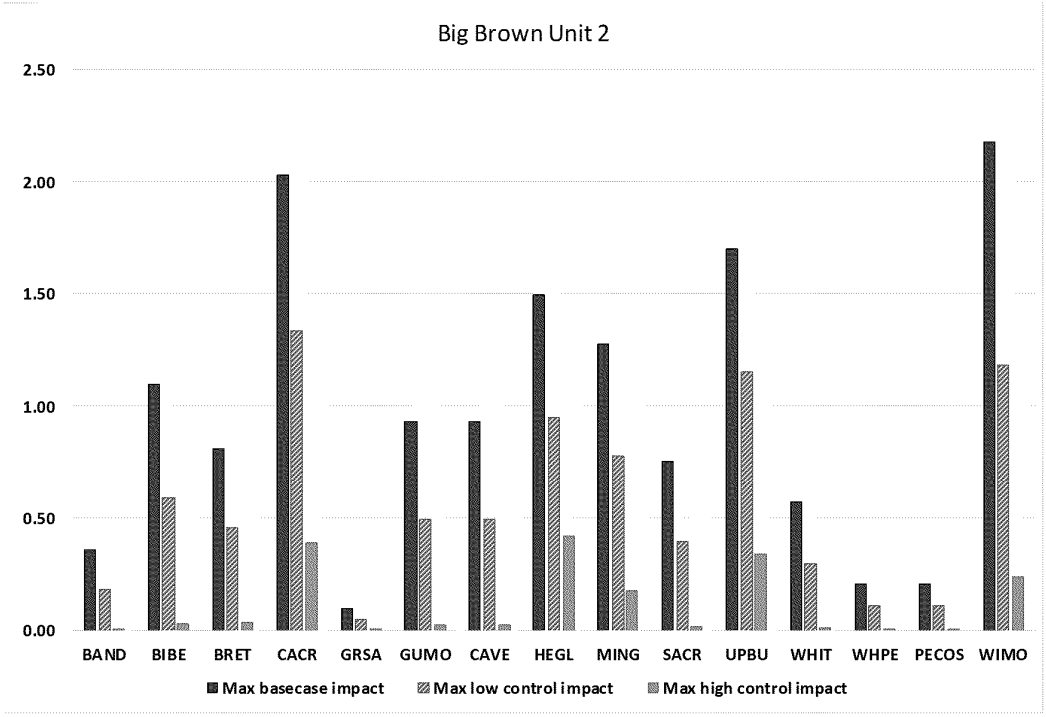


Figure 4.1-6. Average of top ten CAMx modeled impact (dv) – Big Brown Unit 2

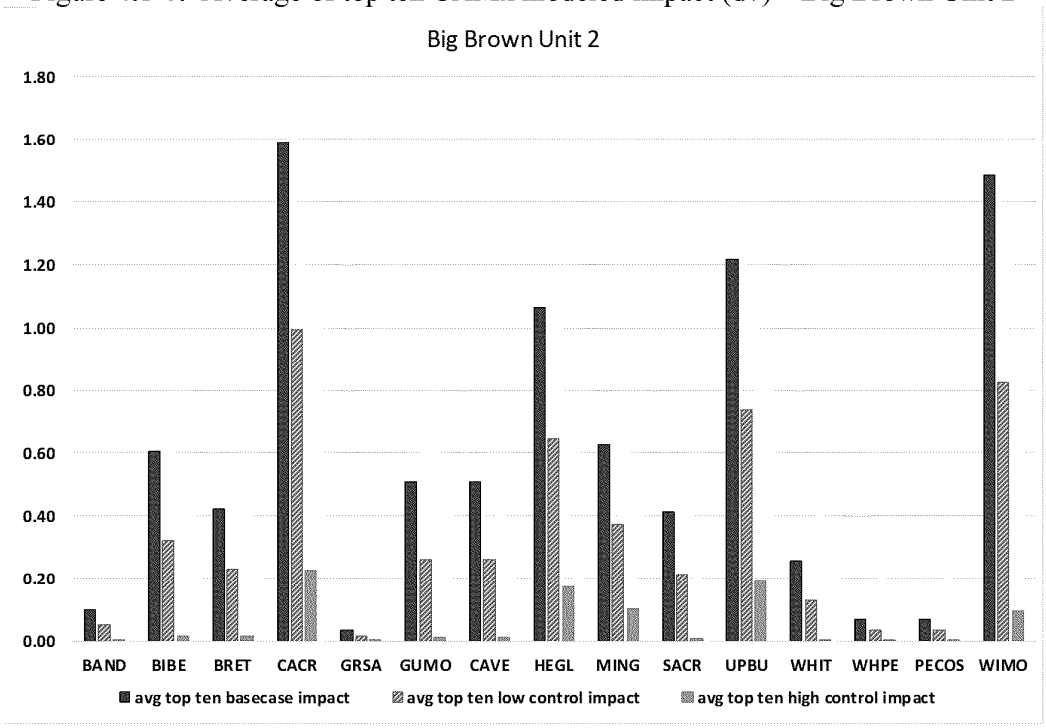


Figure 4.1-7. Annual Average CAMx modeled impact excluding baseline days impacted (dv) less than 0.1 dv – Big Brown Unit 2

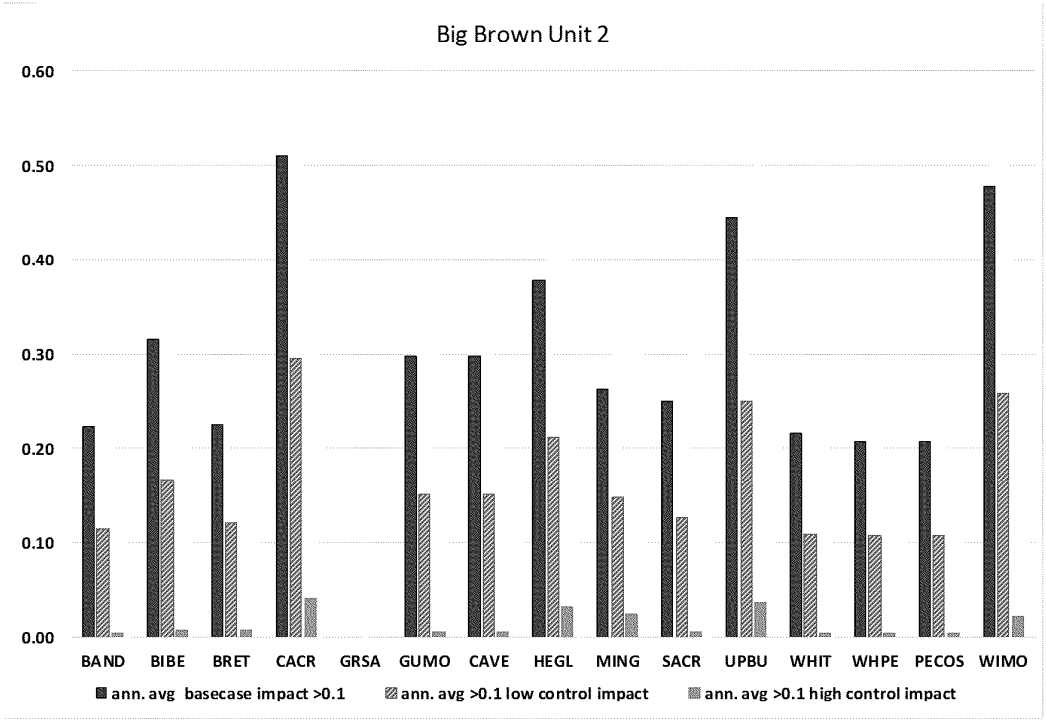
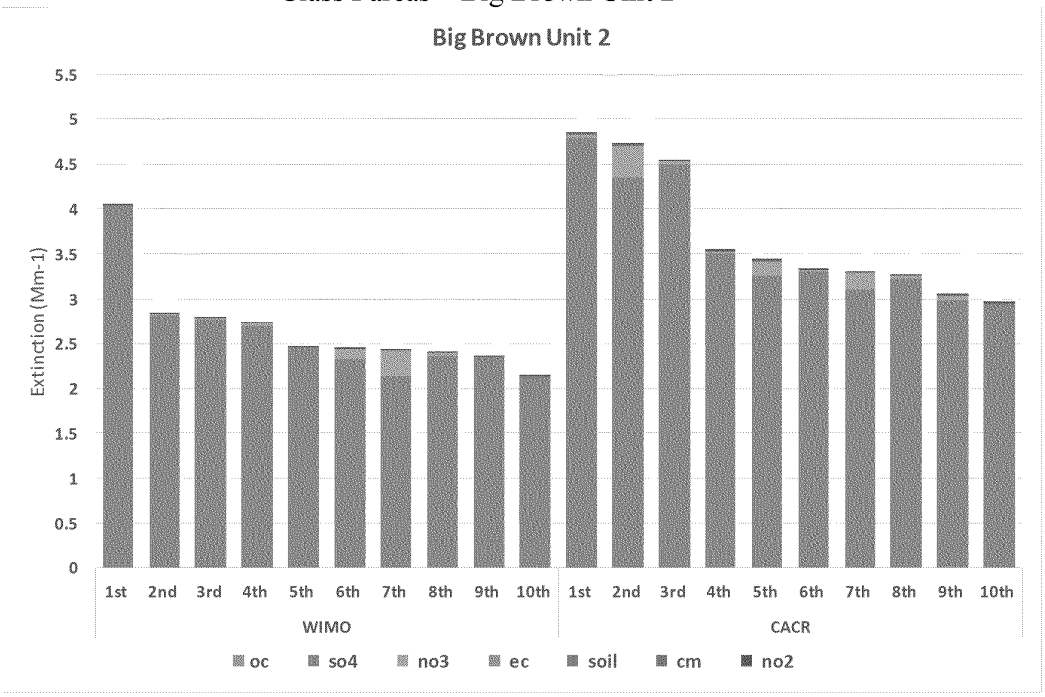


Figure 4.1-8. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Big Brown Unit 2



4.2. Monticello 1 & 2

Similar to the Big Brown units, the installation of wet FGD at Monticello Units 1 and 2 will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.2-1a. Wet FGD Visibility Benefits at Monticello (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	4.87	2.70	10.25	224.67	164.67

Table 4.2-1b. Wet FGD Visibility Benefits at Monticello with Scrubber Upgrade on Unit 3 RNS {2011-2015} (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	3.67	1.88	7.37	201.33	147

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Monticello, we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario

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subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 224.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 13 class I areas included in the CAMx modeling. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to wet FGD levels.

Table 4.2-2. Wet FGD Visibility Benefits at Monticello (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 1	3.783	1.989	12.708	197 / 67	191 / 67
Monticello 2	3.924	2.003	13.025	192 / 57	191 / 57
Source (including unit 3)	8.419	4.962	31.553	520 / 293	460 / 278

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1 dv at all Class I areas on a unit basis, and eliminate all but 15 days across the impacted Class I areas where the source-wide impacts exceeds 1 dv. We note that source-wide modeled benefits include benefits of 95% control scrubber upgrade on Unit 3. At the most impacted Class I area, wet FGD on each unit will each result in visibility improvements of 3.8-3.9 dv on the most impacted day at Caney Creek and 2 dv visibility benefits at Wichita Mountains. DSI operated at 50% control results in less than half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. Figures 4.2-1 (unit 1) and 4.2-5 (unit 2) below show the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figures 4.2-2 and 4.2-6). At the most impacted Class I area, wet FGD on

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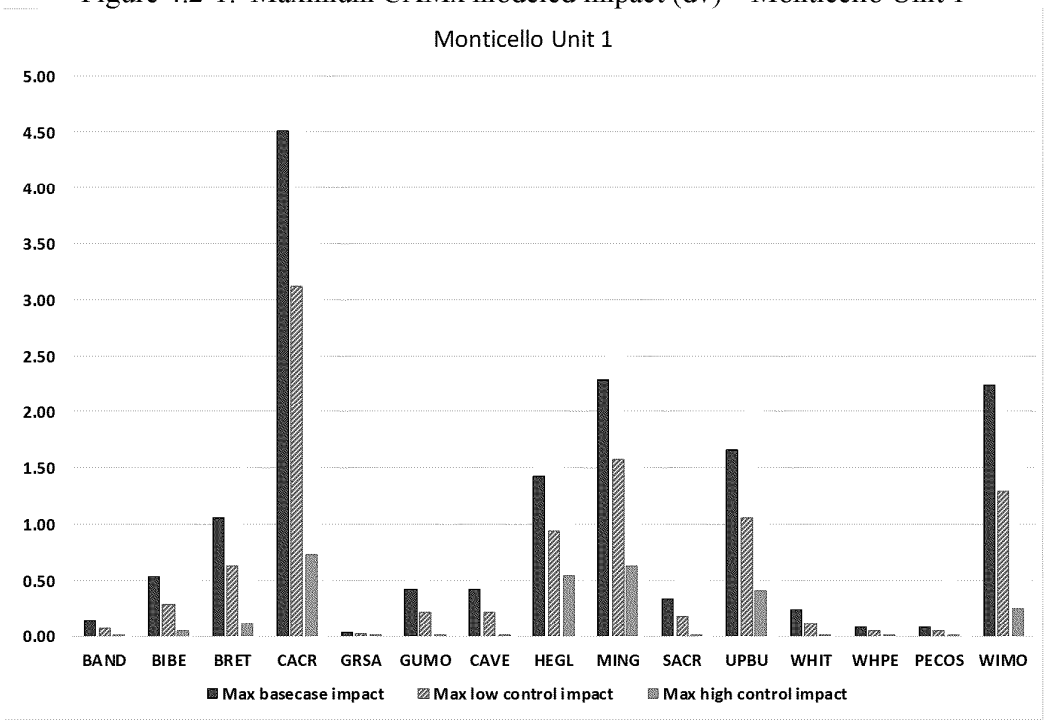
each unit results in visibility improvements of 1.8 dv on average across the top ten most impacted days, and approximately 1.3 dv at the second most impacted Class I area for each unit. Figures 4.1-3 and 4.1-7 show an assessment of the annual average impacts and benefits under the control scenarios.[16] Wet FGD reduces annual average base case impacts from each unit by 84% or more at each Class I area, while DSI at 50% emission reduction reduces annual average impacts at each Class I area by 50% or less. On average across all Class I areas, wet FGD results in a 91% reduction in annual average visibility impacts from each unit. Figures 4.2-4 and 4.2-8 show the contribution to extinction from the units due to each visibility impairing species[17] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Caney Creek and Wichita Mountains) for the base case modeling scenario.[18] These figures show that the impacts from the Monticello units 1 and 2 on these days are primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to these units.

Figure 4.2-1. Maximum CAMx modeled impact (dv) – Monticello Unit 1



[16] 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 at each Class I area with impacts greater than 0.1 dv.

[17] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[18] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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Figure 4.2-2. Average of top ten CAMx modeled impact (dv) – Monticello Unit 1

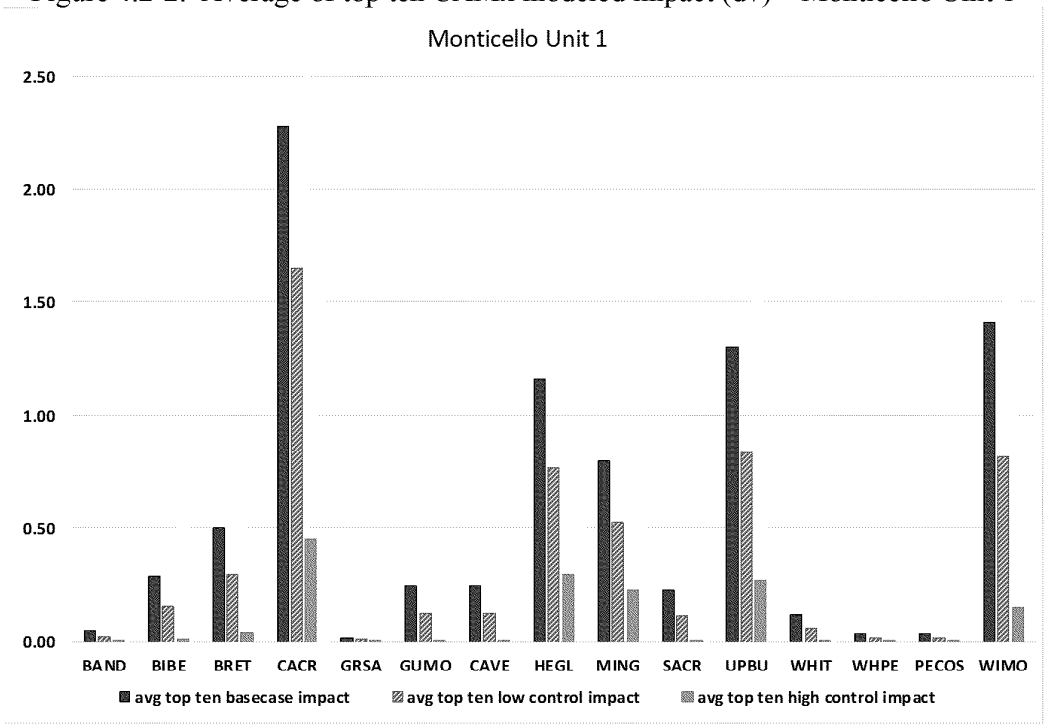

Figure 4.2-3. Annual Average CAMx modeled impact (dv) excluding baseline days impacted less than 0.1 dv – Monticello Unit 1

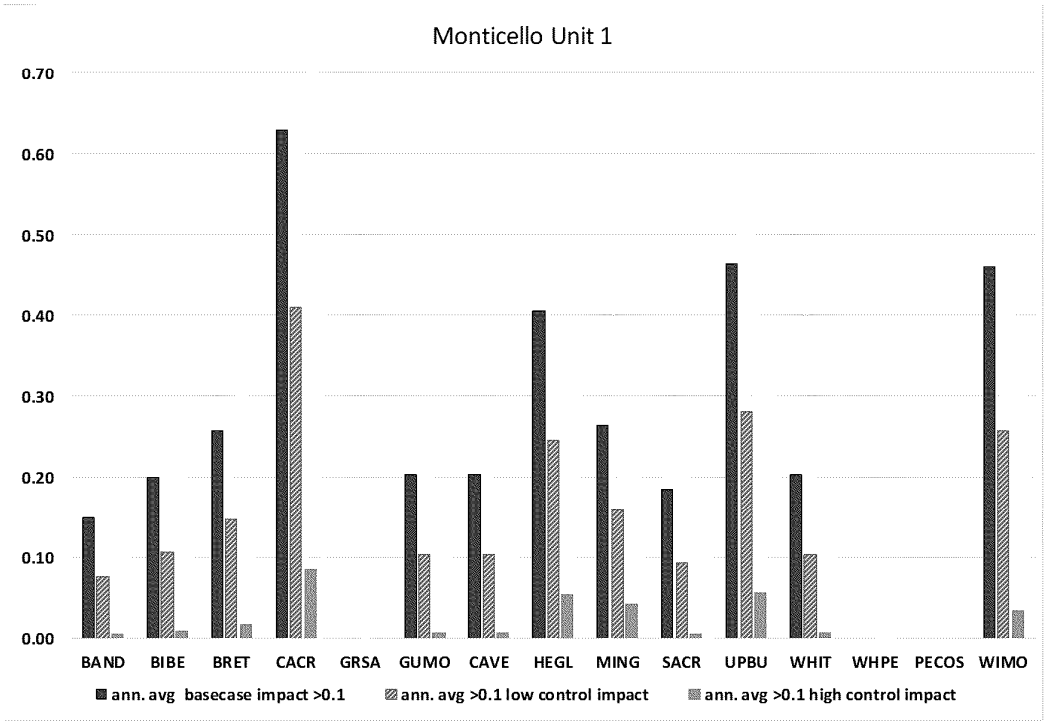

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Figure 4.2-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Monticello Unit 1

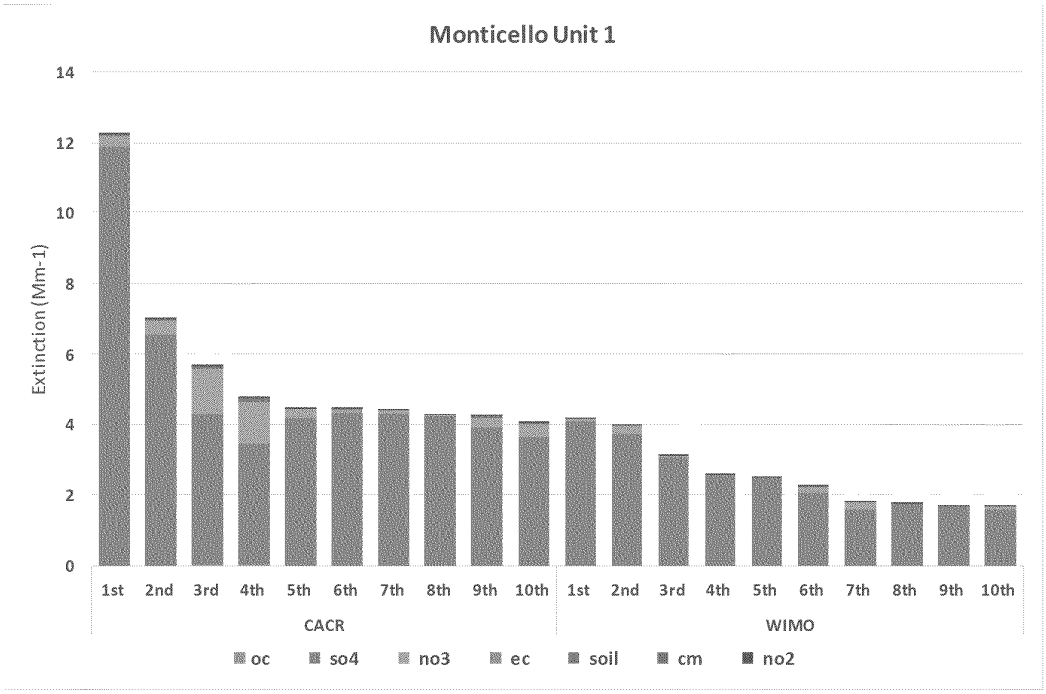


Figure 4.2-5. Maximum CAMx modeled impact (dv) – Monticello Unit 2

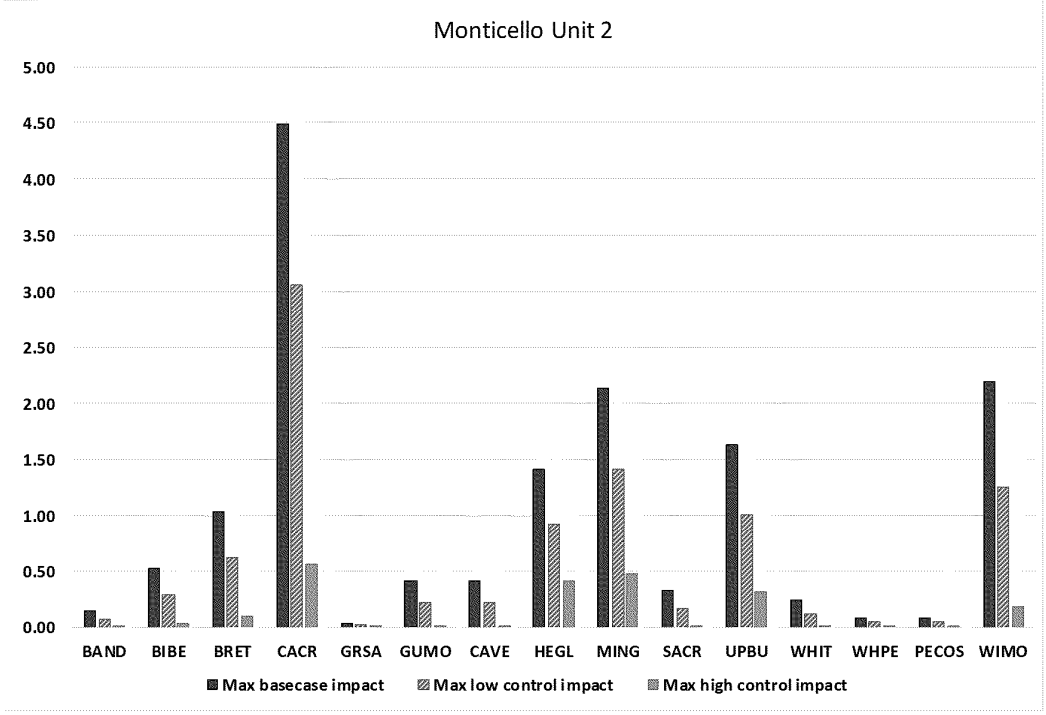


Figure 4.2-6. Average of top ten CAMx modeled impact (dv) – Monticello Unit 2

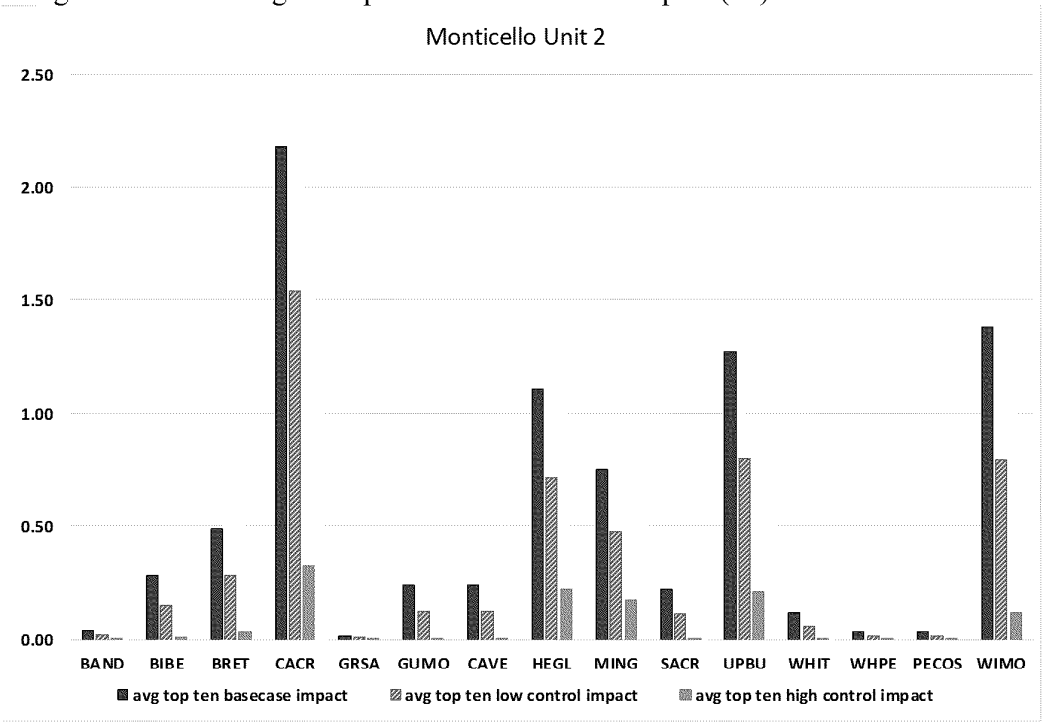


Figure 4.2-7. Annual Average CAMx modeled impact (dv) excluding baseline days impacted less than 0.1 dv – Monticello Unit 2

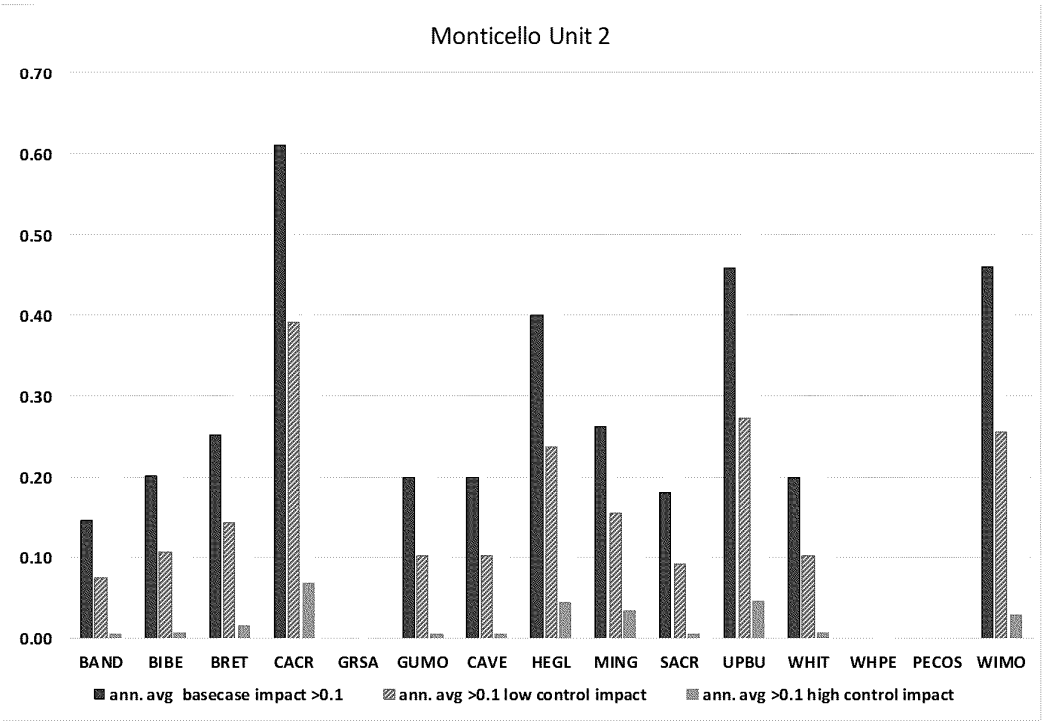
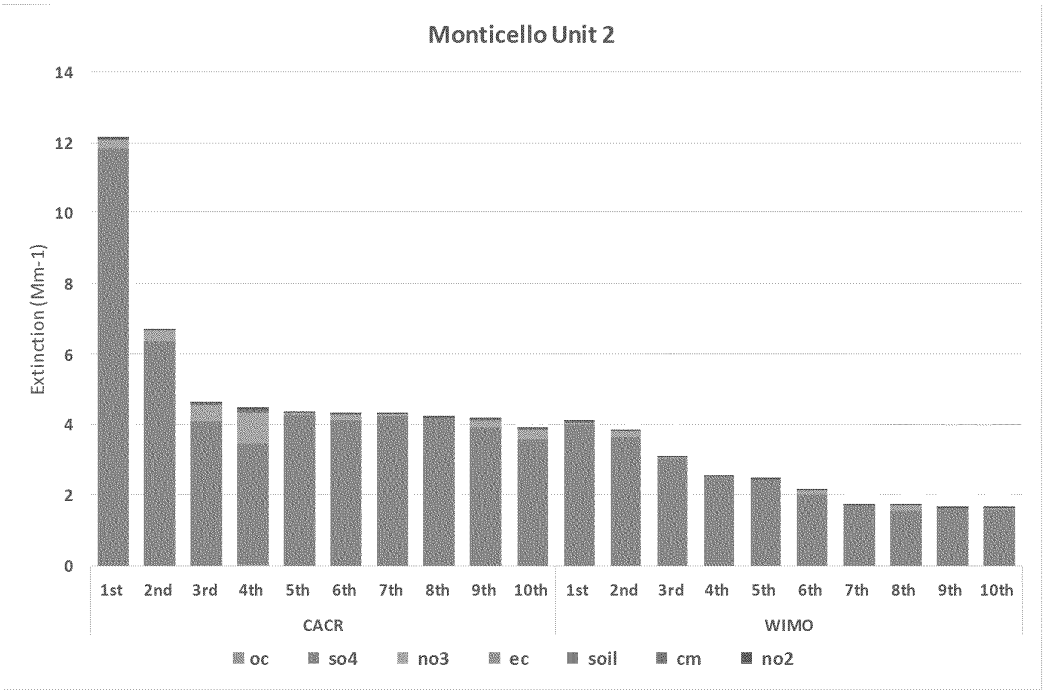


Figure 4.2-8. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Monticello Unit 2



4.3. Coleto Creek 1

In reviewing Coleto Creek Unit 1, we conclude that in comparison with the Monticello units, the installation of a wet FGD is more cost-effective and results in lesser, but still significant visibility benefits. We summarize some of these visibility benefits in the table below:

Table 4.3-1. Wet FGD Visibility Benefits at Coleto Creek Unit 1 (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Coleto Creek 1	0.668	0.606	5.233	17 / 0	17 / 0

[1] 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

[2] 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

[3] 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.

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CAMx modeling results indicate that wet FGD will eliminate all days impacted over 0.5 dv at all Class I areas. At the most impacted Class I area, wet FGD will result in visibility improvements of 0.6 or more on the most impacted days at both Caney Creek and the Wichita Mountains. In addition, seven other Class I areas are improved by amounts ranging from 0.356 to 0.531 dv on the maximum impacted days with wet FGD. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. Figure 4.3-1 below shows the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figure 4.3-2). At the most impacted Class I area, wet FGD results in visibility improvements of 0.53 dv on average across the top ten most impacted days, and approximately 0.41 dv at the second most impacted Class I area. Figure 4.3-3 shows an assessment of the annual average impacts and benefits under the control scenarios.[19] Wet FGD reduces annual average base case impacts by 76% to 95% depending on the Class I area, while DSI at 50% emission reduction reduces annual average impacts at each Class I area by 50% or less. At the most impacted Class I area (Wichita Mountains), wet FGD results in a 90% reduction in annual average visibility impacts, compared to a 46% reduction with DSI. On average across all Class I areas, wet FGD results in a 91% reduction in annual average visibility impacts. Figure 4.3-4 shows the contribution to extinction due to each visibility impairing species[20] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Caney Creek and Wichita Mountains) for the base case modeling scenario.[21] This figure shows that the impacts from Coleto Creek Unit 1 on these days are primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to this unit at these Class I areas.

[19] 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 at each Class I area with impacts greater than 0.1 dv.

[20] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[21] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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Figure 4.3-1. Maximum CAMx modeled impact (dv) – Coleto Creek Unit 1

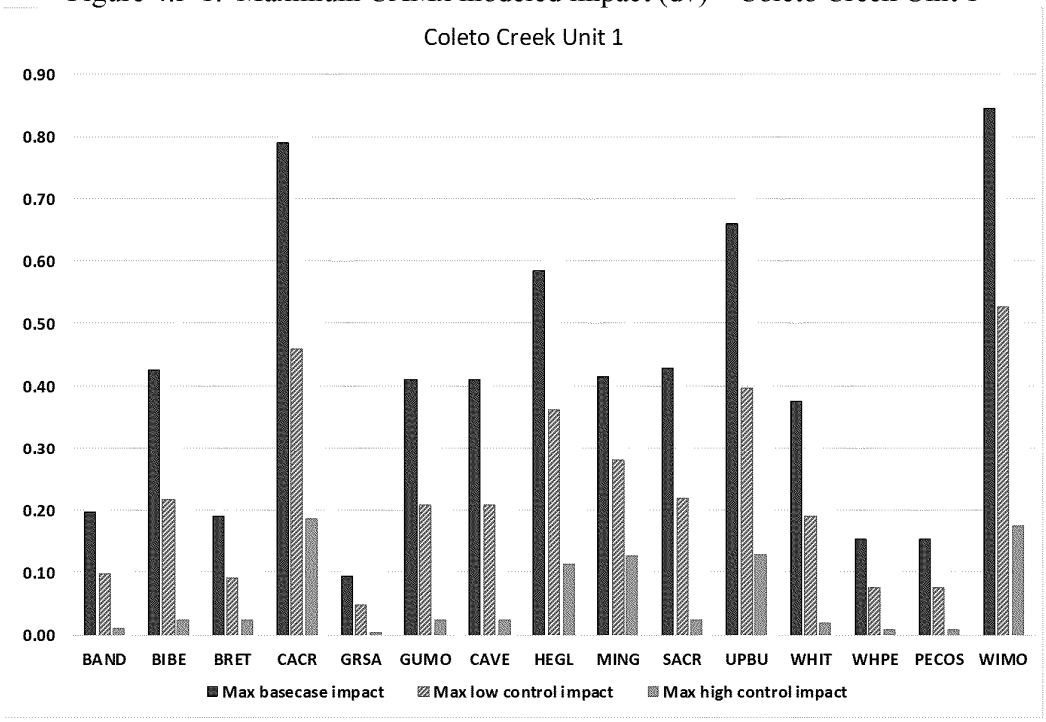

Figure 4.3-2. Average of top ten CAMx modeled impact (dv) – Coleto Creek Unit 1

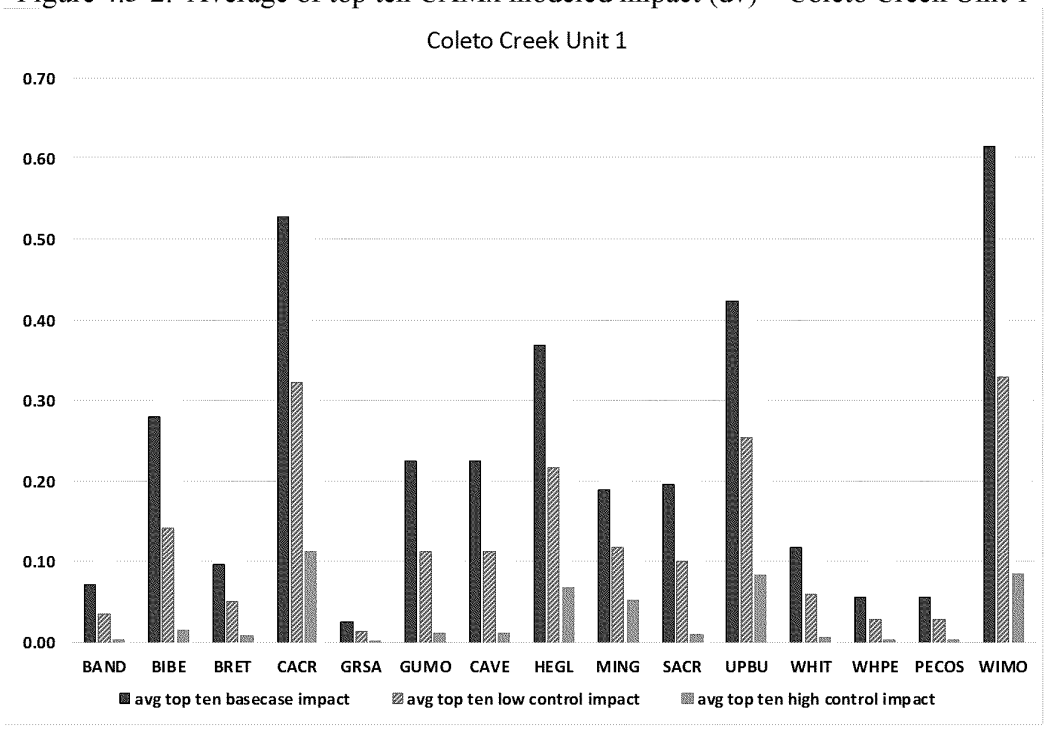

Figure 4.3-3. Annual Average CAMx modeled impact (dv) excluding baseline days impacted

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less than 0.1 dv – Coleto Creek Unit 1

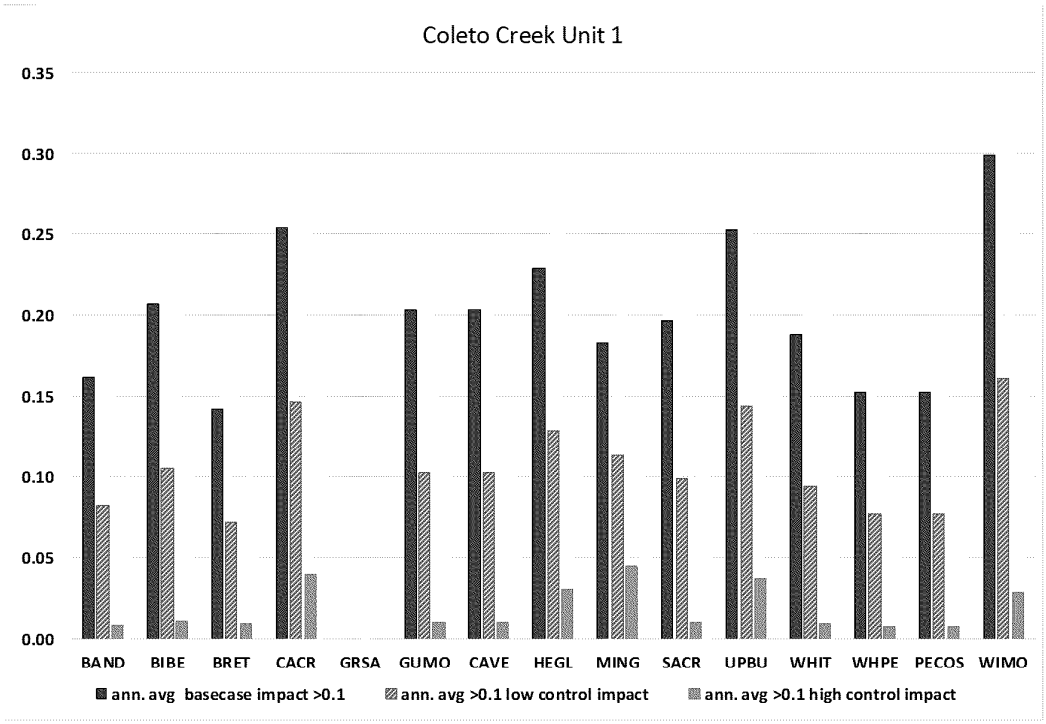
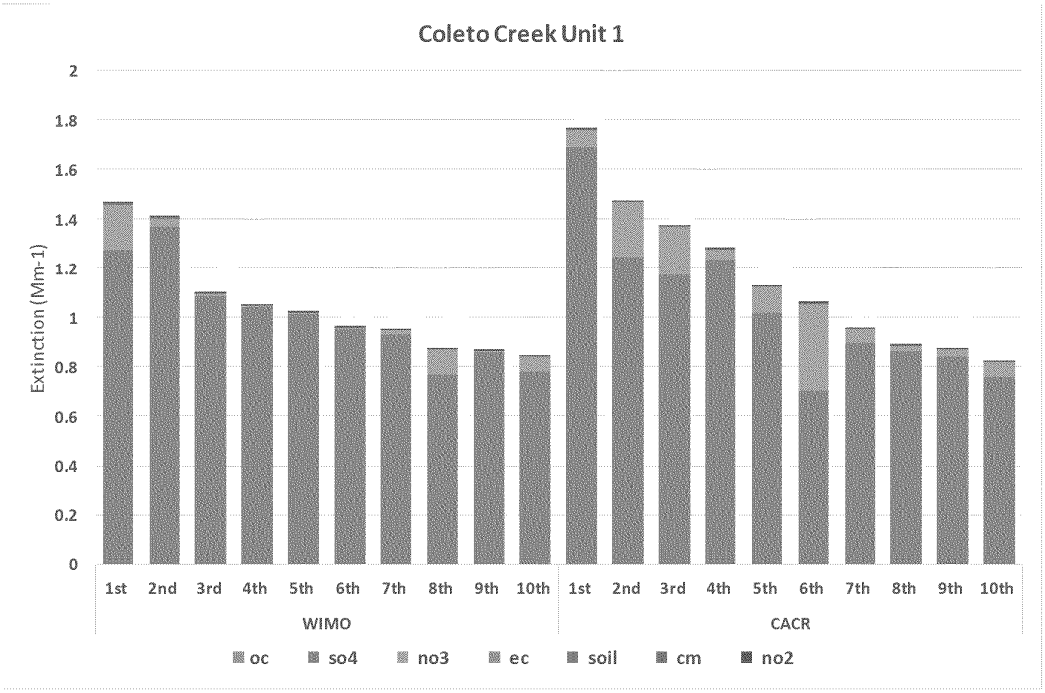


Figure 4.3-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Coleto Creek Unit 1



4.4. Welsh 1

In reviewing Welsh Unit 1, we conclude that the installation of a wet FGD will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.4-1a. Wet FGD Visibility Benefits at Welsh Unit 1 (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Welsh 1	0.72	0.41	1.66	56.67	15

Table 4.4-1b. Wet FGD Visibility Benefits at Welsh RNS {2011-2015} (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Welsh 1	.464	.231	1.05	34	6.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Welsh we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF

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modeling results indicate wet FGD on both units will eliminate 56.67 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to wet FGD levels.

Table 4.4-2. Wet FGD Visibility Benefits at Welsh Unit 1 (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Mingo Wilderness (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Welsh 1	1.521	0.579	4.683	65 / 9	60 / 9
Source (Welsh 1 & 2)	3.754	1.973	13.179	211 / 72	206 / 72

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD on unit 1 will eliminate all days impacted by the unit over 1 dv at all Class I areas and all but 5 days impacted over 0.5 dv. At the most impacted Class I area, wet FGD on unit 1 will result in visibility improvements of 1.521 dv on the most impacted days at Caney Creek. In addition to the visibility benefits at Caney Creek and Mingo, visibility benefits at two additional Class I areas exceed 0.5 dv. We note that source-wide benefits shown include the benefits from the shutdown of unit 2. In addition, cumulative benefits from wet FGD on unit 1 over all 15 Class I areas exceeds 4.5 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. Figure 4.4-1 below shows the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figure 4.4-2). At the most impacted Class I area, wet FGD results in visibility improvements of 0.8 dv on average across the top ten most impacted days. Figure 4.4-3 shows an assessment of the annual average impacts and benefits under the control scenarios.[22]

[22] In order to exclude days with very low impact due to transport conditions that do not result in transport and

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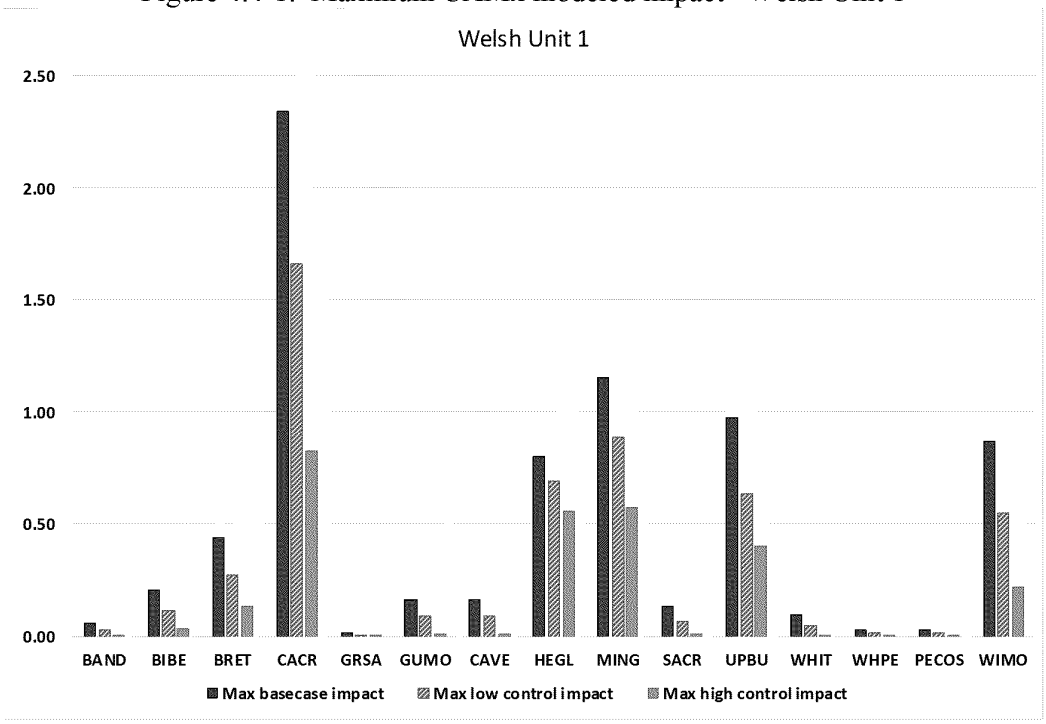
On average across all Class I areas, wet FGD results in a 78% reduction in annual average visibility impacts compared to 38% for DSI. Figure 4.4-4 shows the contribution to extinction due to each visibility impairing species[23] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Caney Creek and Wichita Mountains) for the base case modeling scenario.[24] This figure shows that the impacts from Welsh Unit 1 at CACR on most of these days is primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to this unit on these days. At Mingo, many days are significantly impacted by nitrates and therefore the benefit from reducing SO2 emissions is not as significant as it is as Caney Creek. Other Class I areas, such as Wichita Mountains are significantly impacted by sulfate and benefits from SO2 reductions due to wet FGD are more pronounced.

Figure 4.4-1. Maximum CAMx modeled impact– Welsh Unit 1



impacts to the Class I area, the annual average only includes days during the baseline modeled scenario at each Class I area with impacts greater than 0.1 dv.

[23] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[24] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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Figure 4.4-2. Average of top ten CAMx modeled impact– Welsh Creek Unit 1

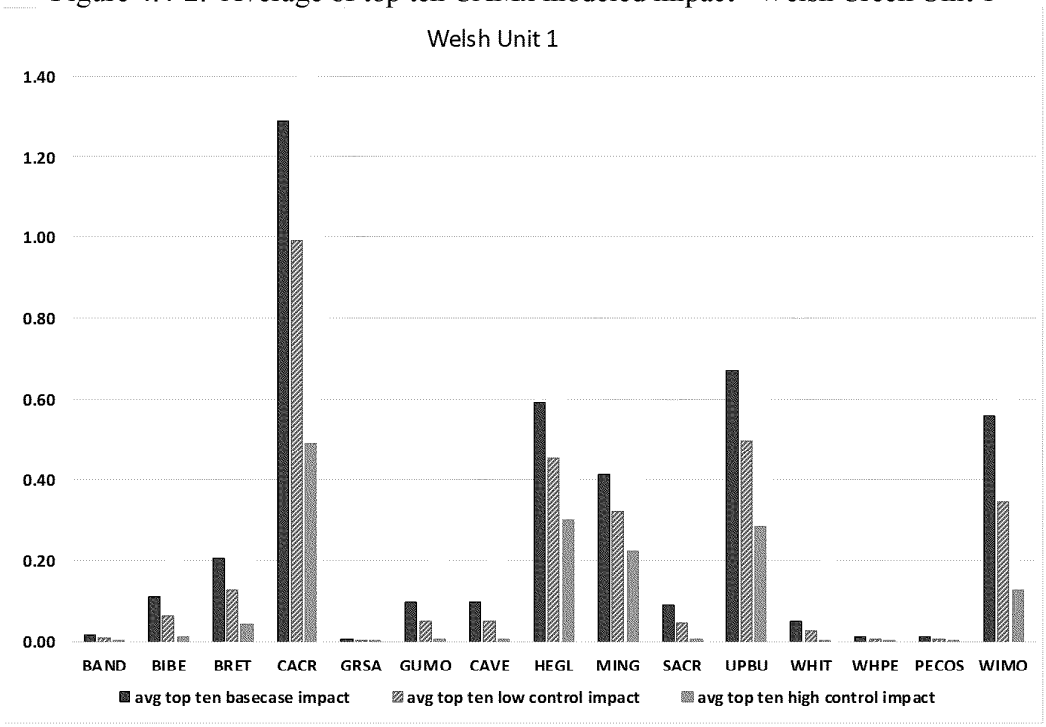

Figure 4.4-3. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – Welsh Unit 1

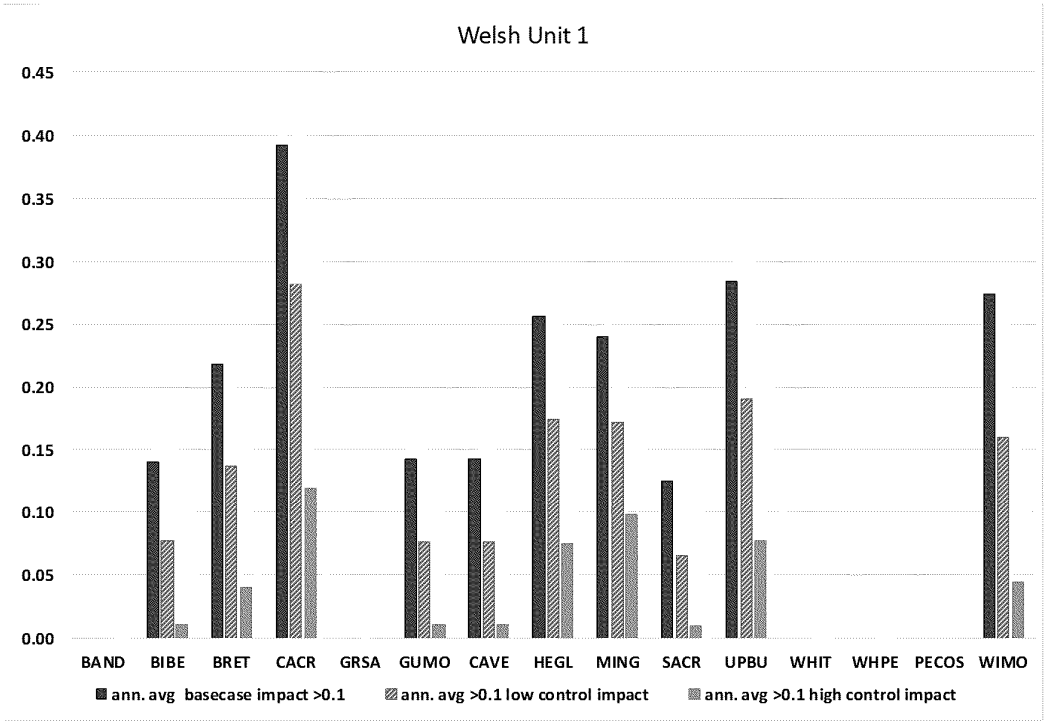

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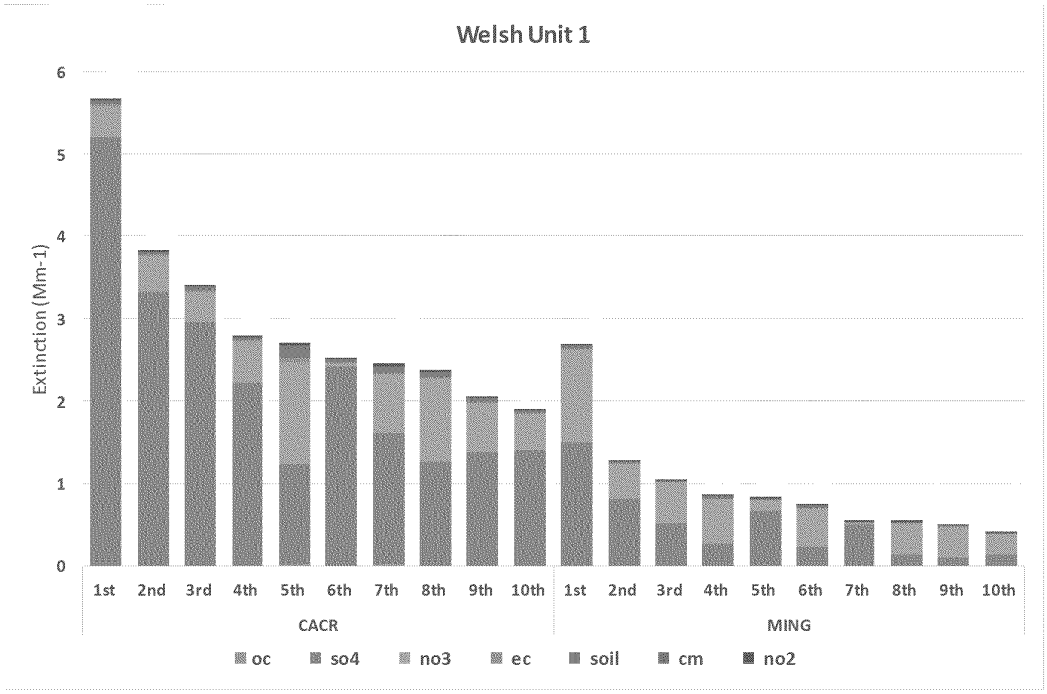
Figure 4.4-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Welsh Unit 1



4.5. Harrington 061B & 062B

In reviewing Harrington, we conclude that the installation of SDA on Units 061B and 062B will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.5-1a. SDA Visibility Benefits at Harrington (CALPUFF)

Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Harrington 061B & 062B	0.45	0.74	2.56	53.67	26

Table 4.5-1b. SDA Visibility Benefits at Harrington RNS {2011-2015} (CALPUFF)

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Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Harrington 061B & 062B	.381	.565	2.42	48	14.67

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, Bandelier, and Wheeler Peak.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, Bandelier and Wheeler Peak.

In evaluating Harrington we note there are five Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the five Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate SDA on both units will eliminate 53.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to SDA levels.

Table 4.5-2. SDA Visibility Benefits at Harrington (CAMx)

Unit	Improvement at Salt Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Harrington 061B	1.170	0.643	4.832	17 / 5	11 / 3

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Harrington 062B	1.279	0.723	5.379	17 / 5	11 / 3
Source (061B & 0622B)	2.053	1.130	9.329	51 / 17	37 / 11

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate SDA on these units will eliminate more than half of all days impacted by the units over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, SDA on each unit will each result in visibility improvements of approximately 1.2 dv on the most impacted days at Salt Creek and 0.6 – 0.7 dv at Wichita Mountains, reducing the number of days impacted over 0.5 and 1.0 dv at these Class I areas. In addition, cumulative benefits from SDA on both units over all 15 Class I areas exceeds 9.3 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the SDA visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. Figures 4.5-1 (unit 1) and 4.5-5 (unit 2) below show the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (SDA) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figures 4.5-2 and 4.5-6). At the most impacted Class I area, SDA on each unit result in visibility improvements of 0.36 (Unit 061B) to 0.40 dv (Unit 062B) on average across the top ten most impacted days, and approximately 0.31 (Unit 061B) to 0.33 (Unit 062B) dv at the second most impacted Class I area for each unit. Figures 4.5-3 and 4.5-7 show an assessment of the annual average impacts and benefits under the control scenarios.[25] SDA reduces annual average base case impacts from each unit by 59% (Unit 061B) to 62% (Unit 062B) reduction in annual average visibility impacts from each unit compared to 31% (Unit 061B) to 32% (Unit 062B) for DSI at the most impacted Class I area. On average across all Class I areas, SDA results in a 59% (Unit 061B) to 62% (Unit 062B) reduction in annual average visibility impacts from each unit compared to 31% (Unit 061B) to 32% (Unit 062B) for DSI. Figures 4.5-4 and 4.5-8 show the contribution to extinction from the units due to each visibility impairing species[26] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Salt Creek and Wichita Mountains) for the base case modeling scenario.[27] These figures show that the impacts from the Harrington units 1 and 2 on these days are due to both sulfate and nitrate, and therefore large reductions in sulfate emissions will result

[25] 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 at each Class I area with impacts greater than 0.1 dv.
[26] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)
[27] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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in significant reductions in visibility impairment due to these units on some days. On other days, remaining nitrate impacts are large and limit the amount of visibility benefits achievable through SO2 emission reductions. As discussed above, annual average impacts across all Class I areas are reduced approximately 60% with SDA. As seen in the top ten average impacts and average annual impacts, a large number of Class I areas are impacted by the source and see benefits with SDA.

Figure 4.5-1. Maximum CAMx modeled impact– Harrington Unit 061B

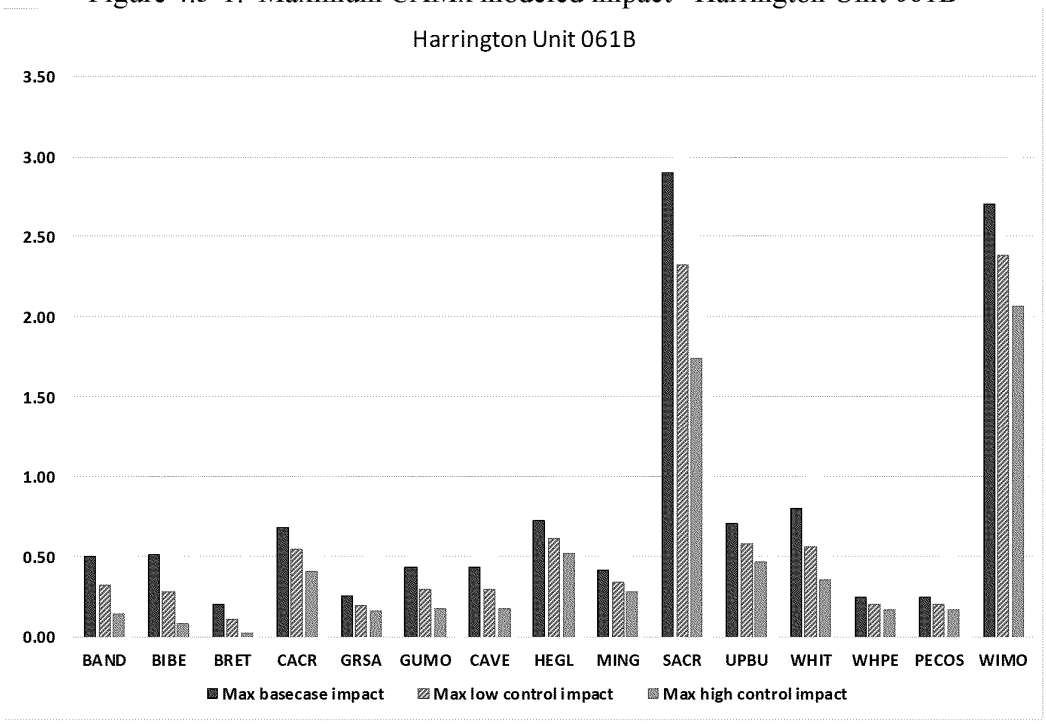

Figure 4.5-2. Average of top ten CAMx modeled impact– Harrington Unit 061B

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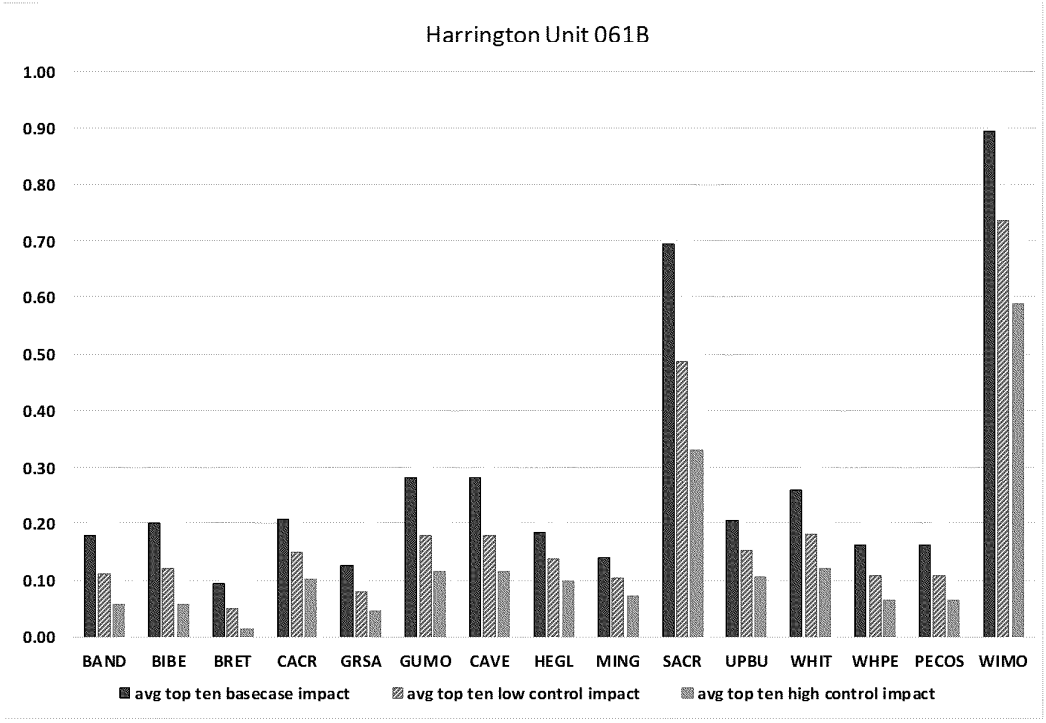


Figure 4.5-3. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – Harrington Unit 061B

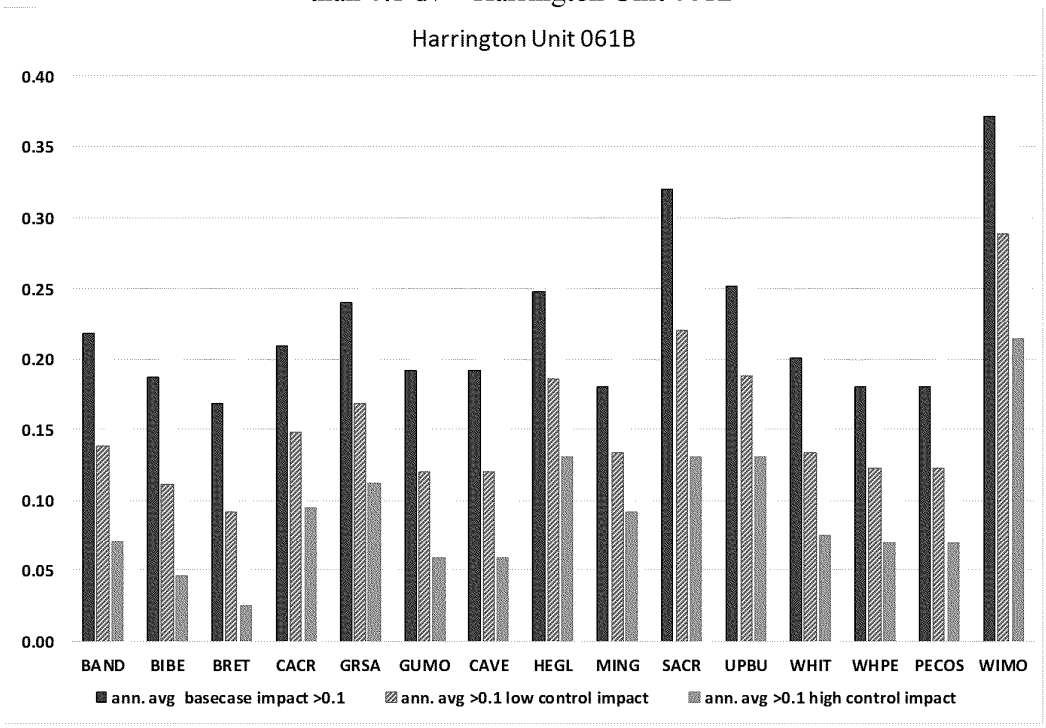


Figure 4.5-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted

Class I areas – Harrington Unit 061B

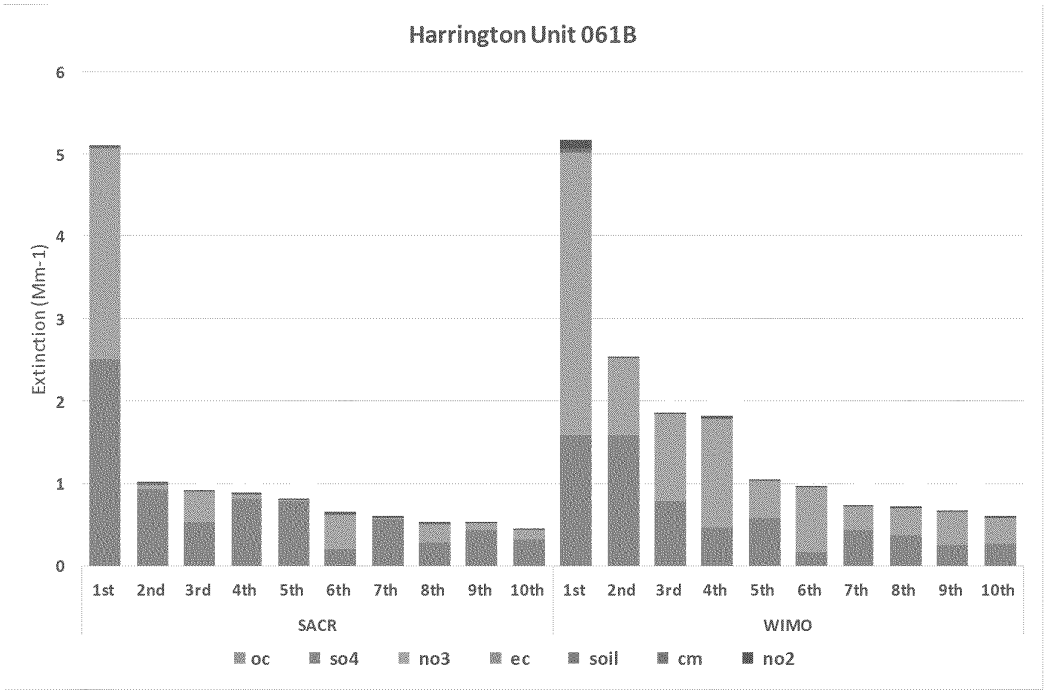


Figure 4.5-5. Maximum CAMx modeled impact– Harrington Unit 062B

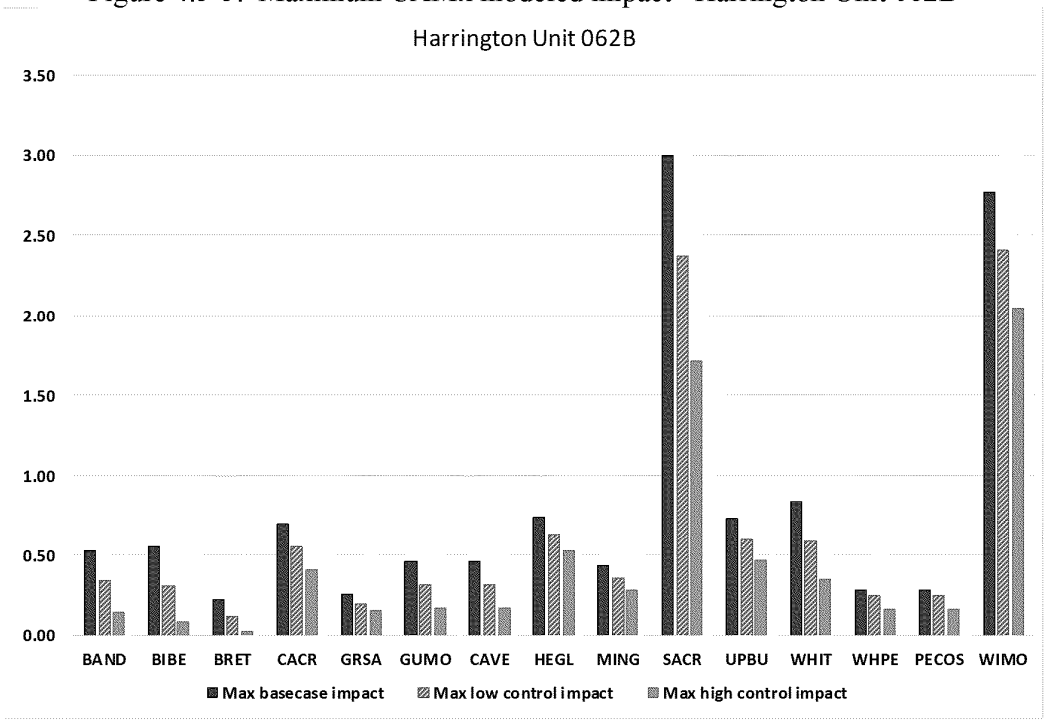


Figure 4.5-6. Average of top ten CAMx modeled impact– Harrington Unit 062B

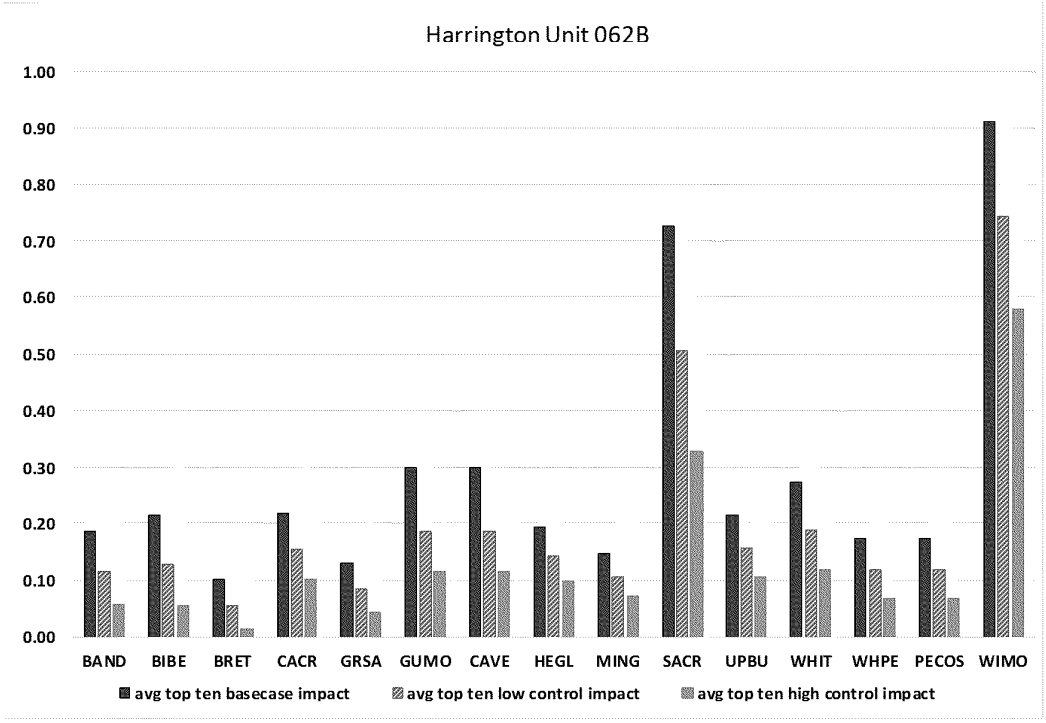


Figure 4.5-7. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – Harrington Unit 062B

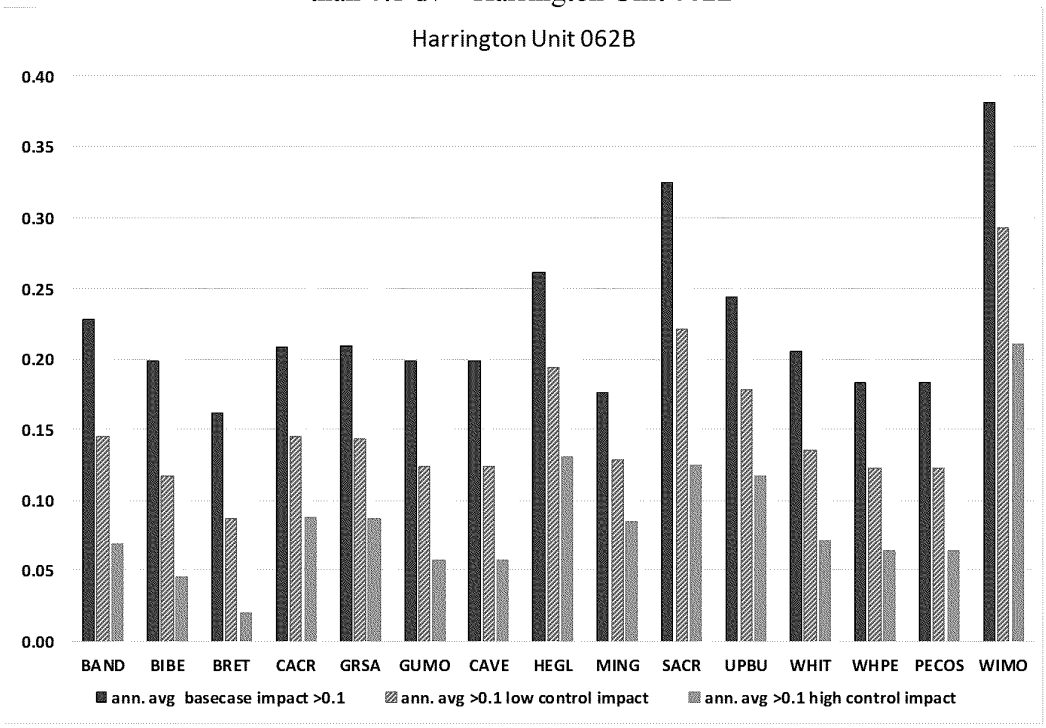
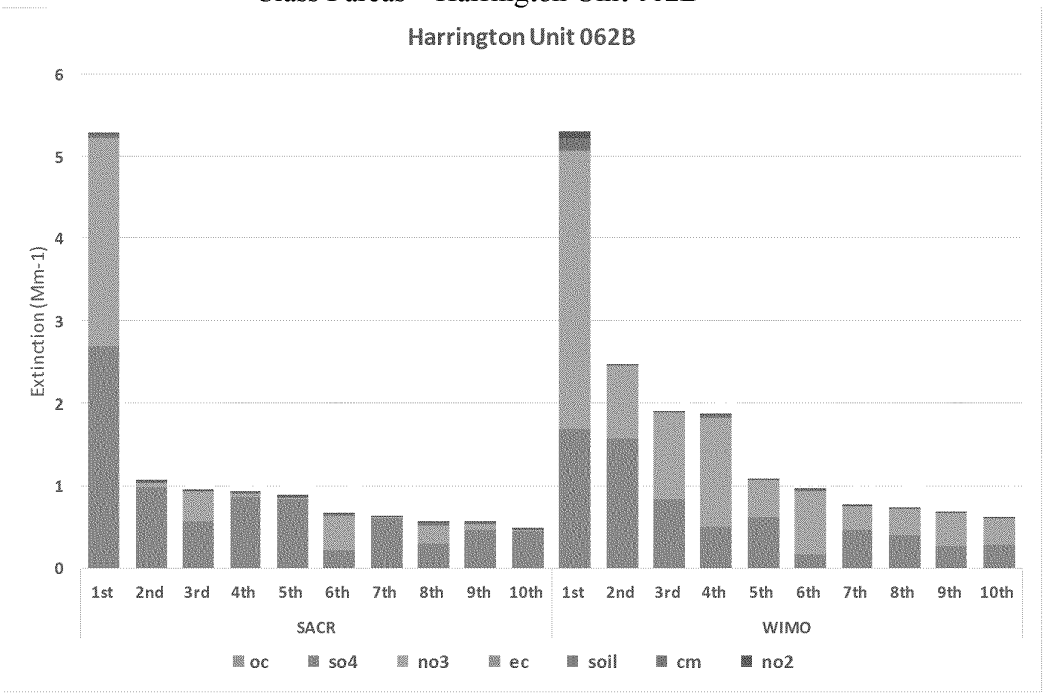


Figure 4.5-8. Species Contribution (Mm-1) on ten highest impact days at two most impacted

Class I areas – Harrington Unit 062B



4.6. W. A. Parish WAP 5 & 6

In reviewing W A Parish, we conclude that the installation of wet FGD on Units 5 and 6 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.6-1. Wet FGD Visibility Benefits at W A Parish (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
W A Parish 5	1.518	0.943	8.171	51 / 9	51 / 9
W A Parish 6	1.492	0.922	7.979	48 / 7	48 / 7
Source (WAP 4, 5 & 6)	2.665	1.760	15.301	163 / 49	162 / 49

[1] 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.
[2] 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.

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[3] 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.

CAMx modeling results indicate that wet FGD on each of these units will eliminate all days impacted by each unit over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of approximately 1.5 dv on the most impacted days at Caney Creek and 0.9 dv at Upper Buffalo. Nine Class I areas have modeled source-wide baseline impacts over 1 dv, and wet FGD on both units results in source-wide improvements of 1 dv or greater on the maximum impacted days at eight of these Class I areas. In addition, cumulative benefits from wet FGD on both units over all 15 Class I areas exceeds 15 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. We note that source-wide modeling includes a small impact from WAP 4. This unit is gas-fired and was modeled at baseline emissions levels for both the baseline and control case scenarios. Figures 4.6-1 (WAP 5) and 4.6-5 (WAP 6) below show the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figures 4.6-2 and 4.6-6). At the most impacted Class I area, wet FGD on each unit result in visibility improvements of 1 dv on average across the top ten most impacted days, and approximately 0.63 dv at the second most impacted Class I area for each unit. Figures 4.6-3 and 4.6-7 show an assessment of the annual average impacts and benefits under the control scenarios.[28] Wet FGD reduces annual average base case impacts from each unit by 91% or more at each Class I area, while DSI at 50% emission reduction reduces annual average impacts at each Class I area by 50% or less. On average across all Class I areas, wet FGD results in a 94% to 95% reduction in annual average visibility impacts from each unit. Figures 4.6-4 and 4.6-8 show the contribution to extinction from the units due to each visibility impairing species[29] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Caney Creek and Upper Buffalo) for the base case modeling scenario.[30] These figures show that the impacts from the W.A. Parish WAP 5 and WAP 6 on these days are primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to these units.

Figure 4.6-1. Maximum CAMx modeled impact– W. A. Parish Unit WAP5

[28] 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 at each Class I area with impacts greater than 0.1 dv.

