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40 CFR Part 52

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

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R06–OAR–2015–0189; FRL–9924–85–Region 6]

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing to promulgate a Federal Implementation Plan (FIP) to address certain regional haze and visibility transport requirements for the State of Arkansas. This FIP would address the requirements of the Regional Haze Rule (RHR) and interstate visibility transport for those portions of Arkansas' State Implementation Plan (SIP) we disapproved in our final action published on March 12, 2012. Specifically, the proposed FIP addresses the requirements for Best Available Retrofit Technology (BART) for those sources for which we did not approve Arkansas' BART determinations, Reasonable Progress Goals (RPGs), reasonable progress controls and a long-term strategy, as well as the interstate visibility transport requirements for pollutants that affect visibility in Class I areas in nearby states. Specific to the reasonable progress controls requirement, we are proposing in the alternative two options for controlling the emissions from the Entergy Independence Plant that is not subject to BART. Under Option 1, we are proposing controls for emissions of SO_2, and NO_X. If we take final action on this finding, the source will be subject to controls for both pollutants. Alternatively, under Option 2, we are proposing controls for only emissions of SO_2 for this planning period. In particular, we are soliciting comments on the alternate proposed Options 1 and 2.

DATES: *Comments:* Comments must be received on or before May 16, 2015.

Public Hearing: We are holding information sessions—for the purpose of providing additional information and informal discussion for our proposal, and public hearings—to accept oral comments into the record, as follows:

Date: Thursday, April 16, 2015.

Time: Information Session: 9 a.m.–9:45 a.m. (break from 9:45 a.m.–10 a.m.)

Public hearing: 10 a.m.–11:30 a.m. (break from 11:30 a.m.–1 p.m.)

Information Session: 1 p.m.–1:45 p.m. (break from 1:45 p.m.–2 p.m.)

Public hearing: 2 p.m.–7:30 p.m. (including break from 4 p.m.–4:30 p.m.).

Please see the **ADDRESSES** *section for the location of the hearing in North Little Rock, AR.*

ADDRESSES: Submit your comments, identified by Docket No. EPA–R06–OAR–2015–0189, by one of the following methods:

- *Federal e-Rulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments.
- *Email: R6AIR_ARHaze@epa.gov.*
- *Mail:* Mr. Guy Donaldson, Chief, Air Planning Section (6PD–L), Environmental Protection Agency, 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733.
- *Hand or Courier Delivery:* Mr. Guy Donaldson, Chief, Air Planning Section (6PD–L), Environmental Protection Agency, 1445 Ross Avenue, Suite 700, Dallas, Texas 75202–2733. Such deliveries are accepted only between the hours of 8 a.m. and 4 p.m. weekdays, and not on legal holidays. Special arrangements should be made for deliveries of boxed information.
- *Fax:* Mr. Guy Donaldson, Chief, Air Planning Section (6PD–L), at fax number 214–665–7263.

Instructions: Direct your comments to Docket No. EPA–R06–OAR–2015–0189. Our policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or email. The *www.regulations.gov* Web site is an ''anonymous access'' system, which means we will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to us without going through *www.regulations.gov* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, we recommend that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If we cannot read your comment due to technical difficulties and cannot contact you for clarification, we may not be able to consider your comment. Electronic files should avoid the use of special characters and any form of encryption, and be free of any defects or viruses.

Docket: All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. SIP materials which are incorporated by reference into 40 Code of Federal Regulations (CFR) part 52 are available for inspection at the following location: Environmental Protection Agency, Region 6, 1445 Ross Avenue, Suite 700, Dallas, TX 75202. Publicly available materials are available either electronically in *www.regulations.gov* or in hard copy at the Region 6 office. The Regional Office hours are Monday through Friday, 8:30 to 4:30, excluding Federal holidays.

Hearing location: Arkansas Department of Environmental Quality, Commission Room, 1st floor, 5301 Northshore Drive, North Little Rock, AR 72118.

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 hearings. 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.

FOR FURTHER INFORMATION CONTACT: To schedule your inspection, contact Ms. Dayana Medina at (214) 665–7241 or via electronic mail at *medina.dayana@epa.gov*.

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

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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 (VOC)). 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 one can see. $PM_{2.5}$ 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. 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 is 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 is less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions. 64 FR 35715 (July 1, 1999).

In section 169A of the 1977 Amendments to the Clean Air Act (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.[2] 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.'' [3] 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.[4] The Regional Haze Rule (RHR) 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 impairment no later than December 17, 2007.[5]

II. Overview of Proposed Actions

A. Regional Haze

We are proposing to promulgate a FIP as described in this notice and summarized in this section to address those portions of Arkansas' regional haze SIP that we disapproved on March 12, 2012.[6] In our March 12, 2012 final action, we disapproved Arkansas' BART control analyses and determinations for nine units at six facilities and the Reasonable Progress Goals (RPGs) analysis and RPGs set by Arkansas, and partially disapproved the long-term strategy for making reasonable progress. We are proposing this FIP because Arkansas has not provided a revision to its SIP to address the deficiencies identified in our March 12, 2012 partial disapproval. We believe, however, it is preferable for states to take the lead in implementing the Regional Haze requirements as envisioned by the Clean Air Act. We will work with the State of Arkansas if it chooses to develop a SIP

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

[2] 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.''

[3] 45 FR 80084 (December 2, 1980).

[4] 64 FR 35714 (July 1, 1999), codified at 40 CFR part 51, subpart P (Regional Haze Rule).

[5] 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).

[6] 77 FR 14604, March 12, 2012.

to meet the Regional Haze requirements to replace this proposed FIP.

The FIP we are proposing includes BART control determinations for sources in Arkansas 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 BART sources addressed in this FIP cause or contribute to visibility impairment at one or more Class I areas in Arkansas and Missouri. The two Class I areas in Arkansas are the Caney Creek Wilderness Area and the Upper Buffalo Wilderness Area. The two Class I areas in Missouri are the Hercules-Glades Wilderness Area and the Mingo National Wildlife Refuge. In this FIP, we are proposing SO_2, NO_X, and PM BART control determinations for nine units at six facilities in Arkansas. We are proposing SO_2, NO_X, and PM BART determinations for Unit 1 of the Arkansas Electric Cooperative Corporation (AECC) Carl E. Bailey Generating Station; SO_2, NO_X, and PM BART determinations for Unit 1 of the AECC John L. McClellan Generating Station; SO_2 and NO_X BART determinations for Boiler No. 1 of the American Electric Power (AEP) Flint Creek Power Plant; SO_2 and NO_X BART determinations for Units 1 and 2 and SO_2, NO_X, and PM BART determinations for the Auxiliary Boiler of the Entergy White Bluff Plant; NO_X BART determination for Unit 4 of the Entergy Lake Catherine Plant; SO_2 and NO_X BART determinations for Power Boiler No. 1 and SO_2, NO_X and PM BART determinations for Power Boiler No. 2 of the Domtar Ashdown Mill. Additionally, for the reasonable progress requirements, we are proposing in the alternative two options for controlling the emissions from the Entergy Independence Plant that is not subject to BART. Under Option 1, under the reasonable progress requirements, we are proposing controls for emissions of SO_2 and NO_X for Units 1 and 2 of the Entergy Independence Plant. Alternatively, under Option 2, we are proposing controls for only emissions of SO_2 for the first planning period. We solicit comments on this proposed alternative approach. We are also soliciting public comment on any alternative control measures for Entergy White Bluff Units 1 and 2 and Independence Units 1 and 2 that would address the BART and reasonable progress requirements for these four units for this regional haze planning period. The measures in the FIP that we are proposing will reduce emissions that contribute to regional haze in Arkansas' Class I areas and other nearby Class I areas. RPGs are interim visibility goals towards meeting the CAA's national visibility goal of preventing any future, and remedying any existing, impairment of visibility resulting from manmade air pollution in Class I areas. This proposed FIP and the portion of the Arkansas regional haze SIP that we approved on March 12, 2012, together would ensure that progress is made toward natural visibility conditions at these Class I areas. This proposed action and the accompanying documents that are available in the Docket explain the basis for our proposed Arkansas Regional Haze FIP. Please refer to our previous rulemaking on the Arkansas regional haze SIP for additional background regarding the CAA, regional haze, and our RHR.[7]

B. Interstate Transport of Pollutants That Affect Visibility

We propose that a combination of those portions of the Arkansas regional haze SIP that we previously approved and the measures in the FIP will satisfy the visibility requirement of CAA section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and 1997 $PM_{2.5}$ national ambient air quality standards (NAAQS). CAA section 110(a)(2)(D)(i)(II) requires that states have a SIP, or submit a SIP revision, containing provisions ''prohibiting any source or other type of emission activity within the state from emitting any air pollutant in amounts which will . . . interfere with measures required to be included in the applicable implementation plan for any other State under part C [of the CAA] to protect visibility.'' Because of the impacts on visibility from the interstate transport of pollutants, we interpret these ''good neighbor'' provisions of section 110 of the Act as requiring states to include in their SIPs measures to prohibit emissions that would interfere with the reasonable progress goals set to protect Class I areas in other states. For Arkansas, we interpret this to mean that the State must include in its SIP a demonstration that emissions from Arkansas sources and activities will not have the prohibited impacts on other states' existing SIPs. We refer herein to this requirement as the interstate transport visibility requirement. The Arkansas Department of Environmental Quality (ADEQ) submitted a SIP revision to address this requirement on April 2, 2008, and submitted supplemental information on September 27, 2011. The April 2, 2008 submittal stated that Arkansas is relying on the Air Pollution Control and Ecology Commission (APCEC) Regulation 19, Chapter 15, also known as the State BART rulemaking, to satisfy the requirements of section 110(a)(2)(D)(i)(II) with respect to visibility transport. The April 2, 2008 SIP submittal, which was submitted prior to Arkansas' submission of the Arkansas regional haze SIP, also stated that it is not possible to assess whether there is any interference with the measures in the applicable SIP for another state designed to protect visibility for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS until Arkansas submits and we approve the Arkansas regional haze SIP. In our final rule published on March 12, 2012, we partially approved and partially disapproved the SIP submittal with respect to the interstate transport visibility requirement under CAA section 110(a)(2)(D)(i)(II), triggering the obligation for us to promulgate a FIP or to fully approve a revised SIP submission from Arkansas to ensure that the requirement is fully addressed.[8] Today's notice describes our proposed FIP, which we propose to find will fully address the deficiencies we identified in our prior partial disapproval action of Arkansas' SIP submittal with respect to the interstate visibility transport requirement under CAA section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS.

C. History of State Submittals and Our Actions

As discussed above, Arkansas submitted a SIP revision on April 2, 2008, to address the interstate transport visibility requirement of CAA section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS. To address the first regional haze implementation period, Arkansas submitted a regional haze SIP on September 23, 2008. On August 3, 2010, Arkansas submitted a SIP revision with non-substantive revisions to the APCEC Regulation 19, Chapter 15, which identified the BART-eligible and subject-to-BART sources in Arkansas and established the BART emission limits that subject-to-BART sources are required to comply with. On September 27, 2011, the State submitted supplemental information on the Arkansas regional haze SIP. We are hereafter referring to these regional haze submittals collectively as the ''2008 Arkansas RH SIP.'' On March 12, 2012, we partially approved and partially disapproved the 2008 Arkansas RH SIP

[7] 77 FR 14604, March 12, 2012.

[8] *Id.*

and the April 2, 2008 SIP submittal concerning the interstate transport visibility requirements for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS.[9]

Our partial disapproval of the 2008 Arkansas RH SIP included a disapproval of the following BART determinations made by Arkansas:

- SO_2, NO_X, and PM BART for the AECC Carl E. Bailey Generating Station Unit 1;
- SO_2, NO_X, and PM BART for the AECC John L. McClellan Generating Station Unit 1;
- SO_2 and NO_X BART for the AEP Flint Creek Power Plant No. 1 Boiler;
- SO_2 and NO_X BART for the bituminous and sub-bituminous coal firing scenarios for the Entergy White Bluff Plant Units 1 and 2;
- SO_2, NO_X, and PM BART for the Entergy White Bluff Plant Auxiliary Boiler;
- NO_X BART for the natural gas firing scenario for the Entergy Lake Catherine Plant Unit 4;
- SO_2, NO_X, and PM BART for the fuel oil firing scenario for the Entergy Lake Catherine Plant Unit 4;
- SO_2 and NO_X BART for the Domtar Ashdown Mill No. 1 Power Boiler; and
- SO_2, NO_X, and PM BART for the Domtar Ashdown Mill No. 2 Power Boiler.

In our final action, we also disapproved Arkansas' determinations that the Georgia Pacific-Crossett Mill 6A Boiler is not BART-eligible, and that the 6A and 9A Boilers are not subject to BART. By partially disapproving Arkansas' BART determinations, we also partially disapproved the corresponding provisions of APCEC Regulation 19, Chapter 15. We also disapproved Arkansas' RPGs for its two Class I areas, the Caney Creek Wilderness Area and the Upper Buffalo Wilderness Area, because Arkansas did not meet the requirement under section 169A(g)(1) of the CAA and 40 CFR 51.308(d)(1)(i)(A) to consider the four statutory factors when establishing its RPGs. Additionally, we partially disapproved Arkansas' long-term strategy because it relied on other disapproved portions of the SIP.

D. Our Authority To Promulgate a FIP

Under section 110(c) of the Act, 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.'' 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.

Thus, because we partially disapproved the 2008 Arkansas RH SIP and the SIP submittal addressing the interstate transport visibility requirement, we are required to promulgate a FIP for Arkansas, unless we first approve a SIP revision that corrects the disapproved portions of these SIP submittals. As Arkansas has not as yet submitted a revised SIP following our partial disapproval, we are proposing a FIP to address those portions of the SIP that we disapproved.

III. Our Proposed BART Analyses and Determinations

Following our 2012 disapproval of the 2008 Arkansas RH SIP, Arkansas began the process of generating additional technical information and analysis for the BART determinations. Arkansas gathered technical documentation from the companies whose BART determinations we disapproved. These documents were provided to us and are the basis for our evaluation of BART determinations for the facilities with prior disapproved BART determinations.

A. Identification of BART-Eligible Sources and Subject to BART Sources

States are required to identify all the BART-eligible sources within their boundaries by utilizing the three eligibility criteria in the BART Guidelines (70 FR 39158) and the RHR (40 CFR 51.301): (1) One or more emission units at the facility fit within one of the 26 categories listed in the BART Guidelines; (2) the emission unit(s) began operation on or after August 6, 1962, and the unit was in existence on August 6, 1977; and (3) the potential emissions of any visibility-impairing pollutant from subject units are 250 tons or more per year. Sources that meet these three criteria are considered BART-eligible. Once a list of the BART-eligible sources within a state has been compiled, states must determine whether to make BART determinations for all of them or to consider exempting some of them from BART because they may not reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. The BART Guidelines present several options that rely on modeling and/or emissions analyses to determine if a source may reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. A source that may not be reasonably anticipated to cause or contribute to any visibility impairment in a Class I area is not ''subject to BART,'' and for such sources, a state need not apply the five statutory factors to make a BART determination.

1. Georgia Pacific-Crossett Mill 6A and 9A Power Boilers

In our March 12, 2012 final action, we approved Arkansas' identification of BART-eligible sources except for the Georgia-Pacific Crossett Mill 6A Boiler. We also approved Arkansas' determination of which sources are subject to BART, with the exception of its determination that the Georgia-Pacific Crossett Mill 6A and 9A Boilers are not subject to BART. Our basis and analyses for our disapproval of Arkansas' determinations that the 6A Boiler is not BART-eligible and that the 6A and 9A Boilers are not subject to BART is found in our October 17, 2011 proposed rulemaking, March 12, 2012 final rulemaking, and the associated TSDs.[10]

A revised Title V permit for the Georgia-Pacific Crossett Mill was issued on August 4, 2011, and again on May 23, 2012. Although no pollution controls were installed, the permitted emission limits for SO_2 and PM_{10} for the 6A Boiler and SO_2, NO_X, and PM_{10} for the 9A Boiler were revised to be more stringent. In a letter dated May 18, 2012,[11] Georgia-Pacific explained to ADEQ that it had conducted additional dispersion modeling in 2011 based on the currently enforceable Title V permit limits for the 6A and 9A Boilers.[12] The results of the 2011 modeling analysis are summarized in the table below. Based on modeling of the current permit limits, the boilers' maximum visibility impact was modeled to be 0.359 dv at Caney Creek (assuming 2002 meteorology). In the letter to ADEQ, Georgia-Pacific stated its belief that the 2011 dispersion modeling analysis and the current Title V permit that enforces the modeled limits are sufficient to

[9] *Id.*

[10] 76 FR 64186 and 77 FR 14604.

[11] May 18, 2012 letter from James W. Cutbirth, Environmental Services Superintendent at Georgia-Pacific Crossett Paper Operations, to Mary Pettyjohn, ADEQ. A copy of this letter can be found in the docket for this proposed rulemaking.

[12] See ADEQ Operating Air Permit No. 0597–AOP–R14, issued on May 23, 2012. A copy of the air permit can be found in the docket for this proposed rulemaking.

demonstrate no cause or contribution to visibility impairment by the 6A and 9A Boilers, and that the boilers are therefore not subject to BART.

TABLE 1—MAXIMUM MODELED VISIBILITY IMPACTS FROM 6A AND 9A BOILERS

[Georgia-Pacific's 2011 Dispersion Modeling Analysis]

Class I area	Maximum Visibility Impact (dv)		
	2001 meteorology	2002 meteorology	2003 meteorology
Caney Creek	0.16	0.359	0.296
Upper Buffalo	0.099	0.074	0.099
Hercules-Glades	0.08	0.288	0.125
Mingo	0.123	0.093	0.168
Sipsey	0.171	0.184	0.119

Following discussions with us and ADEQ, Georgia-Pacific provided additional information and documentation to support its contention that the 6A and 9A Boilers are not subject to BART. Georgia-Pacific calculated maximum 24-hour emission rates from the 2001–2003 baseline period using fuel usage data, and then showed that these estimated maximum 24-hour emission rates are below the revised emission rates it used in the 2011 BART screening modeling. In a letter dated April 1, 2013, Georgia-Pacific provided spreadsheets with fuel usage data for the 6A and 9A Boilers for each day during the 2001–2003 baseline period.[13] The 6A Boiler burned only natural gas during the 2001–2003 baseline period, while the 9A Boiler burned both natural gas and bark. Georgia-Pacific used emission factors from AP–42, *Compilation of Air Pollutant Emission Factors,*[14] to calculate 24-hour emission rates for SO_2, NO_X, and PM_{10} (lb/hr) for the 6A and 9A Boilers for each day during the baseline years. The gas and bark usage value for each day was multiplied by the corresponding AP–42 emission factor to calculate the 24-hour emission rate for each day during the baseline period.[15] Georgia-Pacific then determined the maximum 24-hour emission rates for the 6A and 9A Boilers during the baseline period (see table below).[16]

TABLE 2—GEORGIA-PACIFIC CROSSETT MILL 6A AND 9A BOILER MAXIMUM 24-HOUR EMISSION RATES FROM THE 2001–2003 BASELINE PERIOD

Unit	Maximum 24-Hour Emission Rates (lb/hr)		
	SO_2	NO_X	PM_{10}
6A Boiler	0.2	90.7	2.5
9A Boiler	17.9	174.1	72.0

Georgia-Pacific then compared the calculated maximum 24-hour emission rates from the baseline period with the emission rates it modeled in the 2011 BART screening modeling and with the current Title V permit limits (see table below).[17] A comparison of these values shows that the calculated maximum 24-hour emission rates for each pollutant are below the emission rates Georgia-Pacific modeled in the 2011 BART screening modeling, and also below the currently enforceable Title V permit limits.

TABLE 3—GEORGIA-PACIFIC CROSSETT MILL—COMPARISON OF MAXIMUM 24-HOUR EMISSION RATES WITH MODELED EMISSION RATES AND TITLE V PERMIT LIMITS

	SO_2	NO_X	PM_{10}
6A Boiler			
Calculated Maximum 24-hr Emission Rate (lb/hr)	0.2	90.7	2.5

[13] April 1, 2013 letter from James W. Cutbirth, Environmental Services Superintendent at Georgia-Pacific Crossett Paper Operations, to Mary Pettyjohn, ADEQ. A copy of this letter and all attachments can be found in the docket for this proposed rulemaking.

[14] *AP–42, Compilation of Air Pollutant Emission Factors,* has been published since 1972 as the primary compilation of EPA's emission factor information. It contains emission factors and process information for more than 200 air pollution source categories. The emission factors have been developed and compiled from source test data, material balance studies, and engineering estimates. The Fifth Edition of AP–42 was published in January 1995. Since then, EPA has published supplements and updates to the fifteen chapters available in Volume I, Stationary Point and Area Sources. The latest emissions factors are available at *http://www.epa.gov/ttnchie1/ap42/.*

[15] Please see the TSD for example calculations of the 24-hour emissions rates for the 6A and 9A Boilers. See also the April 1, 2013 letter from James W. Cutbirth, Environmental Services Superintendent at Georgia-Pacific Crossett Paper Operations, to Mary Pettyjohn, ADEQ. The attachments to the April 1, 2013 letter include spreadsheets with the calculated 24-hour emission rates for each day during the 2001–2003 baseline period for the 6A and 9A Boilers. The letter and all attachments are found in the docket for this proposed rulemaking.

[16] The maximum 24-hour emission rate for PM_{10} for the 9A Boiler is based on the results of stack testing Georgia-Pacific conducted when the boiler was firing bark and gas, since the stack test results yielded a higher emission rate than what Georgia-Pacific calculated using AP–42 emission factors.

[17] See ADEQ Operating Air Permit No. 0597–AOP–R14, issued on May 23, 2012. A copy of the air permit can be found in the docket for this proposed rulemaking.

TABLE 3—GEORGIA-PACIFIC CROSSETT MILL—COMPARISON OF MAXIMUM 24-HOUR EMISSION RATES WITH MODELED EMISSION RATES AND TITLE V PERMIT LIMITS—Continued

	SO_2	NO_X	PM_{10}
Modeled Emission Rate (lb/hr)	0.3	120.0	3.3
Title V permit Limit (lb/hr)	0.3	120.0	3.3
9A Boiler			
Calculated Maximum 24-hr Emission Rate (lb/hr)	17.9	174.1	72.0
Modeled Emission Rate (lb/hr)	200.0	218.0	75.8
Title V permit Limit (lb/hr)	199.8	196.0	77.4

Because the 2011 BART screening modeling showed visibility impacts below 0.5 dv from the 6A and 9A Boilers and the recently estimated maximum 24-hour emission rates from the 2001–2003 baseline period are below the modeled emission rates, we propose that it is reasonable to conclude that the boilers had visibility impacts below 0.5 dv during the baseline period. Accordingly, we believe that Georgia-Pacific's newly provided analysis and documentation, as described above and in our TSD in more detail, is appropriate to demonstrate that the 6A and 9A Boilers are not subject to BART. In comparison to the information available to us when we issued our March 12, 2012 final action on the 2008 Arkansas RH SIP, we believe this newly provided analysis allows for a more accurate assessment of whether or not the 6A and 9A Boilers are subject to BART. Based on this newly provided information, we are proposing to find that while the 6A Boiler is a BART-eligible source, it is not subject to BART. The 9A Boiler is also BART-eligible (as the State determined in the 2008 Arkansas RH SIP), but we are also proposing to find that the 9A Boiler is not subject to BART. Therefore, it is not necessary to perform a BART five factor analysis or to make BART determinations for the Georgia-Pacific Crossett Mill 6A and 9A Boilers.

2. AECC Carl E. Bailey Generating Station Unit 1

In our March 12, 2012 final action on the 2008 Arkansas RH SIP, we noted that the original meteorological databases generated by the Central Regional Air Planning Association (CENRAP) and used by Arkansas to conduct its modeling analyses did not include surface and upper air meteorological observations as EPA guidance recommends. Thus, in its evaluation to determine if a source exceeds the 0.5 dv contribution threshold at potentially affected Class I areas, Arkansas used the maximum value (*i.e.,* 1st high value) of modeled visibility impacts instead of the 98th percentile value (*i.e.,* 8th high value). The use of the maximum modeled values in the 2008 Arkansas RH SIP was agreed to by us, representatives of the Federal Land Managers, and CENRAP stakeholders. In our March 12, 2012 final action, we also approved Arkansas' determination that the AECC Carl E. Bailey Generating Station (AECC Bailey) Unit 1 is BART-eligible and subject to BART, based on the maximum value of modeled visibility impacts.

Following our March 12, 2012 final action on the 2008 Arkansas RH SIP, AECC hired a consultant to conduct revised modeling of AECC Bailey Unit 1. Unlike the modeling submitted in the 2008 Arkansas RH SIP, the revised modeling shows visibility impacts from Bailey Unit 1 below 0.5 dv, which is the threshold used by Arkansas to determine if a source is subject to BART. However, we already approved Arkansas' determination that the AECC Bailey Unit 1 is subject to BART in our March 12, 2012 final action on the 2008 Arkansas RH SIP.

We do not have the discretion to reopen the issue of whether the source is subject to BART because we already approved the portion of the 2008 Arkansas RH SIP in which Arkansas determined AECC Bailey Unit 1 is subject to BART and Arkansas has not provided us a SIP revision to replace the previous determination.[18] We cannot reconsider our approval of that portion of the 2008 Arkansas RH SIP to have been in error because Arkansas did not submit the revised modeling to us with a request to remove the source from BART and the modeling approach used by Arkansas in that SIP is consistent with our regional haze regulations and was agreed to by us, representatives of the Federal Land Managers, and CENRAP stakeholders prior to submittal of the 2008 Arkansas RH SIP. Therefore, our proposed FIP is not reopening the issue of whether the source is subject to BART, and our final approval of Arkansas' determination that the source is subject to BART remains in place and in the subsection that follows we evaluate AECC Bailey Unit 1 under BART.

B. BART Factors

The purpose of the BART analysis is to identify and evaluate the best system of continuous emission reduction based on the BART Guidelines.[19] In determining BART, a state, or EPA if 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). Following the BART Guidelines, the BART analysis is broken down into five steps. Steps 1 through 3 address the availability, technical feasibility and effectiveness of retrofit control options. The consideration of the five statutory factors occurs during steps 4 and 5 of the process.

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.

- Factor 1: Costs of compliance.
- Factor 2: Energy and nonair quality environmental impacts of compliance.
- Factor 3: Existing pollution control technology in use at the source.
- Factor 4: Remaining useful life of the facility.

Step 5—Evaluate Visibility Impacts

- Factor 5: Degree of improvement in visibility which may reasonably be

[18] 77 FR 14604, March 12, 2012.

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

anticipated to result from the use of retrofit control technology.

C. BART Determinations and Proposed Federally Enforceable Limits

1. AECC Carl E. Bailey Generating Station

The AECC Bailey Unit 1 is a wall-fired boiler with a gross output of 122 megawatts (MW) and a maximum heat input rate of 1,350 million British thermal units per hour (MMBtu/hr). The unit is currently permitted to burn natural gas and fuel oil. The fuel oil burned is currently subject to a sulfur content limit of 2.3% by weight. AECC hired a consultant to perform a BART five factor analysis for Bailey Unit 1.[20]

The table below summarizes the baseline emission rates modeled for the source. The SO_2 and NO_X baseline emission rates are the highest actual 24-hour emission rates based on 2001–2003 continuous emission monitoring system (CEMS) data, while the PM baseline emission rates are based on stack testing and AP–42 emission factors.

TABLE 4—BASELINE EMISSION RATES FOR AECC BAILEY UNIT 1

Unit/Fuel scenario	SO_2 (lb/hr)	NO_X (lb/hr)	Total PM_{10}[21] (lb/hr)	Inorganic condensable (SO_4) (lb/hr)	Coarse soil (PMc) (lb/hr)	Fine soil (PMf) (lb/hr)	Organic condensable PM (SOA) (lb/hr)	Elemental carbon (EC) (lb/hr)
Bailey, Unit 1—Natural Gas firing	0.5	443.8	10.2	0.3	0.0	0.0	7.4	2.6
Bailey, Unit 1—Fuel Oil firing	2,375.8	408.8	55.8	4.6	13.7	34.1	0.8	2.7

The NO_X and PM baseline emission rates used in AECC's revised modeling for the fuel oil firing scenario were revised from what the State modeled in the 2008 Arkansas RH SIP. The revised NO_X emission rates for the fuel oil firing scenario are higher than what was modeled in the 2008 Arkansas RH SIP, while the revised PM_{10} emission rates for fuel oil firing scenario are lower than what was modeled in the 2008 Arkansas RH SIP. We have some concern with AECC's use of the PM_{10} baseline emission rates, which are based on stack testing, because there is no discussion provided on how the stack test results are representative of the maximum 24-hour emissions. However, because the visibility impacts due to PM_{10} emissions from Bailey Unit 1 are so small, we believe a closer inspection of the revised PM_{10} emission rates and any further updates to these would likely not result in significant changes to the modeled visibility impacts and would not affect our proposed BART decision. As shown in the table below, the percentage of the visibility impairment attributable to PM_{10} from Bailey Unit 1 at the Class I area with the highest baseline visibility impacts (Mingo) is 8.10% for the natural gas firing scenario and 1.26% for the fuel oil firing scenario. Most of the visibility impairment is attributable to NO_3 (83.34%) for the natural gas firing scenario and to SO_4 (93.95%) for the fuel oil firing scenario. Therefore, we did not take further steps to adjust the PM_{10} emission rates or conduct additional modeling.

AECC's modeling for the baseline emission rates uses the CALPUFF dispersion model to determine the baseline visibility impairment attributable to Bailey Unit 1 at the four Class I areas impacted by emissions from BART sources in Arkansas. These Class I areas are the Caney Creek Wilderness Area, Upper Buffalo Wilderness Area, Hercules-Glades Wilderness Area, and Mingo National Wildlife Refuge. The baseline (*i.e.,* existing) visibility impairment attributable to each unit at each Class I area is summarized in the table below.

TABLE 5—98TH PERCENTILE BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO AECC BAILEY UNIT 1 (2001–2003)

Unit/Fuel scenario		Maximum (Δdv)	98th percentile (Δdv)	98th percentile % SO_4	98th percentile % NO_3	98th percentile % PM_{10}
Bailey Unit 1—Natural Gas firing.	Caney Creek	0.219	0.083	0.28	96.36	3.35
	Upper Buffalo	0.170	0.072	0.29	95.02	3.43
	Hercules-Glades	0.238	0.073	0.22	92.76	3.67
	Mingo	0.443	0.102	0.45	83.34	8.10
Bailey Unit 1—Fuel Oil firing	Caney Creek	0.970	0.330	87.19	12.11	0.57
	Upper Buffalo	0.696	0.348	90.73	8.42	0.83
	Hercules-Glades	0.687	0.368	82.74	14.39	2.08
	Mingo	1.592	0.379	93.95	4.68	1.26

a. *Proposed BART Analysis and Determination for SO_2.* The source does not have existing SO_2 pollution control technology. AECC identified all available control technologies, eliminated options that are not technically feasible, and evaluated the control effectiveness of the remaining control options. Each technically feasible control option was then evaluated in terms of a five factor BART analysis.

AECC's BART evaluation considered both flue gas desulfurization (FGD) and fuel switching as possible controls. AECC found that FGD applications have not been used historically for SO_2 control on fuel oil-fired units in the U.S.

[20] See the following BART analyses: ''BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations,'' dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation; and ''BART Five Factor Analysis- NO_X Analysis, Addendum to the July 24, 2012 BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations,'' dated December 2013, Version 3. A copy of these two BART analyses can be found in the docket for our proposed rulemaking.

[21] The National Park Service PM speciation worksheets are typically used to speciate PM_{10} into SO_4, PMc, PMf, SOA, and EC.

electric industry and therefore considered it a technically infeasible option for control of Bailey Unit 1. Accordingly, AECC did not further consider FGD for SO_2 BART. We concur with AECC's decision to focus the SO_2 BART evaluation on fuel switching. Switching to a fuel with a lower sulfur content is expected to reduce SO_2 emissions in proportion to the reduction in the sulfur content of the fuel, assuming that the fuels have similar heat contents. Bailey Unit 1 burns primarily natural gas, but is also permitted to burn fuel oil. The baseline fuel AECC assumed in the BART analysis is No. 6 fuel oil with 1.81% sulfur content, based on the average sulfur content of the fuel oil from the most recent shipment received by the facility in December 2006. According to the facility, a portion of the fuel oil from this shipment still remains in storage at the facility for future use. AECC evaluated switching to the fuel types shown in the table below.

TABLE 6—CONTROL EFFECTIVENESS OF FUEL SWITCHING OPTIONS FOR AECC BAILEY UNIT 1

Fuel switching options	Estimated SO_2 control efficiency %
No. 6 fuel oil, 1% sulfur	45
No. 6 fuel oil, 0.5% sulfur	72
Diesel, 0.05% sulfur	97
Natural gas	99.9

AECC estimated the average cost-effectiveness of switching Bailey Unit 1 to No. 6 fuel oil with 1% sulfur content to be $1,198 per ton of SO_2 removed. Switching from the baseline fuel to No. 6 fuel oil with 0.5% sulfur content was estimated to cost $2,559 per ton of SO_2 removed. The results of AECC's cost analysis are summarized in the table below. For the natural gas switching scenario, AECC found that the current cost of natural gas is actually lower than the cost of the baseline fuel. Therefore, the average cost-effectiveness of switching from the baseline fuel to natural gas is denoted as a negative value (cost savings) in the table below.

TABLE 7—AECC BAILEY UNIT 1: SUMMARY OF COSTS ASSOCIATED WITH FUEL SWITCHING

Fuel switching scenario	Average sulfur content (%)	Baseline emission rate (SO_2 tpy)	Controlled emission rate (SO_2 tpy)	Annual emissions reductions (SO_2 tpy)	Annual fuel usage (Mgal/yr)	Fuel cost ($/MMBtu)	Total annual differential cost of fuel switching ($/yr)	Average cost effectiveness [22] ($/ton)	Incremental cost effectiveness [23] ($/ton)
Baseline	1.81	37.03			252.86	16.00			
No. 6 Fuel Oil—1%	1.00		20.67	16.36	252.86	16.50	19,596	1,198	
No. 6 Fuel Oil—0.5%	0.50		10.23	26.80	252.86	17.75	68,587	2,559	4,693
Diesel	0.05		0.99	36.05	287.86	20.95	194,003	5,382	13,558
Natural Gas	0.04		0.01	37.02	38.77	6.19	−384,550	−10,387	−596,446

AECC's evaluation did not identify any energy or non-air quality environmental impacts associated with switching to 1% sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, or diesel. The evaluation noted that switching to natural gas may have energy impacts during periods of natural gas curtailment. During periods of natural gas curtailment, natural gas infrastructure maintenance, and other emergencies, the AECC Bailey Generating Station relies on the fuel oil stored at the plant to maintain electrical reliability. AECC's evaluation notes that because of this, it is important to maintain the ability to burn fuel oil at AECC Bailey, even if fuel oil is currently more expensive than natural gas.

With regard to consideration of the remaining useful life of Unit 1, this factor does not impact the SO_2 BART analysis because the emissions control approaches being evaluated for BART do not require capital cost expenditures. Thus, there are no control costs that need to be amortized over the lifetime of the unit.

AECC assessed the visibility improvement associated with fuel switching by comparing the 98th percentile modeled visibility impact of the baseline scenario to the 98th percentile modeled visibility impact of each control scenario. The table below shows a comparison of the baseline visibility impacts and the visibility impacts of the different fuel switching control scenarios that were evaluated, including the cumulative visibility benefits.

TABLE 8—AECC BAILEY UNIT 1: SUMMARY OF 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO FUEL SWITCHING

Class I area	Baseline visibility impact (Δdv)	No. 6 fuel oil—1% sulfur	No. 6 fuel oil—0.5% sulfur	Diesel	Natural gas				
					Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)
Caney Creek	0.330	0.193	0.137	0.142	0.188	0.084	0.246	0.083	0.247
Upper Buffalo	0.348	0.194	0.154	0.127	0.221	0.069	0.279	0.072	0.276
Hercules-Glades	0.368	0.206	0.162	0.135	0.233	0.069	0.299	0.073	0.295
Mingo	0.379	0.206	0.173	0.170	0.209	0.095	0.284	0.102	0.277
Cumulative Visibility Improvement (Δdv)			0.626		0.851		1.108		1.095

[22] The average cost-effectiveness was calculated by dividing the total annual differential cost of switching from the baseline fuel oil to the lower sulfur fuel.

[23] 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). See BART Guidelines, 40 CFR Part 51, Appendix Y, section IV.D.4.e.

The table above shows that switching to No. 6 fuel oil with 1% sulfur content at Bailey Unit 1 is projected to result in 0.173 dv visibility improvement at Mingo (based on the 98th percentile modeled visibility impacts). The visibility improvement at each of the other three affected Class I areas is projected to be slightly less than that amount, while the cumulative visibility improvement at the four Class I areas is projected to be 0.626 dv. Switching to No. 6 fuel oil with 0.5% sulfur content is projected to result in meaningful visibility improvement. It is projected to result in 0.233 dv visibility improvement at Hercules-Glades. The visibility improvement at each of the other three affected Class I areas is projected to be slightly less than that amount, while the cumulative visibility improvement at the four Class I areas is projected to be 0.851 dv. Switching to diesel or natural gas is also projected to result in meaningful visibility improvement. The visibility improvement at Hercules-Glades is projected to be 0.299 dv for switching to diesel and 0.295 dv for switching to natural gas, and slightly less than that amount at each of the other three affected Class I areas. The cumulative visibility improvement at the four Class I areas is projected to be 1.108 dv for switching to diesel and 1.095 dv for switching to natural gas.

