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

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R06–OAR–2015–0189; FRL–9952–03-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: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is promulgating a final Federal Implementation Plan (FIP) addressing the requirements of the Regional Haze Rule and interstate visibility transport for the portions of Arkansas' Regional Haze State Implementation Plan (SIP) that EPA disapproved in a final rule published in the **Federal Register** on March 12, 2012. In that action, we partially approved and partially disapproved the State's plan to implement the regional haze program for the first planning period. This final rule addresses the Regional Haze Rule's requirements for Best Available Retrofit Technology (BART), reasonable progress, and a long-term strategy (LTS), as well as the requirements of the Clean Air Act (CAA or Act) regarding interference with other states' programs for visibility protection (interstate visibility transport) triggered by the issuance of the 1997 ozone National Ambient Air Quality Standards (NAAQS) and the 1997 fine particulate matter ($PM_{2.5}$) NAAQS. The FIP includes sulfur dioxide (SO_2), nitrogen oxide (NO_X), and particulate matter (PM) emission limits for nine units located at six facilities to address BART requirements (these limits also satisfy reasonable progress requirements for these sources); and SO_2 and NO_X emission limits for two units located at one power plant to address the reasonable progress requirements. We also provide reasonable progress goals (RPGs) for Arkansas' Class I areas. We are prepared to work with the State on a SIP revision that would replace some or all elements of the FIP.

DATES: This final rule is effective on October 27, 2017.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–R06–OAR–2015–0189. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Publicly available docket materials are available either electronically through *http://www.regulations.gov* or in hard copy at EPA Region 6, 1445 Ross Avenue, Suite 700, Dallas, Texas 75202–2733.

FOR FURTHER INFORMATION CONTACT: Ms. Dayana Medina at 214–665–7241; or *Medina.dayana@epa.gov*.

SUPPLEMENTARY INFORMATION: Throughout this document wherever ''we,'' ''us,'' or ''our'' is used, we mean the EPA. Also throughout this document, when we refer to the Arkansas Department of Environmental Quality (ADEQ), we mean Arkansas.

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I. Introduction

The purpose of Federal and state regional haze plans is to achieve a national goal, declared by Congress, of restoring and protecting visibility at 156 Federal Class I areas across the United States, most of which are national parks and wilderness areas with scenic vistas enjoyed by the American public. The national goal, as described in CAA Section 169A, is ''the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution.'' States are required to submit SIPs that ensure reasonable progress toward the national goal of remedying anthropogenic visibility impairment in Federal Class I areas. Arkansas has two Federal Class I areas, the Caney Creek Wilderness Area (Caney Creek) and Upper Buffalo Wilderness Area (Upper Buffalo). Please refer to our previous rulemaking on the Arkansas Regional Haze SIP for additional background information regarding the CAA, regional haze, and the Regional Haze Rule.[1]

In our previous action on the Arkansas Regional Haze SIP, we approved a number of elements but disapproved others.[2] In this final action, we are addressing these disapproved elements. We are establishing BART emission limits for nine units at six facilities that contribute to visibility impairment at Caney Creek and Upper Buffalo in Arkansas, as well as the Hercules-Glades Wilderness Area (Hercules-Glades) and the Mingo National Wildlife Refuge (Mingo) in Missouri. These facilities are subject to BART controls for emissions of SO_2, NO_X, and PM. The BART sources are the Arkansas Electric Cooperative Corporation Carl E. Bailey Generating Station (AECC Bailey) Unit 1; Arkansas Electric Cooperative Corporation John L. McClellan Generating Station (AECC McClellan) Unit 1; American Electric Power (AEP) Flint Creek Power Plant Unit 1; Entergy White Bluff Plant Units 1, 2, and Auxiliary Boiler; Entergy Lake Catherine Plant Unit 4; and Domtar Ashdown Mill Power Boilers Nos. 1 and 2. In addition, we are establishing SO_2 and NO_X emission limits for the Entergy Independence Plant Units 1 and 2 pursuant to the reasonable progress and long-term strategy provisions of the Regional Haze Rule. We have calculated numerical RPGs for Caney Creek and Upper Buffalo that reflect the visibility improvement anticipated by 2018 from the combination of control measures from the approved portion of the Arkansas Regional Haze SIP and this FIP.

We are also making a finding that the combination of the approved portion of the Arkansas Regional Haze SIP and this FIP satisfy the requirements of CAA section 110(a)(2)(D)(i)(II) with respect to visibility (interstate visibility transport requirement) for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS. This provision of the CAA requires that each state's SIP have adequate provisions to prohibit in-state emissions from interfering with measures required to protect visibility in any other state. To address this requirement, the SIP must address the

[1] 76 FR 64186, October 17, 2011 (proposed action); and 77 FR 14604, March 12, 2012 (final action).

[2] 77 FR 14604.

potential for interference with visibility protection caused by the pollutant (including precursors) to which the new or revised NAAQS applies. In our March 12, 2012 final action on the Arkansas Regional Haze SIP, we also 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). This FIP fully addresses the deficiencies we identified in our final action on the Arkansas Regional Haze SIP 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.

In this document, we summarize our responses to comments received during our comment period on our proposed rule and indicate where we have made adjustments based on the comments and additional information we received. In some cases, we have adjusted the emission limits, compliance deadlines, and requirements for testing and demonstration of compliance in response to information received during the comment period. We also received several comments, from Entergy and Sierra Club, after the close of the comment period, which included new information on an alternative approach for White Bluff. We do not address these late comments in our rulemaking and they are not a basis for our decision in this action. We do note that the new information regarding an alternative approach may have promise with respect to addressing the BART requirements for White Bluff, and we encourage the State to consider it as it develops a SIP revision to replace our FIP.

EPA is promulgating this partial FIP to address the deficiencies in the Arkansas Regional Haze SIP and the SIP revision submitted by the State to address the interstate visibility transport requirements.[3] The State retains its authority to submit a revised state plan consistent with CAA and Regional Haze Rule requirements. EPA stands ready to work with the State on a SIP revision that would replace some or all elements of the FIP.

II. History of State Submittals and Our Actions

A. State Submittals and EPA Actions

Arkansas submitted a SIP to address the regional haze requirements for the first planning period on September 23, 2008. On August 3, 2010, Arkansas submitted a SIP revision that addressed the Arkansas Pollution Control and Ecology Commission (APCEC) Regulation 19, Chapter 15, which is the State rule that identifies the BART-eligible and subject-to-BART sources in Arkansas and establishes the BART emission limits that subject-to-BART sources are required to comply with. On September 27, 2011, the State submitted supplemental information related to regional haze. We are hereafter referring to these regional haze submittals collectively as the ''Arkansas Regional Haze SIP.'' On April 2, 2008, Arkansas submitted a SIP revision to address the interstate visibility transport requirement of CAA section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS. On October 17, 2011, we published our proposed partial approval and partial disapproval of the Arkansas Regional Haze SIP and the interstate visibility transport SIP.[4] Our final rule partially approving and partially disapproving the Arkansas Regional Haze SIP and interstate visibility transport SIP was published on March 12, 2012.[5] We explained in our proposed and final actions on the Arkansas Regional Haze SIP that we elected not to promulgate a FIP concurrently with our partial disapproval action because ADEQ expressed its intent to revise the disapproved portions of the SIP and we therefore wanted to provide the state time to submit a SIP revision.[6]

Our final partial disapproval of the Arkansas RH SIP and interstate visibility transport SIP started a 2-year FIP clock such that we have an obligation to approve a SIP revision and/or promulgate a FIP to address the disapproved portions of the SIP within 2 years of our final partial disapproval action. We began working in 2012 with ADEQ and the affected facilities to revise the disapproved portions of the SIP. However, a SIP revision was not submitted and the FIP clock expired in April 2014. On April 8, 2015, we proposed a FIP to address the disapproved portions of the Arkansas Regional Haze SIP and interstate visibility transport SIP.[7] On May 1, 2015, we published a notice extending the public comment period for our FIP proposal and announcing the availability in the docket of supplemental modeling we performed for the Entergy Independence Plant following the April 8, 2015 publication of our FIP proposal.[8] On July 23, 2015, we published a notice reopening the public comment period for our FIP proposal by 15 days in response to a request we received from the Domtar Ashdown Mill so that the facility would be able to complete modeling work and submit to us information it deemed to be essential and related to a significant aspect of the proposed FIP requirements for the Domtar Ashdown Mill.[9] The reopening of the comment period also allowed other interested persons additional time to submit comments to us on our FIP proposal. On April 4, 2016, we published a notice and welcomed comment on supplemental information added to the docket which we relied on in our FIP proposal published on April 8, 2015, but which was inadvertently omitted from the docket at the time we proposed our FIP.[10] Our notice published on April 4, 2016, also reopened the public comment period for our FIP proposal until May 4, 2016, but strictly limited the reopening of the comment period to our calculations of the revised RPGs, as presented in the spreadsheet we made available at that time in the docket.[11] In this action, we are finalizing our FIP proposal published on April 8, 2015, and the associated aforementioned supplemental notices.