[29] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[30] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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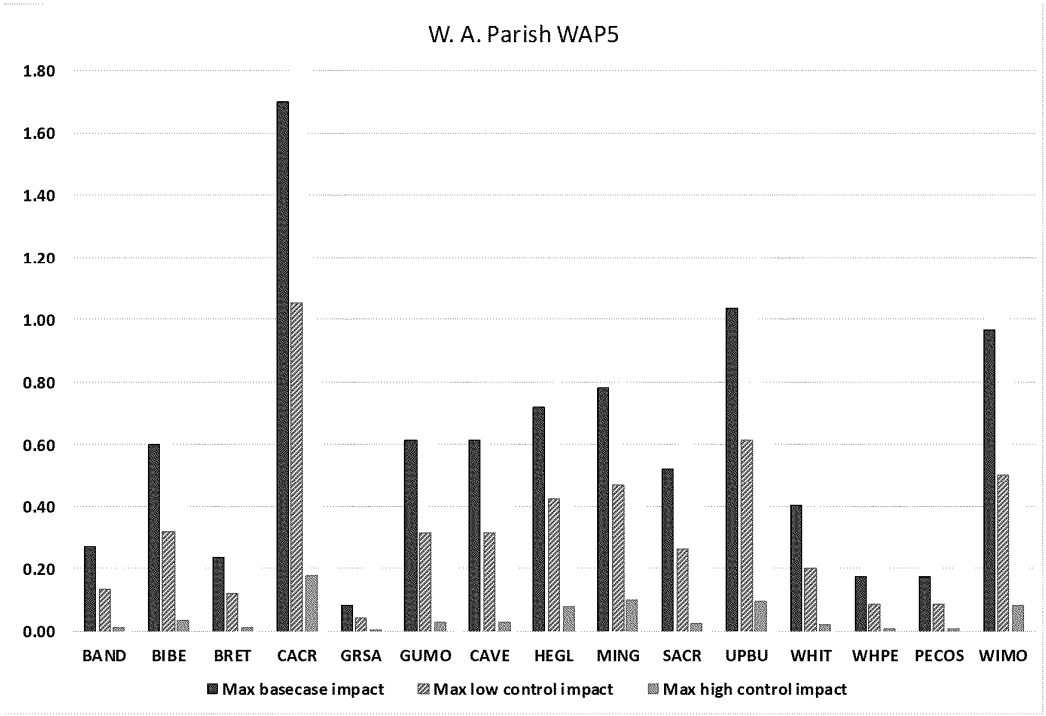

Figure 4.6-2. Average of top ten CAMx modeled impact– W. A. Parish Unit WAP5

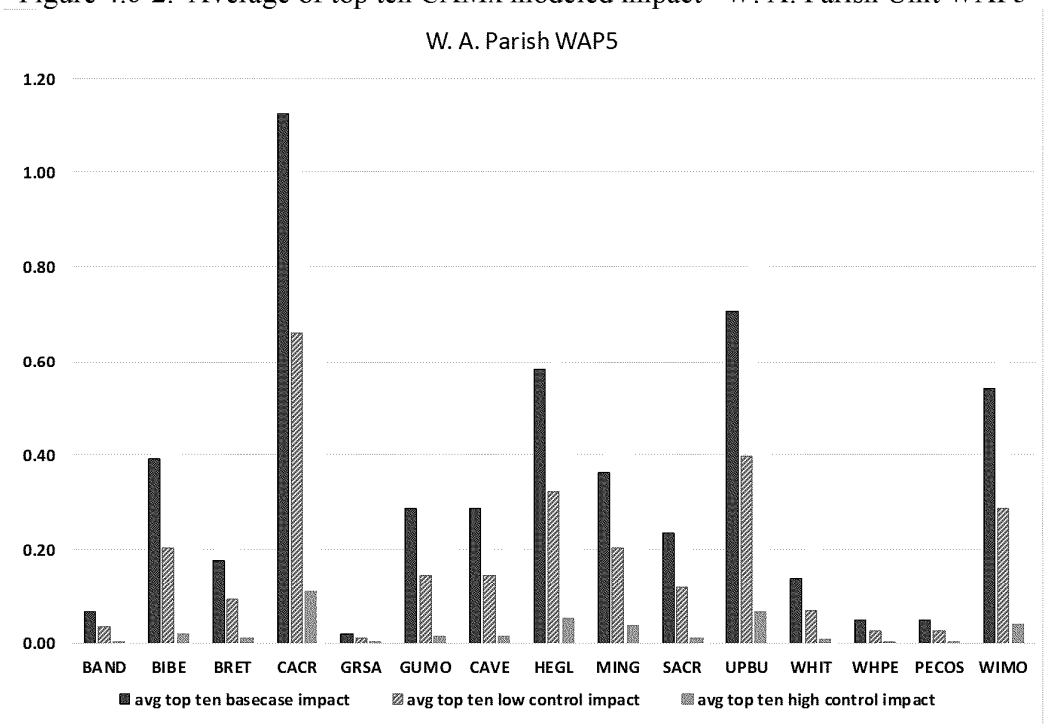

Figure 4.6-3. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – W. A. Parish Unit WAP5

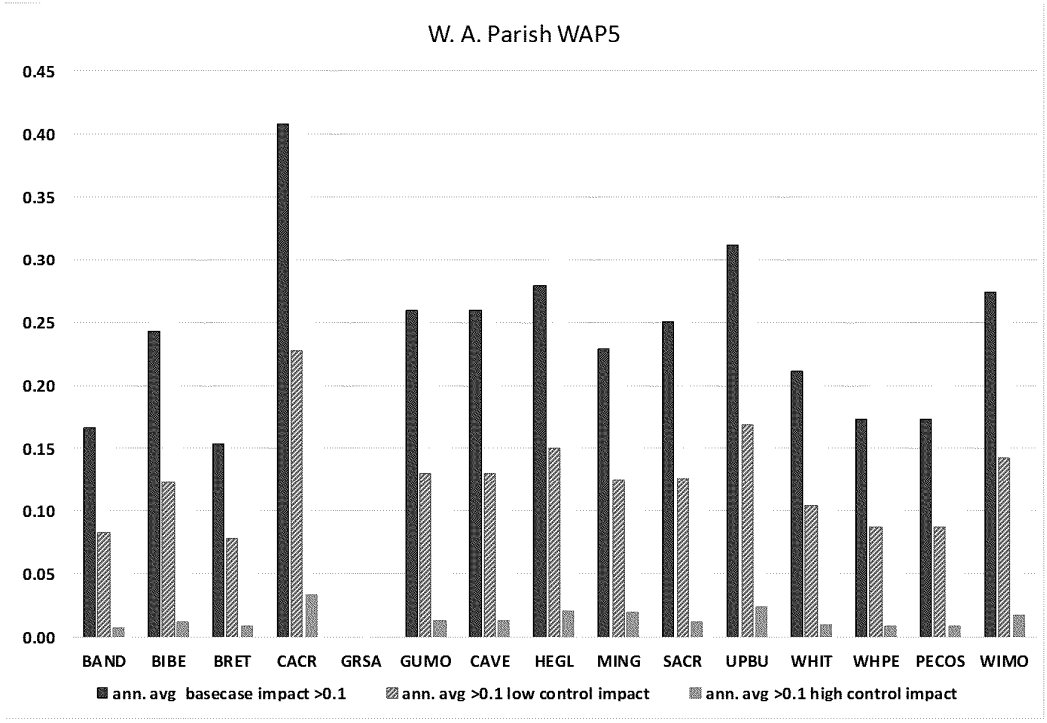

Figure 4.6-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – W.A. Parish WAP5

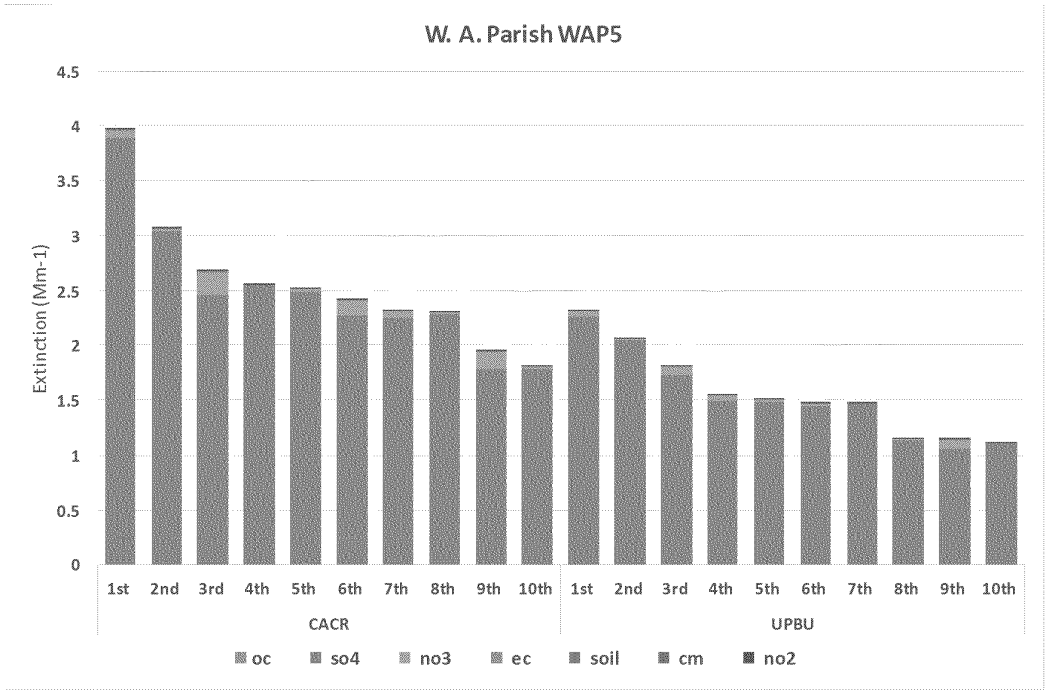

Figure 4.6-5. Maximum CAMx modeled impact– W. A. Parish Unit WAP6

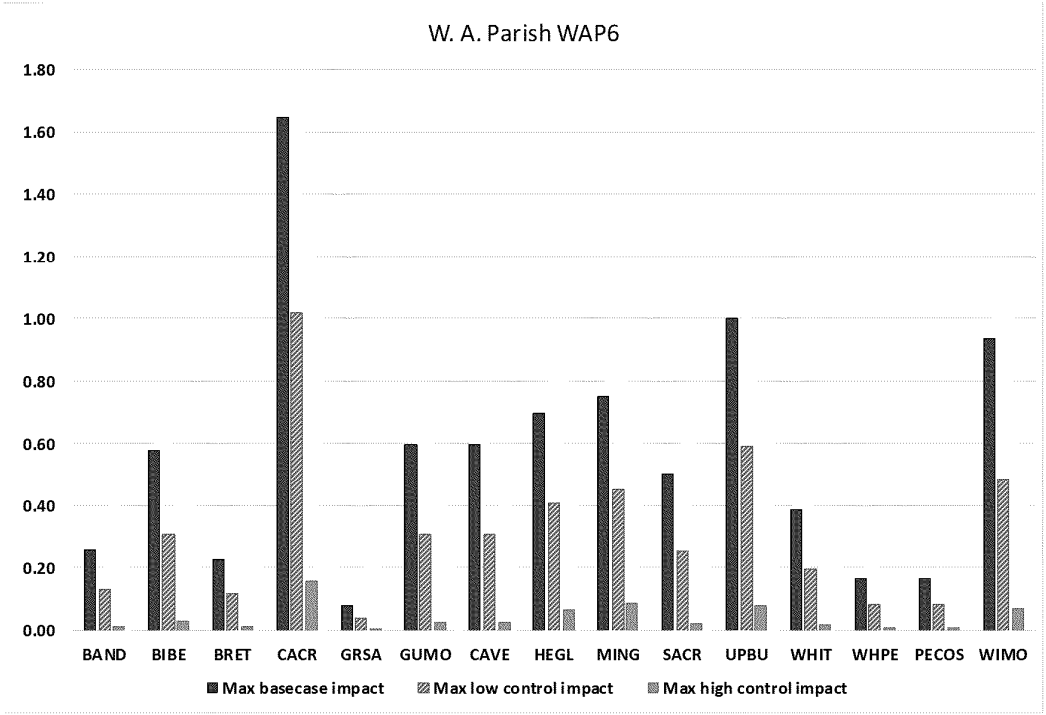

Figure 4.6-6. Average of top ten CAMx modeled impact– W. A. Parish Unit WAP6

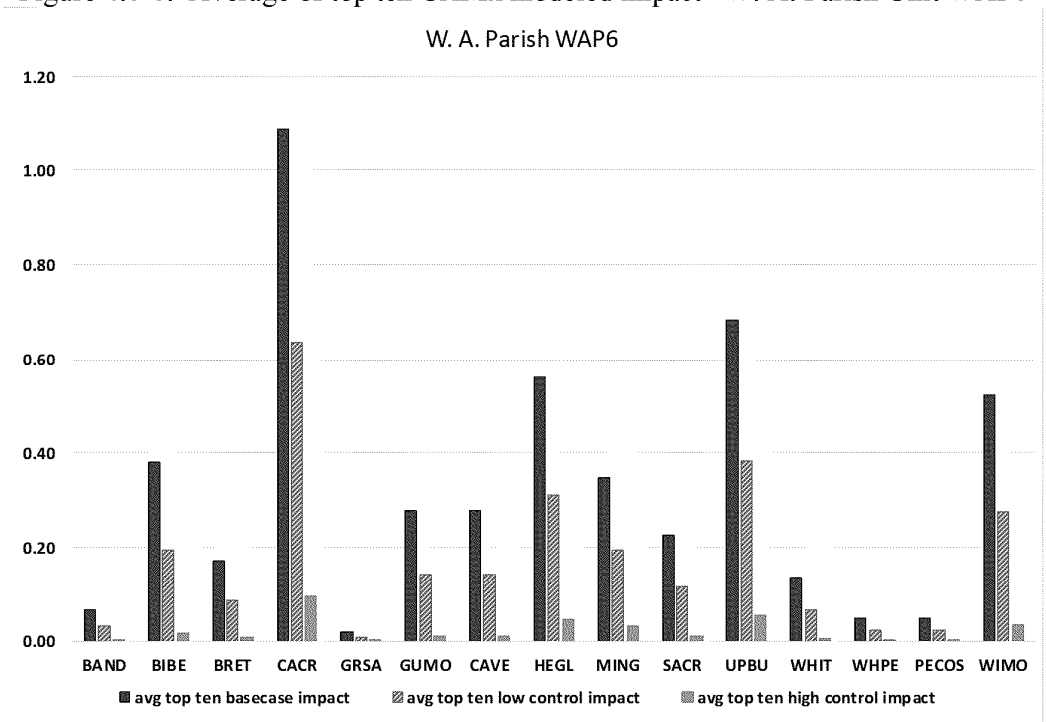

Figure 4.6-7. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – W. A. Parish Unit WAP6

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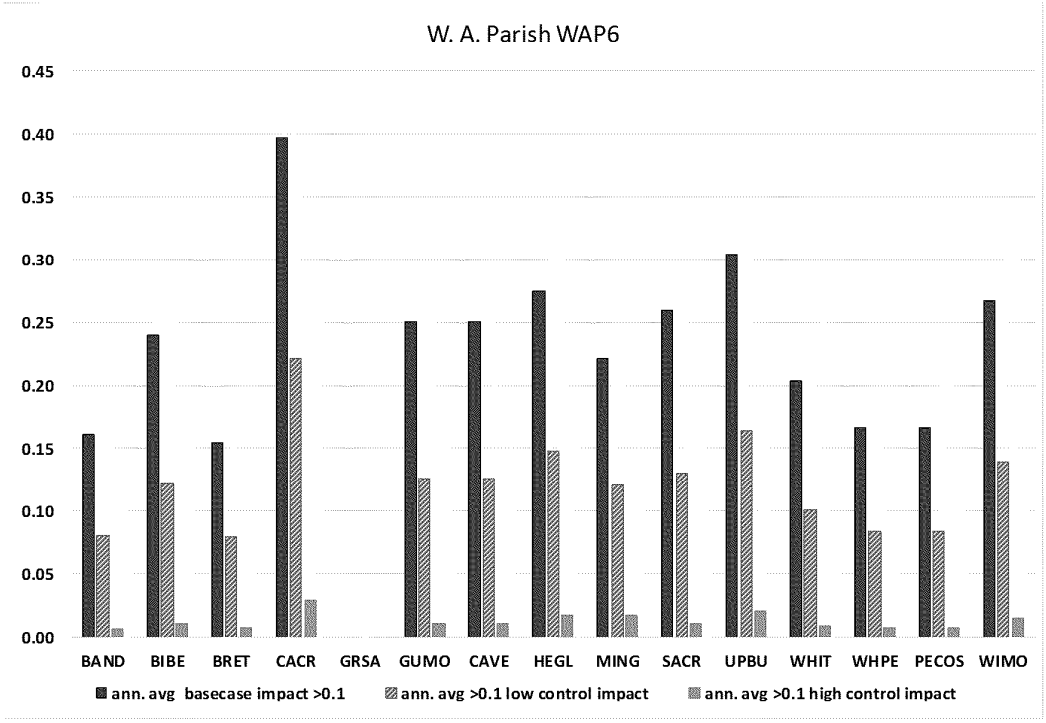
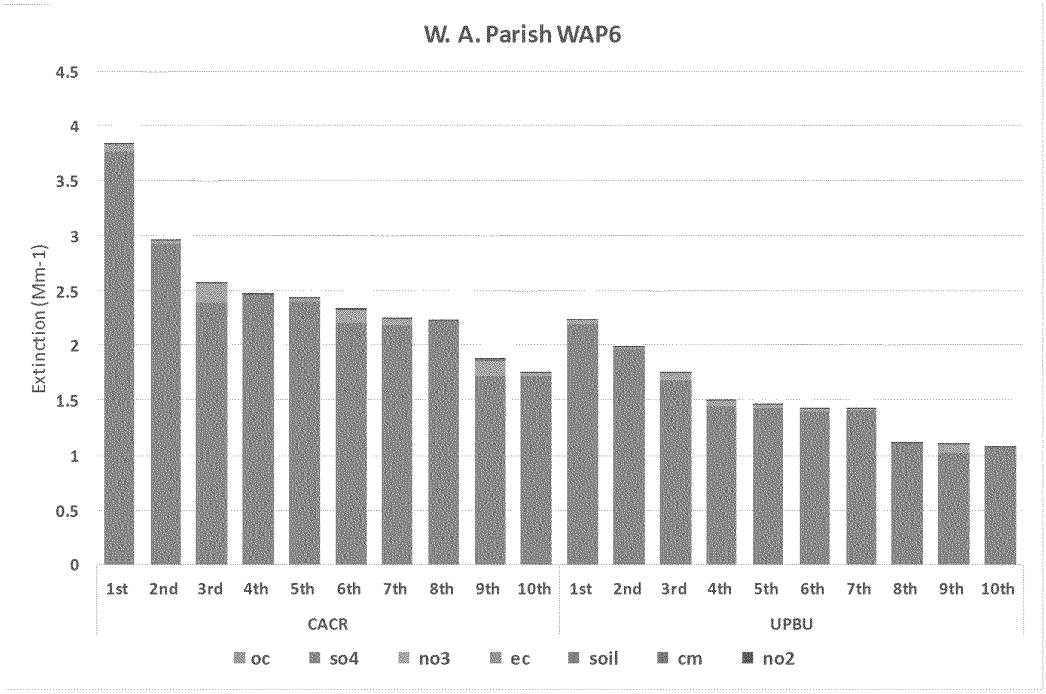


Figure 4.6-8. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – W.A. Parish WAP6



4.7. J T Deely 1 & 2

In reviewing J T Deely, we conclude that the installation of wet FGD on Units 1 and 2 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.7-1 Wet FGD Visibility Benefits at J T Deely (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
J T Deely 1	0.487	0.283	4.785	10 / 0	10 / 0
J T Deely 2	0.298	0.217	3.650	7 / 0	7 / 0
Source (J T Deely 1 & 2, Sommers 1 & 2)	0.699	0.518	8.943	89 / 13	84 / 13

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate wet FGD on each of these units will eliminate all days impacted by each unit over 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of 0.487 dv and 0.298 dv on the most impacted days at Wichita Mountains and 0.283 dv and 0.217 dv at Caney Creek. Larger visibility improvements on the most impacted days are anticipated at other Class I areas. Benefits from wet FGD on unit 1 are 0.583 dv at Big Bend, 0.511 dv at Salt Creek, 0.449 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.475 dv at White Mountains. Benefits from wet FGD on unit 2 are 0.583 dv at Big Bend, 0.441 dv at Salt Creek, 0.354 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.375 dv at White Mountains. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 Class I areas included in the modeling. We note that source-wide modeling includes the impact from Sommers units 1 and 2, and, control case scenarios for these units included benefits from switching to lower sulfur fuel oil. However, these modeled improvements are a small fraction of the total visibility benefits from controls at the source. Figures 4.7-1 (JT Deely unit 1) and 4.7-5 (JT Deely unit 2) below show the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

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We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figures 4.7-2 and 4.7-6). At the most impacted Class I area, wet FGD on unit 1 results in visibility improvements of 0.43 dv on average across the top ten most impacted days, and approximately 0.28 dv at the second most impacted Class I area. At the most impacted Class I area, wet FGD on unit 2 results in visibility improvements of 0.32 dv on average across the top ten most impacted days, and approximately 0.16 dv at the second most impacted Class I area. Figures 4.6-3 and 4.6-7 show an assessment of the annual average impacts and benefits under the control scenarios.[31] Wet FGD reduces annual average base case impacts from each unit by 83% (unit 1) and 88% (unit 2) at the most impacted Class I area, while DSI at 50% emission reduction reduces annual average impacts at the most impacted Class I area by 43% (unit 1) and 45% (unit 2). On average across all Class I areas, wet FGD results in an 81% (unit 1) and 87% (unit 2) reduction in annual average visibility impacts from each unit. Figures 4.6-4 and 4.6-8 show the contribution to extinction from the units due to each visibility impairing species[32] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Wichita Mountains and Caney Creek) for the base case modeling scenario.[33] These figures show that the impacts from the W.A. Parish WAP 5 and WAP 6 on most days are primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to these units on those days. The very highest impacted days at Caney Creek have large impacts from both nitrate and sulfate. While emission reductions of SO2 will greatly reduce the impairment from sulfate on these days, the nitrate impacts remain, limiting the overall benefit from controls on these days. Visibility impacts at Guadalupe Mountains, Carlsbad Caverns and Salt Creek are primarily due to sulfates and reductions in SO2 emissions are effective in reducing the visibility impairment from these units at those Class I areas.

Figure 4.7-1. Maximum CAMx modeled impact– J.T. Deely Unit 1

[31] 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 at each Class I area with impacts greater than 0.1 dv.

[32] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[33] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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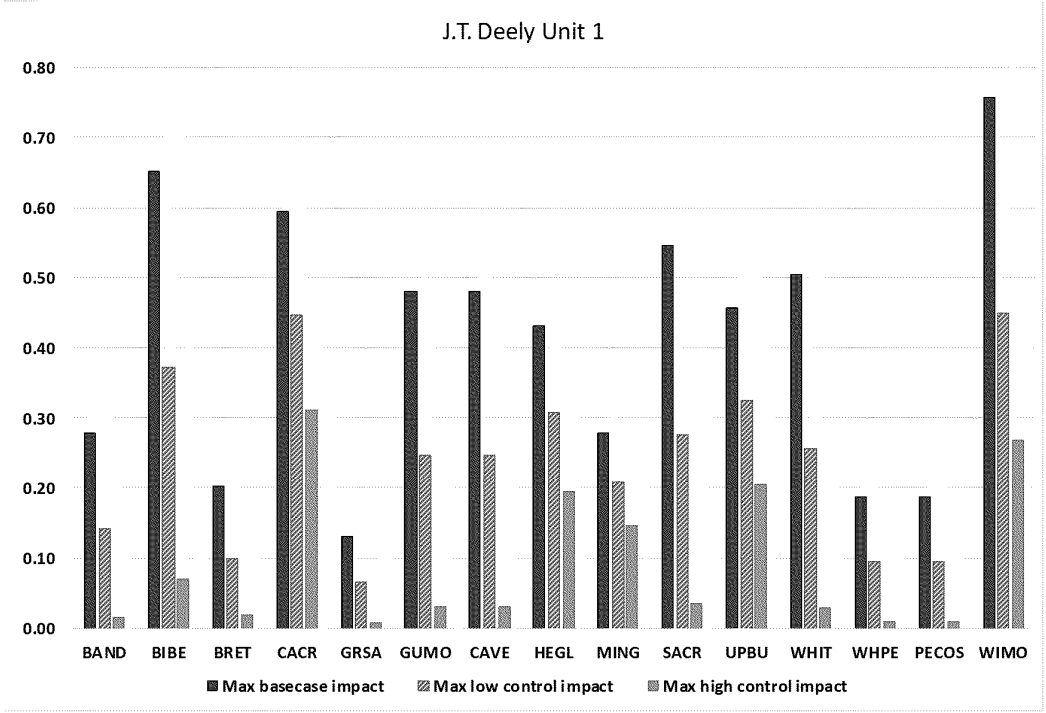

Figure 4.7-2. Average of top ten CAMx modeled impact– J.T. Deely Unit 1

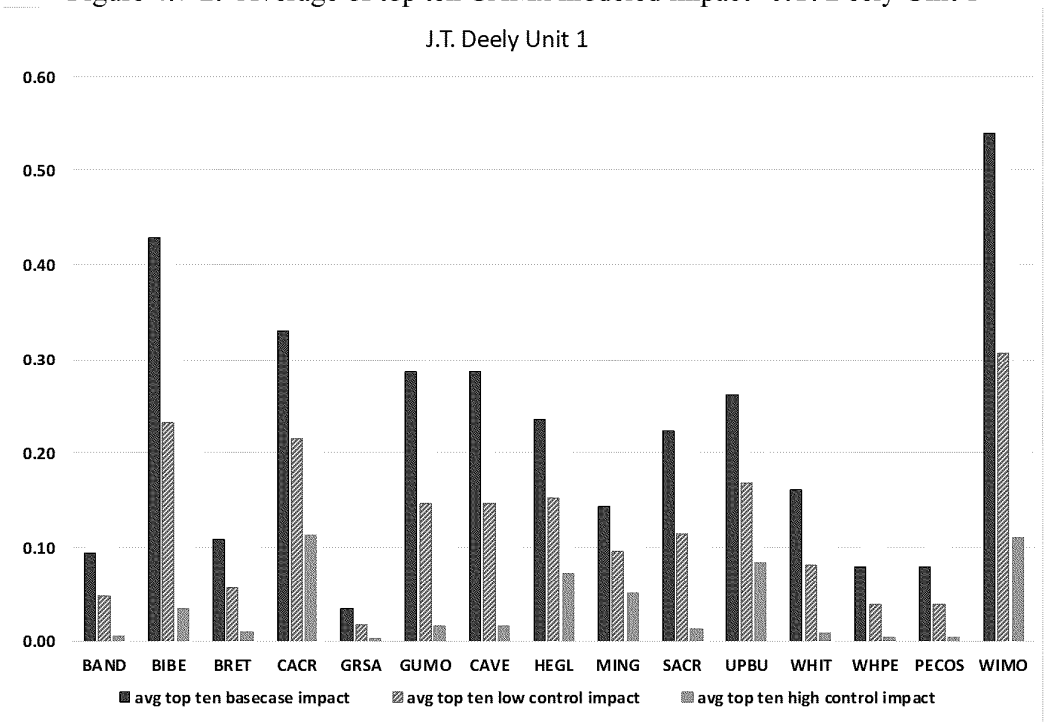

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Figure 4.7-3. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – J.T. Deely Unit 1

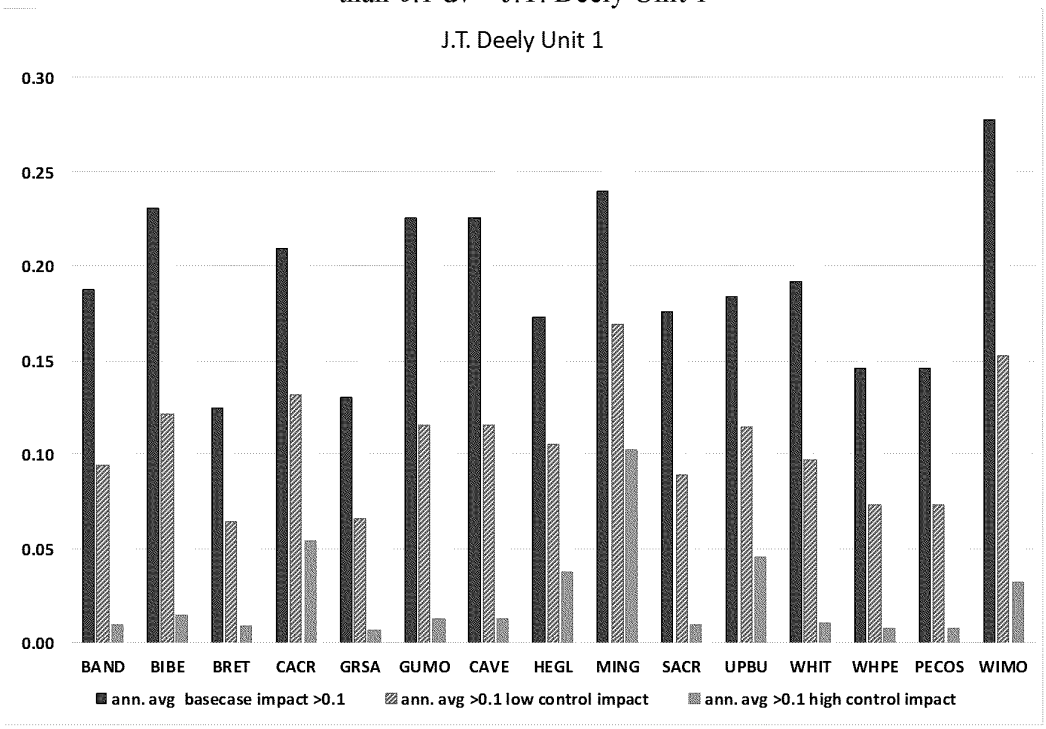

Figure 4.7-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – J.T. Deely Unit 1

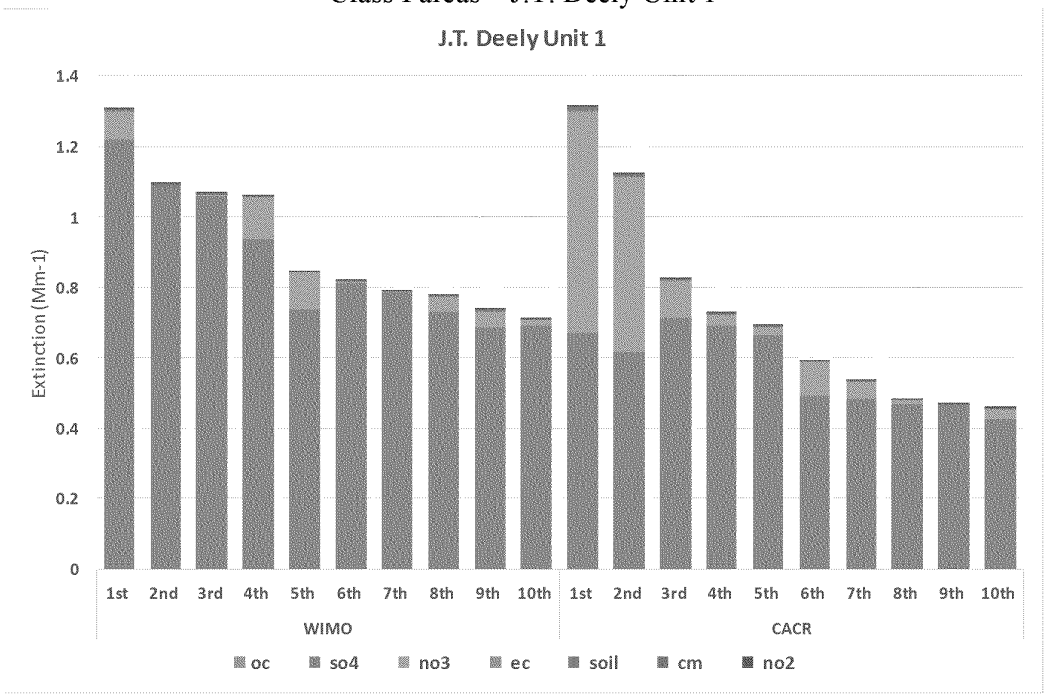

Figure 4.7-5. Maximum CAMx modeled impact– J.T. Deely Unit 2

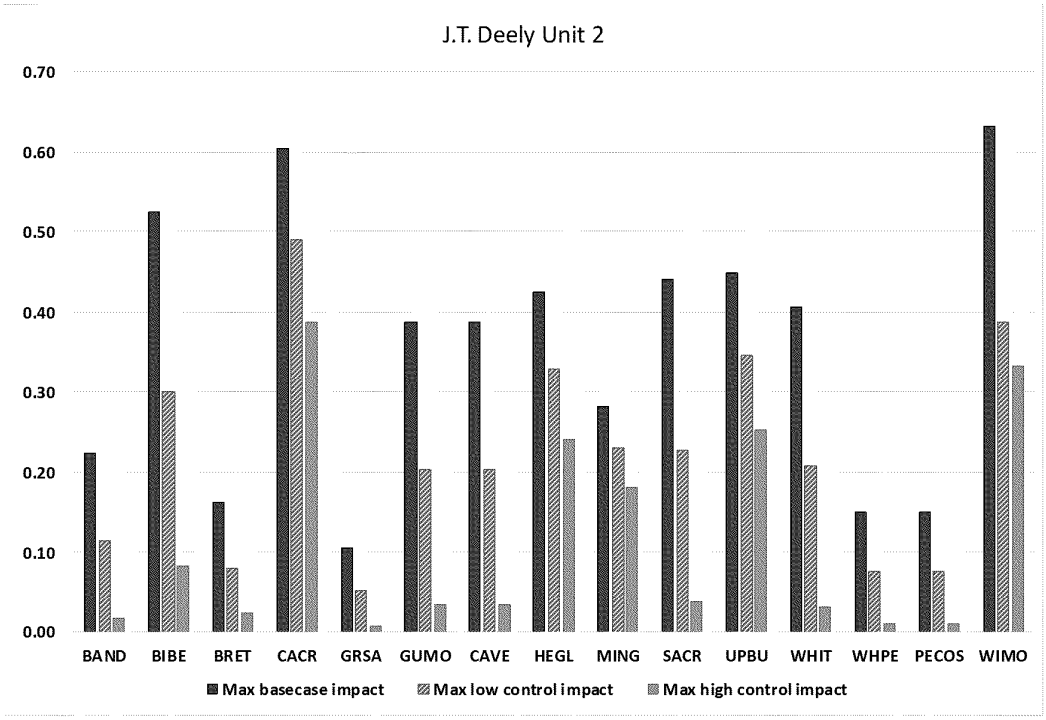

Figure 4.7-6. Average of top ten CAMx modeled impact– J.T. Deely Unit 2

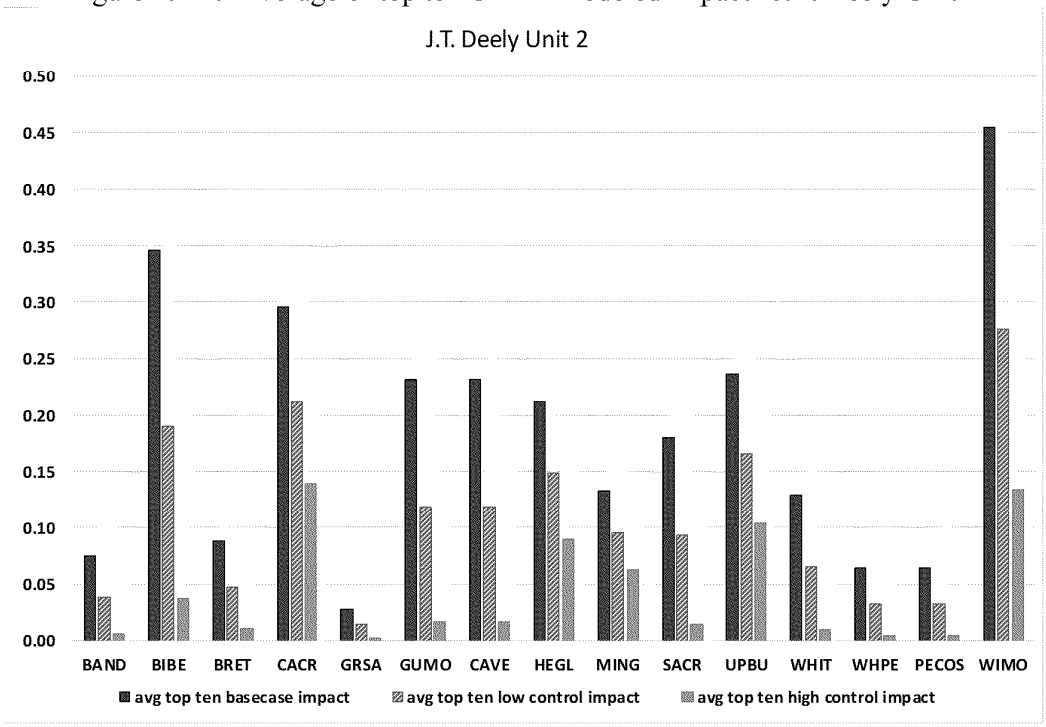

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Figure 4.7-7. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – J.T. Deely Unit 2

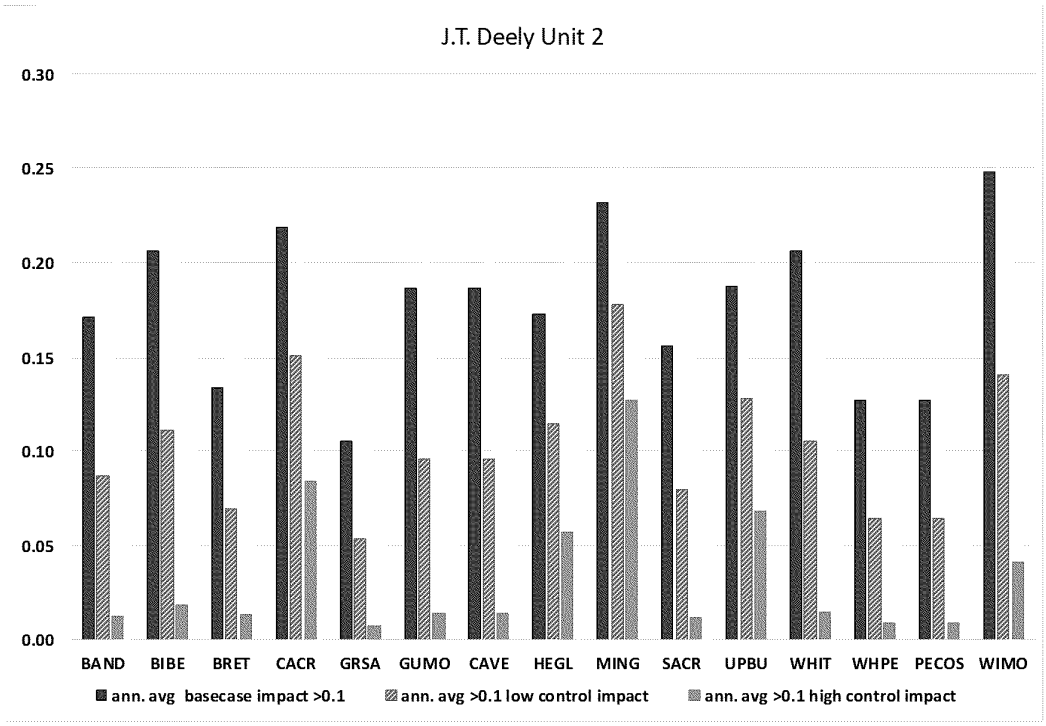
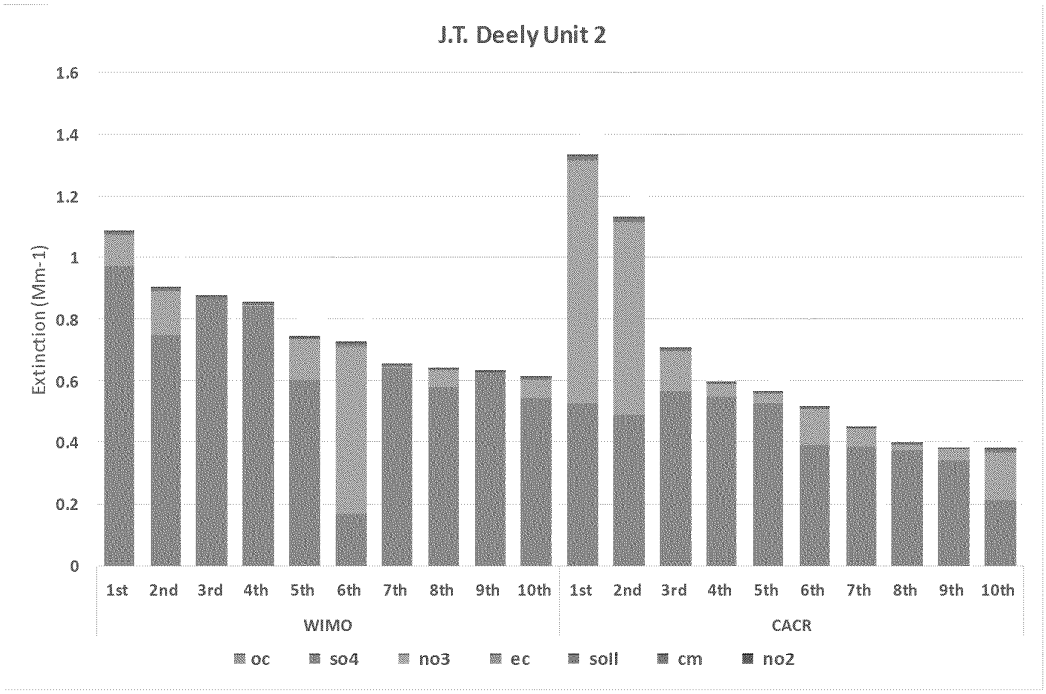


Figure 4.7-8 Species Contribution (Mm-1) on ten highest impact days at two most impacted



5. Visibility Benefits of Scrubber Upgrades for Coal-Fired Units

We also modeled the visibility benefits of those same units for which we conducted control cost analysis for upgrading their existing scrubbers. We assumed the same 95% control level we used in our control cost analyses. We also modeled a lower level control at 90%. The visibility benefits from these scrubber upgrades are summarized in the section below.[34,35] See Appendix E and Appendix F for additional CAMx model results for each class I area. Below, we present a summary of the del-dv visibility benefits and reduction in number of days impacted.

Table 5-1. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CAMx modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Unit 1, 2 & 3)	CACR	Max dv	6.651	4.491	4.321	2.159	2.329
			Days > 0.5 dv	141	75	56	66	85
			Days>1.0 dv	99	31	16	68	83
		UPBU	Max dv	5.803	2.669	2.528	3.134	3.275
			Days > 0.5 dv	99	39	22	60	77
			Days>1.0 dv	67	11	7	56	60
	Unit 1	CACR	Max dv	2.633	1.550	1.468	1.083	1.165
			Days > 0.5 dv	71	17	6	54	65
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.254	0.867	0.805	1.387	1.449
			Days > 0.5 dv	44	6	3	38	41
			Days>1.0 dv	10	0	0	10	10
	Unit 2	CACR	Max dv	2.466	1.882	1.811	0.585	0.655

[34] See spreadsheet: "summary CAMx vis daily.xlsx" in the docket for this action for these and additional model results.

[35] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for summary of base case model results, including species specific 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.

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			Days > 0.5 dv	68	18	9	50	59
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.189	1.077	1.025	1.112	1.164
			Days > 0.5 dv	40	6	5	34	35
			Days>1.0 dv	10	1	1	9	9
	Unit 3	CACR	Max dv	2.755	1.682	1.609	1.074	1.146
			Days > 0.5 dv	76	15	6	61	70
			Days>1.0 dv	29	2	1	27	28
		UPBU	Max dv	2.368	0.942	0.890	1.425	1.478
			Days > 0.5 dv	46	6	4	40	42
			Days>1.0 dv	13	0	0	13	13
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63
			Days>1.0 dv	40	14	0	26	40
	Unit 3	CACR	Max dv	4.632	0.905	0.914	3.728	3.719
			Days > 0.5 dv	79	5	5	74	74
			Days>1.0 dv	32	0	0	32	32
		WIMO	Max dv	2.282	0.462	0.364	1.820	1.918
			Days > 0.5 dv	31	0	0	31	31
			Days>1.0 dv	7	0	0	7	7

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Table 5-2. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Units 1, 2 & 3)	CACR	Max dv	4.46	2.27	1.86	2.18	2.60
			Days > 0.5 dv Avg.	129.67	77.33	63.00	52.33	66.67
			Days>1.0 dv Avg.	91.33	32.67	22.33	58.67	69.00
		UPBU	Max dv	2.73	1.10	0.85	1.63	1.88
			Days > 0.5 dv Avg.	81.67	30.33	18.67	51.33	63.00
			Days>1.0 dv Avg.	46.67	7.33	3.67	39.33	43.00
Monticello[1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	2.41	1.70	2.89	4.87
			Days > 0.5 dv Avg.	143.67	115	62.33	28.67	81.33
			Days>1.0 dv Avg.	113	66.33	23.67	46.67	89.33
		UPBU	Max dv	3.45	1.77	0.765	1.68	2.68
			Days > 0.5 dv Avg.	103	61	13.67	42	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60	34.67	6	25.33	54
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67

[1] Monticello's controlled level is a combination of scrubber upgrade on Unit 3 and scrubber retrofits on Units 1 and 2 in the facility impact modeling with CALPUFF.

Our review of the impacts/benefits of scrubber upgrades on four units at two facilities show that scrubber upgrades conducted at all units would result in significant visibility improvements at impacted Class I areas.

6. Visibility Benefit Analysis of Scrubber Upgrades

The BART Guidelines state that underperforming scrubber systems should be evaluated for upgrades.[36] Other than upgrading the existing scrubbers, all of which are wet FGDs, there are no competing control technologies that could be considered for these units. The CALPUFF modeling generated facility-wide impacts and the benefits of the scrubber upgrade on Monticello Unit 3 and the three Martin Lake facilities are included in Table 5-2 above and Tables 6-1.a-b and 6-2.a-b. The following is a listing of each of the affected units along with additional information on resulting visibility benefits from upgrading their existing scrubbers:

[36] 70 FR 39171 (July 6, 2005).

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Table 6-1.a Scrubber Upgrade and WGFD Visibility Benefits at Monticello (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	4.87	2.68	10.25	224.67	164.67

Table 6-1.b Scrubber Upgrades at Martin Lake (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Martin Lake Units 1, 2 & 3	2.60	2.04	4.64	129.67	112

Table 6-2a. Scrubber Upgrade and WGFD Visibility Benefits at Monticello RNS {2011-2015} (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	3.67	1.82	7.37	201.33	147

Table 6-2b. Scrubber Upgrades at Martin Lake RNS {2011-2015} (CALPUFF)

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Source	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Martin Lake Units 1, 2 & 3	2.354	1.685	4.04	134	98.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: MARTIN LAKE - Caney Creek and Upper Buffalo; MONTICELLO – Caney Creek, Upper Buffalo, and Wichita Mountains.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: MARTIN LAKE - Caney Creek and Upper Buffalo; MONTICELLO – Caney Creek, Upper Buffalo, and Wichita Mountains.

As can be seen in the CALPUFF modeling results, reducing emissions to WFGD emission rate levels yields very large benefits.

Table 6-3. Visibility Benefit for Coal-fired Units with Existing SO_2 Controls (CAMx)

Unit	Improvement at most impacted (dv)	Improvement at 2nd most impacted (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 3	3.719 (CACR)	1.918 (WIMO)	11.940	200 / 66	188 / 66
Martin Lake 1	1.165 (CACR)	1.449 (UPBU)	7.575	160 / 41	151 / 40
Martin Lake 2	0.655 (CACR)	1.164 (UPBU)	6.199	150 / 41	134 / 39
Martin Lake 3	1.146 (CACR)	1.478 (UPBU)	7.863	173 / 47	163 / 46

[1] 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.
[2] 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.
[3] 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.

The figures below show the maximum modeled impact (base case) for these scrubbed units and the modeled impact under the high control (upgrade to 95% control efficiency) scenario at each Class I area.[37] Evaluation of the average across the top ten impact days and annual average visibility impacts show a similar relative reduction in impacts from the base case to the high control case. We conclude that in all cases, scrubber upgrades result in significant visibility

[37] See spreadsheet: "summary CAMx vis daily.xlsx" in the docket for this action for these and additional model results.

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benefits, significantly reducing the impacts from these units and reducing the number of days that Class I areas are impacted over 1.0 dv and 0.5 dv. Scrubber upgrades almost eliminate all days impacted over 1 dv by an individual unit.

Figure 6-1. Maximum CAMx modeled impact (dv)– Martin Lake Unit 1

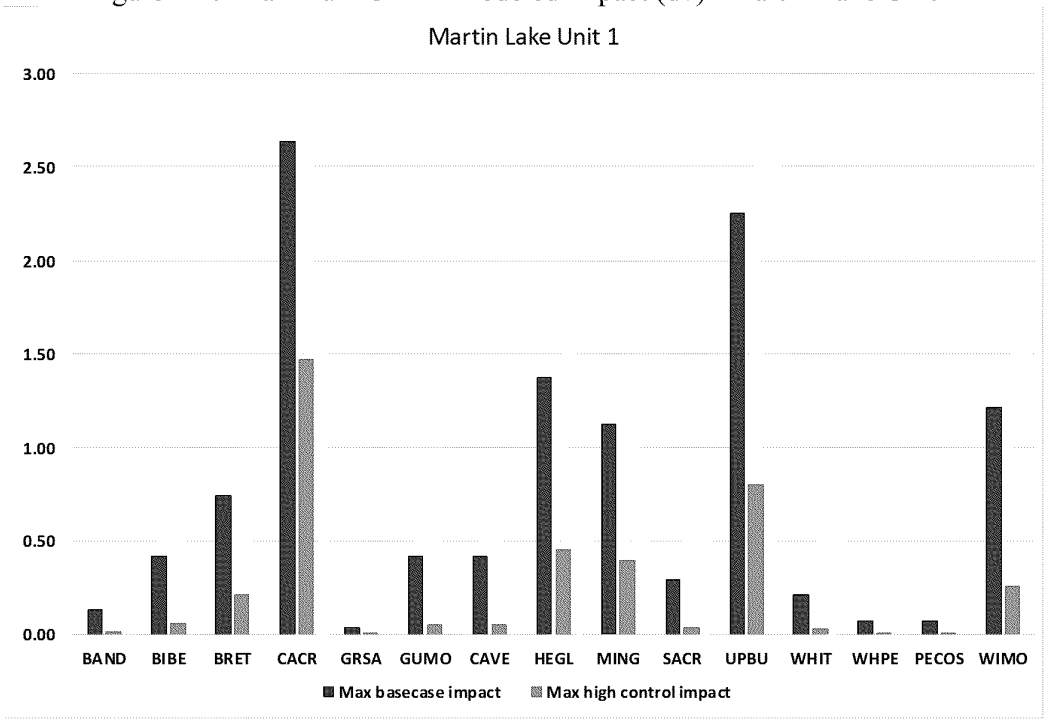

Figure 6-2. Maximum CAMx modeled impact (dv)– Martin Lake Unit 2

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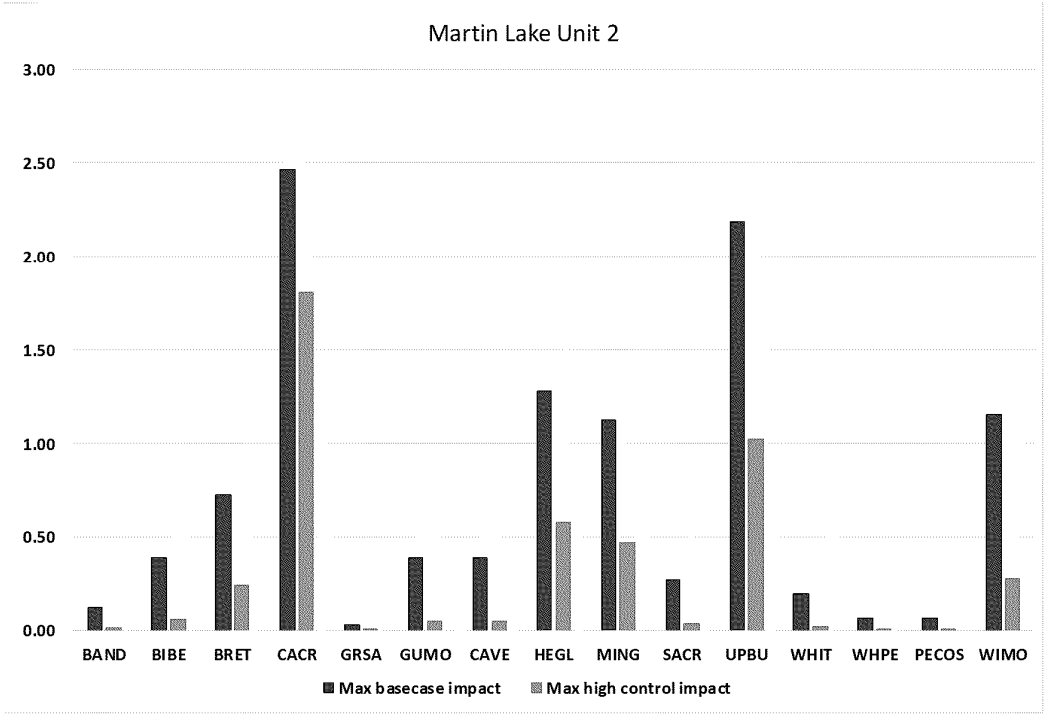


Figure 6-3. Maximum CAMx modeled impact (dv)– Martin Lake Unit 3

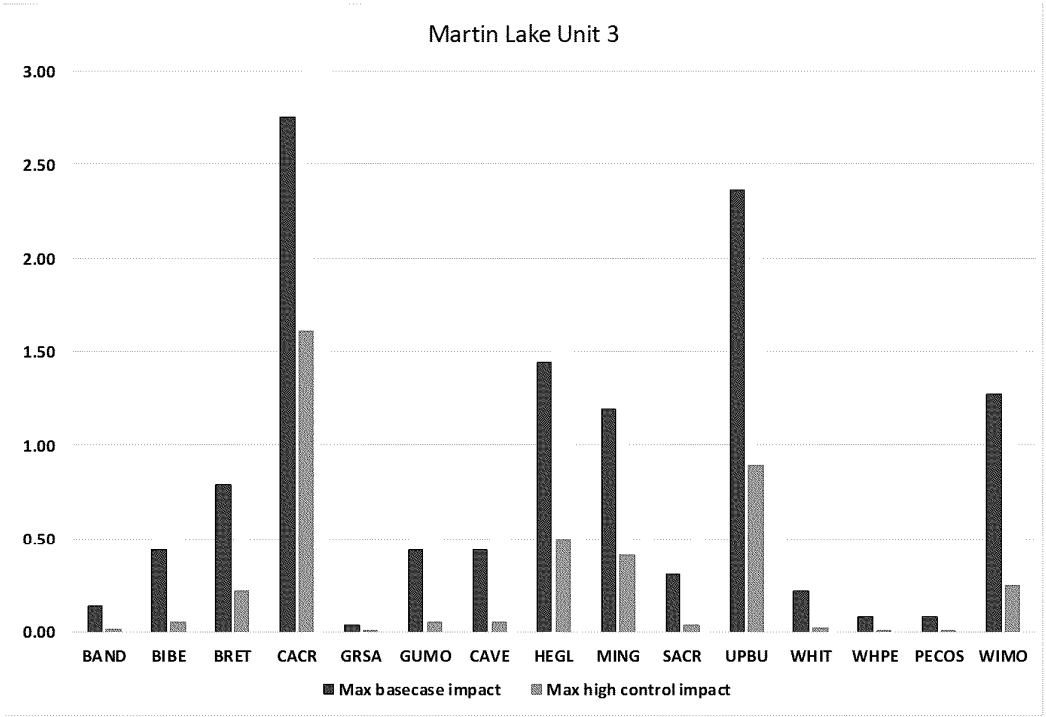
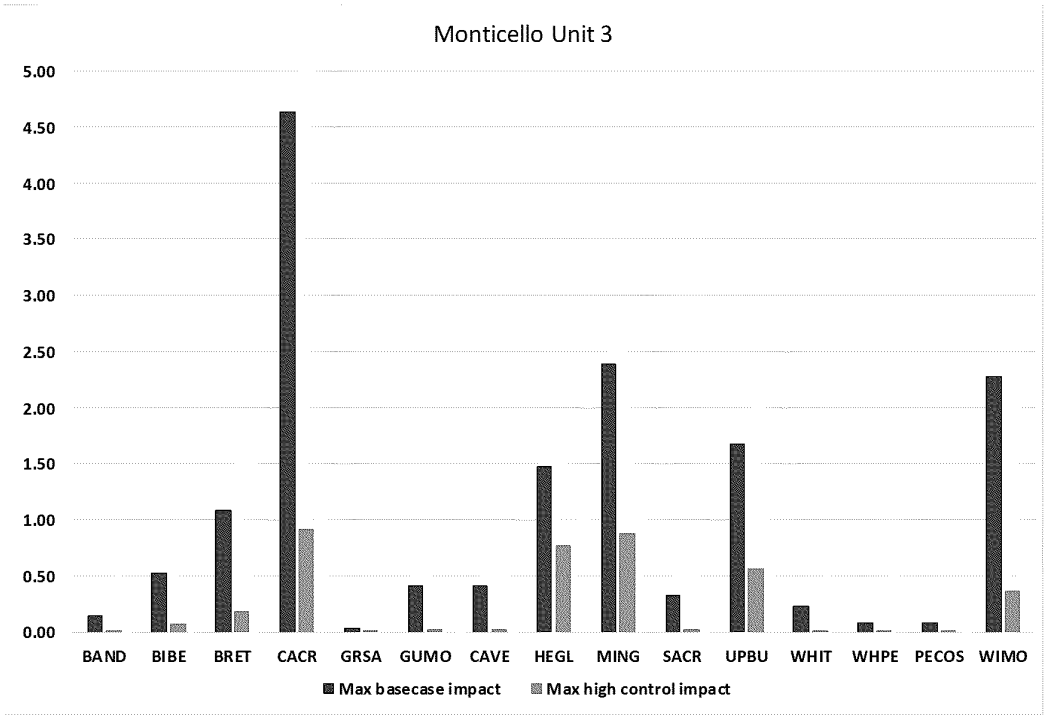


Figure 6-4. Maximum CAMx modeled impact (dv)– Monticello Unit 3



7. Visibility Benefits of Fuel-oil Switching for Gas/Fuel Oil-Fired Units

We also modeled the visibility benefits of those gas/fuel oil-fired units for which we conducted control cost analysis for switching to lower sulfur fuels. We evaluated the visibility benefits of switching to fuel oils corresponding to ultra-low sulfur diesel at 0.0015% sulfur by weight and 0.3% sulfur by weight as we evaluated in our control cost analyses. See the BART Screening TSD for additional information on baseline emissions and modeling. The visibility benefits from these fuel switches are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits. Because fuel oil is fired on an irregular basis for these units (usually less than 10% of the annual BTUs are from fuel oil burning), they are not amenable to a number of days analysis. See the BART FIP TSD for additional EIA information on quantity of fuel oil burned.

Table 7-1. Visibility Benefits from Lower Sulfur Fuel

Facility Name	Emission Unit	Baseline visibility Impact from Source (most impacted Class I area)	Visibility benefit of 0.3% S fuel oil	Visibility benefit of 0.0015% S fuel oil

Stryker	ST2	CALPUFF 0.65 % S: 0.786 dv @ CACR (Facility)	CALPUFF (0.3 % S) : 0.263 dv @ CACR (Facility)	CALPUFF: 0.522 dv @ CACR (Facility)
Graham	Unit 2	CALPUFF 0.69 % S: 1.228 dv @ WIMO (Facility)	CALPUFF (0.3% S): 0.465 dv @ WIMO (Facility	CALPUFF: 0.851 dv @ WIMO (Facility
Wilkes	Units 1, 2, 3	CALPUFF 0.43 % S: 0.698 dv @ CACR (Facility)	CALPUFF (0.1 % S): 0.029 dv @ CACR (Facility)	CALPUFF: 0.037 dv @ CACR (Facility)
Newman[1]	Unit 2	N/A	N/A	N/A
	Unit 3	N/A	N/A	N/A
	Unit 4	N/A	N/A	N/A
Calaveras	Sommers Unit 1	CAMx: 1.513 dv @ WIMO (Source); 0.106 dv @ CACR (Unit)	0.004 dv @ CACR	0.008 dv @ CACR
	Sommers Unit 2	CAMx: 1.513 dv @ WIMO (Source); 0.180 dv @ CACR (Unit)	0.023 @ CACR	0.047 @ CACR

[1] EPA initially considered evaluating with CALPUFF databases, but Newman is located near the edge of the CALMET modeling domain. There are a number of Class I areas that Newman could potentially impact (Gila, Bosque del Apache, Mount Baldy, Chiricahua, White Mountain, etc) and due to the size of the CALMET grid we cannot determine if Newman's impacts are below 0.5 dv at all Class I areas or determine the potential benefits from controls. Since plumes could transport out of the modeling domain and there is no way within the CALPUFF model to account for mass that transports out of the domain that may come back into the domain, the CALPUFF modeling databases cannot be relied on to conclusively assess visibility impacts from the Newman facility.

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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
Big Brown (Luminant)	1	400	21.5	366	30075.75	77.7	*199.095*	*16.157*	*2.9726*	*1.2746*
Big Brown (Luminant)	2	400	21.5	366	30075.75	77.7	*201.073*	*15.303*	*3.0058*	*1.289*
Coleto Creek (Engie)	1	409	20	347	36599.55	116.5	*67.83*	*17.235*	*0.8682*	*0.4412*
Fayette (LCRA)	1	600	23	316	37185.04	89.5	*61.388*	*15.363*	*2.5614*	*0.7432*
Fayette (LCRA)	2	600	23	307	39470.15	95	*61.909*	*13.79*	*4.5982*	*1.3338*
Harrington Station (Xcel)	061B	250	19	300	25148.98	88.7	*40.046*	*19.347*	*2.2942*	*0.0910*
Harrington Station (Xcel)	062B	300	19	300	25148.98	88.7	*42.749*	*19.231*	*6.0826*	*0.0382*
J T Deely (CPS Energy)	1	173	20	309	31227.43	99.4	*65.542*	*18.279*	*3.3732*	*1.5437*
J T Deely (CPS Energy)	2	172	20	309	31227.43	99.4	*52.262*	*23.034*	*5.18*	*1.9814*
Martin Lake (Luminant)	1	452	23	348	37143.49	89.4	*118.569*	*21.52*	*1.614*	*1.0876*
Martin Lake (Luminant)	2	452	23	348	38223.73	92	*109.736*	*28.337*	*2.0232*	*1.3648*
Martin Lake (Luminant)	3	452	23	348	38223.73	92	*124.38*	*24.192*	*1.9116*	*1.2886*
Monticello (Luminant)	1	400	21.5	356	29407.05	81	*142.714*	*18.125*	*6.9642*	*3.4384*
Monticello (Luminant)	2	400	21.5	356	29407.05	81	*139.962*	*13.01*	*8.219*	*3.255*
Monticello (Luminant)	3	460	25.5	329	44431.31	87	*140.815*	*24.586*	*4.8062*	*2.1632*
O W Sommers (CPS Energy)	1	240	20	275	16650.43	53	*10.917*	*8.038*	*0.1768*	*0.1768*
O W Sommers (CPS Energy)	2	240	20	275	16650.43	53	*2.011*	*5.949*	*0.145*	*0.145*
W A Parish (NRG)	WAP4	182	18	281	16413.24	64.5	*0.033*	*9.27*	*0.5044*	*0.5044*

W A Parish (NRG)	WAP5	600	24	332	38453.06	85	*97.654*	*6.018*	*0.6692*	*0.6692*
W A Parish (NRG)	WAP6	600	24	332	38453.06	85	*94.288*	*5.32*	*0.64*	*0.64*
Welsh Power Plant (AEP)	1	300	17	275	13843.1	85	*55.882*	*18.387*	*5.153*	*5.153*
Welsh Power Plant (AEP)	2	300	17	275	13843.1	85	*63.174*	*30.656*	*5.2312*	*5.2312*

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
Big Brown (Luminant)	1	400	21.5	366	30075.75	77.7	99.548	**16.157**	**2.973**	**1.275**
Big Brown (Luminant)	2	400	21.5	366	30075.75	77.7	100.537	**15.303**	**3.006**	**1.289**
Coleto Creek (Engie)	1	409	20	347	36599.55	116.5	33.915	**17.235**	**0.868**	**0.441**
Fayette (LCRA)	1	600	23	316	37185.04	89.5	61.388	**15.363**	**2.561**	**0.743**
Fayette (LCRA)	2	600	23	307	39470.15	95	61.909	**13.790**	**4.598**	**1.334**
Harrington Station (Xcel)	061B	250	19	300	25148.98	88.7	20.023	**19.347**	**2.294**	**0.091**
Harrington Station (Xcel)	062B	300	19	300	25148.98	88.7	21.375	**19.231**	**6.083**	**0.038**
J T Deely (CPS Energy)	1	173	20	309	31227.43	99.4	32.771	**18.279**	**3.373**	**1.544**
J T Deely (CPS Energy)	2	172	20	309	31227.43	99.4	26.131	**23.034**	**5.180**	**1.981**
Martin Lake (Luminant)	1	452	23	348	37143.49	89.4	26.986	**21.520**	**1.614**	**1.088**
Martin Lake (Luminant)	2	452	23	348	38223.73	92	25.595	**28.337**	**2.023**	**1.365**
Martin Lake (Luminant)	3	452	23	348	38223.73	92	24.666	**24.192**	**1.912**	**1.289**
Monticello (Luminant)	1	400	21.5	356	29407.05	81	71.357	**18.125**	**6.964**	**3.438**
Monticello (Luminant)	2	400	21.5	356	29407.05	81	69.981	**13.010**	**8.219**	**3.255**
Monticello (Luminant)	3	460	25.5	329	44431.31	87	13.710	**24.586**	**4.806**	**2.163**
O W Sommers (CPS Energy)	1	240	20	275	16650.43	53	5.746	**8.038**	**0.177**	**0.177**

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O W Sommers (CPS Energy)	2	240	20	275	16650.43	53	1.058	**5.949**	**0.145**	**0.145**
W A Parish (NRG)	WAP4	182	18	281	16413.24	64.5	0.033	**9.270**	**0.504**	**0.504**
W A Parish (NRG)	WAP5	600	24	332	38453.06	85	48.827	**6.018**	**0.669**	**0.669**
W A Parish (NRG)	WAP6	600	24	332	38453.06	85	47.144	**5.320**	**0.640**	**0.640**
Welsh Power Plant (AEP)	1	300	17	275	13843.1	85	27.941	**18.387**	**5.153**	**5.153**
Welsh Power Plant (AEP)	2	300	17	275	13843.1	85	63.174	**30.656**	**5.231**	**5.231**

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
Big Brown (Luminant)	1	400	21.5	366	30075.75	77.7	3.418	16.157	1.486	0.637
Big Brown (Luminant)	2	400	21.5	366	30075.75	77.7	3.507	15.303	1.503	0.645
Coleto Creek (Engie)	1	409	20	347	36599.55	116.5	3.213	17.235	0.434	0.221
Fayette (LCRA)	1	600	23	316	37185.04	89.5	3.071	15.363	1.281	0.372
Fayette (LCRA)	2	600	23	307	39470.15	95	3.310	13.790	2.299	0.667
Harrington Station (Xcel)	061B	250	19	300	25148.98	88.7	3.566	19.347	1.147	0.046
Harrington Station (Xcel)	062B	300	19	300	25148.98	88.7	3.234	19.231	3.041	0.019
J T Deely (CPS Energy)	1	173	20	309	31227.43	99.4	3.173	18.279	1.687	0.772
J T Deely (CPS Energy)	2	172	20	309	31227.43	99.4	3.192	23.034	2.590	0.991
Martin Lake (Luminant)	1	452	23	348	37143.49	89.4	13.493	21.520	1.614	1.088
Martin Lake (Luminant)	2	452	23	348	38223.73	92	12.797	28.337	2.023	1.365
Martin Lake (Luminant)	3	452	23	348	38223.73	92	12.333	24.192	1.912	1.289
Monticello (Luminant)	1	400	21.5	356	29407.05	81	3.185	18.125	3.482	1.719
Monticello (Luminant)	2	400	21.5	356	29407.05	81	3.233	13.010	4.110	1.628

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Monticello (Luminant)	3	460	25.5	329	44431.31	87	6.855	24.586	4.806	2.163
O W Sommers (CPS Energy)	1	240	20	275	16650.43	53	0.086	8.038	0.177	0.177
O W Sommers (CPS Energy)	2	240	20	275	16650.43	53	0.016	5.949	0.145	0.145
W A Parish (NRG)	WAP4	182	18	281	16413.24	64.5	0.033	9.270	0.252	0.252
W A Parish (NRG)	WAP5	600	24	332	38453.06	85	4.654	6.018	0.335	0.335
W A Parish (NRG)	WAP6	600	24	332	38453.06	85	3.893	5.320	0.320	0.320
Welsh Power Plant (AEP)	1	300	17	275	13843.1	85	3.126	18.387	2.577	2.577
Welsh Power Plant (AEP)	2	300	17	275	13843.1	85	0.000	0.000	0.000	0.000

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Appendix B. CALPUFF Modeled emissions

Table B-1. Base case CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	16591.25	3.00	1346.42	123.9	119.3	4.6	101
Big Brown	2	16756.08	3.00	1275.25	125.2	120.6	4.6	101.9
Harrington	061B	3337.17	0.25	1612.25	95.6	92.1	3.5	71.3
Harrington	062B	3562.42	1.64	1602.58	281.6	217	8.3	73.6
Martin Lake	1	9880.75	17.22	1793.33	74.7	57.6	2.2	10.1
Martin Lake	2	9144.67	17.40	2361.42	93.7	72.1	2.8	12.7
Martin Lake	3	10365.00	16.88	2016.00	88.5	68.2	2.6	12.5
Monticello	1	11892.83	2.91	1510.42	290.2	279.4	10.7	97
Monticello	2	11663.50	2.96	1084.17	342.5	329.8	12.7	118.9
Monticello	3	11734.58	12.13	2048.83	222.5	171.4	6.6	22.2
Welsh	1	4656.83	2.37	1532.25	238.6	183.8	7.1	57.7
Welsh	2	5264.50	2.41	2554.67	242.2	186.6	7.2	59.1

Table B-2. Low Control CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	8295.63	3.00	1346.42	123.90	119.30	4.60	101.00
Big Brown	2	8378.04	3.00	1275.25	125.20	120.60	4.60	101.90
Harrington	061B	1668.58	0.25	1612.25	95.60	92.10	3.50	71.30
Harrington	062B	1781.21	1.64	1602.58	281.60	217.00	8.30	73.60

Martin Lake	1	2248.80	17.22	1793.33	74.70	57.60	2.20	10.10
Martin Lake	2	2132.88	17.40	2361.42	93.70	72.10	2.80	12.70
Martin Lake	3	2055.46	16.88	2016.00	88.50	68.20	2.60	12.50
Monticello	1	5946.42	2.91	1510.42	290.20	279.40	10.70	97.00
Monticello	2	5831.75	2.96	1084.17	342.50	329.80	12.70	118.90
Monticello	3	1142.52	12.13	2048.83	222.50	171.40	6.60	22.20
Welsh	1	2328.42	2.37	1532.25	238.60	183.80	7.10	57.70
Welsh	2	2632.25	2.41	2554.67	242.20	186.60	7.20	59.10

Table B-3. High Control CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	284.84	1.20	1346.42	61.90	59.60	2.30	23.50
Big Brown	2	292.24	1.20	1275.25	62.60	60.30	2.30	23.70
Harrington	061B	297.18	0.10	1612.25	47.80	46.00	1.80	71.30
Harrington	062B	269.46	0.66	1602.58	140.80	108.50	4.20	73.60
Martin Lake	1	1124.40	17.22	1793.33	74.70	57.60	2.20	10.10
Martin Lake	2	1066.44	17.40	2361.42	93.70	72.10	2.80	12.70
Martin Lake	3	1027.73	16.88	2016.00	88.50	68.20	2.60	12.50
Monticello	1	265.40	1.16	1510.42	145.10	139.70	5.40	44.10
Monticello	2	269.40	1.19	1084.17	171.20	164.90	6.30	51.70
Monticello	3	571.26	12.13	2048.83	222.50	171.40	6.60	22.20
Welsh	1	260.52	0.95	1532.25	119.30	91.90	3.50	57.70
Welsh	2	245.04	0.96	2554.67	121.10	93.30	3.60	59.10

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Table B-4. SDA Control CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	427.26	0.30	1346.42	61.9	59.6	2.3	23.5
Big Brown	2	438.36	0.30	1275.25	62.6	60.3	2.3	23.7
Monticello	1	398.10	0.29	1510.42	145.1	139.7	5.4	44.1
Monticello	2	404.10	0.30	1084.17	171.2	164.9	6.3	51.7
Welsh	1	390.78	0.03	1532.25	119.3	91.9	3.5	57.7

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Appendix C. CALPUFF Recent NOx and SO2 Emissions (2011-2015)

Table C-1. RNS CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	12939.17	3.00	975.75	123.9	119.3	4.6	101
Big Brown	2	14045	3.00	983.25	125.2	120.6	4.6	101.9
Harrington	061B	2725.25	0.25	1006.17	95.6	92.1	3.5	71.3
Harrington	062B	2759	1.64	1029.17	281.6	217	8.3	73.6
Martin Lake	1	9275.42	17.22	1892.92	74.7	57.6	2.2	10.1
Martin Lake	2	8635	17.40	1633.33	93.7	72.1	2.8	12.7
Martin Lake	3	8243.75	16.88	1458.03	88.5	68.2	2.6	12.5
Monticello	1	7663.75	2.91	924.83	290.2	279.4	10.7	97
Monticello	2	7875	2.96	1036	342.5	329.8	12.7	118.9
Monticello	3	7900.42	12.13	1554.83	222.5	171.4	6.6	22.2
Welsh	1	2922.5	2.37	1274.92	238.6	183.8	7.1	57.7
Welsh	2	0	0	0	0	0	0	0

Table C-2. RNS - Low Control CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	8295.63	3.00	975.75	123.90	119.30	4.60	101.00
Big Brown	2	8378.04	3.00	983.25	125.20	120.60	4.60	101.90
Harrington	061B	1668.58	0.25	1006.17	95.60	92.10	3.50	71.30
Harrington	062B	1781.21	1.64	1029.17	281.60	217.00	8.30	73.60
Martin Lake	1	2192.8	17.22	1892.92	74.70	57.60	2.20	10.10
Martin Lake	2	2116.83	17.40	1633.33	93.70	72.10	2.80	12.70
Martin Lake	3	1991.30	16.88	1458.03	88.50	68.20	2.60	12.50
Monticello	1	3832	2.91	924.83	290.20	279.40	10.70	97.00
Monticello	2	3937.3	2.96	1036	342.50	329.80	12.70	118.90
Monticello	3	1039.26	12.13	1554.83	222.50	171.40	6.60	22.20
Welsh	1	1461	2.37	1274.92	238.60	183.80	7.10	57.70
Welsh	2	0	0	0	0	0	0	0

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Table C-3. RNS - High Control CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	252.04	1.20	975.75	61.90	59.60	2.30	23.50
Big Brown	2	254.21	1.20	983.25	62.60	60.30	2.30	23.70
Harrington	061B	231.49	0.10	1006.17	47.80	46.00	1.80	71.30
Harrington	062B	286.80	0.66	1029.17	140.80	108.50	4.20	73.60
Martin Lake	1	1096.4	17.22	1892.92	74.70	57.60	2.20	10.10
Martin Lake	2	1058.42	17.40	1633.33	93.70	72.10	2.80	12.70
Martin Lake	3	995.65	16.88	1458.03	88.50	68.20	2.60	12.50
Monticello	1	252.45	1.16	924.83	145.10	139.70	5.40	44.10
Monticello	2	261.63	1.19	1036	171.20	164.90	6.30	51.70
Monticello	3	519.63	12.13	1554.83	222.50	171.40	6.60	22.20
Welsh	1	220.61	0.95	1274.92	119.30	91.90	3.50	57.70
Welsh	2	0	0	0	0	0	0	0

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Appendix D. EPRI Calculation for H_2SO_4 Emission Rate for CALPUFF Modeling

From: Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, Electric Power Research Institute; March 2012.

$$ER_{Comb} = K \cdot F1 \cdot K1 \cdot K2 \cdot C1 \cdot S1 \cdot F2_{AH} \cdot F2_{PM} \cdot F2_{FGD}$$

where,:

ERComb = total H_2SO_4 released, lbs/hr

K = Molecular weight and units conversion constant = 98.07 / 64.04 • 2000 = 3,063

(98.07 = Molecular weight of H_2SO_4 ; 64.04 = Molecular weight of SO_2; 2000 = Conversion from tons/hr to lb/hr)

F1 = Fuel Impact Factor (See EPRI 2012 Table 4-1)

C1 = Dry coal burn, tons/hr = Coal Heating Value (MMBtu/ton) • Max Heat input (MMBtu/hr)

S1 = Coal sulfur weighted average, %, dry

K1 = Molecular weight and units conversion constant = (64.04)/(100 • 32.06) = 0.02

(64.04 = molecular weight of SO_2; 32.06 = molecular weight of S; 100 = conversion of % S to a fraction)

K2 = Sulfur conversion to SO_2, implicit from EPA AP-42 (EPA, 1995b)

(0.95 for bituminous coals, 0.875 for subbituminous coals, 0.55 to 0.85 for lignite, based on the Na content, 1.0 for oil)

F2 = Technology Impact Factors (See EPRI 2012 Tables 4-3, 4-4, and 4-5)

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Table D-1. Low Control Scenario

Facility	Unit	Coal	Max Heat input (MMBTU /hr)	C1	Coal Heating Value (MMBtu/ton, HV)	S1	K	K1	K2	F1	F2(AH)	F2(PM)	F2(FGD)	H_2SO_4 (lb/hr)
Big Brown	1	lignite	7782	565.39	6882	0.73	3063	0.02	0.75	0.0044	0.36	0.1	1	3.004
Big Brown	2	lignite	7782	565.14	6885	0.73	3063	0.02	0.75	0.0044	0.36	0.1	1	3.002
Harrington	061B	sub	4631	261.67	8848.86	0.26	3063	0.02	0.875	0.0019	0.36	0.1	1	0.249
Harrington	062B	sub	4222	238.74	8842.08	0.26	3063	0.02	0.875	0.0019	0.36	0.72	1	1.639
Martin Lake	1	lignite	11124	829.78	6703	0.99	3063	0.02	0.75	0.0044	0.36	0.72	0.4	17.218
Martin Lake	2	lignite	11124	830.15	6700	1	3063	0.02	0.75	0.0044	0.36	0.72	0.4	17.400
Martin Lake	3	lignite	11124	830.15	6700	0.97	3063	0.02	0.75	0.0044	0.36	0.72	0.4	16.878
Monticello	1	lignite	9924	768.23	6459	0.52	3063	0.02	0.75	0.0044	0.36	0.1	1	2.907
Monticello	2	lignite	9924	768.59	6456	0.53	3063	0.02	0.75	0.0044	0.36	0.1	1	2.965
Monticello	3	lignite	12870	997.98	6448	0.58	3063	0.02	0.75	0.0044	0.36	0.72	0.4	12.132
Welsh	1	sub	6896	407.32	8465.07	0.22	3063	0.02	0.875	0.0019	0.36	0.72	1	2.366
Welsh	2	sub	7046	414.35	8502.57	0.22	3063	0.02	0.875	0.0019	0.36	0.72	1	2.406

Table D-2. High Control Scenario

Facility	Unit	Coal	Max Heat input (MMBTU /hr)	C1	Coal Heating Value (MMBtu/ton, HV)	S1	K	K1	K2	F1	F2(AH)	F2(PM)	F2(FGD)	H_2SO_4 (lb/hr)
Big Brown	1	lignite	7782	565.39	6882	0.73	3063	0.02	0.75	0.0044	0.36	0.1	0.4	1.201
Big Brown	2	lignite	7782	565.14	6885	0.73	3063	0.02	0.75	0.0044	0.36	0.1	0.4	1.201
Harrington	061B	sub	4631	261.67	8848.86	0.26	3063	0.02	0.875	0.0019	0.36	0.1	0.4	0.100
Harrington	062B	sub	4222	238.74	8842.08	0.26	3063	0.02	0.875	0.0019	0.36	0.72	0.4	0.655
Martin Lake	1	lignite	11124	829.78	6703	0.99	3063	0.02	0.75	0.0044	0.36	0.72	0.4	17.218
Martin Lake	2	lignite	11124	830.15	6700	1	3063	0.02	0.75	0.0044	0.36	0.72	0.4	17.400
Martin Lake	3	lignite	11124	830.15	6700	0.97	3063	0.02	0.75	0.0044	0.36	0.72	0.4	16.878
Monticello	1	lignite	9924	768.23	6459	0.52	3063	0.02	0.75	0.0044	0.36	0.1	0.4	1.163