Our Proposed SO_2 BART Determination: Taking into consideration the five factors, we are proposing to determine that BART for the AECC Bailey Unit 1 is switching to fuels with 0.5% or lower sulfur content by weight. The cost effectiveness of switching to No. 6 fuel oil with 0.5% sulfur content is within the range of what we consider to be cost-effective for BART and it is projected to result in considerable visibility improvement compared to the baseline at the affected Class I areas. Switching to No. 6 fuel oil with 0.5% sulfur content has an estimated average cost-effectiveness of \$2,559 per ton of SO_2 removed and is projected to result in visibility improvement ranging from 0.188 to 0.233 dv at each modeled Class I area, and a cumulative visibility improvement of 0.851 dv at the four modeled Class I areas. Switching to natural gas would currently cost less than the baseline fuel and is projected to result in even greater visibility improvement than switching to No. 6 fuel oil with 0.5% sulfur content. However, the BART Guidelines provide that it is not our intent to direct subject-to-BART sources to switch fuel forms, such as from coal or fuel oil to gas (40 CFR part 51, Appendix Y, section IV.D.1). Because natural gas has a sulfur content by weight that is well below 0.5%, the facility may elect to use this type of fuel to comply with BART, but we are not proposing to require a switch to natural gas for Unit 1. Switching to diesel is projected to result in an almost identical level of visibility improvement at each Class I area as switching to natural gas. The incremental visibility improvement of switching to diesel compared to switching to No. 6 fuel oil with a sulfur content of 0.5% is projected to range from 0.058 dv to 0.075 dv at each affected Class I area but the average cost-effectiveness is estimated to be \$5,382 per ton of SO_2 removed and the incremental cost-effectiveness compared to switching to No. 6 fuel oil with a sulfur content of 0.5% is estimated to be \$13,558 per ton of SO_2 removed, which we do not consider to be very cost-effective in view of the incremental visibility improvement. Because diesel also has a sulfur content by weight that is well below 0.5%, the facility may elect to use this type of fuel to comply with BART, but we are not proposing to require a switch to diesel for Unit 1. We are proposing to determine that SO_2 BART for Bailey Unit 1 is switching to fuels with 0.5% or lower sulfur content by weight. We propose to require that the facility purchase no fuel after the effective date of the rule that does not meet the sulfur content requirement and that 5 years from the effective date of the rule no fuel be burned that does not meet the requirement. We propose that any higher sulfur fuel oil that remains from the facility's 2006 fuel oil shipment cannot be burned past this point. As discussed above, the unit's baseline fuel is No. 6 fuel oil with 1.81% sulfur content, based on the average sulfur content of the fuel oil from the most recent fuel oil shipment received by the facility in 2006. Based on our discussions with the facility, it is our understanding that the unit burns fuel oil primarily during periods of natural gas curtailment and during periodic testing and that the facility still has stockpiles of fuel oil from the most recent shipment. Because the unit burns primarily natural gas and does not ordinarily burn fuel oil on a frequent basis, we believe it is appropriate to allow the facility 5 years to burn its existing supply of No. 6 fuel oil, as the normal course of business dictates and in accordance with any operating restrictions enforced by ADEQ. We believe that a shorter compliance date may result in the facility burning its existing supply of higher sulfur No. 6 fuel oil relatively quickly, resulting in a high amount of SO_2 emissions being emitted by the unit over a short period of time. This is not the intent of our regional haze regulations. We are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with this proposed determination.

b. *Proposed BART Analysis and Determination for NO_X.* AECC's BART evaluation examined BART controls for NO_X for AECC Bailey Unit 1. Bailey Unit 1 does not currently have pollution control equipment for NO_X. AECC's evaluation identified all available control technologies, eliminated options that are not technically feasible, and evaluated the control effectiveness of the remaining control options. Each technically feasible control option was then evaluated in terms of a five factor BART analysis.

For NO_X BART, AECC's evaluation considered both combustion and post-combustion controls. The combustion controls evaluated by AECC consisted of flue gas recirculation (FGR), overfire air (OFA), and low NO_X burners (LNB). The post-combustion controls evaluated consisted of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). AECC found that some boilers may be restricted from installing OFA retrofits due to physical size and space restraints. For purposes of the NO_X BART evaluation, AECC assumed OFA to be a technically feasible option for Bailey Unit 1, but noted that if OFA was determined to be BART based on the evaluation of the five BART factors, then further analyses would have to be performed to determine if: (1) The dimensions of AECC Bailey's main boilers have sufficient upper furnace volume for OFA mixing and complete combustion and (2) the furnace meets the physical space requirements for OFA ports and air supply ducts. The remaining NO_X control options were found to be technically feasible.

AECC evaluated three control scenarios: A combination of combustion controls (FGR, OFA, and LNB); the combination of combustion controls and SNCR; and SCR. Based on literature estimates, AECC found that the estimated NO_X control range for oil and gas wall-fired boilers, such as Bailey Unit 1, is approximately 0.2–0.4 lb/MMBtu using FGR and 0.2–0.3 lb/MMBtu using OFA.[24] When LNB is combined with OFA and FGR, AECC

[24] ''Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options,'' section II, dated July 1994, State and Territorial Air Pollution Program Administrators (STAPPA) and Association of Local Air Pollution Control Officials (ALAPCO).

estimated that a NO_X controlled emission rate of 0.15—0.20 lb/MMBtu can be achieved at Bailey Unit 1. The NO_X controlled emission rate of combustion controls combined with SNCR is estimated to be 0.12 lb/MMBtu. The NO_X control efficiency of SCR is estimated to be 80–90% for gas fired boilers and 70–80% for oil fired boilers, which corresponds to a controlled emission rate of 0.04–0.08 lb/MMBtu for Bailey Unit 1.

AECC's cost analysis for NO_X controls was based on ''budgetary'' cost estimates it obtained by AECC from the pollution control equipment vendor, Babcock Power Systems. AECC estimated the capital and operating costs of controls based on the vendor's estimates, engineering estimates, and published calculation methods using EPA's Air Pollution Control Cost Manual (EPA Control Cost Manual).[25] We are not aware of any enforceable shutdown date for the AECC Bailey Generating Station, nor did AECC's evaluation indicate any future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of controls. Therefore, a 30-year amortization period was assumed in the NO_X BART analysis as the remaining useful life of Unit 1. The table below summarizes the estimated cost for installation and operation of NO_X controls for Bailey Unit 1.

TABLE 9—SUMMARY OF NO_X CONTROL COSTS FOR AECC BAILEY UNIT 1

Control scenario	Baseline emission rate (NO_X tpy)	Natural gas controlled emission level (lb/MMBtu)[26]	Fuel oil controlled emission level (lb/MMBtu)[27]	Controlled emission rate (NO_X tpy)	Annual emissions reductions (NO_X tpy)	Total annual cost ($/yr)	Average cost-effectiveness ($/ton)	Incremental cost-effectiveness($/ton)
Combustion Controls	49.81	0.15	0.15	30.83	18.98	700,477	36,905	
Combustion Controls + SNCR	49.81	0.12	0.12	24.79	25.02	1,223,157	48,884	86,536
SCR[28]	49.81	0.04	0.08	9.65	40.16	1,555,718	38,738	21,966

AECCestimated the average cost-effectiveness of installing and operating combustion controls to be $36,905 per ton of NO_X removed for Bailey Unit 1. The combination of combustion controls and SNCR was estimated to cost $48,884 per ton of NO_X removed, while SCR was estimated to cost $38,738 per ton of NO_X removed. In its evaluation, AECC also explained that it expects the cost-effectiveness of NO_X controls to be lower (*i.e.,* greater dollars per ton removed) in future years due to projected reduced operation of the unit.

AECC did not identify any energy or non-air quality environmental impacts associated with the use of LNB, OFA, or FGR. As for SCR and SNCR, we are not aware of any unusual circumstances at the facility that could create non-air quality environmental impacts associated with the operation of these controls greater than experienced elsewhere and that may therefore provide a basis for their elimination as BART (40 CFR part 51, Appendix Y, section IV.D.4.i.2.). Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with NO_X controls at AECC Bailey Unit 1 that would affect our proposed BART determination.

AECC assessed the visibility improvement associated with NO_X controls by modeling the NO_X emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rates to the visibility impairment associated with the controlled emission rates as measured by the 98th percentile modeled visibility impact. The tables below show a comparison of the baseline (*i.e.,* existing) visibility impacts and the visibility impacts associated with NO_X controls.

TABLE 10—AECC BAILEY UNIT 1: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO NO_X CONTROLS—NATURAL GAS FIRING

Class I area	Baseline visibility impact (Δdv)	Combustion controls		Combustion controls + SNCR		SCR	
		Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	0.083	0.039	0.044	0.032	0.051	0.014	0.069
Upper Buffalo	0.072	0.034	0.038	0.028	0.044	0.013	0.059
Hercules-Glades	0.073	0.035	0.038	0.029	0.044	0.013	0.06
Mingo	0.102	0.051	0.051	0.043	0.059	0.021	0.081
Cumulative Visibility Improvement (Δdv)			0.171		0.198		0.269

[25] EPA's ''Air Pollution Control Cost Manual,'' Sixth edition, January 2002, is located at *www.epa.gov/ttncatc1/products.html#cccinfo.*

[26] See the preceding paragraphs for a discussion of the expected controlled emission rates for natural gas vs. fuel oil firing.

[27] *Id.*

TABLE 11—AECC BAILEY UNIT 1: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO NO_X CONTROLS—FUEL OIL FIRING

Class I area	Baseline visibility impact (Δdv)	Combustion controls		Combustion controls + SNCR		SCR	
		Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	0.330	0.325	0.005	0.325	0.005	0.323	0.007
Upper Buffalo	0.347	0.332	0.015	0.329	0.018	0.325	0.022
Hercules-Glades	0.367	0.339	0.028	0.333	0.034	0.325	0.042
Mingo	0.378	0.369	0.009	0.367	0.011	0.364	0.014
Cumulative Visibility Improvement (Δdv)			0.057		0.068		0.085

The tables above show that the installation and operation of NO_X controls is projected to result in a very modest visibility improvement from the baseline. Combustion controls at Bailey Unit 1 are projected to result in visibility improvement of up to 0.051 dv at any single Class I area for the natural gas firing scenario and 0.028 dv for the fuel oil firing scenario (based on the 98th percentile modeled visibility impacts). A combination of combustion controls and SNCR is projected to result in only slight incremental visibility improvement over combustion controls alone. For example, a combination of combustion controls and SNCR at Bailey Unit 1 is projected to result in visibility improvement of up to 0.059 dv at any single Class I area for natural gas firing and 0.034 dv for fuel oil firing, which is an incremental visibility improvement of 0.008 dv for natural gas firing and 0.006 dv for fuel oil firing compared to combustion controls alone. Similarly, the installation and operation of SCR is projected to result in only slight incremental visibility improvement compared to a combination of combustion controls and SNCR.

Our Proposed NO_X BART Determination: Taking into consideration the five factors, we are proposing to determine that NO_X BART for the AECC Bailey Unit 1 is no additional controls, and are proposing that the facility's existing NO_X emission limit satisfies BART for NO_X. We are proposing the existing emission limit of 887 lb/hr for NO_X BART for Bailey Unit 1.[29] As discussed above, the operation of combustion controls at Bailey Unit 1 is projected to result in a maximum visibility improvement of 0.051 dv (Mingo), and a smaller amount of visibility improvement at each of the other affected Class I areas. The installation and operation of combustion controls at Bailey Unit 1 has an average cost-effectiveness of $36,905 per ton of NO_X removed, which is not within the range of what we consider cost-effective. We believe the relatively small visibility benefit projected from the operation of combustion controls both when combusting fuel oil and natural gas does not justify the estimated cost of those controls. The operation of a combination of combustion controls and SNCR is estimated to cost $48,884 per ton of NO_X removed, which is also not within the range of what we consider cost-effective. A combination of combustion controls and SNCR is projected to result in only slight incremental visibility benefit compared to combustion controls alone. The operation of SCR is estimated to cost $38,738 per ton of NO_X removed, which is not cost-effective, and is projected to result in only slight incremental visibility benefit compared to a combination of combustion controls and SNCR. We are proposing to find that NO_X BART for Bailey Unit 1 is no additional controls and are proposing that the existing NO_X emission limit of 887 lb/hr is BART for NO_X and that compliance be demonstrated using the unit's existing CEMS. We are proposing that this emission limitation be complied with for BART purposes from the date of effectiveness of the finalized action. We are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with these emission limits.

c. *Proposed BART Analysis and Determination for PM.* PM emissions are inherently low when burning natural gas. Bailey Unit 1 does not currently have pollution control equipment for PM. AECC's BART evaluation considered the following control technologies for PM BART: Dry electrostatic precipitator (ESP), wet ESP, fabric filter, wet scrubber, cyclone (*i.e.,* mechanical collector), and fuel switching. Residual fuel, such as the baseline No. 6 fuel oil burned at Bailey Unit 1, has inherent ash that contributes to emissions of filterable PM. Reductions in filterable PM emissions are directly related to the sulfur content of the fuel.[30] Therefore, switching to No. 6 fuel oil with a lower sulfur content is expected to result in lower filterable PM emissions. AECC's evaluation considered switching to No. 6 fuel oil with 1% sulfur content by weight, No. 6 fuel oil with 0.5% sulfur content by weight, diesel, and natural gas. These are the same lower sulfur fuel types evaluated in the SO_2 BART analysis for the unit.

AECC's evaluation noted that the particulate matter from oil-fired boilers tends to be sticky and small, affecting the collection efficiency of dry ESPs and fabric filters. Dry ESPs operate by placing a charge on the particles through a series of electrodes, and then capturing the charged particles on collection plates, while fabric filters work by filtering the PM in the flue gas through filter bags. The collected particles are periodically removed from the filter bag through a pulse jet or reverse flow mechanism. Because of the sticky nature of particles from oil-fired boilers, dry ESPs and fabric filters are deemed technically infeasible for use at Bailey Unit 1. Wet ESPs, cyclones, wet scrubbers, and fuel switching were identified as technically feasible options for Bailey Unit 1. AECC noted that although cyclones and wet scrubbers are considered technically feasible for use at these boiler types, they are not very efficient at controlling particles in the smaller size fraction, particularly particles smaller than a few microns. However, the majority of the PM emissions from Bailey Unit 1 are greater than a few microns in size.

[29] See ADEQ Operating Air Permit No. 0154–AOP–R4, Section IV, Specific Conditions No. 1 and 7.

[30] See ''AP–42, Compilation of Air Pollutant Emission Factors,'' section 1.3.3.1, and Table 1.3–1, available at *http://www.epa.gov/ttnchie1/ap42/.*

AECC estimated that switching to a lower sulfur fuel has a PM control efficiency ranging from approximately 44%–99%, depending on the fuel type. The other technically feasible control technologies are estimated to have the following PM control efficiency: Wet ESP—up to 90%, cyclone—85%, and wet scrubber—55%.

AECC evaluated the capital costs, operating costs, and average cost-effectiveness of wet ESPs, cyclones, and wet scrubbers. It also evaluated the average cost-effectiveness of switching to No. 6 fuel oil with 1% sulfur content, No. 6 fuel oil with 0.5% sulfur content, diesel, and natural gas. AECC developed the capital and operating costs of a wet ESP and wet scrubber using the Electric Power Research Institute's (EPRI) Integrated Emissions Control Cost Estimating Workbook (IECCOST) Software. The capital costs of controls (except for fuel switching) were annualized over a 15-year period and then added to the annual operating costs to obtain the total annualized costs. The table below summarizes the average cost-effectiveness of PM controls. The average cost-effectiveness was determined by dividing the annualized cost of controls by the annual PM emissions reductions. The annual emissions reductions were determined by subtracting the estimated controlled annual emission rates from the baseline annual emission rates. AECC estimated the baseline and controlled annual emission rates by conducting a mass balance on the sulfur content of the various fuels evaluated.

We disagree with two aspects of AECC's cost evaluation for PM controls. First, the total annual cost numbers associated with fuel switching should be the same as those used in the SO_2 BART cost analysis for Bailey Unit 1 (see Table 7). In earlier draft versions of AECC's BART analysis, which were provided to us for review, the cost numbers for fuel switching used in the PM and SO_2 BART analyses were identical. In response to comments provided by us, the total annual cost and average cost-effectiveness numbers for fuel switching were revised in the final version of AECC's SO_2 BART analysis. However, it appears that AECC overlooked updating these cost numbers in the final PM BART analysis.[31] In the table below, we have revised the total annual cost of fuel switching for the PM BART analysis to be consistent with the cost estimates from AECC's SO_2 BART analysis, and we have also updated the PM average cost-effectiveness values. The second aspect of AECC's cost evaluation for PM controls that we disagree with is the use of a 15-year capital cost recovery period for calculating the average cost-effectiveness of a wet ESP, wet scrubber, and cyclone. As previously discussed, we are not aware of any enforceable shutdown date for the AECC Bailey Generating Station, nor did AECC's evaluation indicate any future planned shutdown. Therefore, we believe that assuming a 30-year equipment life rather than a 15-year equipment life would be more appropriate for these control technologies. Extending the amortization period from 15 to 30 years has the effect of decreasing the total annual cost of each control option, thereby improving the average cost-effectiveness value of controls (*i.e.,* less dollars per ton removed). However, after considering all five BART factors, we do not believe AECC's assumption of a 15-year amortization period has an impact on our proposed BART decision and therefore we did not revise the amortization period or the average cost-effectiveness calculations for the PM control options. This is discussed in more detail below. The table below summarizes the estimated cost for fuel switching and the installation and operation of PM control equipment for Bailey Unit 1.

TABLE 12—SUMMARY OF COST OF PM CONTROLS FOR AECC BAILEY UNIT 1—BASELINE IS NO. 6 FUEL OIL WITH 1.81% SULFUR CONTENT BY WEIGHT

Control scenario	Baseline emission rate (PM tpy)	Control efficiency (%)	Controlled emission rate (PM tpy)	Annual emissions eductions (PM tpy)	Capital cost ($)	Total annual cost ($/yr)	Average cost-effectiveness ($/ton)	Incremental cost-effectiveness ($/ton)
Wet Scrubber	25.63	55.0	11.53	14.09	140,957,713	50,150,862	3,558,286	
No. 6 Fuel oil—1% S	25.63	65.7	8.80	16.83		19,596	1,164	−18,296,082
Cyclone	25.63	85.0	3.84	21.78	989,479	1,188,630	54,570	236,168
No. 6 Fuel oil—0.5% S	25.63	89.3	2.75	22.88		68,587	2,997	−1,020,948
Wet ESP	25.63	90.0	2.56	23.06	105,141,431	22,638,340	981,583	125,387,517
Natural Gas	25.63	99.0	0.26	25.37		−384,550	−15,157	−9,966,619
Diesel	25.63	99.5	0.13	25.50		194,003	7,608	4,450,408

The table above shows that the average cost-effectiveness values of all add-on PM control technology options evaluated for AECC Bailey Unit 1 ranged from approximately $55,000 per ton of PM removed to more than $3.5 million per ton of PM removed. The incremental cost-effectiveness of add-on PM control technology options ranged from $236,168 to $125,387,517 per ton of PM removed. Switching to No. 6 fuel oil with either a 1% or 0.5% sulfur content was found to be within the range of what we generally consider cost-effective for BART. Switching to No. 6 fuel oil with 1% sulfur content is estimated to cost $1,164 per ton of PM removed, while switching to No. 6 fuel oil with 0.5% sulfur content is estimated to cost $2,997 per ton of PM removed. As discussed in the SO_2 BART analysis, the current cost of natural gas is actually lower than the cost of the baseline fuel. Therefore, the average cost-effectiveness of switching from the baseline fuel to natural gas is denoted as a negative value in the table above. As discussed above, AECC also explained that it expects the average cost-effectiveness of PM control equipment to be lower (*i.e.,* greater dollars per ton removed) in future years due to projected reduced operation of the unit due to a change in the management of the load control area in which the facility is located.

AECC did not identify any energy or non-air quality environmental impacts associated with fuel switching, but did identify impacts associated with the use of wet ESPs and wet scrubbers due to their electricity usage. Energy use in and of itself does not disqualify a technology (40 CFR part 51, Appendix Y, section IV.D.4.h.1.). In addition, the cost of the electricity needed to operate this equipment has already been factored into the cost of controls. AECC also

[31] The final version of AECC's BART analysis for SO_2 and PM, upon which our analysis is largely based, is titled ''BART Five Factor Analysis Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations, March 2014, Version 4.'' A copy of AECC's analysis can be found in the docket for our proposed rulemaking.

noted that both wet ESPs and wet scrubbers generate wastewater streams that must either be treated on-site or sent to a waste water treatment plant, and the wastewater treatment process will generate a filter cake that would likely require landfilling. The BART Guidelines provide that 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. (40 CFR part 51, Appendix Y, section IV.D.4.i.2.). We are not aware of any unusual circumstances at the AECC Bailey Generating Station that could potentially create greater problems than experienced elsewhere related to the treatment of wastewater and any necessary landfilling, nor did AECC's evaluation discuss or mention any such unusual circumstances. Therefore, the need to treat wastewater or landfill any filter cake or other waste in and of itself does not provide a basis for disqualification or elimination of a wet ESP or wet scrubber.

As previously discussed, we are not aware of any enforceable shutdown date for the AECC Bailey Generating Station, nor did AECC's evaluation indicate any future planned shutdown. Therefore, we believe it is appropriate to assume a 30-year amortization period in the PM BART analysis as the remaining useful life of the unit. Assuming a 30-year amortization period, these controls would have a lower estimated total annual cost and would therefore have an improved cost-effectiveness (*i.e.,* less dollars per ton removed) than estimated in AECC's evaluation. However, we did not adjust the amortization period because we do not believe this has an impact on our proposed BART decision. As discussed in the subsection below, the visibility benefit expected from the installation and operation of PM control equipment is too small to justify the cost of these controls. Therefore, we did not revise the amortization period and the average cost-effectiveness calculations for the PM control equipment options.

As switching to lower sulfur fuels has impacts on both SO_2 and PM emissions, AECC's assessment of the visibility improvement associated with fuel switching is addressed in the SO_2 BART analysis for Bailey Unit 1. Table 8 summarizes the visibility improvement associated with controlled emission rates for SO_2 and PM as a result of fuel switching. AECC assessed the visibility improvement associated with wet ESPs, wet scrubbers, and cyclones by modeling the PM emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rates to the visibility impairment associated with the controlled emission rates as measured by the 98th percentile modeled visibility impact. The controlled PM_{10} emission rates associated with wet ESPs, wet scrubbers, and cyclones were calculated by reducing the uncontrolled annual PM_{10} emission rates by the pollutant removal efficiency of each control technology. The SO_2 and NO_X emission rates modeled in the controlled scenarios are the same as those from the baseline scenario, as it is assumed that SO_2 and NO_X emissions would remain unchanged. The table below shows a comparison of the baseline (*i.e.,* existing) visibility impacts and the visibility impacts associated with PM controls.

TABLE 13—AECC BAILEY UNIT 1: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT FROM PM CONTROLS

Class I area	Baseline visibility impact (Δdv)	Wet ESP		Wet scrubber		Cyclone	
		Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	0.330	0.327	0.003	0.328	0.002	0.328	0.002
Upper Buffalo	0.347	0.343	0.004	0.345	0.002	0.345	0.002
Hercules-Glades	0.367	0.356	0.011	0.360	0.007	0.361	0.006
Mingo	0.378	0.371	0.007	0.374	0.004	0.374	0.004
Cumulative Visibility Improvement (Δdv)	....	....	0.025	....	0.015	....	0.014

The table above shows that the operation of a wet ESP, wet scrubber, or cyclone at Bailey Unit 1 is projected to result in minimal visibility improvement at the four affected Class I areas. The modeled visibility improvement from switching to No. 6 fuel oil with 1% sulfur content, No. 6 fuel oil with 0.5% sulfur content, diesel, or natural gas is summarized in Table 8. The modeled visibility improvement shown in Table 8 reflects both SO_2 and PM emissions reductions as a result of switching to fuels with lower sulfur content. However, the majority of the baseline visibility impact at each Class I area when burning the baseline fuel oil is due to SO_2 emissions, while PM_{10} emissions contribute only a small portion of the baseline visibility impacts at each Class I area (see Table 5). Accordingly, the majority of the visibility improvement associated with switching to lower sulfur fuels can reasonably be expected to be the result of a reduction in SO_2 emissions.

Our Proposed PM BART Determination: Taking into consideration the five factors, we propose to determine that PM BART for the AECC Bailey Unit 1 does not require add-on controls. Consistent with our proposed determination for SO_2 BART, we are proposing that PM BART is satisfied by Unit 1 switching to fuels with 0.5% or lower sulfur content by weight. As discussed above, we disagree with AECC's use of a 15-year amortization period in the cost analysis for a wet ESP, wet scrubber, and cyclone. Assuming a 30-year amortization period, these controls would have lower estimated total annual costs and would therefore have an improved cost-effectiveness (*i.e.,* less dollars per ton removed) compared to what was estimated in AECC's evaluation. However, after considering all five BART factors, even if we revised AECC's cost estimates to reflect a 30-year amortization period, resulting in a lower total annual cost and improved cost-effectiveness, we would still not be able to justify the cost of add-on controls in light of the minimal visibility benefit of these controls (see the table above).

We are proposing to determine that PM BART for Bailey Unit 1 is switching to fuels with 0.5% or lower sulfur content by weight. We propose to require that the facility purchase no fuel after the effective date of the rule that does not meet the sulfur content requirement and that 5 years from the effective date of the rule no fuel be burned that does not meet the requirement. We propose that any higher sulfur fuel oil that remains from the facility's 2006 fuel oil shipment cannot be burned past this point. As previously discussed, the unit's baseline fuel is No. 6 fuel oil with 1.81% sulfur content, based on the average sulfur content of the fuel oil from the most recent shipment received by the facility in 2006. Based on our discussions with the facility, it is our understanding that the unit burns fuel oil primarily during periods of natural gas curtailment and during periodic testing and that the facility still has stockpiles of fuel oil from the most recent fuel oil shipment. Because the unit burns primarily natural gas and does not ordinarily burn fuel oil on a frequent basis, we believe it is appropriate to allow the facility 5 years to burn its existing supply of No. 6 fuel oil, as the normal course of business dictates and in accordance with any operating restrictions enforced by ADEQ. We believe that a shorter compliance date may result in the facility burning its existing supply of higher sulfur No. 6 fuel oil relatively quickly, resulting in a high amount of SO_2 emissions being emitted by the unit over a short period of time. This is not the intent of our regional haze regulations. We are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with this proposed determination.

2. AECC John L. McClellan Generating Station

The AECC McClellan Unit 1 is subject to BART. As mentioned previously, we disapproved Arkansas' BART determinations for SO_2, NO_X, and PM for McClellan Unit 1 in our March 12, 2012 final action (77 FR 14604). The AECC McClellan Unit 1 is a wall-fired boiler with a gross output of 134 MW and a maximum heat input rate of 1,436 MMBtu/hr. The unit is currently permitted to burn natural gas and fuel oil. The fuel oil burned is currently subject to a sulfur content limit of 2.8% by weight. AECC, through its consultant, performed a five-factor analysis for McClellan Unit 1 (AECC's BART analysis).[32]

The table below summarizes the baseline emission rates for the source. The SO_2 and NO_X baseline emission rates are the highest actual 24-hour emission rates based on 2001–2003 CEMS data, while the PM baseline emission rates are based on stack testing and AP–42 emission factors.

TABLE 14—BASELINE EMISSION RATES FOR AECC MCCLELLAN UNIT 1

Unit/fuel scenario	SO_2 (lb/hr)	NO_X (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PMc (lb/hr)	PMf (lb/hr)	SOA (lb/hr)	EC (lb/hr)
McClellan, Unit 1—Natural Gas	0.6	423.9	10.9	0.3	0.0	0.0	7.9	2.7
McClellan, Unit 1—Fuel Oil	2,747.5	579.8	59.4	5.9	14.2	35.4	1.00	2.8

The NO_X and PM baseline emission rates AECC modeled for the fuel oil firing scenario were updated from what the State modeled in the 2008 Arkansas RH SIP. The revised NO_X emission rates for the fuel oil firing scenario are higher than what was modeled in the 2008 Arkansas RH SIP, while the revised PM_{10} emission rates for fuel oil firing scenario are lower than what was modeled in the 2008 Arkansas RH SIP. We have some concern with AECC's use of the PM_{10} baseline emission rates, which were based on stack testing, because there is no discussion provided on how the stack test results are representative of the maximum 24-hour emissions. However, because the visibility impacts due to PM_{10} emissions from McClellan Unit 1 are so small, we believe a closer inspection of the revised PM_{10} emission rates and any further updates to these would likely not result in significant changes to the modeled visibility impacts and would not affect our proposed BART decision. As shown in the table below, the percentage of the visibility impairment attributable to PM_{10} at the Class I area with the highest visibility impacts (Caney Creek) is 6.63% for the natural gas firing scenario and 0.53% for the fuel oil firing scenario. Most of the visibility impairment is attributable to NO_3 (87.09%) for the natural gas firing scenario and to SO_4 (89.86%) for the fuel oil firing scenario. Therefore, we did not take further steps to adjust the PM_{10} emission rates or conduct additional modeling.

AECC modeled the baseline emission rates using the CALPUFF dispersion model to determine the baseline visibility impairment attributable to McClellan Unit 1 at the four Class I areas impacted by emissions from BART sources in Arkansas. These Class I areas are the Caney Creek Wilderness Area, Upper Buffalo Wilderness Area, Hercules-Glades Wilderness Area, and Mingo National Wildlife Refuge. The baseline (*i.e.,* existing) visibility impairment attributable to McClellan Unit 1 at each Class I area is summarized in the table below.

TABLE 15—98TH PERCENTILE BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO AECC MCCLELLAN UNIT 1

[2001–2003]

Unit/fuel scenario	Maximum (Δdv)	98th Percentile (Δdv)	98th Percentile (% SO_4)	98th Percentile (% NO_3)	98th Percentile (% PM_{10})	98th Percentile (% NO_2)
McClellan Unit 1—Natural Gas:						
Caney Creek	0.670	0.125	0.39	87.09	6.63	5.89

[32] See the following BART analyses: ''BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations,'' dated March 2014, Version 4, prepared by Trinity Consultants Inc. in conjunction with Arkansas Electric Cooperative Corporation; and ''BART Five Factor Analysis- NO_X Analysis, Addendum to the July 24, 2012 BART Five Factor Analysis, Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations,'' dated December 2013, Version 3. A copy of these two BART analyses can be found in the docket for our proposed rulemaking.

TABLE 15—98TH PERCENTILE BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO AECC MCCLELLAN UNIT 1—Continued

[2001–2003]

Unit/fuel scenario	Maximum (Δdv)	98th Percentile (Δdv)	98th Percentile (% SO_4)	98th Percentile (% NO_3)	98th Percentile (% PM_{10})	98th Percentile (% NO_2)
Upper Buffalo	0.258	0.052	0.34	91.78	4.82	3.05
Hercules-Glades	0.092	0.040	0.74	86.01	10.18	3.07
Mingo	0.132	0.058	0.33	91.96	5.13	2.58
McClellan Unit 1—Fuel Oil:						
Caney Creek	3.007	0.622	89.86	9.62	0.53	0.00
Upper Buffalo	1.323	0.266	98.47	0.95	0.58	0.00
Hercules-Glades	0.662	0.231	78.67	20.16	1.17	0.01
Mingo	0.547	0.228	80.90	17.89	1.20	0.01

a. *Proposed BART Analysis and Determination for SO_2.* AECC's BART evaluation examined BART controls for SO_2 for the AECC McClellan Unit 1. The source does not have existing SO_2 pollution control technology. AECC identified all available control technologies, eliminated options that are not technically feasible, and evaluated the control effectiveness of the remaining control options. Each technically feasible control option was then evaluated in terms of a five factor BART analysis.

The AECC evaluation considered both FGD and fuel switching as possible controls. AECC found that FGD applications have not been used historically for SO_2 control on fuel oil-fired units in the U.S. electric industry and therefore considered it a technically infeasible option for control of McClellan Unit 1. Accordingly, AECC did not further consider FGD for SO_2 BART. We concur with AECC's decision to focus the SO_2 BART evaluation on fuel switching. Switching to a fuel with a lower sulfur content is expected to reduce SO_2 emissions in proportion to the reduction in the sulfur content of the fuel, assuming the fuels have similar heat contents. McClellan Unit 1 burns primarily natural gas, but is also permitted to burn fuel oil. The baseline fuel AECC assumed in the BART analysis is No. 6 fuel oil with 1.38% sulfur content, based on the average sulfur content of the fuel oil from the most recent fuel oil shipment received by the facility in April 2009. A portion of the fuel oil from this shipment still remains in storage at the facility for future use. AECC evaluated switching to the fuel types shown in the table below.

TABLE 16—CONTROL EFFECTIVENESS OF FUEL SWITCHING OPTIONS FOR AECC MCCLELLAN UNIT 1

Fuel switching options	Estimated SO_2 control efficiency (%)
No. 6 fuel oil, 1% sulfur	28
No. 6 fuel oil, 0.5% sulfur	64
Diesel, 0.05% sulfur	96
Natural gas	99.9

AECC estimated the average cost-effectiveness of switching to No. 6 fuel oil with 1% sulfur content to be $2,613 per ton of SO_2 removed for McClellan Unit 1. Switching from the baseline fuel to No. 6 fuel oil with 0.5% sulfur content was estimated to cost $3,823 per ton of SO_2 removed. The results of AECC's cost analysis are summarized in the table below. For the natural gas switching scenario, AECC found that the current cost of natural gas is actually lower than the cost of the baseline fuel. Therefore, the average cost-effectiveness of switching from the baseline fuel to natural gas is denoted as a negative value (cost savings) in the table below.

TABLE 17—AECC MCCLELLAN UNIT 1: SUMMARY OF COSTS ASSOCIATED WITH FUEL SWITCHING

Fuel switching scenario	Average sulfur content (%)	Baseline emission rate (SO_2 tpy)	Controlled emission rate (SO_2 tpy)	Annual emissions reductions (SO_2 tpy)	Annual fuel usage (Mgal/yr)	Fuel cost ($/MMBtu)	Total annual differential cost of fuel switching ($/yr)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)
Baseline	1.38	209.43			1,882.15	16.00			
No. 6 Fuel Oil—1%	1.00		153.61	55.81	1,882.15	16.50	145,866	2,613	
No. 6 Fuel Oil—0.5%	0.50		75.88	133.55	1,882.15	17.75	510,532	3,823	4,691
Diesel	0.05		7.31	202.11	2,142.73	20.95	1,444,077	7,145	13,616
Natural Gas	0.04		0.07	209.35	288.56	5.97	−2,926,874	−13,980	−603,723

The AECC BART evaluation did not identify any energy or non-air quality environmental impacts associated with switching to 1% sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, or diesel. The evaluation noted that switching to natural gas may have energy impacts during periods of natural gas curtailment. During periods of natural gas curtailment, natural gas infrastructure maintenance, and other emergencies, the McClellan Generating Station relies on the fuel oil stored at the plant to maintain electrical reliability. The AECC evaluation notes that because of this, it is important to maintain the ability to burn fuel oil at McClellan, even if fuel oil is currently more expensive to burn than natural gas.

With regard to consideration of the remaining useful life of Unit 1, this factor does not impact the SO_2 BART analysis because the emissions control approaches being evaluated for BART do not require capital cost expenditures. Thus, there are no control costs that need to be amortized over the lifetime of the unit.

AECC assessed the visibility improvement associated with fuel switching by comparing the 98th percentile modeled visibility impact of the baseline scenario (*i.e.,* existing) to the 98th percentile modeled visibility impact of each control scenario. The table below shows a comparison of the baseline visibility impacts and the visibility impacts of the different fuel switching control scenarios that were evaluated, including the cumulative visibility benefits.

TABLE 18—AECC MCCLELLAN UNIT 1: SUMMARY OF 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO FUEL SWITCHING

Class I area	Baseline visibility impact (Δdv)	No. 6 fuel oil—1% sulfur		No. 6 fuel oil—0.5% sulfur		Diesel		Natural gas	
		Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	0.622	0.537	0.085	0.322	0.3	0.174	0.448	0.125	0.497
Upper Buffalo	0.266	0.231	0.035	0.146	0.12	0.073	0.193	0.052	0.214
Hercules-Glades	0.231	0.202	0.029	0.115	0.116	0.062	0.169	0.040	0.191
Mingo	0.228	0.193	0.035	0.136	0.092	0.080	0.148	0.058	0.17
Cumulative Visibility Improvement (Δdv)			0.184		0.628		0.958		1.072

The table above shows that switching to No. 6 fuel oil with 1% sulfur content at McClellan Unit 1 is projected to result in visibility improvement of 0.085 dv at Caney Creek. The visibility improvement at each of the other three affected Class I areas is projected to be 0.035 dv or less, while the cumulative visibility improvement at the four Class I areas is projected to be 0.184 dv. Switching to No. 6 fuel oil with 0.5% sulfur content is projected to result in considerable visibility improvement. It is projected to result in 0.3 dv visibility improvement at Caney Creek. The visibility improvement at each of the other three affected Class I areas is projected to be 0.12 dv or less, while the cumulative visibility improvement at the four Class I areas is projected to be 0.628 dv. Switching to diesel or natural gas is also projected to result in considerable visibility improvement. The visibility improvement at Caney Creek is projected to be 0.448 dv for switching to diesel and 0.497 dv for switching to natural gas. The cumulative visibility improvement at the four Class I areas is projected to be 0.958 dv for switching to diesel and 1.072 dv for switching to natural gas.