B. EPA's Authority To Promulgate a FIP

Under CAA section 110(c), EPA is required to promulgate a FIP at any time within 2 years of the effective date of a finding that a state has failed to make a required SIP submission or has made an incomplete submission, or of the date that EPA disapproves a SIP in whole or in part. The FIP requirement is terminated only if a state submits a SIP, and EPA approves that SIP as meeting applicable CAA requirements before promulgating a FIP. CAA section 302(y) defines the term ''Federal implementation plan'' in pertinent part, as a plan (or portion thereof) promulgated by EPA ''to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy'' in a SIP, and which includes enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions or emissions allowances).

[3] These deficiencies are discussed in our March 12, 2012 final action on the Arkansas Regional Haze SIP and SIP revision to address the interstate visibility transport requirements. See 77 FR 14604.

[4] 76 FR 64186.

[5] 77 FR 14604.

[6] See 76 FR 64186, 64188 (proposed action) and 77 FR 14604, 14672 (final action).

[7] 80 FR 18944.

[8] 80 FR 24872.

[9] 80 FR 43661.

[10] 81 FR 19097.

[11] See the spreadsheet titled ''Caney Creek and Upper Buffalo Wilderness Areas Reasonable Progress Goals (CACR UPBU RPG analysis.xlsx),'' which is available in the docket for our rulemaking.

As discussed above, in a final action published on March 12, 2012, we disapproved in part the Arkansas Regional Haze SIP and the SIP submitted by the state to address the interstate visibility transport requirement of CAA section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS.[12] That final action became effective on April 11, 2012. Therefore, EPA is required under CAA section 110(c) to promulgate a FIP for the portions of the Arkansas Regional Haze SIP and the SIP submittal to address the interstate visibility transport requirement of CAA section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS that we disapproved on March 12, 2012.

III. Summary of Our Proposed Rule

In this section, we provide a summary of our proposed rule that was published in the **Federal Register** on April 8, 2015,[13] and the associated supplemental notices published on May 1, 2015,[14] and April 4, 2016,[15] as background for understanding this final action. Our electronic docket at *www.regulations.gov* contains Technical Support Documents (TSDs) and other materials that supported our proposal and supplemental notices.

A. Regional Haze

Our FIP proposal addressed the disapproved portions of the Arkansas Regional Haze SIP and interstate visibility transport SIP. In our March 12, 2012 final action on the Arkansas Regional Haze SIP, we disapproved some of the state's BART determinations and we also determined that the SIP did not include the required analysis of the four reasonable progress factors. Therefore, we partially disapproved the state's LTS for Caney Creek and Upper Buffalo and also disapproved the RPGs established by the state.

CAA section 169A(b)(2)(A) requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress towards the natural visibility goal, including a requirement that certain categories of existing major stationary sources built between 1962 and 1977 procure, install, and operate the ''best available retrofit technology,'' as determined by the state or EPA in the case of a plan promulgated under section 110(c) of the CAA. Under the Regional Haze Rule, states are directed to conduct BART determinations for such ''BART-eligible'' sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. Rather than requiring source-specific BART controls, states or EPA in a FIP also have the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provides greater reasonable progress towards improving visibility than BART. CAA section 169(g)(2) and the Regional Haze Rule at 40 Code of Federal Regulations (CFR) § 51.308(e)(1)(A) provide that in determining BART, the state or EPA in a FIP shall take into consideration the following factors: Costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. We commonly refer to these as the BART factors, or the five statutory factors. CAA section 169(g)(1) and § 51.308(d)(1) also require that in determining reasonable progress, there shall be taken into consideration the costs of compliance, the time necessary for compliance, the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements. We commonly refer to these as the reasonable progress factors, or the four statutory factors. Consistent with the requirement in CAA section 169A(b) that states include in their regional haze SIP a 10—15 year strategy for making reasonable progress, § 51.308(d)(3) requires that states include a LTS in their regional haze SIPs. The LTS 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. The LTS must include enforceable emissions limitations, compliance schedules, monitoring and recordkeeping requirements, and various supporting documentation and analyses to ensure that the SIP or FIP will provide reasonable progress toward the national goal of natural visibility conditions.

Our FIP proposal included proposed BART determinations for nine units at six facilities and proposed reasonable progress determinations for two units at one facility in Arkansas. These determinations resulted in proposed emission limits, compliance schedules, and other requirements for these sources. The proposed regulatory language was included under Part 52 at the end of that document. We also addressed the RPGs, as well as the LTS requirements. Lastly, we proposed that the approved measures in the Arkansas Regional Haze SIP and measures in our proposed FIP would adequately address the interstate transport of pollutants that affect visibility requirement for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS.

Georgia Pacific-Crossett Mill 6A and 9A Power Boilers: In our FIP proposal, we proposed to find that the Georgia Pacific-Crossett Mill 6A Boiler is a BART-eligible source, but not subject to BART. We also proposed to find that the 9A Boiler, which the State had previously determined was BART-eligible, is not subject to BART. Our proposed determinations were based on the company's newly provided analysis and documentation, including BART screening modeling conducted in 2011 by Georgia Pacific based on revised emission limits from a permit issued on May 23, 2012, and using 2001, 2002, and 2003 meteorology. The modeling showed the maximum visibility impact from the boilers was 0.359 deciviews (dv) at Caney Creek, which is below the 0.5 dv threshold the state used in the Arkansas Regional Haze SIP to identify subject-to-BART sources. Prior to issuing our FIP proposal, we had communicated to ADEQ our concern with relying on the company's BART screening modeling that was based on revised emission limits from a permit issued in 2012, without documentation that these emission limits were representative of the baseline period emissions.[16] To address our concern, the company provided estimates of maximum 24-hour emission rates for the 6A and 9A Boilers from the 2001–2003 baseline period to demonstrate that these emission rates were lower than the revised emission limits that it modeled in its 2011 BART screening modeling.[17] This indicated that the 2011 BART screening modeling that was based on allowable emissions was conservative in terms of representing the impact that the source had on visibility in the 2001–2003 period, the period that matters for the subject-to-BART determination, and we proposed to find that it is reasonable to conclude based on the modeling analysis and documentation provided by Georgia Pacific that the 6A and 9A Boilers had visibility impacts below 0.5

[12] 77 FR 14604.

[13] 80 FR 18944.

[14] 80 FR 24872.

[15] 81 FR 19097.

[16] See file titled ''Region 6 feedback on Georgia Pacific 6A and 9A Boilers_3–4–2013,'' which is found in the docket associated with this rulemaking.

[17] As discussed in our proposal, Georgia Pacific estimated the maximum 24-hour emission rates using daily fuel usage data and emission factors from AP–42, *Compilation of Air Pollutant Emission Factors.* See 80 FR 18944, 18948.

dv during the 2001–2003 baseline period and are therefore not subject to BART.

AECC Bailey Unit 1: We proposed that BART for SO_2 and PM is the use of fuels with 0.5% or lower sulfur content by weight. We also proposed to require that, after the effective date of the final rule, the facility shall not purchase fuel that does not meet the sulfur content requirement, but to allow the facility 5 years to burn its existing supply of No. 6 fuel oil, in accordance with any operating restrictions enforced by ADEQ. We proposed to require the facility to comply with the requirement to use fuels with 0.5% or lower sulfur content by weight no later than 5 years from the effective date of the final rule. We proposed that BART for NO_X is the existing emission limit in the permit of 887 lb/hr, which would not necessitate the installation of additional controls. We proposed to require the source to comply with this emission limit for BART purposes as of the effective date of the final rule.