Monticello	2	lignite	9924	768.59	6456	0.53	3063	0.02	0.75	0.0044	0.36	0.1	0.4	1.186
Monticello	3	lignite	12870	997.98	6448	0.58	3063	0.02	0.75	0.0044	0.36	0.72	0.4	12.132
Welsh	1	sub	6896	407.32	8465.07	0.22	3063	0.02	0.875	0.0019	0.36	0.72	0.4	0.946
Welsh	2	sub	7046	414.35	8502.57	0.22	3063	0.02	0.875	0.0019	0.36	0.72	0.4	0.963

Table D-3. SDA Control Scenario

Facility	Unit	Coal	Max Heat input (MMBTU /hr)	C1	Coal Heating Value (MMBtu/ton, HV)	S1	K	K1	K2	F1	F2(AH)	F2(PM)	F2(FGD)	H_2SO_4 (lb/hr)
Big Brown	1	lignite	7782	565.39	6882	0.73	3063	0.02	0.75	0.0044	0.36	0.01	1	0.300
Big Brown	2	lignite	7782	565.14	6885	0.73	3063	0.02	0.75	0.0044	0.36	0.01	1	0.300
Monticello	1	lignite	9924	768.23	6459	0.52	3063	0.02	0.75	0.0044	0.36	0.01	1	0.291
Monticello	2	lignite	9924	768.59	6456	0.53	3063	0.02	0.75	0.0044	0.36	0.01	1	0.296
Welsh	1	sub	6896	407.32	8465.07	0.22	3063	0.02	0.875	0.0019	0.36	0.01	1	0.033

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Appendix E. CAMx Maximum Impact at each Class I Area

Table E-1. Base Case (Run 1) Maximum Impact

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0.278	0.224	0.009	0.047	0.205	0.207	0.001	0.270	0.261	0.359	0.362
BIBE	0.652	0.525	0.027	0.111	0.457	0.463	0.002	0.600	0.580	1.087	1.097
BRET	0.203	0.163	0.006	0.034	0.178	0.180	0.005	0.236	0.228	0.802	0.809
CACR	0.595	0.604	0.106	0.180	1.002	0.974	0.163	1.698	1.648	2.016	2.033
CAVE	0.480	0.388	0.017	0.081	0.463	0.468	0.003	0.617	0.596	0.923	0.932
GRSA	0.131	0.105	0.004	0.022	0.081	0.082	0.000	0.082	0.079	0.094	0.095
GUMO	0.480	0.388	0.017	0.081	0.463	0.468	0.003	0.617	0.596	0.923	0.932
HEGL	0.432	0.426	0.066	0.121	0.540	0.537	0.067	0.721	0.696	1.482	1.492
MING	0.278	0.282	0.047	0.081	0.450	0.444	0.070	0.781	0.753	1.266	1.272
PECO	0.188	0.151	0.006	0.031	0.147	0.149	0.001	0.173	0.167	0.206	0.208
SACR	0.546	0.441	0.019	0.092	0.420	0.425	0.003	0.523	0.505	0.750	0.758
UPBU	0.456	0.449	0.070	0.127	0.581	0.579	0.069	1.038	1.003	1.690	1.699
WHIT	0.504	0.406	0.017	0.085	0.347	0.350	0.002	0.402	0.388	0.568	0.574
WHPE	0.188	0.151	0.006	0.031	0.147	0.149	0.001	0.173	0.167	0.206	0.208
WIMO	0.757	0.632	0.101	0.153	0.609	0.598	0.062	0.967	0.935	2.154	2.175
Cumulative	6.168	5.332	0.518	1.277	6.089	6.072	0.451	8.896	8.601	14.525	14.645

Table E-1. Base Case (Run 1) Maximum Impact (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0.198	0.502	0.526	0.131	0.121	0.137	0.149	0.146	0.141	0.066	0.059
BIBE	0.426	0.514	0.555	0.418	0.387	0.438	0.531	0.523	0.521	0.232	0.207
BRET	0.191	0.206	0.223	0.747	0.722	0.787	1.061	1.039	1.083	0.505	0.436
CACR	0.791	0.679	0.701	2.633	2.466	2.755	4.516	4.487	4.632	2.674	2.343
CAVE	0.411	0.435	0.458	0.417	0.387	0.439	0.421	0.414	0.407	0.187	0.166
GRSA	0.094	0.254	0.257	0.032	0.030	0.034	0.036	0.035	0.036	0.016	0.015
GUMO	0.411	0.435	0.458	0.417	0.387	0.439	0.421	0.414	0.407	0.187	0.166
HEGL	0.585	0.721	0.746	1.377	1.278	1.442	1.429	1.410	1.472	1.158	0.797
MING	0.415	0.416	0.431	1.125	1.126	1.189	2.299	2.138	2.394	1.539	1.150
PECO	0.152	0.243	0.284	0.073	0.068	0.077	0.082	0.080	0.078	0.036	0.032
SACR	0.429	2.908	2.998	0.292	0.271	0.306	0.336	0.330	0.325	0.149	0.132
UPBU	0.660	0.706	0.733	2.254	2.189	2.368	1.663	1.628	1.683	1.446	0.978
WHIT	0.376	0.800	0.838	0.210	0.194	0.220	0.243	0.239	0.234	0.112	0.099
WHPE	0.152	0.243	0.284	0.073	0.068	0.077	0.082	0.080	0.078	0.036	0.032
WIMO	0.845	2.708	2.770	1.216	1.156	1.277	2.241	2.189	2.282	1.033	0.864
Cumulative	6.135	11.771	12.262	11.416	10.853	11.985	15.510	15.153	15.775	9.378	7.476

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Table E-2. High Control (Run 3) Maximum Impact

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0.016	0.016	0.001	0.001	0.012	0.012	0.001	0.013	0.011	0.007	0.007
BIBE	0.069	0.084	0.017	0.024	0.025	0.027	0.001	0.033	0.028	0.033	0.031
BRET	0.019	0.023	0.005	0.007	0.030	0.028	0.006	0.014	0.012	0.039	0.039
CACR	0.312	0.387	0.098	0.132	0.480	0.441	0.183	0.180	0.156	0.409	0.391
CAVE	0.031	0.033	0.003	0.004	0.028	0.030	0.002	0.031	0.026	0.021	0.021
GRSA	0.007	0.007	0.001	0.001	0.004	0.005	0.000	0.004	0.003	0.003	0.002
GUMO	0.031	0.033	0.003	0.004	0.028	0.030	0.002	0.031	0.026	0.021	0.021
HEGL	0.194	0.241	0.060	0.081	0.203	0.186	0.073	0.077	0.067	0.438	0.418
MING	0.146	0.182	0.045	0.061	0.157	0.146	0.074	0.102	0.088	0.188	0.179
PECO	0.010	0.011	0.001	0.001	0.008	0.009	0.000	0.008	0.007	0.004	0.004
SACR	0.035	0.037	0.003	0.004	0.026	0.027	0.002	0.026	0.022	0.017	0.017
UPBU	0.204	0.253	0.064	0.086	0.251	0.231	0.072	0.094	0.081	0.356	0.339
WHIT	0.029	0.031	0.002	0.003	0.020	0.021	0.001	0.020	0.016	0.012	0.012
WHPE	0.010	0.011	0.001	0.001	0.008	0.009	0.000	0.008	0.007	0.004	0.004
WIMO	0.270	0.334	0.098	0.133	0.306	0.282	0.068	0.082	0.071	0.245	0.235
Cumulative	1.383	1.683	0.399	0.542	1.586	1.484	0.488	0.725	0.622	1.797	1.721

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Table E-2. High Control (Run 3) Maximum Impact (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0.011	0.142	0.142	0.016	0.015	0.015	0.004	0.004	0.008	0.000	0.004
BIBE	0.023	0.086	0.084	0.058	0.056	0.053	0.042	0.032	0.068	0.000	0.037
BRET	0.023	0.028	0.027	0.211	0.241	0.217	0.124	0.097	0.177	0.000	0.136
CACR	0.186	0.413	0.412	1.468	1.811	1.609	0.733	0.563	0.914	0.000	0.822
CAVE	0.023	0.174	0.173	0.053	0.051	0.049	0.014	0.013	0.026	0.000	0.013
GRSA	0.005	0.158	0.153	0.004	0.004	0.004	0.002	0.002	0.004	0.000	0.002
GUMO	0.023	0.174	0.173	0.053	0.051	0.049	0.014	0.013	0.026	0.000	0.013
HEGL	0.114	0.521	0.525	0.451	0.580	0.500	0.551	0.407	0.767	0.000	0.553
MING	0.128	0.280	0.281	0.392	0.469	0.412	0.629	0.473	0.873	0.000	0.570
PECO	0.008	0.170	0.165	0.009	0.009	0.008	0.002	0.002	0.005	0.000	0.002
SACR	0.025	1.738	1.719	0.036	0.035	0.034	0.011	0.010	0.020	0.000	0.010
UPBU	0.130	0.466	0.469	0.805	1.025	0.890	0.415	0.314	0.565	0.000	0.402
WHIT	0.020	0.354	0.349	0.026	0.025	0.024	0.007	0.007	0.014	0.000	0.007
WHPE	0.008	0.170	0.165	0.009	0.009	0.008	0.002	0.002	0.005	0.000	0.002
WIMO	0.176	2.065	2.046	0.252	0.274	0.251	0.252	0.186	0.364	0.000	0.221
Cumulative	0.902	6.939	6.882	3.842	4.654	4.122	2.803	2.128	3.835	0.000	2.793

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Table E-3. Low Control (Run 4) Maximum Impact

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0.141	0.114	0.005	0.025	0.204	0.207	0.001	0.135	0.130	0.183	0.185
BIBE	0.373	0.300	0.022	0.066	0.460	0.466	0.002	0.319	0.309	0.585	0.591
BRET	0.100	0.080	0.006	0.017	0.173	0.175	0.006	0.124	0.120	0.453	0.457
CACR	0.447	0.490	0.102	0.157	1.046	1.018	0.175	1.052	1.018	1.327	1.338
CAVE	0.248	0.203	0.010	0.045	0.468	0.473	0.003	0.316	0.305	0.489	0.494
GRSA	0.066	0.053	0.002	0.012	0.082	0.083	0.000	0.041	0.040	0.049	0.049
GUMO	0.248	0.203	0.010	0.045	0.468	0.473	0.003	0.316	0.305	0.489	0.494
HEGL	0.309	0.330	0.063	0.102	0.593	0.591	0.071	0.426	0.410	0.948	0.952
MING	0.209	0.230	0.046	0.072	0.488	0.482	0.072	0.470	0.451	0.778	0.777
PECO	0.095	0.077	0.003	0.017	0.148	0.150	0.001	0.087	0.084	0.106	0.107
SACR	0.277	0.227	0.011	0.050	0.420	0.425	0.003	0.264	0.255	0.390	0.394
UPBU	0.326	0.347	0.067	0.107	0.628	0.625	0.071	0.613	0.591	1.148	1.150
WHIT	0.257	0.208	0.009	0.046	0.348	0.352	0.002	0.202	0.195	0.293	0.296
WHPE	0.095	0.077	0.003	0.017	0.148	0.150	0.001	0.087	0.084	0.106	0.107
WIMO	0.449	0.387	0.100	0.144	0.629	0.614	0.066	0.503	0.485	1.168	1.181
Cumulative	3.642	3.325	0.461	0.919	6.302	6.281	0.475	4.956	4.783	8.512	8.571

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Table E-3. Low Control (Run 4) Maximum Impact (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0.099	0.319	0.337	0.031	0.029	0.028	0.077	0.075	0.015	0.067	0.030
BIBE	0.218	0.284	0.306	0.107	0.102	0.098	0.295	0.291	0.073	0.252	0.116
BRET	0.093	0.110	0.119	0.284	0.307	0.282	0.636	0.615	0.193	0.571	0.274
CACR	0.458	0.544	0.557	1.550	1.882	1.682	3.123	3.065	0.905	3.297	1.659
CAVE	0.209	0.300	0.313	0.100	0.095	0.092	0.224	0.220	0.045	0.194	0.089
GRSA	0.048	0.197	0.199	0.008	0.007	0.007	0.019	0.018	0.005	0.016	0.007
GUMO	0.209	0.300	0.313	0.100	0.095	0.092	0.224	0.220	0.045	0.194	0.089
HEGL	0.362	0.617	0.633	0.464	0.583	0.506	0.939	0.922	0.804	1.183	0.686
MING	0.280	0.344	0.354	0.495	0.565	0.505	1.567	1.408	0.960	1.626	0.886
PECO	0.077	0.204	0.248	0.017	0.017	0.016	0.042	0.042	0.008	0.037	0.017
SACR	0.219	2.322	2.373	0.070	0.067	0.064	0.175	0.172	0.036	0.152	0.069
UPBU	0.397	0.582	0.600	0.867	1.077	0.942	1.057	1.014	0.600	1.497	0.631
WHIT	0.191	0.565	0.586	0.050	0.047	0.046	0.125	0.123	0.025	0.112	0.051
WHPE	0.077	0.204	0.248	0.017	0.017	0.016	0.042	0.042	0.008	0.037	0.017
WIMO	0.526	2.382	2.407	0.381	0.395	0.369	1.290	1.252	0.462	1.125	0.546
Cumulative	3.465	9.276	9.594	4.542	5.286	4.745	9.837	9.479	4.185	10.359	5.167

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Appendix F. CAMx Modeled Number of Days impacted

Table F-1. Base Case (Run 1) Number of days impacted over 0.5 dv

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	2	2	0	0	0	0	0	2	2	5	5
BRET	0	0	0	0	0	0	0	0	0	2	2
CACR	2	2	0	0	9	9	0	22	22	58	58
CAVE	0	0	0	0	0	0	0	1	1	3	3
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	1	1	3	3
HEGL	0	0	0	0	1	1	0	8	8	23	23
MING	0	0	0	0	0	0	0	1	1	6	6
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	1	0	0	0	0	0	0	1	1	3	3
UPBU	0	0	0	0	6	6	0	11	9	37	37
WHIT	1	0	0	0	0	0	0	0	0	1	1
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	4	3	0	0	2	2	0	4	3	33	34
Cumulative	10	7	0	0	18	18	0	51	48	174	175

Table F-1. Base Case (Run 1) Number of days impacted over 0.5 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	1	1	0	0	0	0	0	0	0	0
BIBE	0	1	1	0	0	0	1	1	1	0	0
BRET	0	0	0	2	2	3	3	3	3	1	0
CACR	5	1	1	71	68	76	79	78	79	49	37
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	1	1	1	26	27	29	33	31	35	11	8
MING	0	0	0	7	6	8	6	5	6	4	2
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	5	5	0	0	0	0	0	0	0	0
UPBU	2	1	1	44	40	46	45	44	45	18	13
WHIT	0	1	1	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	9	6	6	10	7	11	30	30	31	8	5
Cumulative	17	17	17	160	150	173	197	192	200	91	65

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Table F-2. High Control (Run 3) Number of days impacted over 0.5 dv

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	0	0	0	0	0	0	0	0
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	0	0
MING	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	0	0	0	0	0	0	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	0	0	0	0	0
Cumulative	0	0	0	0	0	0	0	0	0	0	0

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Table F-2. High Control (Run 3) Number of days impacted over 0.5 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	6	9	6	3	1	5	0	3
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	1	1	0	2	0	2	0	3	0	1
MING	0	0	0	0	0	0	1	0	1	0	1
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	1	1	0	0	0	0	0	0	0	0
UPBU	0	0	0	3	5	4	0	0	3	0	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	4	4	0	0	0	0	0	0	0	0
Cumulative	0	6	6	9	16	10	6	1	12	0	5

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Table F-3. Low Control (Run 4) Number of days impacted over 0.5 dv

Class I Area	**J.T. Deely Unit 1**	**J.T. Deely Unit 2**	**OW Sommers Unit 1**	**OW Sommers Unit 2**	**Fayette Unit 1**	**Fayette Unit 2**	**W. A. Parish WAP4**	**W. A. Parish WAP5**	**W. A. Parish WAP6**	**Big Brown Unit 1**	**Big Brown Unit 2**
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	2	2
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	0	9	9	0	9	8	22	23
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	1	1	0	0	0	8	8
MING	0	0	0	0	0	0	0	0	0	2	2
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	7	7	0	1	1	13	13
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	3	3	0	1	0	13	13
Cumulative	0	0	0	0	20	20	0	11	9	60	61

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Table F-3. Low Control (Run 4) Number of days impacted over 0.5 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	2	2	0	1	0
CACR	0	1	1	17	18	15	43	42	5	54	18
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	1	1	0	3	1	12	12	3	15	4
MING	0	0	0	0	1	1	4	4	1	4	1
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	1	1	0	0	0	0	0	0	0	0
UPBU	0	1	1	6	6	6	20	20	3	23	4
WHIT	0	1	1	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	1	5	5	0	0	0	10	10	0	8	2
Cumulative	1	10	10	23	28	23	91	90	12	105	29

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Table F-4. Base Case (Run 1) Number of days impacted over 1.0 dv

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	2	2
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	0	1	0	0	8	6	17	17
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	4	5
MING	0	0	0	0	0	0	0	0	0	1	1
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	0	0	0	1	1	8	8
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	0	0	0	12	12
Cumulative	0	0	0	0	1	0	0	9	7	44	45

Table F-4. Base Case (Run 1) Number of days impacted over 1.0 dv (continued)

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Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	1	1	1	0	0
CACR	0	0	0	26	26	29	32	30	32	9	8
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	3	3	3	10	7	9	1	0
MING	0	0	0	1	1	1	2	1	2	1	1
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	1	1	0	0	0	0	0	0	0	0
UPBU	0	0	0	10	10	13	14	12	15	1	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	4	4	1	1	1	8	6	7	1	0
Cumulative	0	5	5	41	41	47	67	57	66	13	9

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Table F-5. High Control (Run 3) Number of days impacted over 1.0 dv

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	0	0	0	0	0	0	0	0
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	0	0
MING	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	0	0	0	0	0	0	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	0	0	0	0	0
Cumulative	0	0	0	0	0	0	0	0	0	0	0

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Table F-5. High Control (Run 3) Number of days impacted over 1.0 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	1	1	1	0	0	0	0	0
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	0	0
MING	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	1	1	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	1	0	0	0	0	0	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	1	1	0	0	0	0	0	0	0	0
Cumulative	0	2	2	1	2	1	0	0	0	0	0

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Table F-6. Low Control (Run 4) Number of days impacted over 1.0 dv

Class I Area	**J.T. Deely Unit 1**	**J.T. Deely Unit 2**	**OW Sommers Unit 1**	**OW Sommers Unit 2**	**Fayette Unit 1**	**Fayette Unit 2**	**W. A. Parish WAP4**	**W. A. Parish WAP5**	**W. A. Parish WAP6**	**Big Brown Unit 1**	**Big Brown Unit 2**
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	0	1	1	0	1	1	4	4
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	0	0
MING	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	0	0	0	0	0	1	1
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	0	0	0	1	1
Cumulative	0	0	0	0	1	1	0	1	1	6	6

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Table F-6. Low Control (Run 4) Number of days impacted over 1.0 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	3	3	2	16	13	0	15	3
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	1	0
MING	0	0	0	0	0	0	1	1	0	1	0
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	1	1	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	1	0	2	1	0	3	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	2	1	0	0	0	2	2	0	2	0
Cumulative	0	3	2	3	4	2	21	17	0	22	3

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Technical Support Document

Our Visibility Analysis of Potential Controls for Subject to BART sources for the Texas Regional Haze BART Federal Implementation Plan

(BART Modeling TSD)

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November 2016
(Revised December 2016, see Errata- BART Modeling TSD for details)

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Preparation of Emissions Scenarios for Potential Controls - Additional visibility Modeling

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.

1. Background and Introduction

We 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.[1] 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 BART Screening TSD.

Some of the subject-to-BART sources in Texas are very far away from a Class I area yet have high enough emissions that they significantly impact visibility at Class I areas in Texas 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-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 the large emission sources. The CAMx modeling protocol followed is described in detail in the BART Screening TSD. See the UNC-IE memorandum that documents these additional CAMx runs.[2]

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[1] 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.

[2] "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"

Regarding how to use modeling to assess visibility benefits from controls, the BART guidelines state: [3]

- 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. 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.

2. Emission Calculation Methodology

See Appendix A (CAMx) and Appendix B (CALPUFF) for a full summary of emissions modeled for the visibility benefit analysis of controls. Below we describe the methodology applied to estimate the emission reductions anticipated from controls used for visibility modeling.

2.1. SO_2 emissions

As explained below and in more detail in the BART FIP 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 50% control efficiency and modeled SO_2 emissions at 50% of the baseline actual 24-hr maximum emission level obtained from 2000-2004 CAMD data. 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 24-hr heat input (MMBtu/hr) reported in

[3] 40 CFR part 51 Appendix Y Section IV.D.5

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the CAMD data for 2000-2004.

We noted that some of the units we were evaluating were already equipped with older underperforming scrubbers, most of which were partially bypassed. For the units with scrubber bypasses, we lacked information on scrubber absorber efficiencies represented by the recent actual emission levels and the amount of bypass that has occurred. This made it impossible to estimate the current base control efficiency and the amount of additional reductions that would occur if the unit was further controlled based solely on the actual emissions data. Therefore, as is described in our BART TSD, we used Coal Data from EIA Form 923. This information enabled us to assess the total sulfur levels coming into a unit, to determine an uncontrolled baseline, and then estimate the achievable emission rates for the low and high control scenarios, to cover the potential range of upgraded scrubber control efficiencies. The high control emissions were estimated based on 95% control efficiency and the maximum 24-hr heat input (MMBtu/hr) reported in the CAMD data for 2000-2004. The low control scenario for these units was estimated by doubling the high control emission rate to estimate a 90% control efficiency. The table below summarizes the SO_2 emissions modeled with CALPUFF. In addition to these runs, we also performed CALPUFF modeling with an alternative baseline for these units, as explained in more detail later in this TSD. For units evaluated with WFGD level controls in the high control scenario, an additional model run with SDA level controls was also performed. See appendix B for a full list of modeled emissions for all scenarios.

Table 2.1-1. 2000-2004 Baseline CALPUFF Modeled SO_2 emissions: Coal-fired Units

Source	Unit	High Control efficiency	Maximum Heat Input (2000-2004)	SO_2 Emissions (lb/hr)		
				Baseline (2000-2004)	High Control Scenario	Low Control Scenario
Big Brown	1	0.04	7121	16591.25	284.84	8295.63
Big Brown	2	0.04	7306	16756.08	292.24	8378.04
Harrington	061B	0.06	4953	3337.17	297.18	1668.58
Harrington	062B	0.06	4491	3562.42	269.46	1781.21
Martin Lake	1	0.12	9370	9880.75	1124.4	2248.80
Martin Lake	2	0.12	8887	9144.67	1066.44	2132.88
Martin Lake	3	0.11	9343	10365.00	1027.73	2055.46
Monticello	1	0.04	6635	11892.83	265.4	5946.42
Monticello	2	0.04	6735	11663.50	269.4	5831.75
Monticello	3	0.06	9521	11734.58	571.26	1142.52
Welsh	1	0.04	6513	4656.83	260.52	2328.42
Welsh [1]	2	0.04	6126	5264.50	0	0

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[1]We did some initial baseline/screening modeling with Welsh 2 included, but we also did CALPUFF runs with Welsh 2 at zero emissions for baseline and control case modeling for Welsh to reflect the recent shutdown of this unit and isolate the visibility benefits from controlling Welsh unit 1

For the coal-fired EGUs evaluated with CALPUFF, we also evaluated maximum 24-hour NOx and SO_2 from a more recent baseline period (2011-2015) using the 2001-2003 CALMET data since some controls or reductions in emissions may have occurred due to federal rules and we wanted to provide additional information as part of the visibility benefit analysis. For High Control we used the recent Maximum Heat Input and High Control Efficiency to calculate the controlled emission rate. For the Low Control we used a 50% reduction of recent emissions for the units currently unscrubbed. For the units that have underperforming scrubbers, we used the High control emission rate and doubled to estimate a lower scrubbed control.

Table 2.1-2. 2011-2015 Recent NOx and SO_2 Emissions (RNS) CALPUFF Modeled SO_2 emissions: Coal-fired Units

Source	Unit	High Control efficiency	Maximum Heat Input (2011-2015)	SO_2 Emissions (lb/hr)		
				Recent Emissions (2011-2015)	High Control Scenario	Low Control Scenario
Big Brown	1	0.04	6301	12939.17	252.04	8295.63
Big Brown	2	0.04	6355	14045	254.21	8378.04
Harrington	061B	0.06	3858	2725.25	231.49	1668.58
Harrington	062B	0.06	4780	2759	286.80	1781.21
Martin Lake	1	0.12	9137	9275.42	1096.4	2192.8
Martin Lake	2	0.12	8820	8635	1058.42	2116.8
Martin Lake	3	0.11	9051	8243.75	995.65	1991.3
Monticello	1	0.04	6311	7663.75	252.45	3832
Monticello	2	0.04	6541	7875	261.63	3937.3
Monticello	3	0.06	8661	7900.42	519.63	1039.3
Welsh	1	0.04	5515	2922.5	220.61	1461
Welsh [1]	2	0.04	5606	0	0	0

UNC-IE assisted EPA in conducting two additional CAMx runs, with one run being based on

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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 units with existing scrubbers, the low control case assumed scrubber upgrades achieving 90% control efficiency and the high control case assumed scrubber upgrades achieving 95% control efficiency. 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.

W.A. Parish unit 4 and Sommers units 1 and 2 are primarily gas-fired units. Parish unit 4 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 this unit were held at baseline levels for the two control scenarios. The Sommers units burned fuel oil during the baseline period. EIA form 767 data shows that Sommers reported burning 0.19% sulfur fuel oil during 2003 when the maximum 24-hr baseline emissions occurred. High and low control scenario emissions were estimated based on a reduction to ultra-low sulfur diesel (ULSD) at 0.0015% and 0.01% sulfur fuel oil.

Table 2.1-3. CAMx modeled SO_2 emission rates

Source	**Unit**	SO_2 **(tons/day)**		
		Base case (2000-2004)	**Low control**	**High Control**
Big Brown (Luminant)	1	199.095	99.5475	3.41808
Big Brown (Luminant)	2	201.073	100.5365	3.50688
Coleto Creek (Engie)	1	67.83	33.915	3.21264
Fayette (LCRA)	1	61.388	61.388*	3.07056
Fayette (LCRA)	2	61.909	61.909*	3.3096
Harrington Station (Xcel)	061B	40.046	20.023	3.56616
Harrington Station (Xcel)	062B	42.749	21.3745	3.23352
J T Deely (CPS Energy)	1	65.542	32.771	3.17328
J T Deely (CPS Energy)	2	52.262	26.131	3.192
Martin Lake (Luminant)	1	118.569	26.9856	13.4928
Martin Lake (Luminant)	2	109.736	25.59456	12.79728
Martin Lake (Luminant)	3	124.38	24.66552	12.33276
Monticello (Luminant)	1	142.714	71.357	3.1848
Monticello (Luminant)	2	139.962	69.981	3.2328
Monticello (Luminant)	3	140.815	13.71024	6.85512
O W Sommers (CPS				

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Energy)				
O W Sommers (CPS Energy)	2	2.011	1.058421053	0.015876
W A Parish (NRG)	WAP4	0.033	0.033	0.033
W A Parish (NRG)	WAP5	97.654	48.827	4.6536
W A Parish (NRG)	WAP6	94.288	47.144	3.8928
Welsh Power Plant (AEP)	1	55.882	27.941	3.12624
Welsh Power Plant (AEP)	2	63.174	63.174*	0

*Modeled at the baseline rate in the low control scenario. Fayette units already have scrubber installed and Welsh 2 is shut down. No need to examine a low control scenario for these units.

2.2. NOx, PM and Sulfuric Acid Emissions

NOx emissions were held constant at baseline emission levels for all emission units in order to isolate visibility improvements due to SO_2 reductions from any visibility benefits that would result from reductions in NOx emissions.

For the coal-fired EGUs evaluated with CALPUFF, we also evaluated a more recent baseline period (2011-2015) using the 2001-2003 CALMET data since some controls or reductions in emissions may have occurred due to federal rules and we wanted to provide additional information as part of the visibility benefit analysis. In these RNS (Recent NOx and SO2) CALPUFF runs, we used the recent maximum NOx emissions and held the NOx emissions constant for all runs to isolate visibility improvements due to SO_2 reductions from any visibility benefits that would result from reductions in NOx emissions.

For the high control scenarios for dry scrubbing and wet scrubbing retrofits, 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.

Speciated PM emissions for CALPUFF modeling were calculated using the National Park Service (NPS) speciation worksheets corresponding to dry bottom boilers and the emission control equipment present in each modeling scenario for the coal-fired boilers. PM speciation in the NPS worksheets is based on AP-42 Tables 1.1-5 and 1-1.6 (for dry-bottom boilers) and depends on the type of emission control equipment and the coal's sulfur and ash content. PM coarse, PM fine, soil, elemental carbon and SOA emissions were input into CALPUFF. See Appendix E of the BART Screening TSD for summary of coal properties utilized in these calculations.

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Consistent with the methodology used to estimate baseline sulfuric acid emissions for CALPUFF modeling described in the BART Screening TSD, control scenario estimates of H_2SO_4 emissions from the coal-fired units are based on the best current information available from 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 the Electric Power Research Institute (EPRI). 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. For further information about the baseline and control scenario H_2SO_4 emission rates used for CALPUFF modeling see Appendix D of this TSD.

For the RNS CALPUFF runs we adjusted the NOx and SO_2 to reflect more recent maximum emission rates for the recent baseline. We used the same speciated PM and sulfuric acid emission rates as the 2001-2004 baseline and the two control case scenarios. NOx emissions were held constant at the more recent baseline rate. For the actual emission rates used in the RNS baseline and two control scenarios see Appendix C.

2.3. Emissions reductions from Fuel Oil Switching

To evaluate the visibility benefit of switching to lower sulfur fuel oil for those subject-to-BART gas/fuel oil-fired units, we modeled estimated emissions for switching to 0.3% sulfur fuel oil and 0.0015% S fuel oil (ULSD). SO_2 emissions were calculated by multiplying the baseline rate by the ratio of control scenario sulfur content to baseline sulfur content of the fuel oil burned. NOx and PM emissions were held constant at baseline levels. We note that PM emissions from lower sulfur fuel oils are anticipated to be less than baseline levels but visibility impact from direct PM emissions are a very small portion of the overall visibility impact due to the sources emissions. Reducing the PM emissions for the control scenarios would result in slightly greater visibility benefits from fuel switching.[4] See the BART Screening TSD for additional information on estimates of maximum emissions for Stryker and Graham units used for baseline emissions for these units.

Table 2.3-1. CALPUFF Modeled SO_2 emissions: Gas/Fuel-fired Units

Source	Unit	Baseline Fuel oil Sulfur Content (%)[5]	SO_2 Emissions (lb/hr)		
			Baseline	High Control Scenario (0.0015% S)	Low Control Scenario (0.3% S)
Graham	2	0.69	3727.5	7.67	1620.65
Stryker	ST2	0.65	3604.9	7.88	1663.78

[4] See "gas-fired SO_2 emissions comparison and calcs.xlsx" for detailed emission calculations and BART FIP TSD for a summary of EIA data.
[5] Maximum reported fuel oil sulfur content from EIA-767 data for 2001-2004

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Wilkes	1	0.43	323.5	1.13	75.23*
Wilkes	2	NA	1.92	1.92	1.92
Wilkes	3	NA	1.83	1.83	1.83

*Modeled at 0.1% S fuel oil

3. Visibility Benefits of DSI, SDA, and Wet FGD for Coal-Fired Units

We evaluated the visibility benefits of DSI, for the twelve units below that currently have no SO_2 control. We evaluated all the units using the control levels we employed in our control cost analyses. In summary, we evaluated these units at a DSI SO_2 control level of 50%, which we believe is likely achievable for any unit. At the lower performance level we assumed, we conclude that the corresponding visibility benefits from DSI in most cases would be close to half of the benefits from scrubbers resulting in the visibility benefits from scrubber retrofits being much more beneficial. We also evaluated the visibility benefits for scrubber retrofits (wet FGD and SDA) for these same units, assuming the same control levels corresponding to SDA and wet FGD that we used in our control cost analyses. For those sources that are within 50 to 400 km of a Class I area, we utilized CALPUFF modeling and supplemented our analysis with CAMx modeling to assess the visibility benefit of potential controls. For the remaining coal-fired sources (J T Deely, Coleto Creek, Fayette and W A Parish), only CAMx modeling was utilized as these sources are located at much greater distances to the nearest Class I areas. 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.[6] We note that high control scenario modeling for Fayette units 1 and 2 demonstrate the benefit from existing high performing controls. As discussed elsewhere, we found that for these units no additional controls or upgrades were necessary. For a full discussion of our review of all the modeling results, and factors that we considered in evaluating and weighing all the results, see the following sections of this TSD. Below, we present a summary of some of those visibility benefits at the Class I areas most impacted by each source:

Table 3-1. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CAMx modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Unit 1 and 2)	WIMO	Max dv	4.017	2.249	0.474	1.768	3.542
			Days > 0.5 dv	65	33	0	32	65
			Days>1.0 dv	33	13	0	20	33

[6] 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."

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		CACR	Max dv	3.775	2.539	0.787	1.236	2.988
			Days > 0.5 dv	91	62	4	29	87
			Days>1.0 dv	57	21	0	36	57
	Unit 1	WIMO	Max dv	2.154	1.168	0.245	0.986	1.909
			Days > 0.5 dv	33	13	0	20	33
			Days>1.0 dv	12	1	0	11	12
		CACR	Max dv	2.016	1.327	0.409	0.688	1.606
			Days > 0.5 dv	58	22	0	36	58
			Days>1.0 dv	17	4	0	13	17
	Unit 2	WIMO	Max dv	2.175	1.181	0.235	0.994	1.940
			Days > 0.5 dv	34	13	0	21	34
			Days>1.0 dv	12	1	0	11	12
		CACR	Max dv	2.033	1.338	0.391	0.695	1.642
			Days > 0.5 dv	58	23	0	35	58
			Days>1.0 dv	17	4	0	13	17
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63
			Days>1.0 dv	40	14	0	26	40
	Unit 1	CACR	Max dv	4.516	3.123	0.733	1.393	3.783
			Days > 0.5 dv	79	43	3	36	76
			Days>1.0 dv	32	16	0	16	32
		WIMO	Max dv	2.241	1.290	0.252	0.951	1.989
			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	8	2	0	6	8
	Unit 2	CACR	Max dv	4.487	3.065	0.563	1.422	3.924

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			Days > 0.5 dv	78	42	1	36	77
			Days>1.0 dv	30	13	0	17	30
		WIM O	Max dv	2.189	1.252	0.186	0.937	2.003
			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	6	2	0	4	6
Coleto Creek	Source (Unit 1)	WIM O	Max dv	0.845	0.526	0.176	0.318	0.668
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.791	0.458	0.186	0.333	0.606
			Days > 0.5 dv	5	0	0	5	5
			Days>1.0 dv	0	0	0	0	0
Harrington	Source (Unit 061B & 062B)	SACR	Max dv	5.288	4.287	3.235	1.001	2.053
			Days > 0.5 dv	13	7	3	6	10
			Days>1.0 dv	5	1	1	4	4
		WIM O	Max dv	4.928	4.362	3.798	0.565	1.130
			Days > 0.5 dv	15	11	6	4	9
			Days>1.0 dv	6	5	4	1	2
	Unit 061B	SACR	Max dv	2.908	2.322	1.738	0.586	1.170
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIM O	Max dv	2.708	2.382	2.065	0.326	0.643
			Days > 0.5 dv	6	5	4	1	2
			Days>1.0 dv	4	2	1	2	3
	Unit 062B	SACR	Max dv	2.998	2.373	1.719	0.625	1.279
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIM O	Max dv	2.770	2.407	2.046	0.363	0.723

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			Days > 0.5 dv	6	5	4	1	2
			Days>1.0 dv	4	1	1	3	3
JT Deely	Source (Sommers 1&2, JTDeely 1&2)	WIMO	Max dv	1.513	0.939	0.814	0.574	0.699
			Days > 0.5 dv	47	8	1	39	46
			Days>1.0 dv	6	0	0	6	6
		CACR	Max dv	1.423	1.155	0.905	0.268	0.518
			Days > 0.5 dv	7	3	2	4	5
			Days>1.0 dv	2	1	0	1	2
	JT Deely 1	WIMO	Max dv	0.757	0.449	0.270	0.307	0.487
			Days > 0.5 dv	4	0	0	4	4
			Days>1.0 dv	0	0	0	0	0
		BIBE	Max dv	0.652	0.373	0.069	0.279	0.583
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
	JT Deely 2	WIMO	Max dv	0.632	0.387	0.334	0.245	0.298
			Days > 0.5 dv	3	0	0	3	3
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.604	0.490	0.387	0.114	0.217
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
W.A. Parish	Source (WAP 4,5, &6)	CACR	Max dv	3.177	2.032	0.511	1.145	2.665
			Days > 0.5 dv	54	26	1	28	53
			Days>1.0 dv	22	9	0	13	22
		UPBU	Max dv	1.994	1.215	0.234	0.779	1.760
			Days > 0.5 dv	34	14	0	20	34
			Days>1.0 dv	9	1	0	8	9
	WAP 5	CACR	Max dv	1.698	1.052	0.180	0.646	1.518

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			Days > 0.5 dv	22	9	0	13	22
			Days>1.0 dv	8	1	0	7	8
		UPBU	Max dv	1.038	0.613	0.094	0.424	0.943
			Days > 0.5 dv	11	1	0	10	11
			Days>1.0 dv	1	0	0	1	1
	WAP 6	CACR	Max dv	1.648	1.018	0.156	0.630	1.492
			Days > 0.5 dv	22	8	0	14	22
			Days>1.0 dv	6	1	0	5	6
		UPBU	Max dv	1.003	0.591	0.081	0.412	0.922
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	1	0	0	1	1
Welsh	Source (Unit 1 & 2)	CACR	Max dv	4.576		0.822		3.754
			Days > 0.5 dv	92		3		89
			Days>1.0 dv	39		0		39
		MING	Max dv	2.544		0.570		1.973
			Days > 0.5 dv	9		1		8
			Days>1.0 dv	3		0		3
	Unit 1	CACR	Max dv	2.343	1.659	0.822	0.684	1.521
			Days > 0.5 dv	37	18	3	19	34
			Days>1.0 dv	8	3	0	5	8
		MING	Max dv	1.150	0.886	0.570	0.264	0.579
			Days > 0.5 dv	2	1	1	1	1
			Days>1.0 dv	1	0	0	1	1
Fayette	Source (Unit 1 & 2)	CACR	Max dv	1.894		0.903		0.991
			Days > 0.5 dv	26		2		24
			Days>1.0 dv	9		0		9
		WIMO	Max dv	1.175		0.580		0.595

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			Days > 0.5 dv	19		1		18
			Days>1.0 dv	2		0		2
	Unit 1	CACR	Max dv	1.002		0.480		0.522
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	1		0		1
		WIMO	Max dv	0.609		0.306		0.302
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0
	Unit 2	CACR	Max dv	0.974		0.441		0.534
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	0		0		0
		WIMO	Max dv	0.598		0.282		0.316
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0

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Table 3-2. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Units 1 and 2)	WIMO	Max dv	4.27	2.54	0.43	1.73	3.83
			Days > 0.5 dv Avg.	67.33	43.33	2.67	24.00	64.67
			Days>1.0 dv Avg.	42.00	21.00	1.00	21.00	41.00
		CACR	Max dv	4.03	2.41	0.47	1.62	3.55
			Days > 0.5 dv Avg.	91.67	64.33	4.67	27.33	87.00
			Days>1.0 dv Avg.	60.33	30.00	0.00	30.33	60.33
Monticello [1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	3.68	1.70	4.16	4.87
			Days > 0.5 dv Avg.	143.67	115.00	62.33	28.67	81.33
			Days>1.0 dv Avg.	113.00	66.33	23.67	46.67	89.33
		UPBU [4]	Max dv	3.45	1.77	0.77	1.68	2.68
			Days > 0.5 dv Avg.	103.00	61.00	13.67	42.00	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60.00	34.67	6.00	25.33	54.00
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67
Harrington [2]	Source (Units 061B & 062B)	SACR	Max dv	1.06	0.86	0.61	0.20	0.45
			Days > 0.5 dv Avg.	21.00	15.33	6.33	5.67	14.67
			Days>1.0 dv Avg.	6.67	3.00	0.67	3.67	6.00
		WIMO	Max dv	1.29	0.97	0.55	0.32	0.74
			Days > 0.5 dv Avg.	26.00	15.33	8.67	10.67	17.33
			Days>1.0 dv Avg.	9.00	4.67	1.33	4.33	7.67

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Welsh[3]	Source (Unit 1)	CACR	Max dv	1.44	1.12	0.72	0.32	0.72
			Days > 0.5 dv Avg.	50.33	32.67	12.33	17.67	38
			Days>1.0 dv Avg.	15.33	8.00	2.33	7.33	13.00
		UPBU	Max dv	0.76	0.49	0.22	0.27	0.54
			Days > 0.5 dv Avg.	12.00	4.67	0.33	7.33	11.67
			Days>1.0 dv Avg.	0.67	0.00	0.00	0.67	0.67
		WIMO	Max dv	0.56	0.33	0.15	0.23	0.41
			Days > 0.5 dv Avg.	7.33	2.67	0.33	4.67	7.00
			Days>1.0 dv Avg.	1.33	0.33	0.00	1.00	1.33

[1] Monticello's controlled level is a combination of scrubber upgrades and scrubber install in the facility impact modeling with CALPUFF.
[2] Harrington high control scenario for both units is SDA at 95% reduction
[3] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.
[4] UPBU = Upper Buffalo Wilderness Area.

Based on the information presented here, we find that installing either wet FGD or SDA scrubbers on these units would yield significant visibility improvements. Below we provide additional analysis of visibility modeling results for each unit.

4. Visibility Benefit Analysis of DSI, SDA, and wet FGD

CALPUFF[7] and CAMx model results[8,9] shown in the tables below summarize the benefits from the recommended controls at the two Class I areas most impacted by the source or unit in the baseline modeling. As previously discussed and also in the BART Screening TSD, we have utilized CALPUFF for sources within the typical range of CALPUFF. We conducted CALPUFF and CAMx modeling to evaluate the visibility benefits for DSI, SDA, and WFGD but are only explicitly reporting the visibility benefits for the proposed BART level in this TSD. For the visibility benefits for the other potential emission rate/control levels not proposed for BART modeled with CALPUFF, see the spreadsheets that include CALPUFF results listed in the footnotes for this paragraph. For the visibility benefits for the other potential emission

[7] See spreadsheets: "TX_CALPOST_coal_all.xlsx", "TX_CALPOST_coal_RNS_all.xlsx", and "TX_CALPOST_NG-FO_all.xlsx" in the docket for this action for these and additional model results.
[8] See spreadsheet: "summary CAMx vis daily.xlsx" in the docket for this action for these and additional model results.
[9] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for summary of base case model results, including species specific 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.

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rate/control levels not proposed for BART modeled with CAMx, see the figures in the following sections, Appendix E and F, and the spreadsheets that include CAMx results listed in the footnotes for this paragraph.

For the CALPUFF and CAMx modeling, the benefit is calculated as the difference between the maximum impact modeled for the baseline and the maximum impact level modeled under the control scenario and provided in tables for each facility/subsection below. Also summarized are the cumulative benefit and the number of days impacted over 0.5 and 1.0 dv (CALPUFF and CAMx). 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 E for CAMx modeled maximum impact at each Class I area for each model scenario. See Appendix F for CAMx modeled number of days over 0.5 and 1.0 dv at each Class I area for each model scenario.

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 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. The figures in each subsection below show unit-level model results for the base case (Run 1) and the two control scenarios (Run 3 and Run 4) modeled for all unscrubbed units. The low control scenario (Run 4) estimates the visibility impacts and benefits from DSI level controls at 50% for unscrubbed units. The high control scenario (Run 3) estimates visibility impacts and benefits for WFGD/SDA level controls at unscrubbed units. For each unscrubbed unit, there are four figures. The first figure shows the maximum CAMx modeled impact at each Class I area for each modeled scenario, consistent with the data in the tables above. The second figure provides 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. The third figure provides an assessment of 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.[10] Finally, the fourth figure shows the contribution to extinction from the unit due to each

[10] See spreadsheet: "summary CAMx vis daily.xlsx" in the docket for this action for these and additional model

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visibility impairing species[11] 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.[12]

4.1. Big Brown 1 & 2

In reviewing the Big Brown units, we conclude that the installation of wet FGD will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.1-1a. Wet FGD Visibility Benefits at Big Brown (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Big Brown Units 1 & 2	3.83	3.55	7.38	151.67	101.33

Table 4.1-1b. Wet FGD Visibility Benefits at Big Brown RNS {2011-2015} (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Big Brown Units 1 & 2	3.205	2.97	6.175	138.33	83

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek and Wichita Mountains
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek and Wichita Mountains.

results.
[11] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)
[12] 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.

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In evaluating Big Brown, we note there are two Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results, we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the two Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate that wet FGD on both units will eliminate 151.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the visibility benefits in terms of dv benefits at the most impacted Class I areas and about 1/3rd to half the cumulative benefits over the class I areas included in the modeling analysis. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to wet FGD levels.

Table 4.1-2. Wet FGD Visibility Benefits at Big Brown (CAMx)

Unit	Improvement at Wichita mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Big Brown 1	1.909	1.606	12.728	174 / 44	174 / 44
Big Brown 2	1.940	1.642	12.924	175 / 45	175 / 45
Source	3.542	2.988	24.274	372 / 170	362 / 170

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv at all Class I areas on a unit- and source-wide basis, and eliminate all but 10 days across the impacted Class I areas where the source-wide impacts exceeds 0.5 dv. At the most impacted Class I area, wet FGD on each unit result in visibility improvements of 1.9 dv each on the most impacted day. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the CAMx modeling. Figures 4.1-1 (unit 1) and 4.1-5 (unit 2) below show the

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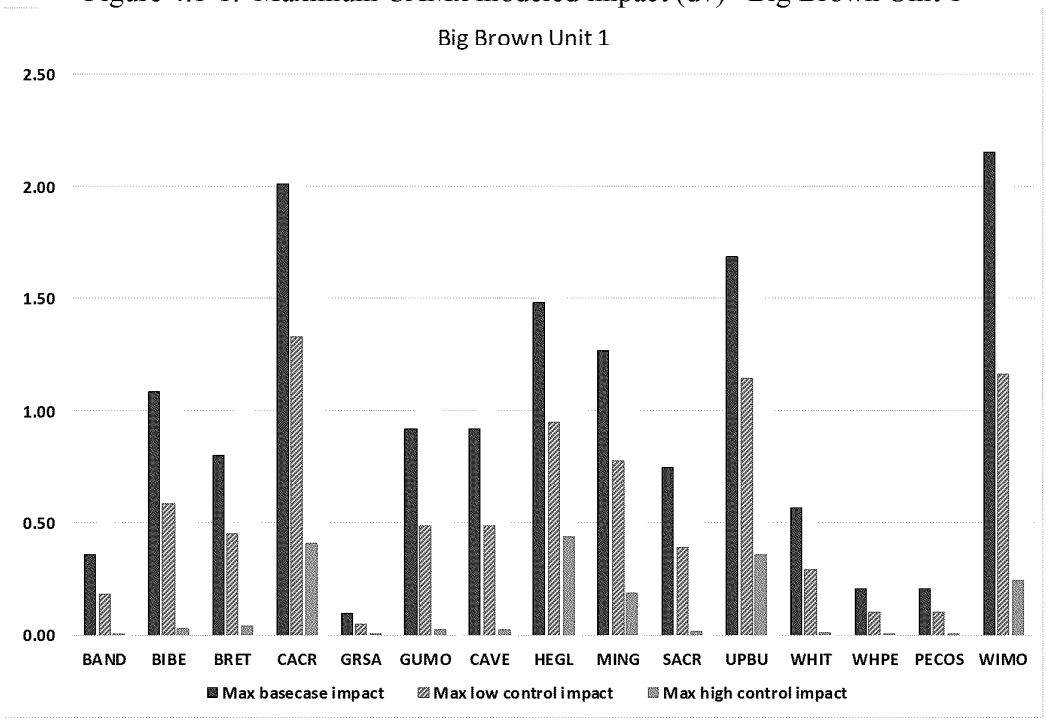
maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figures 4.1-2 and 4.1-6). At the most impacted Class I area, wet FGD on each unit results in visibility improvements of 1.4 dv on average across the top ten most impacted days, and approximately 1.3 dv at the second most impacted Class I area for each unit. Figures 4.1-3 and 4.1-7 show an assessment of the annual average impacts and benefits under the control scenarios.[13] Wet FGD reduces annual average base case impacts from each unit at each Class I area by over 90% while DSI reduces annual average impacts at each Class I area by 50% or less. On average across all Class I areas, Wet FGD results in a 95% reduction in annual average visibility impacts from each unit. Figures 4.1-4 and 4.1-8 show the contribution to extinction from the units due to each visibility impairing species[14] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Wichita Mountains and Caney Creek) for the base case modeling scenario.[15] These figures show that the impacts from the Big Brown units on these days are primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to these units.

Figure 4.1-1. Maximum CAMx modeled impact (dv)– Big Brown Unit 1



[13] 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 at each Class I area with impacts greater than 0.1 dv.

[14] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[15] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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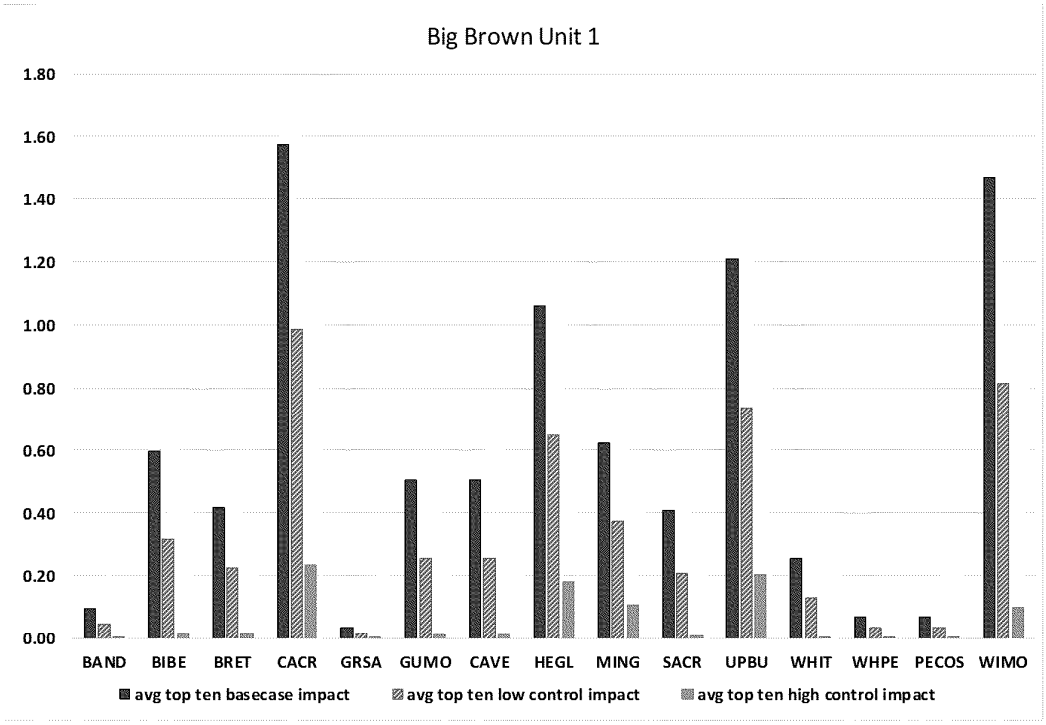

Figure 4.1-2. Average of top ten CAMx modeled impact (dv) – Big Brown Unit 1

Figure 4.1-3. Annual Average CAMx modeled impact (dv) excluding baseline days impacted less than 0.1 dv – Big Brown Unit 1

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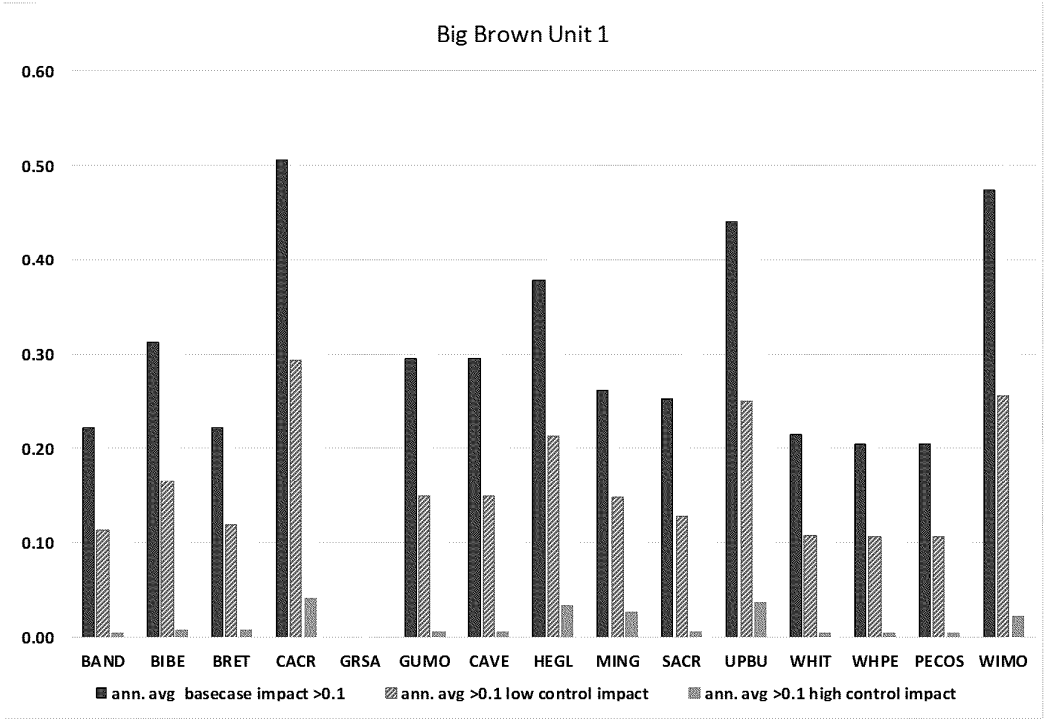

Figure 4.1-4. Species Contribution (Mm-1) on ten highest impact days (base case) at two most impacted Class I areas – Big Brown Unit 1

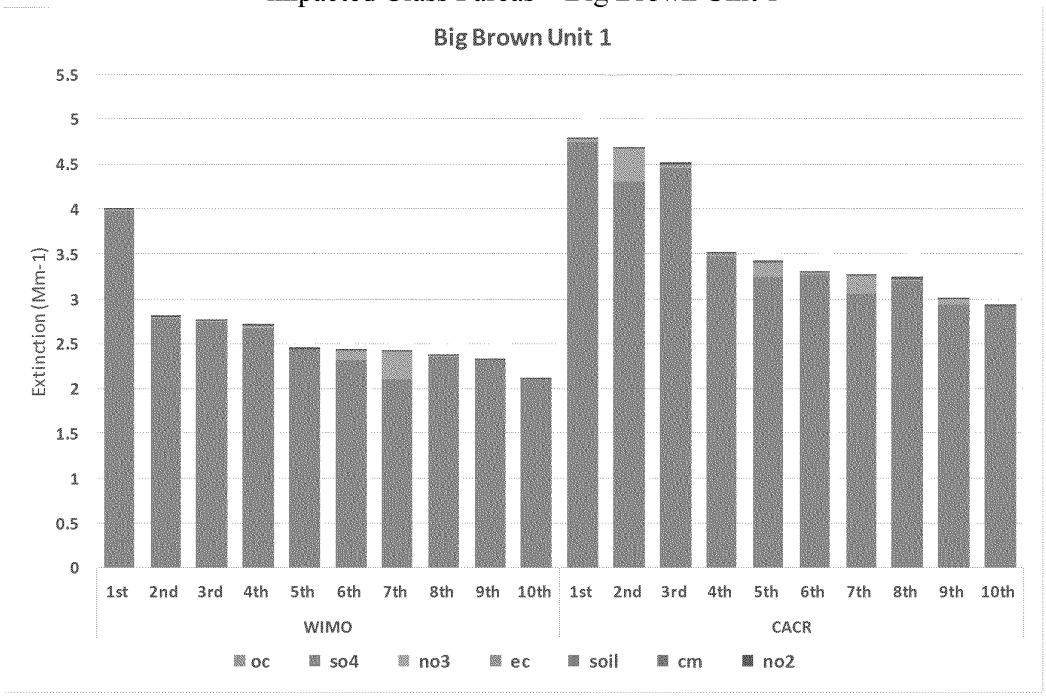

Figure 4.1-5. Maximum CAMx modeled impact (dv) – Big Brown Unit 2

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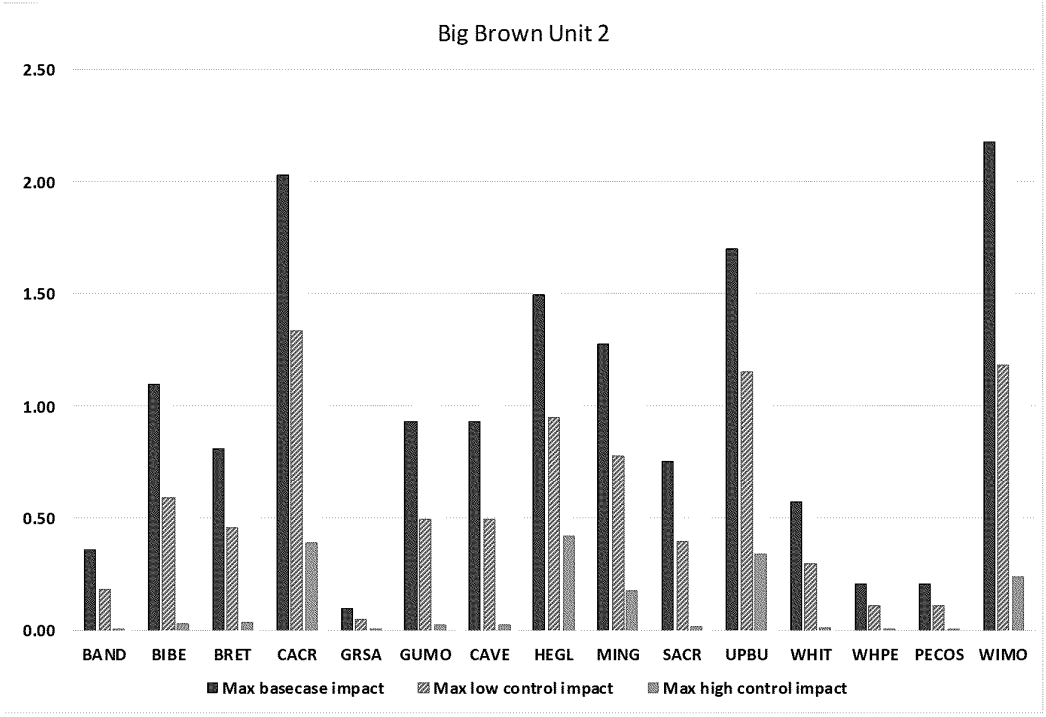


Figure 4.1-6. Average of top ten CAMx modeled impact (dv) – Big Brown Unit 2

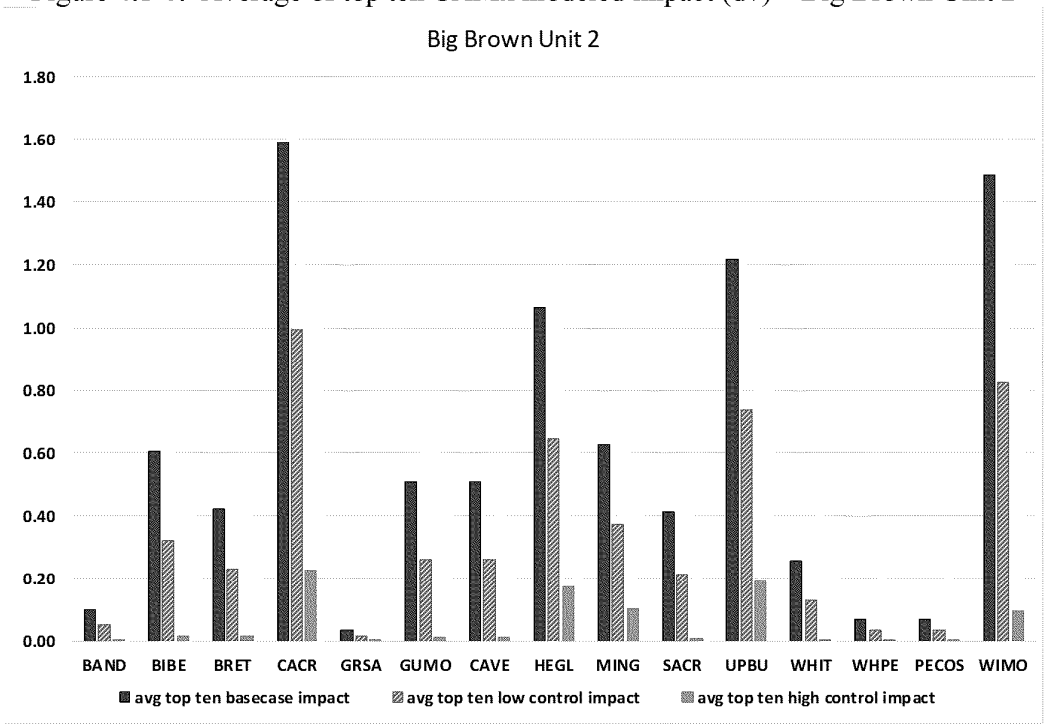


Figure 4.1-7. Annual Average CAMx modeled impact excluding baseline days impacted (dv) less than 0.1 dv – Big Brown Unit 2

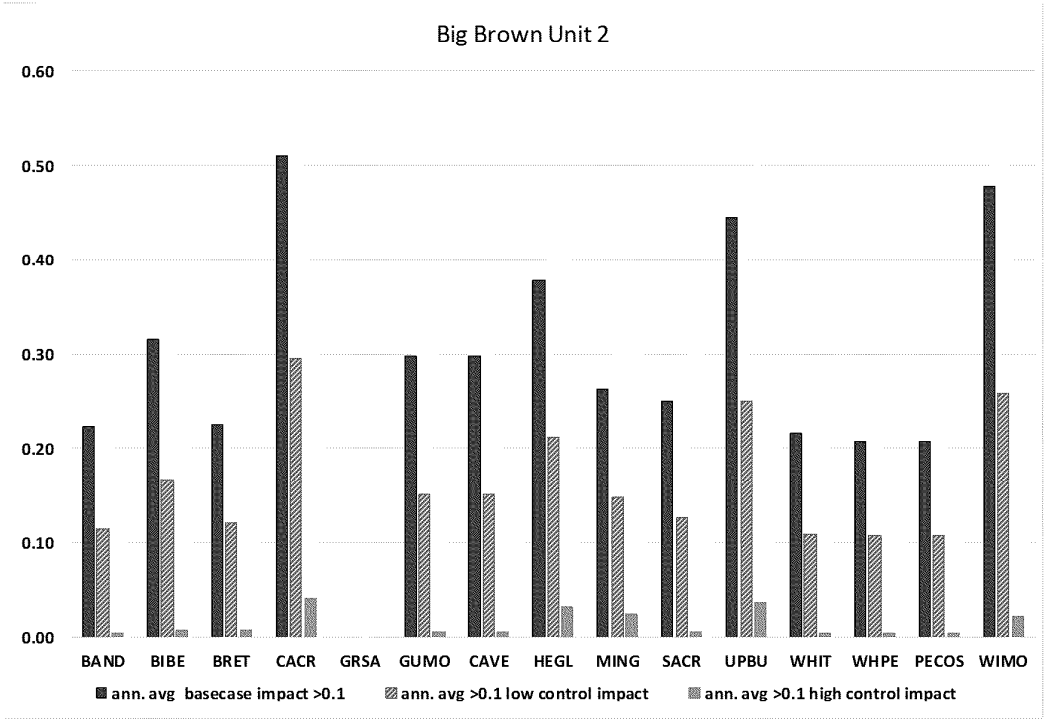
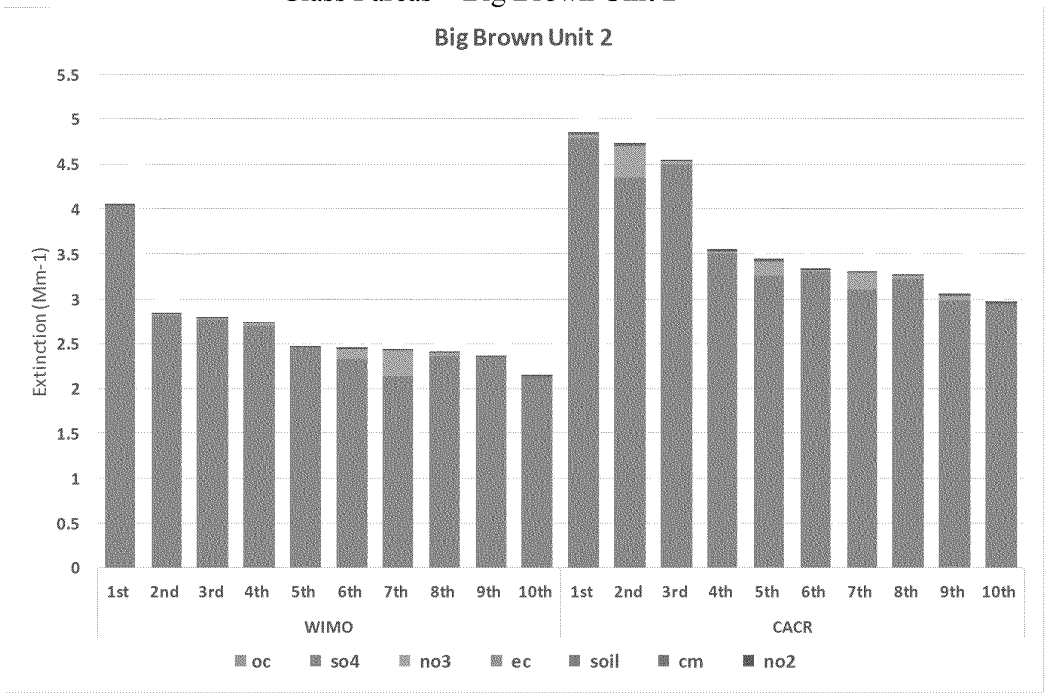


Figure 4.1-8. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Big Brown Unit 2



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4.2. Monticello 1 & 2

Similar to the Big Brown units, the installation of wet FGD at Monticello Units 1 and 2 will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.2-1a. Wet FGD Visibility Benefits at Monticello (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	4.87	2.70	10.25	224.67	164.67

Table 4.2-1b. Wet FGD Visibility Benefits at Monticello with Scrubber Upgrade on Unit 3 RNS {2011-2015} (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	3.67	1.88	7.37	201.33	147

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Monticello, we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario

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subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 224.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 13 class I areas included in the CAMx modeling. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to wet FGD levels.

Table 4.2-2. Wet FGD Visibility Benefits at Monticello (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 1	3.783	1.989	12.708	197 / 67	191 / 67
Monticello 2	3.924	2.003	13.025	192 / 57	191 / 57
Source (including unit 3)	8.419	4.962	31.553	520 / 293	460 / 278

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1 dv at all Class I areas on a unit basis, and eliminate all but 15 days across the impacted Class I areas where the source-wide impacts exceeds 1 dv. We note that source-wide modeled benefits include benefits of 95% control scrubber upgrade on Unit 3. At the most impacted Class I area, wet FGD on each unit will each result in visibility improvements of 3.8-3.9 dv on the most impacted day at Caney Creek and 2 dv visibility benefits at Wichita Mountains. DSI operated at 50% control results in less than half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. Figures 4.2-1 (unit 1) and 4.2-5 (unit 2) below show the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figures 4.2-2 and 4.2-6). At the most impacted Class I area, wet FGD on

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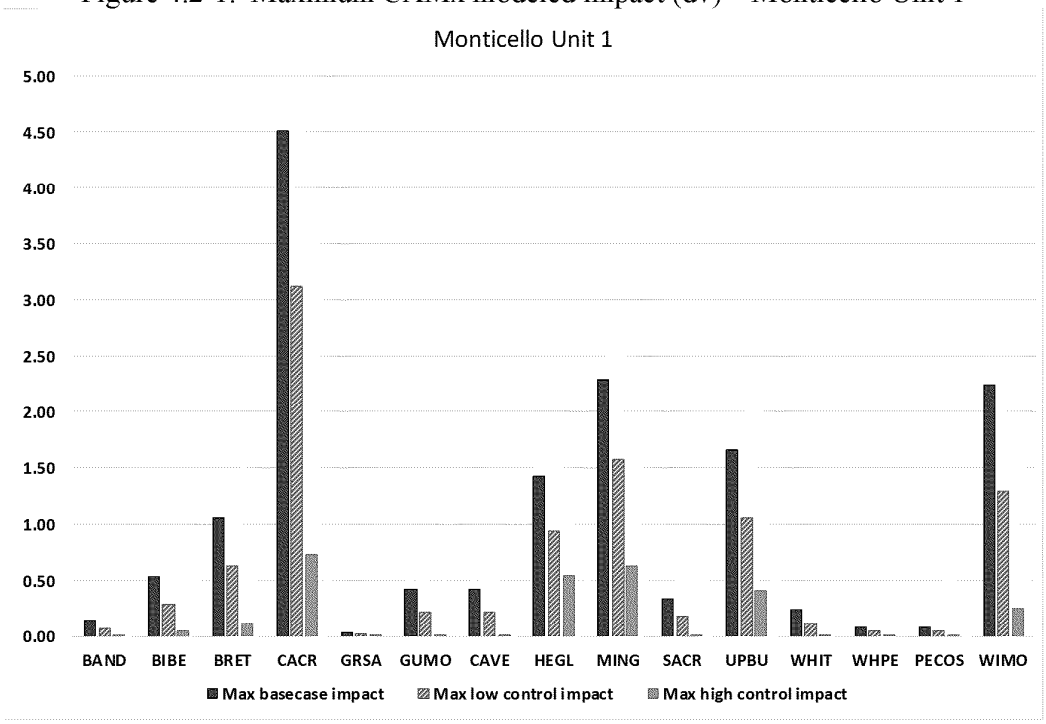
each unit results in visibility improvements of 1.8 dv on average across the top ten most impacted days, and approximately 1.3 dv at the second most impacted Class I area for each unit. Figures 4.1-3 and 4.1-7 show an assessment of the annual average impacts and benefits under the control scenarios.[16] Wet FGD reduces annual average base case impacts from each unit by 84% or more at each Class I area, while DSI at 50% emission reduction reduces annual average impacts at each Class I area by 50% or less. On average across all Class I areas, wet FGD results in a 91% reduction in annual average visibility impacts from each unit. Figures 4.2-4 and 4.2-8 show the contribution to extinction from the units due to each visibility impairing species[17] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Caney Creek and Wichita Mountains) for the base case modeling scenario.[18] These figures show that the impacts from the Monticello units 1 and 2 on these days are primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to these units.

Figure 4.2-1. Maximum CAMx modeled impact (dv) – Monticello Unit 1



[16] 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 at each Class I area with impacts greater than 0.1 dv.

[17] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[18] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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Figure 4.2-2. Average of top ten CAMx modeled impact (dv) – Monticello Unit 1

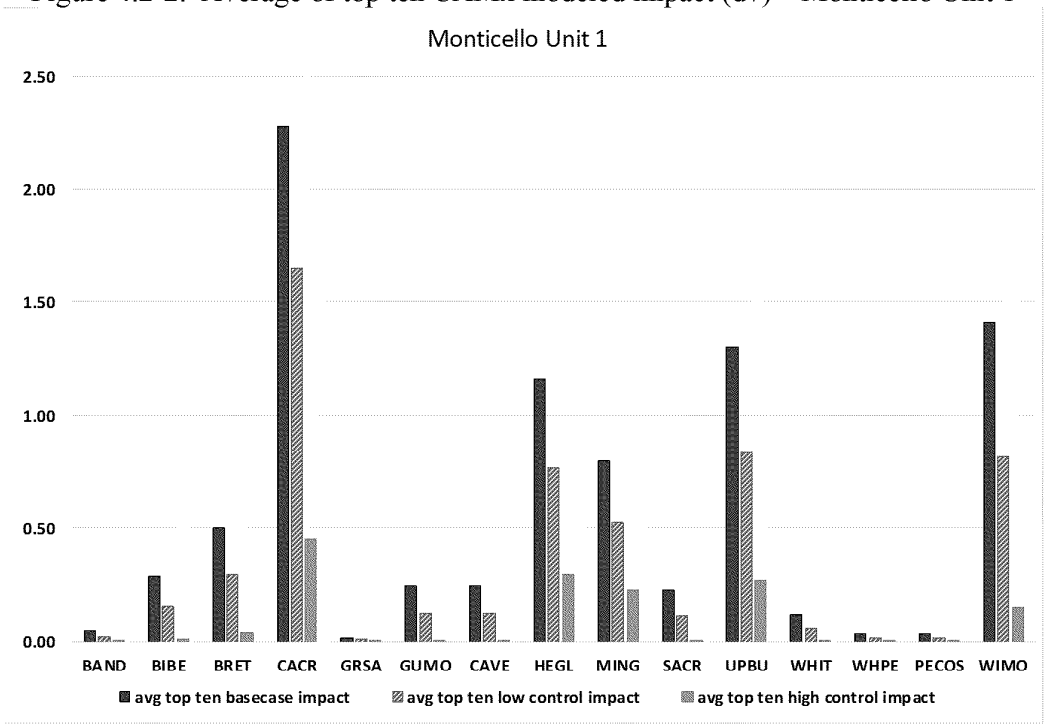

Figure 4.2-3. Annual Average CAMx modeled impact (dv) excluding baseline days impacted less than 0.1 dv – Monticello Unit 1

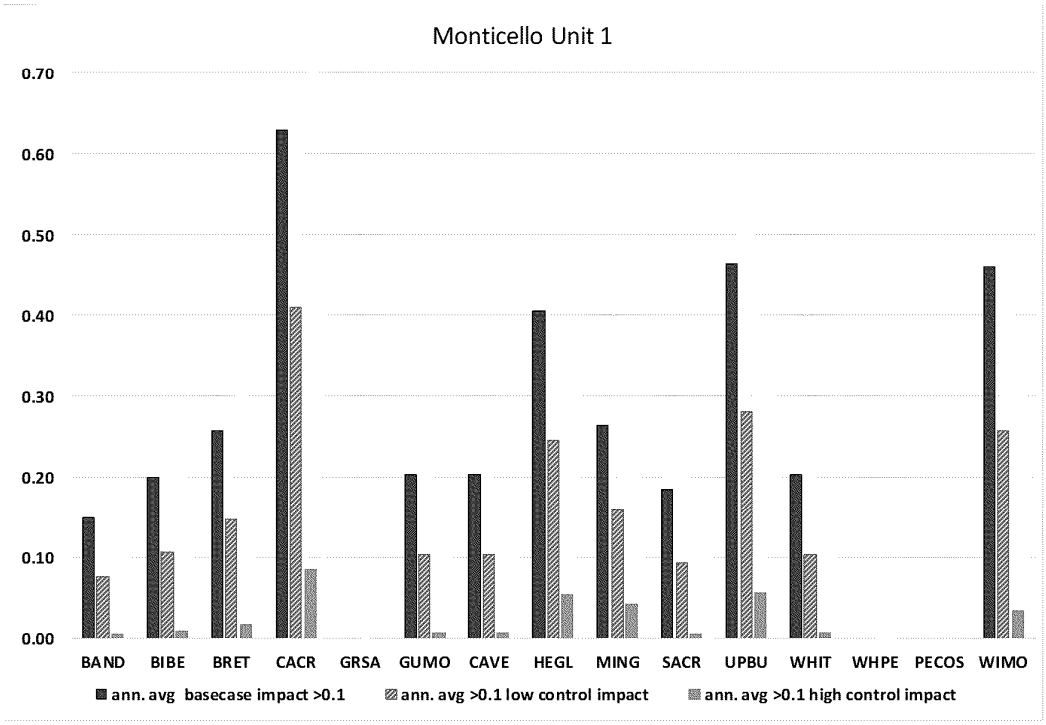

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Figure 4.2-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Monticello Unit 1

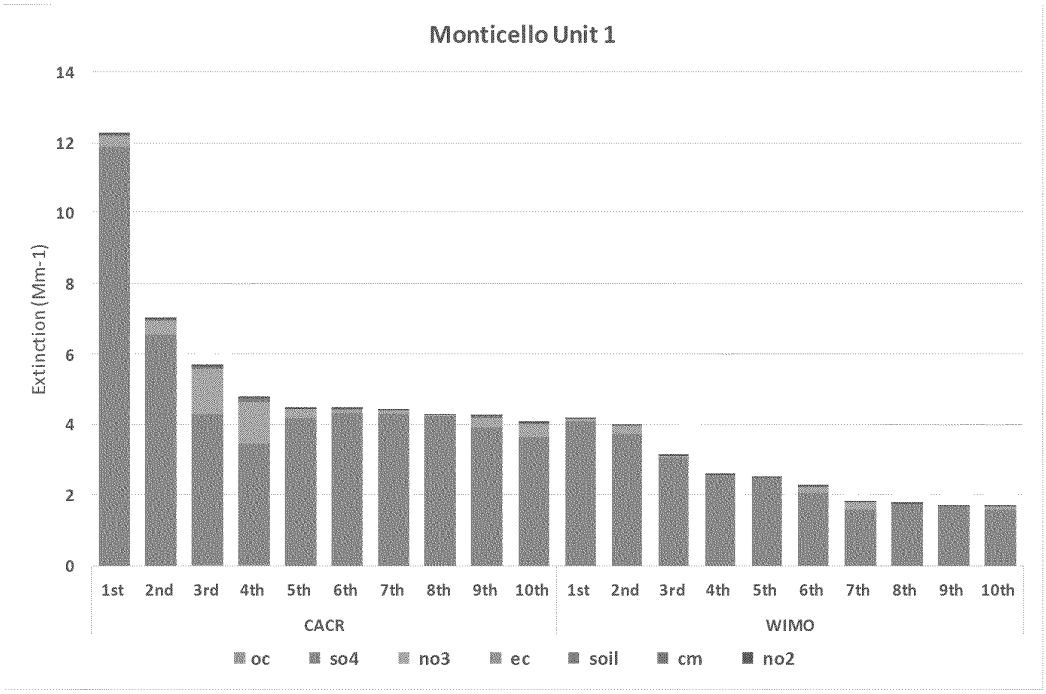

Figure 4.2-5. Maximum CAMx modeled impact (dv) – Monticello Unit 2

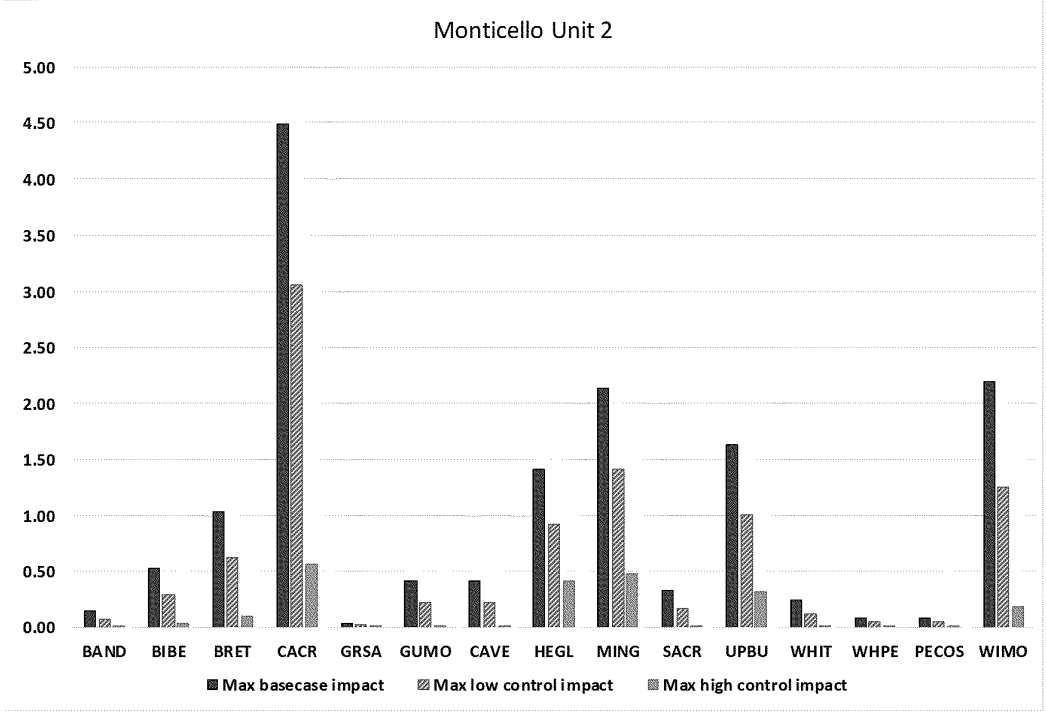

Figure 4.2-6. Average of top ten CAMx modeled impact (dv) – Monticello Unit 2

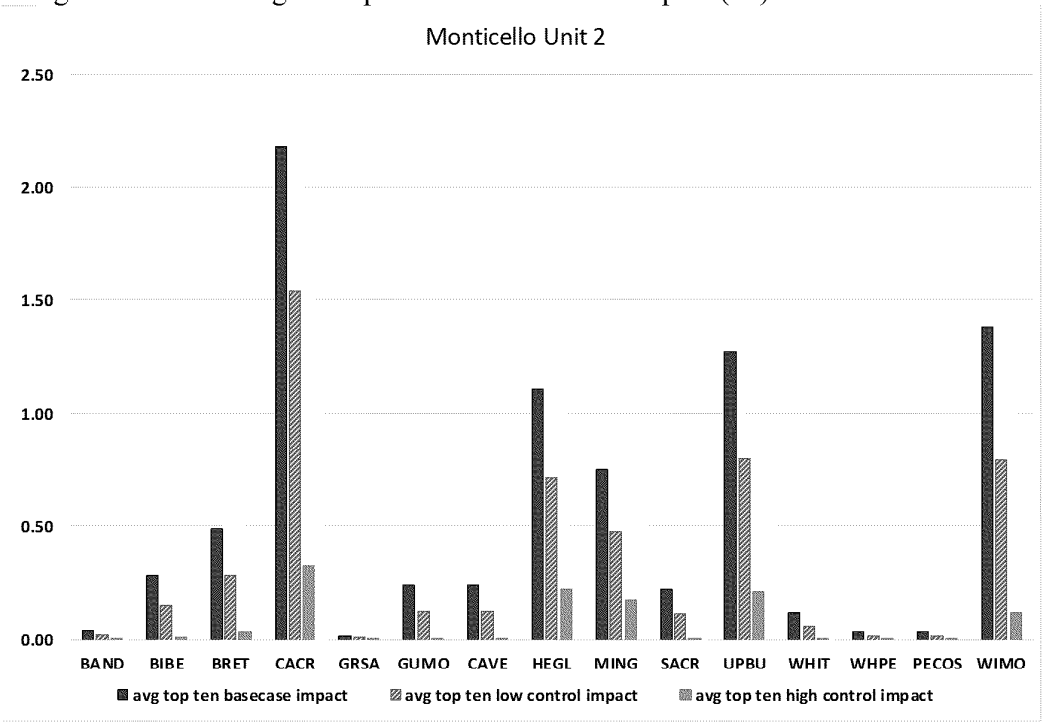

Figure 4.2-7. Annual Average CAMx modeled impact (dv) excluding baseline days impacted less than 0.1 dv – Monticello Unit 2

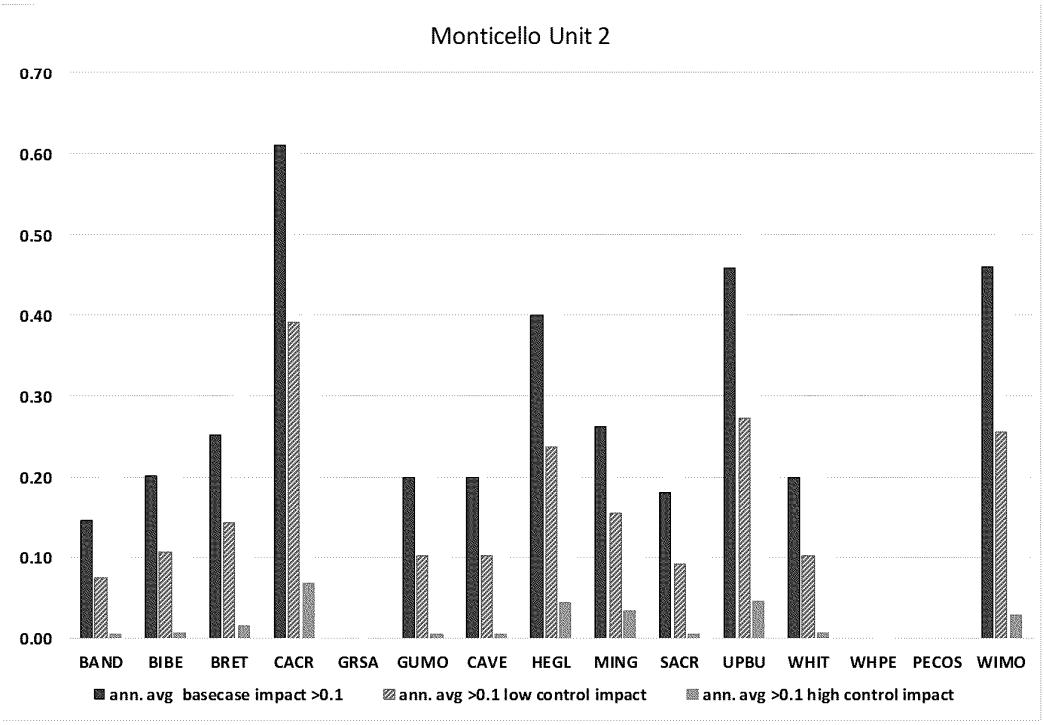

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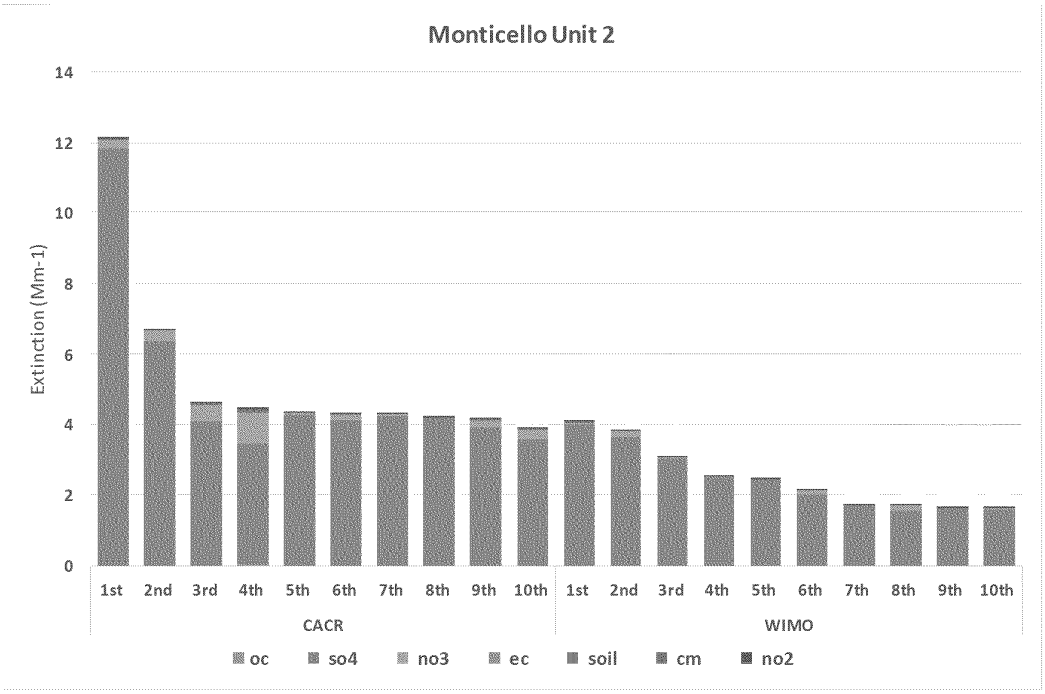
Figure 4.2-8. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Monticello Unit 2



4.3. Coleto Creek 1

In reviewing Coleto Creek Unit 1, we conclude that in comparison with the Monticello units, the installation of a wet FGD is more cost-effective and results in lesser, but still significant visibility benefits. We summarize some of these visibility benefits in the table below:

Table 4.3-1. Wet FGD Visibility Benefits at Coleto Creek Unit 1 (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Coleto Creek 1	0.668	0.606	5.233	17 / 0	17 / 0

[1] 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

[2] 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

[3] 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.