Our Proposed SO_2 BART Determination: Taking into consideration the five factors, we are proposing to determine that BART for McClellan Unit 1 is switching to fuels with 0.5% or lower sulfur content by weight. The cost of switching to No. 6 fuel oil with 0.5% sulfur content is within the range of what we consider to be cost-effective for BART and it is projected to result in considerable visibility improvement compared to the baseline at the affected Class I areas. Switching to No. 6 fuel oil with 0.5% sulfur content has an estimated average cost-effectiveness of $3,823 per ton of SO_2 removed and is projected to result in visibility improvement ranging from 0.092 to 0.3 dv at each modeled Class I area, and a cumulative visibility improvement of 0.628 dv at the four affected Class I areas. Switching to natural gas currently would cost less than the baseline fuel and is projected to result in even greater visibility improvement than switching to No. 6 fuel oil with 0.5% sulfur content. However, the BART Guidelines provide that it is not our intent to direct subject-to-BART sources to switch fuel forms, such as from coal or fuel oil to gas (40 CFR part 51, Appendix Y, section IV.D.1). Because natural gas has a sulfur content by weight that is well below 0.5%, the facility may elect to use this type of fuel to comply with BART, but we are not proposing to require a switch to natural gas for Unit 1. Switching to diesel is projected to result in considerable visibility improvement. The visibility improvement of switching to diesel is projected to range from 0.148 to 0.448 dv at each modeled Class I area, and the cumulative visibility improvement is 0.958 dv at the four affected Class I areas. The incremental visibility improvement of switching to diesel compared to switching to No. 6 fuel oil with a sulfur content of 0.5% is projected to range from 0.056 dv to 0.148 dv at each affected Class I area. However, the average cost-effectiveness of switching to diesel is estimated to be $7,145 and the incremental cost-effectiveness compared to No. 6 fuel oil with a sulfur content of 0.5% is $13,616 per ton of SO_2 removed, which we do not consider to be cost-effective in view of the incremental visibility improvement. Since diesel also has a sulfur content by weight that is well below 0.5%, the facility may elect to use this fuel type to comply with BART, but we are not proposing to require a switch to diesel for Unit 1. We are proposing to determine that SO_2 BART for McClellan Unit 1 is switching to fuels with 0.5% or lower sulfur content by weight. We propose to require that the facility purchase no fuel after the effective date of the rule that does not meet the sulfur content requirement and that 5 years from the effective date of the rule no fuel be burned that does not meet the requirement. We propose that any higher sulfur fuel oil that remains from the facility's 2009 fuel oil shipment cannot be burned past this point. As discussed above, the unit's baseline fuel is No. 6 fuel oil with 1.38% sulfur content, based on the average sulfur content of the fuel oil from the most recent shipment received by the facility in 2009. Based on our discussions with the facility, it is our understanding that the unit burns fuel oil primarily during periods of natural gas curtailment and during periodic testing and that the facility still has stockpiles of fuel oil from the most recent fuel oil shipment. Because the unit burns primarily natural gas and does not ordinarily burn fuel oil on a frequent basis, we believe it is appropriate to allow the facility 5 years to burn its existing supply of No. 6 fuel oil, as the normal course of business dictates and in accordance with any operating restrictions enforced by ADEQ. We believe that a shorter compliance date may result in the facility burning its existing supply of higher sulfur No. 6 fuel oil relatively quickly, resulting in a high amount of SO_2 emissions being emitted by the unit over a short period of time. This is not the intent of our regional haze regulations. We are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with this proposed determination.

b. *Proposed BART Analysis and Determination for NO_X.* The AECC evaluation examined BART controls for NO_X for McClellan Unit 1. McClellan Unit 1 does not currently have pollution control equipment for NO_X. AECC identified all available control technologies, eliminated options that are not technically feasible, and evaluated the control effectiveness of the remaining control options. Each technically feasible control option was then evaluated in terms of a five factor BART analysis.

For NO_X BART, the AECC evaluation considered both combustion and post-combustion controls. The combustion controls evaluated by AECC consisted of FGR, OFA, and LNB. The post-combustion controls evaluated consisted of SCR and SNCR. AECC found that some boilers may be restricted from installing OFA retrofits due to physical size and space restraints. For purposes of the NO_X BART evaluation, AECC assumed OFA to be a technically feasible option for McClellan Unit 1, but noted that if OFA was determined to be BART based on the evaluation of the five BART factors, then further analyses would have to be performed to determine if: (1) The dimensions of McClellan's main boilers have sufficient upper furnace volume for OFA mixing and complete combustion and (2) the furnace meets the physical space requirements for OFA ports and air supply ducts. The remaining NO_X control options were found to be technically feasible.

AECC evaluated three control scenarios: A combination of combustion controls (FGR, OFA, and LNB); the combination of combustion controls and SNCR; and SCR. Based on literature estimates, AECC found that the estimated NO_X control range for oil and gas wall-fired boilers, such as McClellan Unit 1, is approximately 0.2–0.4 lb/MMBtu using FGR and 0.2–0.3 lb/MMBtu using OFA.[33] When LNB is combined with OFA and FGR, AECC estimated that a NO_X controlled emission rate of 0.15–0.20 lb/MMBtu can be achieved at McClellan Unit 1. The NO_X controlled emission rate of combustion controls combined with SNCR is estimated to be 0.10–0.12 lb/MMBtu. The NO_X control efficiency of SCR is estimated to be 80–90% for gas fired boilers and 70–80% for oil fired boilers, which corresponds to a controlled emission rate of 0.05–0.12 lb/MMBtu for McClellan Unit 1.

AECC's cost analysis for NO_X controls was based on ''budgetary'' cost estimates it obtained from the pollution control vendor, Babcock Power Systems. AECC estimated the capital and operating costs of controls based on the vendor's estimates, engineering estimates, and published calculation methods using the EPA Control Cost Manual. We are not aware of any enforceable shutdown date for the McClellan Generating Station, nor did AECC's evaluation indicate any future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of controls. Therefore, a 30-year amortization period was assumed in the NO_X BART analysis as the remaining useful life of Unit 1. The table below summarizes the estimated cost for installation and operation of NO_X controls for McClellan Unit 1.

TABLE 19—SUMMARY OF NO_X CONTROL COSTS FOR AECC MCCLELLAN UNIT 1

Control scenario	Baseline emission rate (NO_X tpy)	Natural gas controlled emission level (lb/MMBtu)	Fuel oil controlled emission level (lb/MMBtu)	Controlled emission rate (tpy)	Annual emissions reductions (NO_X tpy)	Total annual cost ($/yr)	Average cost effectiveness ($/ton)	Incremental cost ($/ton)
Combustion Controls	294.04	0.15	0.15	174.89	119.15	746,051	6,261	
Combustion Controls + SNCR	294.04	0.12	0.10	136.40	157.64	1,990,988	12,630	32,344
SCR	294.04	0.05	0.12	64.98	229.06	1,732,870	7,565	−3,614

AECC estimated the average cost-effectiveness of installing and operating combustion controls to be $6,261 per ton of NO_X removed. The combination of combustion controls and SNCR was estimated to cost $12,630 per ton of NO_X removed, while SCR was estimated to cost $7,565 per ton of NO_X removed. In its evaluation, AECC also explained that AECC expects the average cost-effectiveness of NO_X controls to be lower (*i.e.,* greater dollars per ton removed) in future years due to projected reduced operation of the unit.

AECC did not identify any energy or non-air quality environmental impacts associated with the use of LNB, OFA, or FGR. As for SCR and SNCR, we are not aware of any unusual circumstances at the facility that could create non-air quality environmental impacts associated with the operation of these controls greater than experienced elsewhere and that may therefore provide a basis for their elimination as BART (40 CFR part 51, Appendix Y, section IV.D.4.i.2.). Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with NO_X controls at AECC McClellan Unit 1 that would affect our proposed BART determination.

AECC assessed the visibility improvement associated with NO_X controls by modeling the NO_X emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rates to the visibility impairment associated with the controlled emission rates as measured by the 98th percentile modeled visibility impact. The tables below show a comparison of the baseline (*i.e.,* existing) visibility impacts and the visibility impacts associated with NO_X controls.

[33] ''Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options,'' section II, dated July 1994, State and Territorial Air Pollution Program Administrators (STAPPA) and Association of Local Air Pollution Control Officials (ALAPCO).

TABLE 20—AECC MCCLELLAN UNIT 1: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO NO_X CONTROLS—NATURAL GAS FIRING

[2001–2003]

Class I area	Baseline visibility impact (Δdv)	Combustion controls		Combustion controls + SNCR		SCR	
		Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	0.125	0.068	0.057	0.056	0.069	0.027	0.098
Upper Buffalo	0.052	0.028	0.024	0.023	0.029	0.012	0.04
Hercules-Glades	0.040	0.021	0.019	0.018	0.022	0.009	0.031
Mingo	0.058	0.031	0.027	0.026	0.032	0.012	0.046
Cumulative Visibility Improvement (Δdv)			0.127		0.152		0.215

TABLE 21—AECC MCCLELLAN UNIT 1: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO NO_X CONTROLS—FUEL OIL FIRING

[2001–2003]

Class I area	Baseline visibility impact (Δdv)	Combustion controls		Combustion controls + SNCR		SCR	
		Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	0.621	0.554	0.067	0.542	0.079	0.548	0.073
Upper Buffalo	0.266	0.264	0.002	0.264	0.002	0.264	0.002
Hercules-Glades	0.230	0.209	0.021	0.203	0.027	0.207	0.023
Mingo	0.227	0.203	0.024	0.200	0.027	0.201	0.026
Cumulative Visibility Improvement (Δdv)			0.114		0.135		0.124

The tables above show that the installation and operation of NO_X controls is projected to result in a very modest visibility improvement from the baseline. Combustion controls at McClellan Unit 1 are projected to result in visibility improvement of up to 0.057 dv at any single Class I area for the natural gas firing scenario and 0.067 dv for the fuel oil firing scenario. A combination of combustion controls and SNCR is projected to result in only slight incremental visibility improvement compared to combustion controls alone. For example, a combination of combustion controls and SNCR at McClellan Unit 1 is projected to result in visibility improvement of up to 0.069 dv at any single Class I area for natural gas firing and 0.079 dv for fuel oil firing, which is an incremental visibility improvement for each fuel firing scenario of 0.012 dv going from combustion controls to combustion controls in combination with SNCR. Similarly, the installation and operation of SCR is projected to result in only slight incremental visibility improvement compared to a combination of combustion controls and SNCR, except for the fuel oil firing scenario. For the fuel oil firing scenario, SCR is projected to result in slightly less than or equal visibility improvement than a combination of combustion controls and SNCR.

Our Proposed NO_X BART Determination: Taking into consideration the five factors, we are proposing to determine that NO_X BART for McClellan Unit 1 is no additional controls, and are proposing that the facility's existing NO_X emission limits satisfy BART for NO_X. We are proposing the existing emission limits of 869.1 lb/hr for natural gas firing and 705.8 lb/hr for fuel oil firing for NO_X BART for McClellan Unit 1.[34] As discussed above, the operation of combustion controls at McClellan Unit 1 is projected to result in a maximum visibility improvement of 0.067 dv (Caney Creek), and a smaller amount of visibility improvement at each of the other Class I areas. The installation and operation of combustion controls at McClellan Unit 1 has an average cost-effectiveness of $6,261 per ton of NO_X removed, which is not within the range of what we generally consider to be cost-effective. We believe the relatively small visibility benefit projected from the operation of combustion controls both when combusting fuel oil and natural gas does not justify the high estimated cost of those controls. The operation of a combination of combustion controls and SNCR is estimated to cost $12,630 per ton of NO_X removed, which is not cost-effective. A combination of combustion controls and SNCR is projected to result in only slight incremental visibility benefit compared to combustion controls alone. The operation of SCR is estimated to cost $7,565 per ton of NO_X removed, which is not generally considered cost-effective, and is projected to result in only slight incremental visibility benefit compared to a combination of combustion controls and SNCR. We are proposing to find that NO_X BART for McClellan Unit 1 is no additional controls and are proposing that the existing NO_X emission limits of 869.1 lb/hr for natural gas firing and 705.8 lb/hr for fuel oil firing are BART for NO_X and that compliance be demonstrated using the unit's existing CEMS. We are proposing that these emissions limitations be complied with for BART purposes from the date of effectiveness of the finalized

[34] See ADEQ Operating Air Permit No. 0181–AOP–R5, Section IV, Specific Condition No. 1, 3, and 13.

action. We are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with these emission limits.

c. *Proposed BART Analysis and Determination for PM.* McClellan Unit 1 does not currently have pollution control equipment for PM. For PM BART, AECC's evaluation considered the following control technologies: Dry ESP, wet ESP, fabric filter, wet scrubber, cyclone (*i.e.,* mechanical collector), and fuel switching. Residual fuel, such as the baseline No. 6 fuel oil burned at McClellan Unit 1, has inherent ash that contributes to emissions of filterable PM. Reductions in filterable PM emissions are directly related to the sulfur content of the fuel.[35] Therefore, switching to No. 6 fuel oil with a lower sulfur content is expected to result in lower filterable PM emissions. The AECC evaluation considered switching to No. 6 fuel oil with 1% sulfur content by weight, No. 6 fuel oil with 0.5% sulfur content by weight, diesel, and natural gas. These are the same lower sulfur fuel types evaluated in the SO_2 BART analysis for the unit.

The AECC evaluation noted that the particulate matter from oil-fired boilers tends to be sticky and small, affecting the collection efficiency of dry ESPs and fabric filters. Dry ESPs operate by placing a charge on the particles through a series of electrodes, and then capturing the charged particles on collection plates, while fabric filters work by filtering the PM in the flue gas through filter bags. The collected particles are periodically removed from the filter bag through a pulse jet or reverse flow mechanism. Because of the sticky nature of particles from oil-fired boilers, dry ESPs and fabric filters are deemed technically infeasible for use at McClellan Unit 1. Wet ESPs, cyclones, wet scrubbers, and fuel switching were identified as technically feasible options for McClellan Unit 1. AECC noted that although cyclones and wet scrubbers are considered technically feasible for use at these boiler types, they are not very efficient at controlling particles in the smaller size fraction, particularly particles smaller than a few microns. However, the majority of the PM emissions from McClellan Unit 1 are greater than a few microns in size.

AECC estimated that switching to a lower sulfur fuel has a PM control efficiency ranging from approximately 44%–99%, depending on the fuel type. The other technically feasible control technologies are estimated to have the following PM control efficiency: Wet ESP—up to 90%, cyclone—85%, and wet scrubber—55%.

AECC evaluated the capital costs, operating costs, and average cost-effectiveness of wet ESPs, cyclones, and wet scrubbers. AECC also evaluated the average cost-effectiveness of switching to No. 6 fuel oil with 1% sulfur content, No. 6 fuel oil with 0.5% sulfur content, diesel, and natural gas. AECC developed the capital and operating costs of a wet ESP and wet scrubber using the Electric Power Research Institute's (EPRI) Integrated Emissions Control Cost Estimating Workbook (IECCOST) Software. The capital costs of controls (except for fuel switching) were annualized over a 15-year period and then added to the annual operating costs to obtain the total annualized costs. The table below summarizes the average cost-effectiveness of PM controls. The average cost-effectiveness was determined by dividing the annualized cost of controls by the annual PM emissions reductions. The annual emissions reductions were determined by subtracting the estimated controlled annual emission rates from the baseline annual emission rates. AECC estimated the baseline and controlled annual emission rates by conducting a mass balance on the sulfur content of the various fuels evaluated.

We disagree with two aspects of AECC's cost evaluation for PM controls for McClellan Unit 1. First, the total annual cost numbers associated with fuel switching should be the same as those used in the SO_2 BART cost analysis (see Table 17). In earlier draft versions of AECC's analysis, which were provided to us for review, the cost numbers for fuel switching used in the PM and SO_2 BART analyses were identical. In response to comments provided by us, the total annual cost and average cost-effectiveness numbers for fuel switching were revised in the final version of AECC's SO_2 BART analysis. However, it appears that AECC overlooked updating these cost numbers in the final PM BART analysis.[36] In the table below, we have revised the total annual cost of fuel switching for the PM BART analysis to be consistent with the cost estimates from AECC's SO_2 BART analysis, and we have also updated the PM average cost-effectiveness values. The second aspect of AECC's cost evaluation for PM controls that we disagree with is the use of a 15-year capital cost recovery period for calculating the average cost-effectiveness of a wet ESP, wet scrubber, and cyclone. As previously discussed, we are not aware of any enforceable shutdown date for the AECC McClellan Generating Station, nor did AECC's BART evaluation indicate any future planned shutdown. Therefore, we believe that assuming a 30-year equipment life rather than a 15-year equipment life would be more appropriate for these control technologies. Extending the amortization period from 15 to 30 years has the effect of decreasing the total annual cost of each control option, thereby improving the average cost-effectiveness of controls (*i.e.,* less dollars per ton removed). However, after considering all five BART factors, we do not believe AECC's assumption of a 15-year amortization period has an impact on our proposed BART decision and therefore we did not revise the amortization period or the average cost-effectiveness calculations for the PM control equipment options. This is discussed in more detail below. The table below summarizes the estimated cost for fuel switching and the installation and operation of PM control equipment for McClellan Unit 1.

TABLE 22—SUMMARY OF COST OF PM CONTROLS FOR AECC MCCLELLAN UNIT 1

Control scenario	Baseline emission rate (PM tpy)	Control efficiency (%)	Controlled emission rate (PM tpy)	Annual emissions reduction (PM tpy)	Capital cost ($)	Total annual cost ($/yr)	Average PM cost effectiveness ($/ton)	Incremental cost effectiveness (S/ton)
No. 6 Fuel oil—1% S	136.08	43.6	76.70	59.38		145,866	2,456	
Wet Scrubber	136.08	55.0	61.23	74.84	146,303,011	52,056,542	695,549	3,357,741
No. 6 Fuel oil—0.5% S	136.08	82.4	23.94	112.14		510,532	4,553	−1,381,931
Cyclone	136.08	85.0	20.41	115.67	1,432,971	1,721,384	14,882	343,018
Wet ESP	136.08	90.0	13.61	122.47	151,509,333	32,605,907	266,237	4,541,842

[35] See ''AP–42, Compilation of Air Pollutant Emission Factors,'' section 1.3.3.1, and Table 1.3–1, available at *http://www.epa.gov/ttnchie1/ap42/*.

[36] The final version of AECC's BART analysis for SO_2 and PM, upon which our analysis is largely based, is titled ''BART Five Factor Analysis Arkansas Electric Cooperative Corporation Bailey and McClellan Generating Stations, March 2014, Version 4.'' A copy of AECC's analysis can be found in the docket for our proposed rulemaking.

TABLE 22—SUMMARY OF COST OF PM CONTROLS FOR AECC MCCLELLAN UNIT 1—Continued

Control scenario	Baseline emission rate (PM tpy)	Control efficiency (%)	Controlled emission rate (PM tpy)	Annual emissions reduction (PM tpy)	Capital cost ($)	Total annual cost ($/yr)	Average PM cost effectiveness ($/ton)	Incremental cost effectiveness (S/ton)
Natural Gas	136.08	99.0	1.36	134.72		−2,926,874	−21,725	−2,900,635
Diesel	136.08	99.2	1.10	134.98		1,444,077	10,698	16,811,350

The table above shows that the average cost-effectiveness values of all add-on PM control technology options evaluated for McClellan Unit 1 ranged in cost-effectiveness from approximately $15,000 to $700,000 per ton of PM removed, based on AECC's cost estimates. The incremental cost-effectiveness of add-on PM control technology options ranged from $343,018 to $16,811,350 per ton of PM removed. Switching to No. 6 fuel oil with either a 1% or 0.5% sulfur content was found to be within the range of what we generally consider cost-effective for BART. Switching to No. 6 fuel oil with 1% sulfur content is estimated to cost $2,456 per ton of PM removed, while switching to No. 6 fuel oil with 0.5% sulfur content is estimated to cost $4,553 per ton of PM removed at McClellan Unit 1. As discussed in the SO_2 BART analysis, the current cost of natural gas is actually lower than the cost of the baseline fuel. Therefore, the average cost-effectiveness of switching from the baseline fuel to natural gas is denoted as a negative value in the table above. As discussed above, AECC also explained that it expects the average cost-effectiveness of PM control equipment to be lower (*i.e.,* greater dollars per ton removed) in future years due to projected reduced operation of the units due to a change in the management of the load control area the facilities are located in. Less projected operating time is expected to result in lower annual emissions, which in turn would result in decreased average cost-effectiveness for the add-on PM control technology options.

AECC did not identify any energy or non-air quality environmental impacts associated with fuel switching, but did identify impacts associated with the use of wet ESPs and wet scrubbers due to their electricity usage. Energy use in and of itself does not disqualify a technology (40 CFR part 51, Appendix Y, section IV.D.4.h.1.). In addition, the cost of the electricity needed to operate this equipment has already been factored into the cost of controls. AECC also noted that both wet ESPs and wet scrubbers generate wastewater streams that must either be treated on-site or sent to a waste water treatment plant, and the wastewater treatment process will generate a filter cake that would likely require landfilling. The BART Guidelines provide that 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 (40 CFR part 51, Appendix Y, section IV.D.4.i.2.). We are not aware of any unusual circumstances at the AECC McClellan Generating Station that could potentially create greater problems than experienced elsewhere related to the treatment of wastewater and any necessary landfilling, nor did the AECC BART evaluation discuss or mention any such unusual circumstances. Therefore, the need to treat wastewater or landfill any filter cake or other waste in and of itself does not provide a basis for disqualification or elimination of a wet ESP or wet scrubber.

As previously discussed, we are not aware of any enforceable shutdown date for the AECC McClellan Generating Station, nor did the AECC evaluation indicate any future planned shutdown. Therefore, we believe it is appropriate to assume a 30-year amortization period in the PM BART analysis as the remaining useful life of the unit. Assuming a 30-year amortization period, these controls would have a lower estimated total annual cost and would therefore have an improved cost-effectiveness (*i.e.,* less dollars per ton removed) compared to what was estimated in AECC's evaluation. However, we did not adjust the amortization period because we do not believe this has an impact on our proposed BART decision. As discussed in the subsection below, the visibility benefit expected from the installation and operation of PM control equipment is too small to justify the cost of these controls. Therefore, we did not revise the amortization period and the average cost-effectiveness calculations for the PM control equipment options.

As switching to lower sulfur fuels has impacts on both SO_2 and PM emissions, AECC's assessment of the visibility improvement associated with fuel switching is addressed in the SO_2 BART analysis for McClellan Unit 1. Table 18 summarizes the visibility improvement associated with controlled emission rates for SO_2 and PM as a result of fuel switching. AECC assessed the visibility improvement associated with wet ESPs, wet scrubbers, and cyclones by modeling the PM emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rates to the visibility impairment associated with the controlled emission rates as measured by the 98th percentile modeled visibility impact. The controlled PM_{10} emission rates associated with wet ESPs, wet scrubbers, and cyclones were calculated by reducing the uncontrolled annual PM_{10} emission rates by the pollutant removal efficiency of each control technology. The SO_2 and NO_X emission rates modeled in the controlled scenarios are the same as those from the baseline scenario, as it is assumed that SO_2 and NO_X emissions would remain unchanged. The table below shows a comparison of the baseline (*i.e.,* existing) visibility impacts and the visibility impacts associated with PM controls.

TABLE 23—AECC MCCLELLAN UNIT 1: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT FROM PM CONTROLS

Class I area	Baseline visibility impact (Δdv)	Wet ESP		Wet scrubber		Cyclone	
		Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	0.621	0.617	0.004	0.619	0.002	0.619	0.002
Upper Buffalo	0.266	0.263	0.003	0.264	0.002	0.265	0.001
Hercules-Glades	0.230	0.227	0.003	0.228	0.002	0.229	0.001
Mingo	0.227	0.223	0.004	0.224	0.003	0.225	0.002
Cumulative Visibility Improvement (Δdv)	....	....	0.014	....	0.009	....	0.006

The table above shows that the operation of a wet ESP, wet scrubber, and cyclone at McClellan Unit 1 is projected to result in minimal visibility improvement at the four affected Class I areas. The modeled visibility improvement from switching to No. 6 fuel oil with 1% sulfur content; No. 6 fuel oil with 0.5% sulfur content; diesel; and natural gas are summarized in Table 18. The modeled visibility improvement shown in Table 18 reflects both SO_2 and PM emissions reductions as a result of switching to fuels with lower sulfur content. However, the majority of the baseline visibility impact at each Class I area when burning the baseline fuel oil is due to SO_2 emissions, while PM_{10} emissions contribute only a small portion of the baseline visibility impacts at each Class I area (see Table 15). Accordingly, the majority of the visibility improvement associated with switching to lower sulfur fuels can reasonably be expected to be the result of a reduction in SO_2 emissions.

Our Proposed PM BART Determination: Taking into consideration the five factors, we propose to determine that PM BART for AECC McClellan Unit 1 does not require add-on controls. Consistent with our proposed determination for SO_2 BART, we are proposing that PM BART is satisfied by Unit 1 switching to fuels with 0.5% or lower sulfur content by weight. As discussed above, we disagree with AECC's use of a 15-year amortization period in the cost analysis for a wet ESP, wet scrubber, and cyclone. Assuming a 30-year amortization period, these controls would have a lower estimated total annual cost and would therefore have an improved cost-effectiveness (*i.e.,* less dollars per ton removed) compared to what was estimated in AECC's evaluation. However, after considering all five BART factors, even if we revised AECC's cost estimates to reflect a 30-year amortization period, resulting in a lower total annual cost and improved cost-effectiveness, we would still not be able to justify the cost in light of the minimal visibility benefit of these controls (see the table above).

We are proposing to determine that PM BART for McClellan Unit 1 is switching to fuels with 0.5% or lower sulfur content by weight. We propose to require that the facility purchase no fuel after the effective date of the rule that does not meet the sulfur content requirement and that 5 years from the effective date of the rule no fuel be burned that does not meet the requirement. We propose that any higher sulfur fuel oil that remains from the facility's 2009 fuel oil shipment cannot be burned past this point. As discussed above, the unit's baseline fuel is No. 6 fuel oil with 1.38% sulfur content, based on the average sulfur content of the fuel oil from the most recent shipment received by the facility in 2009. Based on our discussions with the facility, it is our understanding that the unit burns fuel oil primarily during periods of natural gas curtailment and during periodic testing and that the facility still has stockpiles of fuel oil from the most recent fuel oil shipment. Because the unit burns primarily natural gas and does not ordinarily burn fuel oil on a frequent basis, we believe it is appropriate to allow the facility 5 years to burn its existing supply of No. 6 fuel oil, as the normal course of business dictates and in accordance with any operating restrictions enforced by ADEQ. We believe that a shorter compliance date may result in the facility burning its existing supply of higher sulfur No. 6 fuel oil relatively quickly, resulting in a high amount of SO_2 emissions being emitted by the unit over a short period of time. This is not the intent of our regional haze regulations. We are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with this proposed determination.

3. AEP Flint Creek Power Plant

The AEP Flint Creek Power Plant Unit 1 is subject to BART. We previously disapproved Arkansas' BART determination for SO_2 and NO_X for Flint Creek Unit 1 in our March 12, 2012 final action (77 FR 14604). Flint Creek Unit 1 is a dry bottom wall-fired boiler with a nominal generating capacity rating of 558 MW and a nominal design maximum heat input rate of 6,324 MMBtu/hr. The unit burns primarily low-sulfur western coal and is currently equipped with an ESP and low NO_X burners. AEP hired a consultant to prepare a BART five-factor analysis for the AEP Flint Creek Unit 1 (AEP BART analysis).[37]

The table below summarizes the baseline emission rates for this source. The SO_2 and NO_X baseline emission rates are the highest actual 24-hour emission rates based on 2001–2003 CEMS data. The emission rates for the PM_{10} species reflect the breakdown of the filterable and condensable PM_{10} determined from the National Park Service (NPS) ''speciation spreadsheet'' for *Dry Bottom Boiler Burning Pulverized Coal using only ESP.*[38] The sulfate (SO_4) emission rate was calculated using an EPRI methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction

[37] See ''BART Five Factor Analysis Flint Creek Power Plant Gentry, Arkansas (AFIN 04–00107),'' dated September 2013, Version 4, prepared by Trinity Consultants Inc. in conjunction with American Electric Power Service Corporation for the Southwestern Electric Power Company Flint Creek Power Plant. A copy of this BART analysis is found in the docket for our proposed rulemaking.

[38] The NPS Workbook, ''PC Dry Bottom ESP Example.xls'' updated 03/2006, was obtained from the NPS Web site: *http://www.nature.nps.gov/air/Permits/ect/index.cfm.* Trinity input the following parameters into the workbook for speciation determination: total PM_{10} emission rate of 192.5 lb/hr, heat value of 8,500 Btu/lb, sulfur content of 0.31%, ash content of 4.9%.

factors for various downstream equipment.[39]

TABLE 24—AEP FLINT CREEK UNIT 1: BASELINE MAXIMUM 24-HOUR EMISSION RATES

Source	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PMc (lb/hr)	PMf (lb/hr)	SOA (lb/hr)	EC (lb/hr)
Unit 1 (SN–01)	4,728.4	3.1	1,945.0	65.1	50.1	15.1	1.9

AEP modeled the baseline emission rates using the CALPUFF dispersion model to determine the baseline visibility impairment attributable to Flint Creek Unit 1 at the four Class I areas impacted by emissions from BART sources in Arkansas. These Class I areas are the Caney Creek Wilderness Area, Upper Buffalo Wilderness Area, Hercules-Glades Wilderness Area, and Mingo National Wildlife Refuge. The baseline (*i.e.,* 2001–2003) visibility impairment attributable to the source at each Class I area is summarized in the table below.

TABLE 25—BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO AEP FLINT CREEK UNIT 1

[2001–2003]

Unit	Caney Creek	Upper Buffalo	Hercules-Glades	Mingo
AEP Flint Creek Unit 1:				
Maximum (Δdv)	1.318	2.426	2.103	1.488
98th Percentile (Δdv)	0.963	0.965	0.657	0.631

a. *Proposed BART Analysis and Determination for SO_2.* AEP identified all available control technologies, eliminated options that are not technically feasible, and evaluated the control effectiveness of the remaining control options. Each technically feasible control option was then evaluated in terms of a five factor BART analysis.

The AEP evaluation considered Dry Sorbent Injection (DSI), dry FGD (*i.e.,* dry scrubber), and wet FGD (*i.e.,* wet scrubber) for SO_2 BART. All three options were identified as technically feasible for use at Flint Creek Unit 1. The AEP evaluation noted that depending on residence time, gas stream temperature, and limitations of the particulate control device, DSI control efficiency can range between 40 to 60%.[40] Dry FGD control efficiency generally ranges from 60 to 95%. There are various designs of dry FGD systems, including Spray Dryer Absorber (SDA), Circulating Dry Scrubbing (CDS), and Novel Integrated Desulfurization (NID) technology. According to AEP's evaluation, discussions with vendors indicated that an outlet emission rate of 0.06 lb/MMBtu at Flint Creek Unit 1 would be achievable with NID technology. AEP noted that it has no data to suggest that lower emission levels are sustainably achievable with the NID technology in a retrofit application, and that equipment vendors did not guarantee better performance than this. An emission rate of 0.06 lb/MMBtu represents 92% control from the unit's baseline 30-day average rate of 0.75 lb/MMBtu. AEP's analysis notes that dry FGD using lime as the reagent is capable of achieving 80 to 95% control when used with lower sulfur coals such as those burned at Flint Creek Unit 1. The remainder of AEP's analysis focused on wet FGD and dry FGD (NID). We concur with AEP's decision to focus the remainder of the analysis on the two control options with the highest control efficiency.

The estimated capital and operating costs of wet FGD and dry FGD (NID) developed by AEP and used in the cost-effectiveness calculations were based on EPA's Control Cost Manual and supplemented, where available, with vendor and site-specific information obtained by AEP. AEP annualized the capital cost of controls over a 30-year amortization period and then added these to the annual operating costs to obtain the total annualized costs. The average cost-effectiveness was calculated by dividing the total annualized cost of controls by the annual SO_2 emissions reductions. AEP estimated the average cost-effectiveness of a wet FGD system to be $4,919 per ton of SO_2 removed, while the average cost-effectiveness of NID was estimated to be $3,845 per ton of SO_2 removed (see table below).

We disagree with one aspect of AEP's cost analysis.[41] AEP's cost estimates are based on 2016 dollars, which means that they were escalated to a future build date. BART cost analyses should be based on present dollars, and the EPA Control Cost Manual approach explicitly excludes future escalation, as cost comparisons should be made on a current real dollar basis. Escalation of costs from past to the current year of analysis is permitted, as costs are compared based on the time of estimate, but future escalation is not allowed. We expect that de-escalation to 2014 dollars would result in lower cost numbers and overall lower average cost-effectiveness values for all controls evaluated. We believe that wet FGD and NID are both more cost-effective (*i.e.,* less dollars per SO_2 ton removed) than what has been estimated by AEP. However, we did not adjust the cost numbers and the cost-effectiveness values because we do not expect this to change our proposed BART decision. This is discussed in more detail below in the subsection titled ''Our Proposed SO_2 BART Determination.''

[39] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: Version 2010a. EPRI, Palo Alto, CA: 2010.

[40] ''Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities'' Northeast States for Coordinated Air Use Management (NESCAUM), March 2005.

[41] See ''BART Five Factor Analysis Flint Creek Power Plant Gentry, Arkansas (AFIN 04–00107),'' dated September 2013, Version 4, prepared by Trinity Consultants Inc. in conjunction with American Electric Power Service Corporation for the Southwestern Electric Power Company Flint Creek Power Plant. AEP's SO_2 control cost calculations are found in Appendix A of the BART analysis. An Excel file titled ''Consolidated Spreadsheet_2013–09–09'' containing spreadsheets with cost information was also provided by AEP Flint Creek in support of the cost analysis. A copy of the BART analysis and the Excel file is found in the docket for our proposed rulemaking.

TABLE 26—SUMMARY OF COST OF SO_2 CONTROLS FOR AEP FLINT CREEK UNIT 1

Control technology	Baseline emission rate (SO_2 tpy)	Controlled emission rate (SO_2 lb/MMBtu)	Controlled emission rate (SO_2 tpy)	Annual emissions reductions (SO_2 tpy)	Capital cost ($)	Total annual cost ($/yr)	Average cost effectiveness ($/ton)	Incremental cost-effectiveness ($/ton)
NID	11,641	0.06	1,120	10,521	281,738,024	40,448,089	3,845	
Wet Scrubber	11,641	0.04	747	10,894	374,427,351	53,592,663	4,919	35,240

AEP's evaluation noted that the potential negative energy and non-air quality environmental impacts are greater with wet FGD systems than dry FGD systems. AEP noted that wet FGD requires increased water use and generates large volumes of wastewater and solid waste/sludge that must be treated or stabilized before landfilling, placing additional burden on the wastewater treatment and solid waste management capabilities. We do not expect that water availability would affect the feasibility of wet FGD at Flint Creek Unit 1 because the facility is not located in an exceptionally arid region. Additionally, the BART Guidelines provide that 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 (40 CFR part 51, Appendix Y, section IV.D.4.i.2.). In cases where the facility can demonstrate that there are unusual circumstances that would create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control option as BART. But in this case, AEP has not indicated that there are any such unusual circumstances. Another potential negative energy and non-air quality environmental impact associated with wet FGD is the potential for increased power requirements and greater reagent usage compared to dry FGD. The costs associated with increased power requirements and greater reagent usage have already been factored into the cost analysis for wet FGD.

AEP assessed the visibility improvement associated with wet FGD and NID technology by modeling the SO_2 emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rates to the visibility impairment associated with the controlled emission rates as measured by the 98th percentile modeled visibility impact. The table below compares the baseline (*i.e.,* existing) visibility impacts with the visibility impacts associated with SO_2 controls.

TABLE 27—AEP FLINT CREEK UNIT 1: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO SO_2 CONTROLS

Class I area	Baseline visibility impact (Δdv)	NID Technology		Wet scrubber	
		Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	0.963	0.348	0.615	0.334	0.629
Upper Buffalo	0.965	0.501	0.464	0.488	0.477
Hercules-Glades	0.657	0.312	0.345	0.305	0.352
Mingo	0.631	0.217	0.414	0.208	0.423
Cumulative Visibility Improvement (Δdv)			1.838		1.881

The table above shows that the installation and operation of SO_2 controls is projected to result in considerable visibility improvement from the baseline at the four impacted Class I areas. Installation and operation of NID technology is projected to result in visibility improvement of up to 0.615 dv at any single Class I area (based on the 98th percentile modeled visibility impacts), while wet FGD is projected to result in visibility improvement of up to 0.629 dv. Wet FGD is projected to result in very minimal incremental visibility benefit over NID technology, with the projected incremental visibility improvement over NID ranging from 0.007 to 0.014 dv at each Class I area.

Our Proposed SO_2 BART Determination: Taking into consideration the five factors, we propose to determine that BART for AEP Flint Creek Unit 1 is an emission limit of 0.06 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of NID. The operation of NID is projected to result in visibility improvement ranging from 0.352 to 0.629 dv at each affected Class I area (98th percentile basis), and based on AEP's evaluation, is estimated to have an average cost-effectiveness of $3,845 per ton of SO_2 removed. By comparison, AEP estimated wet FGD to have an average cost-effectiveness of $4,919 per ton of SO_2 removed and the incremental cost-effectiveness of wet FGD compared to NID is estimated to be $35,240 per ton of SO_2 removed. As discussed above, we believe that AEP's escalation of the cost of controls to 2016 dollars has likely resulted in the over-estimation of the average cost-effectiveness. Therefore, we believe wet FGD and NID are both more cost-effective (*i.e.,* less dollars per ton of SO_2 removed) than estimated by AEP (see table above). However, we did not adjust the cost numbers and cost-effectiveness calculations because we do not believe that doing so would change our proposed BART determination. We believe that the average cost-effectiveness of both control options was likely over-estimated and the costs associated with wet FGD would continue to be higher than the costs associated with NID if the estimates were adjusted, yet the installation and operation of wet FGD is projected to result in minimal incremental visibility improvement over NID. We are proposing to determine that SO_2 BART for Flint Creek Unit 1 is an emission limit of 0.06 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of NID. We believe that the full compliance time [42] of 5 years is warranted for a new scrubber retrofit and so propose to require compliance with this requirement no later than 5 years from the effective date of the final rule. We are proposing to require that compliance be demonstrated using the unit's existing CEMS. We are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with this emission limit.

b. *Proposed BART Analysis and Determination for NO_X.* AEP's BART evaluation examined BART controls for NO_X for Flint Creek Unit 1 by identifying all available control technologies, eliminating options that are not technically feasible, and evaluating the control effectiveness of the remaining control options. Each technically feasible control option was then evaluated in terms of a five factor BART analysis.