AECC McClellan Unit 1: We proposed that BART for SO_2 and PM is the use of fuels with 0.5% or lower sulfur content by weight. We also proposed to require that, after the effective date of the final rule, the facility shall not purchase fuel that does not meet the sulfur content requirement, but to allow the facility 5 years to burn its existing supply of No. 6 fuel oil, in accordance with any operating restrictions enforced by ADEQ. We proposed to require the source to comply with the requirement to use fuels with 0.5% or lower sulfur content by weight no later than 5 years from the effective date of the final rule. We proposed that BART for NO_X are the existing emission limits in the permit of 869.1 lb/hr for natural gas firing and 705.8 lb/hr for fuel oil firing, which would not necessitate the installation of additional controls. We proposed to require the source to comply with these emission limits for BART purposes as of the effective date of the final rule.

AEP Flint Creek Unit 1: We proposed that BART for SO_2 is an emission limit of 0.06 lb/MMBtu on a 30 boiler-operating-day rolling average, which is consistent with the installation and operation of a type of dry flue gas desulfurization (FGD or ''scrubbers'') system called Novel Integrated Desulfurization (NID) technology. We stated that the full compliance time of 5 years allowed under the CAA and Regional Haze Rule is appropriate for a new scrubber retrofit, and proposed to require the source to comply with this emission limit no later than 5 years from the effective date of the final rule. We proposed that BART for NO_X is an emission limit of 0.23 lb/MMBtu on a 30 boiler-operating-day rolling average, which is consistent with the installation and operation of new low NO_X burners (LNB) with overfire air (OFA). We proposed to require the source to comply with this emission limit no later than 3 years from the effective date of the final rule.

Entergy White Bluff Units 1 and 2: We proposed that BART for SO_2 for Units 1 and 2 is an emission limit of 0.06 lb/MMBtu on a 30 boiler-operating-day rolling average, consistent with the installation and operation of dry FGD or another control technology that achieves that level of control. We proposed to require the source to comply with this emission limit no later than 5 years from the effective date of the final rule. We proposed that BART for NO_X for Units 1 and 2 is an emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average, consistent with the installation and operation of LNB with separated overfire air (SOFA). We proposed to require the source to comply with this emission limit no later than 3 years from the effective date of the final rule.

Entergy White Bluff Auxiliary Boiler: We proposed that the existing emission limit in the permit 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. These emission limits would not necessitate the installation of additional controls. We proposed to require the source to comply with these emission limits for BART purposes as of the effective date of the final rule.

Entergy Lake Catherine Unit 4: We proposed that BART for NO_X for the natural gas-firing scenario is an emission limit of 0.22 lb/MMBtu on a 30 boiler-operating-day rolling average, consistent with the installation and operation of burners out of service (BOOS). We proposed to require the source to comply with this emission limit no later than 3 years from the effective date of the final rule. We invited 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 did not propose BART determinations for the fuel oil-firing scenario for Lake Catherine Unit 4 in light of the source's commitment to submit to Arkansas a five-factor BART analysis for the fuel oil-firing scenario, to then be submitted to us as a SIP revision for approval, before any fuel oil combustion takes place at Unit 4. We proposed that fuel oil-firing is not allowed to take place at Lake Catherine Unit 4 until BART determinations are promulgated for SO_2, NO_X, and PM for the fuel oil-firing scenario through our approval of a SIP revision and/or promulgation of a FIP.

Domtar Ashdown Mill Power Boiler No. 1: We proposed that BART for SO_2 is an emission limit of 21.0 lb/hr on a 30 boiler-operating-day averaging basis, 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 consistent with the Power Boiler's baseline emissions and would not necessitate additional controls. We proposed to require the source to comply with this emission limit as of the effective date of the final rule. We proposed to require the source to use a site-specific curve equation,[18] provided to us by the facility, to calculate the SO_2 emissions from Power Boiler No. 1 when combusting bark for purposes of demonstrating compliance with the BART requirement, and to confirm the curve equation using stack testing no later than 1 year from the effective date of the final rule. We also proposed that to calculate the SO_2 emissions from fuel oil combustion for purposes of demonstrating compliance with the BART requirement, the facility must assume that the SO_2 inlet[19] is equal to the SO_2 being emitted at the stack. We invited public comment on whether this method of demonstrating compliance with the proposed SO_2 BART emission limit for Power Boiler No. 1 is appropriate.

We proposed that BART for NO_X 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 consistent with the Power Boiler's baseline emissions and would not necessitate additional controls. We proposed to require the source to comply with this emission limit as of the effective date of the final rule. To demonstrate compliance with this NO_X BART emission limit, we proposed to require the source to conduct annual stack

[18] 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.

[19] We define SO_2 inlet to be the SO_2 content of the fuel delivered to the fuel inlet of the combustion chamber.

testing. We invited public comment on the appropriateness of this method for demonstrating compliance with the proposed NO_X BART emission limit for Power Boiler No. 1.

Domtar Ashdown Mill Power Boiler No. 2: We proposed that BART for SO_2 is an emission limit of 0.11 lb/MMBtu on a 30 boiler-operating-day rolling average, which we estimated is representative of operating the existing venturi scrubbers at 90% control efficiency and can be achieved through the installation of scrubber pump upgrades and use of additional scrubbing reagent. We indicated that 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. We invited public comment specifically on the appropriateness of our proposed SO_2 emission limit. We proposed to require compliance with this BART emission limit no later than 3 years from the effective date of the final action, but invited public comment on the appropriateness of a compliance date anywhere from 1–5 years. We also proposed to require the source to demonstrate compliance with this emission limit using the existing continuous emissions monitoring system (CEMS).

We proposed that BART for NO_X is an emission limit of 345 lb/hr on a 30 boiler-operating-day rolling averaging basis, consistent with the installation and operation of LNB. We indicated that 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. We proposed to require compliance with this emission limit no later than 3 years from the effective date of the final rule, and invited public comment on the appropriateness of this compliance date. We also proposed to require the source to demonstrate compliance with this emission limit using the existing CEMS.

Power Boiler No. 2 is subject to the Boiler Maximum Achievable Control Technology (MACT) standards for PM 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. We proposed to find that the current Boiler MACT PM standard satisfies the PM BART requirement for Power Boiler No. 2. We also proposed 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. We proposed to require the source to comply with this emission limit for BART purposes as of the effective date of the final rule.

Proposed Reasonable Progress Determinations: In our proposed rule, we explained that the Central Regional Air Planning Association (CENRAP) CAMx modeling with Particulate Source Apportionment Tool (PSAT) showed that point sources are responsible for a majority of the light extinction at Arkansas Class I areas, contributing approximately 60% of the total light extinction at each Class I area on the 20% worst days in 2002. 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 average across the 20% worst days in 2002. Since other source types (*i.e.,* natural, on-road, non-road, and area) each contributed a much smaller proportion of the total light extinction at each Class I area, we decided to focus only on point sources in our reasonable progress analysis for this planning period.

As a starting point in our analysis to determine whether additional controls on Arkansas sources are necessary to make reasonable progress 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 NO_X emissions in Arkansas.[20] 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. As our proposed rule included SO_2 and NO_X emission limits under BART for White Bluff Units 1 and 2 and Flint Creek Unit 1 that are anticipated to result in a substantial reduction in SO_2 and NO_X emissions from these facilities, we proposed to determine that it is appropriate to eliminate these three units from further consideration of additional controls under the reasonable progress requirements for the first planning period. The Entergy Independence Plant is not subject to BART, and its emissions were 30,398 SO_2 tons per year (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. In our proposal, we explained that it is appropriate to focus our reasonable progress analysis on the Entergy Independence Power Plant 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 emissions in the State. We explained that our proposed SO_2 and NO_X controls under BART for White Bluff Units 1 and 2 and Flint Creek Unit 1 and our evaluation of controls under reasonable progress for the Independence facility would address a sufficient amount of SO_2 and NO_X point source emissions in the State in this first planning period. 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 SO_2 and NO_X emissions from the top three point sources (*i.e.,* White Bluff, Independence, and Flint Creek), emissions from these two facilities and remaining point sources in the state are relatively small. Therefore, we did not evaluate other Arkansas point sources in our reasonable progress analysis. We explained that it is therefore appropriate to defer the consideration and evaluation of any additional sources under reasonable progress to future regional haze planning periods.