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CAMx modeling results indicate that wet FGD will eliminate all days impacted over 0.5 dv at all Class I areas. At the most impacted Class I area, wet FGD will result in visibility improvements of 0.6 or more on the most impacted days at both Caney Creek and the Wichita Mountains. In addition, seven other Class I areas are improved by amounts ranging from 0.356 to 0.531 dv on the maximum impacted days with wet FGD. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. Figure 4.3-1 below shows the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figure 4.3-2). At the most impacted Class I area, wet FGD results in visibility improvements of 0.53 dv on average across the top ten most impacted days, and approximately 0.41 dv at the second most impacted Class I area. Figure 4.3-3 shows an assessment of the annual average impacts and benefits under the control scenarios.[19] Wet FGD reduces annual average base case impacts by 76% to 95% depending on the Class I area, while DSI at 50% emission reduction reduces annual average impacts at each Class I area by 50% or less. At the most impacted Class I area (Wichita Mountains), wet FGD results in a 90% reduction in annual average visibility impacts, compared to a 46% reduction with DSI. On average across all Class I areas, wet FGD results in a 91% reduction in annual average visibility impacts. Figure 4.3-4 shows the contribution to extinction due to each visibility impairing species[20] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Caney Creek and Wichita Mountains) for the base case modeling scenario.[21] This figure shows that the impacts from Coleto Creek Unit 1 on these days are primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to this unit at these Class I areas.

[19] 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 at each Class I area with impacts greater than 0.1 dv.

[20] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[21] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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Figure 4.3-1. Maximum CAMx modeled impact (dv) – Coleto Creek Unit 1

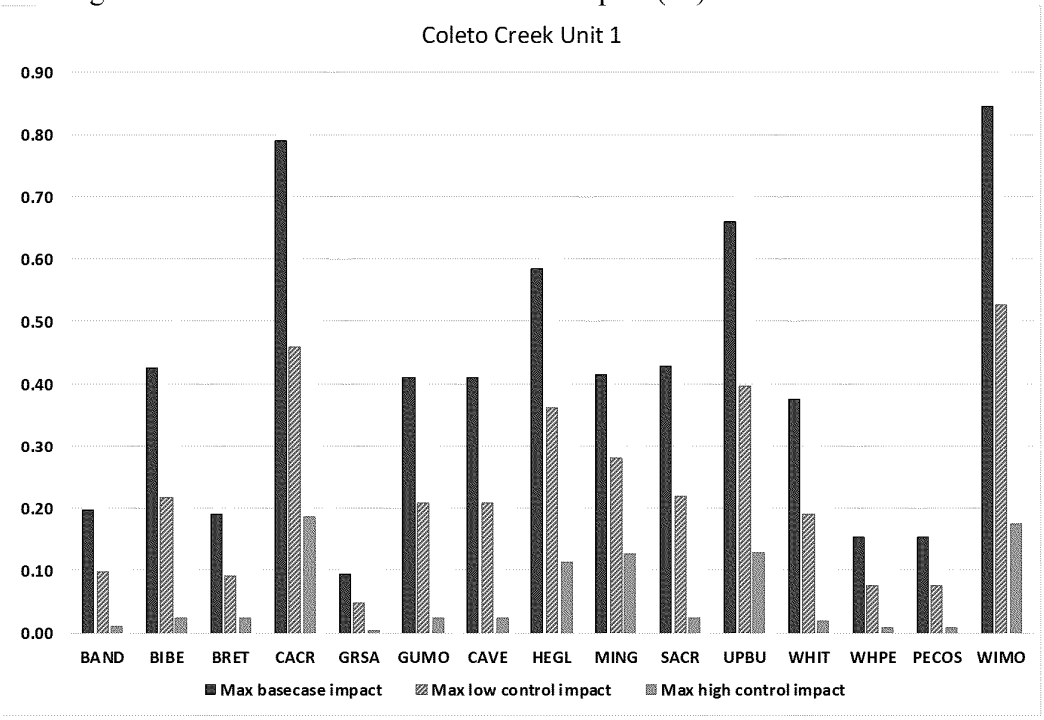

Figure 4.3-2. Average of top ten CAMx modeled impact (dv) – Coleto Creek Unit 1

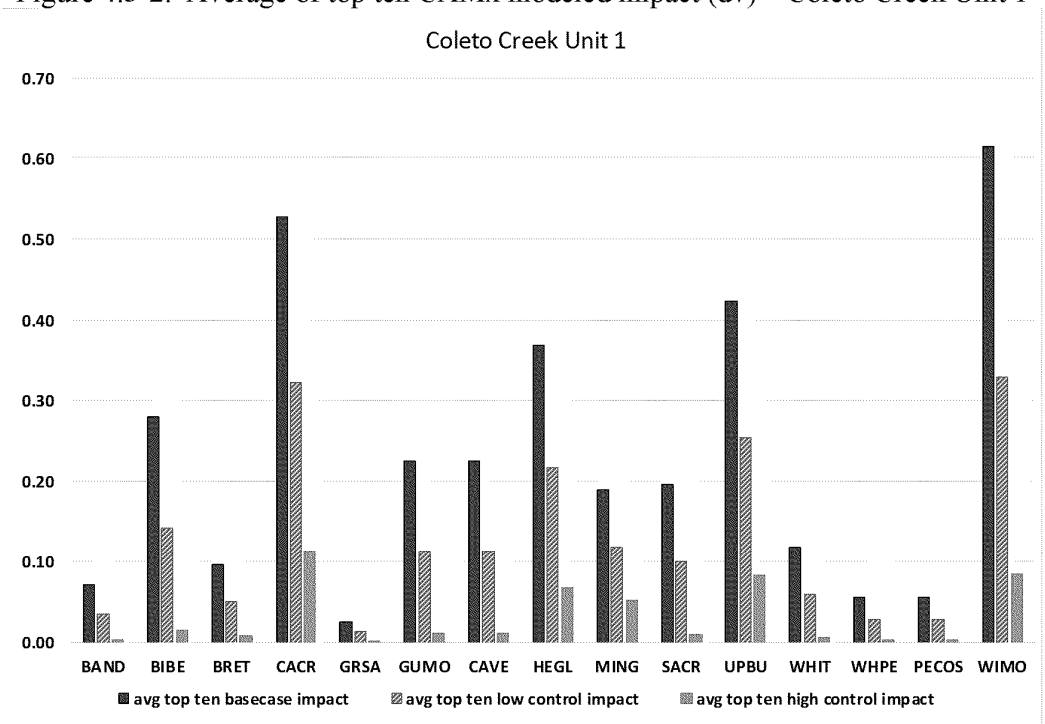

Figure 4.3-3. Annual Average CAMx modeled impact (dv) excluding baseline days impacted

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less than 0.1 dv – Coleto Creek Unit 1

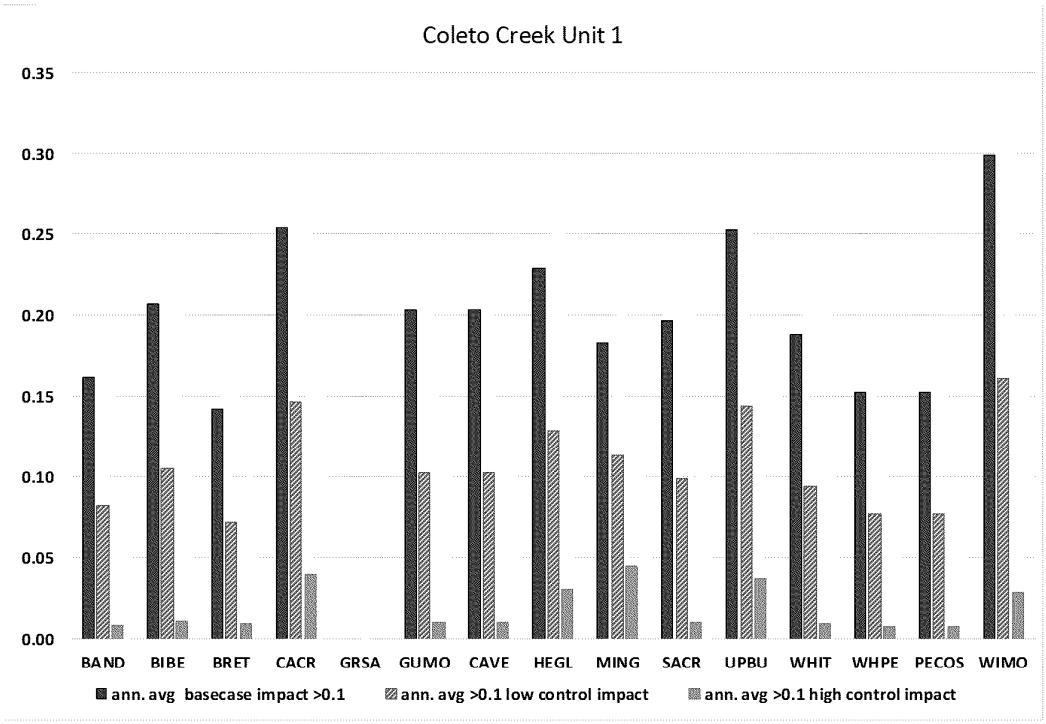
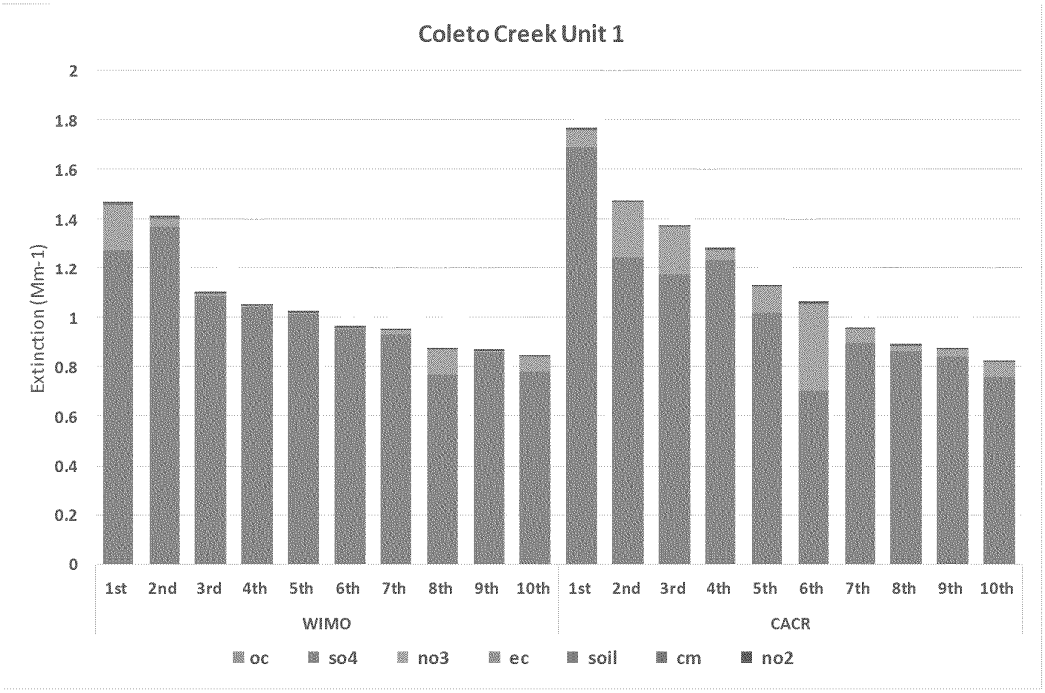


Figure 4.3-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Coleto Creek Unit 1



4.4. Welsh 1

In reviewing Welsh Unit 1, we conclude that the installation of a wet FGD will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.4-1a. Wet FGD Visibility Benefits at Welsh Unit 1 (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Welsh 1	0.72	0.41	1.66	56.67	15

Table 4.4-1b. Wet FGD Visibility Benefits at Welsh RNS {2011-2015} (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Welsh 1	.464	.231	1.05	34	6.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Welsh we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF

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modeling results indicate wet FGD on both units will eliminate 56.67 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to wet FGD levels.

Table 4.4-2. Wet FGD Visibility Benefits at Welsh Unit 1 (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Mingo Wilderness (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Welsh 1	1.521	0.579	4.683	65 / 9	60 / 9
Source (Welsh 1 & 2)	3.754	1.973	13.179	211 / 72	206 / 72

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD on unit 1 will eliminate all days impacted by the unit over 1 dv at all Class I areas and all but 5 days impacted over 0.5 dv. At the most impacted Class I area, wet FGD on unit 1 will result in visibility improvements of 1.521 dv on the most impacted days at Caney Creek. In addition to the visibility benefits at Caney Creek and Mingo, visibility benefits at two additional Class I areas exceed 0.5 dv. We note that source-wide benefits shown include the benefits from the shutdown of unit 2. In addition, cumulative benefits from wet FGD on unit 1 over all 15 Class I areas exceeds 4.5 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. Figure 4.4-1 below shows the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figure 4.4-2). At the most impacted Class I area, wet FGD results in visibility improvements of 0.8 dv on average across the top ten most impacted days. Figure 4.4-3 shows an assessment of the annual average impacts and benefits under the control scenarios.[22]

[22] In order to exclude days with very low impact due to transport conditions that do not result in transport and

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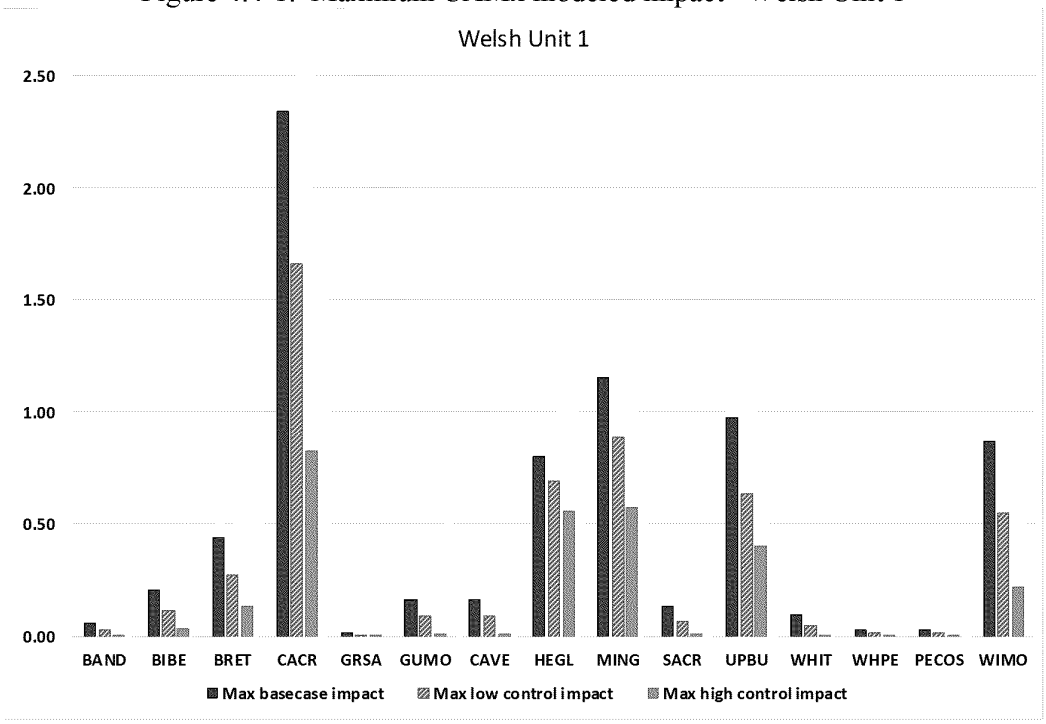
On average across all Class I areas, wet FGD results in a 78% reduction in annual average visibility impacts compared to 38% for DSI. Figure 4.4-4 shows the contribution to extinction due to each visibility impairing species[23] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Caney Creek and Wichita Mountains) for the base case modeling scenario.[24] This figure shows that the impacts from Welsh Unit 1 at CACR on most of these days is primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to this unit on these days. At Mingo, many days are significantly impacted by nitrates and therefore the benefit from reducing SO2 emissions is not as significant as it is as Caney Creek. Other Class I areas, such as Wichita Mountains are significantly impacted by sulfate and benefits from SO2 reductions due to wet FGD are more pronounced.

Figure 4.4-1. Maximum CAMx modeled impact– Welsh Unit 1



impacts to the Class I area, the annual average only includes days during the baseline modeled scenario at each Class I area with impacts greater than 0.1 dv.

[23] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[24] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

Figure 4.4-2. Average of top ten CAMx modeled impact– Welsh Creek Unit 1

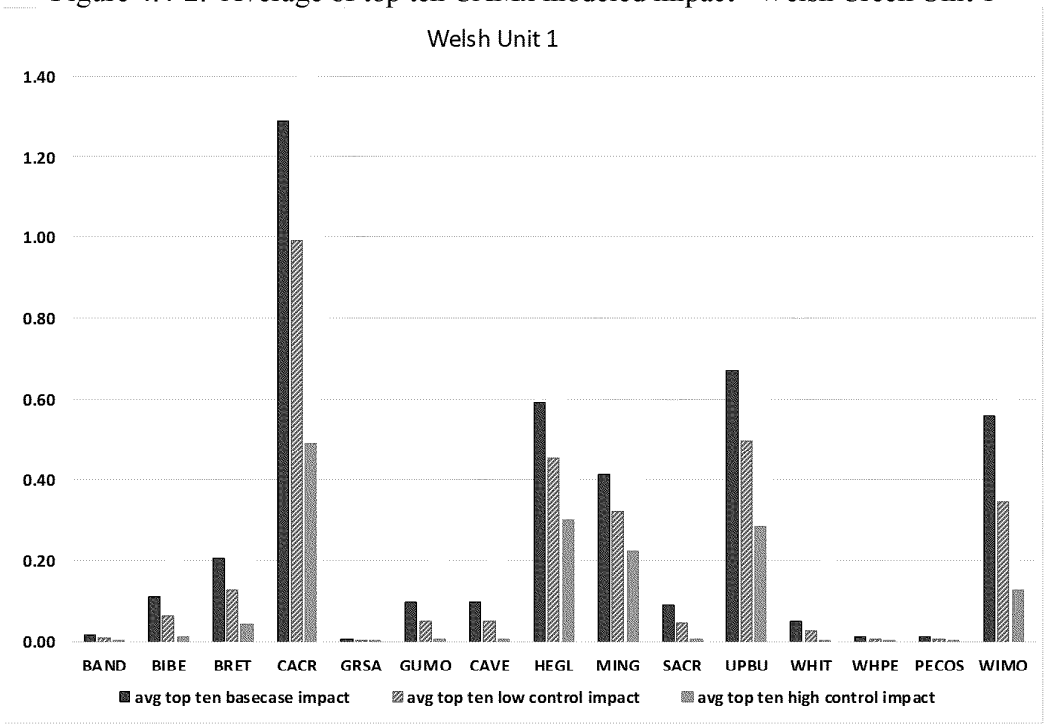


Figure 4.4-3. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – Welsh Unit 1

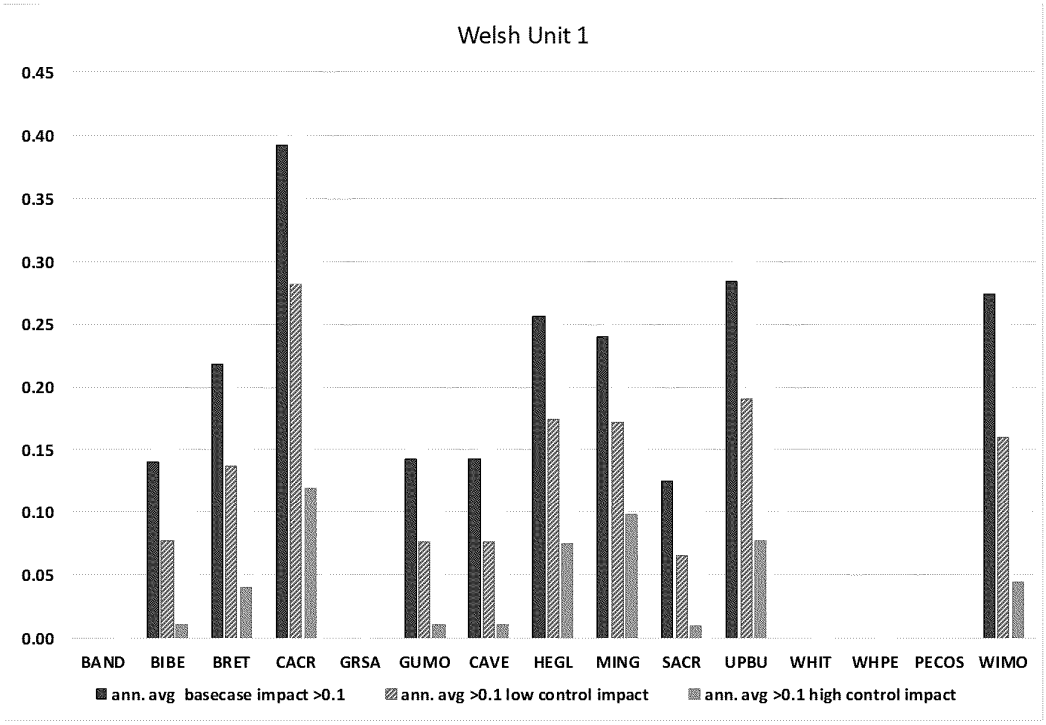


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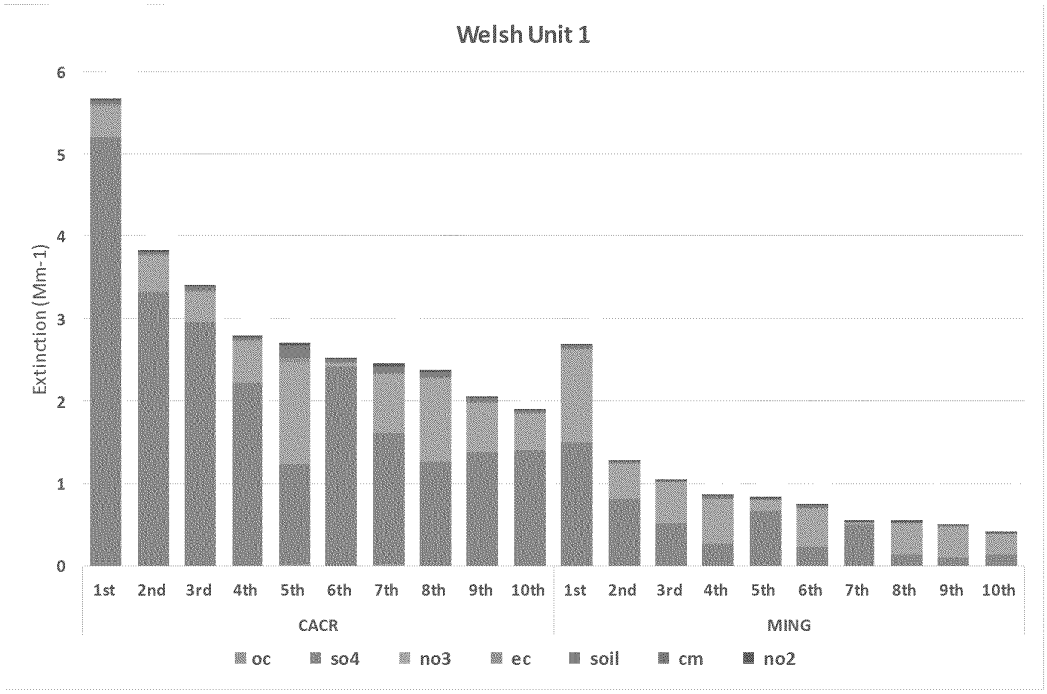
Figure 4.4-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Welsh Unit 1



4.5. Harrington 061B & 062B

In reviewing Harrington, we conclude that the installation of SDA on Units 061B and 062B will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.5-1a. SDA Visibility Benefits at Harrington (CALPUFF)

Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Harrington 061B & 062B	0.45	0.74	2.56	53.67	26

Table 4.5-1b. SDA Visibility Benefits at Harrington RNS {2011-2015} (CALPUFF)

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Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Harrington 061B & 062B	.381	.565	2.42	48	14.67

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, Bandelier, and Wheeler Peak.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, Bandelier and Wheeler Peak.

In evaluating Harrington we note there are five Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the five Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate SDA on both units will eliminate 53.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to SDA levels.

Table 4.5-2. SDA Visibility Benefits at Harrington (CAMx)

Unit	Improvement at Salt Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Harrington 061B	1.170	0.643	4.832	17 / 5	11 / 3

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Harrington 062B	1.279	0.723	5.379	17 / 5	11 / 3
Source (061B & 0622B)	2.053	1.130	9.329	51 / 17	37 / 11

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate SDA on these units will eliminate more than half of all days impacted by the units over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, SDA on each unit will each result in visibility improvements of approximately 1.2 dv on the most impacted days at Salt Creek and 0.6 – 0.7 dv at Wichita Mountains, reducing the number of days impacted over 0.5 and 1.0 dv at these Class I areas. In addition, cumulative benefits from SDA on both units over all 15 Class I areas exceeds 9.3 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the SDA visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. Figures 4.5-1 (unit 1) and 4.5-5 (unit 2) below show the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (SDA) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figures 4.5-2 and 4.5-6). At the most impacted Class I area, SDA on each unit result in visibility improvements of 0.36 (Unit 061B) to 0.40 dv (Unit 062B) on average across the top ten most impacted days, and approximately 0.31 (Unit 061B) to 0.33 (Unit 062B) dv at the second most impacted Class I area for each unit. Figures 4.5-3 and 4.5-7 show an assessment of the annual average impacts and benefits under the control scenarios.[25] SDA reduces annual average base case impacts from each unit by 59% (Unit 061B) to 62% (Unit 062B) reduction in annual average visibility impacts from each unit compared to 31% (Unit 061B) to 32% (Unit 062B) for DSI at the most impacted Class I area. On average across all Class I areas, SDA results in a 59% (Unit 061B) to 62% (Unit 062B) reduction in annual average visibility impacts from each unit compared to 31% (Unit 061B) to 32% (Unit 062B) for DSI. Figures 4.5-4 and 4.5-8 show the contribution to extinction from the units due to each visibility impairing species[26] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Salt Creek and Wichita Mountains) for the base case modeling scenario.[27] These figures show that the impacts from the Harrington units 1 and 2 on these days are due to both sulfate and nitrate, and therefore large reductions in sulfate emissions will result

[25] 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 at each Class I area with impacts greater than 0.1 dv.
[26] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)
[27] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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in significant reductions in visibility impairment due to these units on some days. On other days, remaining nitrate impacts are large and limit the amount of visibility benefits achievable through SO2 emission reductions. As discussed above, annual average impacts across all Class I areas are reduced approximately 60% with SDA. As seen in the top ten average impacts and average annual impacts, a large number of Class I areas are impacted by the source and see benefits with SDA.

Figure 4.5-1. Maximum CAMx modeled impact– Harrington Unit 061B

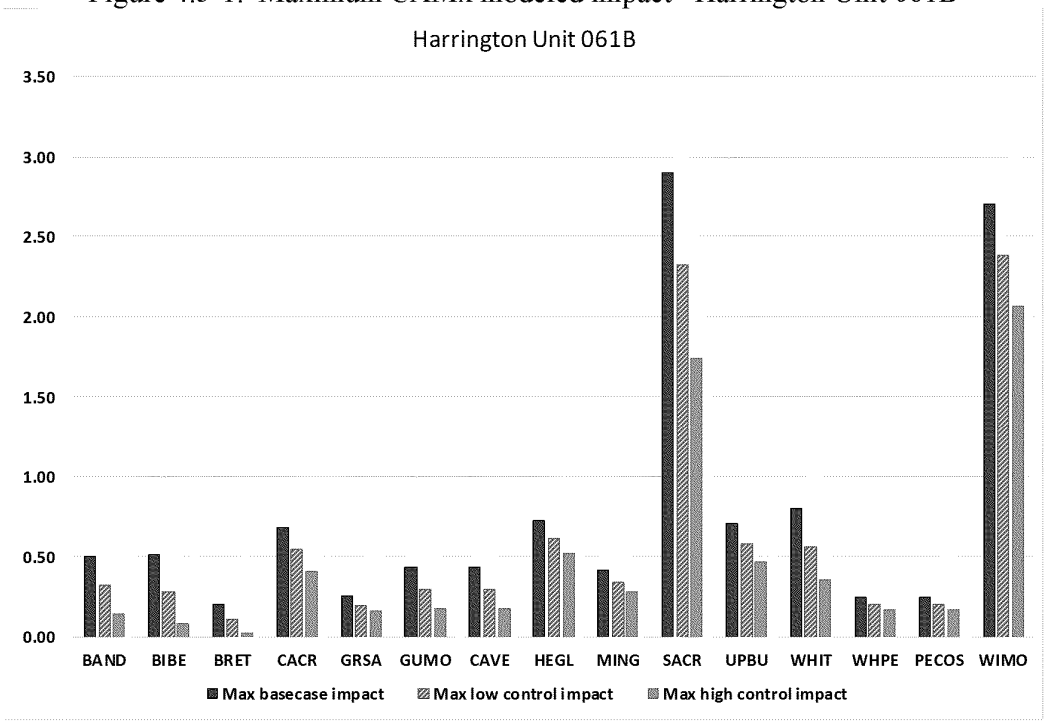

Figure 4.5-2. Average of top ten CAMx modeled impact– Harrington Unit 061B

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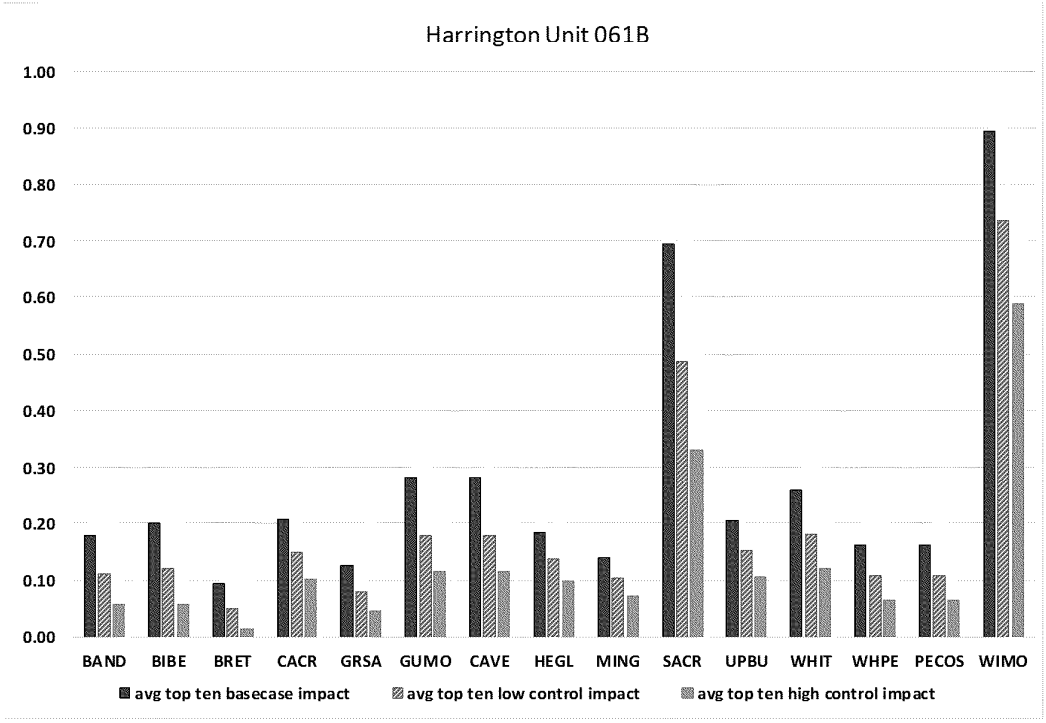


Figure 4.5-3. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – Harrington Unit 061B

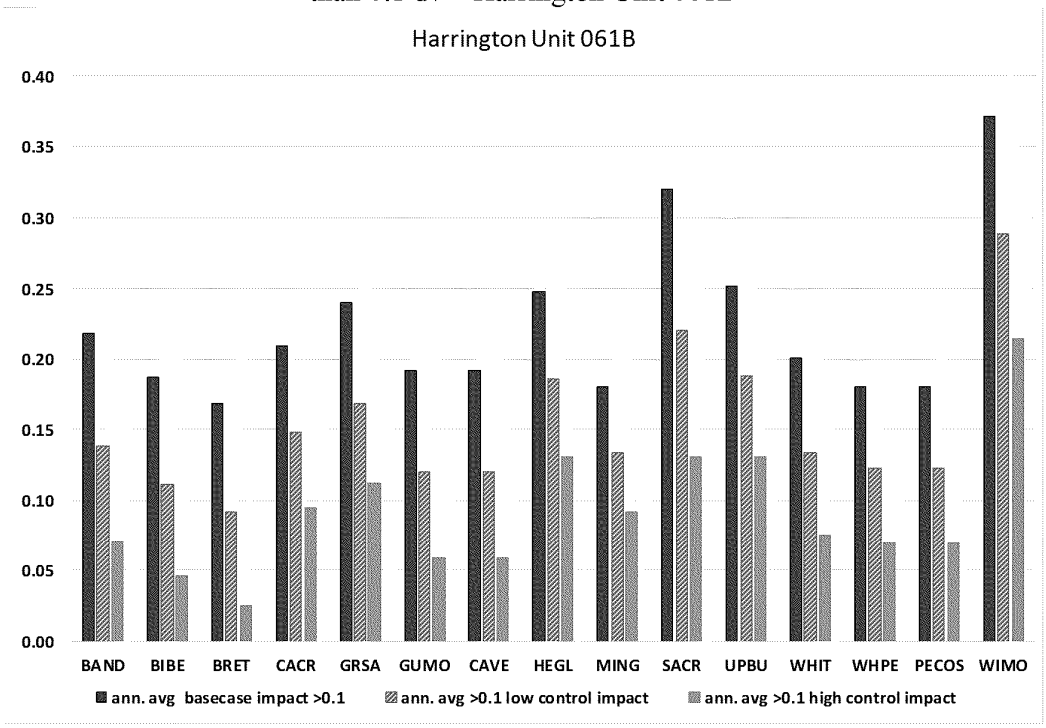


Figure 4.5-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted

Class I areas – Harrington Unit 061B

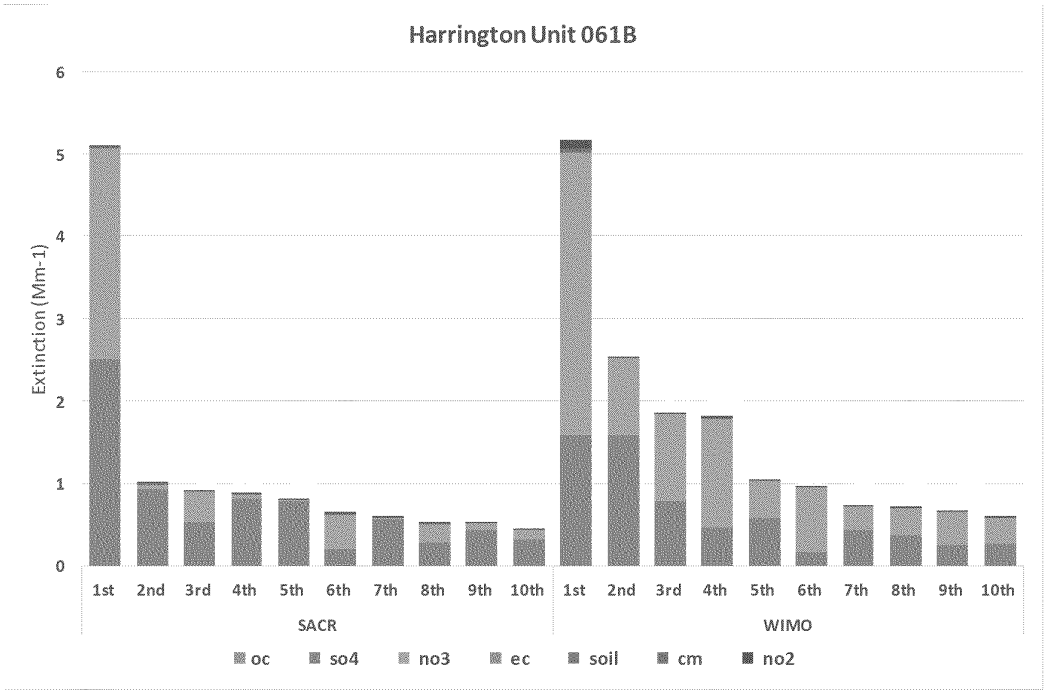


Figure 4.5-5. Maximum CAMx modeled impact– Harrington Unit 062B

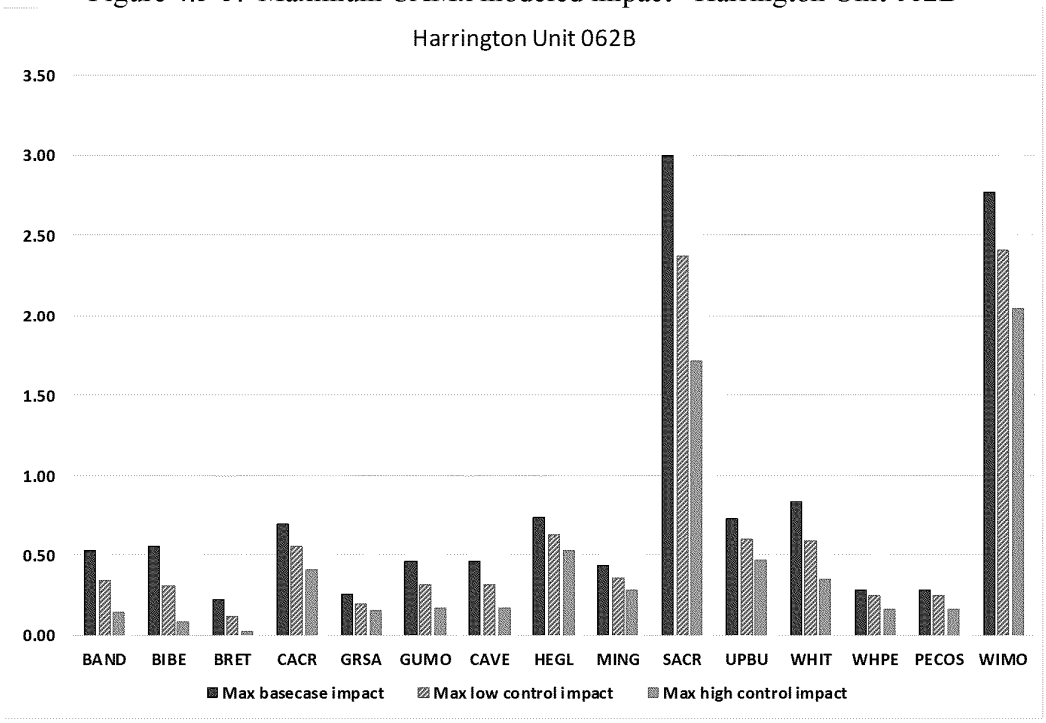


Figure 4.5-6. Average of top ten CAMx modeled impact– Harrington Unit 062B

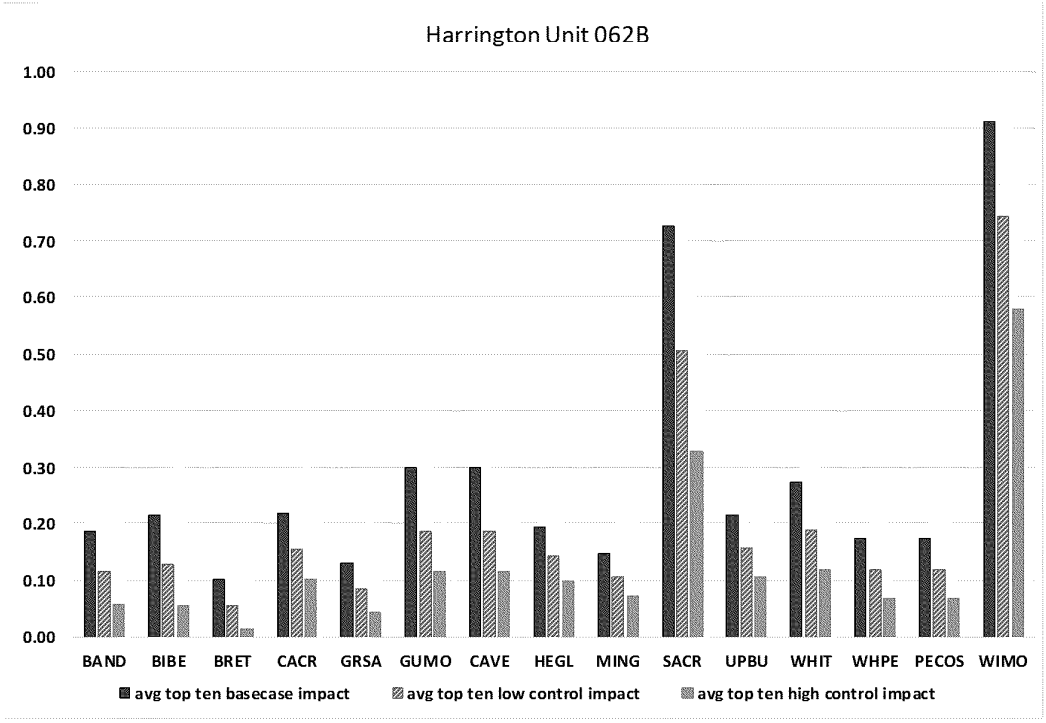


Figure 4.5-7. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – Harrington Unit 062B

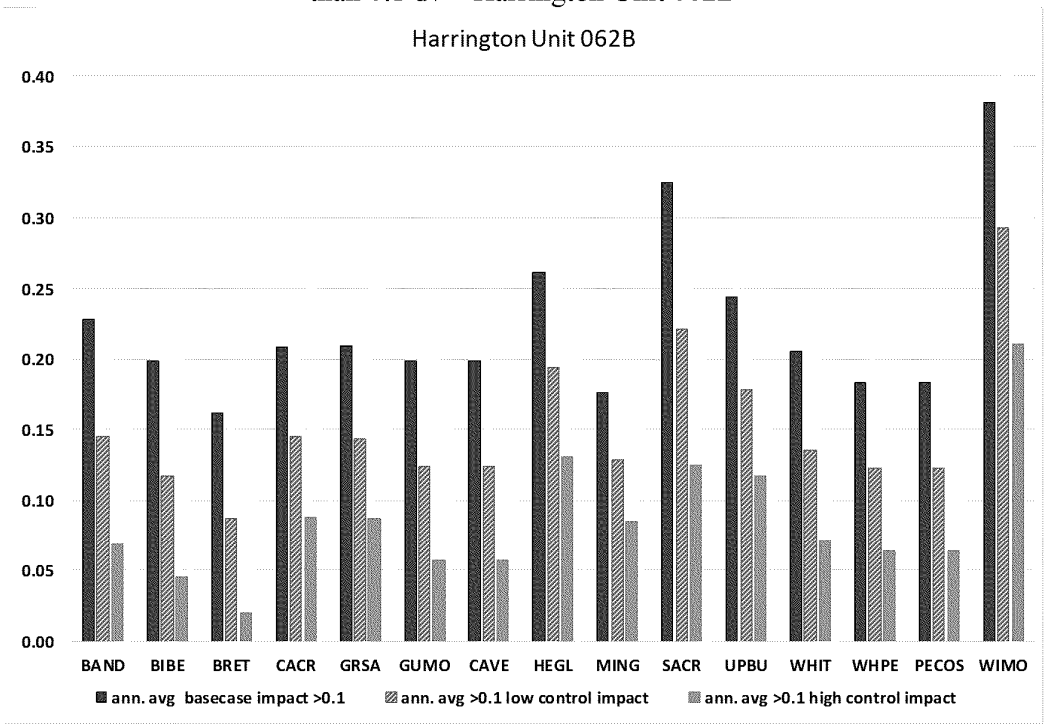
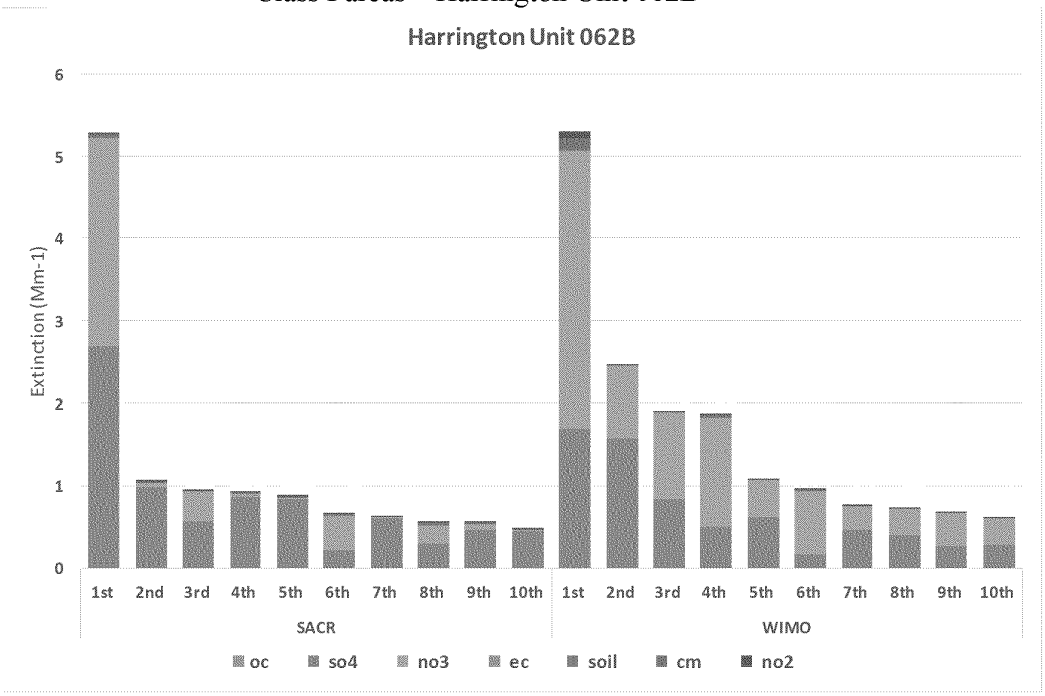


Figure 4.5-8. Species Contribution (Mm-1) on ten highest impact days at two most impacted

Class I areas – Harrington Unit 062B



4.6. W. A. Parish WAP 5 & 6

In reviewing W A Parish, we conclude that the installation of wet FGD on Units 5 and 6 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.6-1. Wet FGD Visibility Benefits at W A Parish (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
W A Parish 5	1.518	0.943	8.171	51 / 9	51 / 9
W A Parish 6	1.492	0.922	7.979	48 / 7	48 / 7
Source (WAP 4, 5 & 6)	2.665	1.760	15.301	163 / 49	162 / 49

[1] 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.
[2] 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.

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[3] 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.

CAMx modeling results indicate that wet FGD on each of these units will eliminate all days impacted by each unit over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of approximately 1.5 dv on the most impacted days at Caney Creek and 0.9 dv at Upper Buffalo. Nine Class I areas have modeled source-wide baseline impacts over 1 dv, and wet FGD on both units results in source-wide improvements of 1 dv or greater on the maximum impacted days at eight of these Class I areas. In addition, cumulative benefits from wet FGD on both units over all 15 Class I areas exceeds 15 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. We note that source-wide modeling includes a small impact from WAP 4. This unit is gas-fired and was modeled at baseline emissions levels for both the baseline and control case scenarios. Figures 4.6-1 (WAP 5) and 4.6-5 (WAP 6) below show the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figures 4.6-2 and 4.6-6). At the most impacted Class I area, wet FGD on each unit result in visibility improvements of 1 dv on average across the top ten most impacted days, and approximately 0.63 dv at the second most impacted Class I area for each unit. Figures 4.6-3 and 4.6-7 show an assessment of the annual average impacts and benefits under the control scenarios.[28] Wet FGD reduces annual average base case impacts from each unit by 91% or more at each Class I area, while DSI at 50% emission reduction reduces annual average impacts at each Class I area by 50% or less. On average across all Class I areas, wet FGD results in a 94% to 95% reduction in annual average visibility impacts from each unit. Figures 4.6-4 and 4.6-8 show the contribution to extinction from the units due to each visibility impairing species[29] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Caney Creek and Upper Buffalo) for the base case modeling scenario.[30] These figures show that the impacts from the W.A. Parish WAP 5 and WAP 6 on these days are primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to these units.

Figure 4.6-1. Maximum CAMx modeled impact– W. A. Parish Unit WAP5

[28] 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 at each Class I area with impacts greater than 0.1 dv.

[29] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[30] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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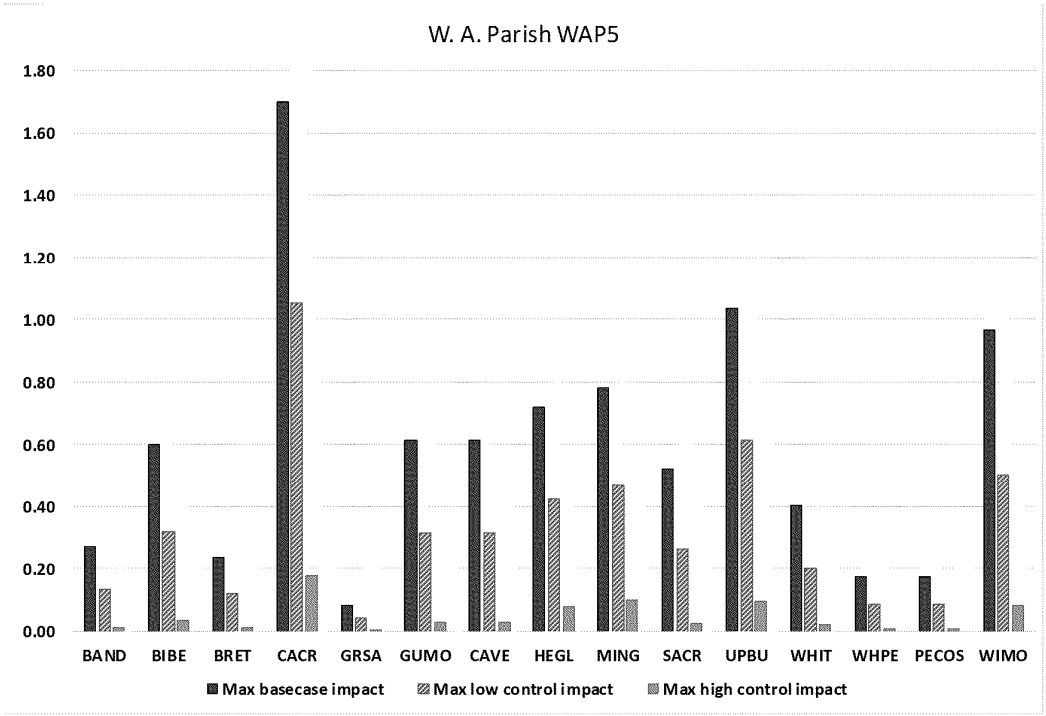

Figure 4.6-2. Average of top ten CAMx modeled impact– W. A. Parish Unit WAP5

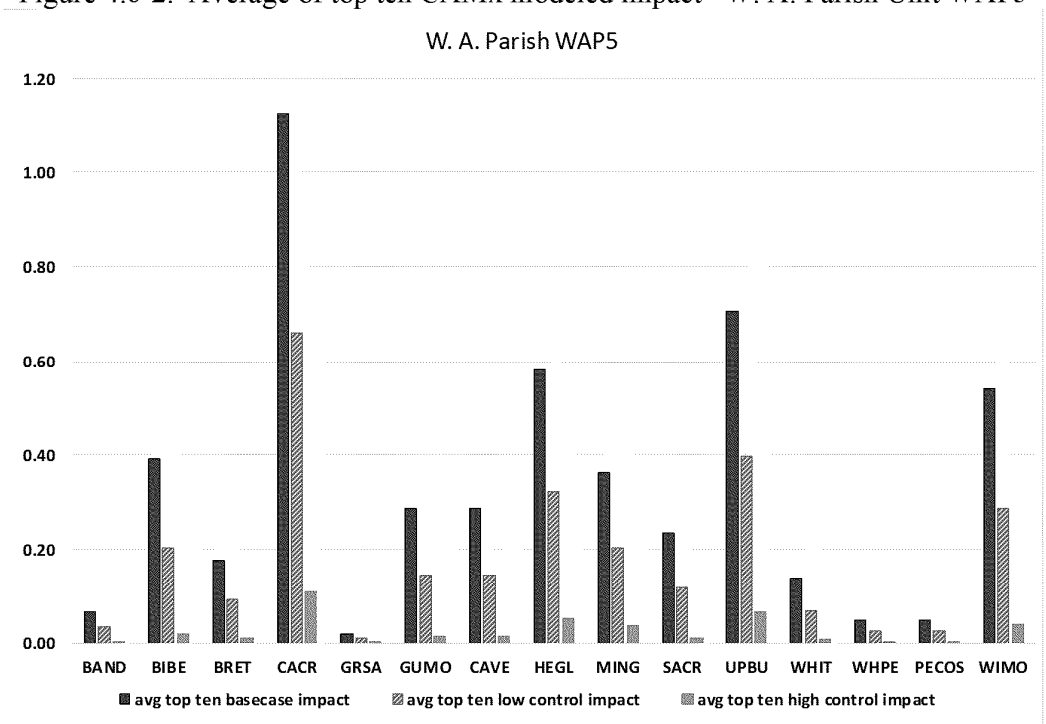

Figure 4.6-3. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – W. A. Parish Unit WAP5

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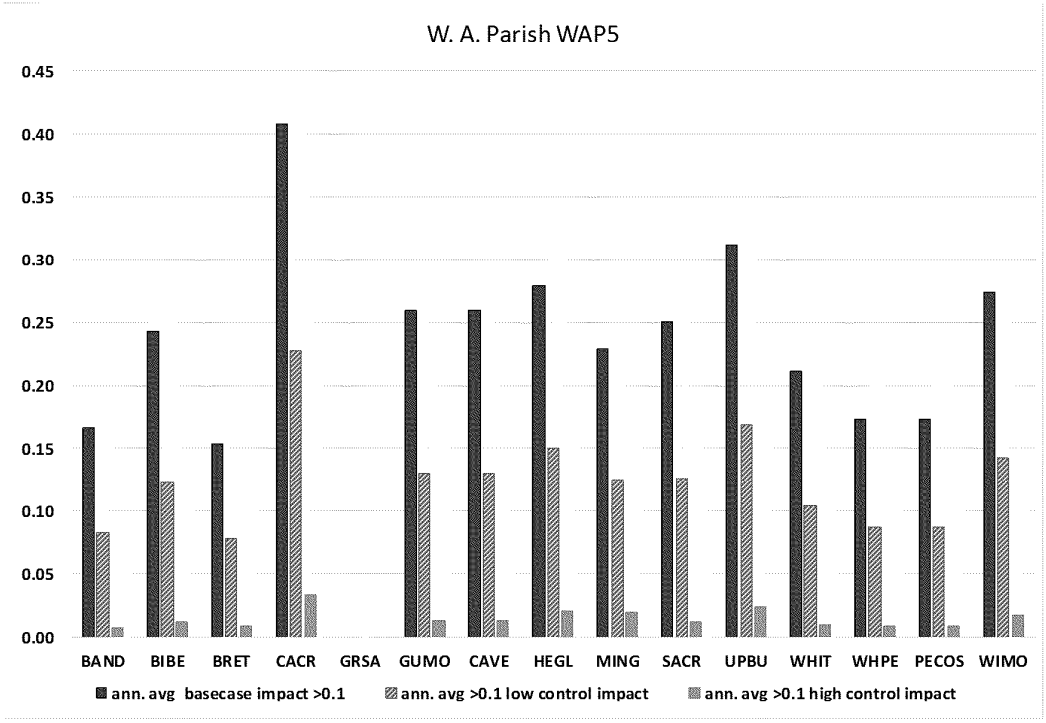

Figure 4.6-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – W.A. Parish WAP5

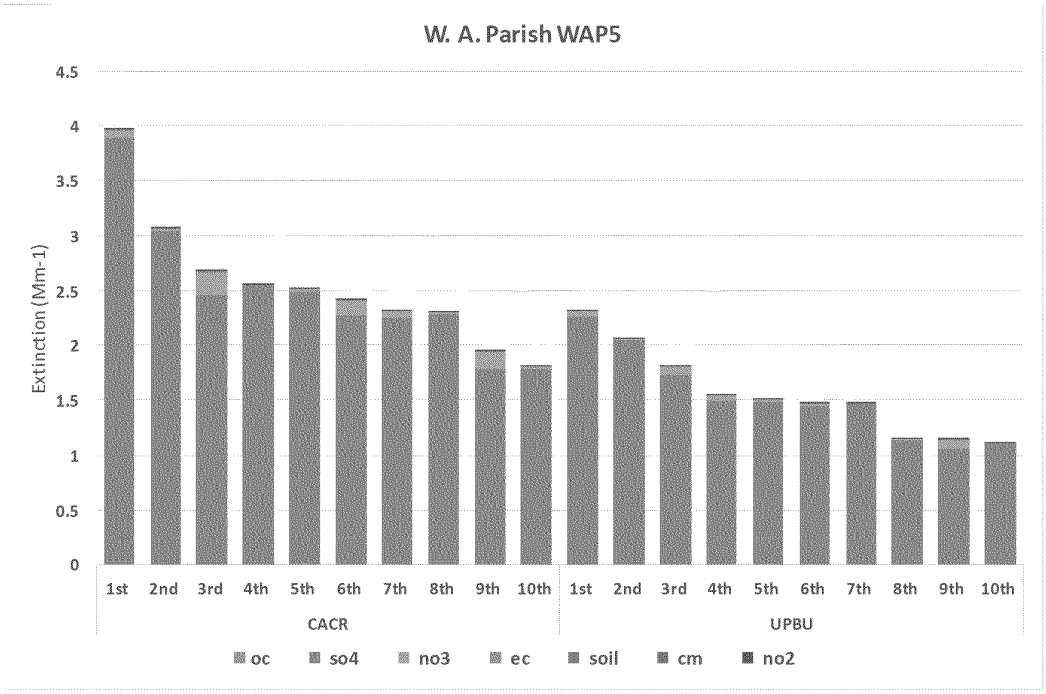

Figure 4.6-5. Maximum CAMx modeled impact– W. A. Parish Unit WAP6

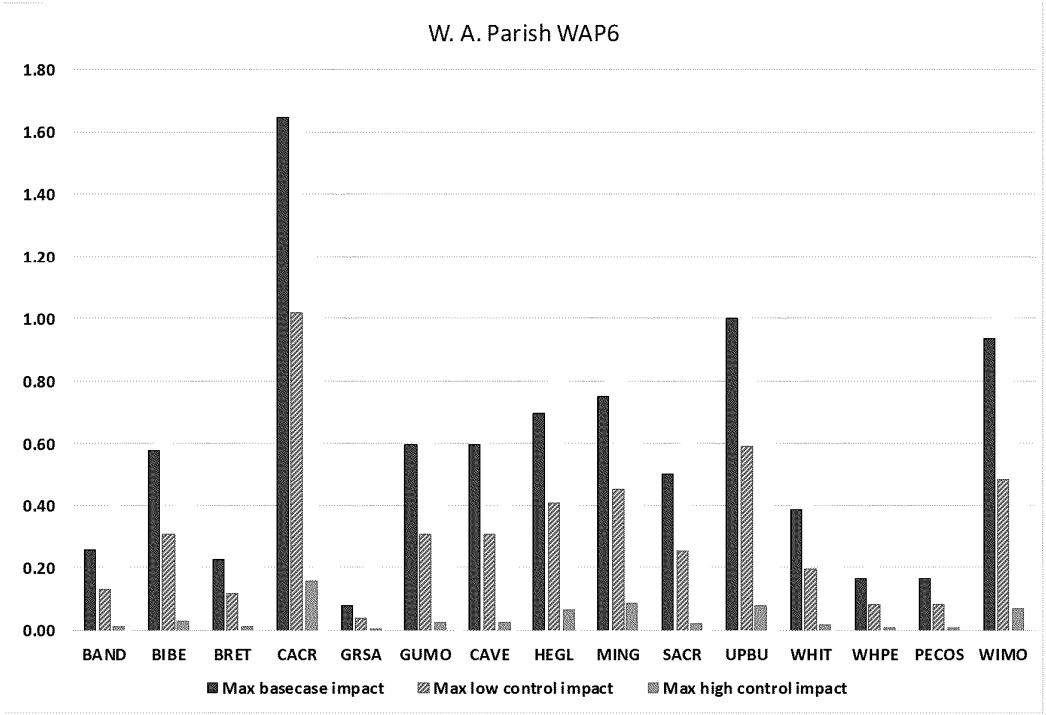

Figure 4.6-6. Average of top ten CAMx modeled impact– W. A. Parish Unit WAP6

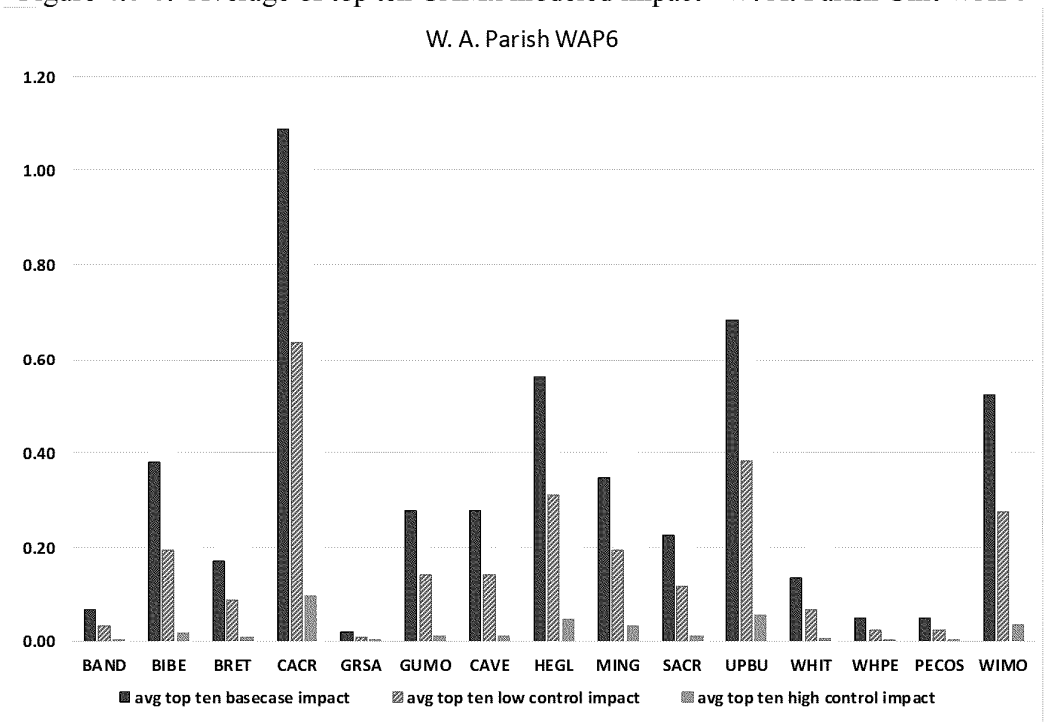

Figure 4.6-7. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – W. A. Parish Unit WAP6

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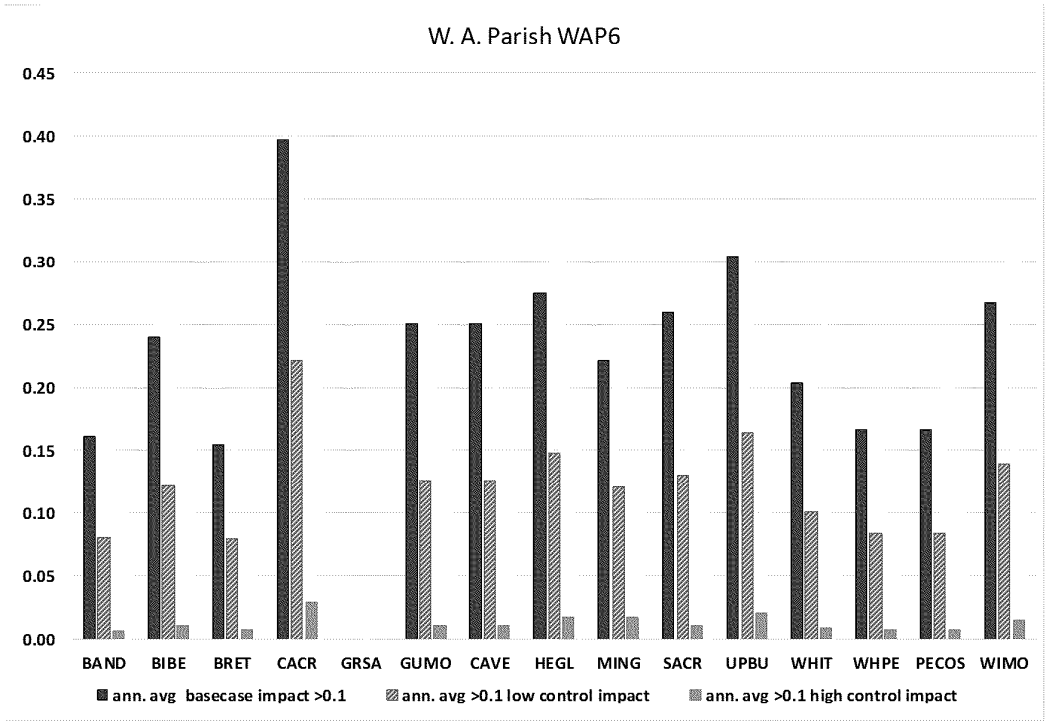
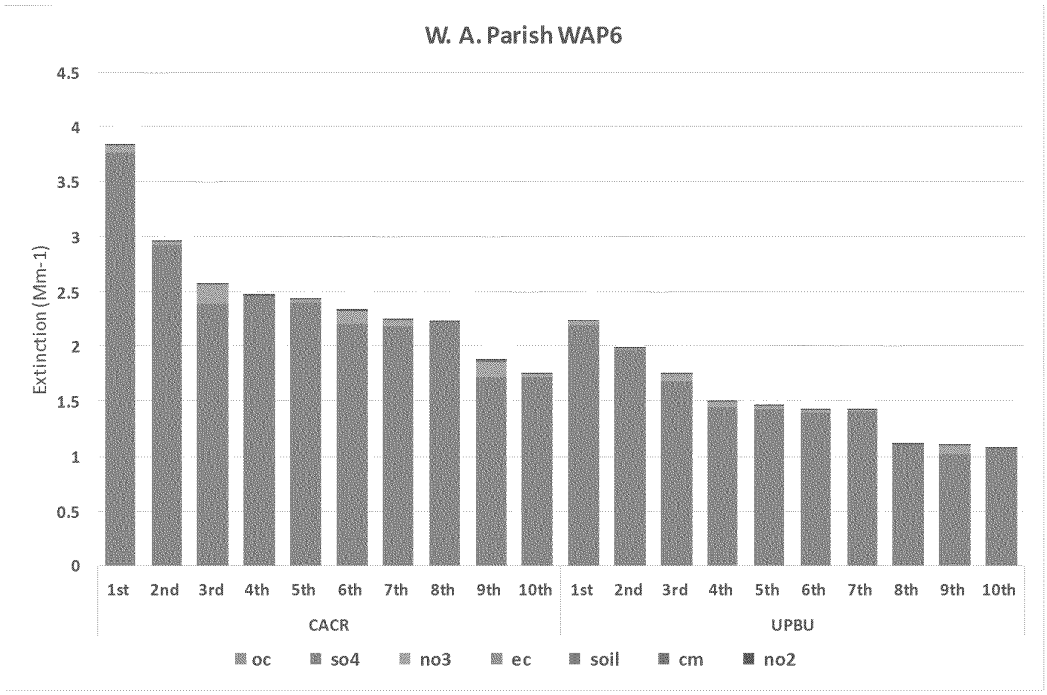


Figure 4.6-8. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – W.A. Parish WAP6



4.7. J T Deely 1 & 2

In reviewing J T Deely, we conclude that the installation of wet FGD on Units 1 and 2 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.7-1 Wet FGD Visibility Benefits at J T Deely (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
J T Deely 1	0.487	0.283	4.785	10 / 0	10 / 0
J T Deely 2	0.298	0.217	3.650	7 / 0	7 / 0
Source (J T Deely 1 & 2, Sommers 1 & 2)	0.699	0.518	8.943	89 / 13	84 / 13

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate wet FGD on each of these units will eliminate all days impacted by each unit over 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of 0.487 dv and 0.298 dv on the most impacted days at Wichita Mountains and 0.283 dv and 0.217 dv at Caney Creek. Larger visibility improvements on the most impacted days are anticipated at other Class I areas. Benefits from wet FGD on unit 1 are 0.583 dv at Big Bend, 0.511 dv at Salt Creek, 0.449 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.475 dv at White Mountains. Benefits from wet FGD on unit 2 are 0.583 dv at Big Bend, 0.441 dv at Salt Creek, 0.354 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.375 dv at White Mountains. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 Class I areas included in the modeling. We note that source-wide modeling includes the impact from Sommers units 1 and 2, and, control case scenarios for these units included benefits from switching to lower sulfur fuel oil. However, these modeled improvements are a small fraction of the total visibility benefits from controls at the source. Figures 4.7-1 (JT Deely unit 1) and 4.7-5 (JT Deely unit 2) below show the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

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We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figures 4.7-2 and 4.7-6). At the most impacted Class I area, wet FGD on unit 1 results in visibility improvements of 0.43 dv on average across the top ten most impacted days, and approximately 0.28 dv at the second most impacted Class I area. At the most impacted Class I area, wet FGD on unit 2 results in visibility improvements of 0.32 dv on average across the top ten most impacted days, and approximately 0.16 dv at the second most impacted Class I area. Figures 4.6-3 and 4.6-7 show an assessment of the annual average impacts and benefits under the control scenarios.[31] Wet FGD reduces annual average base case impacts from each unit by 83% (unit 1) and 88% (unit 2) at the most impacted Class I area, while DSI at 50% emission reduction reduces annual average impacts at the most impacted Class I area by 43% (unit 1) and 45% (unit 2). On average across all Class I areas, wet FGD results in an 81% (unit 1) and 87% (unit 2) reduction in annual average visibility impacts from each unit. Figures 4.6-4 and 4.6-8 show the contribution to extinction from the units due to each visibility impairing species[32] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Wichita Mountains and Caney Creek) for the base case modeling scenario.[33] These figures show that the impacts from the W.A. Parish WAP 5 and WAP 6 on most days are primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to these units on those days. The very highest impacted days at Caney Creek have large impacts from both nitrate and sulfate. While emission reductions of SO2 will greatly reduce the impairment from sulfate on these days, the nitrate impacts remain, limiting the overall benefit from controls on these days. Visibility impacts at Guadalupe Mountains, Carlsbad Caverns and Salt Creek are primarily due to sulfates and reductions in SO2 emissions are effective in reducing the visibility impairment from these units at those Class I areas.

Figure 4.7-1. Maximum CAMx modeled impact– J.T. Deely Unit 1

[31] 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 at each Class I area with impacts greater than 0.1 dv.