For NO_X BART, the AEP evaluation considered both combustion and post-combustion controls. The combustion controls considered by AEP consisted of FGR, OFA, and LNB. The post-combustion controls considered consisted of SCR and SNCR. All control options evaluated were found to be technically feasible. AEP estimated that FGR would be able to achieve a controlled emission rate of 0.23–0.29 lb/MMBtu at Unit 1, which is a less stringent emission rate than would be achieved with LNB/OFA. Therefore, FRG was not further considered in the BART evaluation, while LNB/OFA were further considered. AEP evaluated three control scenarios: (1) LNB with OFA (LNB/OFA); (2) the combination of LNB with OFA and SNCR (LNB/OFA + SNCR); and (3) SCR. The baseline NO_X emission rate assumed by AEP in the analysis is 0.31 lb/MMBtu. AEP estimated that the installation and operation of LNB/OFA at Flint Creek Unit 1 would achieve a NO_X control level of approximately 0.23 lb/MMBtu on a 30 boiler-operating-day averaging basis. It also estimated that LNB/OFA + SNCR would achieve a NO_X control level of approximately 0.20 lb/MMBtu, and that SCR would achieve a NO_X control level of approximately 0.07 lb/MMBtu, also on a 30 boiler-operating-day averaging basis.

AEP estimated the capital costs, operating costs, and average cost-effectiveness of controls based on vendor estimates and published calculation methods. AEP noted that the EPA Control Cost Manual was followed to the extent possible and estimates were supplemented with vendor and site-specific information where available. The cost analysis assumed a 30-year amortization period for LNB/OFA and for SCR, and a 20-year amortization period for SNCR. We discuss the appropriateness of the choice of amortization periods below. The total annual costs were estimated by annualizing the capital cost of controls over either a 30-year or 20-year period and then adding to this value the annual operating cost of controls. AEP determined the annual tons reduced associated with each NO_X control option by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rate is the average rate as reported by AEP Flint Creek in the 2001–2003 air emission inventories. The average cost-effectiveness of NO_X controls was calculated by dividing the total annual cost of each control option by the estimated annual NO_X emissions reductions. The table below summarizes the average-cost effectiveness of NO_X controls for Flint Creek Unit 1.

TABLE 28—SUMMARY OF NO_X CONTROL COSTS FOR FLINT CREEK UNIT 1

Control technology	Baseline emission rate (NO_X tpy)	Controlled emission level (NO_X lb/MMBtu)	Controlled emission rate (NO_X tpy)	Annual emissions reductions (NO_X tpy)	Capital cost ($)	Total annual cost ($/yr)	Average cost effectiveness ($/ton)	Incremental cost-effectiveness ($/ton)
LNB/OFA	5,120	0.23	4,295	826	16,000,000	1,454,621	1,761	
LNB/OFA/SNCR	5,120	0.20	3,772	1,348	23,124,235	4,177,782	3,099	5,217
SCR	5,120	0.07	1,251	3,869	121,440,000	13,769,599	3,559	3,805

AEP estimated the average cost-effectiveness of installing and operating LNB/OFA to be $1,761 per ton of NO_X removed, while the combination of LNB/OFA + SNCR is estimated to cost $3,099 per ton of NO_X removed, and SCR is estimated to cost $3,559 per ton of NO_X removed.

AEP did not identify any energy or non-air quality environmental impacts associated with the use of LNB/OFA. As for SCR and SNCR, we are not aware of any unusual circumstances at the facility that could create non-air quality environmental impacts associated with the operation of these controls greater than experienced elsewhere and that may therefore provide a basis for their elimination as BART (40 CFR part 51, Appendix Y, section IV.D.4.i.2.). Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with the operation of NO_X controls at AEP Flint Creek Unit 1 that would affect our proposed BART determination.

Flint Creek Unit 1 is currently equipped with early generation low NO_X burners for control of NO_X emissions. Consideration of the presence of existing pollution control technology at each source is reflected in the BART analysis in two ways: First, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. The baseline emission rate used in the cost calculations and visibility modeling reflects the operation of these controls. The newer generation low NO_X burners evaluated by AEP are expected to achieve a higher level of NO_X control than the currently installed early generation low NO_X burners.

We are not aware of any enforceable shutdown date for the AEP Flint Creek Power Plant, nor did AEP's evaluation indicate any future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of controls. AEP assumed a 30-year amortization period in the evaluation of LNB, OFA, and SCR as the remaining useful life of the unit, and a 20-year amortization period in the evaluation of SNCR. We disagree with AEP's assumption of a 20-year amortization period in the cost analysis of SNCR. Any air pollution controls on the unit are expected to have the same

[42] Section 51.308(e)(1)(iv), requires, ''each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.''

life as the boiler. Therefore, we believe it is appropriate to assume a 30-year amortization period for SNCR, as was done for SCR and combustion controls. Assuming a 30-year amortization period, SNCR would have a lower estimated total annual cost and would therefore have an improved cost-effectiveness (*i.e.,* less dollars per ton removed) compared to what was estimated in AEP's evaluation. However, we did not adjust the amortization period assumed in AEP's evaluation because we do not believe this has an impact on our proposed BART decision. As discussed in the subsection below, the incremental visibility benefit expected from the installation and operation of SNCR is too small to justify the cost of this control compared to combustion controls alone. Therefore, we did not revise the amortization period and the average cost-effectiveness calculations for SNCR.

AEP assessed the visibility improvement associated with NO_X controls by modeling the NO_X emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rate to the visibility impairment associated with the controlled emission rates as measured by the 98th percentile modeled visibility impact. The table below shows a comparison of the baseline (*i.e.,* existing) visibility impacts and the visibility impacts associated with NO_X controls.

TABLE 29—AEP FLINT CREEK UNIT 1: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO NO_X CONTROLS

Class I area	Baseline visibility impact (Δdv)	LNB/OFA		LNB/OFA + SNCR		SCR	
		Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility Improvement from Baseline (Δdv)	Visibility Impact (Δdv)	Visibility Improvement from Baseline (Δdv)
Caney Creek	0.963	0.882*	0.081*	0.849	0.114	0.718	0.245
Upper Buffalo	0.965	0.939	0.026	0.932	0.033	0.895	0.07
Hercules-Glades	0.657	0.633	0.024	0.623	0.034	0.573	0.084
Mingo	0.631	0.617	0.014	0.612	0.019	0.588	0.043
Cumulative Visibility Improvement (Δdv)	....	....	0.145	....	0.2	....	0.442

* EPA identified a discrepancy in the results presented by AEP and reran the model for the 2003 model year. These values have been adjusted to reflect the results of the EPA model run.

As shown in the table above, the installation and operation of LNB/OFA is projected to result in visibility improvement of up to 0.081 dv at any single Class I area, based on the 98th percentile visibility impairment. The installation and operation of LNB/OFA + SNCR is projected to result in visibility improvement of up to 0.114 dv over the baseline. The installation and operation of SCR is projected to result in visibility improvement of up to 0.245 dv in any single Class I area. The combination of LNB/OFA + SNCR would result in slight incremental visibility benefit over LNB/OFA at Caney Creek and in negligible incremental visibility benefit at the other three affected Class I areas. SCR would result in 0.131 dv incremental visibility benefit over LNB/OFA + SNCR at Caney Creek and less than half as much incremental visibility benefit at the other three affected Class I areas.

Our Proposed NO_X BART Determination: Taking into consideration the five factors, we propose to determine that NO_X BART for Flint Creek Unit 1 is an emission limit of 0.23 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of new LNB/OFA. The operation of new LNB/OFA is projected to result in visibility improvement ranging from 0.014 to 0.081 dv at each affected Class I area (98th percentile basis) and is projected to have a cumulative visibility improvement of 0.145 dv across the four affected Class I areas. The operation of LNB/OFA is estimated to have an average cost-effectiveness of $1,761 per ton of NO_X removed, which we consider to be very cost-effective. By comparison, the operation of LNB/OFA + SNCR is projected to result in small incremental visibility improvement over LNB/OFA, but is estimated to have an average cost-effectiveness of $3,099 per ton of NO_X removed and an incremental cost-effectiveness of $5,217 per ton of NO_X removed. We believe that AEP's assumption of a 20-year amortization period for SNCR has likely resulted in lower cost-effectiveness for SNCR. Therefore, we believe LNB/OFA + SNCR is more cost-effective (*i.e.,* less dollars per ton of NO_X removed) than estimated by AEP (see table above). However, we did not adjust the cost numbers and cost-effectiveness values because we do not believe that doing so would change our proposed BART determination, as the installation and operation of LNB/OFA + SNCR is projected to result in minimal incremental visibility improvement over LNB/OFA alone such that the additional cost of SNCR is not justified.

The operation of SCR is projected to result in visibility improvement ranging from 0.043 to 0.245 dv at each Class I area, and has an average cost-effectiveness of $3,559 per ton of NO_X removed. The incremental visibility benefit of SCR compared to LNB/OFA + SNCR is projected to be 0.131 dv at Caney Creek and is projected to range from 0.024 to 0.05 dv at the remaining Class I areas. The incremental cost-effectiveness of SCR is estimated to be $3,805 per ton of NO_X removed. Although we are not adjusting the cost estimate for the reason discussed above, we note that AEP's assumption of a 20-year amortization period for SNCR has the effect of making the average cost-effectiveness of SCNR appear lower (*i.e.,* greater dollars per ton removed), while the incremental cost-effectiveness of SCR over LNB/OFA + SNCR appears to be higher (*i.e.,* less dollars per ton removed) than it actually is. Therefore, an adjustment of the amortization period and average cost effectiveness for SNCR is expected to result in an incremental cost effectiveness for SCR that is less favorable than currently estimated. While we believe the average and incremental cost-effectiveness of SCR, as calculated by AEP, is within the range of what we consider to be cost-effective, we do not believe the 0.131 dv incremental visibility benefit of SCR over LNB/OFA + SCNR at a single Class I area warrants the higher costs associated with SCR. We are proposing to determine that NO_X BART for Flint

Creek Unit 1 is an emission limit of 0.23 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of new LNB/OFA. We are proposing to require that compliance be demonstrated using the unit's existing CEMS. We consider 3 years to be an adequate time for the installation of NO_X combustion controls and thus propose to require compliance with this requirement no later than 3 years from the effective date of the final rule. We are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with this emission limit.

4. Entergy White Bluff Plant

The Entergy White Bluff Plant Unit 1, Unit 2, and the Auxiliary Boiler are subject to BART. As mentioned previously, we disapproved Arkansas' BART determinations for SO_2 and NO_X for Units 1 and 2 and the BART determination for all pollutants for the Auxiliary Boiler in our March 12, 2012 final action (77 FR 14604). White Bluff Units 1 and 2 are identical tangentially-fired boilers with a maximum net power rating of 850 MW each and a nominal heat input capacity of 8,950 MMBtu/hr each. The boilers burn sub-bituminous coal as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel. Units 1 and 2 are currently equipped with ESPs for control of PM emissions. The Auxiliary Boiler is a 183 MMBtu/hr auxiliary boiler that burns only No. 2 fuel oil or biodiesel, and its purpose is to provide steam for the start-up of the two primary boilers, Units 1 and 2. The Auxiliary Boiler is typically only used in the rare instance when both of the main boilers are not operating.

Entergy hired a consultant to conduct a BART five-factor analysis for White Bluff Units 1, 2, and the Auxiliary Boiler (Entergy BART analysis).[43] The table below summarizes the baseline emission rates Entergy assumed in the BART analysis for the subject to BART units. The SO_2 and NO_X baseline emission rates are the highest actual 24-hour emission rates based on data from the Clean Air Markets Division (CAMD) database from 2001–2003 for SO_2 and from 2009–2011 for NO_X. The 2001–2003 period was not used as the baseline for NO_X because that period no longer represents actual operation of the boilers. In 2006, Entergy completed the addition of a neural network system and conducted extensive boiler tuning that substantially reduced NO_X emissions, resulting in an actual change in operations and emissions between the original baseline period (2001–2003) and current operations. Neural network systems are online enhancements to digital control systems (DCS) and plant information systems that improve boiler performance parameters such as heat rate, NO_X emissions, and carbon monoxide (CO) levels. According to information provided by the facility, the purpose of the neural network system was to monitor and control the heat rate at Units 1 and 2.[44] The neural network system installed at Units 1 and 2 is optimized first for monitoring and controlling the heat rate, and second for minimizing NO_X emissions. We believe the use of 2009–2011 as the new baseline period for NO_X for Units 1 and 2 is consistent with the BART Guidelines, which provide that ''The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source.'' [45] The PM_{10} emission rates are based on emission factors from AP–42 for PM filterable and PM condensable with a 99% control efficiency for ESP applied to the PM_{10} filterable. The emission rates for the PM_{10} species reflect the breakdown of the PM_{10} determined from the National Park Service (NPS) ''speciation spreadsheet'' for Dry Bottom Boiler Burning Pulverized Coal using only ESP.[46] To estimate sulfuric acid emissions to model for the baseline and control cases, AEP assumed all inorganic PM was SO_4. We note that this methodology can overestimate the amount of sulfuric acid emitted from the facility and we recommend that sulfuric acid emissions from power plants be 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).[47] Rather than assuming that 100% of inorganic condensable PM is SO_4, the EPRI method estimates the amount of SO_2 that is oxidized to SO_3, assumes that 100% of SO_3 is converted to H_2SO_4, and then accounts for losses due to downstream equipment. The sulfuric acid emissions for the base and control scenarios may be slightly overestimated in AEP's modeling. However, in this specific situation, we do not anticipate that this difference would significantly impact the relative benefits of the SO_2 controls examined or impact our BART determination since the overall impacts and benefits of control are large.

TABLE 30—ENTERGY WHITE BLUFF: BASELINE MAXIMUM 24-HOUR EMISSION RATES

Subject to BART Unit	SO_2 (lb/hr)	NO_X (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PMc (lb/hr)	PMf (lb/hr)	SOA (lb/hr)	EC (lb/hr)
Unit 1 (SN–01)	7,763.5	3,001.4	118.6	36.8	40.4	31.1	9.2	1.2
Unit 2 (SN–02)	7,825.1	3,527.4	118.6	36.8	40.4	31.1	9.2	1.2
Auxiliary Boiler (SN–05)	5.8	31.7	2.8	0.9	0.5	1.2	0.2	0.1

Entergy modeled the baseline emission rates using the CALPUFF dispersion model to determine the baseline visibility impairment attributable to White Bluff Unit 1, Unit 2, and the Auxiliary Boiler at the four Class I areas impacted by emissions from BART sources in Arkansas. These Class I areas are the Caney Creek Wilderness Area, Upper Buffalo Wilderness Area, Hercules-Glades Wilderness Area, and Mingo National

[43] See ''Revised BART Five Factor Analysis White Bluff Steam Electric Station Redfield, Arkansas (AFIN 35–00110),'' dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc. We refer to this BART analysis as ''Entergy's BART analysis'' throughout this proposed rulemaking, and a copy of it is found in the docket for our proposed rulemaking.

[44] See the ''S&L NO_X Control Technology Study,'' which is found in Appendix E to the ''Revised BART Five Factor Analysis White Bluff Steam Electric Station Redfield, Arkansas (AFIN 35–00110),'' dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc. A copy of this BART analysis and its appendices is found in the docket for our proposed rulemaking.

[45] 40 CFR part 51, Appendix Y, section IV.D.4.c.

[46] The NPS Workbook, ''PC Dry Bottom ESP Example.xls'' updated 03/2006, was obtained from the NPS Web site: *http://www.nature.nps.gov/air/Permits/ect/index.cfm.* Trinity input the following parameters into the workbook for speciation determination: total PM_{10} emission rate of 118.6 lb/hr, heat value of 8,950 Btu/lb, sulfur content of 0.27%, ash content of 4.87%.

[47] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: Version 2010a. EPRI, Palo Alto, CA: 2010

Wildlife Refuge. The baseline (*i.e.,* existing) visibility impairment attributable to the source at each Class I area is summarized in the table below.

TABLE 31—BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO ENTERGY WHITE BLUFF

[2001–2003]

Unit	Caney Creek	Upper Buffalo	Hercules-Glades	Mingo
Unit 1 (SN–01).				
Maximum (Δdv)	4.194	2.339	2.230	1.569
98th Percentile (Δdv)	1.628	1.140	1.041	0.887
Unit 2 (SN–02).				
Maximum (Δdv)	4.437	2.385	2.263	1.701
98th Percentile (Δdv)	1.695	1.185	1.060	0.903
Auxiliary Boiler (SN–05).				
Maximum (Δdv)	0.036	0.014	0.008	0.019
98th Percentile (Δdv)	0.01	0.004	0.004	0.008

a. *Proposed SO_2 BART Analysis and Determination for Units 1 and 2.* In its 2008 RH SIP Arkansas evaluated FGD controls (both wet and dry scrubbers) and determined that SO_2 BART for White Bluff Units 1 and 2 is the presumptive emission limit of 0.15 lb/MMBtu based on the installation of FGD controls. In our March 12, 2012 final action (77 FR 14604), we disapproved Arkansas' SO_2 BART determination because wet and dry FGD were evaluated at the presumptive emission limit only and not at the most stringent level of control these technologies are capable of achieving. In our October 17, 2011 proposed action we discussed that, considering the coal burned in this case, wet FGD is typically capable of achieving a controlled emission rate of 0.04 lb/MMBtu, while dry FGD is typically capable of achieving a controlled emission rate of 0.06 lb/MMBtu (76 FR 64186). We also discussed that operating these controls at the most stringent achievable controlled emission rate versus the presumptive emission limit was not expected to increase the capital cost of controls. Rather, it was expected that a more stringent level of control would increase the operation and maintenance costs as a result of increased reagent usage, among other things. However, we expected the increase in annualized cost to be offset by the increase in tons of SO_2 removed, causing the cost effectiveness ($/ton) to remain the same or slightly improve (*i.e.,* lower $/ton). The fact that wet and dry FGD were not evaluated at the most stringent level of control they are capable of achieving, even though installation and operation of these control technologies at that control level was still expected to be cost-effective was the primary reason for our March 12, 2012 disapproval of Arkansas' SO_2 BART determination for White Bluff Units 1 and 2. We note that the 2008 Arkansas RH SIP included FGD controls for White Bluff Units 1 and 2, and that Entergy submitted an application for a Title V permit modification for the White Bluff facility on February 4, 2009, for the installation of a dry FGD system (*i.e.,* dry scrubbers) to satisfy the SO_2 BART requirement.[48] However, Entergy suspended the project for the installation of these SO_2 controls after our final disapproval of SO_2 BART for Units 1 and 2.

The Entergy BART analysis[49] considered Dry Sorbent Injection (DSI), dry FGD (dry scrubbers), and wet FGD (wet scrubbers) for SO_2 BART. All three options were identified as technically feasible for use at White Bluff Units 1 and 2. Entergy's evaluation noted that DSI control efficiency ranges between 40 to 60%,[50] dry FGD control efficiency ranges from 60 to 95%, and wet FGD ranges from 80–95% control efficiency, but can achieve up to 97% control efficiency when burning higher sulfur coal. Entergy evaluated wet FGD at an outlet SO_2 emission rate of 0.04 lb/MMBtu for Units 1 and 2. The remainder of Entergy's analysis focused on wet FGD and dry FGD. We concur with Entergy's decision to focus the remainder of the analysis on the two control options with the highest control efficiency.

Our Dry Scrubbing Cost Analysis for Entergy White Bluff: Entergy's estimates of the capital and direct operating and maintenance costs of a dry scrubber were based on vendor estimates. Estimates of the indirect operating costs were based on calculation methods from our Control Cost Manual. The estimates of the capital and operating and maintenance costs of wet FGD were based on vendor estimates obtained by Entergy for a system estimated to achieve 97% control and calculation methods from our Control Cost Manual.

We have reviewed the cost analysis that is part of Entergy's evaluation and have analyzed it for compliance with the Regional Haze Rule, and disagree with several aspects of the cost analysis and have made adjustments to it as necessary.[51] First, we found that Entergy assumed in its dry FGD cost analysis that it will burn a coal corresponding to an uncontrolled SO_2 emission rate of 2.0 lb/MMBtu—far in excess of the sulfur level of the coals it has historically burned, presumably for future fuel flexibility. For the years 2009–2013, the maximum monthly SO_2 emission rate for Unit 1 is 0.653 lbs/MMBtu and that for Unit 2 is 0.679 lbs/MMBtu. Thus, Entergy has costed SO_2 dry scrubber systems for the White Bluff facility that are overdesigned compared to its historical needs. Such a system, being capable of a much higher level of sulfur removal than is currently required, has a correspondingly higher cost. Entergy selected its SO_2 emission baseline by using ''the average rate from 2001–2003, as reported by Entergy in their air

[48] See the document titled ''Response of Entergy Arkansas, Inc. to Arkansas Public Service Commission Order No. 17.'' A copy of this document can be found in the docket for this proposed rulemaking.

[49] See ''Revised BART Five Factor Analysis White Bluff Steam Electric Station Redfield, Arkansas (AFIN 35–00110),'' dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc. We refer to this BART analysis as ''Entergy's BART analysis'' throughout this proposed rulemaking, and a copy of it is found in the docket for our proposed rulemaking.

[50] ''Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities'' Northeast States for Coordinated Air Use Management (NESCAUM), March 2005.

[51] See ''Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plan (SO_2 Cost TSD).'' A copy of this document is found in the docket for our proposed rulemaking.

emission inventories,'' [52] while selecting its annualized costs based on a 2.0 lb/MMBtu coal. In calculating baseline emissions, the BART Guidelines assume the source in question is otherwise unchanged in the future, except for the addition of BART controls.[53] Thus, we believe it is appropriate to adjust the cost analysis presented in Entergy's report.[54] Additionally, the cost estimate for dry FGD presented in Entergy's report includes line items that have not been documented, appear to be already covered in other cost items, or do not appear to be valid costs under our Control Cost Manual methodology. This includes line items such as capital suspense,[55] Entergy internal costs, and certain line items under balance of plant (BOP) costs. Please see our SO_2 Cost TSD for more details concerning the adjustments we propose to make to the White Bluff dry FGD cost analysis. A summary of our adjusted cost analysis, which is based on 2013 dollars, is presented in the table below.

TABLE 32—SUMMARY OF EPA DRY FGD COST ANALYSIS FOR WHITE BLUFF UNITS 1 AND 2

Item	White Bluff Unit 1	White Bluff Unit 2
Total Annualized Cost	$31,981,230	$31,981,230
Interest Rate (%)	7	7
Equipment Lifetime (years)	30	30
Capital Recovery Factor (CRF)	0.0806	0.0806
SO_2 Emission Rate (lbs/MMBtu)	0.65	0.68
Controlled SO_2 Emission Rate (%)	90.81	91.16
SO_2 Emission Baseline (tons)	15,816	16,697
SO_2 Emission Reduction (tons)	14,363	15,221
Cost Effectiveness ($/ton)	$2,227	$2,101

Our Wet Scrubbing Cost Analysis for Entergy White Bluff: Entergy uses a 2012 contractor wet FGD estimate for the White Bluff Units 1 and 2 as the starting point for its cost analysis.[56] It then used multiplier approximations from our Control Cost Manual [57] to calculate the Total Capital Investment (TCI). Entergy then calculated the direct annual costs, using fixed and variable O&M costs from another 2011 contractor cost summary as a surrogate for the apparently unavailable direct annual costs from the 2012 estimate.[58] Following this, Entergy calculated the indirect annual costs using additional multiplier approximations from our Control Cost Manual.[59] Lastly, Entergy calculated the annualized capital cost in the usual manner by multiplying the TCI by the capital recovery factor.

As with its dry FGD cost estimates, Entergy designed its wet FGD systems to burn coal corresponding to an uncontrolled SO_2 emission rate of 2.0 lb/MMBtu, which are overdesigned compared to its historical needs. Please see our SO_2 Cost TSD for more details concerning the adjustments we propose to make to the White Bluff wet FGD cost analysis, which is similar to our dry FGD analysis. A summary of our adjusted cost analysis, which is based on 2013 dollars, is presented in the table below:

TABLE 33—SUMMARY OF EPA WET FGD COST ANALYSIS FOR WHITE BLUFF UNITS 1 AND 2

Item	White Bluff Unit 1	White Bluff Unit 2
Total Annualized Cost	$49,526,167	$49,526,167
Interest Rate (%)	7	7
Equipment Lifetime (years)	30	30
Capital Recovery Factor (CRF)	0.0806	0.0806
SO_2 Emission Rate (lbs/MMBtu)	0.65	0.68
Controlled SO_2 Emission Rate (%)	93.87	94.11
SO_2 Emission Baseline (tons)	15,816	16,697
SO_2 Emission Reduction (tons)	14,847	15,713
Cost Effectiveness ($/ton)	$3,336	$3,152

Entergy's evaluation noted that the potential negative non-air quality environmental impacts are greater with wet FGD systems than dry FGD systems. Entergy noted that wet scrubbers require increased water use and generate large

[52] Revised Bart Five Factor Analysis, White Bluff Steam Electric Station, Redfield, Arkansas (AFIN 35–00110), dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc., Page 5–5.

[53] 70 FR 39167.

[54] See ''Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plan (SO_2 Cost TSD),'' for a detailed discussion of how Entergy's cost analysis was adjusted.

[55] Entergy states capital suspense ''is a distribution of overhead costs associated with administrators, engineers, and supervisors and includes function specific rates and A&G (Corporate Accounting) rates. Function specific capital suspense is dependent upon the personal hours allocated to a specific project for a time period. However, the percent of a total project that is dedicated to capital suspense is not a constant. Rather, it is dependent upon the yearly total capital expense budget and the budgeted capital spending for a specific function.'' See Entergy Response to EPA Region 6 comments on Entergy White Bluff draft BART Report 06/10/13.Page 9. A copy of this document is found in the docket for this proposed rulemaking.

[56] White Bluff Station Unit 1 & 2, Wet FGD—2.0 lb/MMBtu, Order Of Magnitude Cost Estimate Summary. Attached as Attachment C to the 6/10/13 Entergy Response to EPA comments on the White Bluff draft BART Report. Pdf page 29. Below is

[57] Section 5.2 Post-Combustion Controls, Chapter 1—Wet Scrubbers for Acid Gas, Table 1.3.

[58] 6/10/13 Entergy Response to EPA comments on the White Bluff draft BART Report. Pdf page 11. This information was supplemented with a cut sheet from the 2011 S&L report via email from David Triplett on 2–10–15. Entergy declined to provide the full report, citing confidentiality concerns.

[59] Section 5.2 Post-Combustion Controls, Chapter 1—Wet Scrubbers for Acid Gas, Table 1.4.

volumes of wastewater and solid waste/sludge that must be treated or stabilized before landfilling, placing additional burden on the wastewater treatment and solid waste management capabilities. We do not expect that water availability would affect the feasibility of a wet scrubber since the facility is not located in an exceptionally arid region. Additionally, the BART Guidelines provide that 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 (40 CFR part 51, Appendix Y, section IV.D.4.i.2.). In cases where the facility can demonstrate that there are unusual circumstances there that would create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control option as BART. But in this case, Entergy White Bluff has not indicated that there are any such unusual circumstances. Another potential negative energy and non-air quality environmental impact associated with wet FGD systems is the potential for increased power requirements and greater reagent usage compared to dry FGD. The costs associated with increased power requirements and greater reagent usage have already been factored into the cost analysis for the wet FGD system.

Entergy assessed the visibility improvement associated with wet FGD and a dry FGD by modeling the SO_2 emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rates to the visibility impairment associated with the controlled emission rates as measured by the 98th percentile modeled visibility impact. The tables below compare the baseline (*i.e.,* existing) visibility impacts with the visibility impacts associated with SO_2 controls.

TABLE 34—ENTERGY WHITE BLUFF UNIT 1: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO SO_2 CONTROLS

Class I area	Visibility impact (Δdv)			Visibility improvement over baseline (dv)		Incremental visibility improvement of wet FGD vs. dry scrubber
	Baseline	Dry scrubber	Wet FGD	Dry scrubber	Wet FGD	
Caney Creek	1.628	0.815	0.794	0.813	0.834	0.021
Upper Buffalo	1.140	0.378	0.350	0.762	0.790	0.028
Hercules-Glades	1.041	0.358	0.360	0.683	0.681	−0.002
Mingo	0.887	0.267	0.271	0.620	0.616	−0.004
Total	4.696	1.818	1.775	2.878	2.921	0.043

TABLE 35—ENTERGY WHITE BLUFF UNIT 2: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO SO_2 CONTROLS

Class I area	Visibility impact (Δdv)			Visibility improvement over baseline (dv)		Incremental visibility improvement of wet FGD vs. dry scrubber
	Baseline	Dry scrubber	Wet FGD	Dry scrubber	Wet FGD	
Caney Creek	1.695	0.941	0.920	0.754	0.775	0.021
Upper Buffalo	1.185	0.418	0.405	0.767	0.780	0.013
Hercules-Glades	1.061	0.415	0.416	0.645	0.644	−0.001
Mingo	0.903	0.310	0.315	0.593	0.588	−0.005
Total	4.844	2.084	2.056	2.759	2.787	0.028

The tables above show that the installation and operation of SO_2 controls is projected to result in considerable visibility improvement over the baseline at the four impacted Class I areas. Installation and operation of dry FGD is projected to result in visibility improvement of up to 0.813 dv at any single Class I area for Unit 1 and 0.767 dv for Unit 2, based on the 98th percentile visibility impairment. Installation and operation of wet FGD is projected to result in visibility improvement of up to 0.834 dv at any single Class I area for Unit 1 and 0.780 dv for Unit 2. The installation and operation of wet FGD is projected to result in very minimal incremental visibility benefit over dry FGD at Caney Creek and Upper Buffalo, while at Hercules-Glades and Mingo, it is projected to result in slightly less visibility improvement than dry FGD (*i.e.,* a slight visibility disbenefit).

Our Proposed SO_2 BART Determination: Based on our cost analysis, a dry FGD system is estimated to have an average cost-effectiveness of $2,227 per ton of SO_2 removed for Unit 1 and $2,101 per ton of SO_2 removed for Unit 2. By comparison, a wet FGD system is estimated to have an average cost-effectiveness of $3,336 per ton of SO_2 removed for Unit 1 and $3,152 per ton of SO_2 removed for Unit 2. Therefore, considering the five BART factors and the slight visibility benefit at Caney Creek and Upper Buffalo and slight disbenefit at Hercules-Glades and Mingo of wet FGD over dry FGD, we are proposing to determine that SO_2 BART for White Bluff Units 1 and 2 is an emission limit of 0.06 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of dry FGD or another control technology that achieves that level of control. We are proposing to require compliance with this requirement no later than 5 years from the effective date of the final rule, consistent with the regional haze regulations.[60] We are proposing to require that compliance be demonstrated using the unit's existing CEMS. We are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with this emission limit.

b. *Proposed NO_X BART Analysis and Determination for Units 1 and 2.* Entergy identified all available control technologies, eliminated options that are not technically feasible, and evaluated the control effectiveness of the remaining NO_X control options for Units 1 and 2. Each technically feasible control option was then evaluated in terms of a five factor BART analysis.

For NO_X BART, Entergy's BART evaluation considered both combustion and post-combustion controls. The combustion controls evaluated consisted of FGR, separated overfire air (SOFA), and LNB. The post-combustion controls evaluated consisted of SCR and SNCR. Entergy found that FGR technology is not currently offered by vendors for coal-fired units. Therefore, it did not consider FGR to be a technically feasible control technology for the coal-fired White Bluff Units 1 and 2. All other available NO_X control options were identified as technically feasible. Entergy evaluated three control scenarios: LNB with SOFA (LNB/SOFA); the combination of LNB, SOFA, and SNCR (LNB/SOFA + SNCR); and the combination of LNB, SOFA, and SCR (LNB/SOFA + SCR). According to Entergy, the baseline NO_X emission rate is approximately 0.31 lb/MMBtu for Unit 1 and 0.36 lb/MMBtu for Unit 2. Entergy relied on literature control ranges and efficiencies, as well as vendor estimates to arrive at the expected controlled emission rates for White Bluff Units 1 and 2. Based on contractor evaluations, SOFA is expected to achieve a controlled NO_X emission rate of 0.28–0.32 lb/MMBtu for Units 1 and 2. When LNB is combined with SOFA, it is expected to achieve a controlled NO_X emission rate of 0.15 lb/MMBtu. When SNCR is combined with LNB and SOFA, it is expected to achieve a controlled NO_X emission rate of 0.13 lb/MMBtu for Units 1 and 2, and when SCR is combined with LNB and SOFA it is expected to achieve a controlled NO_X emission rate of 0.055 lb/MMBtu.

Entergy estimated the capital costs, operating costs, and average cost-effectiveness of LNB, SOFA, SNCR, and SCR. The capital and operating costs of controls were based on vendor estimates specific to Units 1 and 2. The total annual costs were estimated by annualizing the capital cost of controls over a 30-year period and then adding to this value the annual operating cost of controls. Entergy determined the annual emissions reductions associated with each NO_X control option by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rate is the average rate as reported by Entergy in the 2009–2011 air emission inventories. The average cost-effectiveness of controls was calculated by dividing the total annual cost of each control option by the estimated annual NO_X emissions reductions.

We note that Entergy's cost estimate for each NO_X control option includes capital suspense in the total capital costs.[61] A capital cost suspense of $955,673 for both units for LNB/SOFA; $1,745,429 for both units for LNB/SOFA + SNCR; and $20,552,528 for Unit 1 and $21,332,288 for Unit 2 for LNB/SOFA + SCR is included in the capital costs. As discussed above, Entergy described capital suspense as a distribution of overhead costs associated with administrators, engineers, and supervisors that includes function specific rates and corporate accounting rates. However, we do not believe capital suspense should be included in the cost analysis because those costs have not been documented by Entergy and do not appear to be valid costs under the Control Cost Manual methodology. We have adjusted the cost estimate of NO_X controls by subtracting the capital suspense line item from the capital costs.[62] Based on our adjustment of Entergy's cost estimate, the average cost-effectiveness of LNB/SOFA is estimated to be $350 per ton of NO_X removed for Unit 1 and $340 per ton of NO_X removed for Unit 2, while the average cost-effectiveness of LNB/SOFA + SNCR is estimated to be $1,758 per ton of NO_X removed for Unit 1 and $1,449 per ton of NO_X removed for Unit 2 (see table below). The average cost-effectiveness of LNB/SOFA + SCR is estimated to be $3,552 per ton of NO_X removed for Unit 1 and $2,749 per ton of NO_X removed for Unit 2.

TABLE 36—SUMMARY OF NO_X CONTROL COSTS FOR WHITE BLUFF UNITS 1 AND 2

Control technology	Baseline emission rate (NO_X tpy)	Controlled emission level (lb/MMBtu)	Controlled emission rate (tpy)	Annual emissions reduction (NO_X tpy)	Capital cost ($)	Total annual cost ($/yr)	Average cost effectiveness ($/ton)	Incremental cost-effectiveness ($/ton)
Unit 1 (SN–01)								
LNB/SOFA	7,249	0.15	4,145	3,104	9,505,533	1,085,904	350	
LNB/SOFA/SNCR	7,249	0.13	3,593	3,657	19,625,896	6,430,580	1,758	9,665
LNB/SOFA/SCR	7,249	0.055	1,520	5,729	209,776,610	20,349,142	3,552	6,717
Unit 2 (SN–02)								
LNB/SOFA	8,185	0.15	4,060	4,125	13,532,533	1,403,376	340	
LNB/SOFA/SNCR	8,185	0.13	3,519	4,666	23,652,896	6,759,102	1,449	9,900
LNB/SOFA/SCR	8,185	0.055	1,489	6,697	185,415,610	18,407,977	2,749	5,736

Entergy did not identify any energy or non-air quality environmental impacts associated with the use of LNB/SOFA. As for SCR and SNCR, we are not aware of any unusual circumstances at the facility that could create non-air quality

[60] 40 CFR 51.308(e)(1)(iv).

[61] See ''Revised BART Five Factor Analysis White Bluff Steam Electric Station Redfield, Arkansas (AFIN 35–00110),'' dated October 2013, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc. Entergy's NO_X control cost estimates are found in Appendix A of the BART analysis and Appendix E contains the ''NO_X Control Technology Cost and Performance Study'' prepared by Sargent & Lundy on behalf of Entergy. A copy of the BART analysis and all appendices are found in the docket for our proposed rulemaking.

[62] See the spreadsheet titled ''EPA NO_X Control Cost revisions_White Bluff.'' A copy of this spreadsheet is found in the docket for our proposed rulemaking.

environmental impacts associated with the operation of these controls greater than experienced elsewhere and that may therefore provide a basis for their elimination as BART (40 CFR part 51, Appendix Y, section IV.D.4.i.2.). Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with the operation of NO_X controls at Entergy White Bluff Units 1 and 2 that would affect our proposed BART determination.

Consideration of the presence of existing pollution control technology at each source is reflected in the BART analysis in two ways: First, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. Other than the installation of a neural net system in 2006 to optimize boiler combustion efficiency that resulted in lower NO_X emissions compared to the 2001–2003 baseline, White Bluff Units 1 and 2 have no existing NO_X pollution control technology. The lower NO_X emissions achieved as a co-benefit of installing the neural net system is reflected in the analysis by the use of 2009–2011 as the baseline for the NO_X BART analysis.

Entergy assessed the visibility improvement associated with NO_X controls by modeling the NO_X emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rate to the visibility impairment associated with the controlled emission rates as measured by the 98th percentile modeled visibility impact. The tables below show a comparison of the baseline (*i.e.,* existing) visibility impacts and the visibility impacts associated with NO_X controls.