We conducted source-specific reasonable progress analyses of potential SO_2 and NO_X controls for Independence Units 1 and 2 and conducted CALPUFF modeling to assess the baseline visibility impacts from the facility and potential visibility benefits of controls. Based on these analyses, we proposed two options in the alternative for satisfying the reasonable progress requirements for Independence Units 1 and 2. Under Option 1, we proposed to establish both SO_2 and NO_X emission limits. We proposed to require compliance with an SO_2 emission limit of 0.06 lb/MMBtu for Independence Units 1 and 2 based on a 30 boiler-operating-day rolling average basis, consistent with the installation and operation of dry FGD. We proposed to require Independence Units 1 and 2 to comply with this emission limit no later than 5 years from the effective date of the final rule. We proposed to require compliance with a NO_X emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day averaging basis,

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

consistent with the installation and operation of LNB/SOFA. We proposed to require Independence Units 1 and 2 to comply with this emission limit no later than 3 years from the effective date of the final rule.

We proposed to require SO_2 controls based on our evaluation of the four reasonable progress factors, our CALPUFF modeling of the anticipated benefits of controls, and the existing CENRAP CAMx modeling. Specifically, we proposed that dry FGD was cost-effective and would provide considerable visibility improvement on the days where Independence has the largest impacts at nearby Class I areas. Additionally, the CENRAP CAMx modeling showed that on most of the 20% worst days in 2002, total extinction is dominated by sulfate at both Caney Creek and Upper Buffalo.[21] Therefore, we concluded that the substantial SO_2 emissions reductions that would be achieved by our proposed SO_2 controls for Independence Units 1 and 2 would accordingly reduce visibility extinction at Arkansas' Class I areas on the 20% worst days.

We also proposed to require NO_X controls under Option 1 based on our evaluation of the four reasonable progress factors, our CALPUFF modeling of the anticipated benefits of controls, and the existing CENRAP CAMx modeling. Specifically, we proposed that LNB/SOFA was very cost-effective and would provide considerable visibility improvement on the days where Independence has the largest impacts at nearby Class I areas. In addition, the CENRAP CAMx modeling showed that total extinction at Caney Creek was dominated by nitrate on 4 of the days that comprise the 20% worst days in 2002, while a significant portion of the total extinction at Upper Buffalo was due to nitrate on 2 of the days that comprise the 20% worst days in 2002.[22] Therefore, we concluded that our proposed NO_X controls on Independence Units 1 and 2 would improve visibility on some of the 20% worst days. In the alternative, we proposed under Option 2 to require only SO_2 controls for Independence Units 1 and 2 under the CAA's reasonable progress requirements. Our reasoning for proposing to require only SO_2 controls under Option 2 was that nitrate from point sources is not a primary contributor to the total light extinction at Arkansas Class I areas on most of the 20% worst days, so NO_X controls would not offer as much visibility improvement on the most impaired days as SO_2 controls. In our proposed rule, we specifically solicited public comment on Options 1 and 2.

In addition to Options 1 and 2, we also solicited 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. We noted that this could include, but was 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 proposed for these four units in our proposed rule.

On May 1, 2015, we published a notice in the **Federal Register** announcing supplemental modeling that we conducted for Independence Units 1 and 2, and extending the comment period to allow interested persons additional time to provide comments on the supplemental modeling.[23] We performed the supplemental modeling after receiving a letter dated April 13, 2015, that revealed that we made an error in the modeled location of the Entergy Independence facility.[24] The supplemental modeling included the corrected facility location. We provided a summary of our supplemental modeling for Independence Units 1 and 2 in the docket for our proposed rulemaking.[25] In the summary, we provided a comparison of our previous CALPUFF modeling for Independence Units 1 and 2 (*i.e.,* the modeling that was presented in our proposed rule published on April 8, 2015) and our supplemental modeling. We noted that the modeled visibility benefits from our proposed SO_2 controls (dry FGD) for Independence were the same or larger in the supplemental modeling. The largest difference was an increase of 0.29 dv in the modeled visibility benefit from SO_2 controls at Upper Buffalo. The largest modeled benefit from NO_X controls was at Caney Creek and was approximately the same in the supplemental modeling. Modeled visibility benefits from NO_X controls at the three other Class I areas were slightly smaller in the supplemental modeling. The change in location of the modeled facility resulted in different transport patterns from the facility to the Class I areas, which resulted in the modeled 98th percentile visibility impacts being more driven by sulfate impacts. Therefore, the benefits from NO_X controls on the 98th percentile days were slightly reduced. In addition, whereas our previous modeling of the control scenario that included both dry FGD and LNB/SOFA controls showed visibility benefits ranging from 1.18 to 1.48 dv at each Class I area, the supplemental modeling showed larger visibility benefits ranging from 1.40 to 1.52 dv at each Class I area. After reviewing the supplemental modeling, we did not change our proposed reasonable progress controls for Independence Units 1 and 2.

Proposed Reasonable Progress Goals: We proposed RPGs for Caney Creek and Upper Buffalo that reflected the anticipated visibility conditions resulting from the combination of control measures from the approved portion of the 2008 Arkansas Regional Haze SIP and our FIP proposal. As explained more fully in our proposal, we adjusted the 2018 RPGs modeled by CENRAP using a scaling methodology that adjusted visibility extinction components in proportion to emission changes. We recognized that this method was not refined, but explained that it allowed us to incorporate the additional emission reductions achieved through the FIP into the states' RPGs. Based on this methodology, we proposed revised RPGs for the first planning period for the 20% worst days of 22.27 dv for Caney Creek and 22.33 dv for Upper Buffalo.

Our proposed revised RPGs and our methodology for calculating the revised RPGs were discussed in detail in our FIP proposal and in our technical support documentation,[26] which was made available in the docket when the proposed rule was published on April 8, 2015. However, a spreadsheet containing the actual calculations of our proposed revised RPGs for the 20% worst days for the Caney Creek and Upper Buffalo Wilderness Areas was inadvertently omitted from the docket. On April 4, 2016, we published a notice in the **Federal Register** announcing the

[21] See Arkansas Regional Haze SIP, Appendix 8.1—''Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans,'' sections 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas Regional Haze SIP.

[22] See Arkansas Regional Haze SIP, Appendix 8.1—''Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans,'' section 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas Regional Haze SIP.

[23] 80 FR 24872.

[24] April 13, 2015 letter from Mr. Bill Bumpers to Mr. Guy Donaldson, Chief, Air Planning Section, EPA Region 6, ''Entergy Arkansas Inc. (EAI) request for extension of comment period on EPA–R06–OAR–2015–0189–0001.'' This document is found in the docket for this rulemaking.

[25] See document titled ''Summary of Additional Modeling for Entergy Independence,'' dated April 20, 2015. This document is found in the docket for this rulemaking.

[26] See ''Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan'' at page 147.

availability in the docket of the spreadsheet containing the actual calculations of our proposed revised RPGs for the 20% worst days for the Caney Creek and Upper Buffalo Wilderness Areas.[27] The notice also reopened the comment period for our FIP proposal until May 4, 2016, but strictly limited the reopening of the comment period to our calculations of the revised RPGs, as presented in the spreadsheet we made available at that time in the docket.[28]

Long-Term Strategy: We proposed to find that provisions in the approved portion of the Arkansas Regional Haze SIP and our FIP proposal fulfilled the requirements of 40 CFR 51.308(d)(3), which requires emission limitations, compliance schedules, monitoring and recordkeeping requirements, and various supporting documentation and analyses to ensure that the SIP or FIP will provide reasonable progress toward the national goal. Specifically, we proposed to promulgate emission limits, compliance schedules, and other requirements for Arkansas' BART sources and the two units at the Independence facility to address the long-term strategy requirement.