[32] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[33] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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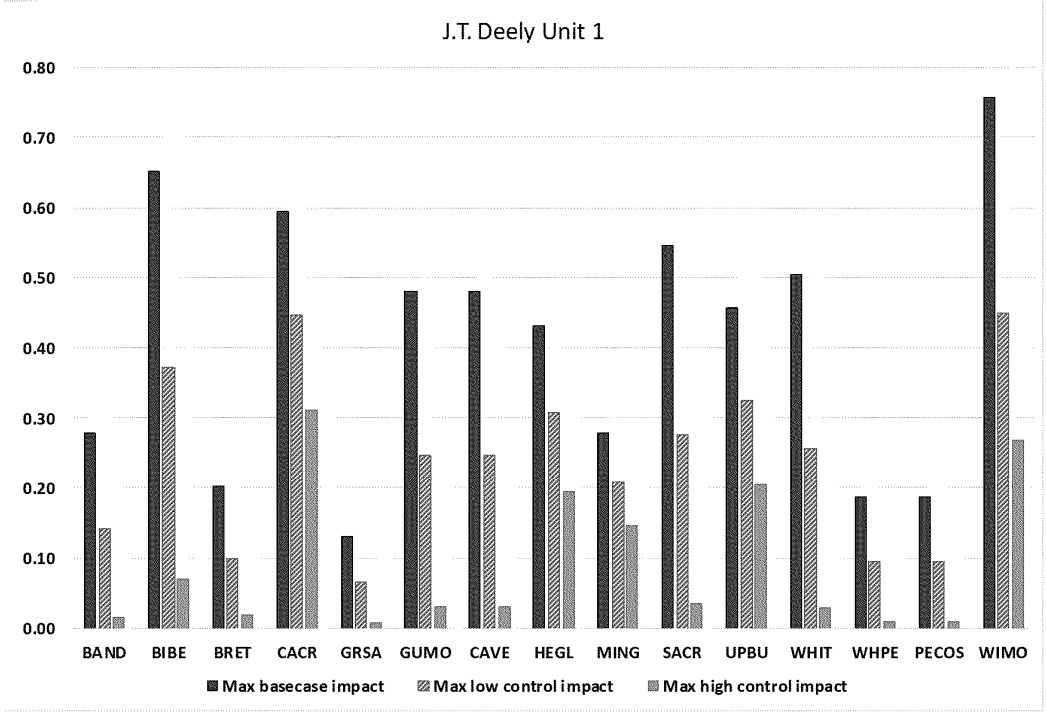

Figure 4.7-2. Average of top ten CAMx modeled impact– J.T. Deely Unit 1

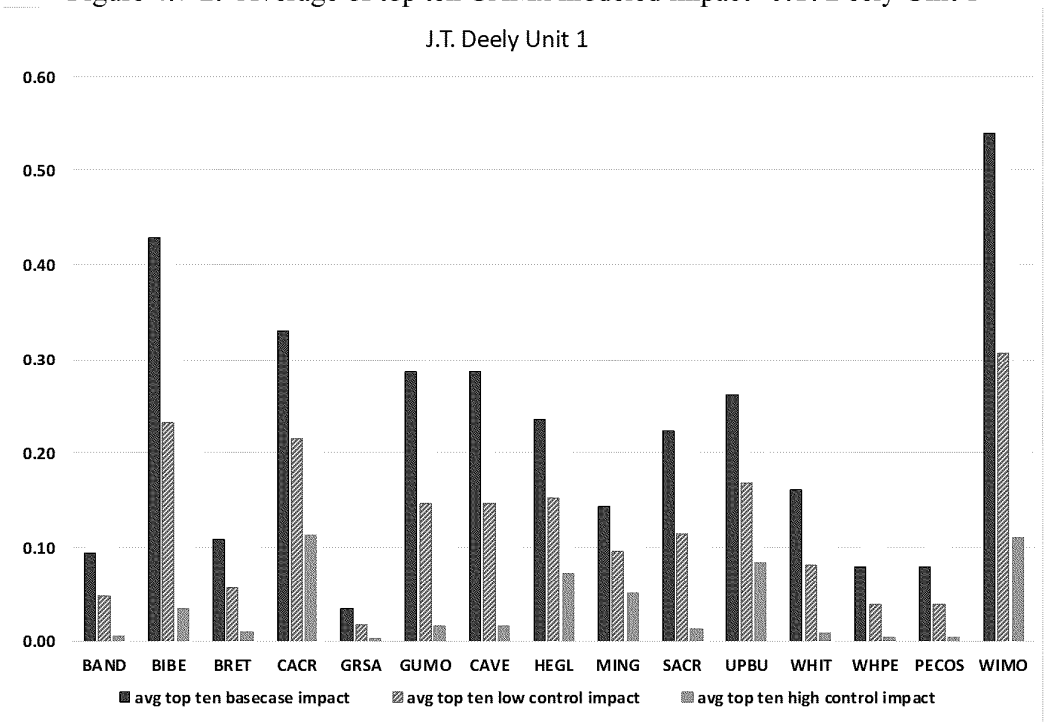

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Figure 4.7-3. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – J.T. Deely Unit 1

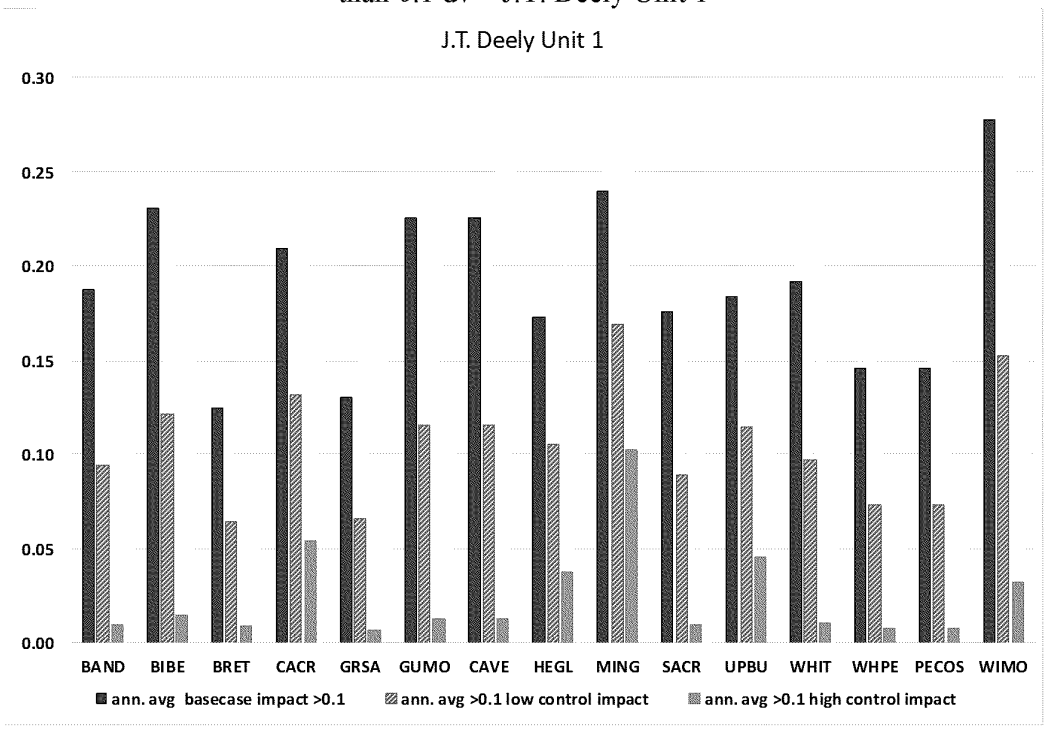

Figure 4.7-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – J.T. Deely Unit 1

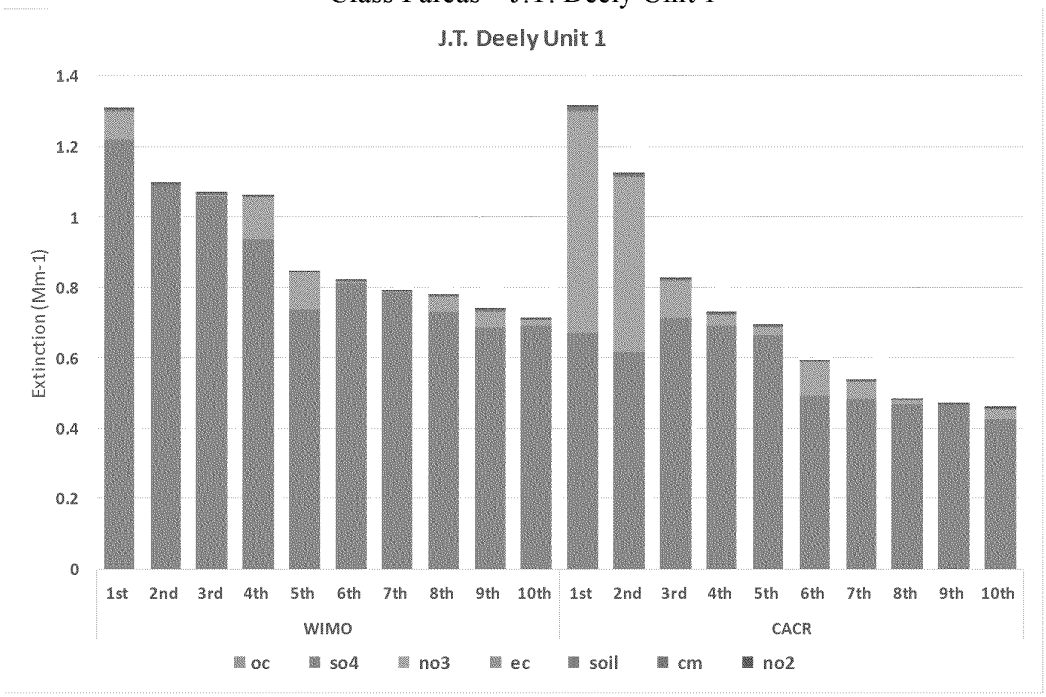

Figure 4.7-5. Maximum CAMx modeled impact– J.T. Deely Unit 2

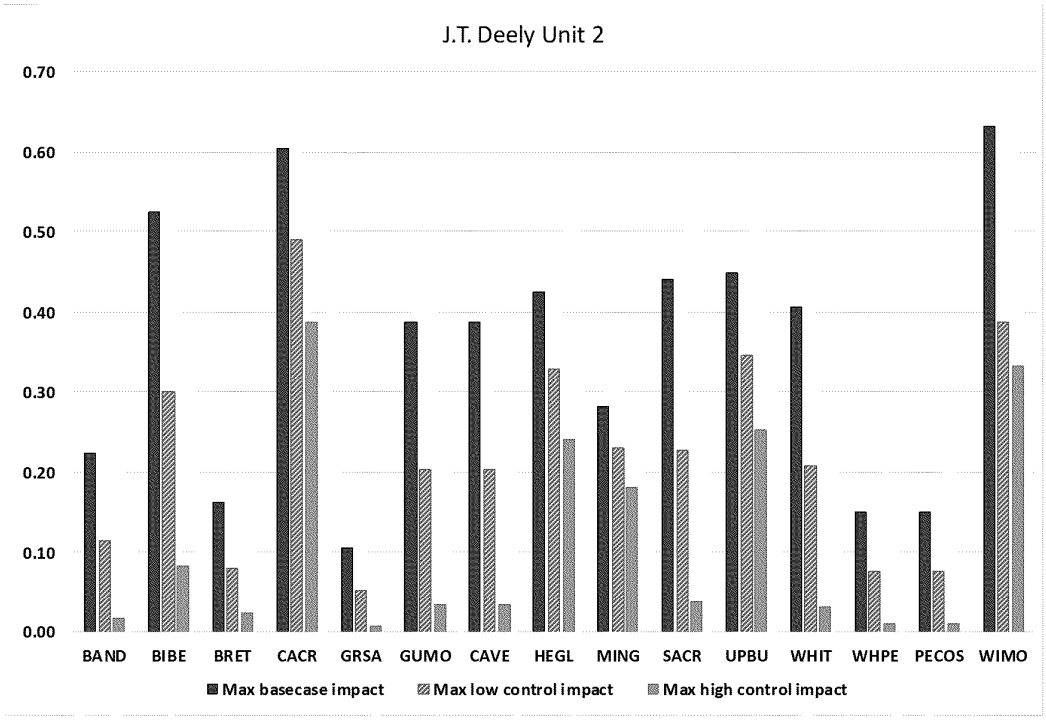

Figure 4.7-6. Average of top ten CAMx modeled impact– J.T. Deely Unit 2

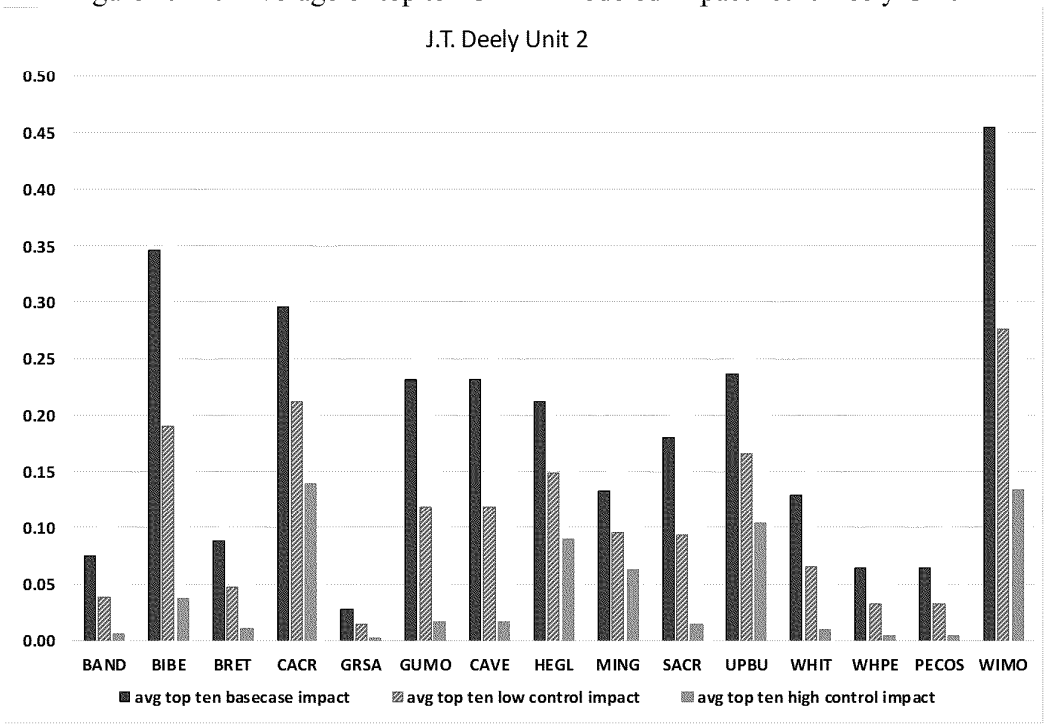

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Figure 4.7-7. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – J.T. Deely Unit 2

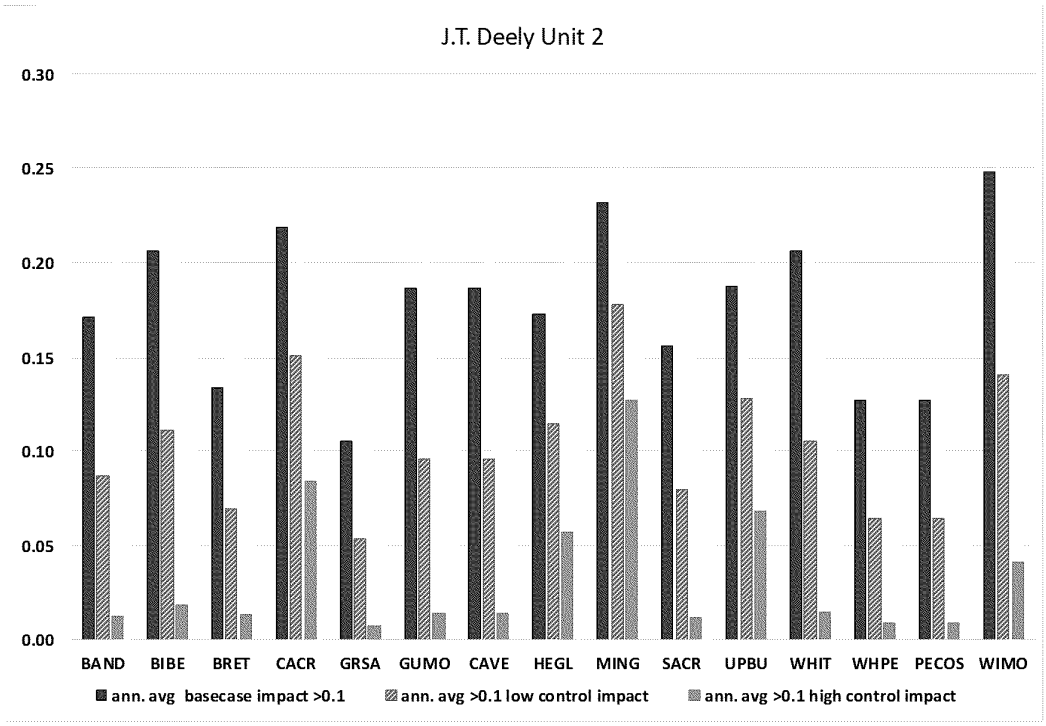
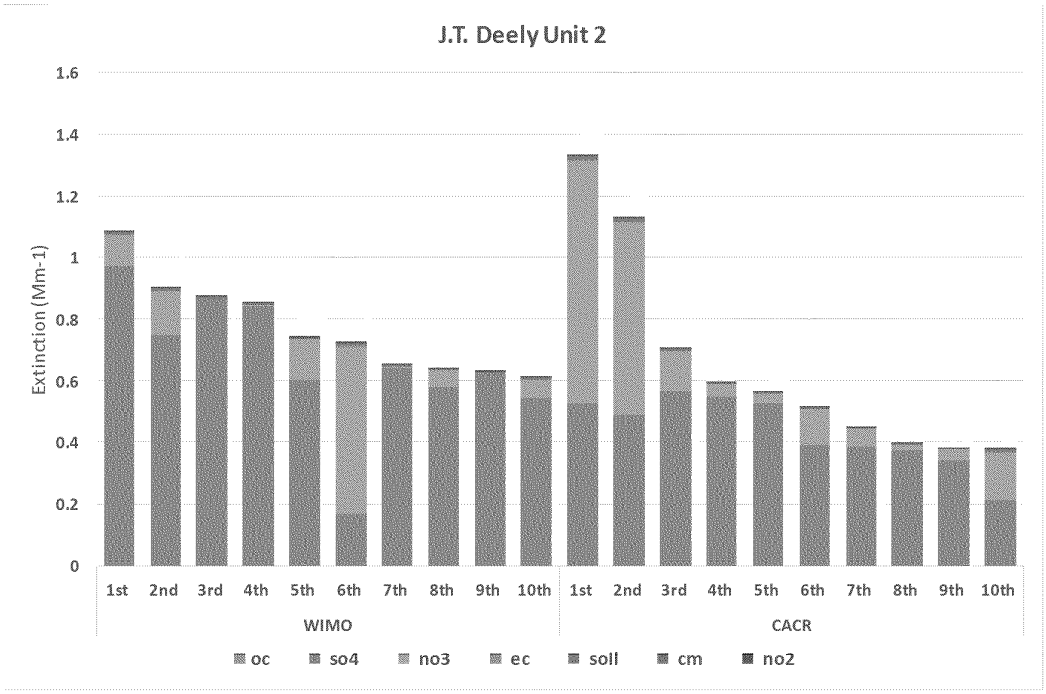


Figure 4.7-8 Species Contribution (Mm-1) on ten highest impact days at two most impacted



5. Visibility Benefits of Scrubber Upgrades for Coal-Fired Units

We also modeled the visibility benefits of those same units for which we conducted control cost analysis for upgrading their existing scrubbers. We assumed the same 95% control level we used in our control cost analyses. We also modeled a lower level control at 90%. The visibility benefits from these scrubber upgrades are summarized in the section below.[34,35] See Appendix E and Appendix F for additional CAMx model results for each class I area. Below, we present a summary of the del-dv visibility benefits and reduction in number of days impacted.

Table 5-1. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CAMx modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Unit 1, 2 & 3)	CACR	Max dv	6.651	4.491	4.321	2.159	2.329
			Days > 0.5 dv	141	75	56	66	85
			Days>1.0 dv	99	31	16	68	83
		UPBU	Max dv	5.803	2.669	2.528	3.134	3.275
			Days > 0.5 dv	99	39	22	60	77
			Days>1.0 dv	67	11	7	56	60
	Unit 1	CACR	Max dv	2.633	1.550	1.468	1.083	1.165
			Days > 0.5 dv	71	17	6	54	65
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.254	0.867	0.805	1.387	1.449
			Days > 0.5 dv	44	6	3	38	41
			Days>1.0 dv	10	0	0	10	10
	Unit 2	CACR	Max dv	2.466	1.882	1.811	0.585	0.655

[34] See spreadsheet: "summary CAMx vis daily.xlsx" in the docket for this action for these and additional model results.

[35] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for summary of base case model results, including species specific 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.

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			Days > 0.5 dv	68	18	9	50	59
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.189	1.077	1.025	1.112	1.164
			Days > 0.5 dv	40	6	5	34	35
			Days>1.0 dv	10	1	1	9	9
	Unit 3	CACR	Max dv	2.755	1.682	1.609	1.074	1.146
			Days > 0.5 dv	76	15	6	61	70
			Days>1.0 dv	29	2	1	27	28
		UPBU	Max dv	2.368	0.942	0.890	1.425	1.478
			Days > 0.5 dv	46	6	4	40	42
			Days>1.0 dv	13	0	0	13	13
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63
			Days>1.0 dv	40	14	0	26	40
	Unit 3	CACR	Max dv	4.632	0.905	0.914	3.728	3.719
			Days > 0.5 dv	79	5	5	74	74
			Days>1.0 dv	32	0	0	32	32
		WIMO	Max dv	2.282	0.462	0.364	1.820	1.918
			Days > 0.5 dv	31	0	0	31	31
			Days>1.0 dv	7	0	0	7	7

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Table 5-2. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Units 1, 2 & 3)	CACR	Max dv	4.46	2.27	1.86	2.18	2.60
			Days > 0.5 dv Avg.	129.67	77.33	63.00	52.33	66.67
			Days>1.0 dv Avg.	91.33	32.67	22.33	58.67	69.00
		UPBU	Max dv	2.73	1.10	0.85	1.63	1.88
			Days > 0.5 dv Avg.	81.67	30.33	18.67	51.33	63.00
			Days>1.0 dv Avg.	46.67	7.33	3.67	39.33	43.00
Monticello[1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	2.41	1.70	2.89	4.87
			Days > 0.5 dv Avg.	143.67	115	62.33	28.67	81.33
			Days>1.0 dv Avg.	113	66.33	23.67	46.67	89.33
		UPBU	Max dv	3.45	1.77	0.765	1.68	2.68
			Days > 0.5 dv Avg.	103	61	13.67	42	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60	34.67	6	25.33	54
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67

[1] Monticello's controlled level is a combination of scrubber upgrade on Unit 3 and scrubber retrofits on Units 1 and 2 in the facility impact modeling with CALPUFF.

Our review of the impacts/benefits of scrubber upgrades on four units at two facilities show that scrubber upgrades conducted at all units would result in significant visibility improvements at impacted Class I areas.

6. Visibility Benefit Analysis of Scrubber Upgrades

The BART Guidelines state that underperforming scrubber systems should be evaluated for upgrades.[36] Other than upgrading the existing scrubbers, all of which are wet FGDs, there are no competing control technologies that could be considered for these units. The CALPUFF modeling generated facility-wide impacts and the benefits of the scrubber upgrade on Monticello Unit 3 and the three Martin Lake facilities are included in Table 5-2 above and Tables 6-1.a-b and 6-2.a-b. The following is a listing of each of the affected units along with additional information on resulting visibility benefits from upgrading their existing scrubbers:

[36] 70 FR 39171 (July 6, 2005).

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Table 6-1.a Scrubber Upgrade and WGFD Visibility Benefits at Monticello (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	4.87	2.68	10.25	224.67	164.67

Table 6-1.b Scrubber Upgrades at Martin Lake (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Martin Lake Units 1, 2 & 3	2.60	2.04	4.64	129.67	112

Table 6-2a. Scrubber Upgrade and WGFD Visibility Benefits at Monticello RNS {2011-2015} (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	3.67	1.82	7.37	201.33	147

Table 6-2b. Scrubber Upgrades at Martin Lake RNS {2011-2015} (CALPUFF)

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Source	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Martin Lake Units 1, 2 & 3	2.354	1.685	4.04	134	98.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: MARTIN LAKE - Caney Creek and Upper Buffalo; MONTICELLO – Caney Creek, Upper Buffalo, and Wichita Mountains.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: MARTIN LAKE - Caney Creek and Upper Buffalo; MONTICELLO – Caney Creek, Upper Buffalo, and Wichita Mountains.

As can be seen in the CALPUFF modeling results, reducing emissions to WFGD emission rate levels yields very large benefits.

Table 6-3. Visibility Benefit for Coal-fired Units with Existing SO_2 Controls (CAMx)

Unit	Improvement at most impacted (dv)	Improvement at 2nd most impacted (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 3	3.719 (CACR)	1.918 (WIMO)	11.940	200 / 66	188 / 66
Martin Lake 1	1.165 (CACR)	1.449 (UPBU)	7.575	160 / 41	151 / 40
Martin Lake 2	0.655 (CACR)	1.164 (UPBU)	6.199	150 / 41	134 / 39
Martin Lake 3	1.146 (CACR)	1.478 (UPBU)	7.863	173 / 47	163 / 46

[1] 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.
[2] 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.
[3] 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.

The figures below show the maximum modeled impact (base case) for these scrubbed units and the modeled impact under the high control (upgrade to 95% control efficiency) scenario at each Class I area.[37] Evaluation of the average across the top ten impact days and annual average visibility impacts show a similar relative reduction in impacts from the base case to the high control case. We conclude that in all cases, scrubber upgrades result in significant visibility

[37] See spreadsheet: "summary CAMx vis daily.xlsx" in the docket for this action for these and additional model results.

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benefits, significantly reducing the impacts from these units and reducing the number of days that Class I areas are impacted over 1.0 dv and 0.5 dv. Scrubber upgrades almost eliminate all days impacted over 1 dv by an individual unit.

Figure 6-1. Maximum CAMx modeled impact (dv)– Martin Lake Unit 1

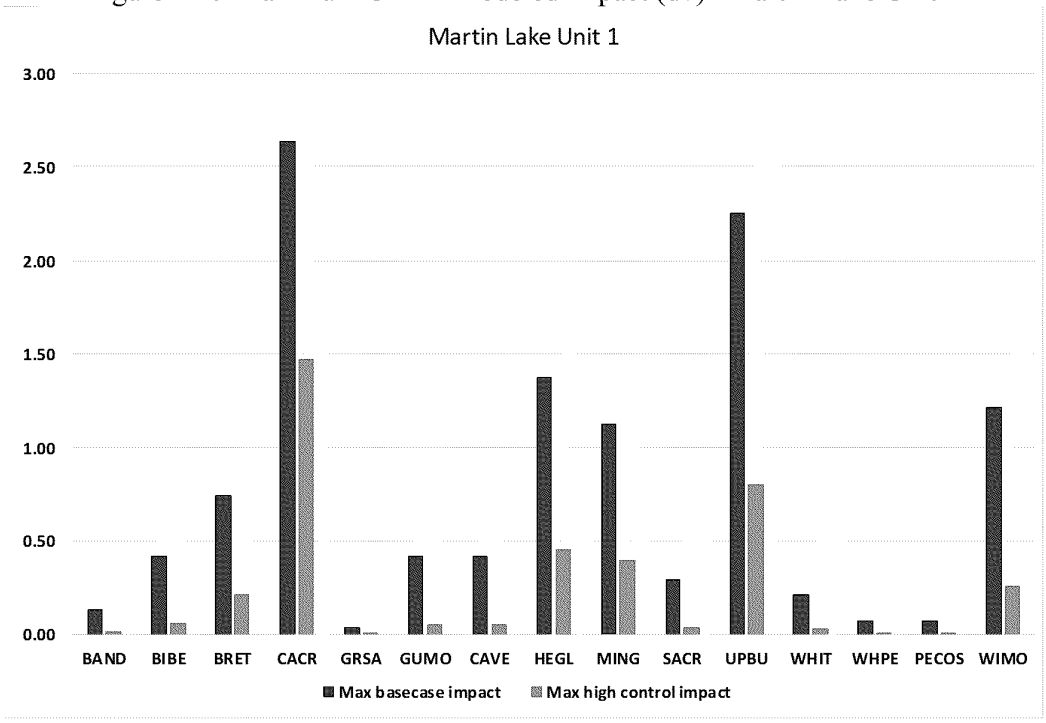

Figure 6-2. Maximum CAMx modeled impact (dv)– Martin Lake Unit 2

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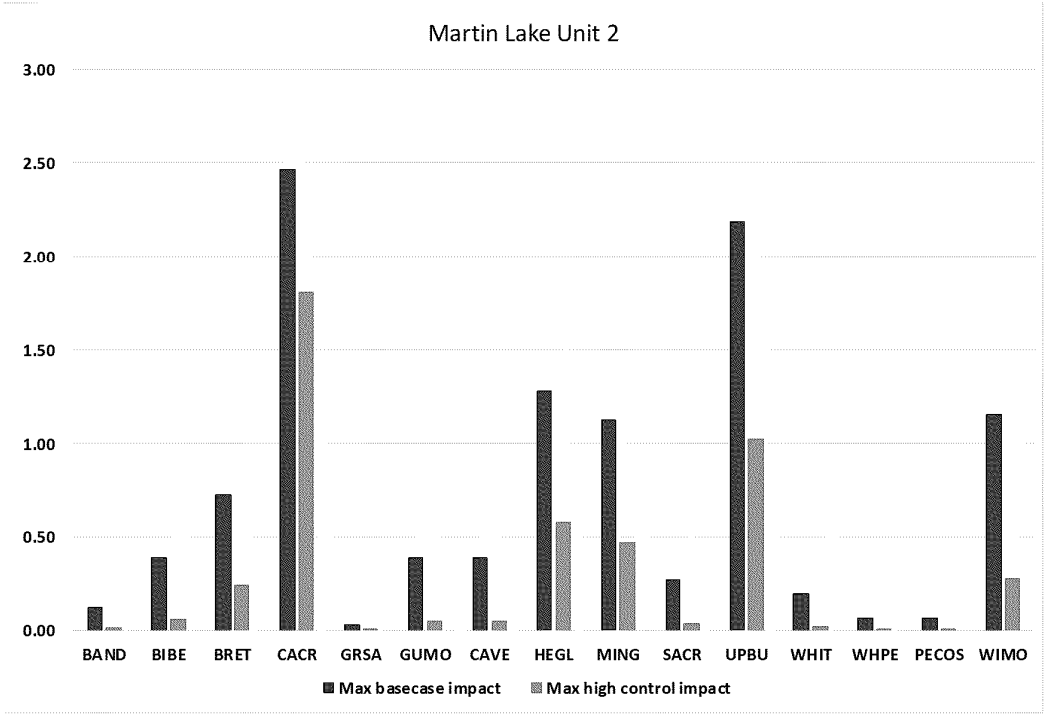


Figure 6-3. Maximum CAMx modeled impact (dv)– Martin Lake Unit 3

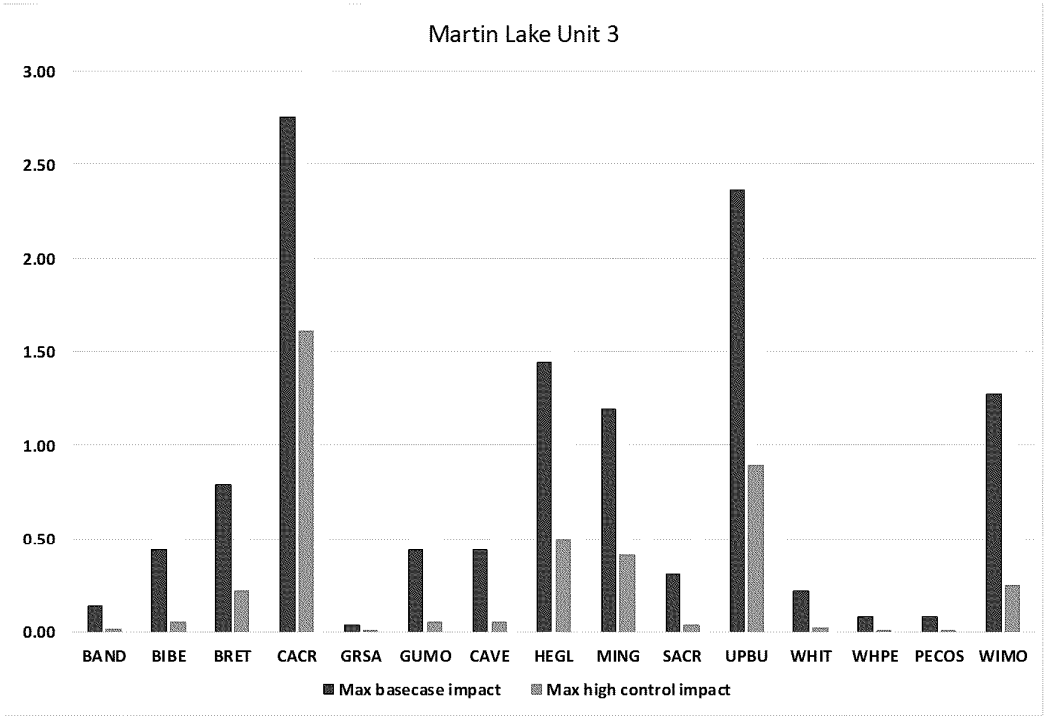
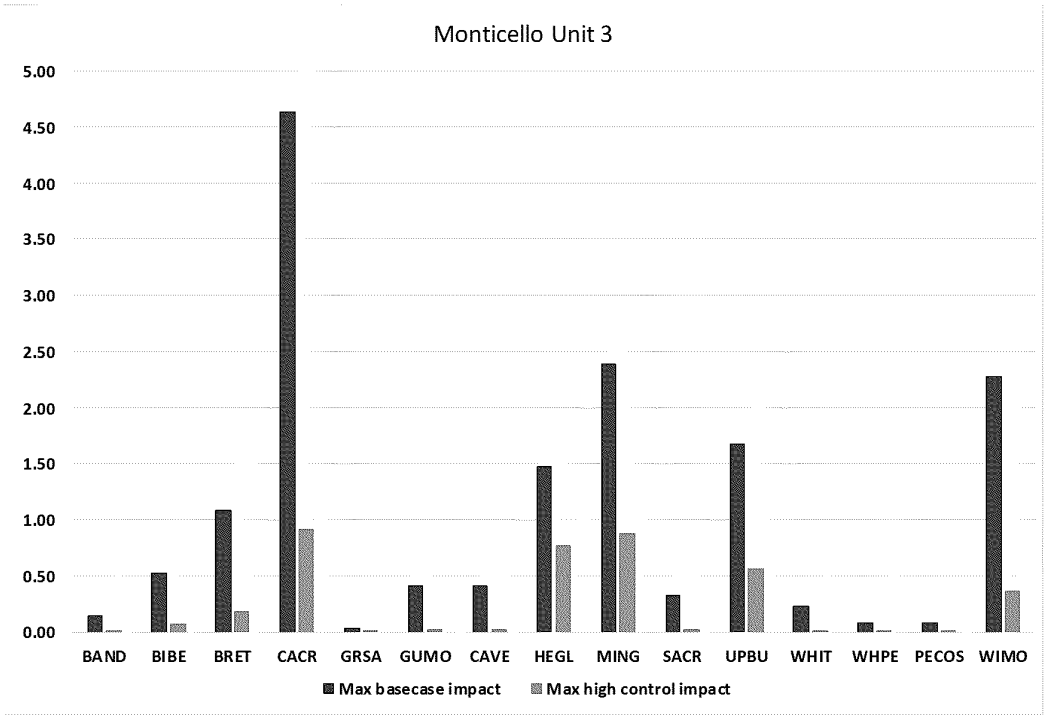


Figure 6-4. Maximum CAMx modeled impact (dv)– Monticello Unit 3



7. Visibility Benefits of Fuel-oil Switching for Gas/Fuel Oil-Fired Units

We also modeled the visibility benefits of those gas/fuel oil-fired units for which we conducted control cost analysis for switching to lower sulfur fuels. We evaluated the visibility benefits of switching to fuel oils corresponding to ultra-low sulfur diesel at 0.0015% sulfur by weight and 0.3% sulfur by weight as we evaluated in our control cost analyses. See the BART Screening TSD for additional information on baseline emissions and modeling. The visibility benefits from these fuel switches are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits. Because fuel oil is fired on an irregular basis for these units (usually less than 10% of the annual BTUs are from fuel oil burning), they are not amenable to a number of days analysis. See the BART FIP TSD for additional EIA information on quantity of fuel oil burned.

Table 7-1. Visibility Benefits from Lower Sulfur Fuel

Facility Name	Emission Unit	Baseline visibility Impact from Source (most impacted Class I area)	Visibility benefit of 0.3% S fuel oil	Visibility benefit of 0.0015% S fuel oil

Stryker	ST2	CALPUFF 0.65 % S: 0.786 dv @ CACR (Facility)	CALPUFF (0.3 % S) : 0.263 dv @ CACR (Facility)	CALPUFF: 0.522 dv @ CACR (Facility)
Graham	Unit 2	CALPUFF 0.69 % S: 1.228 dv @ WIMO (Facility)	CALPUFF (0.3% S): 0.465 dv @ WIMO (Facility	CALPUFF: 0.851 dv @ WIMO (Facility
Wilkes	Units 1, 2, 3	CALPUFF 0.43 % S: 0.698 dv @ CACR (Facility)	CALPUFF (0.1 % S): 0.029 dv @ CACR (Facility)	CALPUFF: 0.037 dv @ CACR (Facility)
Newman[1]	Unit 2	N/A	N/A	N/A
	Unit 3	N/A	N/A	N/A
	Unit 4	N/A	N/A	N/A
Calaveras	Sommers Unit 1	CAMx: 1.513 dv @ WIMO (Source); 0.106 dv @ CACR (Unit)	0.004 dv @ CACR	0.008 dv @ CACR
	Sommers Unit 2	CAMx: 1.513 dv @ WIMO (Source); 0.180 dv @ CACR (Unit)	0.023 @ CACR	0.047 @ CACR

[1] EPA initially considered evaluating with CALPUFF databases, but Newman is located near the edge of the CALMET modeling domain. There are a number of Class I areas that Newman could potentially impact (Gila, Bosque del Apache, Mount Baldy, Chiricahua, White Mountain, etc) and due to the size of the CALMET grid we cannot determine if Newman's impacts are below 0.5 dv at all Class I areas or determine the potential benefits from controls. Since plumes could transport out of the modeling domain and there is no way within the CALPUFF model to account for mass that transports out of the domain that may come back into the domain, the CALPUFF modeling databases cannot be relied on to conclusively assess visibility impacts from the Newman facility.

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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
Big Brown (Luminant)	1	400	21.5	366	30075.75	77.7	*199.095*	*16.157*	*2.9726*	*1.2746*
Big Brown (Luminant)	2	400	21.5	366	30075.75	77.7	*201.073*	*15.303*	*3.0058*	*1.289*
Coleto Creek (Engie)	1	409	20	347	36599.55	116.5	*67.83*	*17.235*	*0.8682*	*0.4412*
Fayette (LCRA)	1	600	23	316	37185.04	89.5	*61.388*	*15.363*	*2.5614*	*0.7432*
Fayette (LCRA)	2	600	23	307	39470.15	95	*61.909*	*13.79*	*4.5982*	*1.3338*
Harrington Station (Xcel)	061B	250	19	300	25148.98	88.7	*40.046*	*19.347*	*2.2942*	*0.0910*
Harrington Station (Xcel)	062B	300	19	300	25148.98	88.7	*42.749*	*19.231*	*6.0826*	*0.0382*
J T Deely (CPS Energy)	1	173	20	309	31227.43	99.4	*65.542*	*18.279*	*3.3732*	*1.5437*
J T Deely (CPS Energy)	2	172	20	309	31227.43	99.4	*52.262*	*23.034*	*5.18*	*1.9814*
Martin Lake (Luminant)	1	452	23	348	37143.49	89.4	*118.569*	*21.52*	*1.614*	*1.0876*
Martin Lake (Luminant)	2	452	23	348	38223.73	92	*109.736*	*28.337*	*2.0232*	*1.3648*
Martin Lake (Luminant)	3	452	23	348	38223.73	92	*124.38*	*24.192*	*1.9116*	*1.2886*
Monticello (Luminant)	1	400	21.5	356	29407.05	81	*142.714*	*18.125*	*6.9642*	*3.4384*
Monticello (Luminant)	2	400	21.5	356	29407.05	81	*139.962*	*13.01*	*8.219*	*3.255*
Monticello (Luminant)	3	460	25.5	329	44431.31	87	*140.815*	*24.586*	*4.8062*	*2.1632*
O W Sommers (CPS Energy)	1	240	20	275	16650.43	53	*10.917*	*8.038*	*0.1768*	*0.1768*
O W Sommers (CPS Energy)	2	240	20	275	16650.43	53	*2.011*	*5.949*	*0.145*	*0.145*
W A Parish (NRG)	WAP4	182	18	281	16413.24	64.5	*0.033*	*9.27*	*0.5044*	*0.5044*

W A Parish (NRG)	WAP5	600	24	332	38453.06	85	*97.654*	*6.018*	*0.6692*	*0.6692*
W A Parish (NRG)	WAP6	600	24	332	38453.06	85	*94.288*	*5.32*	*0.64*	*0.64*
Welsh Power Plant (AEP)	1	300	17	275	13843.1	85	*55.882*	*18.387*	*5.153*	*5.153*
Welsh Power Plant (AEP)	2	300	17	275	13843.1	85	*63.174*	*30.656*	*5.2312*	*5.2312*

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
Big Brown (Luminant)	1	400	21.5	366	30075.75	77.7	99.548	**16.157**	**2.973**	**1.275**
Big Brown (Luminant)	2	400	21.5	366	30075.75	77.7	100.537	**15.303**	**3.006**	**1.289**
Coleto Creek (Engie)	1	409	20	347	36599.55	116.5	33.915	**17.235**	**0.868**	**0.441**
Fayette (LCRA)	1	600	23	316	37185.04	89.5	61.388	**15.363**	**2.561**	**0.743**
Fayette (LCRA)	2	600	23	307	39470.15	95	61.909	**13.790**	**4.598**	**1.334**
Harrington Station (Xcel)	061B	250	19	300	25148.98	88.7	20.023	**19.347**	**2.294**	**0.091**
Harrington Station (Xcel)	062B	300	19	300	25148.98	88.7	21.375	**19.231**	**6.083**	**0.038**
J T Deely (CPS Energy)	1	173	20	309	31227.43	99.4	32.771	**18.279**	**3.373**	**1.544**
J T Deely (CPS Energy)	2	172	20	309	31227.43	99.4	26.131	**23.034**	**5.180**	**1.981**
Martin Lake (Luminant)	1	452	23	348	37143.49	89.4	26.986	**21.520**	**1.614**	**1.088**
Martin Lake (Luminant)	2	452	23	348	38223.73	92	25.595	**28.337**	**2.023**	**1.365**
Martin Lake (Luminant)	3	452	23	348	38223.73	92	24.666	**24.192**	**1.912**	**1.289**
Monticello (Luminant)	1	400	21.5	356	29407.05	81	71.357	**18.125**	**6.964**	**3.438**
Monticello (Luminant)	2	400	21.5	356	29407.05	81	69.981	**13.010**	**8.219**	**3.255**
Monticello (Luminant)	3	460	25.5	329	44431.31	87	13.710	**24.586**	**4.806**	**2.163**
O W Sommers (CPS Energy)	1	240	20	275	16650.43	53	5.746	**8.038**	**0.177**	**0.177**

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O W Sommers (CPS Energy)	2	240	20	275	16650.43	53	1.058	**5.949**	**0.145**	**0.145**
W A Parish (NRG)	WAP4	182	18	281	16413.24	64.5	0.033	**9.270**	**0.504**	**0.504**
W A Parish (NRG)	WAP5	600	24	332	38453.06	85	48.827	**6.018**	**0.669**	**0.669**
W A Parish (NRG)	WAP6	600	24	332	38453.06	85	47.144	**5.320**	**0.640**	**0.640**
Welsh Power Plant (AEP)	1	300	17	275	13843.1	85	27.941	**18.387**	**5.153**	**5.153**
Welsh Power Plant (AEP)	2	300	17	275	13843.1	85	63.174	**30.656**	**5.231**	**5.231**

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
Big Brown (Luminant)	1	400	21.5	366	30075.75	77.7	3.418	16.157	1.486	0.637
Big Brown (Luminant)	2	400	21.5	366	30075.75	77.7	3.507	15.303	1.503	0.645
Coleto Creek (Engie)	1	409	20	347	36599.55	116.5	3.213	17.235	0.434	0.221
Fayette (LCRA)	1	600	23	316	37185.04	89.5	3.071	15.363	1.281	0.372
Fayette (LCRA)	2	600	23	307	39470.15	95	3.310	13.790	2.299	0.667
Harrington Station (Xcel)	061B	250	19	300	25148.98	88.7	3.566	19.347	1.147	0.046
Harrington Station (Xcel)	062B	300	19	300	25148.98	88.7	3.234	19.231	3.041	0.019
J T Deely (CPS Energy)	1	173	20	309	31227.43	99.4	3.173	18.279	1.687	0.772
J T Deely (CPS Energy)	2	172	20	309	31227.43	99.4	3.192	23.034	2.590	0.991
Martin Lake (Luminant)	1	452	23	348	37143.49	89.4	13.493	21.520	1.614	1.088
Martin Lake (Luminant)	2	452	23	348	38223.73	92	12.797	28.337	2.023	1.365
Martin Lake (Luminant)	3	452	23	348	38223.73	92	12.333	24.192	1.912	1.289
Monticello (Luminant)	1	400	21.5	356	29407.05	81	3.185	18.125	3.482	1.719
Monticello (Luminant)	2	400	21.5	356	29407.05	81	3.233	13.010	4.110	1.628

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Monticello (Luminant)	3	460	25.5	329	44431.31	87	6.855	24.586	4.806	2.163
O W Sommers (CPS Energy)	1	240	20	275	16650.43	53	0.086	8.038	0.177	0.177
O W Sommers (CPS Energy)	2	240	20	275	16650.43	53	0.016	5.949	0.145	0.145
W A Parish (NRG)	WAP4	182	18	281	16413.24	64.5	0.033	9.270	0.252	0.252
W A Parish (NRG)	WAP5	600	24	332	38453.06	85	4.654	6.018	0.335	0.335
W A Parish (NRG)	WAP6	600	24	332	38453.06	85	3.893	5.320	0.320	0.320
Welsh Power Plant (AEP)	1	300	17	275	13843.1	85	3.126	18.387	2.577	2.577
Welsh Power Plant (AEP)	2	300	17	275	13843.1	85	0.000	0.000	0.000	0.000

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Appendix B. CALPUFF Modeled emissions

Table B-1. Base case CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	16591.25	3.00	1346.42	123.9	119.3	4.6	101
Big Brown	2	16756.08	3.00	1275.25	125.2	120.6	4.6	101.9
Harrington	061B	3337.17	0.25	1612.25	95.6	92.1	3.5	71.3
Harrington	062B	3562.42	1.64	1602.58	281.6	217	8.3	73.6
Martin Lake	1	9880.75	17.22	1793.33	74.7	57.6	2.2	10.1
Martin Lake	2	9144.67	17.40	2361.42	93.7	72.1	2.8	12.7
Martin Lake	3	10365.00	16.88	2016.00	88.5	68.2	2.6	12.5
Monticello	1	11892.83	2.91	1510.42	290.2	279.4	10.7	97
Monticello	2	11663.50	2.96	1084.17	342.5	329.8	12.7	118.9
Monticello	3	11734.58	12.13	2048.83	222.5	171.4	6.6	22.2
Welsh	1	4656.83	2.37	1532.25	238.6	183.8	7.1	57.7
Welsh	2	5264.50	2.41	2554.67	242.2	186.6	7.2	59.1

Table B-2. Low Control CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	8295.63	3.00	1346.42	123.90	119.30	4.60	101.00
Big Brown	2	8378.04	3.00	1275.25	125.20	120.60	4.60	101.90
Harrington	061B	1668.58	0.25	1612.25	95.60	92.10	3.50	71.30
Harrington	062B	1781.21	1.64	1602.58	281.60	217.00	8.30	73.60

Martin Lake	1	2248.80	17.22	1793.33	74.70	57.60	2.20	10.10
Martin Lake	2	2132.88	17.40	2361.42	93.70	72.10	2.80	12.70
Martin Lake	3	2055.46	16.88	2016.00	88.50	68.20	2.60	12.50
Monticello	1	5946.42	2.91	1510.42	290.20	279.40	10.70	97.00
Monticello	2	5831.75	2.96	1084.17	342.50	329.80	12.70	118.90
Monticello	3	1142.52	12.13	2048.83	222.50	171.40	6.60	22.20
Welsh	1	2328.42	2.37	1532.25	238.60	183.80	7.10	57.70
Welsh	2	2632.25	2.41	2554.67	242.20	186.60	7.20	59.10

Table B-3. High Control CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	284.84	1.20	1346.42	61.90	59.60	2.30	23.50
Big Brown	2	292.24	1.20	1275.25	62.60	60.30	2.30	23.70
Harrington	061B	297.18	0.10	1612.25	47.80	46.00	1.80	71.30
Harrington	062B	269.46	0.66	1602.58	140.80	108.50	4.20	73.60
Martin Lake	1	1124.40	17.22	1793.33	74.70	57.60	2.20	10.10
Martin Lake	2	1066.44	17.40	2361.42	93.70	72.10	2.80	12.70
Martin Lake	3	1027.73	16.88	2016.00	88.50	68.20	2.60	12.50
Monticello	1	265.40	1.16	1510.42	145.10	139.70	5.40	44.10
Monticello	2	269.40	1.19	1084.17	171.20	164.90	6.30	51.70
Monticello	3	571.26	12.13	2048.83	222.50	171.40	6.60	22.20
Welsh	1	260.52	0.95	1532.25	119.30	91.90	3.50	57.70
Welsh	2	245.04	0.96	2554.67	121.10	93.30	3.60	59.10

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Table B-4. SDA Control CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	427.26	0.30	1346.42	61.9	59.6	2.3	23.5
Big Brown	2	438.36	0.30	1275.25	62.6	60.3	2.3	23.7
Monticello	1	398.10	0.29	1510.42	145.1	139.7	5.4	44.1
Monticello	2	404.10	0.30	1084.17	171.2	164.9	6.3	51.7
Welsh	1	390.78	0.03	1532.25	119.3	91.9	3.5	57.7

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Appendix C. CALPUFF Recent NOx and SO2 Emissions (2011-2015)

Table C-1. RNS CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	12939.17	3.00	975.75	123.9	119.3	4.6	101
Big Brown	2	14045	3.00	983.25	125.2	120.6	4.6	101.9
Harrington	061B	2725.25	0.25	1006.17	95.6	92.1	3.5	71.3
Harrington	062B	2759	1.64	1029.17	281.6	217	8.3	73.6
Martin Lake	1	9275.42	17.22	1892.92	74.7	57.6	2.2	10.1
Martin Lake	2	8635	17.40	1633.33	93.7	72.1	2.8	12.7
Martin Lake	3	8243.75	16.88	1458.03	88.5	68.2	2.6	12.5
Monticello	1	7663.75	2.91	924.83	290.2	279.4	10.7	97
Monticello	2	7875	2.96	1036	342.5	329.8	12.7	118.9
Monticello	3	7900.42	12.13	1554.83	222.5	171.4	6.6	22.2
Welsh	1	2922.5	2.37	1274.92	238.6	183.8	7.1	57.7
Welsh	2	0	0	0	0	0	0	0

Table C-2. RNS - Low Control CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	8295.63	3.00	975.75	123.90	119.30	4.60	101.00
Big Brown	2	8378.04	3.00	983.25	125.20	120.60	4.60	101.90
Harrington	061B	1668.58	0.25	1006.17	95.60	92.10	3.50	71.30
Harrington	062B	1781.21	1.64	1029.17	281.60	217.00	8.30	73.60
Martin Lake	1	2192.8	17.22	1892.92	74.70	57.60	2.20	10.10
Martin Lake	2	2116.83	17.40	1633.33	93.70	72.10	2.80	12.70
Martin Lake	3	1991.30	16.88	1458.03	88.50	68.20	2.60	12.50
Monticello	1	3832	2.91	924.83	290.20	279.40	10.70	97.00
Monticello	2	3937.3	2.96	1036	342.50	329.80	12.70	118.90
Monticello	3	1039.26	12.13	1554.83	222.50	171.40	6.60	22.20
Welsh	1	1461	2.37	1274.92	238.60	183.80	7.10	57.70
Welsh	2	0	0	0	0	0	0	0

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Table C-3. RNS - High Control CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	252.04	1.20	975.75	61.90	59.60	2.30	23.50
Big Brown	2	254.21	1.20	983.25	62.60	60.30	2.30	23.70
Harrington	061B	231.49	0.10	1006.17	47.80	46.00	1.80	71.30
Harrington	062B	286.80	0.66	1029.17	140.80	108.50	4.20	73.60
Martin Lake	1	1096.4	17.22	1892.92	74.70	57.60	2.20	10.10
Martin Lake	2	1058.42	17.40	1633.33	93.70	72.10	2.80	12.70
Martin Lake	3	995.65	16.88	1458.03	88.50	68.20	2.60	12.50
Monticello	1	252.45	1.16	924.83	145.10	139.70	5.40	44.10
Monticello	2	261.63	1.19	1036	171.20	164.90	6.30	51.70
Monticello	3	519.63	12.13	1554.83	222.50	171.40	6.60	22.20
Welsh	1	220.61	0.95	1274.92	119.30	91.90	3.50	57.70
Welsh	2	0	0	0	0	0	0	0

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Appendix D. EPRI Calculation for H_2SO_4 Emission Rate for CALPUFF Modeling

From: Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, Electric Power Research Institute; March 2012.

$$ER_{Comb} = K \cdot F1 \cdot K1 \cdot K2 \cdot C1 \cdot S1 \cdot F2_{AH} \cdot F2_{PM} \cdot F2_{FGD}$$

where,:

ERComb = total H_2SO_4 released, lbs/hr

K = Molecular weight and units conversion constant = 98.07 / 64.04 • 2000 = 3,063

(98.07 = Molecular weight of H_2SO_4 ; 64.04 = Molecular weight of SO_2; 2000 = Conversion from tons/hr to lb/hr)

F1 = Fuel Impact Factor (See EPRI 2012 Table 4-1)

C1 = Dry coal burn, tons/hr = Coal Heating Value (MMBtu/ton) • Max Heat input (MMBtu/hr)

S1 = Coal sulfur weighted average, %, dry

K1 = Molecular weight and units conversion constant = (64.04)/(100 • 32.06) = 0.02

(64.04 = molecular weight of SO_2; 32.06 = molecular weight of S; 100 = conversion of % S to a fraction)

K2 = Sulfur conversion to SO_2, implicit from EPA AP-42 (EPA, 1995b)

(0.95 for bituminous coals, 0.875 for subbituminous coals, 0.55 to 0.85 for lignite, based on the Na content, 1.0 for oil)

F2 = Technology Impact Factors (See EPRI 2012 Tables 4-3, 4-4, and 4-5)

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Table D-1. Low Control Scenario

Facility	Unit	Coal	Max Heat input (MMBTU /hr)	C1	Coal Heating Value (MMBtu/ton, HV)	S1	K	K1	K2	F1	F2(AH)	F2(PM)	F2(FGD)	H_2SO_4 (lb/hr)
Big Brown	1	lignite	7782	565.39	6882	0.73	3063	0.02	0.75	0.0044	0.36	0.1	1	3.004
Big Brown	2	lignite	7782	565.14	6885	0.73	3063	0.02	0.75	0.0044	0.36	0.1	1	3.002
Harrington	061B	sub	4631	261.67	8848.86	0.26	3063	0.02	0.875	0.0019	0.36	0.1	1	0.249
Harrington	062B	sub	4222	238.74	8842.08	0.26	3063	0.02	0.875	0.0019	0.36	0.72	1	1.639
Martin Lake	1	lignite	11124	829.78	6703	0.99	3063	0.02	0.75	0.0044	0.36	0.72	0.4	17.218
Martin Lake	2	lignite	11124	830.15	6700	1	3063	0.02	0.75	0.0044	0.36	0.72	0.4	17.400
Martin Lake	3	lignite	11124	830.15	6700	0.97	3063	0.02	0.75	0.0044	0.36	0.72	0.4	16.878
Monticello	1	lignite	9924	768.23	6459	0.52	3063	0.02	0.75	0.0044	0.36	0.1	1	2.907
Monticello	2	lignite	9924	768.59	6456	0.53	3063	0.02	0.75	0.0044	0.36	0.1	1	2.965
Monticello	3	lignite	12870	997.98	6448	0.58	3063	0.02	0.75	0.0044	0.36	0.72	0.4	12.132
Welsh	1	sub	6896	407.32	8465.07	0.22	3063	0.02	0.875	0.0019	0.36	0.72	1	2.366
Welsh	2	sub	7046	414.35	8502.57	0.22	3063	0.02	0.875	0.0019	0.36	0.72	1	2.406

Table D-2. High Control Scenario

Facility	Unit	Coal	Max Heat input (MMBTU /hr)	C1	Coal Heating Value (MMBtu/ton, HV)	S1	K	K1	K2	F1	F2(AH)	F2(PM)	F2(FGD)	H_2SO_4 (lb/hr)
Big Brown	1	lignite	7782	565.39	6882	0.73	3063	0.02	0.75	0.0044	0.36	0.1	0.4	1.201
Big Brown	2	lignite	7782	565.14	6885	0.73	3063	0.02	0.75	0.0044	0.36	0.1	0.4	1.201
Harrington	061B	sub	4631	261.67	8848.86	0.26	3063	0.02	0.875	0.0019	0.36	0.1	0.4	0.100
Harrington	062B	sub	4222	238.74	8842.08	0.26	3063	0.02	0.875	0.0019	0.36	0.72	0.4	0.655
Martin Lake	1	lignite	11124	829.78	6703	0.99	3063	0.02	0.75	0.0044	0.36	0.72	0.4	17.218
Martin Lake	2	lignite	11124	830.15	6700	1	3063	0.02	0.75	0.0044	0.36	0.72	0.4	17.400
Martin Lake	3	lignite	11124	830.15	6700	0.97	3063	0.02	0.75	0.0044	0.36	0.72	0.4	16.878
Monticello	1	lignite	9924	768.23	6459	0.52	3063	0.02	0.75	0.0044	0.36	0.1	0.4	1.163

Monticello	2	lignite	9924	768.59	6456	0.53	3063	0.02	0.75	0.0044	0.36	0.1	0.4	1.186
Monticello	3	lignite	12870	997.98	6448	0.58	3063	0.02	0.75	0.0044	0.36	0.72	0.4	12.132
Welsh	1	sub	6896	407.32	8465.07	0.22	3063	0.02	0.875	0.0019	0.36	0.72	0.4	0.946
Welsh	2	sub	7046	414.35	8502.57	0.22	3063	0.02	0.875	0.0019	0.36	0.72	0.4	0.963

Table D-3. SDA Control Scenario

Facility	Unit	Coal	Max Heat input (MMBTU /hr)	C1	Coal Heating Value (MMBtu/ton, HV)	S1	K	K1	K2	F1	F2(AH)	F2(PM)	F2(FGD)	H_2SO_4 (lb/hr)
Big Brown	1	lignite	7782	565.39	6882	0.73	3063	0.02	0.75	0.0044	0.36	0.01	1	0.300
Big Brown	2	lignite	7782	565.14	6885	0.73	3063	0.02	0.75	0.0044	0.36	0.01	1	0.300
Monticello	1	lignite	9924	768.23	6459	0.52	3063	0.02	0.75	0.0044	0.36	0.01	1	0.291
Monticello	2	lignite	9924	768.59	6456	0.53	3063	0.02	0.75	0.0044	0.36	0.01	1	0.296
Welsh	1	sub	6896	407.32	8465.07	0.22	3063	0.02	0.875	0.0019	0.36	0.01	1	0.033

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Appendix E. CAMx Maximum Impact at each Class I Area

Table E-1. Base Case (Run 1) Maximum Impact

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0.278	0.224	0.009	0.047	0.205	0.207	0.001	0.270	0.261	0.359	0.362
BIBE	0.652	0.525	0.027	0.111	0.457	0.463	0.002	0.600	0.580	1.087	1.097
BRET	0.203	0.163	0.006	0.034	0.178	0.180	0.005	0.236	0.228	0.802	0.809
CACR	0.595	0.604	0.106	0.180	1.002	0.974	0.163	1.698	1.648	2.016	2.033
CAVE	0.480	0.388	0.017	0.081	0.463	0.468	0.003	0.617	0.596	0.923	0.932
GRSA	0.131	0.105	0.004	0.022	0.081	0.082	0.000	0.082	0.079	0.094	0.095
GUMO	0.480	0.388	0.017	0.081	0.463	0.468	0.003	0.617	0.596	0.923	0.932
HEGL	0.432	0.426	0.066	0.121	0.540	0.537	0.067	0.721	0.696	1.482	1.492
MING	0.278	0.282	0.047	0.081	0.450	0.444	0.070	0.781	0.753	1.266	1.272
PECO	0.188	0.151	0.006	0.031	0.147	0.149	0.001	0.173	0.167	0.206	0.208
SACR	0.546	0.441	0.019	0.092	0.420	0.425	0.003	0.523	0.505	0.750	0.758
UPBU	0.456	0.449	0.070	0.127	0.581	0.579	0.069	1.038	1.003	1.690	1.699
WHIT	0.504	0.406	0.017	0.085	0.347	0.350	0.002	0.402	0.388	0.568	0.574
WHPE	0.188	0.151	0.006	0.031	0.147	0.149	0.001	0.173	0.167	0.206	0.208
WIMO	0.757	0.632	0.101	0.153	0.609	0.598	0.062	0.967	0.935	2.154	2.175
Cumulative	6.168	5.332	0.518	1.277	6.089	6.072	0.451	8.896	8.601	14.525	14.645

Table E-1. Base Case (Run 1) Maximum Impact (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0.198	0.502	0.526	0.131	0.121	0.137	0.149	0.146	0.141	0.066	0.059
BIBE	0.426	0.514	0.555	0.418	0.387	0.438	0.531	0.523	0.521	0.232	0.207
BRET	0.191	0.206	0.223	0.747	0.722	0.787	1.061	1.039	1.083	0.505	0.436
CACR	0.791	0.679	0.701	2.633	2.466	2.755	4.516	4.487	4.632	2.674	2.343
CAVE	0.411	0.435	0.458	0.417	0.387	0.439	0.421	0.414	0.407	0.187	0.166
GRSA	0.094	0.254	0.257	0.032	0.030	0.034	0.036	0.035	0.036	0.016	0.015
GUMO	0.411	0.435	0.458	0.417	0.387	0.439	0.421	0.414	0.407	0.187	0.166
HEGL	0.585	0.721	0.746	1.377	1.278	1.442	1.429	1.410	1.472	1.158	0.797
MING	0.415	0.416	0.431	1.125	1.126	1.189	2.299	2.138	2.394	1.539	1.150
PECO	0.152	0.243	0.284	0.073	0.068	0.077	0.082	0.080	0.078	0.036	0.032
SACR	0.429	2.908	2.998	0.292	0.271	0.306	0.336	0.330	0.325	0.149	0.132
UPBU	0.660	0.706	0.733	2.254	2.189	2.368	1.663	1.628	1.683	1.446	0.978
WHIT	0.376	0.800	0.838	0.210	0.194	0.220	0.243	0.239	0.234	0.112	0.099
WHPE	0.152	0.243	0.284	0.073	0.068	0.077	0.082	0.080	0.078	0.036	0.032
WIMO	0.845	2.708	2.770	1.216	1.156	1.277	2.241	2.189	2.282	1.033	0.864
Cumulative	6.135	11.771	12.262	11.416	10.853	11.985	15.510	15.153	15.775	9.378	7.476

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Table E-2. High Control (Run 3) Maximum Impact

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0.016	0.016	0.001	0.001	0.012	0.012	0.001	0.013	0.011	0.007	0.007
BIBE	0.069	0.084	0.017	0.024	0.025	0.027	0.001	0.033	0.028	0.033	0.031
BRET	0.019	0.023	0.005	0.007	0.030	0.028	0.006	0.014	0.012	0.039	0.039
CACR	0.312	0.387	0.098	0.132	0.480	0.441	0.183	0.180	0.156	0.409	0.391
CAVE	0.031	0.033	0.003	0.004	0.028	0.030	0.002	0.031	0.026	0.021	0.021
GRSA	0.007	0.007	0.001	0.001	0.004	0.005	0.000	0.004	0.003	0.003	0.002
GUMO	0.031	0.033	0.003	0.004	0.028	0.030	0.002	0.031	0.026	0.021	0.021
HEGL	0.194	0.241	0.060	0.081	0.203	0.186	0.073	0.077	0.067	0.438	0.418
MING	0.146	0.182	0.045	0.061	0.157	0.146	0.074	0.102	0.088	0.188	0.179
PECO	0.010	0.011	0.001	0.001	0.008	0.009	0.000	0.008	0.007	0.004	0.004
SACR	0.035	0.037	0.003	0.004	0.026	0.027	0.002	0.026	0.022	0.017	0.017
UPBU	0.204	0.253	0.064	0.086	0.251	0.231	0.072	0.094	0.081	0.356	0.339
WHIT	0.029	0.031	0.002	0.003	0.020	0.021	0.001	0.020	0.016	0.012	0.012
WHPE	0.010	0.011	0.001	0.001	0.008	0.009	0.000	0.008	0.007	0.004	0.004
WIMO	0.270	0.334	0.098	0.133	0.306	0.282	0.068	0.082	0.071	0.245	0.235
Cumulative	1.383	1.683	0.399	0.542	1.586	1.484	0.488	0.725	0.622	1.797	1.721

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Table E-2. High Control (Run 3) Maximum Impact (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0.011	0.142	0.142	0.016	0.015	0.015	0.004	0.004	0.008	0.000	0.004
BIBE	0.023	0.086	0.084	0.058	0.056	0.053	0.042	0.032	0.068	0.000	0.037
BRET	0.023	0.028	0.027	0.211	0.241	0.217	0.124	0.097	0.177	0.000	0.136
CACR	0.186	0.413	0.412	1.468	1.811	1.609	0.733	0.563	0.914	0.000	0.822
CAVE	0.023	0.174	0.173	0.053	0.051	0.049	0.014	0.013	0.026	0.000	0.013
GRSA	0.005	0.158	0.153	0.004	0.004	0.004	0.002	0.002	0.004	0.000	0.002
GUMO	0.023	0.174	0.173	0.053	0.051	0.049	0.014	0.013	0.026	0.000	0.013
HEGL	0.114	0.521	0.525	0.451	0.580	0.500	0.551	0.407	0.767	0.000	0.553
MING	0.128	0.280	0.281	0.392	0.469	0.412	0.629	0.473	0.873	0.000	0.570
PECO	0.008	0.170	0.165	0.009	0.009	0.008	0.002	0.002	0.005	0.000	0.002
SACR	0.025	1.738	1.719	0.036	0.035	0.034	0.011	0.010	0.020	0.000	0.010
UPBU	0.130	0.466	0.469	0.805	1.025	0.890	0.415	0.314	0.565	0.000	0.402
WHIT	0.020	0.354	0.349	0.026	0.025	0.024	0.007	0.007	0.014	0.000	0.007
WHPE	0.008	0.170	0.165	0.009	0.009	0.008	0.002	0.002	0.005	0.000	0.002
WIMO	0.176	2.065	2.046	0.252	0.274	0.251	0.252	0.186	0.364	0.000	0.221
Cumulative	0.902	6.939	6.882	3.842	4.654	4.122	2.803	2.128	3.835	0.000	2.793

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Table E-3. Low Control (Run 4) Maximum Impact

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0.141	0.114	0.005	0.025	0.204	0.207	0.001	0.135	0.130	0.183	0.185
BIBE	0.373	0.300	0.022	0.066	0.460	0.466	0.002	0.319	0.309	0.585	0.591
BRET	0.100	0.080	0.006	0.017	0.173	0.175	0.006	0.124	0.120	0.453	0.457
CACR	0.447	0.490	0.102	0.157	1.046	1.018	0.175	1.052	1.018	1.327	1.338
CAVE	0.248	0.203	0.010	0.045	0.468	0.473	0.003	0.316	0.305	0.489	0.494
GRSA	0.066	0.053	0.002	0.012	0.082	0.083	0.000	0.041	0.040	0.049	0.049
GUMO	0.248	0.203	0.010	0.045	0.468	0.473	0.003	0.316	0.305	0.489	0.494
HEGL	0.309	0.330	0.063	0.102	0.593	0.591	0.071	0.426	0.410	0.948	0.952
MING	0.209	0.230	0.046	0.072	0.488	0.482	0.072	0.470	0.451	0.778	0.777
PECO	0.095	0.077	0.003	0.017	0.148	0.150	0.001	0.087	0.084	0.106	0.107
SACR	0.277	0.227	0.011	0.050	0.420	0.425	0.003	0.264	0.255	0.390	0.394
UPBU	0.326	0.347	0.067	0.107	0.628	0.625	0.071	0.613	0.591	1.148	1.150
WHIT	0.257	0.208	0.009	0.046	0.348	0.352	0.002	0.202	0.195	0.293	0.296
WHPE	0.095	0.077	0.003	0.017	0.148	0.150	0.001	0.087	0.084	0.106	0.107
WIMO	0.449	0.387	0.100	0.144	0.629	0.614	0.066	0.503	0.485	1.168	1.181
Cumulative	3.642	3.325	0.461	0.919	6.302	6.281	0.475	4.956	4.783	8.512	8.571

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Table E-3. Low Control (Run 4) Maximum Impact (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0.099	0.319	0.337	0.031	0.029	0.028	0.077	0.075	0.015	0.067	0.030
BIBE	0.218	0.284	0.306	0.107	0.102	0.098	0.295	0.291	0.073	0.252	0.116
BRET	0.093	0.110	0.119	0.284	0.307	0.282	0.636	0.615	0.193	0.571	0.274
CACR	0.458	0.544	0.557	1.550	1.882	1.682	3.123	3.065	0.905	3.297	1.659
CAVE	0.209	0.300	0.313	0.100	0.095	0.092	0.224	0.220	0.045	0.194	0.089
GRSA	0.048	0.197	0.199	0.008	0.007	0.007	0.019	0.018	0.005	0.016	0.007
GUMO	0.209	0.300	0.313	0.100	0.095	0.092	0.224	0.220	0.045	0.194	0.089
HEGL	0.362	0.617	0.633	0.464	0.583	0.506	0.939	0.922	0.804	1.183	0.686
MING	0.280	0.344	0.354	0.495	0.565	0.505	1.567	1.408	0.960	1.626	0.886
PECO	0.077	0.204	0.248	0.017	0.017	0.016	0.042	0.042	0.008	0.037	0.017
SACR	0.219	2.322	2.373	0.070	0.067	0.064	0.175	0.172	0.036	0.152	0.069
UPBU	0.397	0.582	0.600	0.867	1.077	0.942	1.057	1.014	0.600	1.497	0.631
WHIT	0.191	0.565	0.586	0.050	0.047	0.046	0.125	0.123	0.025	0.112	0.051
WHPE	0.077	0.204	0.248	0.017	0.017	0.016	0.042	0.042	0.008	0.037	0.017
WIMO	0.526	2.382	2.407	0.381	0.395	0.369	1.290	1.252	0.462	1.125	0.546
Cumulative	3.465	9.276	9.594	4.542	5.286	4.745	9.837	9.479	4.185	10.359	5.167

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Appendix F. CAMx Modeled Number of Days impacted

Table F-1. Base Case (Run 1) Number of days impacted over 0.5 dv

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	2	2	0	0	0	0	0	2	2	5	5
BRET	0	0	0	0	0	0	0	0	0	2	2
CACR	2	2	0	0	9	9	0	22	22	58	58
CAVE	0	0	0	0	0	0	0	1	1	3	3
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	1	1	3	3
HEGL	0	0	0	0	1	1	0	8	8	23	23
MING	0	0	0	0	0	0	0	1	1	6	6
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	1	0	0	0	0	0	0	1	1	3	3
UPBU	0	0	0	0	6	6	0	11	9	37	37
WHIT	1	0	0	0	0	0	0	0	0	1	1
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	4	3	0	0	2	2	0	4	3	33	34
Cumulative	10	7	0	0	18	18	0	51	48	174	175

Table F-1. Base Case (Run 1) Number of days impacted over 0.5 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	1	1	0	0	0	0	0	0	0	0
BIBE	0	1	1	0	0	0	1	1	1	0	0
BRET	0	0	0	2	2	3	3	3	3	1	0
CACR	5	1	1	71	68	76	79	78	79	49	37
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	1	1	1	26	27	29	33	31	35	11	8
MING	0	0	0	7	6	8	6	5	6	4	2
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	5	5	0	0	0	0	0	0	0	0
UPBU	2	1	1	44	40	46	45	44	45	18	13
WHIT	0	1	1	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	9	6	6	10	7	11	30	30	31	8	5
Cumulative	17	17	17	160	150	173	197	192	200	91	65

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Table F-2. High Control (Run 3) Number of days impacted over 0.5 dv

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	0	0	0	0	0	0	0	0
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	0	0
MING	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	0	0	0	0	0	0	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	0	0	0	0	0
Cumulative	0	0	0	0	0	0	0	0	0	0	0

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Table F-2. High Control (Run 3) Number of days impacted over 0.5 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	6	9	6	3	1	5	0	3
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	1	1	0	2	0	2	0	3	0	1
MING	0	0	0	0	0	0	1	0	1	0	1
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	1	1	0	0	0	0	0	0	0	0
UPBU	0	0	0	3	5	4	0	0	3	0	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	4	4	0	0	0	0	0	0	0	0
Cumulative	0	6	6	9	16	10	6	1	12	0	5

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Table F-3. Low Control (Run 4) Number of days impacted over 0.5 dv

Class I Area	**J.T. Deely Unit 1**	**J.T. Deely Unit 2**	**OW Sommers Unit 1**	**OW Sommers Unit 2**	**Fayette Unit 1**	**Fayette Unit 2**	**W. A. Parish WAP4**	**W. A. Parish WAP5**	**W. A. Parish WAP6**	**Big Brown Unit 1**	**Big Brown Unit 2**
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	2	2
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	0	9	9	0	9	8	22	23
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	1	1	0	0	0	8	8
MING	0	0	0	0	0	0	0	0	0	2	2
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	7	7	0	1	1	13	13
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	3	3	0	1	0	13	13
Cumulative	0	0	0	0	20	20	0	11	9	60	61

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Table F-3. Low Control (Run 4) Number of days impacted over 0.5 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	2	2	0	1	0
CACR	0	1	1	17	18	15	43	42	5	54	18
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	1	1	0	3	1	12	12	3	15	4
MING	0	0	0	0	1	1	4	4	1	4	1
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	1	1	0	0	0	0	0	0	0	0
UPBU	0	1	1	6	6	6	20	20	3	23	4
WHIT	0	1	1	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	1	5	5	0	0	0	10	10	0	8	2
Cumulative	1	10	10	23	28	23	91	90	12	105	29

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Table F-4. Base Case (Run 1) Number of days impacted over 1.0 dv

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	2	2
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	0	1	0	0	8	6	17	17
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	4	5
MING	0	0	0	0	0	0	0	0	0	1	1
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	0	0	0	1	1	8	8
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	0	0	0	12	12
Cumulative	0	0	0	0	1	0	0	9	7	44	45

Table F-4. Base Case (Run 1) Number of days impacted over 1.0 dv (continued)

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Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	1	1	1	0	0
CACR	0	0	0	26	26	29	32	30	32	9	8
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	3	3	3	10	7	9	1	0
MING	0	0	0	1	1	1	2	1	2	1	1
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	1	1	0	0	0	0	0	0	0	0
UPBU	0	0	0	10	10	13	14	12	15	1	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	4	4	1	1	1	8	6	7	1	0
Cumulative	0	5	5	41	41	47	67	57	66	13	9

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Table F-5. High Control (Run 3) Number of days impacted over 1.0 dv

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	0	0	0	0	0	0	0	0
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	0	0
MING	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	0	0	0	0	0	0	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	0	0	0	0	0
Cumulative	0	0	0	0	0	0	0	0	0	0	0

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Table F-5. High Control (Run 3) Number of days impacted over 1.0 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	1	1	1	0	0	0	0	0
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	0	0
MING	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	1	1	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	1	0	0	0	0	0	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	1	1	0	0	0	0	0	0	0	0
Cumulative	0	2	2	1	2	1	0	0	0	0	0

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Table F-6. Low Control (Run 4) Number of days impacted over 1.0 dv

Class I Area	**J.T. Deely Unit 1**	**J.T. Deely Unit 2**	**OW Sommers Unit 1**	**OW Sommers Unit 2**	**Fayette Unit 1**	**Fayette Unit 2**	**W. A. Parish WAP4**	**W. A. Parish WAP5**	**W. A. Parish WAP6**	**Big Brown Unit 1**	**Big Brown Unit 2**
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	0	1	1	0	1	1	4	4
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	0	0
MING	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	0	0	0	0	0	1	1
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	0	0	0	1	1
Cumulative	0	0	0	0	1	1	0	1	1	6	6

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Table F-6. Low Control (Run 4) Number of days impacted over 1.0 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	3	3	2	16	13	0	15	3
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	1	0
MING	0	0	0	0	0	0	1	1	0	1	0
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	1	1	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	1	0	2	1	0	3	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	2	1	0	0	0	2	2	0	2	0
Cumulative	0	3	2	3	4	2	21	17	0	22	3

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Technical Support Document

Our Visibility Analysis of Potential Controls for Subject to BART sources for the Texas Regional Haze BART Federal Implementation Plan

(BART Modeling TSD)

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November 2016
(Revised December 2016, see Errata- BART Modeling TSD for details)

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Preparation of Emissions Scenarios for Potential Controls - Additional visibility Modeling

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.

1. Background and Introduction

We 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.[1] 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 BART Screening TSD.

Some of the subject-to-BART sources in Texas are very far away from a Class I area yet have high enough emissions that they significantly impact visibility at Class I areas in Texas 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-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 the large emission sources. The CAMx modeling protocol followed is described in detail in the BART Screening TSD. See the UNC-IE memorandum that documents these additional CAMx runs.[2]

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[1] 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.

[2] "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

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Regarding how to use modeling to assess visibility benefits from controls, the BART guidelines state: [3]

- 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. 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.

2. Emission Calculation Methodology

See Appendix A (CAMx) and Appendix B (CALPUFF) for a full summary of emissions modeled for the visibility benefit analysis of controls. Below we describe the methodology applied to estimate the emission reductions anticipated from controls used for visibility modeling.

2.1. SO_2 emissions

As explained below and in more detail in the BART FIP 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 50% control efficiency and modeled SO_2 emissions at 50% of the baseline actual 24-hr maximum emission level obtained from 2000-

Region 6, December 8, 2016. Available in the docket for this action as "EPA-R6_RH_Task4_Memo_UNC_08Dec2016.pdf"

[3] 40 CFR part 51 Appendix Y Section IV.D.5

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2004 CAMD data. 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 24-hr heat input (MMBtu/hr) reported in the CAMD data for 2000-2004.

We noted that some of the units we were evaluating were already equipped with older underperforming scrubbers, most of which were partially bypassed. For the units with scrubber bypasses, we lacked information on scrubber absorber efficiencies represented by the recent actual emission levels and the amount of bypass that has occurred. This made it impossible to estimate the current base control efficiency and the amount of additional reductions that would occur if the unit was further controlled based solely on the actual emissions data. Therefore, as is described in our BART TSD, we used Coal Data from EIA Form 923. This information enabled us to assess the total sulfur levels coming into a unit, to determine an uncontrolled baseline, and then estimate the achievable emission rates for the low and high control scenarios, to cover the potential range of upgraded scrubber control efficiencies. The high control emissions were estimated based on 95% control efficiency and the maximum 24-hr heat input (MMBtu/hr) reported in the CAMD data for 2000-2004. The low control scenario for these units was estimated by doubling the high control emission rate to estimate a 90% control efficiency. The table below summarizes the SO_2 emissions modeled with CALPUFF. In addition to these runs, we also performed CALPUFF modeling with an alternative baseline for these units, as explained in more detail later in this TSD. For units evaluated with WFGD level controls in the high control scenario, an additional model run with SDA level controls was also performed. See appendix B for a full list of modeled emissions for all scenarios.

Table 2.1-1. 2000-2004 Baseline CALPUFF Modeled SO_2 emissions: Coal-fired Units

Source	Unit	High Control efficiency	Maximum Heat Input (2000-2004)	SO_2 Emissions (lb/hr)		
				Baseline (2000-2004)	High Control Scenario	Low Control Scenario
Big Brown	1	0.04	7121	16591.25	284.84	8295.63
Big Brown	2	0.04	7306	16756.08	292.24	8378.04
Harrington	061B	0.06	4953	3337.17	297.18	1668.58
Harrington	062B	0.06	4491	3562.42	269.46	1781.21
Martin Lake	1	0.12	9370	9880.75	1124.4	2248.80
Martin Lake	2	0.12	8887	9144.67	1066.44	2132.88
Martin Lake	3	0.11	9343	10365.00	1027.73	2055.46
Monticello	1	0.04	6635	11892.83	265.4	5946.42
Monticello	2	0.04	6735	11663.50	269.4	5831.75
Monticello	3	0.06	9521	11734.58	571.26	1142.52
Welsh	1	0.04	6513	4656.83	260.52	2328.42

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Welsh [1]	2	0.04	6126	5264.50	0	0

[1]We did some initial baseline/screening modeling with Welsh 2 included, but we also did CALPUFF runs with Welsh 2 at zero emissions for baseline and control case modeling for Welsh to reflect the recent shutdown of this unit and isolate the visibility benefits from controlling Welsh unit 1

For the coal-fired EGUs evaluated with CALPUFF, we also evaluated maximum 24-hour NOx and SO_2 from a more recent baseline period (2011-2015) using the 2001-2003 CALMET data since some controls or reductions in emissions may have occurred due to federal rules and we wanted to provide additional information as part of the visibility benefit analysis. For High Control we used the recent Maximum Heat Input and High Control Efficiency to calculate the controlled emission rate. For the Low Control we used a 50% reduction of recent emissions for the units currently unscrubbed. For the units that have underperforming scrubbers, we used the High control emission rate and doubled to estimate a lower scrubbed control.

Table 2.1-2. 2011-2015 Recent NOx and SO_2 Emissions (RNS) CALPUFF Modeled SO_2 emissions: Coal-fired Units

Source	Unit	High Control efficiency	Maximum Heat Input (2011-2015)	SO_2 Emissions (lb/hr)		
				Recent Emissions (2011-2015)	High Control Scenario	Low Control Scenario
Big Brown	1	0.04	6301	12939.17	252.04	8295.63
Big Brown	2	0.04	6355	14045	254.21	8378.04
Harrington	061B	0.06	3858	2725.25	231.49	1668.58
Harrington	062B	0.06	4780	2759	286.80	1781.21
Martin Lake	1	0.12	9137	9275.42	1096.4	2192.8
Martin Lake	2	0.12	8820	8635	1058.42	2116.8
Martin Lake	3	0.11	9051	8243.75	995.65	1991.3
Monticello	1	0.04	6311	7663.75	252.45	3832
Monticello	2	0.04	6541	7875	261.63	3937.3
Monticello	3	0.06	8661	7900.42	519.63	1039.3
Welsh	1	0.04	5515	2922.5	220.61	1461
Welsh [1]	2	0.04	5606	0	0	0

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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 units with existing scrubbers, the low control case assumed scrubber upgrades achieving 90% control efficiency and the high control case assumed scrubber upgrades achieving 95% control efficiency. 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.