TABLE 37—ENTERGY WHITE BLUFF UNIT 1: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO NO_X CONTROLS

Class I area	Baseline visibility impact (Δdv)	LNB/SOFA		LNB/SOFA + SNCR		LNB/SOFA + SCR	
		Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	1.628	1.462	0.166	1.428	0.2	1.359	0.269
Upper Buffalo	1.140	1.039	0.101	1.029	0.111	0.991	0.149
Hercules-Glades	1.041	0.865	0.176	0.844	0.197	0.832	0.209
Mingo	0.887	0.849	0.038	0.842	0.045	0.817	0.07
Cumulative Visibility Improvement (Δdv)			0.481		0.553		0.697

TABLE 38—ENTERGY WHITE BLUFF UNIT 2: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO NO_X CONTROLS

Class I area	Baseline visibility impact (Δdv)	LNB/SOFA		LNB/SOFA + SNCR		LNB/SOFA + SCR	
		Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	1.695	1.47	0.225	1.437	0.258	1.368	0.327
Upper Buffalo	1.185	1.046	0.139	1.035	0.15	0.997	0.188
Hercules-Glades	1.060	0.870	0.190	0.849	0.211	0.838	0.222
Mingo	0.903	0.856	0.047	0.849	0.054	0.823	0.08
Cumulative Visibility Improvement (Δdv)			0.601		0.673		0.817

The tables above show that the installation and operation of LNB/SOFA is projected to result in visibility improvement of up to 0.176 dv at any single Class I area for Unit 1 and 0.225 dv for Unit 2, based on the 98th percentile visibility impairment. The installation and operation of LNB/SOFA + SNCR is projected to result in visibility improvement of up to 0.2 dv in any single Class I area for Unit 1 and 0.258 dv for Unit 2. The installation and operation of LNB/SOFA + SCR is projected to result in visibility improvement of up to 0.269 dv in any single Class I area for Unit 1 and 0.327 dv for Unit 2. The combination of LNB/SOFA + SNCR would result in minimal incremental visibility benefit over LNB/SOFA at all affected Class I areas for both units. The combination of LNB/SOFA + SCR at Unit 1 would result in incremental visibility benefit over LNB/SOFA + SNCR of 0.069 dv at Caney Creek; 0.038 dv at Upper Buffalo; 0.012 dv at Hercules-Glades; and 0.025 dv at Mingo. The combination of LNB/SOFA + SCR at Unit 2 would result in incremental visibility benefit over LNB/SOFA + SNCR of 0.069 dv of at Caney Creek; 0.038 dv at Upper Buffalo; 0.011 dv at Hercules-Glades; and 0.026 dv at Mingo.

Our Proposed NO_X BART Determination for Units 1 and 2: Taking into consideration the five factors, we propose to determine that BART for White Bluff Units 1 and 2 is an emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of LNB/SOFA. The operation of LNB/SOFA is projected to result in visibility improvement ranging from 0.038 to 0.176 dv for Unit 1 and 0.047 to 0.225 dv for Unit 2 at each of the affected Class I areas (98th percentile basis). Based on our adjustments to the cost analysis included in Entergy's evaluation, the operation of LNB/SOFA is estimated to have an average cost-effectiveness of $350 per ton of NO_X removed for Unit 1 and $340 per ton of NO_X removed for Unit 2, which we consider to be very cost-effective. The operation of LNB/SOFA + SNCR is estimated to have an average cost-effectiveness of $1,758 per ton of NO_X removed for Unit 1 and $1,449 per ton of NO_X removed for Unit 2. The incremental cost-effectiveness of LNB/SOFA + SNCR compared to LNB/SOFA is $9,665 per ton of NO_X removed for Unit 1 and $9,900 per ton of NO_X removed for Unit 2.While the average cost-effectiveness of LNB/SOFA + SNCR is still very cost effective, the incremental visibility benefit of LNB/SOFA + SNCR compared to LNB/SOFA is estimated to range from 0.007 to 0.034 dv for Unit 1 and 0.007 to 0.033 dv for Unit 2 at each of the affected Class I areas. We do not believe this small amount of incremental visibility benefit justifies the incremental cost of LNB/SOFA + SNCR.

The operation of LNB/SOFA + SCR at Unit 1 is projected to result in up to 0.269 dv visibility improvement over the baseline at any single Class I area, and based on our adjustments to Entergy's cost analysis, has an average cost-effectiveness of $3,552 per ton of NO_X removed. LNB/SOFA + SCR at Unit 1 is projected to result in up to 0.069 dv of incremental visibility improvement over LNB/SOFA + SNCR at any single Class I area, and its incremental cost-effectiveness is estimated to be $6,717 per ton of NO_X removed. The operation of LNB/SOFA + SCR at Unit 2 is projected to result in up to 0.327 dv visibility improvement over the baseline at any single Class I area, and has an average cost-effectiveness of $2,749 per ton of NO_X removed. LNB/SOFA + SCR at Unit 2 is also projected to result in up to 0.069 dv of incremental visibility improvement over LNB/SOFA + SNCR at any single Class I area, and its incremental cost-effectiveness is estimated to be $5,736 per ton of NO_X removed. Although the average and incremental cost-effectiveness of LNB/SOFA + SCR at Units 1 and 2 is still within the range of what we consider to be cost-effective, we believe the incremental visibility benefit over LNB/SOFA + SNCR of up to 0.069 dv at a single Class I area is relatively small considering the incremental cost-effectiveness of $6,717 per ton of NO_X removed for Unit 1 and $5,736 per ton of NO_X removed for Unit 2. Therefore, we are proposing to determine that NO_X BART for White Bluff Units 1 and 2 is an emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of LNB/SOFA. We are proposing to require compliance with this requirement no later than 3 years from the effective date of the final rule, consistent with our regional haze regulations.[63] We are proposing to require that compliance be demonstrated using the unit's existing CEMS. We are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with this emission limit.

c. *Proposed BART Analysis and Determination for the Auxiliary Boiler.* As shown in the table above, the baseline visibility impairment attributable to the Auxiliary Boiler is 0.01 Δdv at Caney Creek and even lower at the other modeled Class I areas (98th percentile basis). The BART Rule provides:

> ''Consistent with the CAA and the implementing regulations, States can adopt a more streamlined approach to making BART determinations where appropriate. Although BART determinations are based on the totality of circumstances in a given situation, such as the distance of the source from a Class I area, the type and amount of pollutant at issue, and the availability and cost of controls, it is clear that in some situations, one or more factors will clearly suggest an outcome. Thus, for example, a State need not undertake an exhaustive analysis of a source's impact on visibility resulting from relatively minor emissions of a pollutant where it is clear that controls would be costly and any improvements in visibility resulting from reductions in emissions of that pollutant would be negligible.'' (70 FR 39116).

Given the very small baseline visibility impacts from the Auxiliary Boiler, we believe it is appropriate to take a streamlined approach for determining BART in this case. Because of the very low baseline visibility impacts from the Auxiliary Boiler at each modeled Class I area, we believe that the visibility improvement that could be achieved through the installation and operation of controls would be negligible, such that the cost of those controls could not be justified. Therefore, we are proposing that the existing emission limits satisfy BART for SO_2, NO_X, and PM. We are proposing that the existing emission limit of 105.2 lb/hr is BART for SO_2, the existing emission limit of 32.2 lb/hr is BART for NO_X, and the existing emission limit of 4.5 lb/hr is BART for PM for the Auxiliary Boiler.[64] Because we are proposing a BART emission limit that represents current operations and no control equipment installation is necessary, we are proposing that these emissions limitations be complied with for BART purposes from the date of effectiveness of the finalized action.

[63] 40 CFR 51.308(e)(1)(iv).

[64] See ADEQ Operating Air Permit No. 0263–AOP–R7, Section IV, Specific Condition No. 32.

5. Entergy Lake Catherine Plant

The Entergy Lake Catherine Unit 4 is subject to BART. We previously disapproved Arkansas' BART determinations for NO_X for the natural gas firing scenario and for SO_2, NO_X, and PM for the fuel oil firing scenario in our March 12, 2012 final action (77 FR 14604). Lake Catherine Unit 4 is a tangentially-fired boiler with a nominal net power rating of 558 MW and a nominal heat input capacity of 5,850 MMBtu/hr. The boiler is permitted to burn natural gas and No. 6 fuel oil. Entergy hired a consultant to conduct a BART five-factor analysis for Lake Catherine Unit 4 (Entergy's BART analysis).[65] Entergy's analysis states that Lake Catherine Unit 4 has not burned fuel oil since prior to the 2001–2003 baseline period, currently does not burn fuel oil, and that Entergy does not project to burn fuel oil at the unit in the foreseeable future. Therefore, Entergy's analysis [66] addresses BART for the natural gas firing scenario and does not consider emissions from fuel oil firing. Entergy's analysis states that if conditions change such that it becomes economic to burn fuel oil, the facility will submit a BART five factor analysis for the fuel oil firing scenario to the State to be submitted to us as a SIP revision, and that fuel oil combustion will not take place until final EPA approval of BART for the fuel oil firing scenario. We concur with this commitment.[67] Before fuel oil firing is allowed to take place at Lake Catherine Unit 4, revised BART determinations must be promulgated for all pollutants for the fuel oil firing scenario through a FIP and/or through our action upon and approval of revised BART

[65] See ''Revised BART Five Factor Analysis Lake Catherine Steam Electric Station Malvern, Arkansas (AFIN 30–00011),'' dated May 2014, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc. A copy of this BART analysis is found in the docket for our proposed rulemaking.

[66] See ''Revised BART Five Factor Analysis Lake Catherine Steam Electric Station Malvern, Arkansas (AFIN 30–00011),'' dated May 2014, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc. A copy of this BART analysis is found in the docket for our proposed rulemaking.

[67] As stated in the regulatory text for this proposed rulemaking, if Lake Catherine Unit 4 decides to begin burning fuel oil, we will complete a BART analysis for each pollutant for the fuel oil firing scenario after receiving notification that the source will begin burning fuel oil and we will revise the FIP as necessary in accordance with Regional Haze Rule requirements, including the BART provisions in 40 CFR 51.308(e). Alternatively, if the State submits a SIP revision with BART determinations for the fuel oil firing scenario, we will take action on the State's submittal.

determinations submitted by the State as a SIP revision. We approved Arkansas' BART determinations for Lake Catherine Unit 4 for SO_2 and PM for the natural gas firing scenario in our March 12, 2012 final action (77 FR 14604). Therefore, the only BART determination that remains to be addressed for the natural gas firing scenario is NO_X BART.

The table below summarizes the baseline emission rates for Lake Catherine Unit 4. The SO_2 and NO_X baseline emission rates are the highest actual 24-hour emission rates based on CAMD data from 2001–2003 for natural gas burning. The PM_{10} emission rate reflects the breakdown of the filterable and condensable PM_{10} determined from AP–42 Table 1.4–2 *Combustion of Natural Gas.*

TABLE 39—ENTERGY LAKE CATHERINE UNIT 4 (NATURAL GAS FIRING): BASELINE MAXIMUM 24-HOUR EMISSION RATES

Source	SO_2 (lb/hr)	NO_X (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PMc (lb/hr)	PMf (lb/hr)	SOA (lb/hr)	EC (lb/hr)
Unit 4	3.1	2,456.4	44.3	1.5	0.0	0.0	31.8	11.0

Entergy modeled the baseline emission rates using the CALPUFF dispersion model to determine the baseline visibility impairment attributable to Lake Catherine Unit 4 at the four Class I areas impacted by emissions from BART sources in Arkansas. These Class I areas are the Caney Creek Wilderness Area, Upper Buffalo Wilderness Area, Hercules-Glades Wilderness Area, and Mingo National Wildlife Refuge. The baseline (*i.e.,* existing) visibility impairment attributable to the source at each Class I area is summarized in the table below.

TABLE 40—BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO ENTERGY LAKE CATHERINE UNIT 4—NATURAL GAS FIRING

[2001–2003]

Unit	Caney Creek	Upper Buffalo	Hercules-Glades	Mingo
Unit 4 (SN–01):				
Maximum (Δdv)	3.480	2.044	1.016	0.763
98th Percentile (Δdv)	1.371	0.489	0.387	0.429

a. *Proposed NO_X BART Analysis and Determination.* Entergy identified all available control technologies, eliminated options that are not technically feasible, and evaluated the control effectiveness of the remaining control options for Lake Catherine Unit 4. Each technically feasible control option was then evaluated in terms of a five factor BART analysis.

For NO_X BART, the Entergy BART analysis evaluated both combustion and post-combustion controls. The combustion controls evaluated consisted of Burners out of Service (BOOS), FGR, SOFA, and LNB. The post-combustion controls evaluated consisted of SCR and SNCR. In its evaluation, Entergy noted that SNCR combined with LNB/SOFA was being evaluated as a control option for Lake Catherine Unit 4, but SNCR is not adaptable to all gas-fired boilers. All other available NO_X control options were identified as technically feasible.

The baseline NO_X emission rate Entergy used in the analysis is 0.48 lb/MMBtu. Entergy relied on literature control ranges and efficiencies and vendor estimates in arriving at the expected controlled emission rates for Lake Catherine Unit 4. BOOS is a staged combustion technique in which fuel is introduced through operational burners in the lower furnace zone to create fuel-rich conditions, while not introducing fuel to other burners. The removal of fuel from certain zones reduces the temperature and the production of thermal NO_X. Additional air is then supplied to the non-operational burners to complete combustion. Based on a NO_X control study developed by Sargent & Lundy on behalf of Entergy (Sargent & Lundy NO_X Control Study), the estimated controlled NO_X level for Unit 4 while operating BOOS at maximum load is 0.24 lb/MMBtu.[68] Based on the level of control expected to be achieved by BOOS and the expected utilization levels at Unit 4, Entergy believes that an emission rate of 0.22 lb/MMBtu is achievable on a 30 boiler-operating-day rolling average basis. Entergy estimated the controlled NO_X level for Unit 4 operating with FGR to be 0.19 lb/MMBtu. Entergy estimated that when operated without additional controls, SOFA results in NO_X emissions for gas fired boilers of 0.2—0.4 lb/MMBtu. When operated without additional controls, the estimated controlled NO_X emission rate for gas fired boilers operating with LNB is approximately 0.25 lb/MMBtu, and when combined with SOFA, the estimated controlled NO_X emission rate is 0.19 lb/MMBtu. When SNCR is combined with LNB/SOFA it is estimated that the controlled NO_X emission rate is 0.14 lb/MMBtu, and when SCR is combined with LNB/SOFA it is estimated that the controlled NO_X emission rate is 0.03 lb/MMBtu.

In its evaluation, Entergy noted that the Sargent & Lundy NO_X Control Study estimated that FGR would result in the same controlled emission level as LNB/SOFA, but at a higher cost. Therefore, Entergy's evaluation did not further consider FGR. The remainder of the analysis focused on four control scenarios: (1) BOOS; (2) LNB/SOFA; (3) the combination of LNB/SOFA + SNCR; and (4) the combination of LNB/SOFA + SCR. Entergy estimated the capital costs, operating costs, and cost-effectiveness of these four control scenarios based on cost estimates provided by Sargent & Lundy.[69] The capital cost of each NO_X control was annualized over a 30-year period and

[68] See "NO_X Control Technology Cost and Performance Study," Final Report, Rev. 4, dated May 16, 2013, prepared by Sargent & Lundy. A copy of this report is included as Attachment D to Entergy's BART Five Factor Analysis for Lake Catherine Unit 4, which can be found in the docket for this proposed rulemaking.

[69] The capital and operating cost estimates for each control option are found in Appendix A to Entergy's BART Five Factor Analysis for Lake Catherine Unit 4, which can be found in the docket for this proposed rulemaking.

then added to the annual operating costs to obtain the total annualized costs.[70] The annual emissions reductions associated with each NO_X control option were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rate was calculated using the baseline emission level of 0.48 lb/MMBtu and an annual heat input reflecting a 10% capacity factor.[71] Entergy assumed a 10% capacity factor because the annual capacity factor of the unit during each of the years from 2003–2011 was under 10%, and Entergy anticipates that future annual capacity factors are expected to be comparable to those experienced by the unit in 2003–2011. We agree that assuming a 10% capacity factor is consistent with the BART Guidelines, which provide that the baseline emission rate should represent a realistic depiction of anticipated annual emissions for the source.[72]

The controlled annual emission rates were based on the lb/MMBtu levels believed to be achievable from the control technologies multiplied by the annual heat input. The average cost-effectiveness of NO_X controls was calculated by dividing the total annual cost of each control option by the estimated annual NO_X emissions reductions. The incremental cost-effectiveness of controls when compared to BOOS was also calculated. The table below summarizes the cost of NO_X controls for Lake Catherine Unit 4. Based on Entergy's analysis, the average cost-effectiveness of BOOS at a NO_X controlled emission rate of 0.22 lb/MMBtu is estimated to be $138 per ton of NO_X removed, while the average cost-effectiveness of LNB/SOFA is estimated to be $1,596 per ton of NO_X removed. The average cost-effectiveness of a combination of LNB/SOFA + SNCR is estimated to be $3,827 per ton of NO_X removed, while the average cost-effectiveness of the combination of LNB/SOFA + SCR is estimated to be $6,223 per ton of NO_X removed.

We disagree with two aspects of Entergy's cost analysis.[73] First, Entergy's cost estimates for LNB/SOFA, LNB/SOFA + SNCR, and LNB/SOFA + SCR include capital suspense as a line item under the capital costs. However, we do not believe capital suspense should be included in the cost analysis because those costs have not been documented by Entergy and do not appear to be valid costs under the Control Cost Manual methodology. Second, Entergy's cost estimates for these controls also include Allowance for Funds Used During Construction (AFUDC). AFUDC is the cost of capital that is incurred to finance a project during the construction period, and is not a valid cost under the methodology in the EPA Control Cost Manual. The exclusion of capital suspense and AFUDC from the capital cost estimates results in lower total annual costs and improved average cost-effectiveness (*i.e.,* less dollars per NO_X ton removed) for the aforementioned NO_X control options compared to what is estimated in Entergy's evaluation. In the table below, we have revised the cost-effectiveness of NO_X controls for Unit 4 to reflect our adjustments to Entergy's cost estimates.[74]

TABLE 41—SUMMARY OF NO_X CONTROL COSTS FOR LAKE CATHERINE UNIT 4

[Natural gas firing]

	Baseline emission rate (NO_X tpy)	Controlled emission level (lb/MMBtu)	Controlled emission rate (NO_X tpy)	Annual emissions reduction (NO_X tpy)	Capital cost ($)	Total annual cost ($/yr)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)
BOOS	1,236	0.22	564	673	893,000	92,964	138	
LNB/SOFA	1,236	0.19	495	742	10,508,863	1,075,905	1,450	14,246
LNB/SOFA/SNCR	1,236	0.14	371	865	26,015,863	3,047,525	3,523	16,029
LNB/SOFA/SCR	1,236	0.03	77	1159	70,370,863	6,506,935	5,614	11,767

Entergy did not identify any energy or non-air quality environmental impacts associated with the use of BOOS, LNB, or SOFA. As for SCR and SNCR, we are not aware of any unusual circumstances at the facility that could create non-air quality environmental impacts associated with the operation of these controls greater than experienced elsewhere and that may therefore provide a basis for their elimination as BART (40 CFR part 51, Appendix Y, section IV.D.4.i.2.). Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with the operation of NO_X controls at Entergy Lake Catherine Unit 4 that would affect our proposed BART determination.

Lake Catherine Unit 4 is not currently equipped with any NO_X pollution control equipment. The baseline emission rates used in the cost calculations and visibility modeling reflects this.

Entergy assessed the visibility improvement associated with NO_X controls by modeling the NO_X emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rate to the visibility impairment associated with the controlled emission rates as measured by the 98th percentile modeled visibility impact. The table below shows a comparison of the baseline (*i.e.,* existing) visibility impacts and the visibility impacts associated with NO_X controls.

[70] Based on Entergy's evaluation, it is anticipated that BOOS can be implemented at Unit 4 without any capital expenditures, but there are one-time costs associated with BOOS implementation. To provide an ''apples-to-apples'' comparison with the other NO_X control options, these one-time additional costs were treated as if they were a capital expenditure in calculating the cost effectiveness.

[71] The annual heat input reflecting a 10% annual capacity factor is 5,124,600 MMBtu/yr (5,850 MMBtu/hr * 8760 hrs/yr * 10% = 5,124,600 MMBtu/yr).

[72] 40 CFR Appendix Y to Part 51—Guidelines for BART Determinations Under the Regional Haze Rule, section IV.D.4.d.

[73] See ''Revised BART Five Factor Analysis Lake Catherine Steam Electric Station Malvern, Arkansas (AFIN 30–00011),'' dated May 2014, prepared by Trinity Consultants Inc. in conjunction with Entergy Services Inc. Entergy's NO_X control cost estimates are found in Appendices A and D of the BART analysis. A copy of the BART analysis, including the appendices, is found in the docket for our proposed rulemaking.

[74] See the spreadsheet titled ''EPA NO_X Control Cost revisions_Lake Catherine.xlsx.'' A copy of this spreadsheet is found in the docket for our proposed rulemaking.

TABLE 42—ENTERGY LAKE CATHERINE UNIT 4: SUMMARY OF 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO NO_X CONTROLS

[Natural gas firing]

Class I area	Baseline visibility impact (Δdv)	BOOS		LNB/SOFA		LNB/SOFA + SNCR		LNB/SOFA + SCR	
		Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	1.371	0.775	0.596	0.683	0.688	0.529	0.842	0.163	1.208
Upper Buffalo	0.532	0.284	0.248	0.25	0.282	0.193	0.339	0.057	0.475
Hercules-Glades	0.387	0.212	0.175	0.185	0.202	0.141	0.246	0.043	0.344
Mingo	0.429	0.233	0.196	0.204	0.225	0.154	0.275	0.042	0.387
Cumulative Visibility Improvement (Δdv)	....	....	1.215	....	1.397	....	1.702	....	2.414

The table above shows that the installation and operation of BOOS is projected to result in visibility improvement of up to 0.596 dv at any single Class I area (based on the 98th percentile modeled visibility impacts), while LNB/SOFA is projected to result in visibility improvement of up to 0.688 dv. The installation and operation of the combination of LNB/SOFA + SNCR is projected to result in visibility improvement of up to 0.842 dv at any single Class I area, while the combination of LNB/SOFA + SCR is projected to result in visibility improvement of up to 1.208 dv. The installation and operation of LNB/SOFA is projected to result in 0.092 dv of incremental visibility benefit over BOOS at Caney Creek, and much lower incremental visibility benefit over BOOS at the other Class I areas. The combination of LNB/SOFA + SNCR is projected to result in 0.154 dv of incremental visibility benefit over LNB/SOFA at Caney Creek, and 0.057 dv or less incremental visibility benefit at the other affected Class I areas. The combination of LNB/SOFA + SCR is projected to result in 0.366 dv of incremental visibility benefit over LNB/SOFA + SNCR at Caney Creek, 0.136 dv at Upper Buffalo, 0.098 Δdv at Hercules-Glades, and 0.112 dv at Mingo.

Our Proposed NO_X BART Determination: Taking into consideration the five factors, we are proposing to determine that NO_X BART for Lake Catherine Unit 4 for the natural gas firing scenario is an emission limit of 0.22 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of BOOS. The operation of BOOS is projected to result in visibility improvement ranging from 0.175 to 0.596 dv at each affected Class I area (98th percentile basis). The cumulative visibility improvement across the four affected Class I areas is projected to be 1.215 dv. The operation of BOOS is estimated to have an average cost-effectiveness of $138 per ton of NO_X removed, which we consider to be very cost-effective. By comparison, the installation and operation of LNB/SOFA is estimated to have an average cost-effectiveness of $1,450 per ton of NO_X removed, which is still very cost-effective. However, the incremental cost-effectiveness of LNB/SOFA over BOOS is $14,246 per ton of NO_X ton removed, while the incremental visibility benefits are only 0.027 to 0.092 dv (depending on the Class I area). As discussed in the preceding paragraph, the operation of a combination of LNB/SOFA + SNCR is projected to result in visibility improvement over the baseline ranging from 0.246 to 0.842 dv at each affected Class I area and an incremental visibility improvement over LNB/SOFA ranging from 0.05 to 0.154 dv at each Class I area. However, the combination of LNB/SOFA + SNCR has an average cost-effectiveness of $3,523 per ton of NO_X removed and an incremental cost-effectiveness compared to LNB/SOFA of $16,029 per ton of NO_X removed. We believe that the high incremental costs of the combination of LNB/SOFA + SNCR when compared to LNB/SOFA do not justify the amount of incremental visibility benefit projected at the affected Class I areas. The operation of a combination of LNB/SOFA + SCR is projected to result in considerable visibility improvement over the baseline, ranging from 0.344 to 1.208 dv at each affected Class I area. The incremental visibility benefit of the combination of LNB/SOFA + SCR over LNB/SOFA + SNCR ranges from 0.098 to 0.366 dv at each Class I area. However, the combination of LNB/SOFA + SCR has an average cost-effectiveness of $5,614 per ton of NO_X removed and an incremental cost-effectiveness (compared to the combination of LNB/SOFA + SNCR) of $11,767 per ton of NO_X removed. While the incremental visibility benefit is considerable, we do not consider the average and the incremental cost-effectiveness values of the combination of LNB/SOFA + SCR to be cost-effective. Therefore, we are proposing to determine that NO_X BART for Lake Catherine Unit 4 for the natural gas firing scenario is an emission limit of 0.22 lb/MMBtu on a 30 boiler-operating-day rolling average based on the installation and operation of BOOS. We are proposing to require compliance with this requirement no later than 3 years from the effective date of the final rule, consistent with our regional haze regulations.[75] We are proposing to require that compliance be demonstrated using the unit's existing CEMS. We are inviting public comment specifically on whether this proposed NO_X emission limit is appropriate or whether an emission limit based on more stringent NO_X controls would be appropriate. We are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with this emission limit.

6. Domtar Ashdown Paper Mill

The Domtar Ashdown Paper Mill Power Boilers No. 1 and 2 are subject to BART. As mentioned previously, we disapproved Arkansas' BART determinations for SO_2 and NO_X for Power Boiler No. 1 and the BART determination for SO_2, NO_X, and PM for the No. 2 Power Boiler in our March 12, 2012 final action (77 FR 14604). The No. 1 Power Boiler has a heat input rating of 580 MMBtu/hr and an average steam generation rate of approximately 120,000 lb/hr. The No. 1 Power Boiler combusts primarily bark, but is also permitted to burn wood waste, tire-

[75] 40 CFR 51.308(e)(1)(iv).

derived fuel (TDF), municipal yard waste, pelletized paper fuel (PPF), fuel oil, reprocessed fuel oil, and natural gas. It is equipped with a traveling grate, a combustion air system, and a wet ESP. The No. 2 Power Boiler has a heat input rating of 820 MMBtu/hr and an average steam generation rate of approximately 600,000 lb/hr. The No. 2 Power Boiler combusts primarily pulverized bituminous coal, but is also permitted to burn bark, PPF, TDF, municipal yard waste, fuel oil, used oil, natural gas, petroleum coke, and reprocessed fuel oil. It is equipped with a traveling grate, combustion air system including OFA, multiclones for particulate removal, and two venturi scrubbers in parallel for removal of remaining particulates and SO_2. Domtar hired a consultant to perform a BART five-factor analysis for the Domtar Ashdown Mill Power Boilers No. 1 and 2 (Domtar's 2014 BART analysis).[76] In this proposal, we also refer to certain parts of the Domtar BART evaluation submitted by the State in the 2008 Arkansas RH SIP, which we are hereafter referring to as the ''2006/2007 Domtar BART analysis.''[77] Although we already took action on that SIP submittal, we reference the 2006/2007 Domtar BART analysis as it contains the best available information we have related to certain NO_X controls for Power Boilers No. 1 and 2.

The table below summarizes the baseline emission rates for Power Boilers No. 1 and 2. The SO_2 baseline emission rate for Power Boiler No. 1 used in Domtar's 2014 BART analysis is the highest actual 24-hour emission rate estimated using maximum 24-hour fuel usage rates during 2009–2011 and sulfur content values for each fuel type.[78] The 2009–2011 period was used as the baseline in Domtar's evaluation for Power Boiler No. 1 because a wet ESP was installed on Power Boiler No. 1 in 2007 to meet the Maximum Achievable Control Technology (MACT) standards under CAA section 112, resulting in a reduction in PM and SO_2 emissions from Power Boiler No. 1. Therefore, we believe that the 2009–2011 period is more representative of the boiler's current emissions than 2001–2003. We believe the use of 2009–2011 as the new baseline period for Power Boiler No. 1 is consistent with the BART Guidelines, which provide that the baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source.[79] The NO_X and PM baseline emission rates used for Power Boiler No. 1 are the highest actual 24-hour emission rates estimated using the maximum heat input from 2009–2011 and emission factors developed from the analysis of stack testing the facility had previously conducted. For Power Boiler No. 2, the baseline emission rates are the highest actual 24-hour emission rates based on a combination of 2001–2003 CEMS data, source-specific stack testing results, and emission factors from AP–42.

TABLE 43—DOMTAR ASHDOWN MILL: BASELINE MAXIMUM 24-HOUR EMISSION RATES

Subject to BART unit	NO_X Emissions (lb/hr)	SO_2 Emissions (lb/hr)	PM_{10}/PM_f Emissions (lb/hr)
Power Boiler No. 1	207.4	21.0	30.4
Power Boiler No. 2	526.8	788.2	81.6

Domtar modeled the baseline emission rates using the CALPUFF dispersion model to determine the baseline visibility impairment attributable to the Domtar Ashdown Mill's Power Boilers No. 1 and 2 at the four Class I areas impacted by emissions from BART sources in Arkansas. These Class I areas are the Caney Creek Wilderness Area, Upper Buffalo Wilderness Area, Hercules-Glades Wilderness Area, and Mingo National Wildlife Refuge. The baseline visibility impairment attributable to the source at each Class I area is summarized in the table below.

TABLE 44—BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO THE DOMTAR ASHDOWN MILL

Emission unit	Caney Creek	Upper Buffalo	Hercules-Glades	Mingo
Power Boiler No. 1:				
Maximum (Δdv)	0.476	0.090	0.077	0.060
98th Percentile (Δdv)	0.335	0.038	0.020	0.014
Power Boiler No. 2:				
Maximum (Δdv)	1.603	0.381	0.329	0.246
98th Percentile (Δdv)	0.844	0.146	0.105	0.065

a. *Proposed SO_2 BART Analysis and Determination for Power Boiler No. 1.* The table above shows that the baseline visibility impairment attributable to Power Boiler No. 1 is relatively low based on the 98th percentile visibility impacts, ranging from 0.014–0.335 dv at each Class I area. An examination of the species contribution to the 98th percentile visibility impacts shows that SO_2 emissions contribute a very small portion of the visibility impairment

[76] See ''Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41–00002),'' originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis is found in the docket for our proposed rulemaking.

[77] See ''Best Available Retrofit Technology Determination Domtar Industries Inc., Ashdown Mill (AFIN 41–00002),'' originally dated October 31, 2006 and revised on March 26, 2007, prepared by Trinity Consultants Inc. This BART analysis is part of the 2008 Arkansas RH SIP, upon which EPA took final action on March 12, 2012 (77 FR 14604). A copy of this BART analysis is found in the docket for this proposed rulemaking.

[78] In Domtar's 2014 BART analysis, 2009–2011 was used as the baseline period for Power Boiler No. 1 because a wet ESP was installed on Power Boiler No. 1 in 2007. The installation of the wet ESP resulted in a reduction in PM and SO_2 emissions from Power Boiler No. 1. Therefore, 2009–2011 is more representative of the boiler's emissions than 2001–2003.

[79] 40 CFR part 51, Appendix Y, section IV.D.4.c.

attributable to Power Boiler No. 1 (see the table below). The SO_4 species contributes only 2.23—4.03% of the visibility impairment attributable to Power Boiler No. 1 at the modeled Class I areas. We also note that Power Boiler No. 1 combusts primarily bark, which results in very low SO_2 emissions due to the low sulfur content of bark.

TABLE 45—BASELINE VISIBILITY IMPAIRMENT AND SPECIES CONTRIBUTION FOR DOMTAR ASHDOWN MILL—POWER BOILER NO. 1

Emissions unit	Class I area	98th Percentile visibility impacts (dv) [80]	Species contribution to 98th percentile visibility impacts			
			98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Power Boiler No. 1	Caney Creek	0.335	2.23	85.26	6.68	5.83
	Upper Buffalo	0.038	2.75	85.89	8.03	3.32
	Hercules-Glades	0.020	2.70	91.82	3.94	1.55
	Mingo	0.014	4.03	90.06	5.13	0.78

As noted above, we believe that the BART Rule provides that states, or EPA in this case, can adopt a more streamlined approach to making BART determinations where appropriate.[81] Considering the very low baseline visibility impairment that is due to SO_2 emissions from Power Boiler No. 1 and the fact that the boiler combusts primarily bark, which has a low sulfur content, we believe that any visibility improvement that could be achieved as a result of emissions reductions associated with the installation and operation of SO_2 controls would be negligible, and that the cost of those controls could not be justified. Therefore, we are proposing that the SO_2 baseline emission rate of 21.0 lb/hr satisfies SO_2 BART for Power Boiler No. 1. We are proposing this SO_2 emission rate on a 30 boiler-operating-day averaging basis, where in this particular case boiler-operating-day is defined as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. Power Boiler No. 1 is not currently equipped with a CEMS. To demonstrate compliance with this SO_2 BART emission limit we are proposing to require the facility to use a site-specific curve equation,[82] provided to us by the facility, to calculate the SO_2 emissions from Power Boiler No. 1 when combusting bark, and to confirm the curve equation using stack testing.[83] We are also proposing that to calculate the SO_2 emissions from fuel oil combustion, the facility must assume that the SO_2 inlet is equal to the SO_2 being emitted at the stack. We are inviting public comment on whether this method of demonstrating compliance with the proposed BART emission limit is appropriate. Since this proposed BART determination does not require the installation of control equipment, we are proposing that this SO_2 emission limit be complied with by the effective date of the final action.

b. *Proposed NO_X BART Analysis and Determination for Power Boiler No. 1.* For NO_X BART, Domtar's 2014 BART analysis evaluated SNCR and Methane de-NO_X (MdN). In the 2006/2007 Domtar BART analysis, which was submitted in the 2008 Arkansas RH SIP, other NO_X controls were also evaluated but found by Arkansas to be either already in use or not technically feasible for use at Power Boiler No. 1. Fuel blending, boiler operational modifications, and boiler tuning/optimization are already in use at the source, while FGR, LNB, Ultra Low NO_X Burners (ULNB), OFA, and SCR were determined to be technically infeasible for use at Power Boiler No. 1. Domtar did not further evaluate these NO_X controls in its 2014 BART analysis for Power Boiler No. 1, focusing instead on SNCR and MdN.

MdN utilizes the injection of natural gas together with recirculated flue gases to create an oxygen-rich zone above the combustion grate. Air is then injected at a higher furnace elevation to burn the combustibles. In response to comments provided by us regarding Domtar's 2014 BART analysis, Domtar stated that discussions regarding the technical infeasibility of MdN in the 2006/2007 Domtar BART analysis, submitted as part of the 2008 Arkansas RH SIP, remain correct.[84] The 2006/2007 Domtar BART analysis submitted in the 2008 Arkansas RH SIP discussed that MdN has not been fully demonstrated for this source type and incorporates FGR, which is technically infeasible for use at Power Boiler No. 1. Domtar also stated it recently completed additional research and found that since the 2006/2007 Domtar BART analysis, MdN has not been placed into operation in power boilers at paper mills or any comparable source types. We are also not aware of any power boilers at paper mills that operate MdN for NO_X control, and agree that this control can be considered technically infeasible for use at Power Boiler No. 1 and do not further consider it in this evaluation. Domtar also questioned the technical feasibility of SNCR for bark fired boilers and boilers with high load swings such as Power Boiler No. 1, but in response to our comments, SNCR was evaluated for Power Boiler No. 1 in Domtar's 2014 BART analysis.

Domtar's 2014 BART analysis evaluated SNCR at removal efficiencies of 20%, 32.5%, and 45% for Power Boiler No. 1. The estimated 32.5% and 45% removal efficiencies were based on equipment vendor estimates that came from the vendor's proposal,[85] which according to the facility, is not an appropriations request level quote and

[80] The visibility impact shown represents the highest 98th percentile value among the three modeled years.

[81] 70 FR 39116.

[82] The curve equation is Y = 0.4005 * X − 0.2645, where Y = pounds of sulfur emitted per ton dry fuel feed to the boiler and X = pounds of sulfur input per ton of dry bark. The purpose of this equation is to factor in the degree of SO_2 scrubbing provided by the combustion of bark.

[83] Background information and an explanation of the site specific curve equation provided by Domtar can be found in the documents titled ''Site Specific Curve Equation Background_Domtar PB No1,'' and ''1PB SO_2 Emissions from Curve.'' Copies of these documents can be found in the docket for this proposed rulemaking.

[84] See the document titled ''Domtar Responses to ADEQ Regarding Region 6 Comments on Domtar BART Analysis,'' p. 10. A copy of this document can be found in the docket for our proposed rulemaking.

[85] Fuel Tech Proposal titled ''Domtar Paper Ashdown, Arkansas—NO_X Control Options, Power Boilers 1 and 2,'' dated June 29, 2012. A copy of the vendor proposal is included under Appendix D to the ''Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41–00002),'' originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis and its appendices is found in the docket for our proposed rulemaking.

therefore needs further refinement.[86] For example, Domtar's 2014 BART analysis discusses that for a base loaded pulp mill boiler with steady flue gas flow patterns and temperature distribution across the flue gas pathway, SNCR can achieve a 45% removal efficiency. However, Power Boiler No. 1 is not a base loaded boiler. Domtar's 2014 BART analysis states that for pulp mill boilers with fluctuating loads (*i.e.,* high load swing), such as Power Boiler No. 1, SNCR is used primarily for polishing purposes (*i.e.,* < 20 to 30% NO_X reduction) and it is uncertain whether higher removal efficiencies are achievable on a long-term basis. The facility believes that 20% removal efficiency, which has been demonstrated at a similar bark fired power boiler at another paper mill, is the most reasonable estimate of the removal efficiency of SNCR for Power Boiler No. 1.

In Domtar's 2014 BART analysis, the capital costs, operating costs, and cost-effectiveness of SNCR were calculated based on methods and assumptions found in our Control Cost Manual, and supplemented with mill-specific cost information for water, fuels, and ash disposal and urea solution usage estimates from the equipment vendor. The capital cost was annualized over a 30-year period and then added to the annual operating cost to obtain the total annualized costs. The annual emissions reductions associated with each NO_X control option were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emissions used in the calculations are the uncontrolled actual emissions from the 2009–2011 baseline period. The average cost-effectiveness was calculated by dividing the total annual cost by the estimated annual NO_X emissions reductions. The table below summarizes the cost of NO_X controls for Power Boiler No. 1.