B. Interstate Visibility Transport

Among other things, CAA section 110(a)(2)(D)(i)(II) requires that all SIPs contain adequate provisions to prohibit emissions that will interfere with measures required to protect visibility in other states. We refer to this as the interstate transport visibility requirement. Our proposed FIP included emission limits for Arkansas sources under the BART and reasonable progress requirements that would ensure a level of emissions reductions at least as great as what surrounding states relied on in developing their regional haze SIPs. We proposed that the combination of the measures in the approved portions of the Arkansas Regional Haze SIP and our FIP proposal would satisfy the visibility requirement of CAA section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and 1997 $PM_{2.5}$ NAAQS.

IV. Summary of Our Final FIP

Below, we present a summary of our final Arkansas Regional Haze FIP. In this section, we provide a summary of our final BART determinations, reasonable progress determinations, revised RPGs, LTS provisions, and interstate transport provisions. This final FIP includes emission limits, compliance schedules, and requirements for equipment maintenance, monitoring, testing, recordkeeping, and reporting for all affected sources and units.

We note that we are finalizing our FIP with certain changes to our proposal in response to comments we received during the public comment period. In particular, we are finalizing a bifurcated NO_X BART emission limit for White Bluff Units 1 and 2; we are finalizing an SO_2 BART emission limit for the Domtar Ashdown Mill Power Boiler No. 1 in the form of lb/day based on a 30 boiler-operating-day average instead of lb/hr based on a 30 boiler-operating-day average; and we are finalizing an SO_2 BART emission limit for the Domtar Ashdown Mill Power Boiler No. 2 in the form of lb/hr based on a 30 boiler-operating-day average instead of lb/MMBtu based on a 30 boiler-operating-day average. In light of information we received during the public comment period, we are also adjusting the compliance dates for some of our BART determinations. We are requiring AEP Flint Creek Unit 1 to comply with the SO_2 BART emission limit within 18 months of the effective date of this final action, instead of the 5-year compliance date we proposed. We are requiring AEP Flint Creek Unit 1 and White Bluff Units 1 and 2 to comply with the NO_X BART emission limit within 18 months of the effective date of this final action, instead of the 3-year compliance date we proposed. We are requiring the Domtar Ashdown Mill to comply with the SO_2 and NO_X BART emission limits for Power Boiler No. 1 and the PM BART emission limit for Power Boiler No. 2 within 30 days from the effective date of this final action instead of on the date of the final action. We are requiring the Domtar Ashdown Mill to comply with the SO_2 and NO_X BART emission limits for Power Boiler No. 2 within 5 years of the effective date of this final action, instead of the 3-year compliance date we proposed. We are making some adjustments to the requirements for demonstrating compliance, testing, reporting, and recordkeeping for SO_2 and NO_X BART for the Domtar Ashdown Mill Power Boiler No. 1 and for SO_2, NO_X, and PM BART for Power Boiler No. 2. We are also revising the definition of boiler-operating-day as it applies to Power Boilers No. 1 and 2 under this FIP.

We are finalizing SO_2 and NO_X controls under reasonable progress for Independence Units 1 and 2 (our proposed Option 1). In response to comments we received during the public comment period, we are finalizing a bifurcated NO_X emission limit for Independence Units 1 and 2 and are requiring the source to comply with the NO_X emission limit within 18 months of the effective date of this final action instead of the 3-year compliance date we proposed. We are also providing revised RPGs for Arkansas' Class I areas that reflect anticipated visibility conditions at the end of the implementation period in 2018 rather than the anticipated visibility conditions once the FIP has been fully implemented.

These changes to our proposal are discussed in more detail in the subsections that follow and in our separate Response to Comment (RTC) document, which can be found in the docket for this final rulemaking. The final regulatory language for the FIP is under Part 52 at the end of this notice.

The final FIP requires that subject-to-BART sources comply with the emission limits contained in Table 1 below and that the Independence Plant comply with the emission limits contained in Table 2 below. We are determining that the BART emission limits for the sources listed in Table 1 are also sufficient for reasonable progress. Throughout this section of the final rule, we specify the averaging basis of each emission limit and associated compliance dates.

TABLE 1—FINAL BART EMISSION LIMITS

Unit	Final SO_2 emission limit	Final NO_X emission limit	Final PM emission limit
Bailey Unit 1	0.5% limit on sulfur content of fuel combusted.	887 lb/hr [a]	0.5% limit on sulfur content of fuel combusted.
McClellan Unit 1	0.5% limit on sulfur content of fuel combusted.	869.1 lb/hr [b]/705.8 lb/hr [b]	0.5% limit on sulfur content of fuel combusted.

[27] 81 FR 19097.

[28] See the document titled "Caney Creek and Upper Buffalo Wilderness Areas Reasonable Progress Goals (CACR UPBU RPG analysis.xlsx)," which is available in the docket for our rulemaking.

TABLE 1—FINAL BART EMISSION LIMITS—Continued

Unit	Final SO_2 emission limit	Final NO_X emission limit	Final PM emission limit
Flint Creek Unit 1	0.06 lb/MMBtu	0.23 lb/MMBtu	EPA approved the state's BART determination in March 12, 2012 final action (77 FR 14604).
White Bluff Unit 1	0.06 lb/MMBtu	0.15 lb/MMBtu [c]/671 lb/hr [d]	EPA approved the state's BART determination in March 12, 2012 final action (77 FR 14604).
White Bluff Unit 2	0.06 lb/MMBtu	0.15 lb/MMBtu [c]/671 lb/hr [d]	EPA approved the state's BART determination in March 12, 2012 final action (77 FR 14604).
White Bluff Auxiliary Boiler	105.2 lb/hr [a]	32.2 lb/hr [a]	4.5 lb/hr [a].
Lake Catherine Unit 4 [e]	EPA approved the state's BART determination in March 12, 2012 final action (77 FR 14604).	0.22 lb/MMBtu	EPA approved the state's BART determination in March 12, 2012 final action (77 FR 14604).
Domtar Ashdown Mill Power Boiler No. 1.	504 lb/day [f]	207.4 lb/hr [f]	EPA approved the state's BART determination in March 12, 2012 final action (77 FR 14604).
Domtar Ashdown Mill Power Boiler No. 2.	91.5 lb/hr	345 lb/hr	PM BART shall be satisfied by relying on the applicable PM standard under 40 CFR part 63, subpart DDDDD [g].

[a] Existing emission limit; we do not anticipate that the facility will have to install any additional control to comply with this emission limit.
[b] Existing emission limit; we do not anticipate that the facility will have to install any additional control to comply with this emission limit. Emission limit of 869.1 lb/hr applies to the natural gas-firing scenario; emission limit of 705.8 lb/hr applies to the fuel oil-firing scenario.
[c] Emission limit of 0.15 lb/MMBtu applies when unit is operated at 50% or greater of the unit's maximum heat input rating.
[d] Emission limit of 671 lb/hr applies when the unit is operated at less than 50% of the unit's maximum heat input rating.
[e] Emission limit for NO_X applies to the natural gas-firing scenario. The unit shall not burn fuel oil until BART determinations for SO_2, NO_X, and PM are promulgated for the unit for the fuel oil-firing scenario through EPA approval of a SIP revision or a FIP.
[f] Emission limit is representative of baseline emissions; we do not anticipate that the facility will have to install any additional control to comply with this emission limit.
[g] The facility shall rely on the applicable PM standard under 40 CFR part 63, subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, as revised, to satisfy the PM BART requirement.

TABLE 2—FINAL REASONABLE PROGRESS EMISSION LIMITS FOR SOURCES NOT SUBJECT TO BART

Unit	Final SO_2 emission limit	Final NO_X emission limit
Independence Unit 1	0.06 lb/MMBtu	0.15 lb/MMBtu [a]/671 lb/hr [b].
Independence Unit 2	0.06 lb/MMBtu	0.15 lb/MMBtu [a]/671 lb/hr [b].

[a] Emission limit of 0.15 lb/MMBtu applies when unit is operated at 50% or greater of the unit's maximum heat input rating.
[b] Emission limit of 671 lb/hr applies when the unit is operated at less than 50% of the unit's maximum heat input rating.

A. Regional Haze

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

We are finalizing our determination that the Georgia-Pacific Crossett Mill 6A Boiler is a BART-eligible source, but is not subject to BART. We are also finalizing our determination that the 9A Boiler, which the State had previously determined is BART-eligible, is not subject to BART. These determinations are based on the company's newly provided analysis and documentation, as described above and in our proposal. Therefore, the CAA and Regional Haze Rule do not require BART determinations for the 6A and 9A Boilers.