W.A. Parish unit 4 and Sommers units 1 and 2 are primarily gas-fired units. Parish unit 4 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 this unit were held at baseline levels for the two control scenarios. The Sommers units burned fuel oil during the baseline period. EIA form 767 data shows that Sommers reported burning 0.19% sulfur fuel oil during 2003 when the maximum 24-hr baseline emissions occurred. High and low control scenario emissions were estimated based on a reduction to ultra-low sulfur diesel (ULSD) at 0.0015% and 0.01% sulfur fuel oil.

Table 2.1-3. CAMx modeled SO_2 emission rates

Source	**Unit**	SO_2 **(tons/day)**		
		Base case (2000-2004)	**Low control**	**High Control**
Big Brown (Luminant)	1	199.095	99.5475	3.41808
Big Brown (Luminant)	2	201.073	100.5365	3.50688
Coleto Creek (Engie)	1	67.83	33.915	3.21264
Fayette (LCRA)	1	61.388	61.388*	3.07056
Fayette (LCRA)	2	61.909	61.909*	3.3096
Harrington Station (Xcel)	061B	40.046	20.023	3.56616
Harrington Station (Xcel)	062B	42.749	21.3745	3.23352
J T Deely (CPS Energy)	1	65.542	32.771	3.17328
J T Deely (CPS Energy)	2	52.262	26.131	3.192
Martin Lake (Luminant)	1	118.569	26.9856	13.4928
Martin Lake (Luminant)	2	109.736	25.59456	12.79728
Martin Lake (Luminant)	3	124.38	24.66552	12.33276
Monticello (Luminant)	1	142.714	71.357	3.1848
Monticello (Luminant)	2	139.962	69.981	3.2328

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Monticello (Luminant)	3	140.815	13.71024	6.85512
O W Sommers (CPS Energy)	1	10.917	5.745789474	0.086187
O W Sommers (CPS Energy)	2	2.011	1.058421053	0.015876
W A Parish (NRG)	WAP4	0.033	0.033	0.033
W A Parish (NRG)	WAP5	97.654	48.827	4.6536
W A Parish (NRG)	WAP6	94.288	47.144	3.8928
Welsh Power Plant (AEP)	1	55.882	27.941	3.12624
Welsh Power Plant (AEP)	2	63.174	63.174*	0

*Modeled at the baseline rate in the low control scenario. Fayette units already have scrubber installed and Welsh 2 is shut down. No need to examine a low control scenario for these units.

2.2. NOx, PM and Sulfuric Acid Emissions

NOx emissions were held constant at baseline emission levels for all emission units in order to isolate visibility improvements due to SO_2 reductions from any visibility benefits that would result from reductions in NOx emissions.

For the coal-fired EGUs evaluated with CALPUFF, we also evaluated a more recent baseline period (2011-2015) using the 2001-2003 CALMET data since some controls or reductions in emissions may have occurred due to federal rules and we wanted to provide additional information as part of the visibility benefit analysis. In these RNS (Recent NOx and SO2) CALPUFF runs, we used the recent maximum NOx emissions and held the NOx emissions constant for all runs to isolate visibility improvements due to SO_2 reductions from any visibility benefits that would result from reductions in NOx emissions.

For the high control scenarios for dry scrubbing and wet scrubbing retrofits, 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.

Speciated PM emissions for CALPUFF modeling were calculated using the National Park Service (NPS) speciation worksheets corresponding to dry bottom boilers and the emission control equipment present in each modeling scenario for the coal-fired boilers. PM speciation in the NPS worksheets is based on AP-42 Tables 1.1-5 and 1-1.6 (for dry-bottom boilers) and depends on the type of emission control equipment and the coal's sulfur and ash content. PM coarse, PM fine, soil, elemental carbon and SOA emissions were input into CALPUFF. See

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Appendix E of the BART Screening TSD for summary of coal properties utilized in these calculations.

Consistent with the methodology used to estimate baseline sulfuric acid emissions for CALPUFF modeling described in the BART Screening TSD, control scenario estimates of H_2SO_4 emissions from the coal-fired units are based on the best current information available from 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 the Electric Power Research Institute (EPRI). 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. For further information about the baseline and control scenario H_2SO_4 emission rates used for CALPUFF modeling see Appendix D of this TSD.

For the RNS CALPUFF runs we adjusted the NOx and SO_2 to reflect more recent maximum emission rates for the recent baseline. We used the same speciated PM and sulfuric acid emission rates as the 2001-2004 baseline and the two control case scenarios. NOx emissions were held constant at the more recent baseline rate. For the actual emission rates used in the RNS baseline and two control scenarios see Appendix C.

2.3. Emissions reductions from Fuel Oil Switching

To evaluate the visibility benefit of switching to lower sulfur fuel oil for those subject-to-BART gas/fuel oil-fired units, we modeled estimated emissions for switching to 0.3% sulfur fuel oil and 0.0015% S fuel oil (ULSD). SO_2 emissions were calculated by multiplying the baseline rate by the ratio of control scenario sulfur content to baseline sulfur content of the fuel oil burned. NOx and PM emissions were held constant at baseline levels. We note that PM emissions from lower sulfur fuel oils are anticipated to be less than baseline levels but visibility impact from direct PM emissions are a very small portion of the overall visibility impact due to the sources emissions. Reducing the PM emissions for the control scenarios would result in slightly greater visibility benefits from fuel switching.[4] See the BART Screening TSD for additional information on estimates of maximum emissions for Stryker and Graham units used for baseline emissions for these units.

Table 2.3-1. CALPUFF Modeled SO_2 emissions: Gas/Fuel-fired Units

Source	Unit	Baseline Fuel oil Sulfur Content (%)[5]	SO_2 Emissions (lb/hr)		
			Baseline	High Control Scenario (0.0015% S)	Low Control Scenario (0.3% S)
Graham	2	0.69	3727.5	7.67	1620.65

[4] See "gas-fired SO_2 emissions comparison and calcs.xlsx" for detailed emission calculations and BART FIP TSD for a summary of EIA data.
[5] Maximum reported fuel oil sulfur content from EIA-767 data for 2001-2004

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Stryker	ST2	0.65	3604.9	7.88	1663.78
Wilkes	1	0.43	323.5	1.13	75.23*
Wilkes	2	NA	1.92	1.92	1.92
Wilkes	3	NA	1.83	1.83	1.83

*Modeled at 0.1% S fuel oil

3. Visibility Benefits of DSI, SDA, and Wet FGD for Coal-Fired Units

We evaluated the visibility benefits of DSI, for the twelve units below that currently have no SO_2 control. We evaluated all the units using the control levels we employed in our control cost analyses. In summary, we evaluated these units at a DSI SO_2 control level of 50%, which we believe is likely achievable for any unit. At the lower performance level we assumed, we conclude that the corresponding visibility benefits from DSI in most cases would be close to half of the benefits from scrubbers resulting in the visibility benefits from scrubber retrofits being much more beneficial. We also evaluated the visibility benefits for scrubber retrofits (wet FGD and SDA) for these same units, assuming the same control levels corresponding to SDA and wet FGD that we used in our control cost analyses. For those sources that are within 50 to 400 km of a Class I area, we utilized CALPUFF modeling and supplemented our analysis with CAMx modeling to assess the visibility benefit of potential controls. For the remaining coal-fired sources (J T Deely, Coleto Creek, Fayette and W A Parish), only CAMx modeling was utilized as these sources are located at much greater distances to the nearest Class I areas. 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.[6] We note that high control scenario modeling for Fayette units 1 and 2 demonstrate the benefit from existing high performing controls. As discussed elsewhere, we found that for these units no additional controls or upgrades were necessary. For a full discussion of our review of all the modeling results, and factors that we considered in evaluating and weighing all the results, see the following sections of this TSD. Below, we present a summary of some of those visibility benefits at the Class I areas most impacted by each source:

Table 3-1. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CAMx modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Unit 1 and 2)	WIMO	Max dv	4.017	2.249	0.474	1.768	3.542
			Days > 0.5 dv	65	33	0	32	65

[6] 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."

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			Days>1.0 dv	33	13	0	20	33
		CACR	Max dv	3.775	2.539	0.787	1.236	2.988
			Days > 0.5 dv	91	62	4	29	87
			Days>1.0 dv	57	21	0	36	57
	Unit 1	WIMO	Max dv	2.154	1.168	0.245	0.986	1.909
			Days > 0.5 dv	33	13	0	20	33
			Days>1.0 dv	12	1	0	11	12
		CACR	Max dv	2.016	1.327	0.409	0.688	1.606
			Days > 0.5 dv	58	22	0	36	58
			Days>1.0 dv	17	4	0	13	17
	Unit 2	WIMO	Max dv	2.175	1.181	0.235	0.994	1.940
			Days > 0.5 dv	34	13	0	21	34
			Days>1.0 dv	12	1	0	11	12
		CACR	Max dv	2.033	1.338	0.391	0.695	1.642
			Days > 0.5 dv	58	23	0	35	58
			Days>1.0 dv	17	4	0	13	17
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63
			Days>1.0 dv	40	14	0	26	40
	Unit 1	CACR	Max dv	4.516	3.123	0.733	1.393	3.783
			Days > 0.5 dv	79	43	3	36	76
			Days>1.0 dv	32	16	0	16	32
		WIMO	Max dv	2.241	1.290	0.252	0.951	1.989

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			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	8	2	0	6	8
	Unit 2	CACR	Max dv	4.487	3.065	0.563	1.422	3.924
			Days > 0.5 dv	78	42	1	36	77
			Days>1.0 dv	30	13	0	17	30
		WIMO	Max dv	2.189	1.252	0.186	0.937	2.003
			Days > 0.5 dv	30	10	0	20	30
			Days>1.0 dv	6	2	0	4	6
Coleto Creek	Source (Unit 1)	WIMO	Max dv	0.845	0.526	0.176	0.318	0.668
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.791	0.458	0.186	0.333	0.606
			Days > 0.5 dv	5	0	0	5	5
			Days>1.0 dv	0	0	0	0	0
Harrington	Source (Unit 061B & 062B)	SACR	Max dv	5.288	4.287	3.235	1.001	2.053
			Days > 0.5 dv	13	7	3	6	10
			Days>1.0 dv	5	1	1	4	4
		WIMO	Max dv	4.928	4.362	3.798	0.565	1.130
			Days > 0.5 dv	15	11	6	4	9
			Days>1.0 dv	6	5	4	1	2
	Unit 061B	SACR	Max dv	2.908	2.322	1.738	0.586	1.170
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.708	2.382	2.065	0.326	0.643
			Days > 0.5 dv	6	5	4	1	2

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			Days>1.0 dv	4	2	1	2	3
	Unit 062B	SACR	Max dv	2.998	2.373	1.719	0.625	1.279
			Days > 0.5 dv	5	1	1	4	4
			Days>1.0 dv	1	1	1	0	0
		WIMO	Max dv	2.770	2.407	2.046	0.363	0.723
			Days > 0.5 dv	6	5	4	1	2
			Days>1.0 dv	4	1	1	3	3
JT Deely	Source (Sommers 1&2, JTDeely 1&2)	WIMO	Max dv	1.513	0.939	0.814	0.574	0.699
			Days > 0.5 dv	47	8	1	39	46
			Days>1.0 dv	6	0	0	6	6
		CACR	Max dv	1.423	1.155	0.905	0.268	0.518
			Days > 0.5 dv	7	3	2	4	5
			Days>1.0 dv	2	1	0	1	2
	JT Deely 1	WIMO	Max dv	0.757	0.449	0.270	0.307	0.487
			Days > 0.5 dv	4	0	0	4	4
			Days>1.0 dv	0	0	0	0	0
		BIBE	Max dv	0.652	0.373	0.069	0.279	0.583
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
	JT Deely 2	WIMO	Max dv	0.632	0.387	0.334	0.245	0.298
			Days > 0.5 dv	3	0	0	3	3
			Days>1.0 dv	0	0	0	0	0
		CACR	Max dv	0.604	0.490	0.387	0.114	0.217
			Days > 0.5 dv	2	0	0	2	2
			Days>1.0 dv	0	0	0	0	0
	Source	CACR	Max dv	3.177	2.032	0.511	1.145	2.665

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W.A. Parish	(WAP 4,5, &6)		Days > 0.5 dv	54	26	1	28	53
			Days>1.0 dv	22	9	0	13	22
		UPBU	Max dv	1.994	1.215	0.234	0.779	1.760
			Days > 0.5 dv	34	14	0	20	34
			Days>1.0 dv	9	1	0	8	9
	WAP 5	CACR	Max dv	1.698	1.052	0.180	0.646	1.518
			Days > 0.5 dv	22	9	0	13	22
			Days>1.0 dv	8	1	0	7	8
		UPBU	Max dv	1.038	0.613	0.094	0.424	0.943
			Days > 0.5 dv	11	1	0	10	11
			Days>1.0 dv	1	0	0	1	1
	WAP 6	CACR	Max dv	1.648	1.018	0.156	0.630	1.492
			Days > 0.5 dv	22	8	0	14	22
			Days>1.0 dv	6	1	0	5	6
		UPBU	Max dv	1.003	0.591	0.081	0.412	0.922
			Days > 0.5 dv	9	1	0	8	9
			Days>1.0 dv	1	0	0	1	1
Welsh	Source (Unit 1 & 2)	CACR	Max dv	4.576		0.822		3.754
			Days > 0.5 dv	92		3		89
			Days>1.0 dv	39		0		39
		MING	Max dv	2.544		0.570		1.973
			Days > 0.5 dv	9		1		8
			Days>1.0 dv	3		0		3
	Unit 1	CACR	Max dv	2.343	1.659	0.822	0.684	1.521
			Days > 0.5 dv	37	18	3	19	34

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			Days>1.0 dv	8	3	0	5	8
		MING	Max dv	1.150	0.886	0.570	0.264	0.579
			Days > 0.5 dv	2	1	1	1	1
			Days>1.0 dv	1	0	0	1	1
Fayette	Source (Unit 1 & 2)	CACR	Max dv	1.894		0.903		0.991
			Days > 0.5 dv	26		2		24
			Days>1.0 dv	9		0		9
		WIMO	Max dv	1.175		0.580		0.595
			Days > 0.5 dv	19		1		18
			Days>1.0 dv	2		0		2
	Unit 1	CACR	Max dv	1.002		0.480		0.522
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	1		0		1
		WIMO	Max dv	0.609		0.306		0.302
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0
	Unit 2	CACR	Max dv	0.974		0.441		0.534
			Days > 0.5 dv	9		0		9
			Days>1.0 dv	0		0		0
		WIMO	Max dv	0.598		0.282		0.316
			Days > 0.5 dv	2		0		2
			Days>1.0 dv	0		0		0

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Table 3-2. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Units 1 and 2)	WIMO	Max dv	4.27	2.54	0.43	1.73	3.83
			Days > 0.5 dv Avg.	67.33	43.33	2.67	24.00	64.67
			Days>1.0 dv Avg.	42.00	21.00	1.00	21.00	41.00
		CACR	Max dv	4.03	2.41	0.47	1.62	3.55
			Days > 0.5 dv Avg.	91.67	64.33	4.67	27.33	87.00
			Days>1.0 dv Avg.	60.33	30.00	0.00	30.33	60.33
Monticello[1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	3.68	1.70	4.16	4.87
			Days > 0.5 dv Avg.	143.67	115.00	62.33	28.67	81.33
			Days>1.0 dv Avg.	113.00	66.33	23.67	46.67	89.33
		UPBU[4]	Max dv	3.45	1.77	0.77	1.68	2.68
			Days > 0.5 dv Avg.	103.00	61.00	13.67	42.00	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60.00	34.67	6.00	25.33	54.00
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67
Harrington[2]	Source (Units 061B & 062B)	SACR	Max dv	1.06	0.86	0.61	0.20	0.45
			Days > 0.5 dv Avg.	21.00	15.33	6.33	5.67	14.67
			Days>1.0 dv Avg.	6.67	3.00	0.67	3.67	6.00
		WIMO	Max dv	1.29	0.97	0.55	0.32	0.74
			Days > 0.5 dv Avg.	26.00	15.33	8.67	10.67	17.33

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			Days>1.0 dv Avg.	9.00	4.67	1.33	4.33	7.67
Welsh[3]	Source (Unit 1)	CACR	Max dv	1.44	1.12	0.72	0.32	0.72
			Days > 0.5 dv Avg.	50.33	32.67	12.33	17.67	38
			Days>1.0 dv Avg.	15.33	8.00	2.33	7.33	13.00
		UPBU	Max dv	0.76	0.49	0.22	0.27	0.54
			Days > 0.5 dv Avg.	12.00	4.67	0.33	7.33	11.67
			Days>1.0 dv Avg.	0.67	0.00	0.00	0.67	0.67
		WIMO	Max dv	0.56	0.33	0.15	0.23	0.41
			Days > 0.5 dv Avg.	7.33	2.67	0.33	4.67	7.00
			Days>1.0 dv Avg.	1.33	0.33	0.00	1.00	1.33

[1] Monticello's controlled level is a combination of scrubber upgrades and scrubber install in the facility impact modeling with CALPUFF.
[2] Harrington high control scenario for both units is SDA at 95% reduction
[3] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.
[4] UPBU = Upper Buffalo Wilderness Area.

Based on the information presented here, we find that installing either wet FGD or SDA scrubbers on these units would yield significant visibility improvements. Below we provide additional analysis of visibility modeling results for each unit.

4. Visibility Benefit Analysis of DSI, SDA, and wet FGD

CALPUFF[7] and CAMx model results[8,9] shown in the tables below summarize the benefits from the recommended controls at the two Class I areas most impacted by the source or unit in the baseline modeling. As previously discussed and also in the BART Screening TSD, we have utilized CALPUFF for sources within the typical range of CALPUFF. We conducted CALPUFF and CAMx modeling to evaluate the visibility benefits for DSI, SDA, and WFGD but are only explicitly reporting the visibility benefits for the proposed BART level in this TSD. For the

[7] See spreadsheets: "TX_CALPOST_coal_all.xlsx", "TX_CALPOST_coal_RNS_all.xlsx", and "TX_CALPOST_NG-FO_all.xlsx" in the docket for this action for these and additional model results.
[8] See spreadsheet: "summary CAMx vis daily.xlsx" in the docket for this action for these and additional model results.
[9] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for summary of base case model results, including species specific 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.

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visibility benefits for the other potential emission rate/control levels not proposed for BART modeled with CALPUFF, see the spreadsheets that include CALPUFF results listed in the footnotes for this paragraph. For the visibility benefits for the other potential emission rate/control levels not proposed for BART modeled with CAMx, see the figures in the following sections, Appendix E and F, and the spreadsheets that include CAMx results listed in the footnotes for this paragraph.

For the CALPUFF and CAMx modeling, the benefit is calculated as the difference between the maximum impact modeled for the baseline and the maximum impact level modeled under the control scenario and provided in tables for each facility/subsection below. Also summarized are the cumulative benefit and the number of days impacted over 0.5 and 1.0 dv (CALPUFF and CAMx). 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 E for CAMx modeled maximum impact at each Class I area for each model scenario. See Appendix F for CAMx modeled number of days over 0.5 and 1.0 dv at each Class I area for each model scenario.

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 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. The figures in each subsection below show unit-level model results for the base case (Run 1) and the two control scenarios (Run 3 and Run 4) modeled for all unscrubbed units. The low control scenario (Run 4) estimates the visibility impacts and benefits from DSI level controls at 50% for unscrubbed units. The high control scenario (Run 3) estimates visibility impacts and benefits for WFGD/SDA level controls at unscrubbed units. For each unscrubbed unit, there are four figures. The first figure shows the maximum CAMx modeled impact at each Class I area for each modeled scenario, consistent with the data in the tables above. The second figure provides 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. The third figure provides an assessment of 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

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average only includes days during the baseline modeled scenario with impacts greater than 0.1 dv.[10] Finally, the fourth figure shows the contribution to extinction from the unit due to each visibility impairing species[11] 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.[12]

4.1. Big Brown 1 & 2

In reviewing the Big Brown units, we conclude that the installation of wet FGD will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.1-1a. Wet FGD Visibility Benefits at Big Brown (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Big Brown Units 1 & 2	3.83	3.55	7.38	151.67	101.33

Table 4.1-1b. Wet FGD Visibility Benefits at Big Brown RNS {2011-2015} (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Big Brown Units 1 & 2	3.205	2.97	6.175	138.33	83

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek and Wichita Mountains
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the

[10] See spreadsheet: "summary CAMx vis daily.xlsx" in the docket for this action for these and additional model results.
[11] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)
[12] 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.

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chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek and Wichita Mountains.

In evaluating Big Brown, we note there are two Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results, we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the two Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate that wet FGD on both units will eliminate 151.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the visibility benefits in terms of dv benefits at the most impacted Class I areas and about 1/3rd to half the cumulative benefits over the class I areas included in the modeling analysis. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to wet FGD levels.

Table 4.1-2. Wet FGD Visibility Benefits at Big Brown (CAMx)

Unit	Improvement at Wichita mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Big Brown 1	1.909	1.606	12.728	174 / 44	174 / 44
Big Brown 2	1.940	1.642	12.924	175 / 45	175 / 45
Source	3.542	2.988	24.274	372 / 170	362 / 170

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1dv at all Class I areas on a unit- and source-wide basis, and eliminate all but 10 days across the impacted Class I areas where the source-wide impacts exceeds 0.5 dv. At the most impacted Class I area, wet FGD on each unit result in visibility improvements of 1.9 dv each on the most impacted day. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas

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included in the CAMx modeling. Figures 4.1-1 (unit 1) and 4.1-5 (unit 2) below show the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figures 4.1-2 and 4.1-6). At the most impacted Class I area, wet FGD on each unit results in visibility improvements of 1.4 dv on average across the top ten most impacted days, and approximately 1.3 dv at the second most impacted Class I area for each unit. Figures 4.1-3 and 4.1-7 show an assessment of the annual average impacts and benefits under the control scenarios.[13] Wet FGD reduces annual average base case impacts from each unit at each Class I area by over 90% while DSI reduces annual average impacts at each Class I area by 50% or less. On average across all Class I areas, Wet FGD results in a 95% reduction in annual average visibility impacts from each unit. Figures 4.1-4 and 4.1-8 show the contribution to extinction from the units due to each visibility impairing species[14] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Wichita Mountains and Caney Creek) for the base case modeling scenario.[15] These figures show that the impacts from the Big Brown units on these days are primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to these units.

[13] 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 at each Class I area with impacts greater than 0.1 dv.

[14] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[15] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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Figure 4.1-1. Maximum CAMx modeled impact (dv)– Big Brown Unit 1

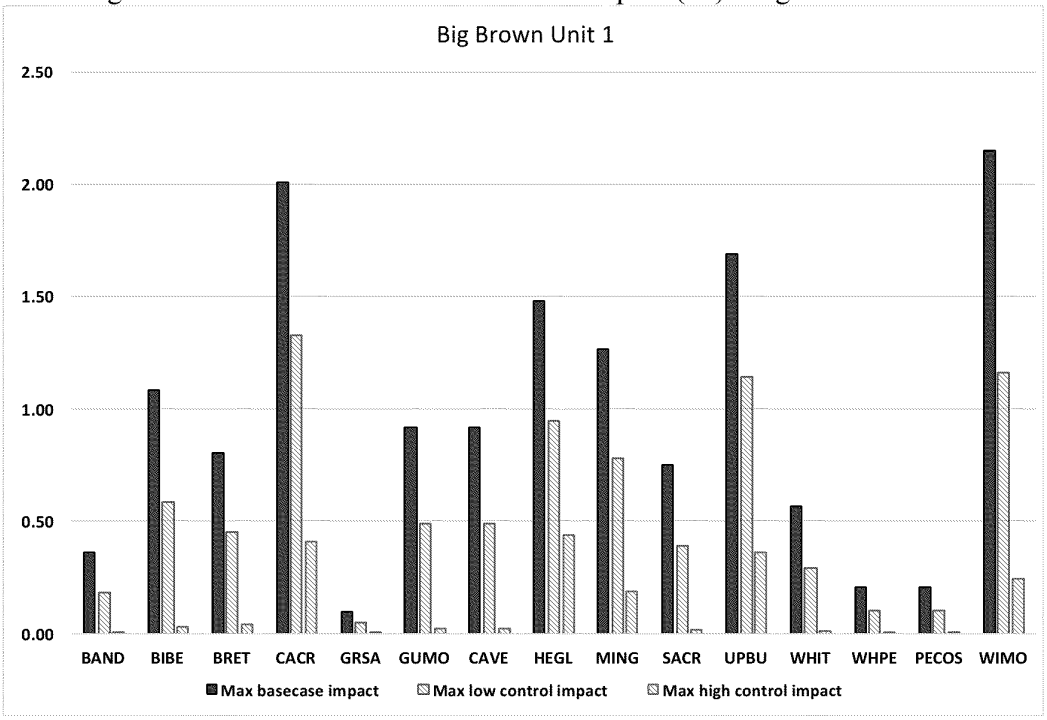

Figure 4.1-2. Average of top ten CAMx modeled impact (dv) – Big Brown Unit 1

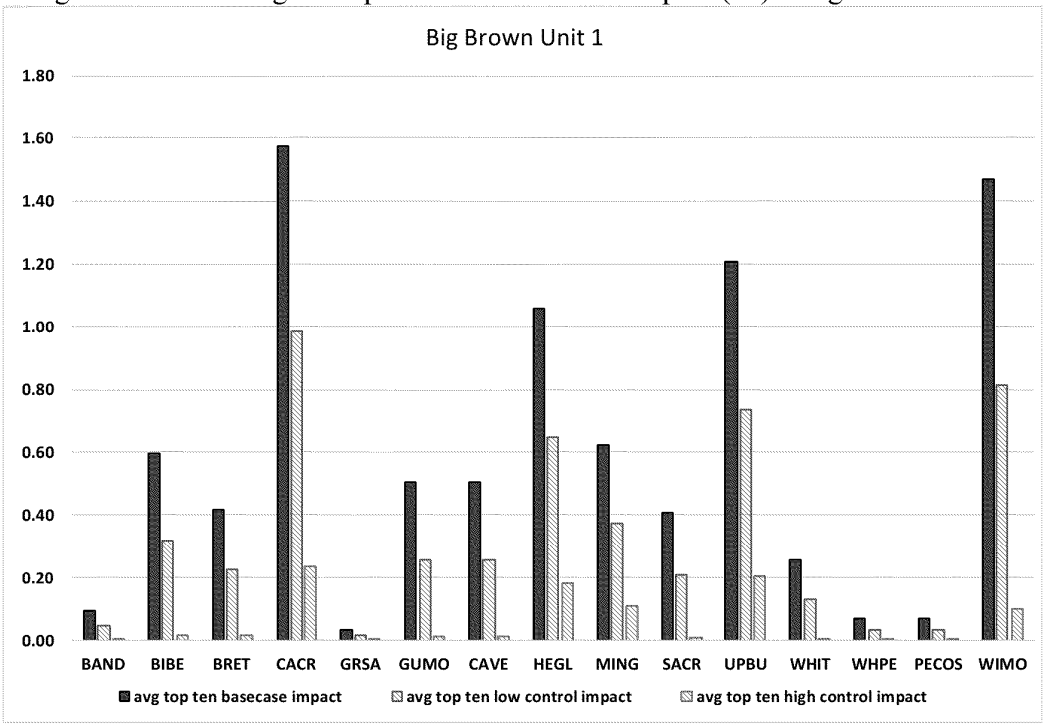

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Figure 4.1-3. Annual Average CAMx modeled impact (dv) excluding baseline days impacted less than 0.1 dv – Big Brown Unit 1

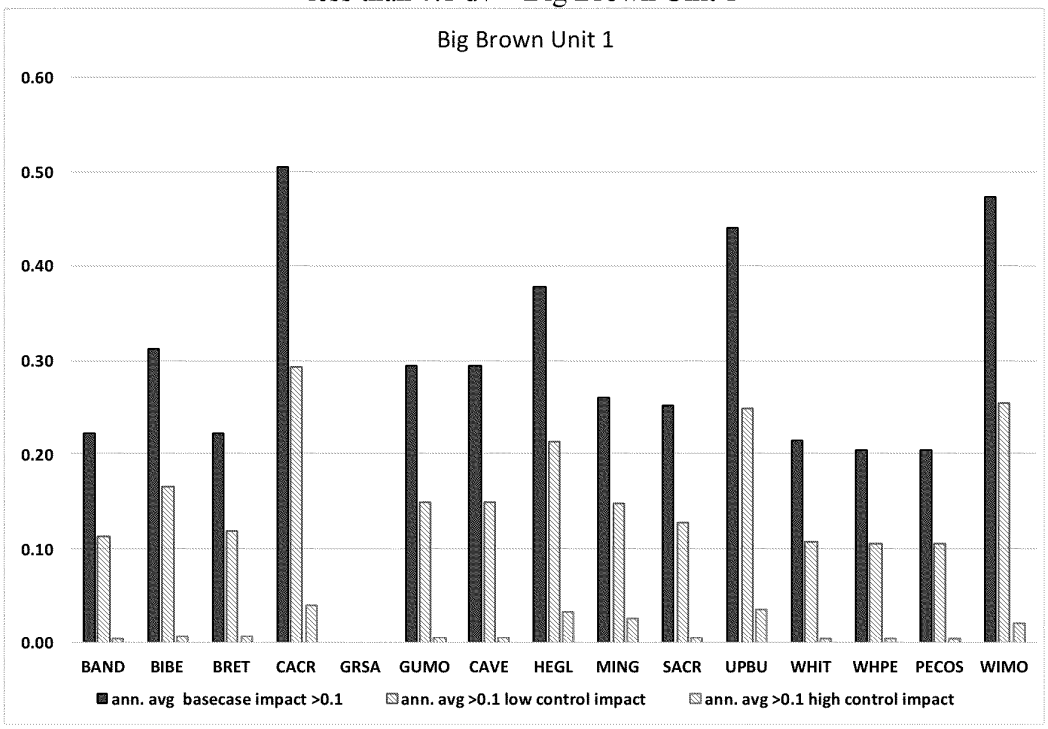

Figure 4.1-4. Species Contribution (Mm-1) on ten highest impact days (base case) at two most impacted Class I areas – Big Brown Unit 1

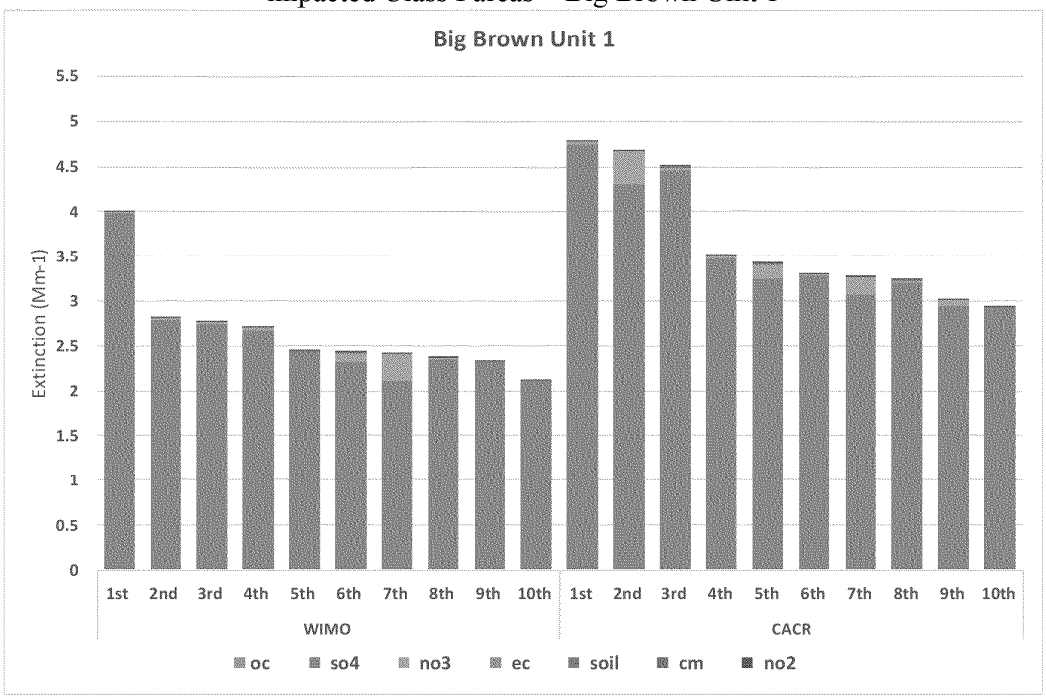

Figure 4.1-5. Maximum CAMx modeled impact (dv) – Big Brown Unit 2

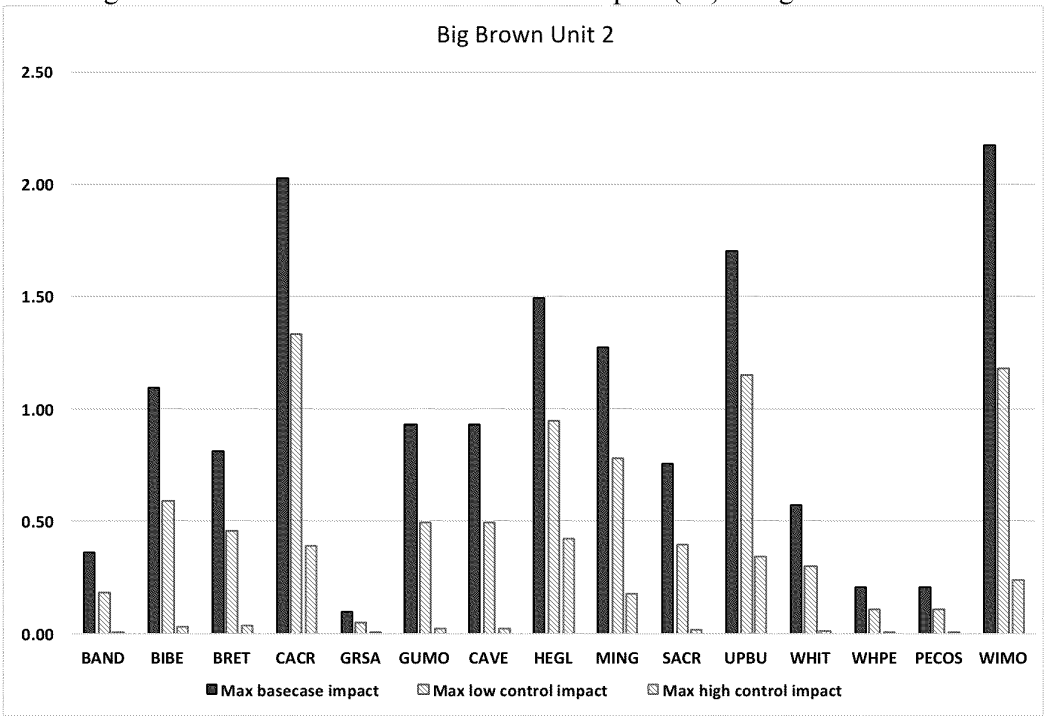

Figure 4.1-6. Average of top ten CAMx modeled impact (dv) – Big Brown Unit 2

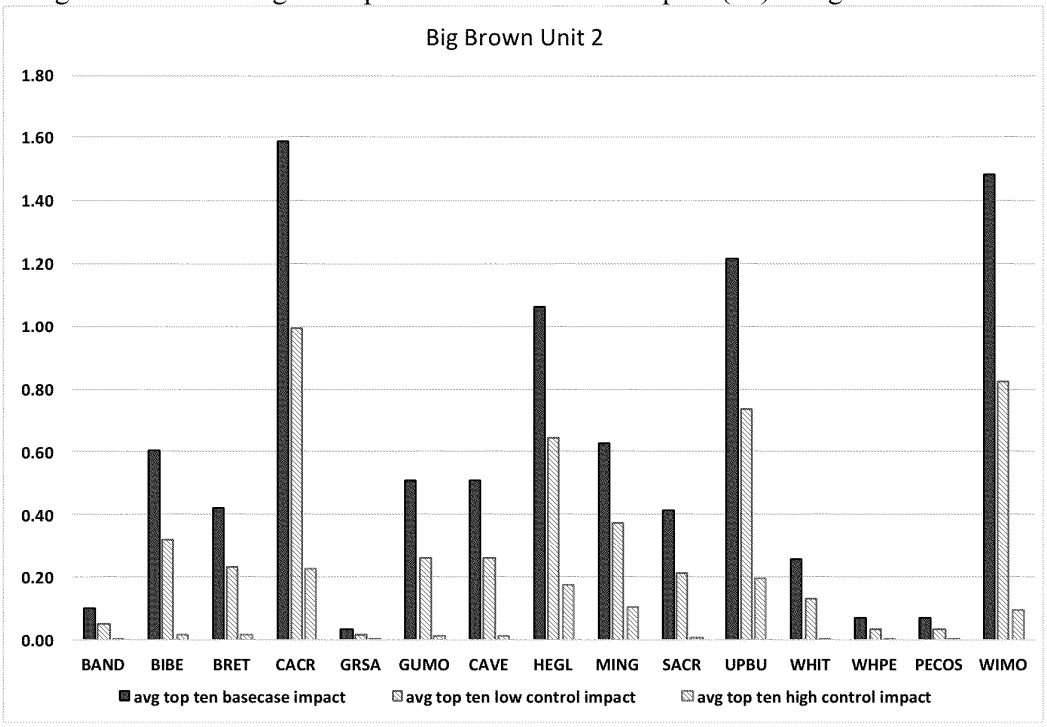

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Figure 4.1-7. Annual Average CAMx modeled impact excluding baseline days impacted (dv) less than 0.1 dv – Big Brown Unit 2

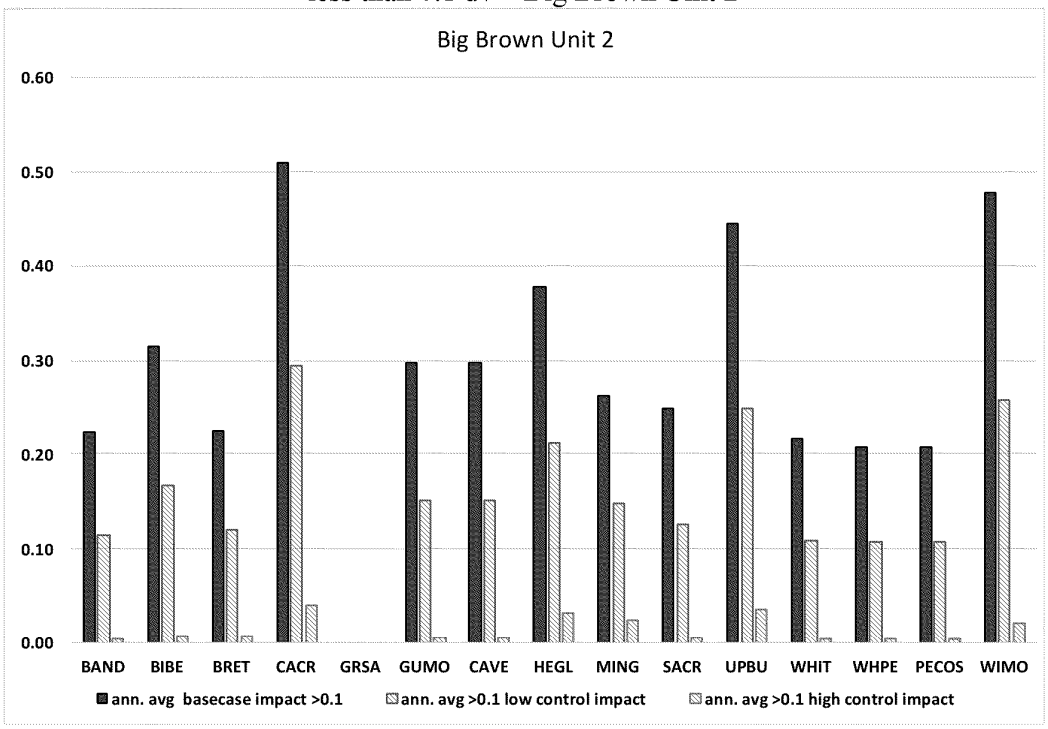
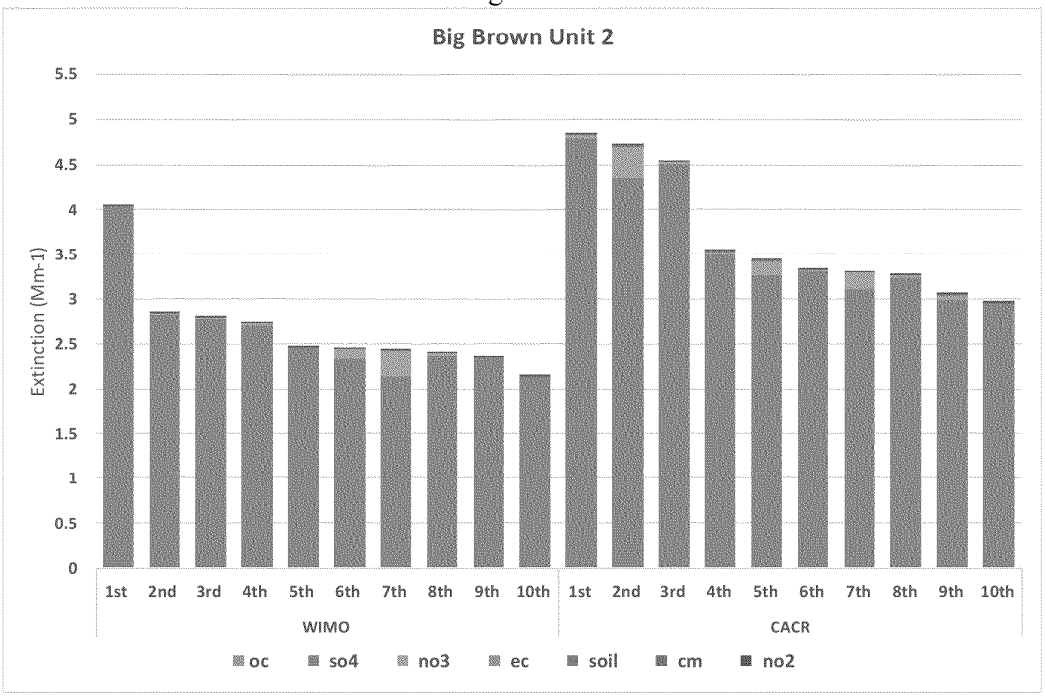


Figure 4.1-8. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Big Brown Unit 2



4.2. Monticello 1 & 2

Similar to the Big Brown units, the installation of wet FGD at Monticello Units 1 and 2 will result in very significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.2-1a. Wet FGD Visibility Benefits at Monticello (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	4.87	2.70	10.25	224.67	164.67

Table 4.2-1b. Wet FGD Visibility Benefits at Monticello with Scrubber Upgrade on Unit 3 RNS {2011-2015} (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	3.67	1.88	7.37	201.33	147

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Monticello, we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by

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the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate wet FGD on both units will eliminate 224.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 13 class I areas included in the CAMx modeling. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to wet FGD levels.

Table 4.2-2. Wet FGD Visibility Benefits at Monticello (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 1	3.783	1.989	12.708	197 / 67	191 / 67
Monticello 2	3.924	2.003	13.025	192 / 57	191 / 57
Source (including unit 3)	8.419	4.962	31.553	520 / 293	460 / 278

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD will eliminate all days impacted over 1 dv at all Class I areas on a unit basis, and eliminate all but 15 days across the impacted Class I areas where the source-wide impacts exceeds 1 dv. We note that source-wide modeled benefits include benefits of 95% control scrubber upgrade on Unit 3. At the most impacted Class I area, wet FGD on each unit will each result in visibility improvements of 3.8-3.9 dv on the most impacted day at Caney Creek and 2 dv visibility benefits at Wichita Mountains. DSI operated at 50% control results in less than half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. Figures 4.2-1 (unit 1) and 4.2-5 (unit 2) below show the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figures 4.2-2 and 4.2-6). At the most impacted Class I area, wet FGD on

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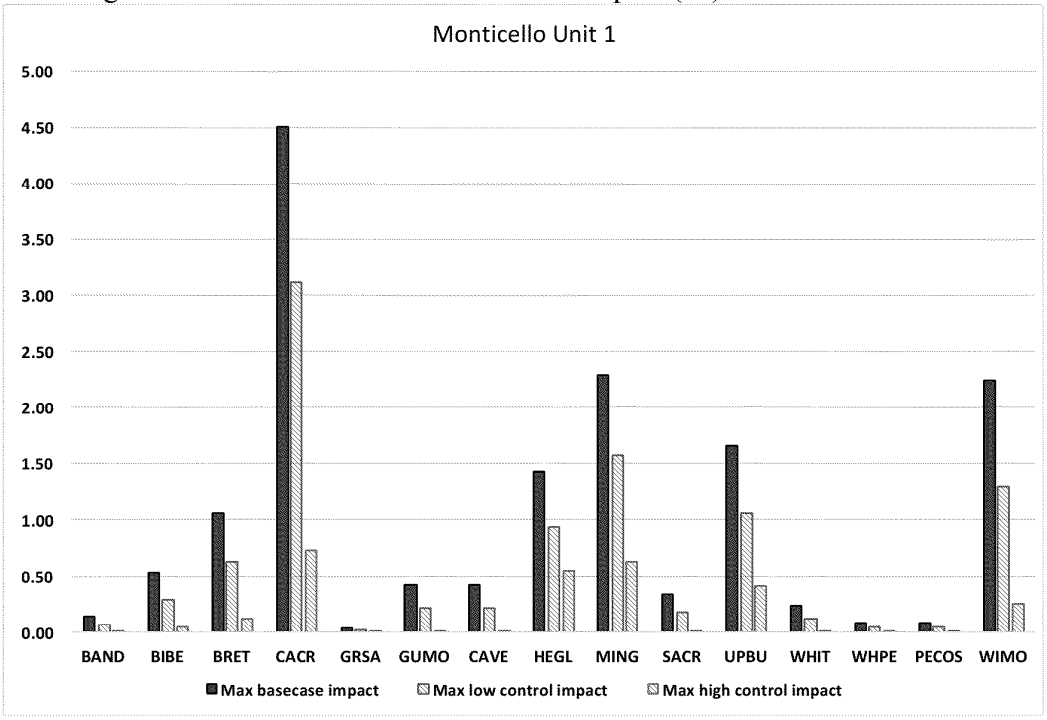
each unit results in visibility improvements of 1.8 dv on average across the top ten most impacted days, and approximately 1.3 dv at the second most impacted Class I area for each unit. Figures 4.1-3 and 4.1-7 show an assessment of the annual average impacts and benefits under the control scenarios.[16] Wet FGD reduces annual average base case impacts from each unit by 84% or more at each Class I area, while DSI at 50% emission reduction reduces annual average impacts at each Class I area by 50% or less. On average across all Class I areas, wet FGD results in a 91% reduction in annual average visibility impacts from each unit. Figures 4.2-4 and 4.2-8 show the contribution to extinction from the units due to each visibility impairing species[17] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Caney Creek and Wichita Mountains) for the base case modeling scenario.[18] These figures show that the impacts from the Monticello units 1 and 2 on these days are primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to these units.

Figure 4.2-1. Maximum CAMx modeled impact (dv) – Monticello Unit 1



[16] 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 at each Class I area with impacts greater than 0.1 dv.

[17] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[18] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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Figure 4.2-2. Average of top ten CAMx modeled impact (dv) – Monticello Unit 1

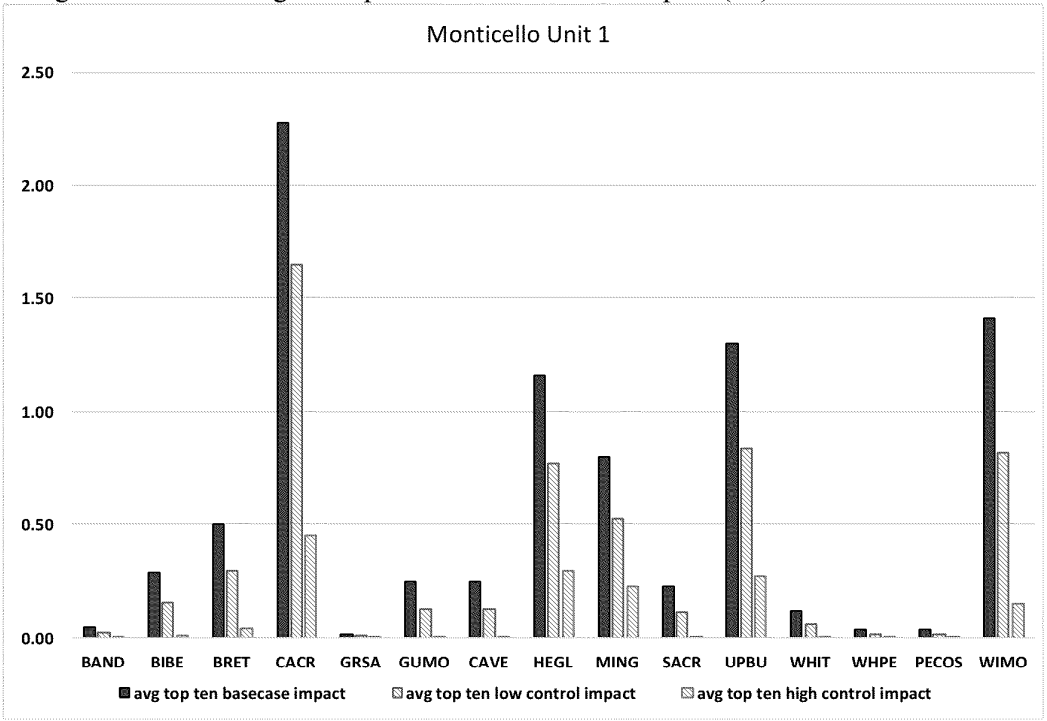

Figure 4.2-3. Annual Average CAMx modeled impact (dv) excluding baseline days impacted less than 0.1 dv – Monticello Unit 1

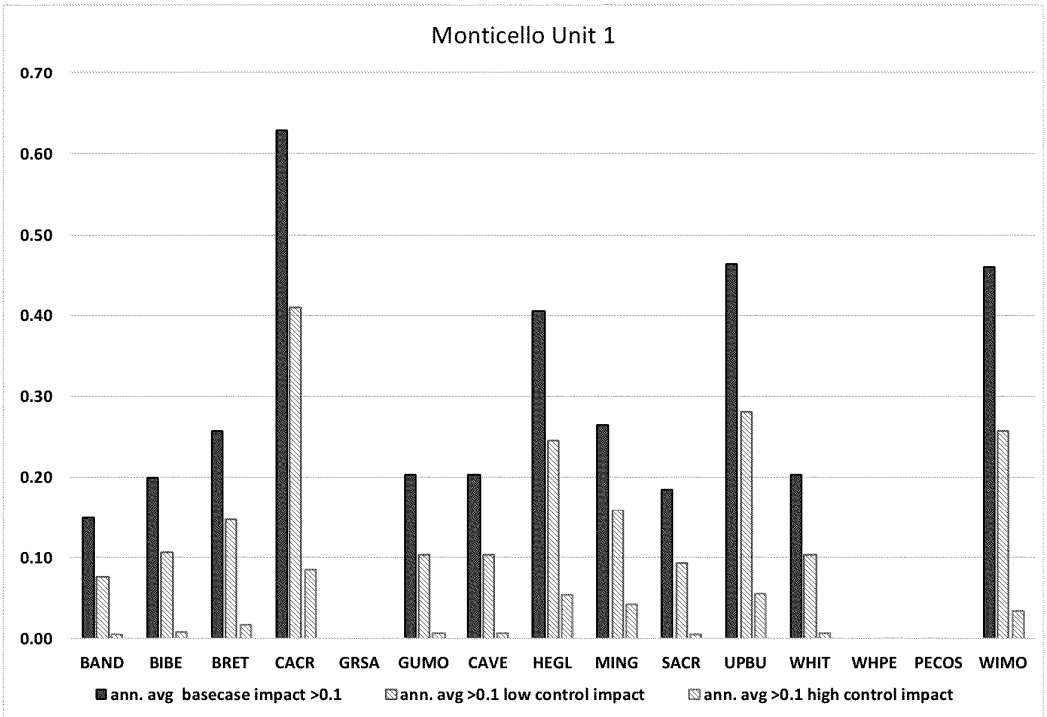

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Figure 4.2-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Monticello Unit 1

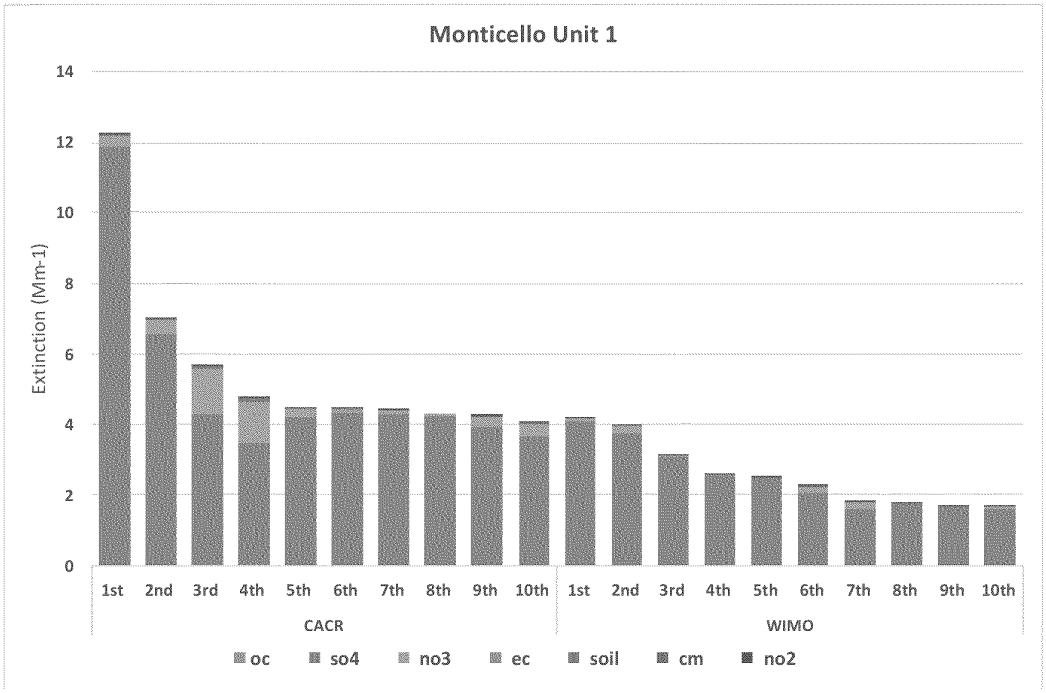

Figure 4.2-5. Maximum CAMx modeled impact (dv) – Monticello Unit 2

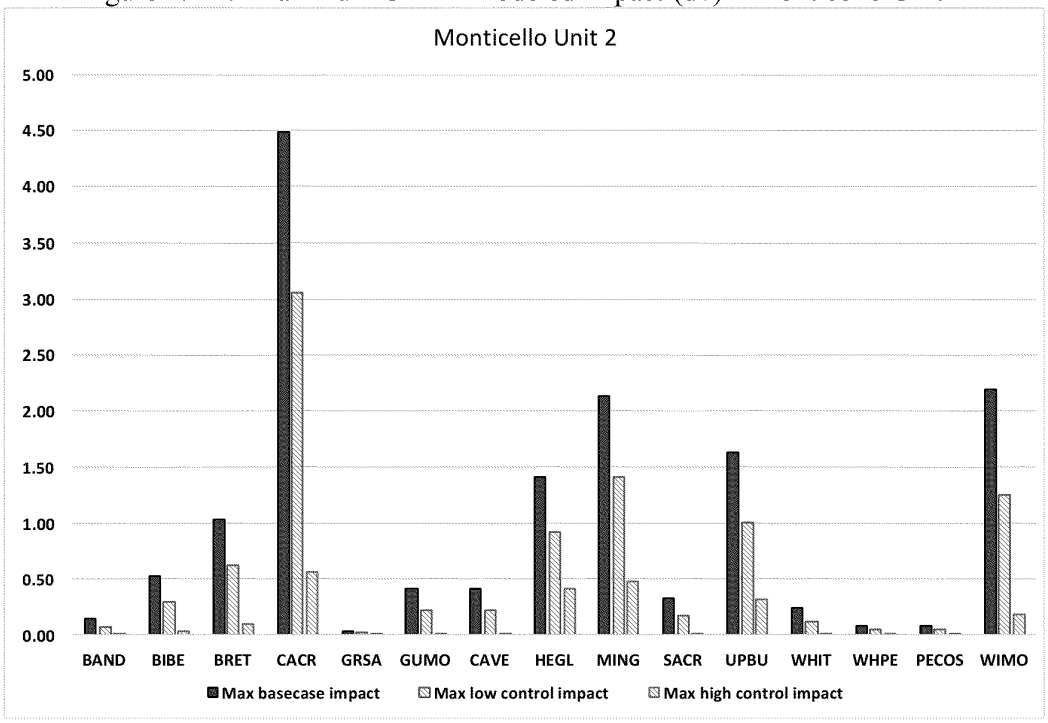

Figure 4.2-6. Average of top ten CAMx modeled impact (dv) – Monticello Unit 2

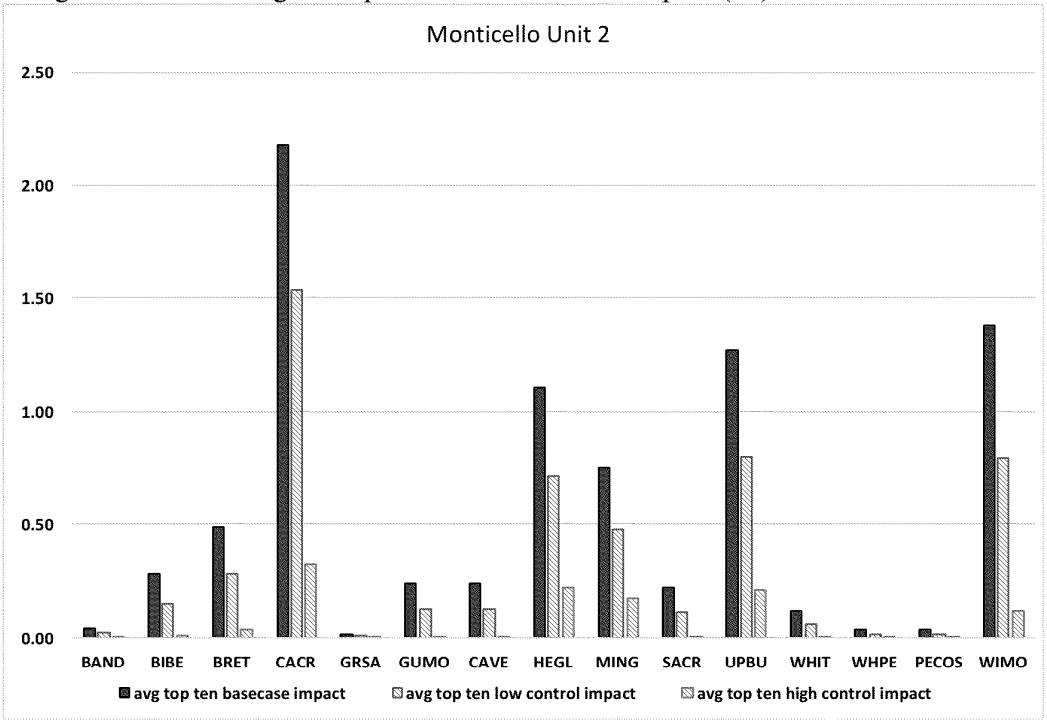

Figure 4.2-7. Annual Average CAMx modeled impact (dv) excluding baseline days impacted less than 0.1 dv – Monticello Unit 2

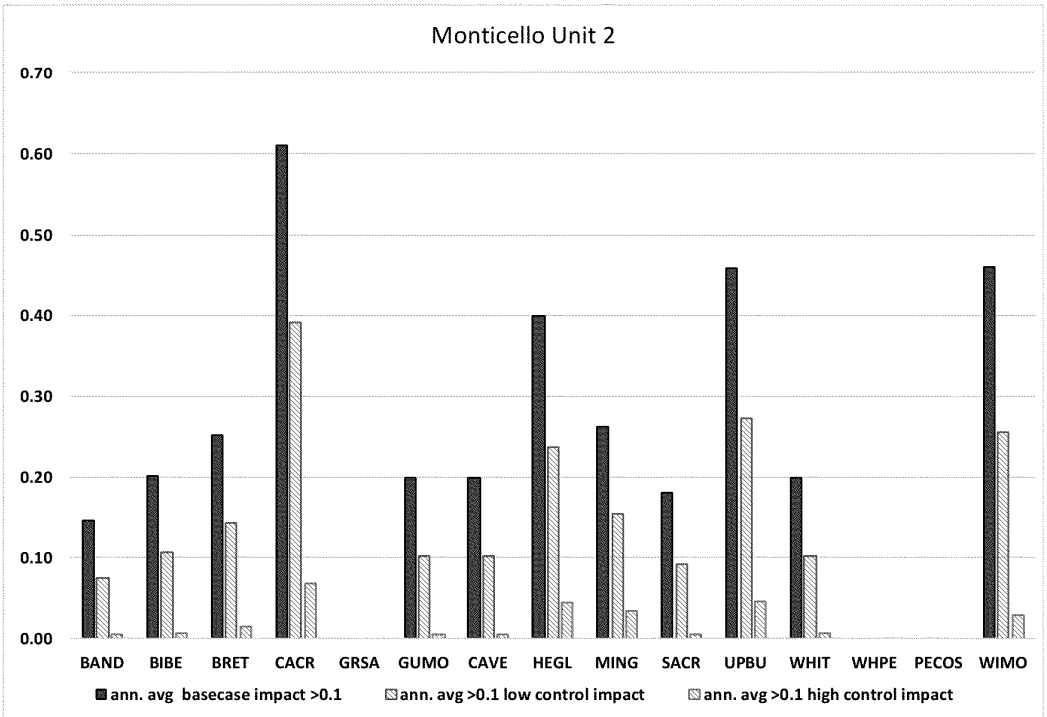

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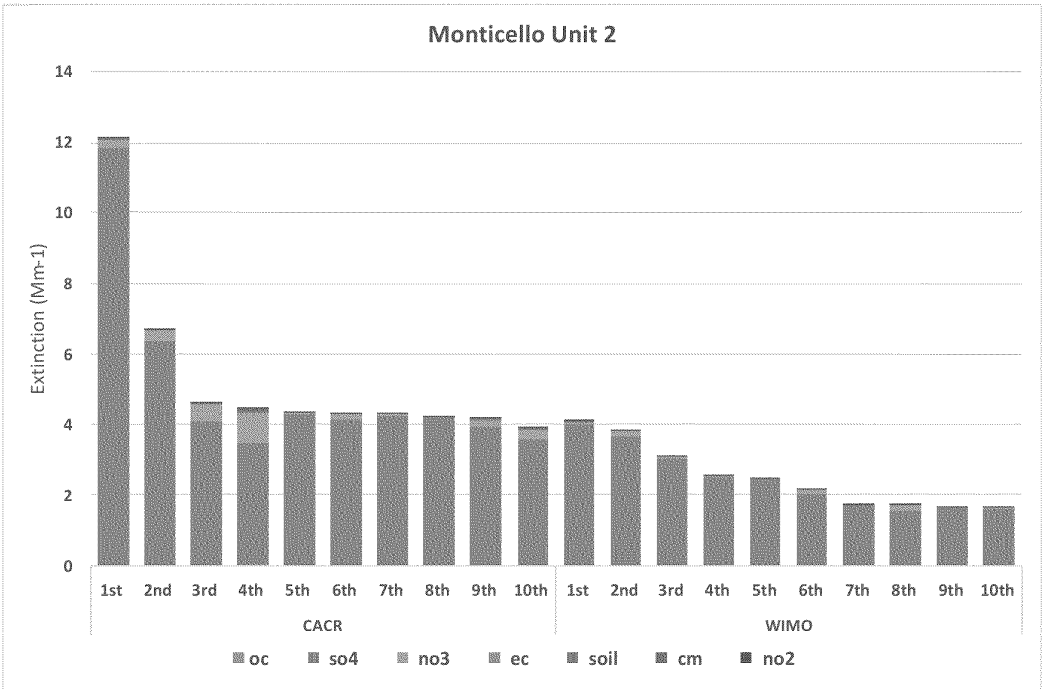
Figure 4.2-8. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Monticello Unit 2



4.3. Coleto Creek 1

In reviewing Coleto Creek Unit 1, we conclude that in comparison with the Monticello units, the installation of a wet FGD is more cost-effective and results in lesser, but still significant visibility benefits. We summarize some of these visibility benefits in the table below:

Table 4.3-1. Wet FGD Visibility Benefits at Coleto Creek Unit 1 (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Coleto Creek 1	0.668	0.606	5.233	17 / 0	17 / 0

[1] 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

[2] 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

[3] 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.

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CAMx modeling results indicate that wet FGD will eliminate all days impacted over 0.5 dv at all Class I areas. At the most impacted Class I area, wet FGD will result in visibility improvements of 0.6 or more on the most impacted days at both Caney Creek and the Wichita Mountains. In addition, seven other Class I areas are improved by amounts ranging from 0.356 to 0.531 dv on the maximum impacted days with wet FGD. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. Figure 4.3-1 below shows the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figure 4.3-2). At the most impacted Class I area, wet FGD results in visibility improvements of 0.53 dv on average across the top ten most impacted days, and approximately 0.41 dv at the second most impacted Class I area. Figure 4.3-3 shows an assessment of the annual average impacts and benefits under the control scenarios.[19] Wet FGD reduces annual average base case impacts by 76% to 95% depending on the Class I area, while DSI at 50% emission reduction reduces annual average impacts at each Class I area by 50% or less. At the most impacted Class I area (Wichita Mountains), wet FGD results in a 90% reduction in annual average visibility impacts, compared to a 46% reduction with DSI. On average across all Class I areas, wet FGD results in a 91% reduction in annual average visibility impacts. Figure 4.3-4 shows the contribution to extinction due to each visibility impairing species[20] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Caney Creek and Wichita Mountains) for the base case modeling scenario.[21] This figure shows that the impacts from Coleto Creek Unit 1 on these days are primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to this unit at these Class I areas.

[19] 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 at each Class I area with impacts greater than 0.1 dv.

[20] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[21] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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Figure 4.3-1. Maximum CAMx modeled impact (dv) – Coleto Creek Unit 1

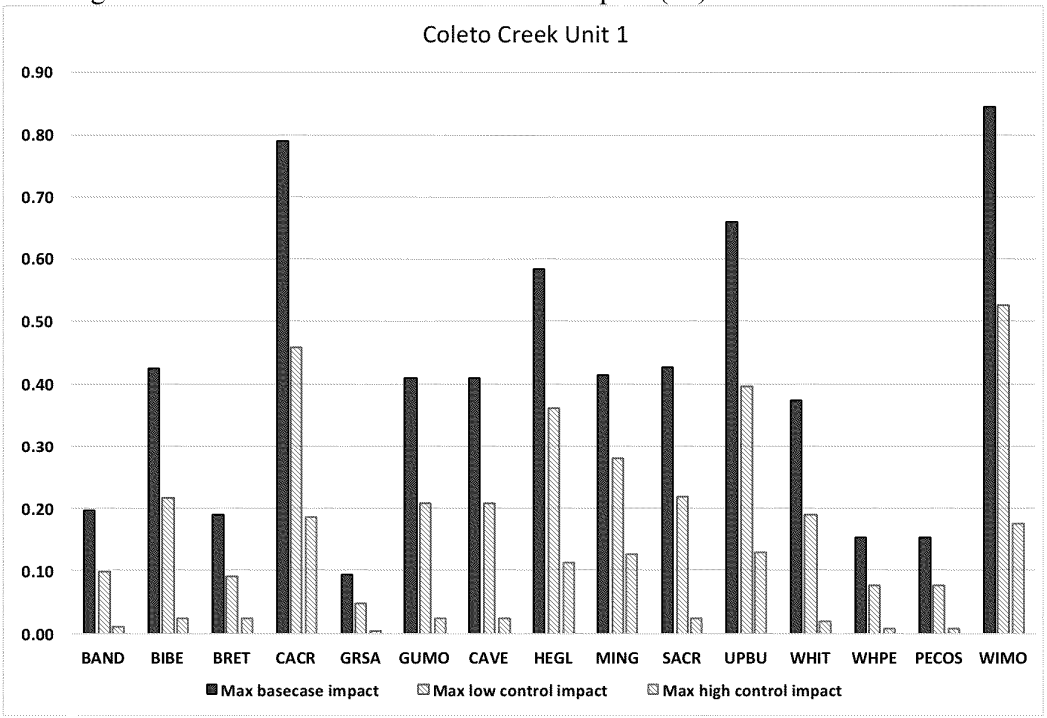

Figure 4.3-2. Average of top ten CAMx modeled impact (dv) – Coleto Creek Unit 1

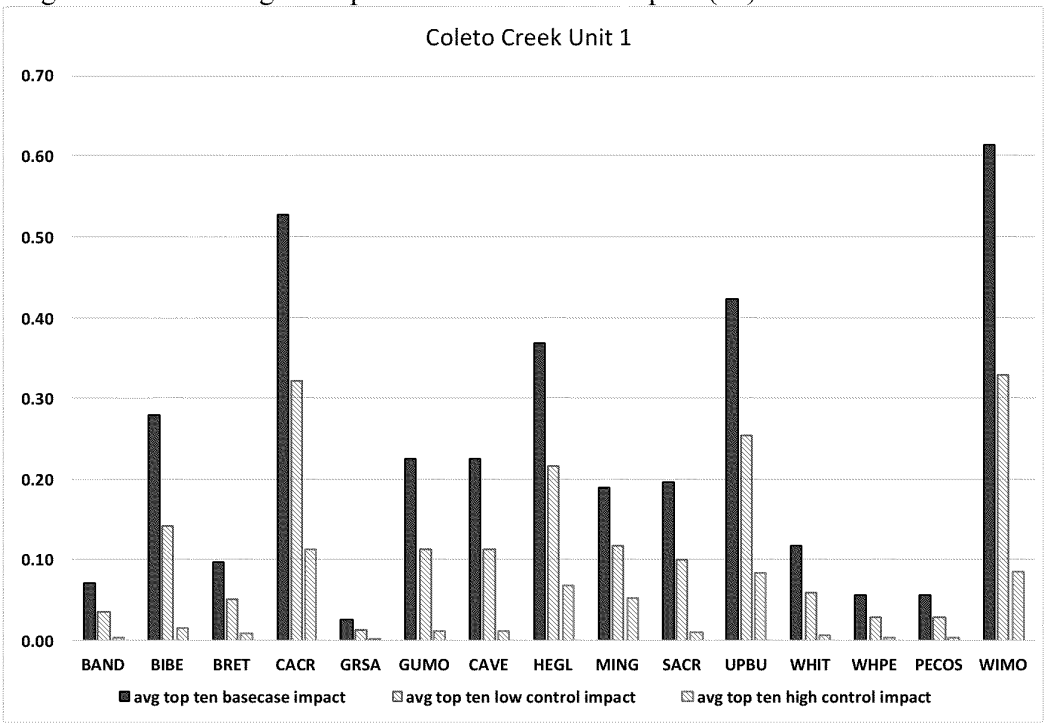

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Figure 4.3-3. Annual Average CAMx modeled impact (dv) excluding baseline days impacted less than 0.1 dv – Coleto Creek Unit 1

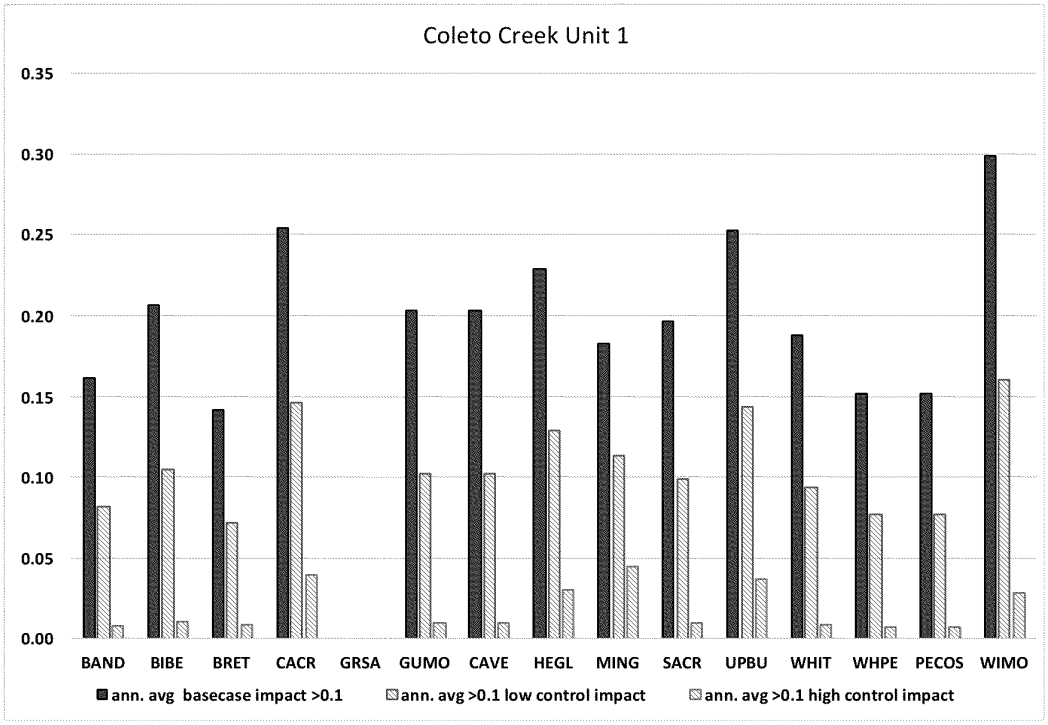
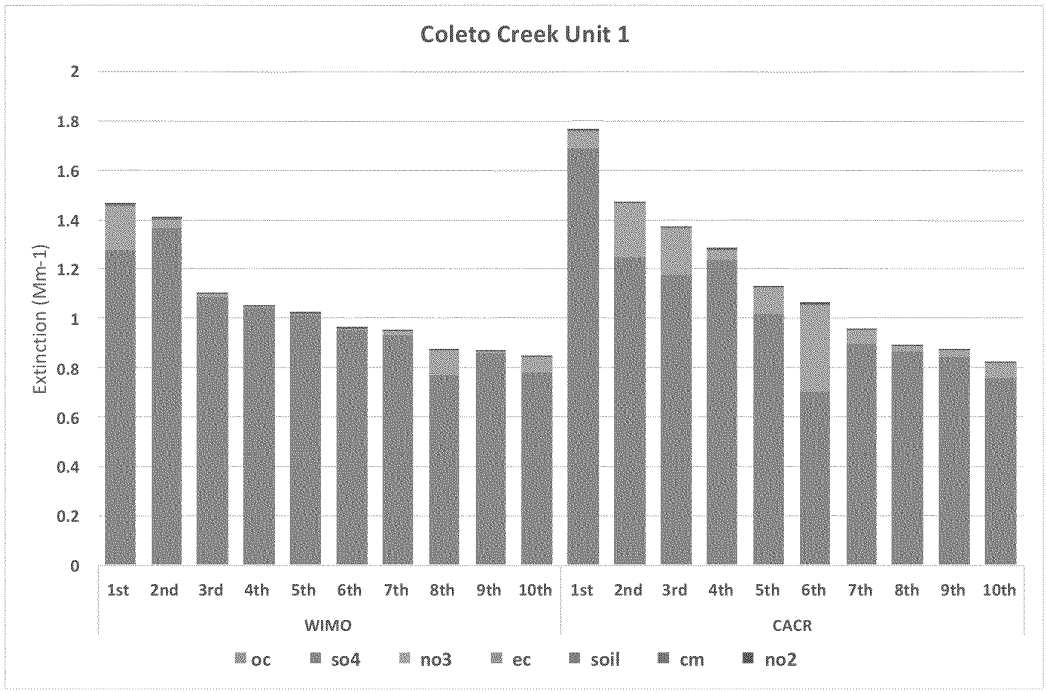


Figure 4.3-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Coleto Creek Unit 1



4.4. Welsh 1

In reviewing Welsh Unit 1, we conclude that the installation of a wet FGD will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.4-1a. Wet FGD Visibility Benefits at Welsh Unit 1 (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Welsh 1	0.72	0.41	1.66	56.67	15

Table 4.4-1b. Wet FGD Visibility Benefits at Welsh RNS {2011-2015} (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Welsh 1	.464	.231	1.05	34	6.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Welsh we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF

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modeling results indicate wet FGD on both units will eliminate 56.67 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to wet FGD levels.

Table 4.4-2. Wet FGD Visibility Benefits at Welsh Unit 1 (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Mingo Wilderness (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Welsh 1	1.521	0.579	4.683	65 / 9	60 / 9
Source (Welsh 1 & 2)	3.754	1.973	13.179	211 / 72	206 / 72

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD on unit 1 will eliminate all days impacted by the unit over 1 dv at all Class I areas and all but 5 days impacted over 0.5 dv. At the most impacted Class I area, wet FGD on unit 1 will result in visibility improvements of 1.521 dv on the most impacted days at Caney Creek. In addition to the visibility benefits at Caney Creek and Mingo, visibility benefits at two additional Class I areas exceed 0.5 dv. We note that source-wide benefits shown include the benefits from the shutdown of unit 2. In addition, cumulative benefits from wet FGD on unit 1 over all 15 Class I areas exceeds 4.5 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. Figure 4.4-1 below shows the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figure 4.4-2). At the most impacted Class I area, wet FGD results in visibility improvements of 0.8 dv on average across the top ten most impacted days. Figure 4.4-

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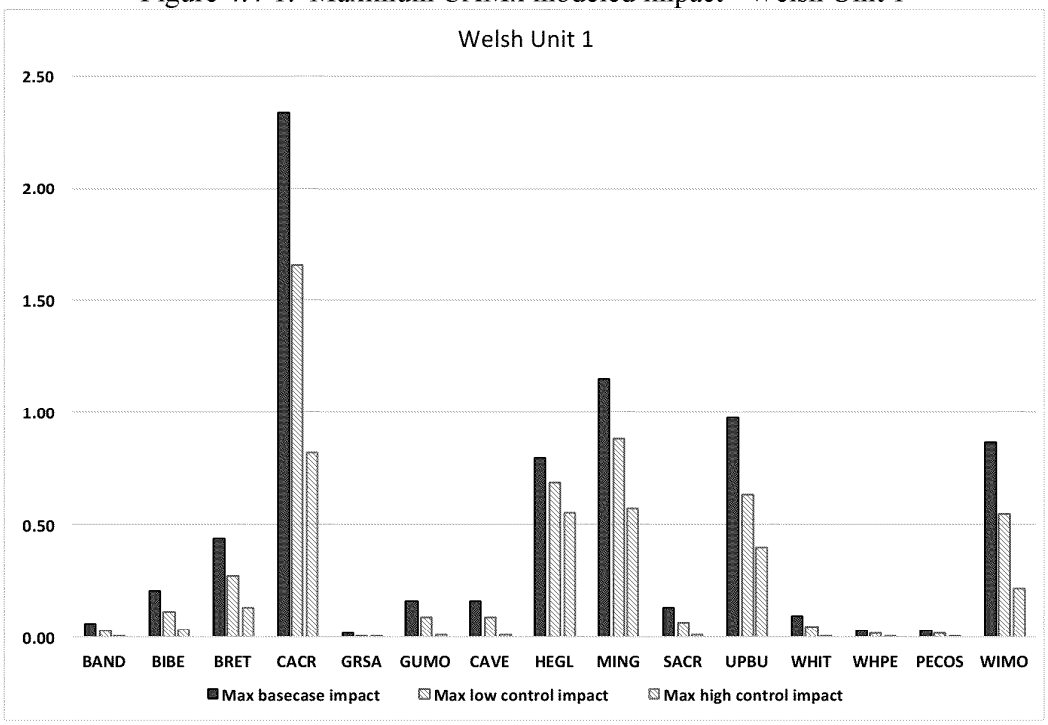
3 shows an assessment of the annual average impacts and benefits under the control scenarios.[22] On average across all Class I areas, wet FGD results in a 78% reduction in annual average visibility impacts compared to 38% for DSI. Figure 4.4-4 shows the contribution to extinction due to each visibility impairing species[23] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Caney Creek and Wichita Mountains) for the base case modeling scenario.[24] This figure shows that the impacts from Welsh Unit 1 at CACR on most of these days is primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to this unit on these days. At Mingo, many days are significantly impacted by nitrates and therefore the benefit from reducing SO2 emissions is not as significant as it is as Caney Creek. Other Class I areas, such as Wichita Mountains are significantly impacted by sulfate and benefits from SO2 reductions due to wet FGD are more pronounced.

Figure 4.4-1. Maximum CAMx modeled impact– Welsh Unit 1



[22] 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 at each Class I area with impacts greater than 0.1 dv.