TABLE 46—SUMMARY OF COST OF NO_X CONTROLS FOR POWER BOILER NO. 1

NO_X Control scenarios	Baseline emission rate (NO_X tpy)	NO_X Control efficiency (%)	Annual emissions reduction (NO_X tpy)	Capital cost ($)	Total annual cost ($/yr)	Average cost effectiveness ($/ton)	Incremental cost-effectiveness ($/ton)
SNCR—20%	440	20	88	2,152,365	1,118,178	12,700	....
SNCR—32.5%	440	32.5	143	2,423,587	1,144,103	7,996	471
SNCR—45%	440	45	198	2,707,431	1,513,602	7,640	6,718

Domtar's 2014 BART analysis did not identify any energy or non-air quality environmental impacts associated with the use of SNCR. We are not aware of any unusual circumstances at the facility that create greater non-air quality environmental impacts than experienced elsewhere that may provide a basis for the elimination of these control options as BART (40 CFR part 51, Appendix Y, section IV.D.4.i.2.). Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with the operation of NO_X controls at Power Boiler No. 1 that would affect our proposed BART determination.

Consideration of the presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: First, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. Power Boiler No. 1 is currently equipped with a combustion air system to optimize boiler combustion efficiency, which has the co-benefit of reducing emissions. The baseline emission rate used in the cost calculations and visibility modeling reflects the use of the existing combustion air system.

In the 2014 BART analysis, Domtar assessed the visibility improvement associated with SNCR by modeling the NO_X emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rate to the visibility impairment associated with the controlled emission rates as measured by the 98th percentile modeled visibility impact. The table below shows a comparison of the baseline (*i.e.,* existing) visibility impacts and the visibility impacts associated with SNCR.

TABLE 47—DOMTAR ASHDOWN MILL POWER BOILER NO. 1: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO SNCR

Class I area	Baseline visibility impact (dv)	SNCR—20%		SNCR—32.5%		SNCR—45%	
		Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	0.335	0.274	0.061	0.237	0.098	0.199	0.136
Upper Buffalo	0.038	0.031	0.007	0.027	0.011	0.023	0.015
Hercules-Glades	0.020	0.017	0.003	0.014	0.006	0.012	0.008
Mingo	0.014	0.011	0.003	0.009	0.005	0.008	0.006
Cumulative Visibility Improvement (Δdv)	....	....	0.074	....	0.12	....	0.165

The table above shows that the installation and operation of SNCR is projected to result in visibility improvements of up to 0.136 dv at any single Class I area when operated at 45% removal efficiency, 0.098 dv when operated at 32.5% removal efficiency, and 0.061 dv when operated at 20%

[86] See the document titled "Domtar Responses to ADEQ Regarding Region 6 Comments on Domtar BART Analysis," p. 9. A copy of this document can be found in the docket for our proposed rulemaking.

removal efficiency (based on the 98th percentile modeled visibility impacts).

Our Proposed NO_X BART Determination: Taking into consideration the five factors, we are proposing to determine that NO_X BART for the Domtar Ashdown Mill Power Boiler No. 1 is an emission limit of 207.4 lb/hr on a 30 boiler-operating-day rolling average, where boiler-operating-day is defined as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. This emission limit is based on the boiler's NO_X baseline emission rate and therefore represents current operating conditions. MdN was determined to be not technically feasible for use at Power Boiler No. 1 because it has not been fully demonstrated for this source type and incorporates FGR, which is technically infeasible for use at the boiler. The installation and operation of SNCR is projected to result in some visibility improvement at the Class I areas. As discussed in more detail above, we concur with Domtar's position that 20% removal efficiency is the most reasonable estimate of the level of NO_X control SNCR can achieve at Power Boiler No. 1. When operated at 20% removal efficiency, SNCR is projected to result in visibility improvement of up to 0.061 dv at any single Class I area and is estimated to cost $12,700 per ton of NO_X removed. We do not believe this high cost justifies the modest visibility improvement projected from the installation and operation of SNCR at 20% removal efficiency. Although there is uncertainty as to whether SNCR can achieve a long term removal efficiency of 45% or even 32.5% at Power Boiler No. 1, we believe that the associated costs are also too high to justify the small projected visibility benefits. Installation and operation of SNCR at a 45% removal efficiency is projected to result in a visibility improvement of up to 0.136 dv at any single Class I area and is estimated to cost $7,640 per ton of NO_X removed. The operation of SNCR at a 32.5% removal efficiency is projected to result in visibility improvement of up to 0.098 dv at any single Class I area and is estimated to cost $7,996 per ton of NO_X removed. Therefore, we are proposing to determine that NO_X BART for Power Boiler No. 1 is no additional control and are proposing that an emission limit of 207.4 lb/hr on a 30 boiler-operating-day rolling average satisfies NO_X BART. In this particular case, we are defining boiler-operating-day as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. Power Boiler No. 1 is not currently equipped with a CEMS. To demonstrate compliance with this NO_X BART emission limit we are proposing to require annual stack testing. We are inviting public comment on the appropriateness of this method for demonstrating compliance with the NO_X BART emission limit for Power Boiler No. 1. Since this proposed BART determination does not require the installation of control equipment, we are proposing that this NO_X emission limit be complied with by the effective date of the final action. We are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with this proposed BART determination.

c. *Proposed SO_2 BART Analysis and Determination for Power Boiler No. 2.* Power Boiler No. 2 is currently equipped with two venturi wet scrubbers in parallel for removal of particulates and SO_2. Domtar's 2014 BART analysis evaluated upgrades to the existing venturi wet scrubbers and new add-on spray scrubbers for Power Boiler No. 2.[87] Domtar's analysis explains that it contracted with a vendor to evaluate upgrades to the existing venturi scrubbers and provide a quote for a new add-on spray scrubber system that would be installed downstream of the existing venturi scrubbers.[88] Domtar's analysis states that the existing venturi scrubbers achieve an SO_2 control efficiency of approximately 90% and notes that this is within the normal range for the highest control efficiency achieved by SO_2 control technologies. Domtar's analysis indicates that the upgrades it considered for the existing venturi scrubbers include: (1) The elimination of bypass reheat, (2) the installation of liquid distribution rings, (3) the installation of perforated trays, (4) improvements to the auxiliary system requirement, and (5) a redesign of spray header and nozzle configuration. Domtar's analysis states that any additional control that could potentially be achieved from implementation of such upgrades would be marginal, but the facility was unable to quantify the potential additional control. Therefore, it was determined that the installation of new add-on spray scrubbers to operate downstream of the existing scrubbers was more feasible than any upgrade option. The remainder of Domtar's analysis focused on the add-on spray scrubber option. Based on the information provided to Domtar by the vendor, the add-on spray scrubbers would utilize sodium hydroxide (NaOH), bleach plant EO filtrate (*i.e.,* bleaching filtrate), and water as the scrubbing reagent. The add-on spray scrubbers are estimated to achieve 90% control efficiency above the SO_2 removal the existing venturi scrubbers are currently achieving. In Domtar's analysis, it is estimated that a controlled SO_2 emission rate of 78.8 lb/hr would be achieved by the operation of add-on spray scrubbers installed downstream of the existing venturi scrubbers.

Domtar's estimates of the capital and operating and maintenance costs of add-on spray scrubbers for Power Boiler No. 2 were based on the equipment vendor's budget proposal and on calculation methods from our Control Cost Manual. Domtar annualized the capital cost of the add-on spray scrubbers over a 30-year amortization period and then added these to the annual operating costs to obtain the total annualized cost.[89] The average cost-effectiveness in dollars per ton removed was calculated by dividing the total annualized cost by the annual SO_2 emissions reductions. The average cost-effectiveness of the add-on spray scrubbers for Power Boiler No. 2 was estimated to be $5,258 per ton of SO_2 removed (see table below). Domtar's analysis notes that because of constricted space, there is no existing property or adequate structure to support the add-on spray scrubber equipment. In our discussions with Domtar, the facility indicated that the installation of add-on spray scrubbers would require construction at the facility to accommodate the equipment, but an estimate of these costs was not available and therefore not factored into the cost estimates presented in Domtar's analysis.

[87] See ''Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41–00002),'' originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis is found in the docket for our proposed rulemaking.

[88] See ''Lundberg Budget Proposal Spray Scrubber—Domtar Industries, Ashdown, AR,'' dated April 17, 2014. The vendor proposal is found under Appendix D to Domtar's BART analysis titled ''Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41–00002),'' originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC.

[89] See Appendices B and D to the ''Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41–00002),'' originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC.

TABLE 48—SUMMARY OF COSTS FOR ADD-ON SPRAY SCRUBBER FOR POWER BOILER NO. 2

Control technology	Baseline emission rate (SO_2 tpy)	Controlled emission level (lb/hr)	Controlled emission rate (tpy)	Annual emissions reductions (SO_2 tpy)	Capital cost * ($)	Annual direct O&M cost ($/yr)	Annual indirect O&M cost ($/yr)	Total annual cost ($/yr)	Average cost effectiveness ($/ton)
Add-on Spray Scrubber	2,078	78.8	208	1,870	7,175,000	8,833,382	421,789	9,833,378	5,258

* Capital cost does not include new construction to accommodate equipment.

Domtar's 2014 BART analysis did not identify any energy or non-air quality environmental impacts associated with the use of add-on spray scrubbers. We are not aware of any unusual circumstances at the facility that create non-air quality environmental impacts associated with the use of add-on spray scrubbers greater than experienced elsewhere that may therefore provide a basis for the elimination of this control option as BART (40 CFR part 51, Appendix Y, section IV.D.4.i.2.). Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with this control option at Power Boiler No. 2 that would affect our proposed BART determination.

Consideration of the presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: First, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. Power Boiler No. 2 is equipped with multiclones for particulate removal and two venturi scrubbers in parallel for control of SO_2 emissions. It is also equipped with a combustion air system including overfire air to optimize boiler combustion efficiency, which also helps control emissions. The baseline emission rate used in the cost calculations and visibility modeling reflects the use of these existing controls. As discussed above, Domtar's analysis also evaluated upgrades to the existing venturi scrubbers to potentially achieve greater SO_2 control efficiency. Another option we have identified to achieve greater SO_2 control efficiency of the existing scrubbers involves using additional scrubbing reagent, but this was not considered in Domtar's 2014 BART analysis. Our analysis of this control option is presented below, following the analysis of add-on spray scrubbers.

In the 2014 BART analysis, Domtar assessed the visibility improvement associated with the add-on spray scrubbers by modeling the controlled SO_2 emission rate using CALPUFF, and then comparing the visibility impairment associated with the controlled emission rate to that of the baseline emission rate as measured by the 98th percentile modeled visibility impact. The table below shows a comparison of the baseline (*i.e.,* existing) visibility impacts and the visibility impacts associated with the add-on spray scrubbers. The installation and operation of add-on spray scrubbers is projected to result in visibility improvement of 0.146 dv at Caney Creek. The visibility improvement is projected to range from 0.026–0.053 dv at each of the other Class I areas.

TABLE 49—DOMTAR ASHDOWN MILL POWER BOILER NO. 2: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO ADD-ON SPRAY SCRUBBERS

Class I area	Baseline visibility impact [90] (dv)	Add-on spray scrubbers	
		Visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	0.844	0.698	0.146
Upper Buffalo	0.146	0.093	0.053
Hercules-Glades	0.105	0.054	0.051
Mingo	0.065	0.039	0.026
Cumulative Visibility Improvement (Δdv)			0.276

As mentioned above, another option not evaluated in Domtar's 2014 BART analysis is the optimization of the existing venturi scrubbers to achieve a higher SO_2 control efficiency through the use of additional scrubbing reagent. Following discussions between us and Domtar, the facility provided additional information regarding the existing venturi scrubbers, including a description of the internal structure of the scrubbers, whether any scrubber upgrades have taken place, the type of reagent used, how the facility determines how much reagent to use, and the SO_2 control efficiency.[91] Domtar confirmed that no upgrades to the scrubbers have ever been performed and stated that 100% of the flue gas is treated by the scrubber systems. The scrubbing solution used in the venturi scrubbers is made up of three components: 15% caustic solution (*i.e.,* NaOH), bleach plant EO filtrate (typical pH above 9.0), and demineralizer anion rinse water (approximately 2.5% NaOH). The bleach plant EO filtrate and demineralizer anion rinse water are both waste byproducts from the processes at the plant. The 15% caustic solution is added to adjust the pH of the scrubbing solution and maintain it within the required range to ensure that sufficient SO_2 is removed from the flue gas in the scrubber to meet the permitted SO_2

[90] The baseline visibility impacts reflect the operation of the existing venturi scrubbers.

[91] See the following: Letters dated July 9, 2014; July 21, 2014; August 15, 2014; August 29, 2014; and September 12, 2014, from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. Copies of these letters and all attachments are found in the docket for our proposed rulemaking.

emission limit of 1.20 lb/MMBtu on a three hour average. Each venturi scrubber has a recirculation tank that is equipped with level control systems to ensure that an adequate supply of the scrubbing solution is maintained. There are pH controllers in place that provide signals for the 15% caustic flow controllers to adjust the flow of the caustic solution to bring the pH into the desired set point range. The pH controllers are overridden in the event that SO_2 levels measured at the stack by the CEMS are above the operator set point of 0.86 lb/MMBtu on a two hour average (the SO_2 permit limit is 1.20 lb/MMBtu on a three hour average). This allows additional caustic feed to the scrubber solution to increase the pH and reduce the SO_2 measured at the stack. According to Domtar, the scrubber systems operate in this manner to maintain continuous compliance with permitted emission limits.

Domtar provided monthly average data for 2011, 2012, and 2013 on monitored SO_2 emissions from Power Boiler No. 2, mass of the fuel burned for each fuel type, and the percent sulfur content of each fuel type burned.[92] Based on the information provided by Domtar, the monthly average SO_2 control efficiency of the existing scrubbers for the 2011–2013 period ranged from 57% to 90%. The data indicate that the monthly average control efficiency of the scrubbers is usually below 90%. The information provided also indicates that the facility could add more scrubbing solution to achieve greater SO_2 removal than what is necessary to meet permit limits. We believe that it is feasible for the facility to use additional scrubbing solution to consistently achieve at least a 90% SO_2 removal on a monthly average basis. To estimate the SO_2 annual emissions reductions expected from increasing the control efficiency of the scrubbers through the use of additional scrubbing solution, we calculated the annual average SO_2 control efficiency of the existing scrubbers. Based on the monthly average SO_2 control efficiency data for the 2011–2013 period, we estimated the annual average SO_2 control efficiency for the three-year period to be approximately 69%.[93] Considering the baseline annual emissions for Power Boiler No. 2 are 2,078 SO_2 tpy, and assuming that the scrubbers currently operate at an annual average control efficiency of 69%, we have estimated that the uncontrolled annual emissions would be 6,769 SO_2 tpy and that operating the scrubbers at 90% control efficiency would result in controlled annual emissions of 677 SO_2 tpy. By subtracting the controlled annual emission rate of 677 SO_2 tpy from the baseline annual emission rate of 2,078 SO_2 tpy, we estimate that increasing the control efficiency of the existing venturi scrubbers from current levels to 90% control efficiency would result in annual emissions reductions of 1,401 SO_2 tpy from baseline levels.[94] Based on the cost information provided by the facility, increasing the monthly average SO_2 control efficiency of the existing venturi scrubbers from current levels to 90% control efficiency would require replacing two scrubber pumps, which involves capital costs of $200,000.[95] It would also require additional scrubbing reagent, treatment of additional wastewater, treatment of additional raw water, and additional energy usage, which involves annual operation and maintenance costs of approximately $1.96 million. Based on the information provided by Domtar, we estimate the average cost-effectiveness of using additional scrubbing reagent to increase the SO_2 control efficiency of the existing venturi scrubbers from the current control efficiency (estimated to be 69%) to 90% is $1,411 per ton of SO_2 removed. The cost information is presented in the table below. To determine the controlled emission rate that corresponds to the operation of the existing venturi scrubbers at a 90% removal efficiency, we first determined the SO_2 emission rate that corresponds to the operation of the scrubbers at the current control efficiency of 69%. Based on emissions data we obtained from Domtar, we determined that the No. 2 Power Boiler's annual average SO_2 emission rate for the years 2009–2011 was 280.9 lb/hr.[96] This annual average SO_2 emission rate corresponds to the operation of the scrubbers at a 69% removal efficiency. We also estimated that 100% uncontrolled emissions would correspond to an emission rate of approximately 915 lb/hr. Application of 90% control efficiency to this results in a controlled emission rate of 91.5 lb/hr, or 0.11 lb/MMBtu based on the boiler's maximum heat input of 820 MMBtu.[97]

TABLE 50—SUMMARY OF COST OF USING ADDITIONAL SCRUBBING REAGENT TO INCREASE CONTROL EFFICIENCY OF EXISTING VENTURI SCRUBBERS AT POWER BOILER NO. 2

Control option	Baseline emission rate (SO_2 tpy)	Controlled emission rate (tpy)	Annual emissions reductions (SO_2 tpy)	Capital costs [98] ($)	Operation & maintenance cost [99] ($/yr)	Total annual cost ($/yr)	Average cost effectiveness ($/ton)
Use of Additional Scrubbing Reagent	2,078	677	1,401	200,000	1,960,434	1,976,554	1,411

[92] August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. A copy of this letter and an Excel file attachment titled ''Domtar 2PB Monthly SO_2 Data,'' are found in the docket for our proposed rulemaking.

[93] See the spreadsheet titled ''Domtar 2PB Monthly SO_2 Data.'' This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled ''Domtar PB No2—Cost Effectiveness calculations.'' Copies of these documents can be found in the docket for this proposed rulemaking.

[94] See the spreadsheet titled ''Domtar PB No2—Cost Effectiveness calculations.'' A copy of this spreadsheet can be found in the docket for this proposed rulemaking.

[95] September 30, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled ''Domtar PB No2—Cost of Using Additional Scrubbing Reagent. Copies of these documents can be found in the docket for this proposed rulemaking.

[96] See the spreadsheet titled ''Domtar 2PB Monthly SO_2 Data.'' This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled ''No2 Boiler_Monthly Avg SO_2 emission rate and calculations.'' Copies of these documents can be found in the docket for this proposed rulemaking.

[97] See the spreadsheet titled ''No2 Boiler_ Monthly Avg SO_2 emission rate and calculations.'' A copy of this spreadsheet can be found in the docket for this proposed rulemaking.

[98] The capital costs consist of two new pumps for the existing scrubber system.

[99] The operation and maintenance costs consist of the following costs: Additional scrubbing reagent, treatment of additional wastewater, treatment of additional raw water, and additional energy usage.

Using the visibility modeling analysis of the baseline visibility impacts from Power Boiler No. 2 and the visibility improvement projected from the installation and operation of new add-on spray scrubbers, we have extrapolated the visibility improvement projected as a result of using additional scrubbing reagent to increase the SO_2 control efficiency of the existing venturi scrubbers from the current control efficiency (estimated to be 69%) to 90%, or an outlet emission rate of 0.11 lb/MMBtu. We have assumed that the maximum 24-hour baseline emission rate used in the visibility modeling represents the operation of the existing venturi scrubbers at a 69% control efficiency. We estimate that the visibility improvement of using additional scrubbing reagent to increase the SO_2 control efficiency of the existing venturi scrubbers to 90% control efficiency is 0.139 dv at Caney Creek and 0.05 dv or less at each of the other Class I areas (see table below).

TABLE 51—DOMTAR ASHDOWN MILL POWER BOILER NO. 2: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT FROM USE OF ADDITIONAL SCRUBBING REAGENT

Class I area	Baseline visibility impact (dv)	Add-on spray scrubber impacts (dv)		Estimated impacts from use of additional reagent (dv)	
		Visibility impact (dv)	Visibility improvement from baseline (dv)	Visibility impact (dv)	Visibility improvement from baseline (dv)
Caney Creek	0.844	0.698	0.146	0.705	0.139
Upper Buffalo	0.146	0.093	0.053	0.096	0.05
Hercules-Glades	0.105	0.054	0.051	0.057	0.048
Mingo	0.065	0.039	0.026	0.04	0.025
Cumulative Visibility Improvement (dv)			0.276		0.262

Our Proposed SO_2 BART Determination: Taking into consideration the five factors, we propose to determine that SO_2 BART for Power Boiler No. 2 is an emission limit of 0.11 lb/MMBtu on a 30 boiler-operating-day rolling average, which we estimate is representative of operating the existing scrubbers at 90% control efficiency. In this particular case, we define boiler-operating-day as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. We are inviting public comment specifically on the appropriateness of this proposed SO_2 emission limit. We believe that this emission limit can be achieved by using additional scrubbing reagent in the operation of the existing venturi scrubbers. We estimate that operating the existing scrubbers to achieve this level of control would result in visibility improvement of 0.139 dv at Caney Creek and 0.05 dv or lower at each of the other Class I areas. We estimate the cumulative visibility improvement at the four Class I areas to be 0.262 dv. Based on the cost information provided by the facility, we have estimated that the use of additional scrubbing reagent to increase the control efficiency of the existing venturi scrubbers is estimated to cost $1,411 per ton of SO_2 removed. Based on Domtar's BART analysis, new add-on spray scrubbers that would be operated downstream of the existing venturi scrubbers are projected to result in visibility improvement of 0.146 dv at Caney Creek and 0.053 dv or lower at each of the other Class I areas. The cumulative visibility improvement at the four Class I areas is projected to be 0.276 dv. The cost of add-on spray scrubbers is estimated to be $5,258 per ton of SO_2 removed, not including additional construction costs that would likely be incurred to make space to house the new scrubbers. We do not believe that the amount of visibility improvement that is projected from the installation and operation of new add-on spray scrubbers would justify their high average cost-effectiveness. The incremental visibility improvement of new add-on spray scrubbers compared to using additional scrubbing reagent to increase the control efficiency of the existing venturi scrubbers ranges from 0.001 to 0.007 dv at each Class I area, yet the incremental cost-effectiveness is estimated to be $16,752. We do not believe the incremental visibility benefit warrants the higher cost associated with new add-on spray scrubbers. Therefore, we are proposing to determine that SO_2 BART for Power Boiler No. 2 is an emission limit of 0.11 lb/MMBtu on a 30 boiler-operating-day rolling averaging basis, and are inviting comment on the appropriateness of this emission limit. We propose to require the facility to demonstrate compliance with this emission limit using the existing CEMS. Since the SO_2 emission limit we are proposing can be achieved with the use of the existing venturi scrubbers but will require scrubber pump upgrades and additional scrubbing reagent, we propose to require compliance with this BART emission limit no later than 3 years from the effective date of the final action, but are inviting public comment on the appropriateness of a compliance date anywhere from 1–5 years.

d. *Proposed NO_X BART Analysis and Determination for Power Boiler No. 2.* For NO_X BART, Domtar's 2014 BART analysis evaluated LNB, SNCR, and Methane de-NO_X (MdN). In the 2006/2007 Domtar BART analysis, which was submitted in the 2008 Arkansas RH SIP, other NO_X controls were also evaluated but found by the State to be either already in use or not technically feasible for use at Power Boiler No. 2. Fuel blending, boiler operational modifications, and boiler tuning/optimization are already in use at the source, while FGR, OFA, and SCR were found to be technically infeasible for use at Power Boiler No. 2. Domtar did not further evaluate these NO_X controls, and instead focused on LNB, SNCR, and MdN in its 2014 BART analysis for Power Boiler No. 2.

MdN utilizes the injection of natural gas together with recirculated flue gases to create an oxygen-rich zone above the combustion grate. Air is then injected at a higher furnace elevation to burn the combustibles. In response to comments provided by us regarding Domtar 2014 BART analysis, Domtar stated that discussions regarding the technical infeasibility of MdN in the 2006/2007 Domtar BART analysis, submitted as part of the 2008 Arkansas RH SIP, remain correct.[100] The 2006/2007 Domtar BART analysis submitted in the 2008 Arkansas RH SIP discussed that MdN has not been fully demonstrated for this type of boiler and incorporates FGR, which is considered technically infeasible for use at Power Boiler No. 2. Domtar also stated it recently completed additional research and found that since the 2006/2007 Domtar BART analysis, MdN has not been placed into operation in power boilers at paper mills or any comparable source types. We are also not aware of any power boilers at paper mills that operate MdN for NO_X control, and agree that this control can be considered technically infeasible for use at Power Boiler No. 2 and do not further consider it in this evaluation. Domtar also questioned the technical feasibility of SNCR for boilers with high load swing such as Power Boiler No. 2, but in response to comments from us, SNCR was evaluated in Domtar's 2014 BART analysis.

Based on vendor estimates, the 2006/2007 Domtar BART analysis estimated the potential control efficiency of LNB to be 30%. In Domtar's 2014 BART analysis, SNCR was evaluated at a control efficiency of 27.5% and 35% for Power Boiler No. 2. These values were based on SNCR control efficiency estimates that came from the equipment vendor's proposal,[101] which according to the facility, is not an appropriations request level quote and therefore requires further refinement.[102] For example, Domtar's 2014 BART analysis discusses that for a base loaded coal boiler with steady flue gas flow patterns and temperature distribution across the flue gas pathway, SNCR is typically capable of achieving 50% NO_X reduction. However, Power Boiler No. 2 is not a base loaded boiler and does not have steady flue gas flow patterns or steady temperature distribution across the flue gas pathway. To demonstrate the wide range in temperature at Power Boiler No. 2 and its relationship to steam demand, Domtar obtained an analysis of furnace exit gas temperatures for Power Boiler No. 2 from an engineering consultant.[103] The furnace exit gas temperatures were analyzed for a 12-day period that according to Domtar is representative of typical boiler operations. The consultant's report indicated that furnace exit gas temperatures are representative of temperatures in the upper portion of the furnace, which is the optimal location for installation of the SNCR injection nozzles. The consultant estimated that 1700–1800°F represents the temperature range at which SNCR can be expected to reach 40% control efficiency at the current boiler operating conditions. It was found that there is wide variability in the furnace exit gas temperatures for Power Boiler No. 2, with temperatures ranging from 1000–2000°F. The data also indicate that there is a direct positive relationship between boiler steam demand and furnace exit gas temperatures. It was also found that Power Boiler No. 2 operated in the optimal temperature zone at which SNCR can be expected to reach 40% control efficiency for only a total of 20 hours over the 12-day period analyzed (288 continuous hours), which is approximately 7% of the time. According to Domtar, the significant temperature swings, which are due to load following and steam demand variability, create a scenario where urea injection will either be too high or too low. When not enough urea is injected, NO_X removal will be less than projected and when too much urea is injected, excess ammonia slip will occur. Domtar stated that the observed significant temperature swings demonstrate that it will be difficult to maintain stable, optimal furnace temperatures at which urea can be injected to effectively reduce NO_X with minimal ammonia slip. We agree that because of the wide variability in steam demand and wide range in furnace temperature observed at Power Boiler No. 2, the NO_X control efficiency of SNCR at the boiler would not reach optimal control levels on a long-term basis. We also believe there is uncertainty as to the level of control efficiency that SNCR would be able to achieve on a long-term basis for Power Boiler No. 2. However, we further consider SNCR in the remainder of the analysis.

In the 2006/2007 Domtar BART analysis, the capital cost, operating cost, and cost-effectiveness of LNB were estimated based on vendor estimates. The analysis was based on a 10-year amortization period, based on the equipment's life expectancy. However, since we believe a 30-year equipment life is a more appropriate estimate for LNB, we have revised the cost estimate for LNB.[104] The annual emissions reductions used in the cost-effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. We have also revised the average cost-effectiveness calculations presented in the 2006/2007 Domtar BART analysis for LNB by using the boiler's actual annual uncontrolled NO_X emissions rather than the maximum 24-hour emission rate as the baseline annual emissions. The table below summarizes the estimated cost of LNB for Power Boiler No. 2, based on the cost estimates in the 2006/2007 Domtar BART analysis our revisions discussed above.

In Domtar's 2014 BART analysis, the capital costs, operating costs, and cost-effectiveness of SNCR were calculated based on methods and assumptions found in our Control Cost Manual, and supplemented with mill-specific cost information for water, fuels, and ash disposal and urea solution usage estimates from the equipment vendor. The two SNCR control scenarios evaluated were 27.5% and 35% control efficiencies. The capital cost was annualized over a 30-year period and then added to the annual operating cost to obtain the total annualized costs. The annual emissions reductions associated with each NO_X control option were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emissions used in the calculations are the uncontrolled actual emissions from the 2001–2003 baseline period. The average cost-effectiveness was calculated by dividing the total annual cost by the estimated annual NO_X emissions reductions. The table below summarizes the cost of SNCR for Power Boiler No. 2.

[100] A copy of Domtar's response is found in the docket for this proposed rulemaking. See email from Kelly Crouch, dated May 16, 2014.

[101] Fuel Tech Proposal titled ''Domtar Paper Ashdown, Arkansas- NO_X Control Options, Power Boilers 1 and 2,'' dated June 29, 2012. A copy of the vendor proposal is included under Appendix D to the ''Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41–00002),'' originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis and its appendices is found in the docket for our proposed rulemaking.

[102] See the document titled ''Domtar Responses to ADEQ Regarding Region 6 Comments on Domtar BART Analysis,'' p. 9. A copy of this document can be found in the docket for our proposed rulemaking.

[103] September 12, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. A copy of this letter and its attachments are found in the docket for our proposed rulemaking.

[104] See the spreadsheet titled ''Domtar PB No. 2 LNB_cost revisions.'' A copy of this spreadsheet is found in the docket for this proposed rulemaking.

TABLE 52—SUMMARY OF COST OF NO_X CONTROLS FOR POWER BOILER NO. 2

NO_X Control scenario	Baseline emission rate (NO_X tpy)	NO_X Removal efficiency of controls (%)	Annual emissions reduction (NO_X tpy)	Capital cost ($)	Total annual cost ($/yr)	Average cost effectiveness ($/ton)	Incremental cost-effectiveness ($/ton)
SNCR—27.5%	1,536	27.5	422	2,681,678	843,575	1,998	
LNB	1,536	30	461	6,131,745	899,605	1,951	1,437
SNCR—35%	1,536	35	537	2,877,523	1,026,214	1,909	1,666

Domtar's 2014 BART analysis did not identify any energy or non-air quality environmental impacts associated with the use of LNB or SNCR. We are not aware of any unusual circumstances at the facility that could create non-air quality environmental impacts associated with the operation of NO_X controls greater than experienced elsewhere and that may therefore provide a basis for the elimination of these control options as BART (40 CFR part 51, Appendix Y, section IV.D.4.i.2.). Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with NO_X controls at Power Boiler No. 2 that would affect our proposed BART determination.

Consideration of the presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: First, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. Power Boiler No. 2 is equipped with multiclones for particulate removal and two venturi scrubbers in parallel for control of SO_2 emissions. It is also equipped with a combustion air system including overfire air to optimize boiler combustion efficiency, which also helps control emissions. The NO_X baseline emission rate used in the cost calculations and visibility modeling reflects the use of these existing controls.

In the 2014 BART analysis, Domtar assessed the visibility improvement associated with LNB and SNCR by modeling the NO_X emission rates associated with each control option using CALPUFF, and then comparing the visibility impairment associated with the baseline emission rate to the visibility impairment associated with the controlled emission rates as measured by the 98th percentile modeled visibility impact. The table below shows a comparison of the baseline (*i.e.,* existing) visibility impacts and the visibility impacts associated with LNB and SNCR.

TABLE 53—DOMTAR ASHDOWN MILL POWER BOILER NO. 2: SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO NO_X CONTROLS

Class I area	Baseline visibility impact (dv)	SNCR—27.5% Control efficiency		LNB 30% Control efficiency		SNCR—35% Control efficiency	
		Visibility impact (dv)	Visibility improvement from baseline (dv)	Visibility impact (dv)	Visibility improvement from baseline (dv)	Visibility impact (dv)	Visibility improvement from baseline (dv)
Caney Creek	0.844	0.678	0.166	0.663	0.181	0.632	0.212
Upper Buffalo	0.146	0.134	0.012	0.132	0.014	0.129	0.017
Hercules-Glades	0.105	0.095	0.010	0.094	0.011	0.092	0.013
Mingo	0.065	0.060	0.005	0.060	0.005	0.059	0.006
Cumulative Visibility Improvement (dv)			0.193		0.211		0.248

The table above shows that the installation and operation of SNCR when operated at 35% control efficiency, if feasible, is projected to result in visibility improvement of 0.212 dv at Caney Creek and 0.017 dv or less at each of the other Class I areas. When operated at 27.5% control efficiency, if feasible, SNCR is projected to result in visibility improvement of 0.166 dv at Caney Creek and 0.012 dv or less at each of the other Class I areas. The installation and operation of LNB is projected to result in visibility improvement of 0.181 dv at Caney Creek and 0.014 dv or less at each of the other Class I areas.

Our Proposed NO_X BART Determination: Taking into consideration the five factors, we are proposing to determine that NO_X BART for the Domtar Ashdown Mill Power Boiler No. 2 is an emission limit of 345 lb/hr on a 30 boiler-operating-day rolling averaging basis, based on the installation and operation of LNB. In this particular case, we define boiler-operating-day as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. MdN was determined to be not technically feasible for use at Power Boiler No. 2 because it has not been fully demonstrated for this type of boiler and incorporates FGR, which is technically infeasible for use at the boiler. The installation and operation of SNCR is projected to result in some visibility improvement at the Class I areas when operated at 27.5% and 35% control efficiency. However, based on the information provided by the facility, we believe that because of the wide variability in steam demand and wide range in furnace temperature observed in Power Boiler No. 2, the NO_X control efficiency of SNCR at the boiler would not reach optimal control levels on a long-term basis. There is uncertainty as to the level of control efficiency that SNCR would be able to achieve on a long-term basis for Power Boiler No. 2. The installation and operation of LNB is projected to result in visibility improvement of 0.181 dv at Caney Creek and 0.005–0.014 dv at each of the other Class I areas. The installation and operation of LNB is estimated to cost $1,951 per ton of NO_X removed, which we consider to be cost-effective. Therefore, we are proposing to determine that NO_X BART for Power Boiler No. 2 is an emission limit of 345 lb/hr on a 30 boiler-operating-day rolling average basis, based on the installation and operation of LNB. We are proposing to require compliance with this emission limit no later than 3 years from the effective date of the final rule, and are inviting public comment on the appropriateness of this compliance date. We are proposing that the facility demonstrate compliance with this emission limit using the existing CEMS. We are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with this emission limit.

e. *PM BART Analysis and Determination for Power Boiler No. 2.* PM BART for Power Boiler No. 2 is addressed in Domtar's 2014 BART analysis. Power Boiler No. 2 is subject to the Boiler MACT standards required under CAA section 112, and found at 40 CFR part 63, subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Domtar streamlined the BART analysis for Power Boiler No. 2 by relying on the Boiler MACT standards for PM to satisfy the PM BART requirement. Power Boiler No. 2 was determined to fall under the ''biomass hybrid suspension grate'' subcategory for the Boiler MACT.[105] As such, Power Boiler No. 2 is subject to the Boiler MACT PM emission limit of 0.44 lb/MMBtu. The BART Guidelines provide that for VOC and PM sources subject to MACT standards, the BART analysis may be streamlined by including a discussion of the MACT controls and whether any major new technologies have been developed subsequent to the MACT standards.[106] The BART Guidelines discuss that there are many VOC and PM sources that are well controlled because they are regulated by the MACT standards, and in many cases it will be unlikely that emission controls more stringent than the MACT standards will be identified without identifying control options that would cost many thousands of dollars per ton. Therefore, the BART Guidelines provide that unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, the MACT standards may be relied on for purposes of BART. Domtar's 2014 BART analysis does not discuss whether any new technologies subsequent to the MACT standards have become available and whether they would lead to cost-effective increases in the level of PM control for Power Boiler No. 2. However, Domtar at one point estimated the cost of installing both an add-on spray scrubber and wet ESP on Power Boiler No. 2. Based on this cost information previously provided by Domtar,[107] we have determined that a wet ESP alone would have a purchased equipment cost (PEC) of $3.22 million and capital costs of approximately $11.3 million. The total annual cost of a wet ESP alone is estimated to be approximately $1.96 million. The average annual PM emissions from Power Boiler No. 2 for the 2001–2003 baseline period were 183 tpy. Assuming that the wet ESP has a 95% control efficiency for PM emissions, we estimate that it would remove 174 PM tpy. Based on this, we estimate that the average cost-effectiveness of installing and operating a wet ESP on Power Boiler No. 2 is $11,254 per PM ton removed. Additionally, an examination of the species contribution to the 98th percentile visibility impacts shows that PM emissions contribute a very small portion of the visibility impairment attributable to Power Boiler No. 2. As shown in the table below, the baseline visibility impairment attributable to Power Boiler No. 2 is 0.844 dv at Caney Creek and 0.146 dv or less at each of the other Class I areas, based on the 98th percentile visibility impacts. The PM species contribute only 1.06–4.58% of the baseline visibility impairment attributable to Power Boiler No. 2 at the modeled Class I areas.

TABLE 54—BASELINE VISIBILITY IMPAIRMENT AND SPECIES CONTRIBUTION FOR DOMTAR ASHDOWN MILL—POWER BOILER NO. 2

Emissions unit	Class I area	98th Percentile visibility impacts (dv) [108]	Species contribution to 98th percentile visibility impacts			
			98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Power Boiler No. 2	Caney Creek	0.844	22.04	70.68	4.58	2.69
	Upper Buffalo	0.146	76.99	20.76	2.26	0.00
	Hercules-Glades	0.105	61.17	37.68	1.06	0.09
	Mingo	0.065	81.46	15.47	3.07	0.00

Because of the very low baseline visibility impacts that are due to PM emissions from Power Boiler No. 2, we believe that there is potential for a very small amount of visibility improvement from the installation and operation of a wet ESP. We conclude that the installation and operation of a wet ESP for PM control is not cost-effective in light of the relatively small improvement in visibility. Therefore, we are proposing to find that the current Boiler MACT PM standard of 0.44 lb/MMBtu satisfies the PM BART requirement for Power Boiler No. 2. We are also proposing that the same method for demonstrating compliance with the Boiler MACT PM standard is to be used for demonstrating compliance with the PM BART emission limit. Because we are proposing a BART emission limit that represents current/baseline operations and no control equipment installation is necessary, we are proposing that this emission limitation be complied with for BART purposes from the date of effectiveness of the finalized action.

[105] See letter dated October 28, 2013, from Thomas Rheaume, Permits Branch Manager, ADEQ, to Ms. Kelly Crouch, Manager of Environmental, Energy, and Pulp Tech. at Domtar Ashdown Mill. A copy of this letter is found in the docket for this proposed rulemaking.