2. BART Determinations

a. AECC Bailey Unit 1

Bailey Unit 1 burns primarily natural gas, but is also permitted to burn fuel oil. Our proposal explains why the source needs to retain the flexibility to use fuel oil. Taking into consideration the BART factors, we are finalizing BART determinations and emission limits for SO_2, NO_X, and PM as proposed. Our final BART determination for SO_2 and PM is the use of fuels with 0.5% or lower sulfur content by weight. After the effective date of this final rule, the facility shall not purchase fuel for use in Unit 1 that does not meet this sulfur-content requirement. We are allowing the facility 5 years to burn its existing supply of No. 6 fuel oil in accordance with any operating restrictions enforced by ADEQ. Providing this time period will avoid creating an incentive for the source to burn large amounts of this fuel during a short period, which could affect visibility on individual days more adversely. We are requiring the facility to comply with the requirement to use only fuels with 0.5% or lower sulfur content by weight no later than 5 years from the effective date of this final rule. We discussed in detail in our proposal the cost effectiveness and projected visibility improvement of switching from the baseline fuel to fuels with a sulfur content by weight of 0.5% or lower, and also present this information in Tables 3 and 4.[29] We are not making changes to the analysis we presented in our proposal of the cost and visibility improvement of this control measure. As discussed in our proposal, the cost of switching from the baseline fuel to fuels with a sulfur content by weight of 0.5% or lower is within the range of what we consider to be cost effective for BART and it is projected to result in considerable visibility improvement at the affected Class I areas.[30] We are finalizing this BART determination for SO_2 and PM as proposed.

[29] See also 80 FR 18944, 18951, and 18955.

[30] 80 FR 18944, 18952, 18956.

TABLE 3—AECC BAILEY UNIT 1—COST EFFECTIVENESS OF SWITCHING TO FUEL WITH SULFUR CONTENT OF 0.5% OR LOWER

Pollutant	No. 6 Fuel oil—0.5% sulfur content ($/ton)
SO_2	2,559
PM	2,997

TABLE 4—AECC BAILEY UNIT 1—SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT OF SWITCHING TO FUEL WITH SULFUR CONTENT OF 0.5% OR LOWER

Class I area	Baseline visibility impact (Δdv)	Visibility improvement from baseline (Δdv)—reflects improvement from SO_2 and PM reductions
		No. 6 Fuel oil—0.5% sulfur content
Caney Creek	0.330	0.188
Upper Buffalo	0.348	0.221
Hercules-Glades	0.368	0.233
Mingo	0.379	0.209
Cumulative Visibility Improvement (Δdv)		0.851

Our final BART determination for NO_X is an emission limit of 887 lb/hr, which is the existing emission limit and does not necessitate the installation of additional controls. The source must comply with the NO_X emission limit for BART purposes as of the effective date of this final rule.

b. AECC McClellan Unit 1

AECC McClellan Unit 1 burns primarily natural gas, but is also permitted to burn fuel oil. Our proposal explains why the source needs to retain the flexibility to use fuel oil. Taking into consideration the BART factors, we are finalizing BART determinations and emission limits for SO_2, NO_X, and PM as proposed. Our final BART determination for SO_2 and PM is the use of fuels with 0.5% or lower sulfur content by weight. After the effective date of this final rule, the facility shall not purchase fuel for use in Unit 1 that does not meet this sulfur content requirement. We are allowing the facility 5 years to burn its existing supply of No. 6 fuel oil, in accordance with any operating restrictions enforced by ADEQ. We are requiring the facility to comply with the requirement to use only fuels with 0.5% or lower sulfur content by weight no later than 5 years from the effective date of this final rule. Providing this time period will avoid creating an incentive for the source to burn large amounts of this fuel during a short period, which could affect visibility on individual days more adversely. We discussed in detail in our proposal the cost effectiveness and projected visibility improvement of switching from the baseline fuel to fuels with a sulfur content by weight of 0.5% or lower, and also present this information in Tables 5 and 6.[31] We are not making changes to the analysis we presented in our proposal of the cost and visibility improvement of this control measure. As discussed in our proposal, the cost of switching from the baseline fuel to fuels with a sulfur content by weight of 0.5% or lower is within the range of what we consider to be cost effective for BART and it is projected to result in considerable visibility improvement at the affected Class I areas.[32] We are finalizing this BART determination for SO_2 and PM as proposed.

TABLE 5—AECC MCCLELLAN UNIT 1—COST EFFECTIVENESS OF SWITCHING TO FUEL WITH SULFUR CONTENT OF 0.5% OR LOWER

Pollutant	No. 6 Fuel oil—0.5% sulfur content ($/ton)
SO_2	3,823
PM	4,553

[31] See also 80 FR 18944, 18958, 18959, and 18962.

[32] 80 FR 18944, 18959, 18962.

TABLE 6—AECC MCCLELLAN UNIT 1—SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT OF SWITCHING TO FUEL WITH SULFUR CONTENT OF 0.5% OR LOWER

Class I area	Baseline visibility impact (Δdv)	Visibility improvement from baseline (Δdv)—reflects improvement from SO_2 and PM reductions
		No. 6 Fuel oil—0.5% sulfur content
Caney Creek	0.622	0.3
Upper Buffalo	0.266	0.12
Hercules-Glades	0.231	0.116
Mingo	0.228	0.092
Cumulative Visibility Improvement (Δdv)	....	0.628

Our final BART determination for NO_X is an emission limit of 869.1 lb/hr for natural gas firing and 705.8 lb/hr for fuel oil firing, which are the existing emission limits and do not necessitate the installation of additional controls. The source must comply with the NO_X emission limits for BART purposes as of the effective date of the final rule.

c. AEP Flint Creek Unit 1

Taking into consideration the BART factors, we are finalizing our determination that BART for SO_2 is an emission limit of 0.06 lb/MMBtu on a 30 boiler-operating-day rolling average, which is consistent with the installation and operation of NID technology (a type of dry scrubbing system). As discussed in detail in our RTC document, we are not making changes to the analysis we presented in our proposal of the cost and visibility improvement of this control measure. We discussed in our proposal that the cost of NID on Flint Creek Unit 1 is estimated to be $3,845/$SO_2$ ton removed, which is within the range of what we consider to be cost effective for BART, and it is projected to result in considerable visibility improvement at the affected Class I areas (see Table 7).[33] Therefore, we are finalizing this SO_2 BART emission limit as proposed.

TABLE 7—AEP FLINT CREEK UNIT 1—SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT OF NID TECHNOLOGY

Class I area	Baseline visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	0.963	0.615
Upper Buffalo	0.965	0.464
Hercules-Glades	0.657	0.345
Mingo	0.631	0.414
Cumulative Visibility Improvement (Δdv)	....	1.838

In our proposal, we stated that we believed that the maximum compliance time of 5 years allowed under the CAA and Regional Haze Rule was appropriate for a new scrubber retrofit and proposed to require the source to comply with this emission limit no later than 5 years from the effective date of the final rule.[34] We received comments during the public comment period that brought to our attention that the Arkansas Public Service Commission (PSC) has determined that dry scrubber installation at Flint Creek is in the public interest and that the installation of NID controls is already underway and anticipated by the company to be completed by May 29, 2016. The Arkansas PSC requires Flint Creek to provide quarterly reports on the progress of the installation of these controls, which are publicly available online on the Arkansas PSC Web site.[35] The first quarterly report submitted by the company to the Arkansas PSC is dated March 26, 2014, and stated that the FGD project includes the installation of an Alstom NID system to comply with the Mercury and Air Toxics Standards (MATS) Rule and in anticipation of the BART requirements. The report also stated that the company established design, procurement, and construction schedules to bring the upgraded plant fully on line by May 29, 2016. The most recent quarterly report available on the Arkansas PSC Web site is dated March 10, 2016, and covers the fourth quarter in 2015. This report indicated that the company still expected that the upgraded plant would be fully on line by May 29, 2016. We verified the status of the installation of the controls with the company, who confirmed that installation of the NID controls was completed in June 2016, and that the plant is now operating with those controls.[36] We proposed a 5-year compliance date without knowing that installation of these controls was well underway. After carefully considering

[33] 80 FR 18944, 18966.