[23] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[24] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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Figure 4.4-2. Average of top ten CAMx modeled impact– Welsh Creek Unit 1

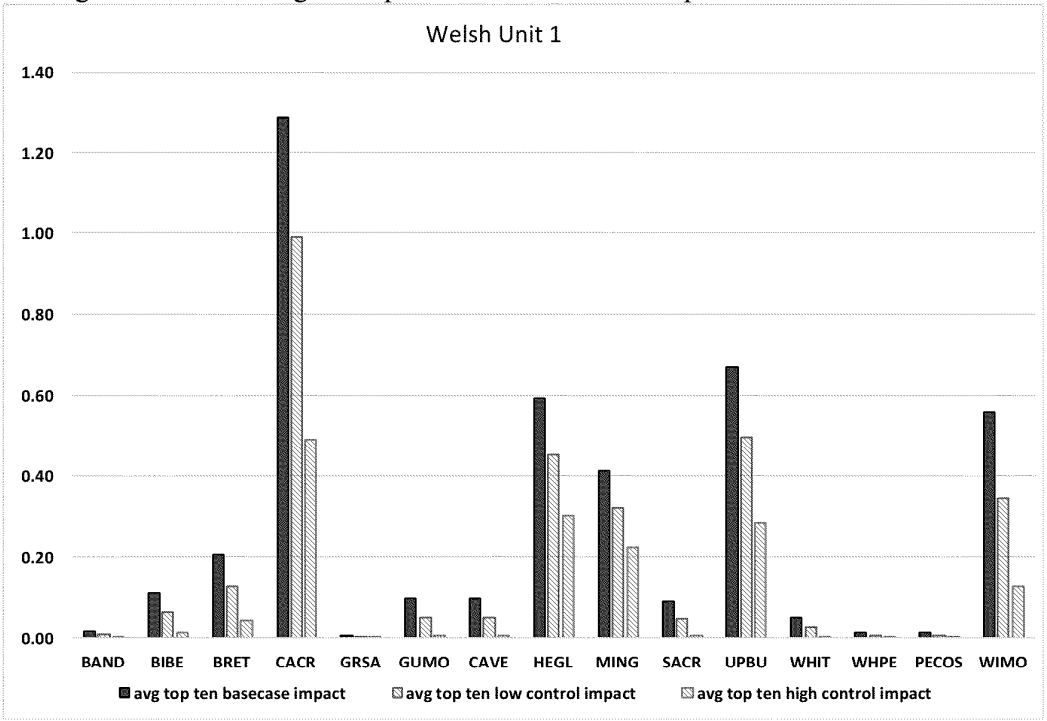

Figure 4.4-3. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – Welsh Unit 1

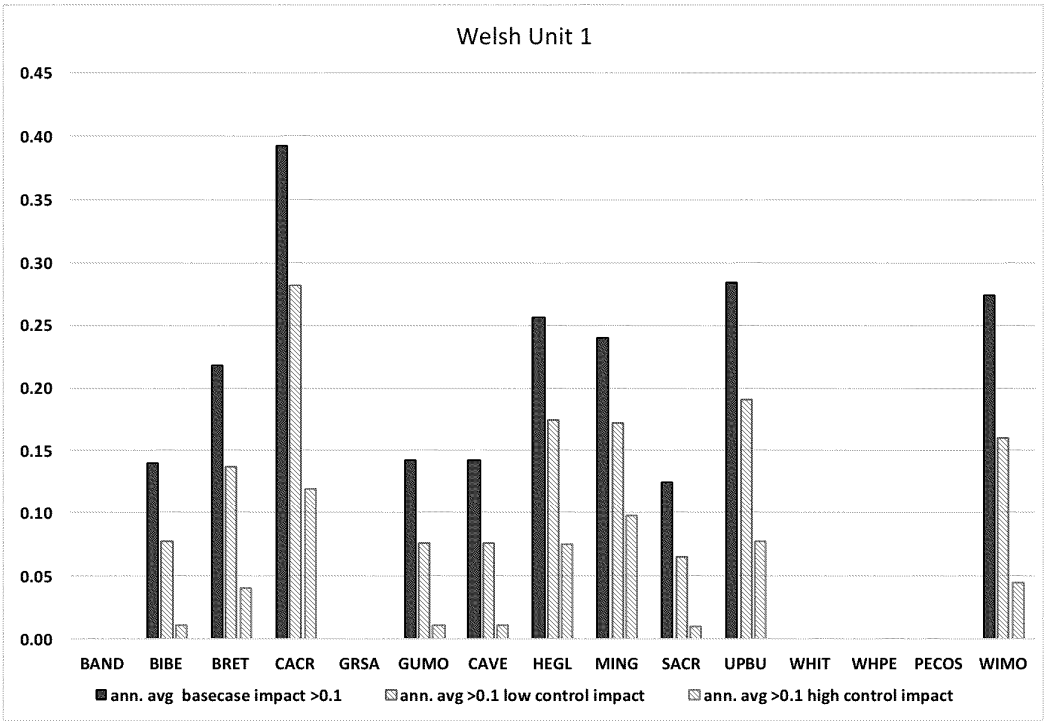

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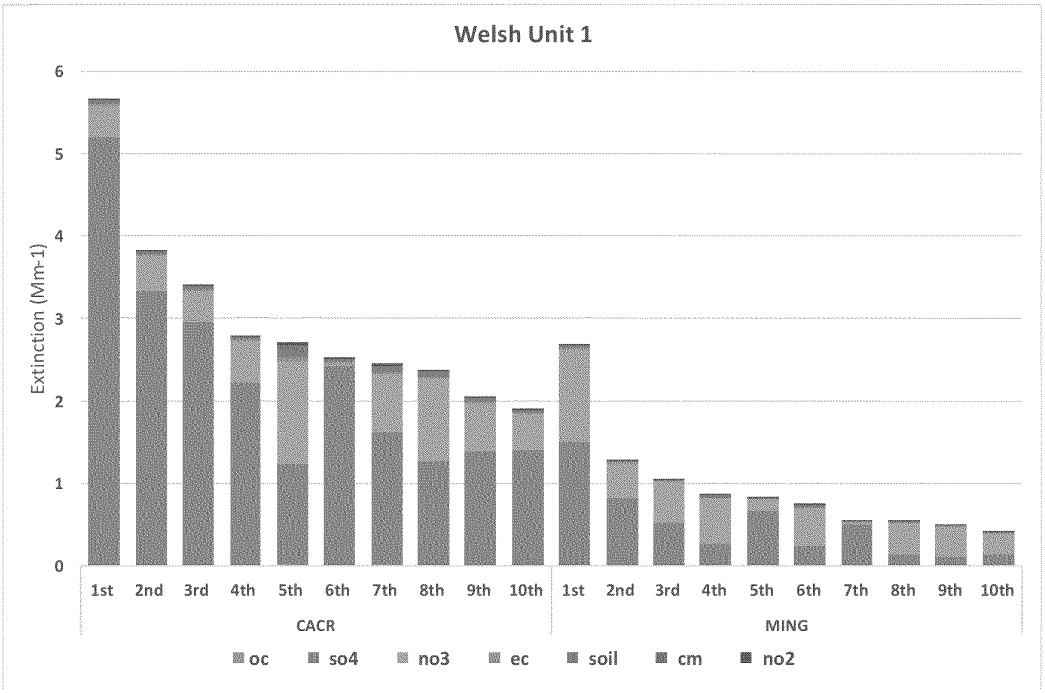
Figure 4.4-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Welsh Unit 1



4.5. Harrington 061B & 062B

In reviewing Harrington, we conclude that the installation of SDA on Units 061B and 062B will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.5-1a. SDA Visibility Benefits at Harrington (CALPUFF)

Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Harrington 061B & 062B	0.45	0.74	2.56	53.67	26

Table 4.5-1b. SDA Visibility Benefits at Harrington RNS {2011-2015} (CALPUFF)

Source	Improvement at Salt Creek	Improvement at Wichita	Total Cumulative	Cumulative Reduction	Cumulative Reduction

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	(dv)	Mtns. (dv)	Visibility Benefit (dv)[1]	in number of days above 0.5 dv[2]	in number of days above 1.0 dv[2]
Harrington 061B & 062B	.381	.565	2.42	48	14.67

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, Bandelier, and Wheeler Peak.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, Bandelier and Wheeler Peak.

In evaluating Harrington we note there are five Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the five Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate SDA on both units will eliminate 53.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to SDA levels.

Table 4.5-2. SDA Visibility Benefits at Harrington (CAMx)

Unit	Improvement at Salt Creek (dv)	Improvement at Wichita Mountains (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Harrington 061B	1.170	0.643	4.832	17 / 5	11 / 3
Harrington 062B	1.279	0.723	5.379	17 / 5	11 / 3
Source (061B & 0622B)	2.053	1.130	9.329	51 / 17	37 / 11

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control

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scenario runs summed across 15 Class I areas included in the CAMx modeling.
[2] 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.
[3] 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.

CAMx modeling results indicate SDA on these units will eliminate more than half of all days impacted by the units over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, SDA on each unit will each result in visibility improvements of approximately 1.2 dv on the most impacted days at Salt Creek and 0.6 – 0.7 dv at Wichita Mountains, reducing the number of days impacted over 0.5 and 1.0 dv at these Class I areas. In addition, cumulative benefits from SDA on both units over all 15 Class I areas exceeds 9.3 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the SDA visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. Figures 4.5-1 (unit 1) and 4.5-5 (unit 2) below show the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (SDA) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figures 4.5-2 and 4.5-6). At the most impacted Class I area, SDA on each unit result in visibility improvements of 0.36 (Unit 061B) to 0.40 dv (Unit 062B) on average across the top ten most impacted days, and approximately 0.31 (Unit 061B) to 0.33 (Unit 062B) dv at the second most impacted Class I area for each unit. Figures 4.5-3 and 4.5-7 show an assessment of the annual average impacts and benefits under the control scenarios.[25] SDA reduces annual average base case impacts from each unit by 59% (Unit 061B) to 62% (Unit 062B) reduction in annual average visibility impacts from each unit compared to 31% (Unit 061B) to 32% (Unit 062B) for DSI at the most impacted Class I area. On average across all Class I areas, SDA results in a 59% (Unit 061B) to 62% (Unit 062B) reduction in annual average visibility impacts from each unit compared to 31% (Unit 061B) to 32% (Unit 062B) for DSI. Figures 4.5-4 and 4.5-8 show the contribution to extinction from the units due to each visibility impairing species[26] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Salt Creek and Wichita Mountains) for the base case modeling scenario.[27] These figures show that the impacts from the Harrington units 1 and 2 on these days are due to both sulfate and nitrate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to these units on some days. On other days, remaining nitrate impacts are large and limit the amount of visibility benefits achievable through SO2 emission reductions. As discussed above, annual average impacts across all Class I areas are reduced approximately 60% with SDA. As seen in the top ten average impacts and average annual impacts, a large number of Class I areas are impacted by the source and see benefits with SDA.

[25] 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 at each Class I area with impacts greater than 0.1 dv.
[26] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)
[27] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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Figure 4.5-1. Maximum CAMx modeled impact– Harrington Unit 061B

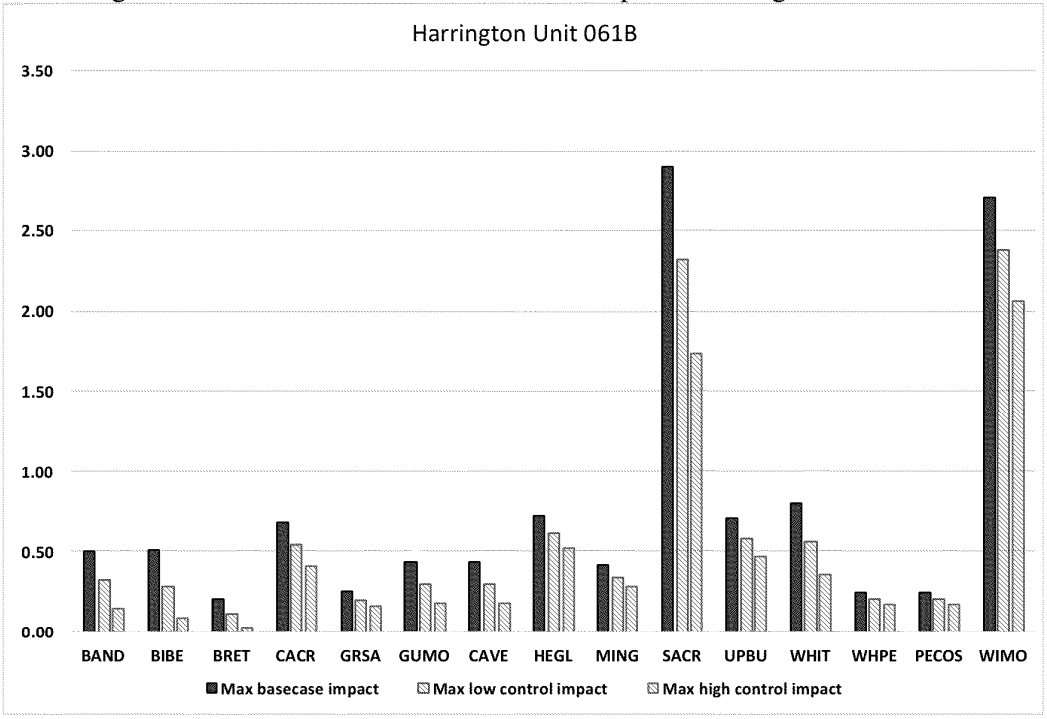

Figure 4.5-2. Average of top ten CAMx modeled impact– Harrington Unit 061B

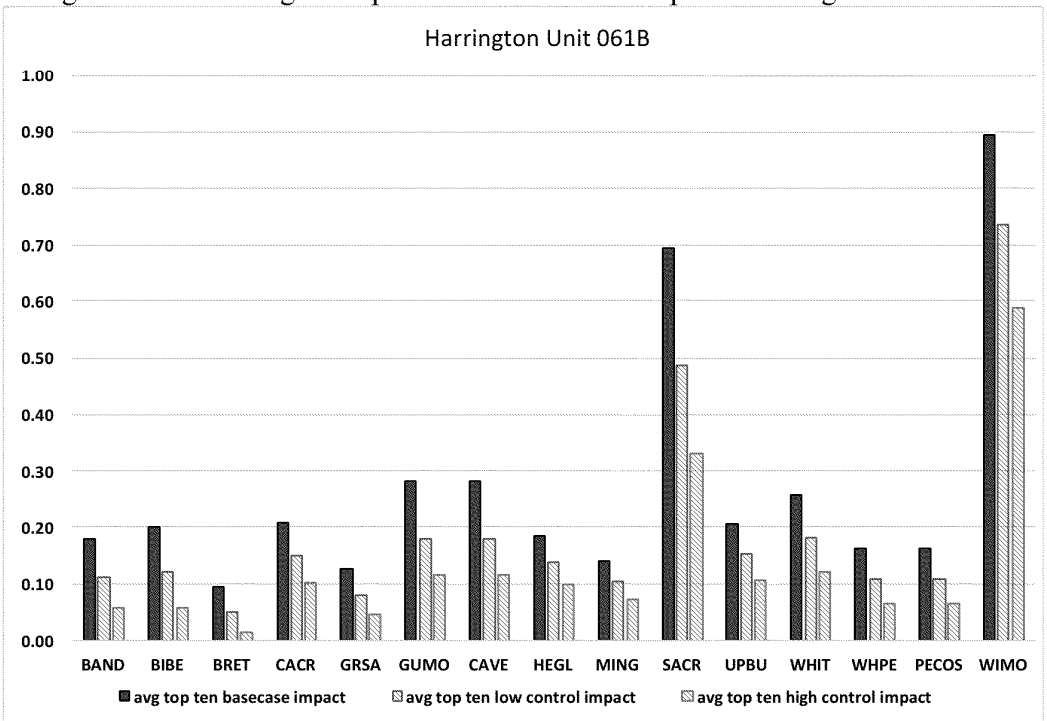

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Figure 4.5-3. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – Harrington Unit 061B

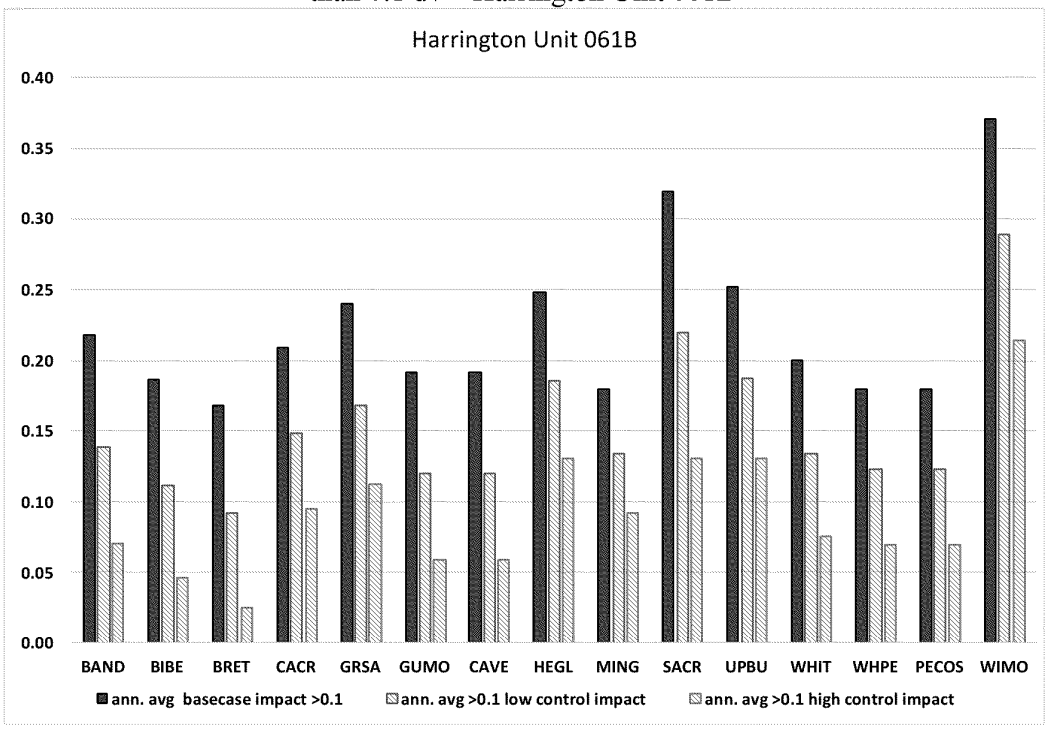

Figure 4.5-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Harrington Unit 061B

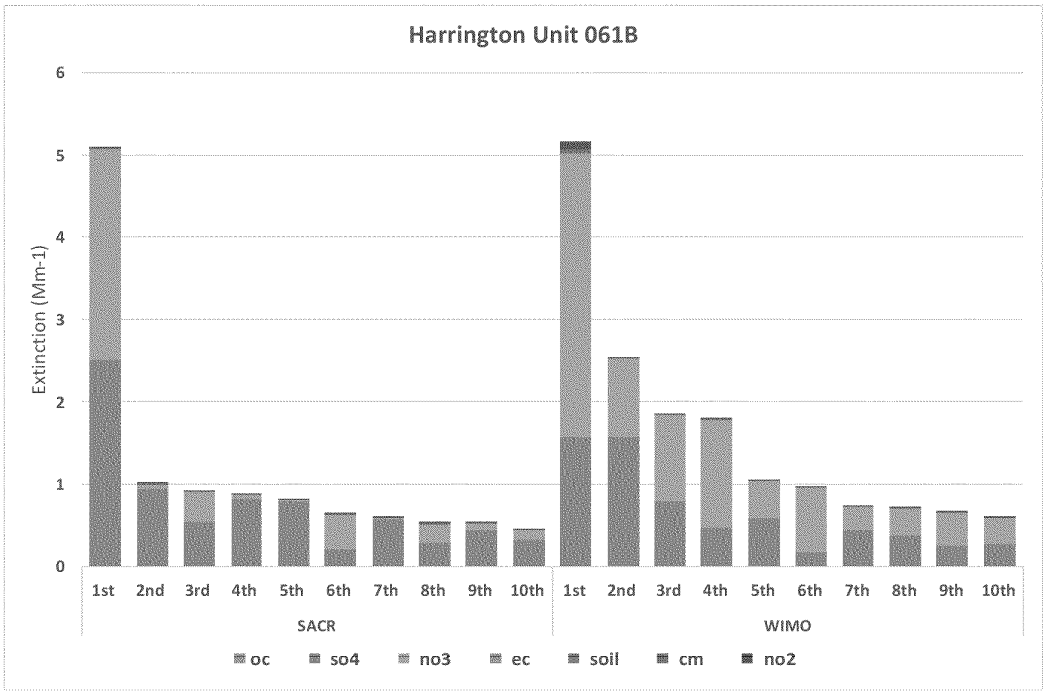

Figure 4.5-5. Maximum CAMx modeled impact– Harrington Unit 062B

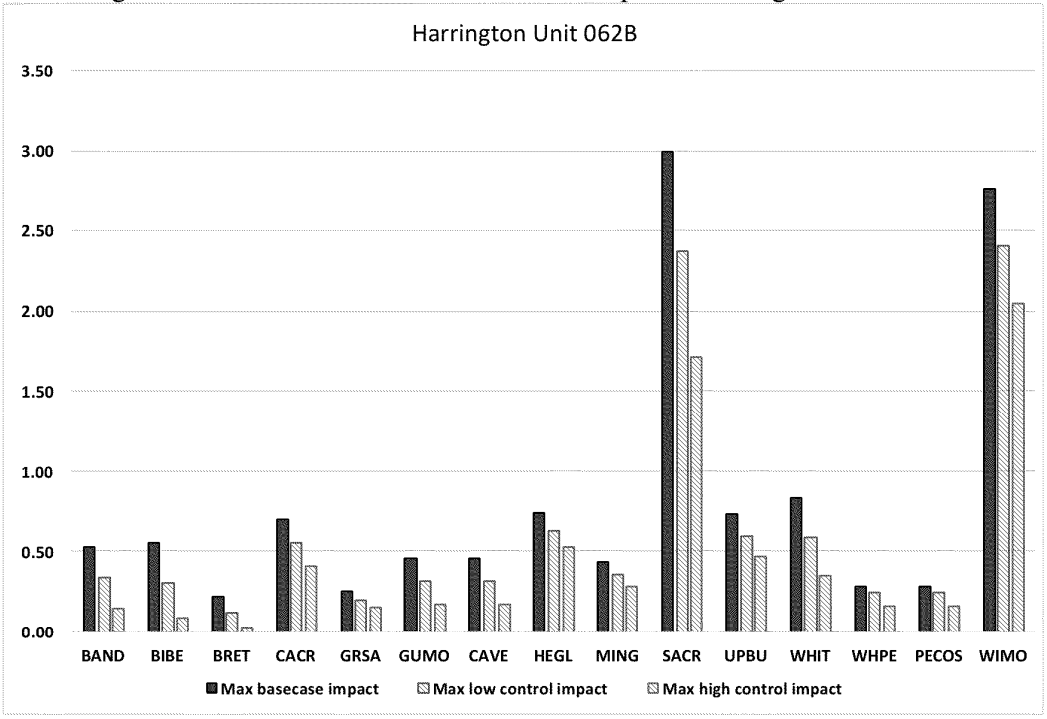

Figure 4.5-6. Average of top ten CAMx modeled impact– Harrington Unit 062B

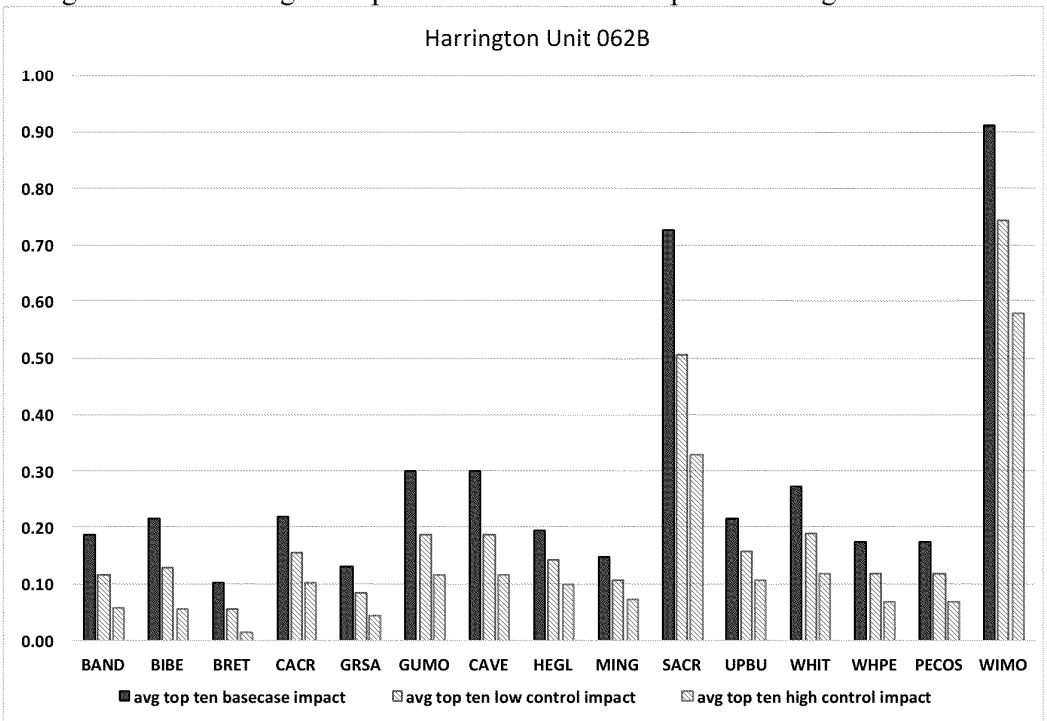

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Figure 4.5-7. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – Harrington Unit 062B

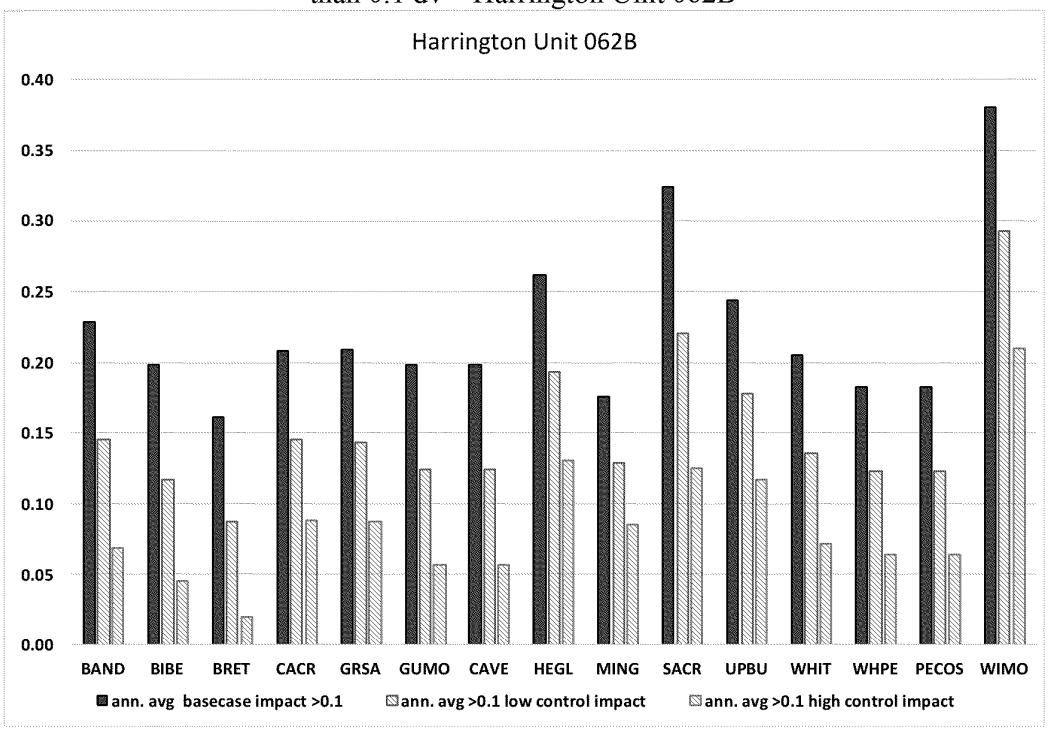
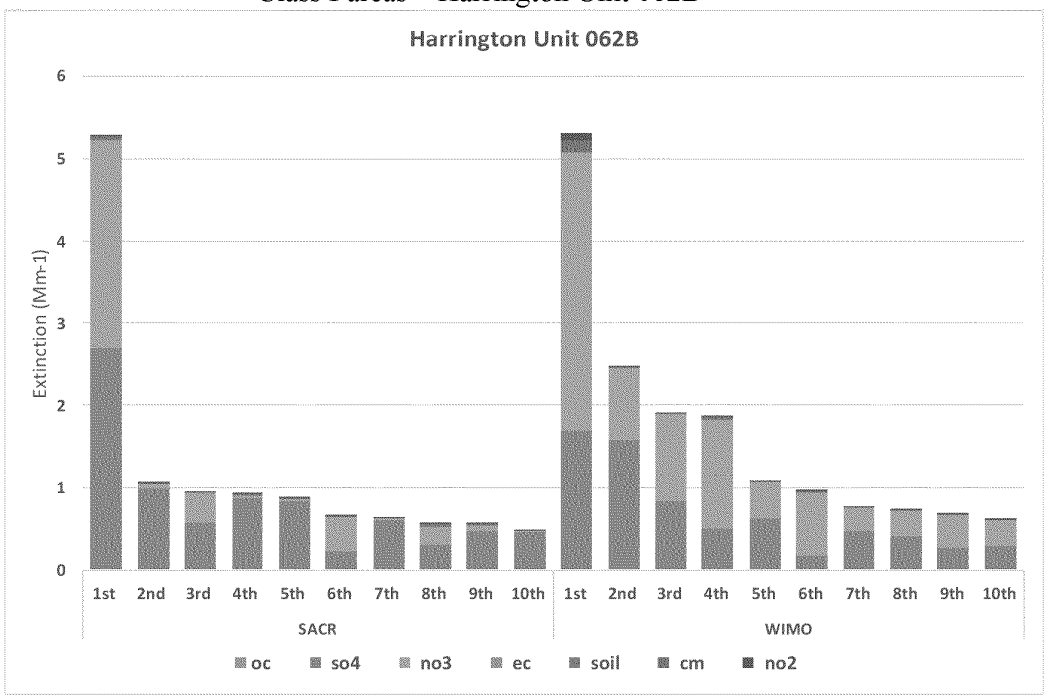


Figure 4.5-8. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – Harrington Unit 062B



4.6. W. A. Parish WAP 5 & 6

In reviewing W A Parish, we conclude that the installation of wet FGD on Units 5 and 6 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.6-1. Wet FGD Visibility Benefits at W A Parish (CAMx)

Unit	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
W A Parish 5	1.518	0.943	8.171	51 / 9	51 / 9
W A Parish 6	1.492	0.922	7.979	48 / 7	48 / 7
Source (WAP 4, 5 & 6)	2.665	1.760	15.301	163 / 49	162 / 49

[1] 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.
[2] 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.
[3] 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.

CAMx modeling results indicate that wet FGD on each of these units will eliminate all days impacted by each unit over 1 dv and 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of approximately 1.5 dv on the most impacted days at Caney Creek and 0.9 dv at Upper Buffalo. Nine Class I areas have modeled source-wide baseline impacts over 1 dv, and wet FGD on both units results in source-wide improvements of 1 dv or greater on the maximum impacted days at eight of these Class I areas. In addition, cumulative benefits from wet FGD on both units over all 15 Class I areas exceeds 15 dv on the maximum impacted days. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 class I areas included in the modeling. We note that source-wide modeling includes a small impact from WAP 4. This unit is gas-fired and was modeled at baseline emissions levels for both the baseline and control case scenarios. Figures 4.6-1 (WAP 5) and 4.6-5 (WAP 6) below show the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figures 4.6-2 and 4.6-6). At the most impacted Class I area, wet FGD on

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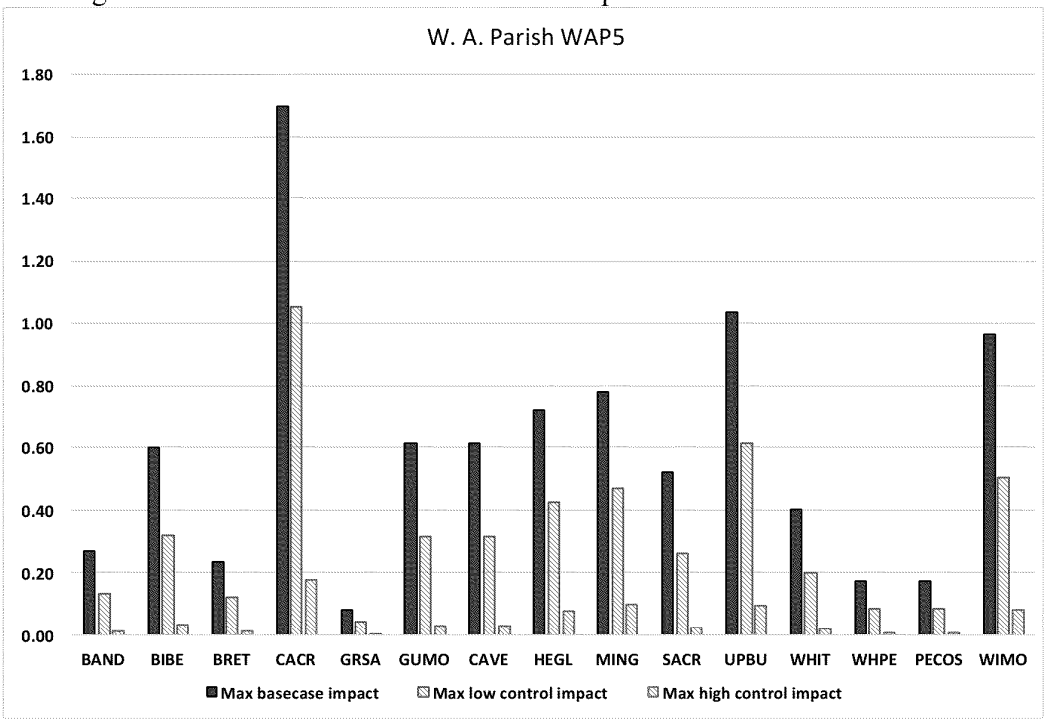
each unit result in visibility improvements of 1 dv on average across the top ten most impacted days, and approximately 0.63 dv at the second most impacted Class I area for each unit. Figures 4.6-3 and 4.6-7 show an assessment of the annual average impacts and benefits under the control scenarios.[28] Wet FGD reduces annual average base case impacts from each unit by 91% or more at each Class I area, while DSI at 50% emission reduction reduces annual average impacts at each Class I area by 50% or less. On average across all Class I areas, wet FGD results in a 94% to 95% reduction in annual average visibility impacts from each unit. Figures 4.6-4 and 4.6-8 show the contribution to extinction from the units due to each visibility impairing species[29] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Caney Creek and Upper Buffalo) for the base case modeling scenario.[30] These figures show that the impacts from the W.A. Parish WAP 5 and WAP 6 on these days are primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to these units.

Figure 4.6-1. Maximum CAMx modeled impact– W. A. Parish Unit WAP5



[28] 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 at each Class I area with impacts greater than 0.1 dv.

[29] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)

[30] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

Figure 4.6-2. Average of top ten CAMx modeled impact– W. A. Parish Unit WAP5

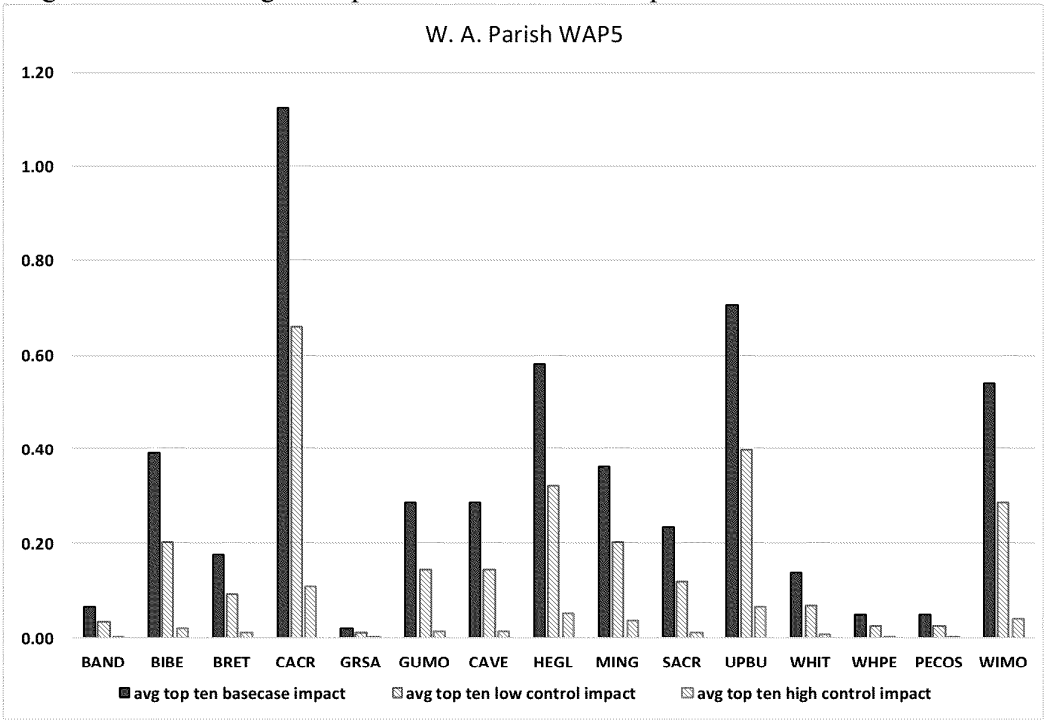


Figure 4.6-3. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – W. A. Parish Unit WAP5

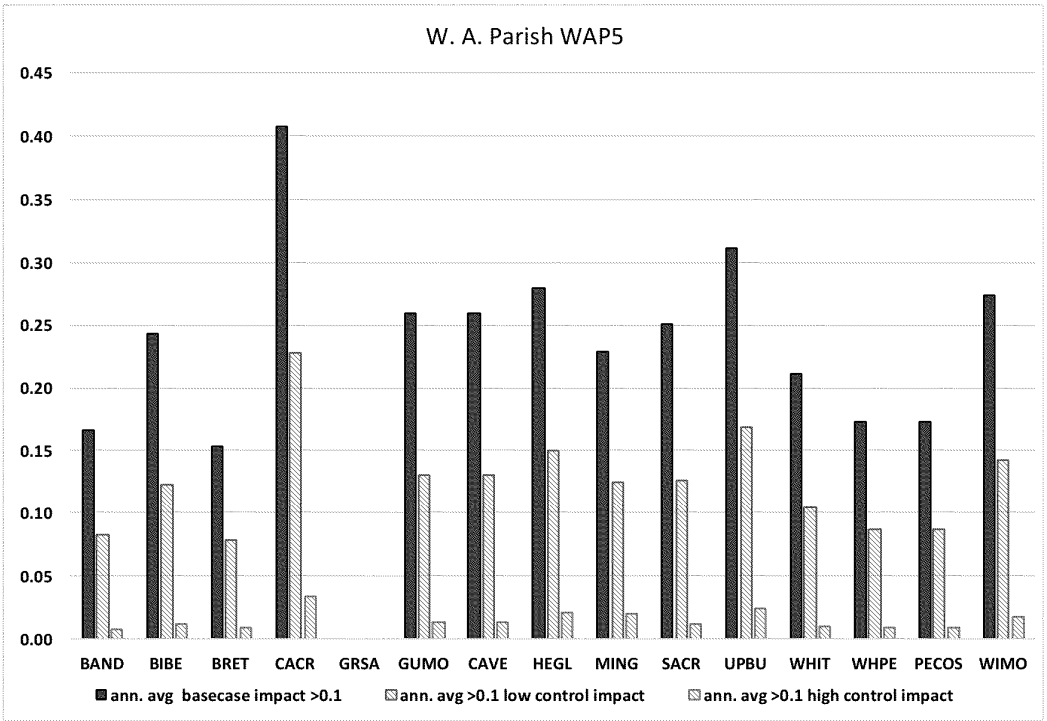


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Figure 4.6-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – W.A. Parish WAP5

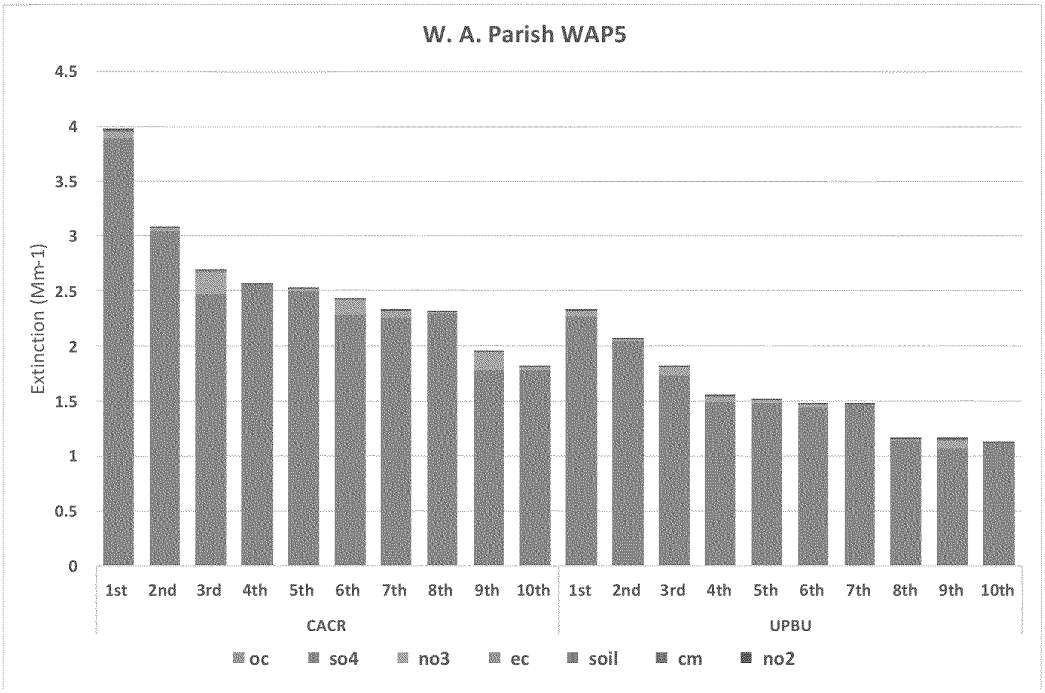

Figure 4.6-5. Maximum CAMx modeled impact– W. A. Parish Unit WAP6

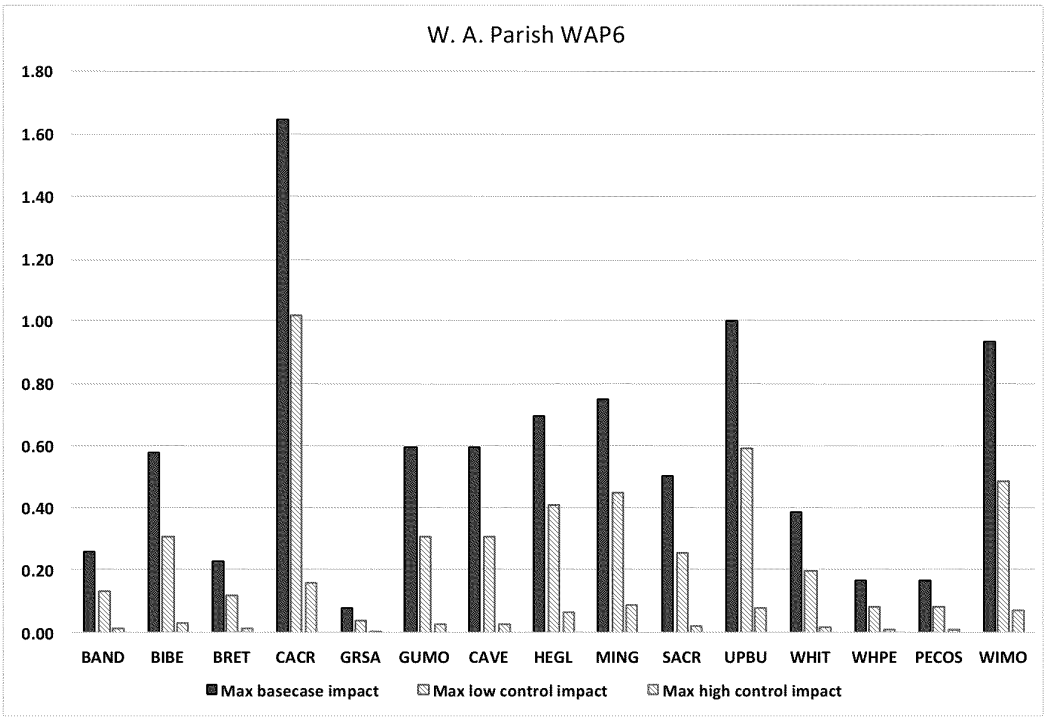

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Figure 4.6-6. Average of top ten CAMx modeled impact– W. A. Parish Unit WAP6

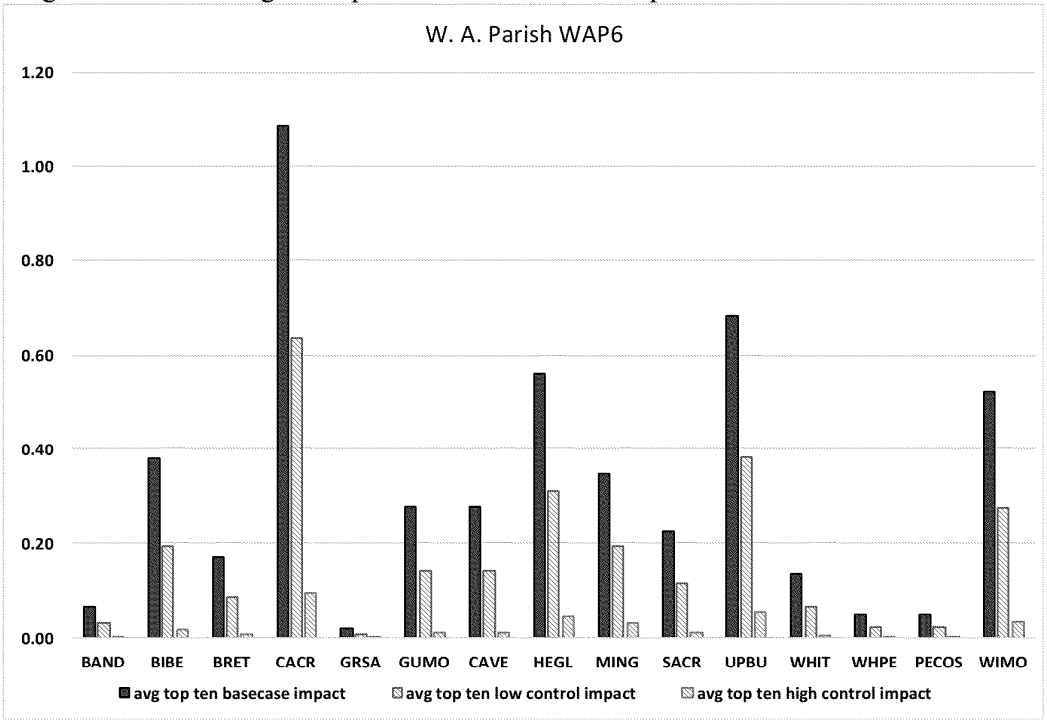

Figure 4.6-7. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – W. A. Parish Unit WAP6

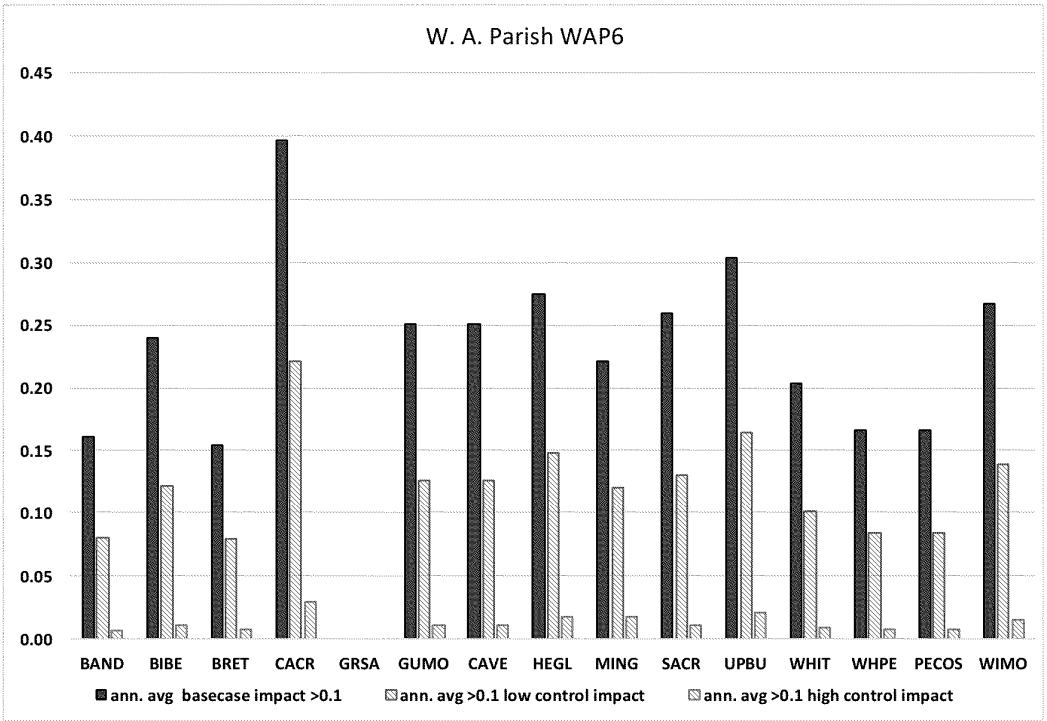

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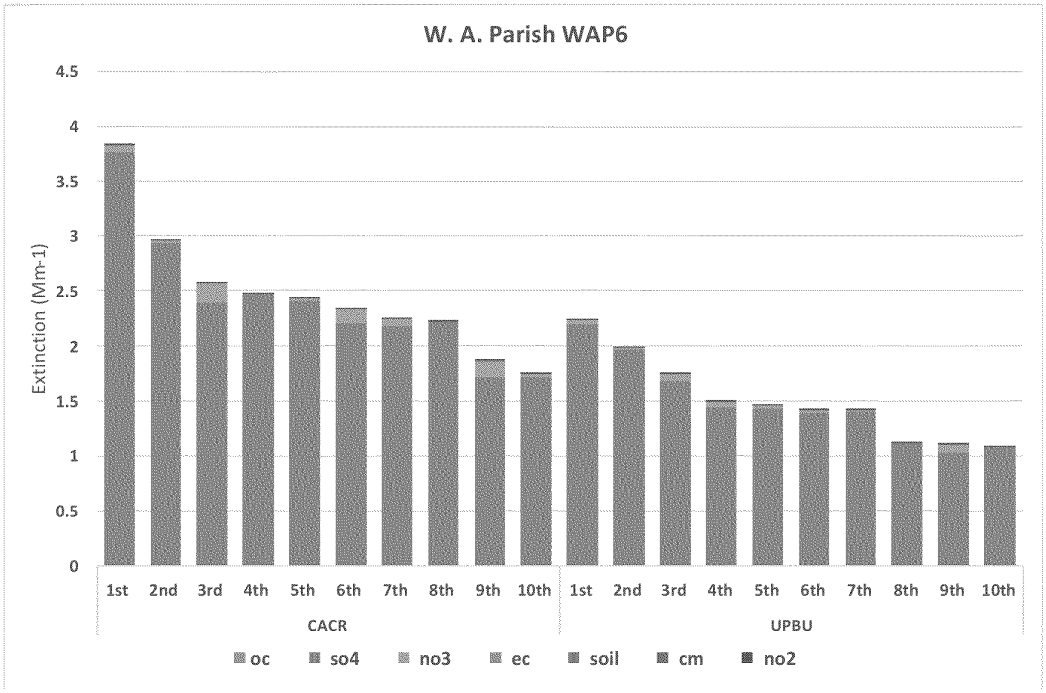
Figure 4.6-8. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – W.A. Parish WAP6



4.7. J T Deely 1 & 2

In reviewing J T Deely, we conclude that the installation of wet FGD on Units 1 and 2 will result in significant visibility benefits. We summarize some of these visibility benefits in the tables below:

Table 4.7-1 Wet FGD Visibility Benefits at J T Deely (CAMx)

Unit	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
J T Deely 1	0.487	0.283	4.785	10 / 0	10 / 0
J T Deely 2	0.298	0.217	3.650	7 / 0	7 / 0
Source (J T Deely 1 & 2, Sommers 1 & 2)	0.699	0.518	8.943	89 / 13	84 / 13

[1] 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.

[2] 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.
[3] 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.

CAMx modeling results indicate wet FGD on each of these units will eliminate all days impacted by each unit over 0.5 dv at all Class I areas. At the most impacted Class I areas, wet FGD on each unit will each result in visibility improvements of 0.487 dv and 0.298 dv on the most impacted days at Wichita Mountains and 0.283 dv and 0.217 dv at Caney Creek. Larger visibility improvements on the most impacted days are anticipated at other Class I areas. Benefits from wet FGD on unit 1 are 0.583 dv at Big Bend, 0.511 dv at Salt Creek, 0.449 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.475 dv at White Mountains. Benefits from wet FGD on unit 2 are 0.583 dv at Big Bend, 0.441 dv at Salt Creek, 0.354 dv at Guadalupe Mountains and Carlsbad Caverns, and 0.375 dv at White Mountains. DSI operated at 50% control results in approximately half of the wet FGD visibility benefits, at the most impacted Class I areas and half of the cumulative benefits over the 15 Class I areas included in the modeling. We note that source-wide modeling includes the impact from Sommers units 1 and 2, and, control case scenarios for these units included benefits from switching to lower sulfur fuel oil. However, these modeled improvements are a small fraction of the total visibility benefits from controls at the source. Figures 4.7-1 (JT Deely unit 1) and 4.7-5 (JT Deely unit 2) below show the maximum visibility impact for the base case and compares it to the modeled maximum impacts under the low control (DSI) and high control (wet FGD) scenarios at each Class I area.

We also examined the average visibility benefit of controls across the top ten impacted days at each Class I area (See figures 4.7-2 and 4.7-6). At the most impacted Class I area, wet FGD on unit 1 results in visibility improvements of 0.43 dv on average across the top ten most impacted days, and approximately 0.28 dv at the second most impacted Class I area. At the most impacted Class I area, wet FGD on unit 2 results in visibility improvements of 0.32 dv on average across the top ten most impacted days, and approximately 0.16 dv at the second most impacted Class I area. Figures 4.6-3 and 4.6-7 show an assessment of the annual average impacts and benefits under the control scenarios.[31] Wet FGD reduces annual average base case impacts from each unit by 83% (unit 1) and 88% (unit 2) at the most impacted Class I area, while DSI at 50% emission reduction reduces annual average impacts at the most impacted Class I area by 43% (unit 1) and 45% (unit 2). On average across all Class I areas, wet FGD results in an 81% (unit 1) and 87% (unit 2) reduction in annual average visibility impacts from each unit. Figures 4.6-4 and 4.6-8 show the contribution to extinction from the units due to each visibility impairing species[32] in inverse megameters (Mm-1) on the ten highest impact days at the top two impacted Class I areas (Wichita Mountains and Caney Creek) for the base case modeling scenario.[33] These figures show that the impacts from the W.A. Parish WAP 5 and WAP 6 on most days are

[31] 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 at each Class I area with impacts greater than 0.1 dv.
[32] ammonia nitrate (no3), ammonia sulfate (so4), elemental carbon (ec), organic carbon (oc), coarse mass (cm), soil, and nitrogen dioxide (no2)
[33] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for base case model results, including species specific extinction and total visibility impairment from each unit and subject-to-BART source

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primarily due to sulfate, and therefore large reductions in sulfate emissions will result in significant reductions in visibility impairment due to these units on those days. The very highest impacted days at Caney Creek have large impacts from both nitrate and sulfate. While emission reductions of SO2 will greatly reduce the impairment from sulfate on these days, the nitrate impacts remain, limiting the overall benefit from controls on these days. Visibility impacts at Guadalupe Mountains, Carlsbad Caverns and Salt Creek are primarily due to sulfates and reductions in SO2 emissions are effective in reducing the visibility impairment from these units at those Class I areas.

Figure 4.7-1. Maximum CAMx modeled impact– J.T. Deely Unit 1

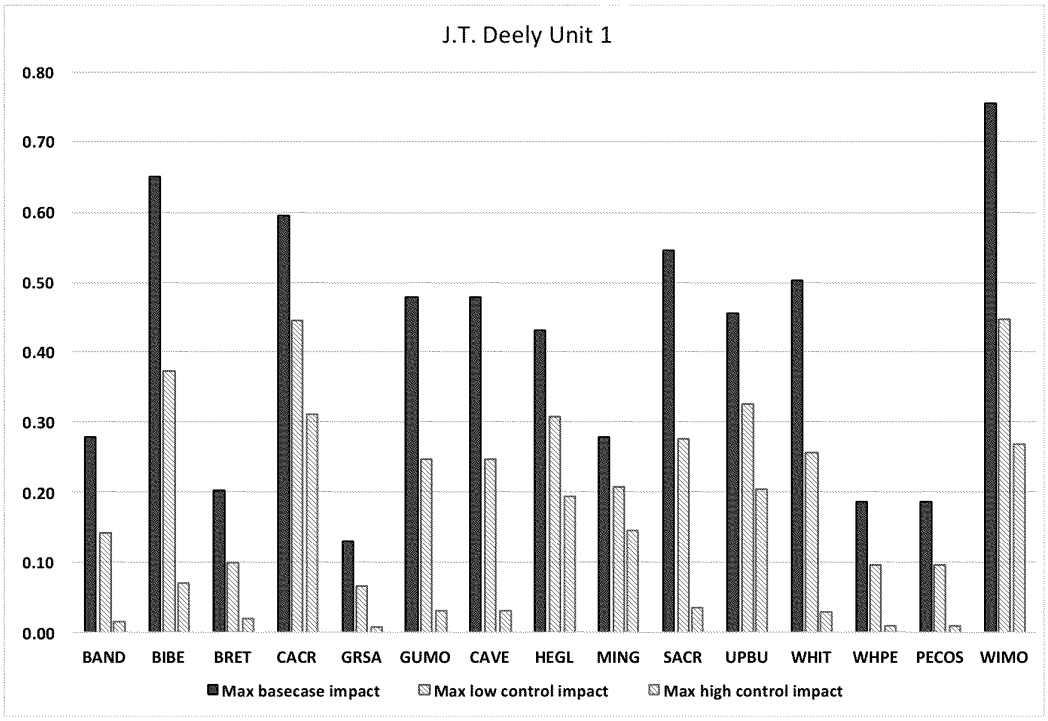

Figure 4.7-2. Average of top ten CAMx modeled impact– J.T. Deely Unit 1

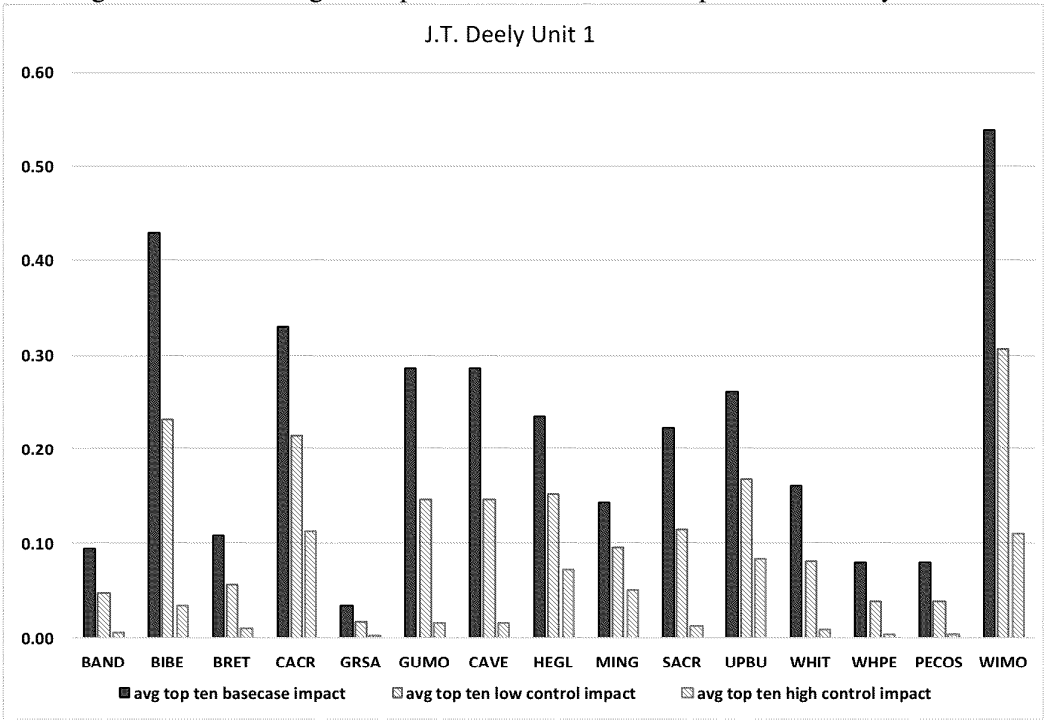

Figure 4.7-3. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – J.T. Deely Unit 1

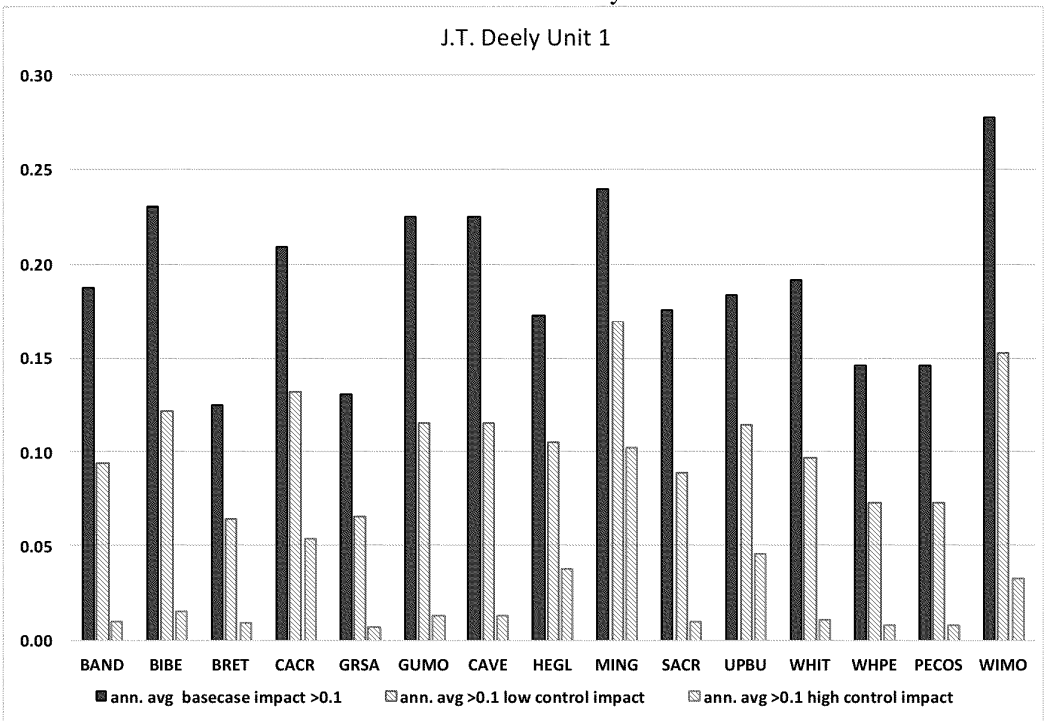

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Figure 4.7-4. Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – J.T. Deely Unit 1

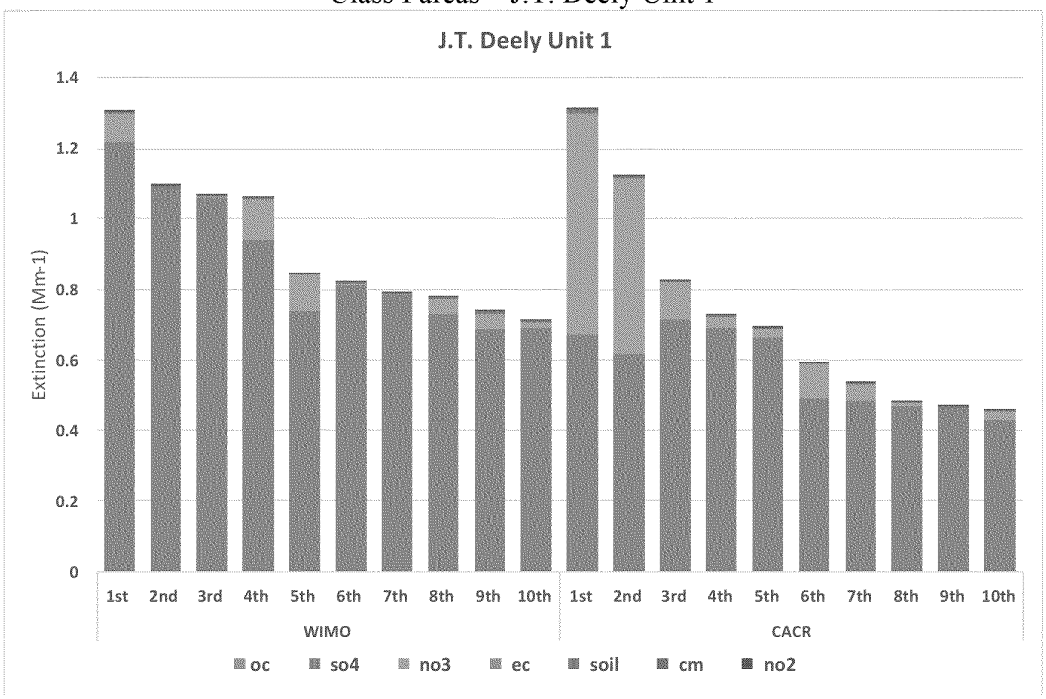


Figure 4.7-5. Maximum CAMx modeled impact– J.T. Deely Unit 2

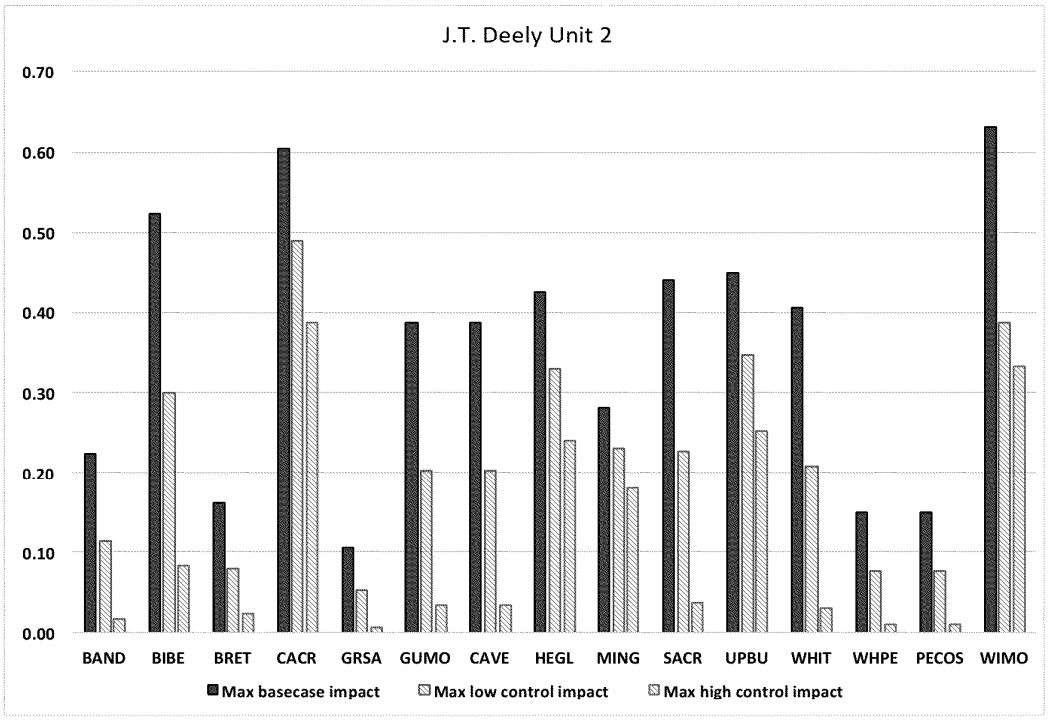


Figure 4.7-6. Average of top ten CAMx modeled impact– J.T. Deely Unit 2

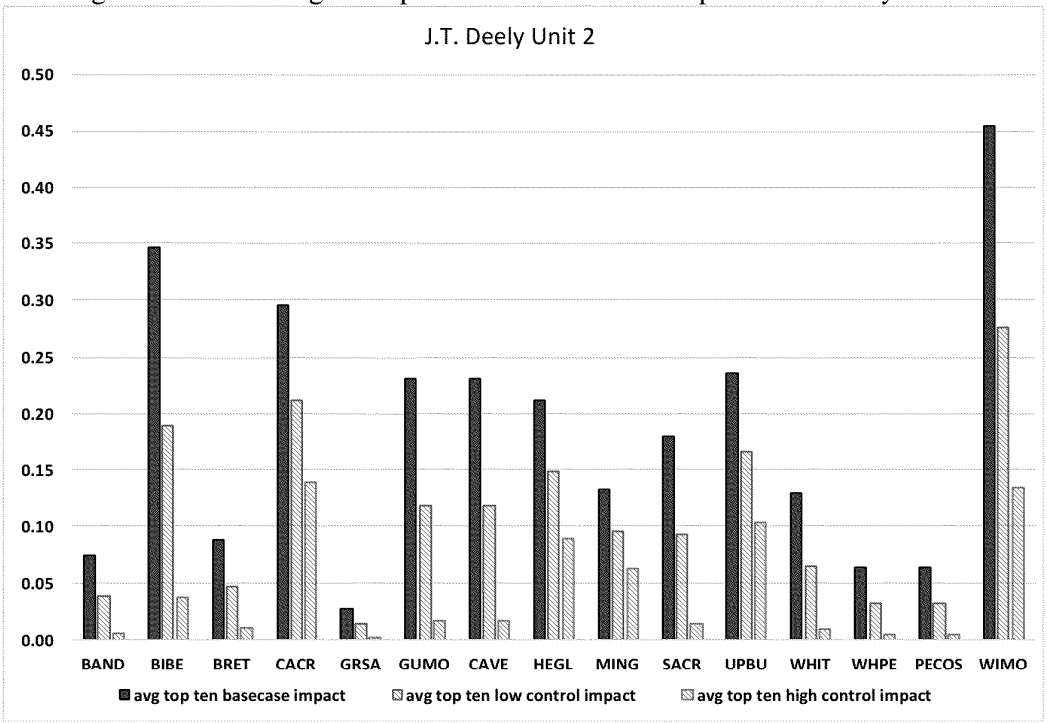


Figure 4.7-7. Annual Average CAMx modeled impact excluding baseline days impacted less than 0.1 dv – J.T. Deely Unit 2

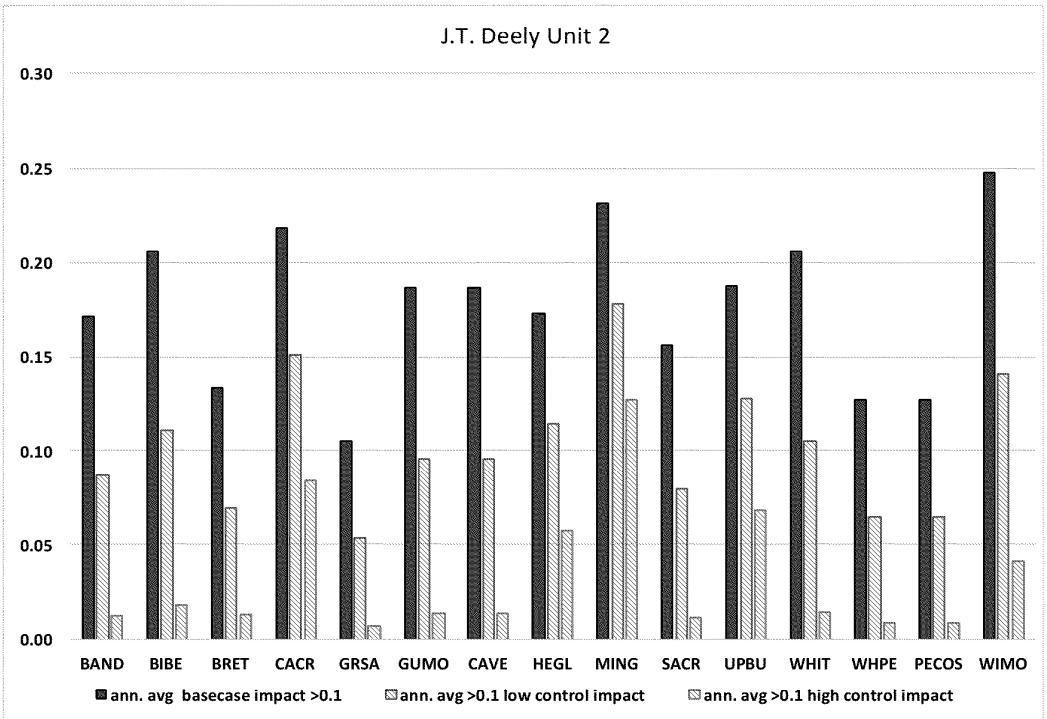
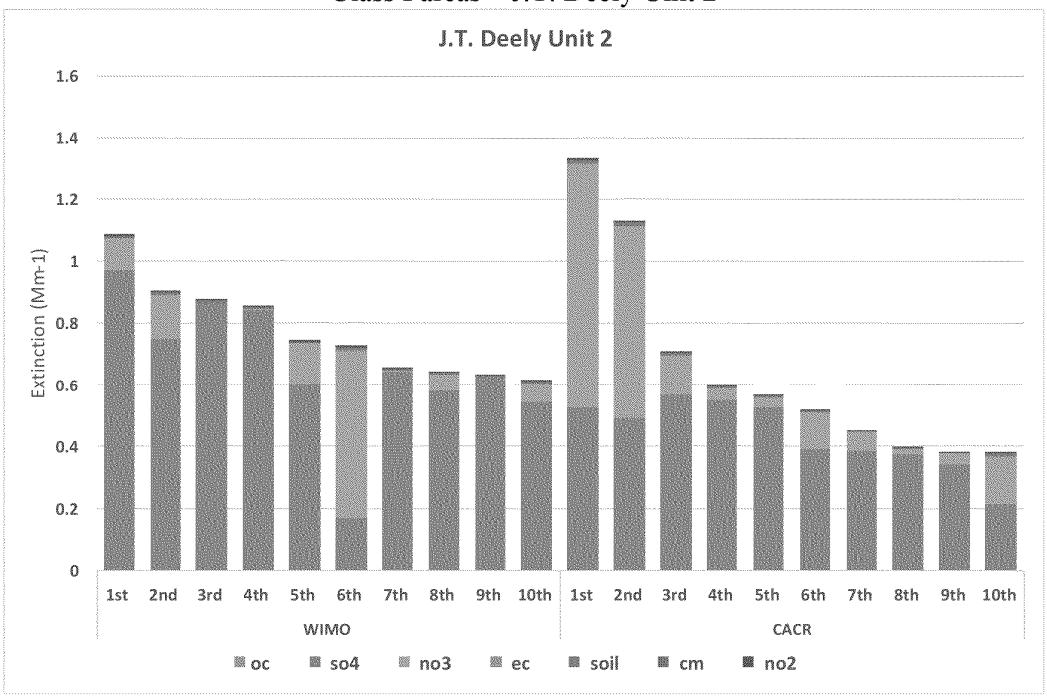


Figure 4.7-8 Species Contribution (Mm-1) on ten highest impact days at two most impacted Class I areas – J.T. Deely Unit 2



5. Visibility Benefits of Scrubber Upgrades for Coal Units

We also modeled the visibility benefits of those same units for which we conducted control cost analysis for upgrading their existing scrubbers. We assumed the same 95% control level we used in our control cost analyses. We also modeled a lower level control at 90%. The visibility benefits from these scrubber upgrades are summarized in the section below.[34,35] See Appendix E and Appendix F for additional CAMx model results for each class I area. Below, we present a summary of the del-dv visibility benefits and reduction in number of days impacted.

[34] See spreadsheet: "summary CAMx vis daily.xlsx" in the docket for this action for these and additional model results.

[35] See "camx_v630.EPA-R6-2016.TX-BART.CAMxRun1.final.xlsx" for summary of base case model results, including species specific 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.

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Table 5-1. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CAMx modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Unit 1, 2 & 3)	CACR	Max dv	6.651	4.491	4.321	2.159	2.329
			Days > 0.5 dv	141	75	56	66	85
			Days>1.0 dv	99	31	16	68	83
		UPBU	Max dv	5.803	2.669	2.528	3.134	3.275
			Days > 0.5 dv	99	39	22	60	77
			Days>1.0 dv	67	11	7	56	60
	Unit 1	CACR	Max dv	2.633	1.550	1.468	1.083	1.165
			Days > 0.5 dv	71	17	6	54	65
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.254	0.867	0.805	1.387	1.449
			Days > 0.5 dv	44	6	3	38	41
			Days>1.0 dv	10	0	0	10	10
	Unit 2	CACR	Max dv	2.466	1.882	1.811	0.585	0.655
			Days > 0.5 dv	68	18	9	50	59
			Days>1.0 dv	26	3	1	23	25
		UPBU	Max dv	2.189	1.077	1.025	1.112	1.164
			Days > 0.5 dv	40	6	5	34	35
			Days>1.0 dv	10	1	1	9	9
	Unit 3	CACR	Max dv	2.755	1.682	1.609	1.074	1.146
			Days > 0.5 dv	76	15	6	61	70
			Days>1.0 dv	29	2	1	27	28
		UPBU	Max dv	2.368	0.942	0.890	1.425	1.478

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			Days > 0.5 dv	46	6	4	40	42
			Days>1.0 dv	13	0	0	13	13
Monticello	Source (Unit 1,2 and 3)	CACR	Max dv	10.498	6.121	2.079	4.377	8.419
			Days > 0.5 dv	152	107	28	45	124
			Days>1.0 dv	111	54	8	57	103
		WIMO	Max dv	5.736	2.769	0.774	2.968	4.962
			Days > 0.5 dv	67	35	4	32	63
			Days>1.0 dv	40	14	0	26	40
	Unit 3	CACR	Max dv	4.632	0.905	0.914	3.728	3.719
			Days > 0.5 dv	79	5	5	74	74
			Days>1.0 dv	32	0	0	32	32
		WIMO	Max dv	2.282	0.462	0.364	1.820	1.918
			Days > 0.5 dv	31	0	0	31	31
			Days>1.0 dv	7	0	0	7	7

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Table 5-2. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Units 1, 2 & 3)	CACR	Max dv	4.46	2.27	1.86	2.18	2.60
			Days > 0.5 dv Avg.	129.67	77.33	63.00	52.33	66.67
			Days>1.0 dv Avg.	91.33	32.67	22.33	58.67	69.00
		UPBU	Max dv	2.73	1.10	0.85	1.63	1.88
			Days > 0.5 dv Avg.	81.67	30.33	18.67	51.33	63.00
			Days>1.0 dv Avg.	46.67	7.33	3.67	39.33	43.00
Monticello [1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	2.41	1.70	2.89	4.87
			Days > 0.5 dv Avg.	143.67	115	62.33	28.67	81.33
			Days>1.0 dv Avg.	113	66.33	23.67	46.67	89.33
		UPBU	Max dv	3.45	1.77	0.765	1.68	2.68
			Days > 0.5 dv Avg.	103	61	13.67	42	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60	34.67	6	25.33	54
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67

[1] Monticello's controlled level is a combination of scrubber upgrade on Unit 3 and scrubber retrofits on Units 1 and 2 in the facility impact modeling with CALPUFF.

Our review of the impacts/benefits of scrubber upgrades on four units at two facilities show that scrubber upgrades conducted at all units would result in significant visibility improvements at impacted Class I areas.

6. Visibility Benefit Analysis of Scrubber Upgrades

The BART Guidelines state that underperforming scrubber systems should be evaluated for upgrades.[36] Other than upgrading the existing scrubbers, all of which are wet FGDs, there are no competing control technologies that could be considered for these units. The CALPUFF modeling generated facility-wide impacts and the benefits of the scrubber upgrade on Monticello Unit 3 and the three Martin Lake facilities are included in Table 5-2 above and Tables 6-1.a-b

[36] 70 FR 39171 (July 6, 2005).