[106] 40 CFR part 51, Appendix Y, section IV.C.

[107] The cost estimate of new add-on spray scrubbers and a wet ESP for Power Boiler No. 2 is found in Appendix B to the analysis titled ''Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41–00002),'' dated June 28, 2013, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of the BART analysis is found in the docket for our proposed rulemaking.

[108] The visibility impact shown represents the highest 98th percentile value among the three modeled years.

IV. Our Proposed Reasonable Progress Analysis and Determinations

The Regional Haze Rule does not mandate specific milestones or rates of progress towards achieving the national visibility goal, but instead calls for states to establish goals that provide for ''reasonable progress'' toward achieving natural (*i.e.,* ''background'') visibility conditions. The Regional Haze Rule and section 169A of the CAA require the states, or us in the case of a FIP, to set RPGs by considering four factors: The costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources (collectively ''the RP factors'').[109] States, or us in the case of a FIP, have considerable flexibility in how they take these factors into consideration, as noted in our Reasonable Progress Guidance.[110] The RPGs must provide for an improvement in visibility on the most impaired days, and ensure no degradation in visibility on the least impaired days during the planning period.[111] Furthermore, if the projected progress for the worst days is less than the Uniform Rate of Progress (URP), then the state or EPA must demonstrate, based on the factors above, that it is not reasonable to provide for a rate of progress consistent with the URP.[112]

In our final action on the Arkansas RH SIP published on March 12, 2012, we disapproved the RPGs established by Arkansas for Caney Creek and Upper Buffalo because Arkansas did not establish the RPGs in accordance with the requirements of the CAA and the RHR.[113] Specifically, Arkansas did not take into consideration the four RP factors in establishing its RPGs for Caney Creek and Upper Buffalo, stating that it was an unnecessary exercise. Arkansas believed, incorrectly, that no additional analysis of potential reasonable progress measures was necessary because visibility projections for the Class I areas indicated improvements in visibility consistent with the URP. As discussed in our disapproval action, a state must determine whether additional control measures are reasonable based on a consideration of the four RP factors. Accordingly, in this proposed rule, we are evaluating the four RP factors to determine whether additional controls are reasonable and we are establishing RPGs for Caney Creek and Upper Buffalo after consideration of the RP factors.

A. Reasonable Progress Analysis of Point Sources

A discussion of the particular pollutants that contribute to visibility impairment at Arkansas' two Class I areas was provided in our October 17, 2011 proposed action on the 2008 Arkansas RH SIP (see 76 FR 64186). In that proposed action, we explained that CENRAP used CAMx with its Particulate Source Apportionment (PSAT) tool to provide source apportionment by geographic region and major source category (*i.e.,* point, natural, on-road, non-road, and area sources). Sulfate from all the source categories combined contributed 87.05 inverse megameters (Mm^{-1}) out of 133.93 Mm^{-1} of light extinction at Caney Creek and 83.18 Mm^{-1} out of 131.79 Mm^{-1} of light extinction at Upper Buffalo on the 20% worst days in 2002, which is approximately 65% and 63% of the total light extinction at each Class I area, respectively. Nitrate from all source categories combined contributed 13.78 Mm^{-1} out of 133.93 Mm^{-1} of light extinction at Caney Creek and 13.30 Mm^{-1} out of 131.79 Mm^{-1} of light extinction at Upper Buffalo, which is approximately 10% of the total light extinction in 2002 on the 20% worst days at each Class I area. The source category point sources contributed 81.04 Mm^{-1} out of 133.93 Mm^{-1} of light extinction at Caney Creek and 77.80 Mm^{-1} out of 131.79 Mm^{-1} of light extinction at Upper Buffalo on the 20% worst days in 2002 (see the tables below). This represents approximately 60% of the total light extinction at each Class I area. Each of the source categories other than the point source category, contribute a much smaller proportion of the total light extinction at each Class I area. We are therefore focusing only on the point sources category in our reasonable progress analysis for this regional haze planning period. Sulfate from point sources contributed 75.1 Mm^{-1} out of 133.93 Mm^{-1} of light extinction at Caney Creek and 72.17 Mm^{-1} out of 131.79 Mm^{-1} of light extinction at Upper Buffalo, which is approximately 56% of the total light extinction at Caney Creek and 55% of the total light extinction at Upper Buffalo. Nitrate from point sources contributed 4.06 Mm^{-1} out of 133.93 Mm^{-1} of light extinction at Caney Creek and 3.93 Mm^{-1} out of 131.79 Mm^{-1} of light extinction at Upper Buffalo, which is approximately 3% of the total light extinction at each Class I area. On the 20% worst days in 2002, sulfate from Arkansas point sources contributed 2.20% of the total light extinction at Caney Creek and 1.99% at Upper Buffalo, and nitrate from Arkansas point sources contributed 0.27% of the total light extinction at Caney Creek and 0.14% at Upper Buffalo.[114] For both Caney Creek and Upper Buffalo, SO_2 emissions (sulfate precursor) are the principal driver of regional haze on the 20% worst days in Arkansas' Class I areas, as visibility impairment in 2002 on the 20% worst days is largely due to sulfate from point sources.

TABLE 55—MODELED BASELINE LIGHT EXTINCTION FOR 20% WORST DAYS AT CANEY CREEK WILDERNESS AREA IN 2002 (Mm^{-1})

	Total [1]	Point	Natural	On-road	Non-road	Area
SO_4	87.05	75.10	0.09	1.19	1.70	5.66
NO_3	13.78	4.06	0.64	4.70	2.45	1.37
POA	10.50	1.29	1.33	0.46	1.34	5.32
EC	4.80	0.19	0.33	0.86	1.79	1.40
SOIL	1.12	0.19	0.01	0.01	0.01	0.87
CM	3.73	0.21	0.04	0.03	0.02	3.19

[109] 40 CFR 51.308(d)(1)(i)(A) and CAA section 169A(g)(1).

[110] *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program,* June 1, 2007, memorandum from William L. Wehrum, Acting Assistant Administrator for Air and Radiation, to EPA Regional Administrators, EPA Regions 1–10 (pp. 4–2, 5–1).

[111] *Id.*

[112] 40 CFR 51.308(d)(1)(ii).

[113] 77 FR 14604, March 12, 2012.

[114] See the CENRAP TSD and the August 27, 2007 CENRAP PSAT tool (CENRAP_PSAT_Tool_ENVIRON_Aug27_2007.mdb). A copy of the CENRAP TSD and instructions for accessing the August 27, 2007 CENRAP PSAT tool can be found in the docket for this proposed rulemaking.

TABLE 55—MODELED BASELINE LIGHT EXTINCTION FOR 20% WORST DAYS AT CANEY CREEK WILDERNESS AREA IN 2002 (Mm^{-1})—Continued

	Total [1]	Point	Natural	On-road	Non-road	Area
Sum	133.93	81.04	2.45	7.26	7.31	17.81

[1]Totals include contributions from boundary conditions. Sums include secondary organic matter.

TABLE 56—MODELED BASELINE LIGHT EXTINCTION FOR 20% AT UPPER BUFFALO WILDERNESS AREA IN 2002 (Mm^{-1})

	Total [1]	Point	Natural	On-road	Non-road	Area
SO_4	83.18	72.17	0.08	1.15	1.67	5.24
NO_3	13.30	3.93	0.61	4.14	2.71	1.23
POA	10.85	1.06	1.33	0.47	1.38	5.75
EC	4.72	0.16	0.31	0.80	1.93	1.30
SOIL	1.21	0.20	0.02	0.01	0.01	0.93
CM	6.85	0.29	0.05	0.05	0.02	6.02
Sum	131.79	77.80	2.39	6.62	7.72	20.46

[1]Totals include contributions from boundary conditions. Sums include secondary organic matter.

The CENRAP's 2018 visibility projections show the total extinction at Caney Creek for the 20% worst days is estimated to be 85.84 Mm − 1, which is a reduction of approximately 36% from 2002 levels (see table below). The total extinction at Upper Buffalo for the 20% worst days in 2018 is estimated to be 86.16 Mm^{-1}, which is a reduction of approximately 35% from 2002 levels (see the table below).Sulfate from all source categories combined is projected to contribute 48.95 Mm^{-1} out of 85.84 Mm^{-1} of light extinction at Caney Creek on the 20% worst days in 2018, or approximately 57% of the total light extinction. Nitrate from all source categories combined is projected to contribute 7.57 Mm^{-1} out of 85.84 Mm^{-1} of light extinction at Caney Creek on the 20% worst days in 2018, or approximately 9% of the total light extinction. The other source categories are each projected to continue contributing a much smaller proportion of the total light extinction at each Class I area. At Upper Buffalo, sulfate from all source categories combined is projected to contribute 45.38 Mm^{-1} out of 86.16 Mm^{-1} of light extinction on the 20% worst days in 2018, which is approximately 53% of the total light extinction. Nitrate from all source categories combined is projected to contribute 9.22 Mm^{-1} out of 86.16 Mm^{-1} of light extinction on the 20% worst days at Upper Buffalo, which is approximately 11% of the total light extinction. Sulfate from point sources is projected to contribute 39.83 Mm^{-1} out of 85.84 Mm^{-1} of light extinction at Caney Creek on the 20% worst days in 2018, or approximately 46% of the total light extinction. Nitrate from point sources is projected to contribute 2.84 Mm^{-1} out of 85.84 Mm^{-1} of light extinction at Caney Creek on the 20% worst days, which is approximately 3% of the total light extinction. At Upper Buffalo, sulfate from point sources is projected to contribute 37.09 Mm^{-1} out of 86.16 Mm^{-1} of light extinction on the 20% worst days in 2018, which is approximately 43% of the total light extinction. On the 20% worst days in 2018, sulfate from Arkansas point sources is projected to contribute 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo, and nitrate from Arkansas point sources is projected to contribute 0.29% of the total light extinction at Caney Creek and 0.25% at Upper Buffalo.[115] Based on the 2018 visibility projections, sulfate from point sources is expected to continue being the principal driver of regional haze on the 20% worst days at Arkansas Class I areas.

TABLE 57—MODELED FUTURE LIGHT EXTINCTION FOR 20% WORST DAYS AT CANEY CREEK WILDERNESS AREA IN 2018 (Mm^{-1})

	Total [1]	Point	Natural	On-road	Non-road	Area
SO_4	48.95	39.83	0.07	0.12	0.44	5.31
NO_3	7.57	2.84	0.53	0.97	1.33	1.37
POA	9.93	1.76	1.18	0.14	1.03	5.09
EC	3.17	0.24	0.30	0.16	0.94	1.31
SOIL	1.29	0.35	0.01	0.01	0.01	0.87
CM	3.58	0.24	0.04	0.03	0.01	3.02
Sum	85.84	45.27	2.12	1.44	3.76	16.96

[1]Totals include contributions from boundary conditions and secondary organic matter.

[115] See the CENRAP TSD and the August 27, 2007 CENRAP PSAT tool (CENRAP_PSAT_Tool_ENVIRON_Aug27_2007.mdb). A copy of the CENRAP TSD and instructions for accessing the August 27, 2007 CENRAP PSAT tool can be found in the docket for this proposed rulemaking.

TABLE 58—MODELED FUTURE LIGHT EXTINCTION FOR 20% WORST DAYS AT UPPER BUFFALO WILDERNESS AREA IN 2018 (Mm^{-1})

	Total [1]	Point	Natural	On-road	Non-road	Area
SO_4	45.38	37.09	0.06	0.12	0.42	4.95
NO_3	9.22	3.48	0.63	1.10	1.81	1.48
POA	10.17	1.48	1.20	0.14	1.01	5.49
EC	3.07	0.21	0.28	0.15	0.99	1.21
SOIL	1.40	0.40	0.01	0.01	0.01	0.93
CM	6.53	0.36	0.05	0.04	0.02	5.65
Sum	86.16	43.02	2.24	1.57	4.25	19.71

[1] Totals include contributions from boundary conditions and secondary organic matter.

As a starting point in our analysis to determine whether additional controls on Arkansas sources are reasonable in the first regional haze planning period, we examined the most recent SO_2 and NO_X emissions inventories for point sources in Arkansas. Based on the 2011 National Emissions Inventory (NEI), the Entergy White Bluff Plant, the Entergy Independence Plant, and the AEP Flint Creek Power Plant are the three largest point sources of SO_2 and NOx emissions in Arkansas (see table below).[116] The combined annual emissions from these three sources make up approximately 84% of the statewide SO_2 point-source emissions and 55% of the statewide NO_X point-source emissions. We have evaluated White Bluff Units 1 and 2 and Flint Creek Unit 1 for controls under BART and are proposing to require these units to install SO_2 and NO_X controls to meet the BART requirements. We believe that our five-factor BART analysis for these three units is adequate for this first planning period to eliminate these sources from further consideration of controls under the reasonable progress requirements for this first regional haze planning period. Compliance with the BART requirements is anticipated to result in a substantial reduction in SO_2 and NO_X emissions from these two facilities. The Entergy Independence Plant is not subject to BART, but its emissions were 30,398 SO_2 tpy and 13,411 NO_X tpy based on the 2011 NEI. The Entergy Independence Plant is the second largest source of SO_2 and NO_X point-source emissions in Arkansas, accounting for approximately 36% of the SO_2 point-source emissions and 21% of the NO_X point-source emissions in the State. Additionally, as we discuss in more detail in the proceeding subsection, the White Bluff and Independence Plants are sister facilities with nearly identical units. Based on this, we expect that the cost-effectiveness of controls will be very similar for the two facilities.

TABLE 59—TEN LARGEST SO_2 AND NO_X POINT SOURCES IN ARKANSAS (NEI 2011 V1)

Facility name	County	NEI 2011 v1 Emissions (tpy)	
		SO_2	NO_X
Entergy Arkansas—White Bluff	Jefferson	*31,684	*16,013
Entergy-Services Inc—Independence Plant	Independence	30,398	13,411
Flint Creek Power Plant (SWEPCO)	Benton	*8,620	*5,326
FutureFuel Chemical Company	Independence	3,421	385
Plum Point Energy Station Unit 1	Mississippi	2,830	1,525
Evergreen Packaging—Pine Bluff	Jefferson	1,755	1,010
Domtar A.W. LLC, Ashdown Mill	Little River	*1,603	*3,152
Albemarle Corporation—South Plant	Columbia	1,279	443
Nucor-Yamato Steel Company	Mississippi	607	263
Ash Grove Cement Company	Little River	440	1,081
Georgia-Pacific LLC—Crossett Paper	Ashley	215	2,402
Marion Intermodal	Crittenden	12	1,328
Natural Gas Pipeline Co of America #308	Randolph	0.4	3,194
Natural Gas Pipeline Co of America #307	White	0.4	2,941
Natural Gas Pipeline Co of America #305	Miller	0.3	1,731

* Proposed FIP controls under BART requirements will result in emission reductions.

Because in our March 12, 2012 final partial approval and partial disapproval of the 2008 Arkansas RH SIP we made a finding that Arkansas did not complete a reasonable progress analysis and did not properly demonstrate that additional controls were not reasonable under 40 CFR 51.308(d)(1)(i)(A) and we disapproved the RPGs it established for Caney Creek and Upper Buffalo, we are required to complete the reasonable progress analysis and establish revised RPGs, unless we first approve a SIP revision that corrects the disapproved portions of the SIP submittal. As Arkansas has not as yet submitted a revised SIP following our partial disapproval, we must now complete the reasonable progress analysis and establish revised RPGs for Caney Creek and Upper Buffalo. We believe it is appropriate that our evaluation of the reasonable progress factors focuses on the Entergy Independence Power Plant

[116] See NEI 2011 v1. A spreadsheet containing the emissions inventory is found in the docket for our proposed rulemaking.

because it is a significant source of SO_2 and NO_X, as it is the second largest point source for both NO_X and SO_2 point source emissions in the State.

We believe it is appropriate to evaluate Entergy Independence even though Arkansas Class I areas and those outside of Arkansas most significantly impacted by Arkansas sources are projected to meet the URP for the first planning period. This is because we believe that in determining whether reasonable progress is being achieved, it would be unreasonable to ignore a source representing more than a third of the State's SO_2 emissions and a significant portion of NO_X point source emissions. The preamble to the Regional Haze Rule also states that the URP does not establish a ''safe harbor'' for the state in setting its progress goals.[117] If the state determines that the amount of progress identified through the URP analysis is reasonable based upon the statutory factors, the state, or us in the case of a FIP, should identify this amount of progress as its reasonable progress goal for the first long-term strategy, unless it determines that additional progress beyond this amount is also reasonable. If the state or we determine that additional progress is reasonable based on the statutory factors, that amount of progress should be adopted as the goal for the first long-term strategy.

In this proposed rulemaking, we are proposing controls for the largest and third largest point sources for both NO_X and SO_2 emissions in Arkansas under the BART requirements. As these two BART sources combined with Independence make up a large majority of the SO_2 point source emissions (84%) and a large proportion of the NO_X point source emissions (55%) in Arkansas, we believe that a sufficient amount of point source emissions in the State would be addressed in this first regional haze planning period by addressing the Independence facility in our reasonable progress analysis, which as we note above is the second largest source of both SO_2 and NO_X. We are proposing under Option 1 to control Entergy Independence for the first planning period for both SO_2 and NO_X. Alternatively, under Option 2, for the first planning period, we are proposing to control Entergy Independence only for SO_2. The fourth largest SO_2 and NO_X point sources in Arkansas are the Future Fuel Chemical Company, with emissions of 3,421 SO_2 tpy, and the Natural Gas Pipeline Company of America #308, with emissions of 3,194 NO_X tpy (2011 NEI). In comparison to the emissions of the top three sources, emissions from these two facilities are relatively small. Therefore, we are not proposing controls in this first planning period for these two facilities because we believe it is appropriate to defer the consideration of any additional sources besides Independence to future regional haze planning periods. For Independence, however, under Option 1, in combination with the BART sources we would be addressing 84% of the SO_2 point source emissions in the State and over 55% of the NO_X point source emissions. Under Option 2, we would be deferring the consideration of additional NO_X controls to future regional haze planning periods. In the next section, we describe our consideration of the four reasonable progress factors for the Entergy Independence Plant as well as the CALPUFF modeling we conducted to assess the potential visibility benefits of controls.[118]

1. Entergy Independence Plant Units 1 and 2

a. *Reasonable Progress Analysis for SO_2 Controls—Costs of Compliance:* The Entergy Independence Plant is an electric generating station with two nearly identical coal-fired units (Units 1 and 2) with a nameplate capacity of 900 MW each. Units 1 and 2 are tangentially-fired boilers that burn sub-bituminous coal as their primary fuel and No. 2 fuel oil or Bio-diesel as the start-up fuel. To verify that the White Bluff and Independence Plants are sister facilities, we have constructed a master spreadsheet[119] that contains information concerning ownership, location, boiler type, environmental controls and other pertinent information on these facilities. The spreadsheet includes information contained within EIA Forms 860 and 923. According to EIA,[120] the boilers were manufactured by Combustion Engineering with installation dates of 1974 for White Bluff, and 1983 and 1984 for Independence. The two units at White Bluff and the two units at Independence are tangentially firing boilers having nameplate capacities of 900 MW and similar gross ratings. All four units burn coal from the Powder River Basin (PRB) of Wyoming with similar characteristics. All four units employ cold side ESPs for particulate collection. Other pertinent characteristics are similar. The layout of the White Bluff and Independence facilities are also very similar.[121] Due to the similarity of these facilities, we applied the total annualized dry FGD and wet FGD costs we developed for the White Bluff units to the Independence units. However, we adjusted the cost-effectiveness ($/ton) due to the differing baseline SO_2 emissions from the units.

Consistent with the cost estimate we developed for White Bluff, we estimated a total annual cost for dry FGD at Independence of approximately $31,981,230 at each unit.[122] We expect dry FGD to achieve a controlled emission level of 0.06 lb/MMBtu, and estimate that the annual emissions reductions at Unit 1 would be 12,912 SO_2 tpy, assuming baseline emissions[123] of 14,269 SO_2 tpy (see table below). The average cost-effectiveness of dry FGD at Unit 1 is estimated to be $2,477 per SO_2 ton removed. For Unit 2, we estimate that the annual emissions reductions would be 13,990 SO_2 tpy, assuming baseline emissions of 15,511 SO_2 tpy. The average cost-effectiveness of dry FGD at Unit 2 is estimated to be $2,286 per SO_2 ton removed.

[117] See 64 FR 35732.

[118] While visibility is not an explicitly listed factor to consider when determining whether additional controls are reasonable, the purpose of the four-factor analysis is to determine what degree of progress toward natural visibility conditions is reasonable. Therefore, it is appropriate to consider the projected visibility benefit of the controls when determining if the controls are needed to make reasonable progress.

[119] This spreadsheet, entitled ''EIA Consolidated Data_WB and Ind_Y2012.xlsx,'' is located in the docket for our proposed rulemaking.

[120] See ''EIA Consolidated Data_WB and IND_Y2012.xlsx.''

[121] See ''Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plan (SO_2 Cost TSD),'' Figures 1 and 2.

[122] See ''Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plan (SO_2 Cost TSD).'' A copy of this TSD is found in the docket for our proposed rulemaking.

[123] Baseline emissions were determined by examining annual SO_2 emissions for the years 2009–2013, eliminating the year with the highest emissions and the year with the lowest emissions, and obtaining the average of the three remaining years.

TABLE 60—SUMMARY OF DRY FGD COSTS FOR ENTERGY INDEPENDENCE UNITS 1 AND 2

Unit	Baseline emission rate (SO_2 tpy)	Controlled emission level (lb/MMBtu)	Annual emissions reductions (SO_2 tpy)	Total annual cost ($/yr)	Average cost effectiveness ($/ton)
Unit 1	14,269	0.06	12,912	$31,981,230	$2,477
Unit 2	15,511	0.06	13,990	31,981,230	2,286

Because our proposed BART determination for the White Bluff facility is that dry FGD is more cost-effective (lower $/ton) than wet FGD, and that the additional visibility benefits obtained as a result of the greater level of control wet FGD offers over dry FGD are not worth the additional cost of wet FGD, we expect that the same would apply to Independence Units 1 and 2. Therefore, our evaluation of SO_2 controls for Independence Units 1 and 2 focuses on dry FGD. Nevertheless, we have calculated the cost-effectiveness of wet FGD for Independence Units 1 and 2 using the total annualized cost estimate provided by Entergy for White Bluff Units 1 and 2, with certain adjustments we made to the cost estimate provided by the facility.[124] Consistent with our estimate for White Bluff, we estimated a total annual cost for wet FGD at Independence of approximately $49,526,167 at each unit.[125] We expect wet FGD to achieve a controlled emission level of 0.04 lb/MMBtu, and estimate that the annual emissions reductions at Unit 1 would be 13,364 SO_2 tpy, assuming baseline emissions[126] of 14,269 SO_2 tpy (see table below). The average cost-effectiveness of wet FGD at Unit 1 is estimated to be $3,706 per SO_2 ton removed. For Unit 2, we estimate that the annual emissions reductions would be 14,497 SO_2 tpy, assuming baseline emissions of 15,511 SO_2 tpy. The average cost-effectiveness of wet FGD at Unit 2 is estimated to be $3,416 per SO_2 ton removed.

TABLE 61—SUMMARY OF WET FGD COSTS FOR ENTERGY INDEPENDENCE UNITS 1 AND 2

Unit	Baseline emission rate (SO_2 tpy)	Controlled emission level (lb/MMBtu)	Annual emissions reductions (SO_2 tpy)	Total annual cost ($/yr)	Average cost effectiveness ($/ton)
Unit 1	14,269	0.04	13,463	$49,526,167	$3,706
Unit 2	15,511	0.04	14,532	49,526,167	3,416

Time Necessary for Compliance: As is generally the case for installation of scrubber controls on EGUs, we expect that 5 years from the date of our final action would be sufficient time for Independence to install and operate either dry or wet FGD controls at Units 1 and 2 and to comply with the associated emission limits.

Energy and Non-Air Quality Environmental Impacts of Compliance: The installation and operation of wet FGD at Independence Units 1 and 2 would require greater energy usage and reagent usage compared to dry FGD. The cost of this additional energy usage and reagent usage has already been factored into the cost analysis. Non-air quality environmental impacts associated with wet FGD systems include increased water usage and the generation of large volumes of wastewater and solid waste/sludge that must be treated or stabilized before landfilling. Because the facility is not located in an exceptionally arid region, we do not anticipate that there would be water-availability issues that would affect the feasibility of wet FGD. Lastly, wet FGD systems have the potential for increased particulate and sulfuric acid mist releases that contribute to regional haze, which we are taking into consideration through an evaluation of the visibility benefits of each control option.

Remaining Useful Life: Independence Units 1 and 2 were installed in 1983 and 1984. Unit 1 was placed into operation in 1983 and Unit 2 was placed into operation in 1985. As there is no enforceable shut-down date for Units 1 and 2, we assume an equipment life of 30 years.[127]

Degree of Improvement in Visibility: While visibility is not an explicitly listed factor to consider when determining whether additional controls are reasonable under the reasonable progress requirements, the purpose of the four-factor analysis is to determine what degree of progress toward natural visibility conditions is reasonable. Therefore, it is appropriate to consider the projected visibility benefit of the controls when determining if the controls are needed to make reasonable progress.[128] There are four Class I areas within 300 km of the Entergy Independence Plant. We conducted CALPUFF modeling to determine the visibility improvement of SO_2 controls at these Class I areas, based on the 98th percentile visibility impacts.[129] As shown in the tables below, both dry FGD and wet FGD are projected to result in considerable visibility improvement from the baseline at each modeled Class I area. For Unit 1, dry FGD is projected to result in almost 0.5 dv of visibility improvement at each modeled Class I area, and for Unit 2 it is projected to result in almost or slightly greater than

[124] See our discussion above of the cost analysis for SO_2 BART for White Bluff Units 1 and 2, under section III.C.4 of this proposed rulemaking.

[125] See our Cost Analysis TSD titled "Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plan (SO_2 Cost TSD)." The TSD is found in the docket for our proposed rulemaking.

[126] Baseline emissions were determined by examining annual SO_2 emissions for the years 2009–2013, eliminating the year with the highest emissions and the year with the lowest emissions, and obtaining the average of the three remaining years.

[127] As we note in our Oklahoma FIP, we typically assume a 30 year equipment life for scrubbers, as we do here. Please see 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. Page 35.

[128] See 79 FR at 74838, 74840, and 74874.

[129] See Appendix C to the TSD, titled "Technical Support Document for Visibility Modeling Analysis for Entergy Independence Generating Station," for a detailed discussion of the visibility modeling protocol and model inputs. A copy of the TSD and its appendices is found in the docket for this proposed rulemaking.

0.5 dv of visibility improvement at each Class I area. The incremental visibility improvement of wet FGD over dry FGD is projected to be minimal, ranging from 0.008–0.028 dv at each Class I area for Unit 1 and 0.009–0.022 dv for Unit 2.

TABLE 62—ENTERGY INDEPENDENCE UNIT 1: EPA MODELED 98TH PERCENTILE VISIBILITY IMPACTS OF SO_2 CONTROLS

Class I area	Distance (km)	Visibility impact (Δdv)			Visibility improvement over baseline (dv)		Incremental visibility improvement of wet FGD vs. dry FGD
		Baseline	Dry FGD	Wet FGD	Dry FGD	Wet FGD	
Caney Creek	277	1.133	0.657	0.64	0.476	0.493	0.017
Upper Buffalo	180	0.845	0.385	0.377	0.460	0.468	0.008
Hercules-Glades	173	0.793	0.295	0.267	0.498	0.526	0.028
Mingo	174	0.739	0.298	0.284	0.441	0.455	0.014
Total	....	3.51	1.635	1.568	1.875	1.942	0.067

TABLE 63—ENTERGY INDEPENDENCE UNIT 2: EPA MODELED 98TH PERCENTILE VISIBILITY IMPACTS OF SO_2 CONTROLS

Class I area	Distance (km)	Visibility impact (Δdv)			Visibility improvement over baseline (dv)		Incremental visibility improvement of wet FGD vs. dry FGD
		Baseline	Dry FGD	Wet FGD	Dry FGD	Wet FGD	
Caney Creek	277	1.412	0.865	0.843	0.547	0.569	0.022
Upper Buffalo	180	0.997	0.509	0.499	0.488	0.498	0.01
Hercules-Glades	173	0.977	0.364	0.355	0.613	0.622	0.009
Mingo	174	0.883	0.388	0.374	0.495	0.509	0.014
Total	....	4.269	2.126	2.071	2.143	2.198	0.055

TABLE 64—ENTERGY INDEPENDENCE: EPA MODELED 98TH PERCENTILE VISIBILITY IMPACTS OF SO_2 CONTROLS (FACILITY-WIDE)

Class I area	Distance (km)	Visibility impact (Δdv)			Visibility improvement over baseline (dv)		Incremental visibility improvement of wet FGD vs. dry FGD
		Baseline	Dry FGD	Wet FGD	Dry FGD	Wet FGD	
Caney Creek	277	2.412	1.474	1.442	0.938	0.97	0.032
Upper Buffalo	180	1.764	0.876	0.86	0.888	0.904	0.016
Hercules-Glades	173	1.704	0.648	0.608	1.056	1.096	0.04
Mingo	174	1.547	0.676	0.649	0.871	0.898	0.027
Total	....	7.427	3.674	3.559	3.753	3.868	0.115

Proposed RP Determination for SO_2: Based on our analysis of the four RP factors, as well as the considerable projected visibility improvement, we propose to require compliance with an emission limit of 0.06 lb/MMBtu for Independence Units 1 and 2 based on a 30 boiler-operating-day rolling average basis. We propose to find that this emission limit, which is based on the installation and operation of dry FGD, is cost-effective at $2,477 per SO_2 ton removed for Unit 1 and $2,286 per SO_2 ton removed for Unit 2, and would result in significant visibility benefits at the Caney Creek and Upper Buffalo Wilderness Areas and the two Class I areas in Missouri. Under either Option 1 or 2, we are proposing SO_2 controls on Independence Units 1 and 2 for the first planning period. We note that more recent emission data show an overall increase in SO_2 emissions from the facility. Therefore anticipated visibility improvement from controls would be anticipated to be larger and the $/$SO_2$ ton reduced would be smaller had we used a more recent time period for the baseline emissions modeled. We found that in this instance, the cost of wet FGD on a dollars per ton removed basis is higher than that of dry FGD. We found the cost of wet FGD to be $3,706 and $3,416 per ton of SO_2 removed at Units 1 and 2, respectively. We found the cost of dry FGD to be $2,477 and $2,286 per ton of SO_2 removed for Units 1 and 2, respectively. We do not believe that the minimal amount of incremental visibility improvement projected to result from wet FGD justifies the higher cost compared to dry FGD. We are proposing to require compliance with an emission limit of 0.06 lb/MMBtu based on a 30 boiler-operating-day rolling average basis for Independence Units 1 and 2 no later than 5 years from the effective date of the final rule, based on the installation and operation of dry FGD. We are proposing that the facility demonstrate compliance with this emission limit using the existing CEMS. We are also proposing regulatory text that includes monitoring, reporting, and recordkeeping requirements associated with this emission limit.

b. *Reasonable Progress Analysis for NO_X controls.* As noted previously, monitoring data as well as CENRAP's CAMx source apportionment modeling results for 2002 and 2018 show that visibility impairment is not projected to be significantly impacted by nitrate on the 20% worst days at Caney Creek or Upper Buffalo. Point source emissions of NO_X are projected to contribute to less than 5% of the total impairment on the 20% worst days in both 2002 and 2018. The CENRAP CAMx source apportionment modeling does not provide visibility impairment estimates for individual facilities.

As part of our analysis for Independence, we performed modeling using CALPUFF to assess the facility's individual visibility impact and the visibility benefit of controls, as was done for the subject-to-BART units discussed above including the sister facility, White Bluff. CALPUFF is the recommended model [130] for visibility impact analysis for BART determinations and other single source visibility modeling where the Class I areas of interest are within 300 km of the source. This modeling provided information on the total visibility impairment from emissions from the source, including impacts from SO_2 and NO_X emissions. The primary goal of this modeling was to assess the potential visibility benefit of SO_2 controls, given the relatively large emissions of SO_2 from the facility and that SO_2 emissions are the primary cause of visibility impairment on the 20% worst days at the Class I areas of interest. The results of this analysis of SO_2 controls are discussed in the section above. These CALPUFF results also indicated that impacts from NO_X emissions can be significant on some days, and as discussed further below, NO_X emission controls can be anticipated to result in a sizeable reduction in the maximum impacts from the facility. The analysis of the sister facility, Entergy Independence, revealed similar results.

In evaluating CALPUFF modeling results for BART, the 98th percentile ranked impact (H8H) was used consistent with our guideline techniques in conducting the CALPUFF modeling. CALPUFF modeling provides an assessment of the near maximum (98th percentile) visibility impairment on nearby Class I areas from the source of interest based on the facility's maximum short term emissions modeled over a three year period. It is important to note that a specific facility's maximum impact on a Class I area may not correlate with the same meteorological conditions or days when visibility is most impaired at a particular Class I area since CALPUFF modeling is only for one facility and does not include other facilities and emissions sources. Because of the nature of visibility impairment, we consider it appropriate to assess visibility impacts from a single source against a natural background. Visibility impairment on the 20% worst days may be driven by impacts from other facilities and different meteorological conditions. Identification of the 20% worst days is determined by IMPROVE monitor data during the baseline period at each Class I area. The source apportionment results for the 20% worst days are then based on CAMx modeling using a single year of meteorological data (2002) and using estimates of actual emissions from 2002 and projected to 2018 for all emission sources in the modeling domain (continental U.S.). Due in large part to the difference in metrics between the maximum impact as modeled by CALPUFF and the average impact during the 20% worst days, the CALPUFF modeling results discussed below indicate a more significant impact than suggested by the source apportionment CAMx results. We also note that differences in the metrics examined (maximum 98th percentile impact versus average impact during the 20% worst days), emissions modeled (single–source maximum 24-hour actual emissions versus actual emissions from all emission sources [131]), and differences in chemistry models result in CAMx visibility analysis results for a source or group of sources being much lower in magnitude than visibility impacts as modeled by CALPUFF.

The single source CALPUFF modeling shows that sizeable reductions to the maximum 98th percentile visibility impact from the Independence facility may be achieved through NO_X controls. We recognize, however, that at this time, point source NO_X emissions are not the main contributors to visibility impairment on the 20% worst days at Arkansas' Class I areas, as projected by CAMx source apportionment modeling. Also, Arkansas Class I areas are projected to achieve progress greater than that needed to meet the URP. Because our assessment of the Independence facility indicates that it is potentially one of the largest single contributors to visibility impairment at Class I areas in Arkansas, we believe that it is appropriate to evaluate the appropriateness of NO_X controls during this planning period.

As discussed above, due to the similarity of these facilities, we applied the total annualized LNB/SOFA cost developed by Entergy for White Bluff Units 1 and 2, with one line item revision made by us, to Independence Units 1 and 2.[132] However, we adjusted the cost-effectiveness ($/ton) due to the differing NO_X emissions from the units. Since our proposed BART determination for the White Bluff facility is that LNB/SOFA is more cost effective (lower $/ton) than SNCR or SCR, and that the additional visibility benefits obtained as a result of the greater level of control SNCR and SCR offer over combustion controls are not worth the additional cost of SNCR or SCR, we expect that the same would apply to Independence Units 1 and 2. Therefore, our evaluation of NO_X controls for Independence Units 1 and 2 will focus solely on LNB/SOFA.

Consistent with the cost estimate developed for White Bluff, we estimated a total annual cost for LNB/SOFA at Independence of approximately $1,085,904 at Unit 1 and $1,403,376 at Unit 2.[133] We expect LNB/SOFA to achieve a controlled emission level of 0.15 lb/MMBtu, and estimate that the annual emissions reductions at Unit 1 would be 2,710 NO_X tpy, assuming baseline emissions [134] of 6,329 NO_X tpy (see table below). The average cost-effectiveness of LNB/SOFA at Unit 1 is estimated to be $401 per NO_X ton removed. For Unit 2, we estimate that the annual emissions reductions would be 3,217 NO_X tpy, assuming baseline emissions of 6,384 NO_X tpy. The average cost-effectiveness of LNB/SOFA at Unit 2 is estimated to be $436 per NO_X ton removed.

[130] 70 FR 39104.

[131] Emissions used in CALPUFF modeling represented the maximum 24-hour emission rate. Based on evaluation of some sources that had both annual and maximum 24-hour actual data, EPA recommended that sources could use an emission rate that was double the annual emission rate (used in CAMx) to approximate the maximum 24-hour actual emission rates for some sources for CALPUFF modeling when there was not enough data to generate a maximum 24-hr actual emission rate.

[132] See our discussion above of the cost analysis for NO_X BART for White Bluff Units 1 and 2, under section III.C.4 of this proposed rulemaking.

[133] See the spreadsheet titled ''Independence Cost Spreadsheet_LNB–SOFA.'' A copy of this spreadsheet is found in the docket for our proposed rulemaking.

[134] Baseline emissions were determined by examining annual NO_X emissions for the years 2009–2013, eliminating the year with the highest emissions and the year with the lowest emissions, and obtaining the average of the three remaining years.

TABLE 65—SUMMARY OF LNB/SOFA COSTS FOR ENTERGY INDEPENDENCE UNITS 1 AND 2

Unit	Baseline emission rate (NO_X tpy)	Controlled emission level (lb/MMBtu)	Annual emissions reductions (NO_X tpy)	Total annual cost ($/yr)	Average cost effectiveness ($/ton)
Unit 1	6,329	0.15	2,710	$1,085,904	$401
Unit 2	6,384	0.15	3,217	1,403,376	436

Time Necessary for Compliance: As is generally the case for installation of NO_X controls on EGUs, we expect that 3 years from the date of our final action would be sufficient time for Independence to install and operate LNB/SOFA controls at Units 1 and 2 and to comply with the associated emission limits.

Energy and Non-Air Quality Environmental Impacts of Compliance: We are not aware of any energy or non-air quality environmental impacts that would preclude LNB/SOFA from consideration at Independence Units 1 and 2.