[34] 80 FR 18944, 18967.

[35] See the Arkansas PSC Web site at *http://www.apscservices.info/efilings/docket_search.asp.* The quarterly reports the company is required to submit to the Arkansas PSC are available by searching for docket No. 12–008–U.

[36] See file titled ''Record of Call—Flint Creek_August 10 2016,'' which is found in the docket for this rulemaking.

the comments we received, we have determined that a 5-year compliance date is not appropriate because the CAA requires that sources comply with BART as expeditiously as practicable.[37] Therefore, we are finalizing a shorter compliance date.[38] The information that has been made available to us during the comment period indicates that Flint Creek intends to operate the NID system to comply with the alternative SO_2 emission limit under the Utility MATS rule. The applicable MATS SO_2 emission limit is 0.2 lb/MMBtu. The SO_2 emission limit we are requiring in our FIP to satisfy the SO_2 BART requirement is 0.06 lb/MMBtu. The comments and documentation submitted to us indicate that the company intends to use the same NID system to comply with MATS and the SO_2 BART requirement. We expect that in order to achieve an emission rate of 0.06 lb/MMBtu, additional scrubbing reagent would be needed beyond that required to meet the 0.2 lb/MMBtu emission limit the company was required to meet by April 2016 under MATS. We also recognize that it is possible that the reagent handling system installed to meet the 0.2 lb/MMBtu emission limit would need some upgrades in order to accommodate the additional scrubbing reagent that would be needed to achieve the more stringent 0.06 lb/MMBtu emission limit we are requiring in this FIP. Therefore, to allow the facility sufficient time to secure the additional scrubbing reagent that would be needed to comply with the SO_2 BART emission limit and to make any necessary upgrades to the reagent handling system, we are finalizing an 18-month compliance date for Flint Creek Unit 1 to comply with the SO_2 BART requirement. We believe that this will provide sufficient time for the facility to be able to achieve the SO_2 BART requirement while still meeting the statutory mandate that BART controls be installed and operated as expeditiously as practicable.

Taking into consideration the BART factors, we are finalizing our determination that BART for NO_X is an emission limit of 0.23 lb/MMBtu on a 30 boiler-operating-day rolling average, which is consistent with the installation and operation of new LNB/OFA. In response to comments we received on our initial cost analysis presented in our proposal, we have revised our cost estimate for LNB/OFA for AEP Flint Creek Unit 1. Based on this revision to our cost analysis, we find that LNB/OFA is estimated to cost \$1,258/NO_X ton removed, which is even more cost effective (lower \$/ton) than we estimated in our proposal. LNB/OFA is also projected to result in considerable visibility improvement at the affected Class I areas (see Table 8). As we discuss in our RTC document, after revising our cost analysis of NO_X controls for AEP Flint Creek, we find that the additional cost of more stringent controls such as SNCR and SCR is not justified by the incremental visibility benefits of the more stringent controls. Therefore, we are finalizing the NO_X BART emission limit as proposed, consistent with installation of LNB/OFA controls.

TABLE 8—AEP FLINT CREEK UNIT 1—SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT OF LNB/OFA

Class I area	Baseline visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	0.963	0.081
Upper Buffalo	0.965	0.026
Hercules-Glades	0.657	0.024
Mingo	0.631	0.014
Cumulative Visibility Improvement (Δdv)	....	0.145

We received comments from the company requesting that we extend our proposed 3-year compliance date for the NO_X BART requirement to 5 years to allow sufficient time for planning, selection of engineering and design professionals, vendors, contractors, permitting, start up and commissioning, and coordinating and scheduling unit outages. We also received comments from an environmental group stating that we should shorten the compliance date because the typical installation timeframe for low NO_X burners is 6–8 months from bid evaluation through startup of the technology. The environmental group also indicated that the company may have already started the process of installing LNB/OFA controls in anticipation of the BART requirement. We do not have information corroborating that the installation of these controls is already underway, but we agree with the environmental group that LNB/OFA can be installed within a 6–8 month timeframe. The company did not provide specific information to support its contention that a longer compliance date that extends beyond the 6–8 month typical installation timeframe for LNB/OFA, measured from bid evaluation, is needed for AEP Flint Creek. Although we agree that 6–8 months is the typical installation timeframe for LNB/OFA controls, in determining the appropriate compliance date we have also taken into consideration that we are finalizing NO_X emission limits that are based on LNB/OFA or LNB/SOFA controls for a total of five EGUs in this FIP and that the installation of these controls will require outage time. These five EGUs combined accounted for approximately 45% of the state's 2015 heat input.[39] Because of the heavy reliance on these EGUs for electricity generation in the state, we recognize that it may be difficult to schedule outage time to install LNB/OFA or LNB/SOFA on all five of these units within the typical installation timeframe of 6–8 months and at the same time supply adequate electricity to meet demand in the state. As we discuss in section V.F. of this final rule, in light of these unique circumstances, we believe that it is appropriate to finalize an 18-month compliance date for these EGUs to comply with the NO_X emission limits required by this FIP. This compliance date provides the affected utilities considerable time beyond typical LNB/

[37] CAA section 169A(b)(2)(A).

[38] The shorter compliance timeframe we are finalizing is a logical outgrowth of our proposal based on the comments received, which are discussed in more detail elsewhere in the final rule and our RTC document. *See Int'l Union, UMW,* 407 F.3d at 1259; *Fertilizer Inst.,* 935 F.2d at 1311; *Chocolate Mfrs. Ass'n,* 755 F.2d 1098.

[39] These five EGUs are White Bluff Units 1 and 2, Independence Units 1 and 2, and Flint Creek Unit 1.

OFA installation timeframes to install these controls and comply with their NO_X emission limits.

Several commenters submitted comments stating that Arkansas is subject to the Cross State Air Pollution Rule (CSAPR) for ozone season NO_X, so we should rely on CSAPR to satisfy the NO_X BART requirement instead of promulgating source-specific NO_X BART determinations. In the same way that a state subject to CSAPR for ozone season NO_X has the discretion to decide whether to conduct source-specific BART determinations for NO_X or to rely on EPA's 2012 finding that CSAPR is better than BART, EPA has the same discretion in promulgating a FIP. Our decision to propose source-specific NO_X BART determinations for Arkansas was reasonable for multiple reasons: It is the approach Congress chose in the statute itself; it is consistent with Arkansas' earlier decision to conduct source-specific BART determinations in lieu of relying on the Clean Air Interstate Rule (CAIR) to meet the BART requirements; and at the time of our proposed action, it properly accounted for uncertainty in the CSAPR better-than-BART regulation created by ongoing litigation regarding the CSAPR program. Further, subsequent to our proposal, the D.C Circuit Court issued a July 2015 decision upholding CSAPR but remanding without vacatur a number of the Rule's state NO_X and SO_2 emissions budgets. Arkansas' ozone season NO_X budget is not itself affected by the remand. However, the Court's remand of the affected states' emissions budgets has implications for CSAPR better-than BART, since the demonstration underlying that rulemaking relied on the emission budgets of all states subject to CSAPR, including those that the D.C. Circuit remanded, to establish that CSAPR provides for greater reasonable progress than BART. As of the time EPA is taking this action to finalize Arkansas' Regional Haze FIP, we are in the process of acting on the Court's remand consistent with the planned response we outlined in a June 2016 memorandum.[40] For these reasons, which we discuss in more detail in our RTC document, we are finalizing source-specific NO_X BART determinations for AEP Flint Creek Unit 1 and other Arkansas EGUs subject to BART. As we have noted throughout this document, we are willing to work with ADEQ to develop a SIP revision that could replace our FIP. Such a SIP revision will need to meet the CAA and EPA's Regional Haze regulations. In its SIP revision, ADEQ may elect to rely on CSAPR to satisfy the NO_X BART requirements for Arkansas' EGUs instead of doing source-specific NO_X BART determinations. Such an approach could be appropriate if, as we expect, the uncertainty created by the D.C. Circuit's remand of the affected states' emission budgets will shortly be resolved.

d. White Bluff Units 1 and 2

Taking into consideration the BART factors, we are finalizing our determination that BART for SO_2 for White Bluff Units 1 and 2 is an emission limit of 0.06 lb/MMBtu on a 30 boiler-operating-day rolling average, consistent with the installation and operation of dry FGD or another control technology that achieves that level of control. We are requiring the source to comply with this emission limit no later than 5 years from the effective date of the final rule. In response to comments we received on our initial cost analysis presented in our proposal, we have revised our cost estimate for dry FGD for White Bluff Units 1 and 2. Based on this revision to our cost analysis, we find that dry FGD is estimated to cost \$2,565/SO_2 ton removed at Unit 1 and \$2,421/SO_2 ton removed at Unit 2. Although these cost estimates are slightly higher than we estimated in our proposal, we continue to find these controls to be cost effective and would result in considerable visibility improvement (see Table 9).[41] Therefore, we are finalizing the SO_2 BART emission limit as proposed.