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and 6-2.a-b. The following is a listing of each of the affected units along with additional information on resulting visibility benefits from upgrading their existing scrubbers:

Table 6-1.a Scrubber Upgrade and WGFD Visibility Benefits at Monticello (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	4.87	2.68	10.25	224.67	164.67

Table 6-1.b Scrubber Upgrades at Martin Lake (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Martin Lake Units 1, 2 & 3	2.60	2.04	4.64	129.67	112

Table 6-2a. Scrubber Upgrade and WGFD Visibility Benefits at Monticello RNS {2011-2015} (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Monticello Units 1, 2 & 3	3.67	1.82	7.37	201.33	147

Table 6-2b. Scrubber Upgrades at Martin Lake RNS {2011-2015} (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Upper Buffalo (dv)	Total Cumulative Visibility	Cumulative Reduction in number	Cumulative Reduction in number

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			Benefit (dv)[1]	of days above 0.5 dv[2]	of days above 1.0 dv[2]
Martin Lake Units 1, 2 & 3	2.354	1.685	4.04	134	98.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: MARTIN LAKE - Caney Creek and Upper Buffalo; MONTICELLO – Caney Creek, Upper Buffalo, and Wichita Mountains.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: MARTIN LAKE - Caney Creek and Upper Buffalo; MONTICELLO – Caney Creek, Upper Buffalo, and Wichita Mountains.

As can be seen in the CALPUFF modeling results, reducing emissions to WFGD emission rate levels yields very large benefits.

Table 6-3. Visibility Benefit for Coal-fired Units with Existing SO_2 Controls (CAMx)

Unit	Improvement at most impacted (dv)	Improvement at 2nd most impacted (dv)	Total Cumulative Visibility Benefit (dv) [1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 3	3.719 (CACR)	1.918 (WIMO)	11.940	200 / 66	188 / 66
Martin Lake 1	1.165 (CACR)	1.449 (UPBU)	7.575	160 / 41	151 / 40
Martin Lake 2	0.655 (CACR)	1.164 (UPBU)	6.199	150 / 41	134 / 39
Martin Lake 3	1.146 (CACR)	1.478 (UPBU)	7.863	173 / 47	163 / 46

[1] 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.
[2] 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.
[3] 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.

The figures below show the maximum modeled impact (base case) for these scrubbed units and the modeled impact under the high control (upgrade to 95% control efficiency) scenario at each Class I area.[37] Evaluation of the average across the top ten impact days and annual average visibility impacts show a similar relative reduction in impacts from the base case to the high control case. We conclude that in all cases, scrubber upgrades result in significant visibility benefits, significantly reducing the impacts from these units and reducing the number of days that Class I areas are impacted over 1.0 dv and 0.5 dv. Scrubber upgrades almost eliminate all days impacted over 1 dv by an individual unit.

[37] See spreadsheet: "summary CAMx vis daily.xlsx" in the docket for this action for these and additional model results.

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Figure 6-1. Maximum CAMx modeled impact (dv)– Martin Lake Unit 1

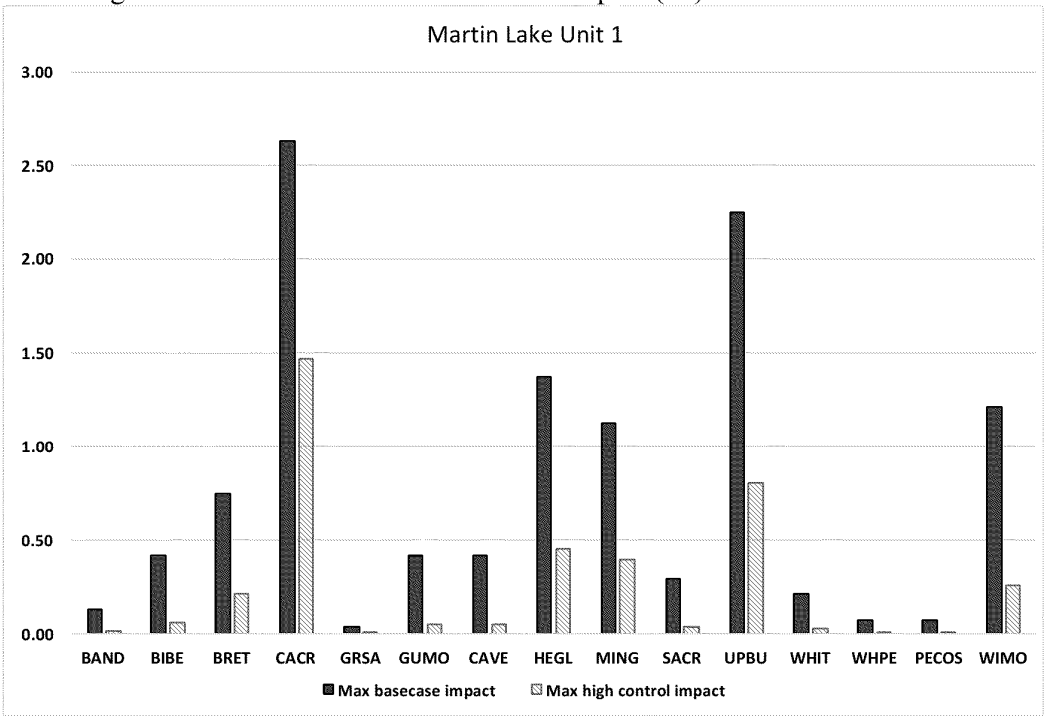

Figure 6-2. Maximum CAMx modeled impact (dv)– Martin Lake Unit 2

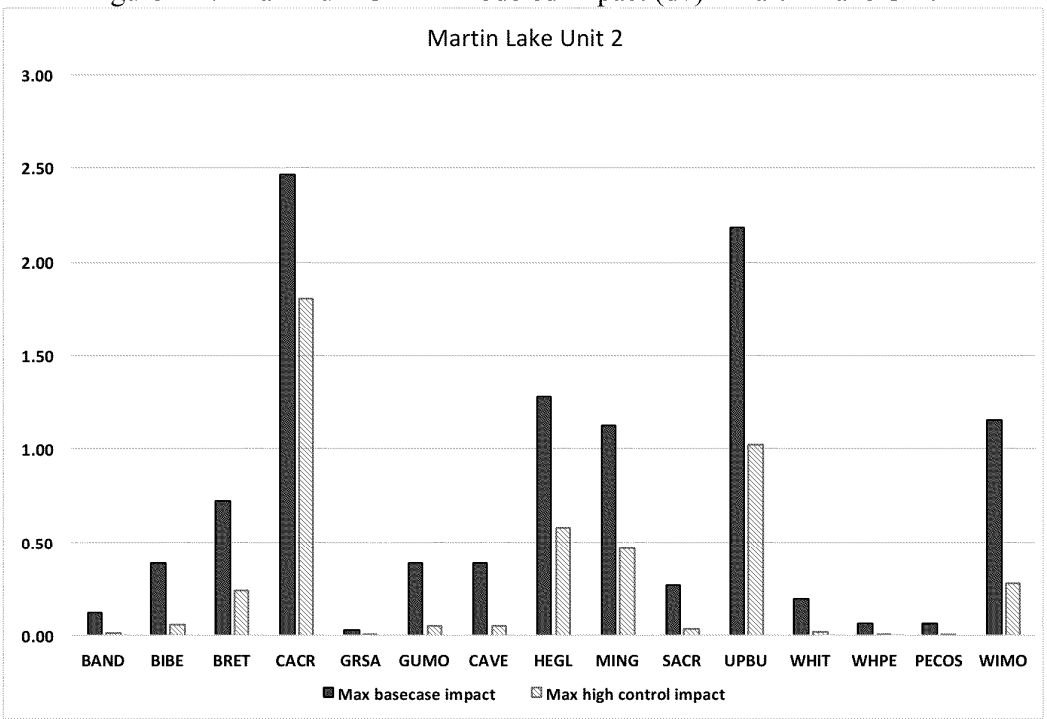

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Figure 6-3. Maximum CAMx modeled impact (dv)– Martin Lake Unit 3

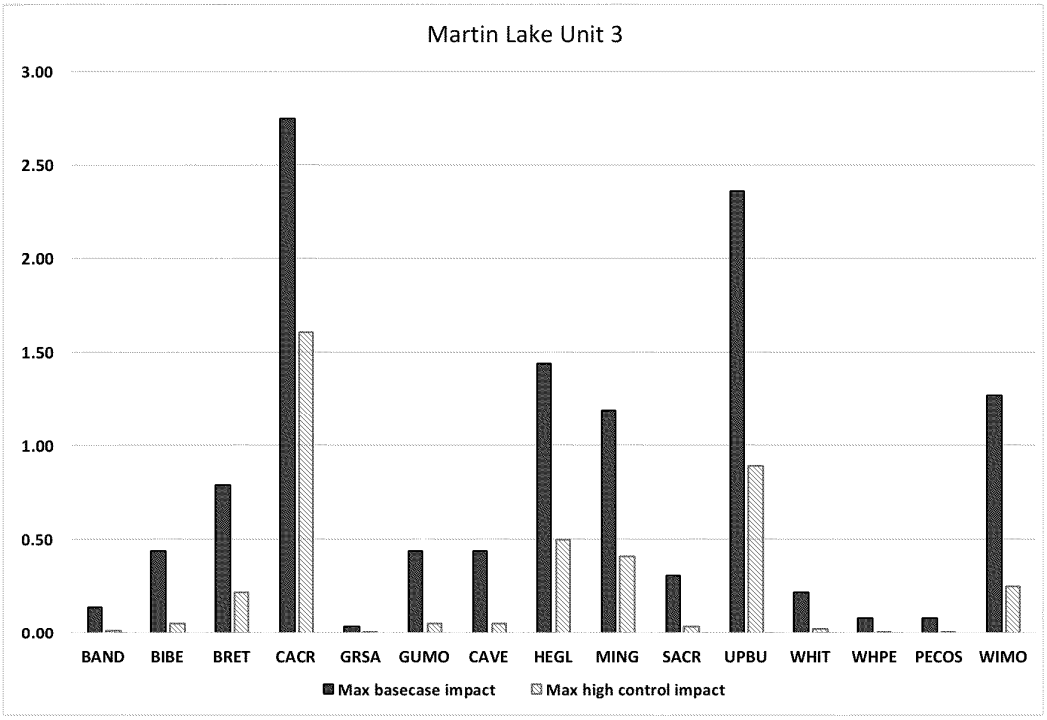
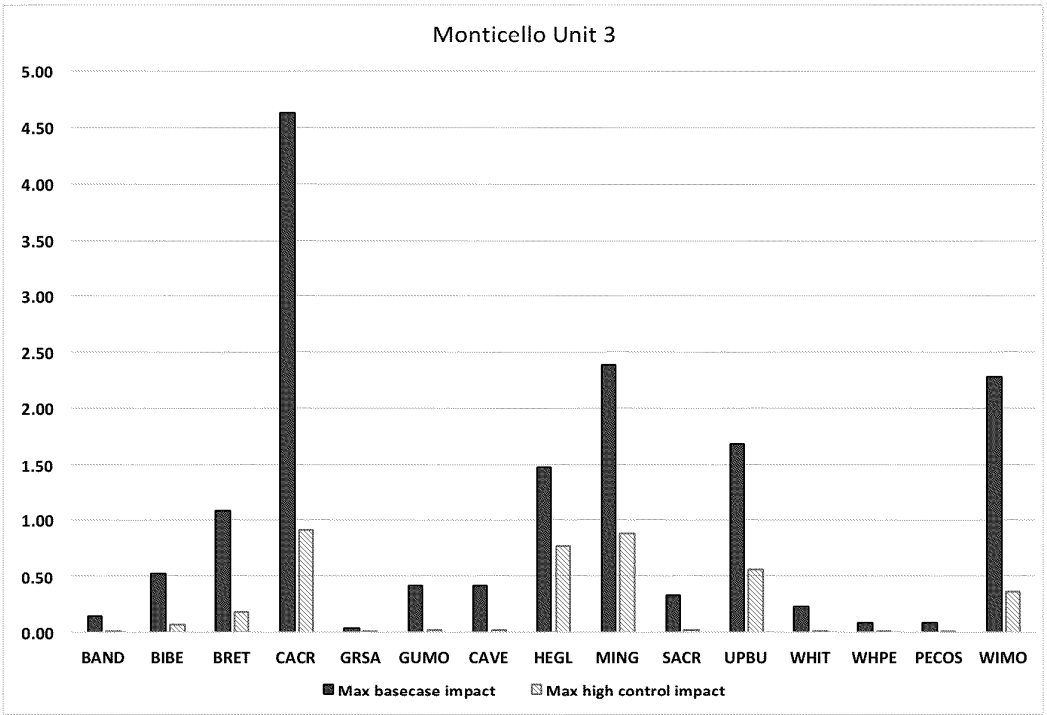


Figure 6-4. Maximum CAMx modeled impact (dv)– Monticello Unit 3



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7. Visibility Benefits of Fuel Switching for Gas/Fuel Oil-Fired Units

We also modeled the visibility benefits of those gas/fuel oil-fired units for which we conducted control cost analysis for switching to lower sulfur fuels. We evaluated the visibility benefits of switching to fuel oils corresponding to ultra-low sulfur diesel at 0.0015% sulfur by weight and 0.3% sulfur by weight as we evaluated in our control cost analyses. See the BART Screening TSD for additional information on baseline emissions and modeling. The visibility benefits from these fuel switches are quantified specifically in our BART Modeling TSD. Below, we present a summary of the del-dv visibility benefits. Because fuel oil is fired on an irregular basis for these units (usually less than 10% of the annual BTUs are from fuel oil burning), they are not amenable to a number of days analysis. See the BART FIP TSD for additional EIA information on quantity of fuel oil burned.

Table 7-1. Visibility Benefits from Lower Sulfur Fuel

Facility Name	Emission Unit	Baseline visibility Impact from Source (most impacted Class I area)	Visibility benefit of 0.3% S fuel oil	Visibility benefit of 0.0015% S fuel oil
Stryker	ST2	CALPUFF 0.65 % S: 0.786 dv @ CACR (Facility)	CALPUFF (0.3 % S) : 0.263 dv @ CACR (Facility)	CALPUFF: 0.522 dv @ CACR (Facility)
Graham	Unit 2	CALPUFF 0.69 % S: 1.228 dv @ WIMO (Facility)	CALPUFF (0.3% S): 0.465 dv @ WIMO (Facility	CALPUFF: 0.851 dv @ WIMO (Facility
Wilkes	Units 1, 2, 3	CALPUFF 0.43 % S: 0.698 dv @ CACR (Facility)	CALPUFF (0.1 % S): 0.029 dv @ CACR (Facility)	CALPUFF: 0.037 dv @ CACR (Facility)
Newman[1]	Unit 2	N/A	N/A	N/A
	Unit 3	N/A	N/A	N/A
	Unit 4	N/A	N/A	N/A

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Calaveras	Sommers Unit 1	CAMx: 1.513 dv @ WIMO (Source); 0.106 dv @ CACR (Unit)	0.004 dv @ CACR	0.008 dv @ CACR
	Sommers Unit 2	CAMx: 1.513 dv @ WIMO (Source); 0.180 dv @ CACR (Unit)	0.023 @ CACR	0.047 @ CACR

[1] EPA initially considered evaluating with CALPUFF databases, but Newman is located near the edge of the CALMET modeling domain. There are a number of Class I areas that Newman could potentially impact (Gila, Bosque del Apache, Mount Baldy, Chiricahua, White Mountain, etc) and due to the size of the CALMET grid we cannot determine if Newman's impacts are below 0.5 dv at all Class I areas or determine the potential benefits from controls. Since plumes could transport out of the modeling domain and there is no way within the CALPUFF model to account for mass that transports out of the domain that may come back into the domain, the CALPUFF modeling databases cannot be relied on to conclusively assess visibility impacts from the Newman facility.

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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
Big Brown (Luminant)	1	400	21.5	366	30075.75	77.7	*199.095*	*16.157*	*2.9726*	*1.2746*
Big Brown (Luminant)	2	400	21.5	366	30075.75	77.7	*201.073*	*15.303*	*3.0058*	*1.289*
Coleto Creek (Engie)	1	409	20	347	36599.55	116.5	*67.83*	*17.235*	*0.8682*	*0.4412*
Fayette (LCRA)	1	600	23	316	37185.04	89.5	*61.388*	*15.363*	*2.5614*	*0.7432*
Fayette (LCRA)	2	600	23	307	39470.15	95	*61.909*	*13.79*	*4.5982*	*1.3338*
Harrington Station (Xcel)	061B	250	19	300	25148.98	88.7	*40.046*	*19.347*	*2.2942*	*0.0910*
Harrington Station (Xcel)	062B	300	19	300	25148.98	88.7	*42.749*	*19.231*	*6.0826*	*0.0382*
J T Deely (CPS Energy)	1	173	20	309	31227.43	99.4	*65.542*	*18.279*	*3.3732*	*1.5437*
J T Deely (CPS Energy)	2	172	20	309	31227.43	99.4	*52.262*	*23.034*	*5.18*	*1.9814*
Martin Lake (Luminant)	1	452	23	348	37143.49	89.4	*118.569*	*21.52*	*1.614*	*1.0876*
Martin Lake (Luminant)	2	452	23	348	38223.73	92	*109.736*	*28.337*	*2.0232*	*1.3648*
Martin Lake (Luminant)	3	452	23	348	38223.73	92	*124.38*	*24.192*	*1.9116*	*1.2886*
Monticello (Luminant)	1	400	21.5	356	29407.05	81	*142.714*	*18.125*	*6.9642*	*3.4384*
Monticello (Luminant)	2	400	21.5	356	29407.05	81	*139.962*	*13.01*	*8.219*	*3.255*
Monticello (Luminant)	3	460	25.5	329	44431.31	87	*140.815*	*24.586*	*4.8062*	*2.1632*
O W Sommers (CPS Energy)	1	240	20	275	16650.43	53	*10.917*	*8.038*	*0.1768*	*0.1768*

O W Sommers (CPS Energy)	2	240	20	275	16650.43	53	*2.011*	*5.949*	*0.145*	*0.145*
W A Parish (NRG)	WAP4	182	18	281	16413.24	64.5	*0.033*	*9.27*	*0.5044*	*0.5044*
W A Parish (NRG)	WAP5	600	24	332	38453.06	85	*97.654*	*6.018*	*0.6692*	*0.6692*
W A Parish (NRG)	WAP6	600	24	332	38453.06	85	*94.288*	*5.32*	*0.64*	*0.64*
Welsh Power Plant (AEP)	1	300	17	275	13843.1	85	*55.882*	*18.387*	*5.153*	*5.153*
Welsh Power Plant (AEP)	2	300	17	275	13843.1	85	*63.174*	*30.656*	*5.2312*	*5.2312*

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
Big Brown (Luminant)	1	400	21.5	366	30075.75	77.7	99.548	**16.157**	**2.973**	**1.275**
Big Brown (Luminant)	2	400	21.5	366	30075.75	77.7	100.537	**15.303**	**3.006**	**1.289**
Coleto Creek (Engie)	1	409	20	347	36599.55	116.5	33.915	**17.235**	**0.868**	**0.441**
Fayette (LCRA)	1	600	23	316	37185.04	89.5	61.388	**15.363**	**2.561**	**0.743**
Fayette (LCRA)	2	600	23	307	39470.15	95	61.909	**13.790**	**4.598**	**1.334**
Harrington Station (Xcel)	061B	250	19	300	25148.98	88.7	20.023	**19.347**	**2.294**	**0.091**
Harrington Station (Xcel)	062B	300	19	300	25148.98	88.7	21.375	**19.231**	**6.083**	**0.038**
J T Deely (CPS Energy)	1	173	20	309	31227.43	99.4	32.771	**18.279**	**3.373**	**1.544**
J T Deely (CPS Energy)	2	172	20	309	31227.43	99.4	26.131	**23.034**	**5.180**	**1.981**
Martin Lake (Luminant)	1	452	23	348	37143.49	89.4	26.986	**21.520**	**1.614**	**1.088**
Martin Lake (Luminant)	2	452	23	348	38223.73	92	25.595	**28.337**	**2.023**	**1.365**

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Martin Lake (Luminant)	3	452	23	348	38223.73	92	24.666	**24.192**	**1.912**	**1.289**
Monticello (Luminant)	1	400	21.5	356	29407.05	81	71.357	**18.125**	**6.964**	**3.438**
Monticello (Luminant)	2	400	21.5	356	29407.05	81	69.981	**13.010**	**8.219**	**3.255**
Monticello (Luminant)	3	460	25.5	329	44431.31	87	13.710	**24.586**	**4.806**	**2.163**
O W Sommers (CPS Energy)	1	240	20	275	16650.43	53	5.746	**8.038**	**0.177**	**0.177**
O W Sommers (CPS Energy)	2	240	20	275	16650.43	53	1.058	**5.949**	**0.145**	**0.145**
W A Parish (NRG)	WAP4	182	18	281	16413.24	64.5	0.033	**9.270**	**0.504**	**0.504**
W A Parish (NRG)	WAP5	600	24	332	38453.06	85	48.827	**6.018**	**0.669**	**0.669**
W A Parish (NRG)	WAP6	600	24	332	38453.06	85	47.144	**5.320**	**0.640**	**0.640**
Welsh Power Plant (AEP)	1	300	17	275	13843.1	85	27.941	**18.387**	**5.153**	**5.153**
Welsh Power Plant (AEP)	2	300	17	275	13843.1	85	63.174	**30.656**	**5.231**	**5.231**

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
Big Brown (Luminant)	1	400	21.5	366	30075.75	77.7	3.418	16.157	1.486	0.637
Big Brown (Luminant)	2	400	21.5	366	30075.75	77.7	3.507	15.303	1.503	0.645
Coleto Creek (Engie)	1	409	20	347	36599.55	116.5	3.213	17.235	0.434	0.221
Fayette (LCRA)	1	600	23	316	37185.04	89.5	3.071	15.363	1.281	0.372
Fayette (LCRA)	2	600	23	307	39470.15	95	3.310	13.790	2.299	0.667
Harrington Station (Xcel)	061B	250	19	300	25148.98	88.7	3.566	19.347	1.147	0.046

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Harrington Station (Xcel)	062B	300	19	300	25148.98	88.7	3.234	19.231	3.041	0.019
J T Deely (CPS Energy)	1	173	20	309	31227.43	99.4	3.173	18.279	1.687	0.772
J T Deely (CPS Energy)	2	172	20	309	31227.43	99.4	3.192	23.034	2.590	0.991
Martin Lake (Luminant)	1	452	23	348	37143.49	89.4	13.493	21.520	1.614	1.088
Martin Lake (Luminant)	2	452	23	348	38223.73	92	12.797	28.337	2.023	1.365
Martin Lake (Luminant)	3	452	23	348	38223.73	92	12.333	24.192	1.912	1.289
Monticello (Luminant)	1	400	21.5	356	29407.05	81	3.185	18.125	3.482	1.719
Monticello (Luminant)	2	400	21.5	356	29407.05	81	3.233	13.010	4.110	1.628
Monticello (Luminant)	3	460	25.5	329	44431.31	87	6.855	24.586	4.806	2.163
O W Sommers (CPS Energy)	1	240	20	275	16650.43	53	0.086	8.038	0.177	0.177
O W Sommers (CPS Energy)	2	240	20	275	16650.43	53	0.016	5.949	0.145	0.145
W A Parish (NRG)	WAP4	182	18	281	16413.24	64.5	0.033	9.270	0.252	0.252
W A Parish (NRG)	WAP5	600	24	332	38453.06	85	4.654	6.018	0.335	0.335
W A Parish (NRG)	WAP6	600	24	332	38453.06	85	3.893	5.320	0.320	0.320
Welsh Power Plant (AEP)	1	300	17	275	13843.1	85	3.126	18.387	2.577	2.577
Welsh Power Plant (AEP)	2	300	17	275	13843.1	85	0.000	0.000	0.000	0.000

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Appendix B. CALPUFF Modeled emissions

Table B-1. Base case CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	16591.25	3.00	1346.42	123.9	119.3	4.6	101
Big Brown	2	16756.08	3.00	1275.25	125.2	120.6	4.6	101.9
Harrington	061B	3337.17	0.25	1612.25	95.6	92.1	3.5	71.3
Harrington	062B	3562.42	1.64	1602.58	281.6	217	8.3	73.6
Martin Lake	1	9880.75	17.22	1793.33	74.7	57.6	2.2	10.1
Martin Lake	2	9144.67	17.40	2361.42	93.7	72.1	2.8	12.7
Martin Lake	3	10365.00	16.88	2016.00	88.5	68.2	2.6	12.5
Monticello	1	11892.83	2.91	1510.42	290.2	279.4	10.7	97
Monticello	2	11663.50	2.96	1084.17	342.5	329.8	12.7	118.9
Monticello	3	11734.58	12.13	2048.83	222.5	171.4	6.6	22.2
Welsh	1	4656.83	2.37	1532.25	238.6	183.8	7.1	57.7
Welsh	2	5264.50	2.41	2554.67	242.2	186.6	7.2	59.1

Table B-2. Low Control CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	8295.63	3.00	1346.42	123.90	119.30	4.60	101.00
Big Brown	2	8378.04	3.00	1275.25	125.20	120.60	4.60	101.90
Harrington	061B	1668.58	0.25	1612.25	95.60	92.10	3.50	71.30
Harrington	062B	1781.21	1.64	1602.58	281.60	217.00	8.30	73.60

Martin Lake	1	2248.80	17.22	1793.33	74.70	57.60	2.20	10.10
Martin Lake	2	2132.88	17.40	2361.42	93.70	72.10	2.80	12.70
Martin Lake	3	2055.46	16.88	2016.00	88.50	68.20	2.60	12.50
Monticello	1	5946.42	2.91	1510.42	290.20	279.40	10.70	97.00
Monticello	2	5831.75	2.96	1084.17	342.50	329.80	12.70	118.90
Monticello	3	1142.52	12.13	2048.83	222.50	171.40	6.60	22.20
Welsh	1	2328.42	2.37	1532.25	238.60	183.80	7.10	57.70
Welsh	2	2632.25	2.41	2554.67	242.20	186.60	7.20	59.10

Table B-3. High Control CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	284.84	1.20	1346.42	61.90	59.60	2.30	23.50
Big Brown	2	292.24	1.20	1275.25	62.60	60.30	2.30	23.70
Harrington	061B	297.18	0.10	1612.25	47.80	46.00	1.80	71.30
Harrington	062B	269.46	0.66	1602.58	140.80	108.50	4.20	73.60
Martin Lake	1	1124.40	17.22	1793.33	74.70	57.60	2.20	10.10
Martin Lake	2	1066.44	17.40	2361.42	93.70	72.10	2.80	12.70
Martin Lake	3	1027.73	16.88	2016.00	88.50	68.20	2.60	12.50
Monticello	1	265.40	1.16	1510.42	145.10	139.70	5.40	44.10
Monticello	2	269.40	1.19	1084.17	171.20	164.90	6.30	51.70
Monticello	3	571.26	12.13	2048.83	222.50	171.40	6.60	22.20
Welsh	1	260.52	0.95	1532.25	119.30	91.90	3.50	57.70
Welsh	2	245.04	0.96	2554.67	121.10	93.30	3.60	59.10

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Table B-4. SDA Control CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	427.26	0.30	1346.42	61.9	59.6	2.3	23.5
Big Brown	2	438.36	0.30	1275.25	62.6	60.3	2.3	23.7
Monticello	1	398.10	0.29	1510.42	145.1	139.7	5.4	44.1
Monticello	2	404.10	0.30	1084.17	171.2	164.9	6.3	51.7
Welsh	1	390.78	0.03	1532.25	119.3	91.9	3.5	57.7

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Appendix C. CALPUFF Recent NOx and SO2 Emissions (2011-2015)

Table C-1. RNS CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	12939.17	3.00	975.75	123.9	119.3	4.6	101
Big Brown	2	14045	3.00	983.25	125.2	120.6	4.6	101.9
Harrington	061B	2725.25	0.25	1006.17	95.6	92.1	3.5	71.3
Harrington	062B	2759	1.64	1029.17	281.6	217	8.3	73.6
Martin Lake	1	9275.42	17.22	1892.92	74.7	57.6	2.2	10.1
Martin Lake	2	8635	17.40	1633.33	93.7	72.1	2.8	12.7
Martin Lake	3	8243.75	16.88	1458.03	88.5	68.2	2.6	12.5
Monticello	1	7663.75	2.91	924.83	290.2	279.4	10.7	97
Monticello	2	7875	2.96	1036	342.5	329.8	12.7	118.9
Monticello	3	7900.42	12.13	1554.83	222.5	171.4	6.6	22.2
Welsh	1	2922.5	2.37	1274.92	238.6	183.8	7.1	57.7
Welsh	2	0	0	0	0	0	0	0

Table C-2. RNS - Low Control CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	8295.63	3.00	975.75	123.90	119.30	4.60	101.00
Big Brown	2	8378.04	3.00	983.25	125.20	120.60	4.60	101.90
Harrington	061B	1668.58	0.25	1006.17	95.60	92.10	3.50	71.30
Harrington	062B	1781.21	1.64	1029.17	281.60	217.00	8.30	73.60
Martin Lake	1	2192.8	17.22	1892.92	74.70	57.60	2.20	10.10
Martin Lake	2	2116.83	17.40	1633.33	93.70	72.10	2.80	12.70
Martin Lake	3	1991.30	16.88	1458.03	88.50	68.20	2.60	12.50
Monticello	1	3832	2.91	924.83	290.20	279.40	10.70	97.00
Monticello	2	3937.3	2.96	1036	342.50	329.80	12.70	118.90
Monticello	3	1039.26	12.13	1554.83	222.50	171.40	6.60	22.20
Welsh	1	1461	2.37	1274.92	238.60	183.80	7.10	57.70
Welsh	2	0	0	0	0	0	0	0

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Table C-3. RNS - High Control CALPUFF emissions (lb/hr)

Source	Unit	SO_2	**SO4**	**NOx**	**PMc**	**PMf**	**EC**	**SOA**
Big Brown	1	252.04	1.20	975.75	61.90	59.60	2.30	23.50
Big Brown	2	254.21	1.20	983.25	62.60	60.30	2.30	23.70
Harrington	061B	231.49	0.10	1006.17	47.80	46.00	1.80	71.30
Harrington	062B	286.80	0.66	1029.17	140.80	108.50	4.20	73.60
Martin Lake	1	1096.4	17.22	1892.92	74.70	57.60	2.20	10.10
Martin Lake	2	1058.42	17.40	1633.33	93.70	72.10	2.80	12.70
Martin Lake	3	995.65	16.88	1458.03	88.50	68.20	2.60	12.50
Monticello	1	252.45	1.16	924.83	145.10	139.70	5.40	44.10
Monticello	2	261.63	1.19	1036	171.20	164.90	6.30	51.70
Monticello	3	519.63	12.13	1554.83	222.50	171.40	6.60	22.20
Welsh	1	220.61	0.95	1274.92	119.30	91.90	3.50	57.70
Welsh	2	0	0	0	0	0	0	0

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Appendix D. EPRI Calculation for H_2SO_4 Emission Rate for CALPUFF Modeling

From: Estimating Total Sulfuric Acid Emissions from Stationary Power Plants, Electric Power Research Institute; March 2012.

$$ER_{Comb} = K \cdot F1 \cdot K1 \cdot K2 \cdot C1 \cdot S1 \cdot F2_{AH} \cdot F2_{PM} \cdot F2_{FGD}$$

where,:

ERComb = total H_2SO_4 released, lbs/hr

K = Molecular weight and units conversion constant = 98.07 / 64.04 • 2000 = 3,063

(98.07 = Molecular weight of H_2SO_4 ; 64.04 = Molecular weight of SO_2; 2000 = Conversion from tons/hr to lb/hr)

F1 = Fuel Impact Factor (See EPRI 2012 Table 4-1)

C1 = Dry coal burn, tons/hr = Coal Heating Value (MMBtu/ton) • Max Heat input (MMBtu/hr)

S1 = Coal sulfur weighted average, %, dry

K1 = Molecular weight and units conversion constant = (64.04)/(100 • 32.06) = 0.02

(64.04 = molecular weight of SO_2; 32.06 = molecular weight of S; 100 = conversion of % S to a fraction)

K2 = Sulfur conversion to SO_2, implicit from EPA AP-42 (EPA, 1995b)

(0.95 for bituminous coals, 0.875 for subbituminous coals, 0.55 to 0.85 for lignite, based on the Na content, 1.0 for oil)

F2 = Technology Impact Factors (See EPRI 2012 Tables 4-3, 4-4, and 4-5)

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Table D-1. Low Control Scenario

Facility	Unit	Coal	Max Heat input (MMBTU /hr)	C1	Coal Heating Value (MMBtu/ton, HV)	S1	K	K1	K2	F1	F2(AH)	F2(PM)	F2(FGD)	H_2SO_4 (lb/hr)
Big Brown	1	lignite	7782	565.39	6882	0.73	3063	0.02	0.75	0.0044	0.36	0.1	1	3.004
Big Brown	2	lignite	7782	565.14	6885	0.73	3063	0.02	0.75	0.0044	0.36	0.1	1	3.002
Harrington	061B	sub	4631	261.67	8848.86	0.26	3063	0.02	0.875	0.0019	0.36	0.1	1	0.249
Harrington	062B	sub	4222	238.74	8842.08	0.26	3063	0.02	0.875	0.0019	0.36	0.72	1	1.639
Martin Lake	1	lignite	11124	829.78	6703	0.99	3063	0.02	0.75	0.0044	0.36	0.72	0.4	17.218
Martin Lake	2	lignite	11124	830.15	6700	1	3063	0.02	0.75	0.0044	0.36	0.72	0.4	17.400
Martin Lake	3	lignite	11124	830.15	6700	0.97	3063	0.02	0.75	0.0044	0.36	0.72	0.4	16.878
Monticello	1	lignite	9924	768.23	6459	0.52	3063	0.02	0.75	0.0044	0.36	0.1	1	2.907
Monticello	2	lignite	9924	768.59	6456	0.53	3063	0.02	0.75	0.0044	0.36	0.1	1	2.965
Monticello	3	lignite	12870	997.98	6448	0.58	3063	0.02	0.75	0.0044	0.36	0.72	0.4	12.132
Welsh	1	sub	6896	407.32	8465.07	0.22	3063	0.02	0.875	0.0019	0.36	0.72	1	2.366
Welsh	2	sub	7046	414.35	8502.57	0.22	3063	0.02	0.875	0.0019	0.36	0.72	1	2.406

Table D-2. High Control Scenario

Facility	Unit	Coal	Max Heat input (MMBTU /hr)	C1	Coal Heating Value (MMBtu/ton, HV)	S1	K	K1	K2	F1	F2(AH)	F2(PM)	F2(FGD)	H_2SO_4 (lb/hr)
Big Brown	1	lignite	7782	565.39	6882	0.73	3063	0.02	0.75	0.0044	0.36	0.1	0.4	1.201
Big Brown	2	lignite	7782	565.14	6885	0.73	3063	0.02	0.75	0.0044	0.36	0.1	0.4	1.201
Harrington	061B	sub	4631	261.67	8848.86	0.26	3063	0.02	0.875	0.0019	0.36	0.1	0.4	0.100
Harrington	062B	sub	4222	238.74	8842.08	0.26	3063	0.02	0.875	0.0019	0.36	0.72	0.4	0.655
Martin Lake	1	lignite	11124	829.78	6703	0.99	3063	0.02	0.75	0.0044	0.36	0.72	0.4	17.218
Martin Lake	2	lignite	11124	830.15	6700	1	3063	0.02	0.75	0.0044	0.36	0.72	0.4	17.400
Martin Lake	3	lignite	11124	830.15	6700	0.97	3063	0.02	0.75	0.0044	0.36	0.72	0.4	16.878
Monticello	1	lignite	9924	768.23	6459	0.52	3063	0.02	0.75	0.0044	0.36	0.1	0.4	1.163

Monticello	2	lignite	9924	768.59	6456	0.53	3063	0.02	0.75	0.0044	0.36	0.1	0.4	1.186
Monticello	3	lignite	12870	997.98	6448	0.58	3063	0.02	0.75	0.0044	0.36	0.72	0.4	12.132
Welsh	1	sub	6896	407.32	8465.07	0.22	3063	0.02	0.875	0.0019	0.36	0.72	0.4	0.946
Welsh	2	sub	7046	414.35	8502.57	0.22	3063	0.02	0.875	0.0019	0.36	0.72	0.4	0.963

Table D-3. SDA Control Scenario

Facility	Unit	Coal	Max Heat input (MMBTU /hr)	C1	Coal Heating Value (MMBtu/ton, HV)	S1	K	K1	K2	F1	F2(AH)	F2(PM)	F2(FGD)	H_2SO_4 (lb/hr)
Big Brown	1	lignite	7782	565.39	6882	0.73	3063	0.02	0.75	0.0044	0.36	0.01	1	0.300
Big Brown	2	lignite	7782	565.14	6885	0.73	3063	0.02	0.75	0.0044	0.36	0.01	1	0.300
Monticello	1	lignite	9924	768.23	6459	0.52	3063	0.02	0.75	0.0044	0.36	0.01	1	0.291
Monticello	2	lignite	9924	768.59	6456	0.53	3063	0.02	0.75	0.0044	0.36	0.01	1	0.296
Welsh	1	sub	6896	407.32	8465.07	0.22	3063	0.02	0.875	0.0019	0.36	0.01	1	0.033

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Appendix E. CAMx Maximum Impact at each Class I Area

Table E-1. Base Case (Run 1) Maximum Impact

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0.278	0.224	0.009	0.047	0.205	0.207	0.001	0.270	0.261	0.359	0.362
BIBE	0.652	0.525	0.027	0.111	0.457	0.463	0.002	0.600	0.580	1.087	1.097
BRET	0.203	0.163	0.006	0.034	0.178	0.180	0.005	0.236	0.228	0.802	0.809
CACR	0.595	0.604	0.106	0.180	1.002	0.974	0.163	1.698	1.648	2.016	2.033
CAVE	0.480	0.388	0.017	0.081	0.463	0.468	0.003	0.617	0.596	0.923	0.932
GRSA	0.131	0.105	0.004	0.022	0.081	0.082	0.000	0.082	0.079	0.094	0.095
GUMO	0.480	0.388	0.017	0.081	0.463	0.468	0.003	0.617	0.596	0.923	0.932
HEGL	0.432	0.426	0.066	0.121	0.540	0.537	0.067	0.721	0.696	1.482	1.492
MING	0.278	0.282	0.047	0.081	0.450	0.444	0.070	0.781	0.753	1.266	1.272
PECO	0.188	0.151	0.006	0.031	0.147	0.149	0.001	0.173	0.167	0.206	0.208
SACR	0.546	0.441	0.019	0.092	0.420	0.425	0.003	0.523	0.505	0.750	0.758
UPBU	0.456	0.449	0.070	0.127	0.581	0.579	0.069	1.038	1.003	1.690	1.699
WHIT	0.504	0.406	0.017	0.085	0.347	0.350	0.002	0.402	0.388	0.568	0.574
WHPE	0.188	0.151	0.006	0.031	0.147	0.149	0.001	0.173	0.167	0.206	0.208
WIMO	0.757	0.632	0.101	0.153	0.609	0.598	0.062	0.967	0.935	2.154	2.175
Cumulative	6.168	5.332	0.518	1.277	6.089	6.072	0.451	8.896	8.601	14.525	14.645

Table E-1. Base Case (Run 1) Maximum Impact (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0.198	0.502	0.526	0.131	0.121	0.137	0.149	0.146	0.141	0.066	0.059
BIBE	0.426	0.514	0.555	0.418	0.387	0.438	0.531	0.523	0.521	0.232	0.207
BRET	0.191	0.206	0.223	0.747	0.722	0.787	1.061	1.039	1.083	0.505	0.436
CACR	0.791	0.679	0.701	2.633	2.466	2.755	4.516	4.487	4.632	2.674	2.343
CAVE	0.411	0.435	0.458	0.417	0.387	0.439	0.421	0.414	0.407	0.187	0.166
GRSA	0.094	0.254	0.257	0.032	0.030	0.034	0.036	0.035	0.036	0.016	0.015
GUMO	0.411	0.435	0.458	0.417	0.387	0.439	0.421	0.414	0.407	0.187	0.166
HEGL	0.585	0.721	0.746	1.377	1.278	1.442	1.429	1.410	1.472	1.158	0.797
MING	0.415	0.416	0.431	1.125	1.126	1.189	2.299	2.138	2.394	1.539	1.150
PECO	0.152	0.243	0.284	0.073	0.068	0.077	0.082	0.080	0.078	0.036	0.032
SACR	0.429	2.908	2.998	0.292	0.271	0.306	0.336	0.330	0.325	0.149	0.132
UPBU	0.660	0.706	0.733	2.254	2.189	2.368	1.663	1.628	1.683	1.446	0.978
WHIT	0.376	0.800	0.838	0.210	0.194	0.220	0.243	0.239	0.234	0.112	0.099
WHPE	0.152	0.243	0.284	0.073	0.068	0.077	0.082	0.080	0.078	0.036	0.032
WIMO	0.845	2.708	2.770	1.216	1.156	1.277	2.241	2.189	2.282	1.033	0.864
Cumulative	6.135	11.771	12.262	11.416	10.853	11.985	15.510	15.153	15.775	9.378	7.476

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Table E-2. High Control (Run 3) Maximum Impact

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0.016	0.016	0.001	0.001	0.012	0.012	0.001	0.013	0.011	0.007	0.007
BIBE	0.069	0.084	0.017	0.024	0.025	0.027	0.001	0.033	0.028	0.033	0.031
BRET	0.019	0.023	0.005	0.007	0.030	0.028	0.006	0.014	0.012	0.039	0.039
CACR	0.312	0.387	0.098	0.132	0.480	0.441	0.183	0.180	0.156	0.409	0.391
CAVE	0.031	0.033	0.003	0.004	0.028	0.030	0.002	0.031	0.026	0.021	0.021
GRSA	0.007	0.007	0.001	0.001	0.004	0.005	0.000	0.004	0.003	0.003	0.002
GUMO	0.031	0.033	0.003	0.004	0.028	0.030	0.002	0.031	0.026	0.021	0.021
HEGL	0.194	0.241	0.060	0.081	0.203	0.186	0.073	0.077	0.067	0.438	0.418
MING	0.146	0.182	0.045	0.061	0.157	0.146	0.074	0.102	0.088	0.188	0.179
PECO	0.010	0.011	0.001	0.001	0.008	0.009	0.000	0.008	0.007	0.004	0.004
SACR	0.035	0.037	0.003	0.004	0.026	0.027	0.002	0.026	0.022	0.017	0.017
UPBU	0.204	0.253	0.064	0.086	0.251	0.231	0.072	0.094	0.081	0.356	0.339
WHIT	0.029	0.031	0.002	0.003	0.020	0.021	0.001	0.020	0.016	0.012	0.012
WHPE	0.010	0.011	0.001	0.001	0.008	0.009	0.000	0.008	0.007	0.004	0.004
WIMO	0.270	0.334	0.098	0.133	0.306	0.282	0.068	0.082	0.071	0.245	0.235
Cumulative	1.383	1.683	0.399	0.542	1.586	1.484	0.488	0.725	0.622	1.797	1.721

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Table E-2. High Control (Run 3) Maximum Impact (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0.011	0.142	0.142	0.016	0.015	0.015	0.004	0.004	0.008	0.000	0.004
BIBE	0.023	0.086	0.084	0.058	0.056	0.053	0.042	0.032	0.068	0.000	0.037
BRET	0.023	0.028	0.027	0.211	0.241	0.217	0.124	0.097	0.177	0.000	0.136
CACR	0.186	0.413	0.412	1.468	1.811	1.609	0.733	0.563	0.914	0.000	0.822
CAVE	0.023	0.174	0.173	0.053	0.051	0.049	0.014	0.013	0.026	0.000	0.013
GRSA	0.005	0.158	0.153	0.004	0.004	0.004	0.002	0.002	0.004	0.000	0.002
GUMO	0.023	0.174	0.173	0.053	0.051	0.049	0.014	0.013	0.026	0.000	0.013
HEGL	0.114	0.521	0.525	0.451	0.580	0.500	0.551	0.407	0.767	0.000	0.553
MING	0.128	0.280	0.281	0.392	0.469	0.412	0.629	0.473	0.873	0.000	0.570
PECO	0.008	0.170	0.165	0.009	0.009	0.008	0.002	0.002	0.005	0.000	0.002
SACR	0.025	1.738	1.719	0.036	0.035	0.034	0.011	0.010	0.020	0.000	0.010
UPBU	0.130	0.466	0.469	0.805	1.025	0.890	0.415	0.314	0.565	0.000	0.402
WHIT	0.020	0.354	0.349	0.026	0.025	0.024	0.007	0.007	0.014	0.000	0.007
WHPE	0.008	0.170	0.165	0.009	0.009	0.008	0.002	0.002	0.005	0.000	0.002
WIMO	0.176	2.065	2.046	0.252	0.274	0.251	0.252	0.186	0.364	0.000	0.221
Cumulative	0.902	6.939	6.882	3.842	4.654	4.122	2.803	2.128	3.835	0.000	2.793

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Table E-3. Low Control (Run 4) Maximum Impact

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0.141	0.114	0.005	0.025	0.204	0.207	0.001	0.135	0.130	0.183	0.185
BIBE	0.373	0.300	0.022	0.066	0.460	0.466	0.002	0.319	0.309	0.585	0.591
BRET	0.100	0.080	0.006	0.017	0.173	0.175	0.006	0.124	0.120	0.453	0.457
CACR	0.447	0.490	0.102	0.157	1.046	1.018	0.175	1.052	1.018	1.327	1.338
CAVE	0.248	0.203	0.010	0.045	0.468	0.473	0.003	0.316	0.305	0.489	0.494
GRSA	0.066	0.053	0.002	0.012	0.082	0.083	0.000	0.041	0.040	0.049	0.049
GUMO	0.248	0.203	0.010	0.045	0.468	0.473	0.003	0.316	0.305	0.489	0.494
HEGL	0.309	0.330	0.063	0.102	0.593	0.591	0.071	0.426	0.410	0.948	0.952
MING	0.209	0.230	0.046	0.072	0.488	0.482	0.072	0.470	0.451	0.778	0.777
PECO	0.095	0.077	0.003	0.017	0.148	0.150	0.001	0.087	0.084	0.106	0.107
SACR	0.277	0.227	0.011	0.050	0.420	0.425	0.003	0.264	0.255	0.390	0.394
UPBU	0.326	0.347	0.067	0.107	0.628	0.625	0.071	0.613	0.591	1.148	1.150
WHIT	0.257	0.208	0.009	0.046	0.348	0.352	0.002	0.202	0.195	0.293	0.296
WHPE	0.095	0.077	0.003	0.017	0.148	0.150	0.001	0.087	0.084	0.106	0.107
WIMO	0.449	0.387	0.100	0.144	0.629	0.614	0.066	0.503	0.485	1.168	1.181
Cumulative	3.642	3.325	0.461	0.919	6.302	6.281	0.475	4.956	4.783	8.512	8.571

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Table E-3. Low Control (Run 4) Maximum Impact (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0.099	0.319	0.337	0.031	0.029	0.028	0.077	0.075	0.015	0.067	0.030
BIBE	0.218	0.284	0.306	0.107	0.102	0.098	0.295	0.291	0.073	0.252	0.116
BRET	0.093	0.110	0.119	0.284	0.307	0.282	0.636	0.615	0.193	0.571	0.274
CACR	0.458	0.544	0.557	1.550	1.882	1.682	3.123	3.065	0.905	3.297	1.659
CAVE	0.209	0.300	0.313	0.100	0.095	0.092	0.224	0.220	0.045	0.194	0.089
GRSA	0.048	0.197	0.199	0.008	0.007	0.007	0.019	0.018	0.005	0.016	0.007
GUMO	0.209	0.300	0.313	0.100	0.095	0.092	0.224	0.220	0.045	0.194	0.089
HEGL	0.362	0.617	0.633	0.464	0.583	0.506	0.939	0.922	0.804	1.183	0.686
MING	0.280	0.344	0.354	0.495	0.565	0.505	1.567	1.408	0.960	1.626	0.886
PECO	0.077	0.204	0.248	0.017	0.017	0.016	0.042	0.042	0.008	0.037	0.017
SACR	0.219	2.322	2.373	0.070	0.067	0.064	0.175	0.172	0.036	0.152	0.069
UPBU	0.397	0.582	0.600	0.867	1.077	0.942	1.057	1.014	0.600	1.497	0.631
WHIT	0.191	0.565	0.586	0.050	0.047	0.046	0.125	0.123	0.025	0.112	0.051
WHPE	0.077	0.204	0.248	0.017	0.017	0.016	0.042	0.042	0.008	0.037	0.017
WIMO	0.526	2.382	2.407	0.381	0.395	0.369	1.290	1.252	0.462	1.125	0.546
Cumulative	3.465	9.276	9.594	4.542	5.286	4.745	9.837	9.479	4.185	10.359	5.167

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Appendix F. CAMx Modeled Number of Days impacted

Table F-1. Base Case (Run 1) Number of days impacted over 0.5 dv

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	2	2	0	0	0	0	0	2	2	5	5
BRET	0	0	0	0	0	0	0	0	0	2	2
CACR	2	2	0	0	9	9	0	22	22	58	58
CAVE	0	0	0	0	0	0	0	1	1	3	3
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	1	1	3	3
HEGL	0	0	0	0	1	1	0	8	8	23	23
MING	0	0	0	0	0	0	0	1	1	6	6
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	1	0	0	0	0	0	0	1	1	3	3
UPBU	0	0	0	0	6	6	0	11	9	37	37
WHIT	1	0	0	0	0	0	0	0	0	1	1
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	4	3	0	0	2	2	0	4	3	33	34
Cumulative	10	7	0	0	18	18	0	51	48	174	175

Table F-1. Base Case (Run 1) Number of days impacted over 0.5 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	1	1	0	0	0	0	0	0	0	0
BIBE	0	1	1	0	0	0	1	1	1	0	0
BRET	0	0	0	2	2	3	3	3	3	1	0
CACR	5	1	1	71	68	76	79	78	79	49	37
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	1	1	1	26	27	29	33	31	35	11	8
MING	0	0	0	7	6	8	6	5	6	4	2
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	5	5	0	0	0	0	0	0	0	0
UPBU	2	1	1	44	40	46	45	44	45	18	13
WHIT	0	1	1	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	9	6	6	10	7	11	30	30	31	8	5
Cumulative	17	17	17	160	150	173	197	192	200	91	65

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Table F-2. High Control (Run 3) Number of days impacted over 0.5 dv

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	0	0	0	0	0	0	0	0
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	0	0
MING	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	0	0	0	0	0	0	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	0	0	0	0	0
Cumulative	0	0	0	0	0	0	0	0	0	0	0

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Table F-2. High Control (Run 3) Number of days impacted over 0.5 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	6	9	6	3	1	5	0	3
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	1	1	0	2	0	2	0	3	0	1
MING	0	0	0	0	0	0	1	0	1	0	1
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	1	1	0	0	0	0	0	0	0	0
UPBU	0	0	0	3	5	4	0	0	3	0	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	4	4	0	0	0	0	0	0	0	0
Cumulative	0	6	6	9	16	10	6	1	12	0	5

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Table F-3. Low Control (Run 4) Number of days impacted over 0.5 dv

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	2	2
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	0	9	9	0	9	8	22	23
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	1	1	0	0	0	8	8
MING	0	0	0	0	0	0	0	0	0	2	2
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	7	7	0	1	1	13	13
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	3	3	0	1	0	13	13
Cumulative	0	0	0	0	20	20	0	11	9	60	61

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Table F-3. Low Control (Run 4) Number of days impacted over 0.5 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	2	2	0	1	0
CACR	0	1	1	17	18	15	43	42	5	54	18
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	1	1	0	3	1	12	12	3	15	4
MING	0	0	0	0	1	1	4	4	1	4	1
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	1	1	0	0	0	0	0	0	0	0
UPBU	0	1	1	6	6	6	20	20	3	23	4
WHIT	0	1	1	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	1	5	5	0	0	0	10	10	0	8	2
Cumulative	1	10	10	23	28	23	91	90	12	105	29

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Table F-4. Base Case (Run 1) Number of days impacted over 1.0 dv

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	2	2
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	0	1	0	0	8	6	17	17
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	4	5
MING	0	0	0	0	0	0	0	0	0	1	1
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	0	0	0	1	1	8	8
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	0	0	0	12	12
Cumulative	0	0	0	0	1	0	0	9	7	44	45

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Table F-4. Base Case (Run 1) Number of days impacted over 1.0 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	1	1	1	0	0
CACR	0	0	0	26	26	29	32	30	32	9	8
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	3	3	3	10	7	9	1	0
MING	0	0	0	1	1	1	2	1	2	1	1
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	1	1	0	0	0	0	0	0	0	0
UPBU	0	0	0	10	10	13	14	12	15	1	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	4	4	1	1	1	8	6	7	1	0
Cumulative	0	5	5	41	41	47	67	57	66	13	9

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Table F-5. High Control (Run 3) Number of days impacted over 1.0 dv

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	0	0	0	0	0	0	0	0
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	0	0
MING	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	0	0	0	0	0	0	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	0	0	0	0	0
Cumulative	0	0	0	0	0	0	0	0	0	0	0

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Table F-5. High Control (Run 3) Number of days impacted over 1.0 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	1	1	1	0	0	0	0	0
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	0	0
MING	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	1	1	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	1	0	0	0	0	0	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	1	1	0	0	0	0	0	0	0	0
Cumulative	0	2	2	1	2	1	0	0	0	0	0

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Table F-6. Low Control (Run 4) Number of days impacted over 1.0 dv

Class I Area	J.T. Deely Unit 1	J.T. Deely Unit 2	OW Sommers Unit 1	OW Sommers Unit 2	Fayette Unit 1	Fayette Unit 2	W. A. Parish WAP4	W. A. Parish WAP5	W. A. Parish WAP6	Big Brown Unit 1	Big Brown Unit 2
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	0	1	1	0	1	1	4	4
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	0	0
MING	0	0	0	0	0	0	0	0	0	0	0
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	0	0	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	0	0	0	0	0	1	1
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	0	0	0	0	0	0	0	0	1	1
Cumulative	0	0	0	0	1	1	0	1	1	6	6

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Table F-6. Low Control (Run 4) Number of days impacted over 1.0 dv (continued)

Class I Area	Coleto Creek Unit 1	Harrington Unit 061B	Harrington Unit 062B	Martin Lake Unit 1	Martin Lake Unit 2	Martin Lake Unit 3	Monticello Unit 1	Monticello Unit 2	Monticello Unit 3	Welsh Unit 2	Welsh Unit 1
BAND	0	0	0	0	0	0	0	0	0	0	0
BIBE	0	0	0	0	0	0	0	0	0	0	0
BRET	0	0	0	0	0	0	0	0	0	0	0
CACR	0	0	0	3	3	2	16	13	0	15	3
CAVE	0	0	0	0	0	0	0	0	0	0	0
GRSA	0	0	0	0	0	0	0	0	0	0	0
GUMO	0	0	0	0	0	0	0	0	0	0	0
HEGL	0	0	0	0	0	0	0	0	0	1	0
MING	0	0	0	0	0	0	1	1	0	1	0
PECO	0	0	0	0	0	0	0	0	0	0	0
SACR	0	1	1	0	0	0	0	0	0	0	0
UPBU	0	0	0	0	1	0	2	1	0	3	0
WHIT	0	0	0	0	0	0	0	0	0	0	0
WHPE	0	0	0	0	0	0	0	0	0	0	0
WIMO	0	2	1	0	0	0	2	2	0	2	0
Cumulative	0	3	2	3	4	2	21	17	0	22	3

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December, 19, 2016

Technical Support Document

for the

Texas Regional Haze BART Federal Implementation Plan
(BART FIP TSD)

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November 2016
(Revised December 2016, see Errata- BART Modeling TSD for details)

Errata – Technical Support Document for the Texas Regional Hase BART for the Texas Regional Haze BART Federal Implementation Plan (BART FIP TSD)

In review of final materials prior to publication a few errors were identified in some TSDs. This errata corrects errors in BART FIP TSD for the notice signed on December 9, 2016, and titled *Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan*. As depicted below, these changes correct errors in transferring information from certain spreadsheets that included the original CALPUFF and CAMx output data and summary tables. The correct values and values for underlying calculations appear elsewhere in the rulemaking record for the proposal.

Pre-publication changes made to Title Page

Pre-publication changes made to Table 41 (pages 87-89):

Table 41. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Units 1 and 2)	WIMO	Max dv	4.27	2.54	0.43	1.73	3.83
			Days > 0.5 dv Avg.	67.33	43.33	2.67	24.00	64.67
			Days>1.0 dv Avg.	42.00	21.00	1.00	21.00	41.00
		CACR	Max dv	4.03	2.41	0.47	1.62	3.55
			Days > 0.5 dv Avg.	~~91.00~~67	~~62.00~~64.33	4.~~00~~67	~~29.00~~27.33	87.00

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Pre-publication changes made to Table 43 (pages 90-91):

Table 43. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Units 1, 2 & 3)	CACR	Max dv	4.46	2.27	1.86	2.18	2.60
			Days > 0.5 dv Avg.	129.67	77.33	63.00	52.33	66.67
			Days>1.0 dv Avg.	91.33	32.67	22.33	58.67	69.00
		UPBU	Max dv	2.73	~~0.86~~1.10	~~0.69~~85	1.~~87~~63	~~2.04~~1.88
			Days > 0.5 dv Avg.	81.67	30.33	18.67	51.33	63.00
			Days>1.0 dv Avg.	46.67	7.33	3.67	39.33	43.00
Monticello [1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	~~2.41~~3.68	1.70	2.89	4.87
			Days > 0.5 dv Avg.	143.67	115	62.33	28.67	81.33
			Days>1.0 dv Avg.	113	66.33	23.67	46.67	89.33
		UPBU	Max dv	3.45	1.77	0.765	1.68	2.68
			Days > 0.5 dv Avg.	103	61	13.67	42	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60	34.67	6	25.33	54
			Days > 0.5 dv Avg.	7.33	2.67	0.33	4.67	7.00
			Days>1.0 dv Avg.	1.33	0.33	0.00	1.00	1.33

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[1] Monticello's controlled level is a combination of scrubber upgrades and scrubber install in the facility impact modeling with CALPUFF.
[2] Harrington high control scenario for both units is SDA at 95% reduction
[3] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.
* UPBU = Upper Buffalo Wilderness Area.

Pre-publication changes made to Table 45 (page 98):

Table 45. Wet FGD Visibility Benefits at Big Brown (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Big Brown Units 1 & 2	3.83	3.55	7.38	151.67	~~93.33~~101.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek and Wichita Mountains

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek and Wichita Mountains.

Pre-publication changes made to Table 50 and text (page 102):

Table 50. Wet FGD Visibility Benefits at Welsh Unit 1 (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Welsh 1	0.72	0.41	1.66	~~31~~ 56.67	15

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Welsh we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate wet FGD on both units will eliminate ~~31~~ 56.67 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

Pre-publication changes made to Table 52 (pages 103-104):

Table 52. SDA Visibility Benefits at Harrington (CALPUFF)

Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Harrington 061B & 062B	0.~~7345~~	0.44~~74~~	2.56	53.67	26

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

Pre-publication changes made to text (page 104):

In evaluating Harrington we note there are five Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the five Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate ~~wet FGD~~SDA on both units will eliminate 53.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

Pre-publication changes made to Table 56 (pages 107-108):

Table 56. Visibility Benefit for Coal-fired Units with Existing SO_2 Controls (CAMx)

Unit	Improvement at most impacted (dv)	Improvement at 2nd most impacted (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 3	3.719 (CACR)	~~2.283~~1.918 (WIMO)	11.940	200 / 66	188 / 66
Martin Lake 1	1.165 (CACR)	1.449 (UPBU)	7.575	160 / 41	151 / 40
Martin Lake 2	0.655 (CACR)	1.164 (UPBU)	6.199	150 / 41	134 / 39
Martin Lake 3	1.146 (CACR)	1.478 (UPBU)	7.863	173 / 47	163 / 46

[18] We have read reports that CPS Energy, is planning to retire J T Deely Units 1 and 2 by the end of 2018, but we have no enforceable documents to that effect.
[19] 70 FR 39171 (July 6, 2005).

[1] 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.
[2] 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.
[3] 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.

December, 19, 2016

Errata – Technical Support Document for the Texas Regional Hase BART for the Texas Regional Haze BART Federal Implementation Plan (BART FIP TSD)

In review of final materials prior to publication a few errors were identified in some TSDs. This errata corrects errors in BART FIP TSD for the notice signed on December 9, 2016, and titled *Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan*. As depicted below, these changes correct errors in transferring information from certain spreadsheets that included the original CALPUFF and CAMx output data and summary tables. The correct values and values for underlying calculations appear elsewhere in the rulemaking record for the proposal.

Pre-publication changes made to Title Page

Technical Support Document

for the

Texas Regional Haze BART Federal Implementation Plan
(BART FIP TSD)

Prepared and Reviewed by:

Joe Kordzi
Erik Snyder
Michael Feldman
Robert Imhoff

November 2016
(Revised December 2016, see Errata- BART Modeling TSD for details)

Pre-publication changes made to Table 41 (pages 87-89):

Table 41. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Units 1 and 2)	WIMO	Max dv	4.27	2.54	0.43	1.73	3.83
			Days > 0.5 dv Avg.	67.33	43.33	2.67	24.00	64.67
			Days>1.0 dv Avg.	42.00	21.00	1.00	21.00	41.00
		CACR	Max dv	4.03	2.41	0.47	1.62	3.55
			Days > 0.5 dv Avg.	~~91.00~~67	~~62.00~~64.33	4.~~00~~67	~~29.00~~27.33	87.00

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Pre-publication changes made to Table 43 (pages 90-91):

Table 43. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Units 1, 2 & 3)	CACR	Max dv	4.46	2.27	1.86	2.18	2.60
			Days > 0.5 dv Avg.	129.67	77.33	63.00	52.33	66.67
			Days>1.0 dv Avg.	91.33	32.67	22.33	58.67	69.00
		UPBU	Max dv	2.73	~~0.86~~1.10	0.~~69~~85	1.~~83~~63	~~2.04~~1.88
			Days > 0.5 dv Avg.	81.67	30.33	18.67	51.33	63.00
			Days>1.0 dv Avg.	46.67	7.33	3.67	39.33	43.00
Monticello [1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	~~2.41~~3.68	1.70	2.89	4.87
			Days > 0.5 dv Avg.	143.67	115	62.33	28.67	81.33
			Days>1.0 dv Avg.	113	66.33	23.67	46.67	89.33
		UPBU	Max dv	3.45	1.77	0.765	1.68	2.68
			Days > 0.5 dv Avg.	103	61	13.67	42	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60	34.67	6	25.33	54
			Days > 0.5 dv Avg.	7.33	2.67	0.33	4.67	7.00
			Days>1.0 dv Avg.	1.33	0.33	0.00	1.00	1.33

[1] Monticello's controlled level is a combination of scrubber upgrades and scrubber install in the facility impact modeling with CALPUFF.
[2] Harrington high control scenario for both units is SDA at 95% reduction.
[1] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.
* UPBU = Upper Buffalo Wilderness Area.

Pre-publication changes made to Table 45 (page 98):

Table 45. Wet FGD Visibility Benefits at Big Brown (CALPUFF)

Source	Improvement at Wichita Mountains (dv)	Improvement at Caney Creek (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Big Brown Units 1 & 2	3.83	3.55	7.38	151.67	~~93.33~~101.33

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek and Wichita Mountains

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The Reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek and Wichita Mountains.

Pre-publication changes made to Table 50 and text (page 102):

Table 50. Wet FGD Visibility Benefits at Welsh Unit 1 (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Welsh 1	0.72	0.41	1.66	~~31~~56.67	15

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Caney Creek, Wichita Mountains, and Upper Buffalo.
[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Caney Creek, Wichita Mountains, and Upper Buffalo.

In evaluating Welsh we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate wet FGD on both units will eliminate ~~31~~ 56.67 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

Pre-publication changes made to Table 52 (pages 103-104):

Table 52. SDA Visibility Benefits at Harrington (CALPUFF)

Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Harrington 061B & 062B	0.~~7245~~	0.4~~1~~74	2.56	53.67	26

[1] Cumulative benefit is calculated as the difference in the maximum visibility impacts from the baseline and control scenario runs summed across the following Class I areas: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

[2] Using the three years (2001-2003) of CALPUFF modeling results an annual average of the number of days reduced was calculated. The reduction in number of days is calculated as the sum of the number of days over the chosen threshold across the following Class I areas for the baseline scenario subtracted by the number of days over the threshold for the control scenario: Salt Creek, Wichita Mountains, Pecos, Carlsbad Caverns, and Wheeler Peak.

Pre-publication changes made to text (page 104):

In evaluating Harrington we note there are five Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the five Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate ~~wet FGD~~SDA on both units will eliminate 53.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD.

Pre-publication changes made to Table 56 (pages 107-108):

Table 56. Visibility Benefit for Coal-fired Units with Existing SO_2 Controls (CAMx)

Unit	Improvement at most impacted (dv)	Improvement at 2nd most impacted (dv)	Total Cumulative Visibility Benefit (dv)[1]	Baseline Total Cumulative number of days over 0.5/1.0 dv[2]	Reduction in number of days above 0.5/1.0 dv[3]
Monticello 3	3.719 (CACR)	~~2.282~~1.918 (WIMO)	11.940	200 / 66	188 / 66
Martin Lake 1	1.165 (CACR)	1.449 (UPBU)	7.575	160 / 41	151 / 40
Martin Lake 2	0.655 (CACR)	1.164 (UPBU)	6.199	150 / 41	134 / 39
Martin Lake 3	1.146 (CACR)	1.478 (UPBU)	7.863	173 / 47	163 / 46

[18] We have read reports that CPS Energy, is planning to retire J T Deely Units 1 and 2 by the end of 2018, but we have no enforceable documents to that effect.
[19] 70 FR 39171 (July 6, 2005).

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[1] 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.
[2] 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.
[3] 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.

December, 19, 2016

Errata – Technical Support Document Our Visibilty Analysis of Potential Controls for Subject to BART sources for the Texas Regional Haze BART Federal Implementation Plan (BART Modeling TSD)

In review of final materials prior to publication a few errors were identified in some TSDs. This errata corrects errors in BART Modeling TSD for the notice signed on December 9, 2016, and titled *Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan*. As depicted below, these changes correct errors in transferring information from certain spreadsheets that included the original CALPUFF and CAMx output data and summary tables. The correct values and values for underlying calculations appear elsewhere in the rulemaking record for the proposal.

Pre-publication changes made to Title Page:

Prepared and Reviewed by:

Erik Snyder
Michael Feldman
Robert Imhoff
Joe Kordzi

November 2016
(Revised December 2016, see Errata- BART Modeling TSD for details)

Pre-publication changes made to Table 3-2 (pages 19-20):

Table 3-2. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Units 1 and 2)	WIMO	Max dv	4.27	2.54	0.43	1.73	3.83
			Days > 0.5 dv Avg.	67.33	43.33	2.67	24.00	64.67
			Days>1.0 dv Avg.	42.00	21.00	1.00	21.00	41.00
		CACR	Max dv	4.03	2.41	0.47	1.62	3.55
			Days > 0.5 dv Avg.	91.~~00~~67	~~62.00~~64.33	4.~~00~~67	~~29.00~~27.33	87.00
			Days>1.0 dv Avg.	60.33	30.00	0.00	30.33	60.33
Monticello[1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	~~2.41~~3.68	1.70	4.16	4.87
			Days > 0.5 dv Avg.	143.67	115.00	62.33	28.67	81.33
			Days>1.0 dv Avg.	113.00	66.33	23.67	46.67	89.33
		UPBU[4]	Max dv	3.45	1.77	0.77	1.68	2.68
			Days > 0.5 dv Avg.	103.00	61.00	13.67	42.00	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60.00	34.67	6.00	25.33	54.00
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67
Harrington[2]	Source (Units 061B & 062B)	SACR	Max dv	1.06	0.86	0.61	0.20	0.45
			Days > 0.5 dv Avg.	21.00	15.33	6.33	5.67	14.67
			Days>1.0 dv Avg.	6.67	3.00	0.67	3.67	6.00
		WIMO	Max dv	1.29	0.97	0.55	0.32	0.74
			Days > 0.5 dv Avg.	26.00	15.33	8.67	10.67	17.33

			Days>1.0 dv Avg.	9.00	4.67	1.33	4.33	7.67
Welsh[5]	Source (Unit 1)	CACR	Max dv	1.44	1.12	0.72	0.32	0.72
			Days > 0.5 dv Avg.	50.33	32.67	~~38.00~~12.33	17.67	~~12.33~~38
			Days>1.0 dv Avg.	15.33	8.00	2.33	7.33	13.00
		UPBU	Max dv	0.76	0.49	0.22	0.27	0.54
			Days > 0.5 dv Avg.	12.00	4.67	0.33	7.33	11.67
			Days>1.0 dv Avg.	0.67	0.00	0.00	0.67	0.67
		WIMO	Max dv	0.56	0.33	0.15	0.23	0.41
			Days > 0.5 dv Avg.	7.33	2.67	0.33	4.67	7.00
			Days>1.0 dv Avg.	1.33	0.33	0.00	1.00	1.33

[1] Monticello's controlled level is a combination of scrubber upgrades and scrubber install in the facility impact modeling with CALPUFF.
[2] Harrington high control scenario for both units is SDA at 95% reduction
[5] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.
[4] UPBU = Upper Buffalo Wilderness Area.

Pre-publication changes made to Table 4.4-1a (page 39):

Table 4.4-1a. Wet FGD Visibility Benefits at Welsh Unit 1 (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Welsh 1	0.72	0.41	1.66	~~31~~56.67	15

Pre-publication changes made to text (page 39-40):

In evaluating Welsh we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF

modeling results indicate wet FGD on both units will eliminate ~~31~~ 56.67 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to wet FGD levels.

Pre-publication changes made to Table 4.5-1a (page 43):

Table 4.5-1a. SDA Visibility Benefits at Harrington (CALPUFF)

Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Harrington 061B & 062B	0.~~72~~45	0.~~41~~74	2.56	53.67	26

Pre-publication changes made to text (page 44):

In evaluating Harrington we note there are five Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the five Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate SDA on both units will eliminate 53.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to SDA levels.

Pre-publication changes made to Table 5-2 (page 64):

Table 5-2. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Units 1, 2 & 3)	CACR	Max dv	4.46	2.27	1.86	2.18	2.60
			Days > 0.5 dv Avg.	129.67	77.33	63.00	52.33	66.67
			Days>1.0 dv Avg.	91.33	32.67	22.33	58.67	69.00
		UPBU	Max dv	2.73	~~0.86~~1.10	0.~~69~~85	1.~~87~~63	1.88~~2.04~~
			Days > 0.5 dv Avg.	81.67	30.33	18.67	51.33	63.00
			Days>1.0 dv Avg.	46.67	7.33	3.67	39.33	43.00
Monticello [1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	2.41	1.70	2.89	4.87
			Days > 0.5 dv Avg.	143.67	115	62.33	28.67	81.33
			Days>1.0 dv Avg.	113	66.33	23.67	46.67	89.33
		UPBU	Max dv	3.45	1.77	0.765	1.68	2.68
			Days > 0.5 dv Avg.	103	61	13.67	42	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60	34.67	6	25.33	54
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67

[1] Monticello's controlled level is a combination of scrubber upgrade on Unit 3 and scrubber retrofits on Units 1 and 2 in the facility impact modeling with CALPUFF.

Pre-publication changes made to Table 6-3 (page 66)

Table 6-3. Visibility Benefit for Coal-fired Units with Existing SO_2 Controls (CAMx)

Unit	Improvement at most impacted (dv)	Improvement at 2nd most impacted (dv)	**Total Cumulative Visibility Benefit (dv)** [1]	**Baseline Total Cumulative number of days over 0.5/1.0 dv** [2]	**Reduction in number of days above 0.5/1.0 dv** [3]
Monticello 3	3.719 (CACR)	~~2.282~~1.918 (WIMO)	11.940	200 / 66	188 / 66
Martin Lake 1	1.165 (CACR)	1.449 (UPBU)	7.575	160 / 41	151 / 40
Martin Lake 2	0.655 (CACR)	1.164 (UPBU)	6.199	150 / 41	134 / 39
Martin Lake 3	1.146 (CACR)	1.478 (UPBU)	7.863	173 / 47	163 / 46

[1] 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.

[2] 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.

[3] 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.

December, 19, 2016

Errata – Technical Support Document Our Visibilty Analysis of Potential Controls for Subject to BART sources for the Texas Regional Haze BART Federal Implementation Plan (BART Modeling TSD)

In review of final materials prior to publication a few errors were identified in some TSDs. This errata corrects errors in BART Modeling TSD for the notice signed on December 9, 2016, and titled *Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan*. As depicted below, these changes correct errors in transferring information from certain spreadsheets that included the original CALPUFF and CAMx output data and summary tables. The correct values and values for underlying calculations appear elsewhere in the rulemaking record for the proposal.

Pre-publication changes made to Title Page:

Prepared and Reviewed by:

Erik Snyder
Michael Feldman
Robert Imhoff
Joe Kordzi

November 2016
(Revised December 2016, see Errata- BART Modeling TSD for details)

Pre-publication changes made to Table 3-2 (pages 19-20):

Table 3-2. Visibility Benefit of Retrofit Controls: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Big Brown	Source (Units 1 and 2)	WIMO	Max dv	4.27	2.54	0.43	1.73	3.83
			Days > 0.5 dv Avg.	67.33	43.33	2.67	24.00	64.67
			Days>1.0 dv Avg.	42.00	21.00	1.00	21.00	41.00
		CACR	Max dv	4.03	2.41	0.47	1.62	3.55
			Days > 0.5 dv Avg.	91.~~00~~67	~~62.00~~64.33	4.~~00~~67	~~39.00~~27.33	87.00
			Days>1.0 dv Avg.	60.33	30.00	0.00	30.33	60.33
Monticello[1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	~~2.41~~3.68	1.70	4.16	4.87
			Days > 0.5 dv Avg.	143.67	115.00	62.33	28.67	81.33
			Days>1.0 dv Avg.	113.00	66.33	23.67	46.67	89.33
		UPBU[4]	Max dv	3.45	1.77	0.77	1.68	2.68
			Days > 0.5 dv Avg.	103.00	61.00	13.67	42.00	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60.00	34.67	6.00	25.33	54.00
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67
Harrington[2]	Source (Units 061B & 062B)	SACR	Max dv	1.06	0.86	0.61	0.20	0.45
			Days > 0.5 dv Avg.	21.00	15.33	6.33	5.67	14.67
			Days>1.0 dv Avg.	6.67	3.00	0.67	3.67	6.00
		WIMO	Max dv	1.29	0.97	0.55	0.32	0.74
			Days > 0.5 dv Avg.	26.00	15.33	8.67	10.67	17.33

			Days>1.0 dv Avg.	9.00	4.67	1.33	4.33	7.67
Welsh[4]	Source (Unit 1)	CACR	Max dv	1.44	1.12	0.72	0.32	0.72
			Days > 0.5 dv Avg.	50.33	32.67	~~38.00~~33	17.67	~~12.33~~38
			Days>1.0 dv Avg.	15.33	8.00	2.33	7.33	13.00
		UPBU	Max dv	0.76	0.49	0.22	0.27	0.54
			Days > 0.5 dv Avg.	12.00	4.67	0.33	7.33	11.67
			Days>1.0 dv Avg.	0.67	0.00	0.00	0.67	0.67
		WIMO	Max dv	0.56	0.33	0.15	0.23	0.41
			Days > 0.5 dv Avg.	7.33	2.67	0.33	4.67	7.00
			Days>1.0 dv Avg.	1.33	0.33	0.00	1.00	1.33

[1] Monticello's controlled level is a combination of scrubber upgrades and scrubber install in the facility impact modeling with CALPUFF.
[2] Harrington high control scenario for both units is SDA at 95% reduction
[4] Welsh Unit 2 and Fayette Units 1 & 2 were not modeled at DSI level control. Welsh Unit 2 has shut down and Fayette units have WFGD installed. Welsh source-wide modeling for high control includes a unit 2 shutdown.
[4] UPBU = Upper Buffalo Wilderness Area.

Pre-publication changes made to Table 4.4-1a (page 39):

Table 4.4-1a. Wet FGD Visibility Benefits at Welsh Unit 1 (CALPUFF)

Source	Improvement at Caney Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Welsh 1	0.72	0.41	1.66	~~31~~56.67	15

Pre-publication changes made to text (page 39-40):

In evaluating Welsh we note there are three Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the three Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF

modeling results indicate wet FGD on both units will eliminate ~~31~~ 56.67 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to wet FGD levels.

Pre-publication changes made to Table 4.5-1a (page 43):

Table 4.5-1a. SDA Visibility Benefits at Harrington (CALPUFF)

Source	Improvement at Salt Creek (dv)	Improvement at Wichita Mtns. (dv)	Total Cumulative Visibility Benefit (dv)[1]	Cumulative Reduction in number of days above 0.5 dv[2]	Cumulative Reduction in number of days above 1.0 dv[2]
Harrington 061B & 062B	0.~~72~~45	0.~~41~~74	2.56	53.67	26

Pre-publication changes made to text (page 44):

In evaluating Harrington we note there are five Class I areas within the typical range that CALPUFF has been used for assessing visibility impacts. Using the three years of 2001-2003 CALPUFF modeling results we assessed the annual average number of days when the facility impacts were greater than 0.5 del-dv at each of the Class I areas and then summed this value for each of the Class I areas to yield an annual average cumulative value for total number of days impacts were above 0.5 del-dv at all Class I areas within typical CALPUFF range. The reduction in the number of days (annual average) was calculated as the cumulative value of the number of days over the 0.5 del-dv threshold across the Class I areas for the baseline scenario subtracted by the cumulative number of days over the threshold for the control scenario. For the five Class I areas that are within the range that CALPUFF is typically used, the 2001-2003 CALPUFF modeling results indicate SDA on both units will eliminate 53.6 days annually (3 year average) when the facility has impacts greater than 0.5 delta deciview. The same analysis was also calculated using a 1.0 del-dv threshold and is reported in the table above. CALPUFF modeling indicates that DSI operated at 50% results in approximately half the benefits of WGFD. CALPUFF modeling utilizing more recent baseline emissions (2011-2015) also show large benefits from reducing emissions to SDA levels.

Pre-publication changes made to Table 5-2 (page 64):

Table 5-2. Visibility Benefit of Scrubber Upgrades: Coal-Fired Units (CALPUFF modeling)

Facility Name	Emission Unit	Class I area	Metric	Visibility impact			Visibility Benefit	
				Baseline	DSI (50%)	WFGD (98%)	DSI benefit	WFGD benefit
Martin Lake	Source (Units 1, 2 & 3)	CACR	Max dv	4.46	2.27	1.86	2.18	2.60
			Days > 0.5 dv Avg.	129.67	77.33	63.00	52.33	66.67
			Days>1.0 dv Avg.	91.33	32.67	22.33	58.67	69.00
		UPBU	Max dv	2.73	~~0.86~~1.10	0.~~69~~85	1.~~87~~63	1.88~~2.04~~
			Days > 0.5 dv Avg.	81.67	30.33	18.67	51.33	63.00
			Days>1.0 dv Avg.	46.67	7.33	3.67	39.33	43.00
Monticello [1]	Source (Unit 1,2 and 3)	CACR	Max dv	6.57	2.41	1.70	2.89	4.87
			Days > 0.5 dv Avg.	143.67	115	62.33	28.67	81.33
			Days>1.0 dv Avg.	113	66.33	23.67	46.67	89.33
		UPBU	Max dv	3.45	1.77	0.765	1.68	2.68
			Days > 0.5 dv Avg.	103	61	13.67	42	89.33
			Days>1.0 dv Avg.	39.33	16.67	2.67	22.67	36.67
		WIMO	Max dv	3.23	1.60	0.54	1.63	2.70
			Days > 0.5 dv Avg.	60	34.67	6	25.33	54
			Days>1.0 dv Avg.	39.33	16.67	0.67	22.67	38.67

[1] Monticello's controlled level is a combination of scrubber upgrade on Unit 3 and scrubber retrofits on Units 1 and 2 in the facility impact modeling with CALPUFF.

Pre-publication changes made to Table 6-3 (page 66)

Table 6-3. Visibility Benefit for Coal-fired Units with Existing SO_2 Controls (CAMx)

Unit	Improvement at most impacted (dv)	Improvement at 2nd most impacted (dv)	**Total Cumulative Visibility Benefit (dv)** [1]	**Baseline Total Cumulative number of days over 0.5/1.0 dv** [2]	**Reduction in number of days above 0.5/1.0 dv** [3]
Monticello 3	3.719 (CACR)	~~2.283~~1.918 (WIMO)	11.940	200 / 66	188 / 66
Martin Lake 1	1.165 (CACR)	1.449 (UPBU)	7.575	160 / 41	151 / 40
Martin Lake 2	0.655 (CACR)	1.164 (UPBU)	6.199	150 / 41	134 / 39
Martin Lake 3	1.146 (CACR)	1.478 (UPBU)	7.863	173 / 47	163 / 46

[1] 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.
[2] 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.
[3] 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.

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From: Theresa Pella
Sent: Mon 12/19/2016 5:58:30 PM
Subject: Fw: EPA RH webinar [WARNING: DKIM validation failed]
EPA RH webinar

Date and time for EPA's webinar is Tuesday, Jan. 10th, from 11:30 - 1:00 pm central

time.

https://www.epa.gov/visibility/webinar-announcement-informational-public-webinar-discuss-final-regional-haze-rule

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