Remaining Useful Life: Independence Units 1 and 2 were installed in 1983 and 1984. Unit 1 was placed into operation in 1983 and Unit 2 was placed into operation in 1985. As there is no enforceable shut-down date for Units 1 and 2, we presume that the units would continue to operate for greater than 30 years and fully amortize the cost of controls. In our analysis of the cost of controls we have assumed an equipment life of 30 years.

Degree of Improvement in Visibility: While visibility is not an explicitly listed factor to consider when determining whether additional controls are reasonable under the reasonable progress requirements, the purpose of the four-factor analysis is to determine what degree of progress toward natural visibility conditions is reasonable. Therefore, it is appropriate to consider the projected visibility benefit of the controls when determining if the controls are needed to make reasonable progress.[135] There are four Class I areas within 300 km of the Entergy Independence Plant. We conducted CALPUFF modeling to determine the visibility improvement of NO_X controls at these Class I areas, based on the 98th percentile visibility impacts.[136] As shown in the table below, LNB/SOFA is projected to result in a visibility improvement from the baseline at each modeled Class I area.[137] On a facility-wide basis, the installation and operation of LNB/SOFA on Units 1 and 2 is projected to result in 0.461 dv in visibility improvement at Caney Creek, while the projected visibility improvement at each of the other modeled Class I areas ranges from 0.213–0.264 dv. We also conducted a modeling run of both LNB/OFA and dry FGD, which shows projected visibility benefits ranging from 1.18–1.48 dv at each Class I area.[138] As discussed above, more recent emission data show an overall increase in SO_2 emissions from the facility. Therefore anticipated visibility improvement from controls would be anticipated to be larger and there would be an improvement in the cost-effectiveness (*i.e.,* lower dollars per ton removed) of controls had we used a more recent time period for the baseline emissions modeled.

TABLE 66—ENTERGY INDEPENDENCE UNITS 1 AND 2 (FACILITY-WIDE): EPA MODELED 98TH PERCENTILE VISIBILITY IMPACTS OF LNB/SOFA

Class I area	Distance (km)	Visibility impact (Δdv)		Visibility improvement of LNB/SOFA over baseline (dv)
		Baseline [139]	LNB/SOFA	
Caney Creek	277	2.054	1.593	0.461
Upper Buffalo	180	1.724	1.476	0.248
Hercules-Glades	173	1.482	1.218	0.264
Mingo	174	1.492	1.279	0.213
Total	....	6.752	5.566	1.186

Proposed RP Determination for NO_X: As discussed above, based on the CENRAP's CAMx modeling, sulfate from point sources is the driver of regional haze at Caney Creek and Upper Buffalo on the 20% worst days in both 2002 and 2018. Nitrate from point sources is not considered a driver of regional haze at these Class I areas on the 20% worst days, contributing only approximately 3% of the total light extinction. The Regional Haze Rule requires that the established RPGs provide for an improvement in visibility for the most impaired days (*i.e.,* the 20% worst days) over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period (40 CFR 51.308(d)(1)). Because of the small contribution of nitrate from point sources to the total light extinction at Caney Creek and Upper Buffalo on the most impaired days, we do not expect that NO_X controls under the reasonable progress requirements would offer as much improvement on the most impaired days compared to SO_2 controls. However, upon evaluation of the four reasonable progress factors, we found that the installation and operation of LNB/SOFA at Independence Units 1 and 2 is estimated to cost $401/$NO_X$ ton

[135] See 79 FR at 74838, 74840, and 74874.

[136] See Appendix C to the TSD, titled ''Technical Support Document for Visibility Modeling Analysis for Entergy Independence Generating Station,'' for a detailed discussion of the visibility modeling protocol and model inputs. A copy of the TSD and its appendices is found in the docket for this proposed rulemaking.

[137] *Id.*

[138] This is discussed in more detail in Appendix C to the TSD, titled ''Technical Support Document for Visibility Modeling Analysis for Entergy Independence Generating Station.''

[139] Baseline NO_X emissions were updated to the maximum 24-hr emissions from 2011–2013 for the evaluation of the anticipated benefit from NO_X controls.

removed at Unit 1 and $436/$NO_X$ ton removed at Unit 2, which we consider to be very cost-effective. These NO_X controls are also projected to result in significant visibility improvements at Arkansas and Missouri Class I areas, based on CALPUFF modeling using the 98th percentile modeled visibility impacts. Therefore, under Option 1, for the first planning period, we are proposing both an SO_2 emission limit as described above and a NO_X emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day averaging basis based on the installation and operation of LNB/SOFA, in light of their cost-effectiveness and visibility benefit based on CALPUFF modeling, even though nitrate from point sources is projected to contribute a very small proportion of the total light extinction at Caney Creek and Upper Buffalo on the 20% worst days in 2018. Based on our visibility modeling of both LNB/OFA and dry FGD, proposed Option 1 is projected to have visibility benefits ranging from 1.18—1.48 dv at each Class I area.[140] Under Option 2, we are proposing only SO_2 controls for Independence Units 1 and 2 under the reasonable progress requirements. Based on our visibility modeling of dry FGD, proposed Option 2 is projected to have visibility benefits ranging from 0.87—1.06 dv at each Class I area. We specifically solicit public comment on this proposed alternative approach.

In addition to options 1 and 2, we also solicit public comment on any alternative SO_2 and NO_X control measures that would address the regional haze requirements for Entergy White Bluff Units 1 and 2 and Entergy Independence Units 1 and 2 for this planning period. This includes, but is not limited to, a combination of early unit shutdowns and other emissions control measures that would achieve greater reasonable progress than the BART and reasonable progress requirements we have proposed for these four units in this rulemaking.

B. Reasonable Progress Goals

We propose RPGs for Caney Creek and Upper Buffalo that are consistent with the combination of control measures from the approved portion of the 2008 Arkansas RH SIP and our proposed Arkansas RH FIP. In total, these final and proposed controls to meet the BART and RP requirements will result in higher emissions reductions and commensurate visibility improvements beyond what was in the 2008 Arkansas RH SIP. Development of refined numerical RPGs for Arkansas' Class I areas would require photochemical grid modeling of a multistate area, involving thousands of emission sources, unlike the comparatively simple single-source CALPUFF modeling used for individual BART assessments. In order to accurately reflect all emissions reductions expected to occur during this planning period, the new photochemical modeling would require an update of the emissions inventory for Arkansas and the surrounding states to include not just the actions under this FIP, but all EPA and state regulatory actions on point, area, and mobile sources. After the inventory is developed and reviewed by the affected states for accuracy, it must be converted to a model-ready format before air quality modeling can be used to estimate the future visibility levels at the Class I areas. This modeling would require specialized and extensive computing hardware and expertise. Developing all of the necessary input files, running the photochemical model, and post-processing the model outputs would take several months at a minimum. Therefore, we are not conducting new photochemical grid modeling to establish revised numeric RPGs for Caney Creek and Upper Buffalo.

In order to provide RPGs that account for emission reductions from the FIP controls, we have used a method similar to the one used in our Regional Haze FIP for Hawaii [141] and Arizona,[142] which is based on a scaling of visibility extinction components in proportion to emission changes. To determine the new RPGs for Caney Creek and Upper Buffalo, we started with the 2018 projection of extinction components from the CENRAP's CAMx photochemical modeling with source apportionment. The 2018 CAMx emission scenario included some assumptions of state BART determinations and other SIP controls, as well as projected emissions from other point, area, and mobile sources. We scaled the modeled visibility extinction components for sulfate (SO_4) and nitrate (NO_3) from point sources in Arkansas in proportion to the FIP's emission reductions for SO_2 and NO_X, respectively. The sulfate scaling factor was the 2018 CENRAP emission inventory for Arkansas point source SO_2 emissions with FIP controls for BART and RP sources in place, divided by the original 2018 CENRAP emission inventory for Arkansas point source SO_2 emissions. We conducted the same scaling exercise with nitrate and NO_X. The scaled sulfate and nitrate extinctions were added to the unscaled extinctions for organic mass and other components to get total extinction, and then this was used to calculate post-FIP RPGs in deciviews. Although we recognize that this method is not refined, it allows us to translate the emission reductions contained in this proposed FIP into quantitative RPGs, based on modeling previously performed by the CENRAP. These RPGs reflect rates of progress that are faster than the rates projected by Arkansas. The revised RPGs for the first planning period for the 20% worst days are 22.27 dv for Caney Creek and 22.33 dv for Upper Buffalo. The results of our analysis are shown in the table below.[143] The RPG calculation was performed for both our proposed Options 1 and 2. Under Option 1 we are proposing to control Entergy Independence Units 1 and 2 for the first planning period for both SO_2 and NO_X. Alternatively, under Option 2, we are proposing to control Entergy Independence Units 1 and 2 only for SO_2 for the first planning period. Due to the small impact from all Arkansas point source NOx emissions combined on the 20% worst days and the scaling approach utilized to estimate the adjustment to the RPG, the difference between the two proposed options results in a very small difference in the calculated RPGs for Caney Creek and Upper Buffalo (less than 0.003 dv). We note that some FIP controls will not be in place by 2018, however, for the purpose of this calculation, we included reductions from all FIP controls. Arkansas will have to re-evaluate during the next regional haze planning period what BART and reasonable progress controls are in place and re-calculate the RPGs for the next planning period as needed. We also note that RPGs, unlike the emission limits that apply to specific RP sources, are not directly enforceable.[144] Rather, they are an analytical framework considered by us in evaluating whether measures in the implementation plan are sufficient to

[140] See Appendix C to the TSD, titled ''Technical Support Document for Visibility Modeling Analysis for Entergy Independence Generating Station,'' for a detailed discussion of the visibility modeling protocol and model inputs. A copy of the TSD and its appendices is found in the docket for this proposed rulemaking.

[141] See 77 FR 31692, 31708.

[142] See 79 FR 52420, 52468.

[143] Please see Appendix C to the TSD, titled ''Technical Support Document for Visibility Modeling Analysis for Entergy Independence Generating Station,'' and the RPG calculation spreadsheet for additional details on calculations. These documents are found in the docket for our proposed rulemaking.

[144] 40 CFR 51.308(d)(1)(v).

achieve reasonable progress.[145] Arkansas may choose to use these RPGs for purposes of its progress report, or may develop new RPGs for approval by us along with its progress report, based on new modeling or other appropriate techniques, in accordance with the requirements of 40 CFR 51.308(d)(1).

TABLE 67—PROPOSED REASONABLE PROGRESS GOALS FOR 20% WORST DAYS

[In Deciviews]

Class I area	2000–2004 Baseline	2064 Natural conditions	2018 URP	2018 Projection by CENRAP	Estimated FIP effect	Estimated FIP 2018 RPG
Caney Creek	26.36	11.58	22.91	22.48	−0.21	22.27
Upper Buffalo	26.27	11.57	22.84	22.52	−0.19	22.33

V. Our Proposed Long-Term Strategy

Section 169A(b) of the CAA and 40 CFR 51.308(d)(3) require that states include in their SIP a 10 to 15-year strategy, referred to as the long-term strategy, for making reasonable progress for each Class I area within their state. This long-term strategy is the compilation of all control measures a state will use during the implementation period of the specific SIP submittal to meet any applicable RPGs for a particular Class I area. The long-term strategy must include ''enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals'' for all Class I areas within, or affected by emissions from, the state.[146]

Section 51.308(d)(3)(v) requires that a state consider certain factors (the long-term strategy factors) in developing its long-term strategy for each Class I area. These factors are the following: (1) Emission reductions due to ongoing air pollution control programs, including measures to address RAVI; (2) measures to mitigate the impacts of construction activities; (3) emissions limitations and schedules for compliance to achieve the reasonable progress goal; (4) source retirement and replacement schedules; (5) smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for these purposes; (6) enforceability of emissions limitations and control measures; and (7) the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy. Since states are required to consider emissions limitations and schedules of compliance to achieve the RPGs for each Class I area, the BART emission limits that are in the state's regional haze SIP are an element of the state's long-term strategy (40 CFR 51.308(d)(3)) for each Class I area. In our March 11, 2012 final action on the 2008 Arkansas RH SIP, since we disapproved a portion of Arkansas' BART determinations and both RPGs for Arkansas' two Class I areas, we also disapproved these elements and approved all other elements of Arkansas' long-term strategy. The BART limits and two RPGs for Arkansas' Class I areas that are in this proposed FIP address our March 11, 2011 disapproval of Arkansas' BART limits and two RPGs. We propose to find that the proposed BART limits and two RPGs that are in this proposed FIP also correct the deficiency in Arkansas' long-term strategy for each of its Class I areas.

VI. Our Proposal for Interstate Visibility Transport

We received the Arkansas Interstate Visibility Transport SIP that addresses the interstate visibility transport requirements of CAA section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS on April 2, 2008. In its Interstate Visibility Transport SIP, Arkansas stated that its regional haze regulation, the APC&E Commission Regulation 19, chapter 15, codifying its Regional Haze SIP, satisfies the requirement of section 110(a)(2)(D)(i)(II) regarding the protection of visibility, and that it was not possible to assess whether there is any interference with measures in the applicable SIP for another state designed to protect visibility for the 8-hour ozone and $PM_{2.5}$ NAAQS in other states until Arkansas submits and we approve the 2008 Arkansas RH SIP. In our March 12, 2012 final action, we partially approved and partially disapproved the Arkansas Interstate Visibility Transport SIP because we partially approved and partially disapproved the 2008 Arkansas RH SIP. In particular, we disapproved a large portion of Arkansas' BART determinations, and as a result, the corresponding emissions reductions other states had relied upon in their RPG demonstrations under the RHR would not take place. Therefore, we made a finding that Arkansas' SIP does not fully ensure that emissions from sources in Arkansas do not interfere with other states' visibility programs as required by section 110(a)(2)(D)(i)(II) of the CAA. Our proposed regional haze FIP would address all disapproved BART determinations for sources in Arkansas as well as all other disapproved portions of the 2008 Arkansas RH SIP. Our proposed regional haze FIP together with our prior approval of portions of the Arkansas Regional Haze SIP would ensure that the emissions reductions other sates relied upon in their RPG demonstrations take place. Therefore, we propose to find that the deficiencies we identified in our prior disapproval action on the Arkansas Interstate Visibility Transport SIP are addressed by our proposed regional haze FIP along with our prior approval of portions of the Arkansas Regional Haze SIP. We are also proposing to find that the requirements of CAA section 110(a)(2)(D)(i)(II) with respect to visibility transport for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS will be satisfied by the combination of the emission control measures in this proposed regional haze FIP and the previously approved portion of the Arkansas Interstate Visibility Transport SIP.

VII. Summary of Proposed Actions

A. Regional Haze

We propose to promulgate a FIP to address those portions of Arkansas' regional haze SIP that we disapproved on March 12, 2012, which include requirements for BART, reasonable progress, and the long-term strategy.[147] The FIP we are proposing includes BART emission limits for sources in Arkansas to reduce emissions that contribute to regional haze in Arkansas' two Class I areas and other nearby Class I areas and make reasonable progress for

[145] 64 FR 35733 and 40 CFR 51.308(d)(1)(v).

[146] 40 CFR 51.308(d)(3).

[147] 77 FR 14604.

the first regional haze planning period for Arkansas' two Class I areas. This includes more stringent SO_2 emission limits in comparison to what the 2008 Arkansas RH SIP contained for the AECC Carl E. Bailey Generating Station Unit 1, the AECC John L McClellan Generating Station Unit 1, the AEP Flint Creek Power Plant Unit 1, Entergy White Bluff Plant Units 1 and 2, and the Domtar Ashdown Paper Mill Power Boiler No. 2. We are also proposing in the alternative two options for addressing the reasonable progress requirements for this first planning period by controlling the Entergy Independence Power Plant for both the Caney Creek and Upper Buffalo Class I areas. Under Option 1, we propose to require SO_2 and NO_X emission reductions from the Entergy Independence Power Plant under the reasonable progress requirements. Under Option 2, we are also proposing only SO_2 controls for Independence Units 1 and 2 under the reasonable progress requirements. In particular, we are inviting public comment on the alternate proposed Options 1 and 2. We also solicit public comment on any alternative control measures for Entergy White Bluff Units 1 and 2 and Independence Units 1 and 2 that would address the regional haze requirements for these four units for this planning period. We also propose to find that the proposed BART and reasonable progress limits and RPGs that are in this proposed FIP correct the deficiency in Arkansas' long-term strategy for both Class I areas. Our proposed FIP, once finalized, along with the previously approved portion of the Arkansas regional haze SIP, will constitute Arkansas' regional haze program for the first planning period that ends in 2018.

B. Interstate Visibility Transport

We propose to find that the deficiencies we identified in our prior disapproval action on the Arkansas Interstate Visibility Transport SIP to address the requirement of CAA section 110(a)(2)(D)(i)(II) with respect to visibility transport for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS will be remedied by our proposed Arkansas Regional Haze FIP along with our March 2, 2012 partial approval of certain elements of the 2008 Arkansas RH SIP. In its Interstate Visibility Transport SIP, Arkansas stated that its regional haze regulation, the APC&E Commission Regulation 19, chapter 15, codifying the Arkansas Regional Haze SIP, satisfies the requirement of section 110(a)(2)(D)(i)(II) regarding the protection of visibility, and that it was not possible to assess whether there is any interference with measures in the applicable SIP for another state designed to protect visibility for the 8-hour ozone and $PM_{2.5}$ NAAQS in other states until Arkansas submits and we approve the 2008 Arkansas RH SIP. Since our FIP addresses the portions of Arkansas Regional Haze SIP that we previously disapproved, we propose to find that the requirements of CAA section 110(a)(2)(D)(i)(II) with respect to visibility transport for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS will be satisfied by the combination of this proposed regional haze FIP and the previously approved portion of the Arkansas Interstate Visibility Transport SIP.

VIII. 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 (six 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. 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 SIP action under Section 110 of the CAA will not in-and-of itself create any new requirements on small entities but simply approves or disapproves certain state requirements for inclusion into the SIP. 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 six 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 rulemaking.

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 [148] 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. This proposed federal rule limits emissions of NO_X, SO_2, and PM from six facilities in Arkansas.

[148] 62 FR 19885 (Apr. 23, 1997).

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: March 6, 2015.

Samuel Coleman, P.E.

Acting 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 E—Arkansas

■ 2. Section 52.173 is amended by adding paragraphs (c) and (d) to read as follows:

§ 52.173 Visibility protection.

* * * * *

(c) Requirements for AECC Carl E. Bailey Unit 1; AECC John L. McClellan Unit 1; AEP Flint Creek Unit 1; Entergy White Bluff Units 1, 2, and Auxiliary Boiler; Entergy Lake Catherine Unit 4; Domtar Ashdown Paper Mill Power Boilers No. 1 and 2; and Entergy Independence Units 1 and 2 affecting visibility.

(1) *Applicability.* The provisions of this section shall apply to each owner

or operator, or successive owners or operators, of the sources designated as: AECC Carl E. Bailey Unit 1; AECC John L. McClellan Unit 1; AEP Flint Creek Unit 1; Entergy White Bluff Units 1, 2, and Auxiliary Boiler; Entergy Lake Catherine Unit 4; Domtar Ashdown Paper Mill Power Boilers No. 1 and 2; and Entergy Independence Units 1 and 2.

(2) *Definitions.* All terms used in this part but not defined herein shall have the meaning given them in the Clean Air Act and in parts 51 and 60 of CFR title 40. 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 which would be emitted to the atmosphere.

Boiler-operating-day for electric generating units listed under paragraph (c)(1) of this section 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. For power boilers listed under paragraph (c)(1) of this section, we define boiler-operating-day as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is fed into and/ or combusted at any time in the Power Boiler.

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 units or power boilers listed under paragraph (c)(1) of this section.

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

Unit means one of the natural gas, fuel oil, or coal fired boilers covered under paragraph (c) of this section.

(3) *Emissions limitations for AECC Bailey Unit 1 and AECC McClellan Unit 1.* The individual SO_2, NO_X, and PM emission limits for each unit shall be as listed in the following table.

Unit	SO_2 Emission limit	NO_X Emission limit	PM Emission limit
AECC Bailey Unit 1	Use of fuel with a sulfur content limit of 0.5% by weight.	887 lb/hr	Use of fuel with a sulfur content limit of 0.5% by weight.
AECC McClellan Unit 1	Use of fuel with a sulfur content limit of 0.5% by weight.	869.1 lb/hr (Natural Gas firing) 705.8 lb/hr (Fuel Oil firing)	Use of fuel with a sulfur content limit of 0.5% by weight.

(4) *Compliance dates for AECC Bailey Unit 1 and AECC McClellan Unit.* The owner or operator of each unit shall comply with the SO_2 and PM requirements listed in paragraph (c)(3) of this section within 5 years of the effective date of this rule. As of the effective date of this rule, the owner/ operator of each unit shall not purchase fuel for combustion at the unit that does not meet the sulfur content limit in paragraph (c)(3) of this section. Five years from the effective date of the rule only fuel that meets the sulfur content limit in paragraph (c)(3) of this section shall be burned at each unit. The owner/ operator of each unit shall comply with the NO_X emission limits in paragraph (c)(3) of this section as of the effective date of this rule.

(5) *Compliance determinations for AECC Bailey Unit 1 and AECC McClellan Unit*—(i) *SO_2 and PM.* To determine compliance with the SO_2 and PM requirements listed in paragraph (c)(3) of this section, the owner/operator shall sample and analyze each shipment of fuel to determine the sulfur content, except for natural gas shipments. A ''shipment'' is considered delivery of the entire amount of each order of fuel purchased. Fuel sampling and analysis may be performed by the owner or operator of an affected unit, an outside laboratory, or a fuel supplier.

(ii) *NO_X.* To determine compliance with the NO_X emission limits of paragraph (c)(3) of this section, the owner/operator shall determine the average emissions (arithmetic average of three contiguous one hour periods) of NO_X as measured by a CEMS and converted to pounds per hour using corresponding average (arithmetic average of three contiguous one hour periods) stack gas flow rates.

(iii) The owner or operator shall continue to maintain and operate a CEMS for NO_X on the units listed in paragraph (c)(3) of this section in accordance with 40 CFR 60.8 and 60.13(e), (f), and (h), and appendix B of part 60. The owner or operator shall comply with the quality assurance procedures for CEMS found in 40 CFR part 75. Compliance with the emission limits for NO_X shall be determined by using data from a CEMS.

(iv) Continuous emissions monitoring shall apply during all periods of operation of the units listed in paragraph (c)(3) of this section, including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments. Continuous monitoring systems for measuring NO_X 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 NO_X pounds per hour 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.

(6) *Emissions limitations for AEP Flint Creek Unit 1 and Entergy White Bluff Units 1 and 2.* The individual SO_2 and NO_X emission limits for each unit shall be as listed in the following table in pounds per million British thermal units (lb/MMBtu) as averaged over a rolling 30 boiler-operating-day period.

Unit	SO_2 Emission limit (lb/MMBtu)	NO_X Emission limit (lb/MMBtu)
AEP Flint Creek Unit 1	0.06	0.23
Entergy White Bluff Unit 1	0.06	0.15
Entergy White Bluff Unit 2	0.06	0.15

(7) *Compliance dates for AEP Flint Creek Unit 1 and Entergy White Bluff Units 1 and 2.* The owner or operator of each unit shall comply with the SO_2 emission limit listed in paragraph (c)(6) of this section within 5 years of the effective date of this rule and the NO_X emission limit within 3 years of the effective date of this rule.

(8) *Compliance determination for AEP Flint Creek Unit 1 and Entergy White Bluff Units 1 and 2.* (i) For each unit, SO_2 and NO_X emissions for each calendar day shall be determined by summing the hourly emissions measured in pounds of SO_2 or pounds of NO_X. For each unit, heat input for each boiler-operating-day shall be determined by adding together all hourly heat inputs, in millions of BTU. Each boiler-operating-day of the thirty-day rolling average for a unit shall be determined by adding together the pounds of SO_2 or NO_X from that day and the preceding 29 boiler-operating-days and dividing the total pounds of SO_2 or NO_X by the sum of the heat input during the same 30 boiler-operating-day period. The result shall be the 30 boiler-operating-day rolling average in terms of lb/MMBtu emissions of SO_2 or NO_X. If a valid SO_2 or NO_X pounds per hour or heat input is not available for any hour for a unit, that heat input and SO_2 or NO_X pounds per hour shall not be used in the calculation of the 30 boiler-operating-day rolling average for SO_2 or NO_X.

(ii) The owner or operator shall continue to maintain and operate a CEMS for SO_2 and NO_X on the units listed in paragraph (c)(6) of this section in accordance with 40 CFR 60.8 and 60.13(e), (f), and (h), and Appendix B of Part 60. The owner or operator shall comply with the quality assurance procedures for CEMS found in 40 CFR part 75. Compliance with the emission limits for SO_2 and NO_X shall be determined by using data from a CEMS.

(iii) Continuous emissions monitoring shall apply during all periods of operation of the units listed in paragraph (c)(6) of this section, 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 NO_X 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 or NO_X pounds per hour 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.

(9) *Emissions limitations for Entergy White Bluff Auxiliary Boiler.* The individual SO_2, NO_X, and PM emission limits for the unit shall be as listed in the following table in pounds per hour (lb/hr).

Unit	SO_2 Emission limit (lb/hr)	NO_X Emission limit (lb/hr)	PM Emission limit (lb/hr)
Entergy White Bluff Auxiliary Boiler	105.2	32.2	4.5

(10) *Compliance dates for Entergy White Bluff Auxiliary Boiler.* The owner or operator of the unit shall comply with the SO_2, NO_X, and PM emission limits listed in paragraph (c)(9) of this section as of the effective date of this rule.

(11) *Emissions limitations for Entergy Lake Catherine Unit 4.* The individual NO_X emission limit for the unit for natural gas firing shall be as listed in the following table in pounds per million British thermal units (lb/MMBtu) as averaged over a rolling 30 boiler-operating-day period. The unit shall not burn fuel oil until BART determinations are promulgated for the unit for SO_2, NO_X, and PM for the fuel oil firing scenario through a FIP and/or through EPA action upon and approval of revised BART determinations submitted by the State as a SIP revision.

Unit	NO_X Emission limit—natural gas firing (lb/MMBtu)
Entergy Lake Catherine Unit 4	0.22

(12) *Compliance dates for Entergy Lake Catherine Unit 4.* The owner or operator of the unit shall comply with the NO_X emission limit listed in paragraph (c)(11) of this section within 3 years of the effective date of this rule.

(13) *Compliance determination for Entergy Lake Catherine Unit 4.* (i) NO_X emissions for each calendar day shall be determined by summing the hourly emissions measured in pounds of NO_X. The heat input for each boiler-operating-day shall be determined by adding together all hourly heat inputs, in millions of BTU. Each boiler-operating-day of the thirty-day rolling average for the unit shall be determined by adding together the pounds of NO_X from that day and the preceding 29 boiler-operating-days and dividing the total pounds of NO_X by the sum of the heat input during the same 30 boiler-operating-day period. The result shall be the 30 boiler-operating-day rolling average in terms of lb/MMBtu emissions of NO_X. If a valid NO_X pounds per hour or heat input is not available for any hour for the unit, that heat input and NO_X pounds per hour shall not be used in the calculation of the 30 boiler-operating-day rolling average for NO_X.

(ii) The owner or operator shall continue to maintain and operate a CEMS for NO_X on the unit listed in paragraph (c)(11) of this section in accordance with 40 CFR 60.8 and 60.13(e), (f), and (h), and appendix B of part 60. The owner or operator shall comply with the quality assurance procedures for CEMS found in 40 CFR part 75. Compliance with the emission limit for NO_X shall be determined by using data from a CEMS.

(iii) Continuous emissions monitoring shall apply during all periods of operation of the unit listed in paragraph (c)(11) of this section, including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments. Continuous monitoring systems for measuring NO_X 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 NO_X pounds per hour 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.

(14) *Emissions limitations for Domtar Ashdown Paper Mill Power Boiler No.1.* The individual SO_2 and NO_X emission limits for the power boiler shall be as listed in the following table in pounds per hour (lb/hr) as averaged over a rolling 30 boiler-operating-day period. For this power boiler, boiler-operating-day is defined as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the power boiler.

Unit	SO_2 Emission limit (lb/hr)	NO_X Emission limit (lb/hr)
Domtar Ashdown Paper Mill Power Boiler No. 1	21.0	207.4

(15) *Compliance dates for Domtar Ashdown Mill Power Boiler No. 1.* The owner or operator of the power boiler shall comply with the SO_2 and NO_X emission limits listed in paragraph (c)(14) of this section as of the effective date of this rule.

(16) *Compliance determination for Domtar Ashdown Paper Mill Power Boiler No. 1.* (i) SO_2 emissions for each calendar day shall be determined by summing the hourly emissions measured in pounds of SO_2. SO_2 emissions from combustion of bark shall be determined by using the following site-specific curve equation, which accounts for the SO_2 scrubbing capabilities of bark combustion:

$$Y = 0.4005 * X - 0.2645$$

Where:

Y= pounds of sulfur emitted per ton of dry fuel feed to the boiler
X= pounds of sulfur input per ton of dry bark

The owner or operator shall confirm the site-specific curve equation through stack testing. No later than 1 year after the effective date of this rule, the owner or operator shall provide a report to EPA showing confirmation of the site specific-curve equation accuracy. Stack SO_2 emissions from combustion of fuel oil shall be determined by assuming that the SO_2 inlet is equal to the SO_2 being emitted at the stack.

(ii) To demonstrate compliance with the NO_X emission limit under paragraph (c)(14) of this section, the owner or operator shall conduct annual stack testing.

(iii) Each boiler-operating-day of the thirty-day rolling average for the power boiler shall be determined by adding together the pounds of SO_2 or NO_X from that day and the preceding 29 boiler-operating-days and dividing the total pounds of SO_2 or NO_X by the sum of the total number of hours during the same 30 boiler-operating-day period. The result shall be the 30 boiler-operating-day rolling average in terms of lb/hr emissions of SO_2 or NO_X. If a valid SO_2 or NO_X pounds per hour is not available for any hour for the power boiler, that SO_2 or NO_X pounds per hour shall not be used in the calculation of the applicable 30 boiler-operating-day rolling average.

(17) *SO_2 and NO_X emissions limitations for Domtar Ashdown Paper Mill Power Boiler No.2.* The individual SO_2 and NO_X emission limits for the power boiler shall be as listed in the following table in pounds per hour (lb/hr) or pounds per million British thermal units (lb/MMBtu) as averaged over a rolling 30 boiler-operating-day period. For this power boiler, boiler-operating-day is defined as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the power boiler.

Unit	SO_2 Emission limit (lb/MMBtu)	NO_X Emission limit (lb/hr)
Domtar Ashdown Paper Mill Power Boiler No. 2	0.11	345

(18) *SO_2 and NO_X compliance dates for Domtar Ashdown Mill Power Boiler No. 2.* The owner or operator of the power boiler shall comply with the SO_2 and NO_X emission limits listed in paragraph (c)(17) of this section within 3 year of the effective date of this rule.

(19) *SO_2 and NO_X compliance determination for Domtar Ashdown Mill Power Boiler No. 2.* (i) SO_2 emissions for each calendar day shall be determined by summing the hourly emissions measured in pounds of SO_2. The heat input for each boiler-operating-day shall be determined by adding together all hourly heat inputs, in millions of BTU. Each boiler-operating-day of the thirty-day rolling average for a unit shall be determined by adding together the pounds of SO_2 from that day and the preceding 29 boiler-operating-days and dividing the total pounds of SO_2 by the sum of the heat input during the same 30 boiler-operating-day period. The result shall be the 30 boiler-operating-day rolling average in terms of lb/MMBtu emissions of SO_2. If a valid SO_2 pounds per hour or heat input is not available for any hour for a unit, that heat input and SO_2 pounds per hour shall not be used in the calculation of the 30 boiler-operating-day rolling average for SO_2.

(ii) NO_X emissions for each calendar day shall be determined by summing the hourly emissions measured in pounds of NO_X. Each boiler-operating-day of the thirty-day rolling average for the power boiler shall be determined by adding together the pounds of NO_X from that day and the preceding 29 boiler-operating-days and dividing the total pounds of NO_X by the sum of the total number of hours during the same 30 boiler-operating-day period. The result shall be the 30 boiler-operating-day rolling average in terms of lb/hr emissions of NO_X. If a valid NO_X pounds per hour is not available for any hour for the power boiler, that NO_X pounds per hour shall not be used in the calculation of the 30 boiler-operating-day rolling average for NO_X.

(iii) The owner or operator shall continue to maintain and operate a CEMS for SO_2 and NO_X on the power boiler listed in paragraph (c)(17) of this section in accordance with 40 CFR 60.8 and 60.13(e), (f), and (h), and Appendix B of Part 60. The owner or operator shall comply with the quality assurance procedures for CEMS found in 40 CFR part 75. Compliance with the emission limits for SO_2 and NO_X shall be determined by using data from a CEMS.

(iv) Continuous emissions monitoring shall apply during all periods of operation of the units listed in paragraph (c)(17) of this section, 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 NO_X 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 or NO_X pounds per hour 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.

(20) *PM Emissions limitations for Domtar Ashdown Paper Mill Power Boiler No.2.* The individual particulate matter emission limit for the power boiler shall be as listed in the following table in pounds per million British thermal units (lb/MMBtu).

Unit	PM Emission limit (lb/MMBtu)
Domtar Ashdown Paper Mill Power Boiler No. 2	0.44

(21) *PM compliance dates for Domtar Ashdown Mill Power Boiler No. 2.* The owner or operator of the power boiler shall comply with the PM emission limit listed in paragraph (c)(20) of this section as of the effective date of this rule.

(22) *PM compliance determination for Domtar Ashdown Paper Mill Power Boiler No.2.* Compliance with the PM emission limit listed in paragraph (c)(20) of this section shall be determined by maintaining the 30-day rolling average wet scrubber pressure drop and the 30-day rolling average wet scrubber liquid flow rate at or above the lowest one-hour average pressure drop and the lowest one-hour average liquid flow rate, respectively, measured during the most recent performance test demonstrating compliance with the PM emission limit according to 40 CFR 63.7530(b) and Table 7 to subpart DDDDD of part 63. The pressure drop and liquid flow rate monitoring system data shall be collected according to 40 CFR 63.7525 and 63.7535; data shall be reduced to 30-day rolling averages; and the 30-day rolling average pressure drop and liquid flow-rate shall be maintained at or above the operating limits established during the performance test according to 40 CFR 63.7530(b).

(23) *Emissions limitations for Entergy Independence Units 1 and 2.* The individual emission limits for each unit shall be as listed in the following table in pounds per million British thermal units (lb/MMBtu) as averaged over a rolling 30 boiler-operating-day period. EPA is taking comment on two possible options. Under Option 1, the SO_2 and a NO_X emission limits as listed in the following table shall apply to each unit. Under Option 2, only the SO_2 emission limit as listed in the following table shall apply to each unit. EPA expects only to finalize one of these options.

Unit		SO_2 Emission limit (lb/MMBtu)	NO_X Emission limit (lb/MMBtu)
Option 1	Entergy Independence Unit 1 and 2	0.06	0.15
Option 2	Entergy Independence Unit 1 and 2	0.06	

(24) *Compliance dates for Entergy Independence Units 1 and 2.* The owner or operator of each unit shall comply with the SO_2 emission limit in paragraph (c)(23) of this section within 5 years of the effective date of this rule and the NO_X emission limit within 3 years of the effective date of this rule.

(25) *Compliance determination for Entergy Independence Units 1 and 2.* (i) For each unit, SO_2 and NO_X emissions for each calendar day shall be determined by summing the hourly emissions measured in pounds of SO_2 or pounds of NO_X. For each unit, heat input for each boiler-operating-day shall be determined by adding together all hourly heat inputs, in millions of BTU. Each boiler-operating-day of the thirty-day rolling average for a unit shall be determined by adding together the pounds of SO_2 or NO_X from that day and the preceding 29 boiler-operating-days and dividing the total pounds of SO_2 or NO_X by the sum of the heat input during the same 30 boiler-operating-day period. The result shall be the 30 boiler-operating-day rolling average in terms of lb/MMBtu emissions of SO_2 or NO_X. If a valid SO_2 or NO_X pounds per hour or heat input is not available for any hour for a unit, that heat input and SO_2 or NO_X pounds per hour shall not be used in the calculation of the applicable 30 boiler-operating-day rolling average.

(ii) The owner or operator shall continue to maintain and operate a CEMS for SO_2 and NO_X on the units listed in paragraph (c)(23) of this section in accordance with 40 CFR 60.8 and 60.13(e), (f), and (h), and appendix B of part 60. The owner or operator shall comply with the quality assurance procedures for CEMS found in 40 CFR part 75. Compliance with the emission limits for SO_2 and NO_X shall be determined by using data from a CEMS.

(iii) Continuous emissions monitoring shall apply during all periods of operation of the units listed in paragraph (c)(23) of this section, 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 NO_X 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 or NO_X pounds per hour 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.

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

(i) For each emissions limit under paragraph (c) of this section where compliance shall be determined by using data from a CEMS, comply with the notification, reporting, and recordkeeping requirements for CEMS compliance monitoring in 40 CFR 60.7(c) and (d).

(ii) For each day, provide the total SO_2 emitted that day by AEP Flint Creek Unit 1, Entergy White Bluff Units 1 and 2, Domtar Ashdown Mill Power Boilers No. 1 and 2, and Entergy Independence Units 1 and 2. For each day, provide the total NO_X emitted that day by AECC Bailey Unit 1, AECC McClellan Unit 1, AEP Flint Creek Unit 1, Entergy White Bluff Units 1 and 2, Entergy Lake Catherine Unit 4, Domtar Ashdown Mill Power Boiler No. 2, and Entergy Independence Units 1 and 2. For any hours on any unit or power boiler 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.

(27) *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.

(28) *Enforcement.* (i) 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.

(ii) 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.

(d) *Measures addressing partial disapproval of portion of Interstate Visibility Transport SIP for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS.* (1) The deficiencies identified in EPA's partial disapproval of the portion of the SIP pertaining to adequate provisions to prohibit emissions in Arkansas from interfering with measures required in another state to protect visibility, submitted on March 28, 2008, and supplemented on September 27, 2011 are satisfied by § 52.173.

(2) [Reserved]

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