TABLE 9—ENTERGY WHITE BLUFF UNITS 1 AND 2—SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT OF DRY FGD

Class I area	White Bluff Unit 1		White Bluff Unit 2	
	Baseline visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Baseline visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	1.628	0.813	1.695	0.754
Upper Buffalo	1.140	0.762	1.185	0.767
Hercules-Glades	1.041	0.683	1.061	0.645
Mingo	0.887	0.620	0.903	0.593
Cumulative Visibility Improvement (Δdv)	....	2.878	....	2.759

Several commenters requested that we rely on CSAPR to satisfy the NO_X BART requirement for Arkansas EGUs in our final FIP. We discuss in section V.H. of this final rule that we have concluded for a number of reasons that it would not be appropriate to rely on CSAPR as an alternative to NO_X BART for EGUs in Arkansas at this time. Therefore, we are finalizing source-specific NO_X BART determinations for all Arkansas EGUs, including White Bluff Units 1 and 2. We proposed that BART for NO_X for Units 1 and 2 is an emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average, consistent with the installation and operation of LNB/SOFA. We received comments from the company stating that White Bluff Units 1 and 2 are no longer expected to be able to consistently meet our proposed NO_X emission limit of 0.15 lb/MMBtu over a 30-boiler-operating-day period based on LNB/SOFA controls. We have determined that the company has provided sufficient information to substantiate that the units are not expected to be able to meet our proposed NO_X emission limit of 0.15 lb/MMBtu when the units are primarily operated at less than 50% of their operating capacity. In particular, LNB/SOFA is expected to achieve optimal NO_X control when the boiler is operated from 50–100% steam flow because the heat input across this range is sufficient to safely redirect a substantial portion of combustion air through the overfire air registers. This allows the combustion

[40] *https://www3.epa.gov/airtransport/CSAPR/pdfs/CSAPR_SO2_Remand_Memo.pdf.*

[41] See also 80 FR 18944, 18972.

zone airflow to be sub-stoichiometric and oxygen to be reduced to the point where much of the elemental nitrogen in the fuel and combustion air can pass through the boiler without converting to NO_X. When a boiler is operated below the 50–100% capacity range, NO_X concentrations on a lb/MMBtu basis can be elevated due to the lower heat input rating, even though the pounds of NO_X emitted per hour are less due to the reduced amount of fuel and air. In light of the information provided by the company, we are finalizing a bifurcated NO_X emission limit for each unit, where our proposed 0.15 lb/MMBtu emission limit will address emissions when the unit is operated at high capacities and a mass-based emission limit will address emissions when the unit is operated at low capacities. The bifurcated emission limits we are finalizing are a logical outgrowth of our proposal based on the company's comments, which are discussed in more detail elsewhere in the final rule and our RTC document.[42]

We are requiring White Bluff Units 1 and 2 to each meet a NO_X emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average, where the average is to be calculated by including only the hours during which the unit was dispatched at 50% or greater of maximum capacity. In this particular case, the 30 boiler-operating-day rolling average is to be calculated for each unit by the following procedure: (1) Summing the total pounds of NO_X emitted during the current boiler-operating day and the preceding 29 boiler-operating days, including only emissions during hours when the unit was dispatched at 50% or greater of maximum capacity; (2) summing the total heat input in MMBtu to the unit during the current boiler-operating day and the preceding 29 boiler-operating days, including only the heat input during hours when the unit was dispatched at 50% or greater of maximum capacity; and (3) dividing the total pounds of NO_X emitted as calculated in step 1 by the total heat input to the unit as calculated in step 2.

In addition to the 0.15 lb/MMBtu emission limit that is intended to control NO_X emissions when the units are operated at 50% or greater of maximum capacity, we are establishing a limit in lb/hr that applies when the units are operated at lower capacity. The company suggested an emission limit of 1,342.5 lb/hr on a 30 boiler-operating-day rolling average applicable at all times regardless of the capacity at which the unit is operated. Based on the information available to us, we find that an emission limit of 1,342.5 lb/hr is too high to appropriately control NO_X emissions when the units are operated at low capacities. It appears that the company calculated the emission limit by multiplying the 0.15 lb/MMBtu limit by the maximum heat input rating for each unit (8,950 MMBtu/hr), which yielded 1,342.5 lb/hr. We find that an emission limit of 1,342.5 lb/hr would be appropriate when the unit is operated at high capacities considering that the limit was calculated based on the unit's maximum heat input rating. However, such an emission limit would not be sufficiently protective or appropriate when the unit is operated at lower capacities since the mass of NO_X emitted is expected to be lower compared to operation at high capacity. To address this concern, we calculated a new emission limit of 671 lb/hr that is based on 50% of the unit's maximum heat input rating, and is applicable only when the unit is being operated at less than 50% of maximum heat input rating. We calculated this limit by multiplying 0.15 lb/MMBtu by 50% of the maximum heat input rating for each unit (*i.e.,* 50% of 8,950 MMBtu/hr, or 4,475 MMBtu/hr). This emission limit is on a rolling 3-hour average, where the average is to be calculated by including emissions only for the hours during which the unit was dispatched at less than 50% of maximum capacity (*i.e.,* hours when the heat input to the unit is less than 4,475 MMBtu). We are not establishing a lb/hr emission limit that applies when the units are operated at 50% or greater of maximum heat input rating because the 0.15 lb/MMBtu emission limit will address NO_X emission during those operating conditions. We discussed in our proposal that the cost of LNB/SOFA on White Bluff Units 1 and 2 is estimated to be $350/$NO_X$ ton removed for Unit 1 and $340/$NO_X$ ton removed for Unit 2,[43] which we consider to be very cost effective, and it would also result in considerable visibility improvement at the affected Class I areas (see Table 10).[44] Therefore, we are finalizing the NO_X BART emission limits as described above.

As discussed in section V.F. of this final rule, in response to comments we received, we are shortening the compliance date for the NO_X BART requirement for White Bluff Units 1 and 2 from our proposed 3 years to 18 months.

TABLE 10—ENTERGY WHITE BLUFF UNITS 1 AND 2—SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT OF LNB/SOFA

Class I area	White Bluff Unit 1		White Bluff Unit 2	
	Baseline visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Baseline visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	1.628	0.166	1.695	0.225
Upper Buffalo	1.140	0.101	1.185	0.139

[42] A final rule is a logical outgrowth of the proposed rule ''if interested parties should have anticipated that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period.'' *Int'l Union,UMW* v. *MSHA,* 407 F.3d 1250, 1259 (D.C. Cir. 2005) (internal quotations omitted); *see also, Fertilizer Inst.* v. *EPA,* 935 F.2d 1303, 1311 (D.C. Cir. 1991). No additional notice or opportunity to comment is necessary where, as here, the final rule is ''in character with the original scheme,'' and does not ''substantially depart [] from the terms or substance'' of the proposal. *Chocolate Mfrs. Ass'n* v. *Block,* 755 F.2d 1098 (4th Cir. 1985).

[43] Our cost analysis and visibility modeling analysis for LNB/SOFA for White Bluff Units 1 and 2, as presented in our proposal, is based on an emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average. As discussed in this final action, we received new information from Entergy that indicates that the source expects to be operating at less than 50% load more frequently and therefore no longer expects to be able to meet our proposed NO_X emission limit. We are therefore finalizing the bifurcated NO_X emission limit described in this final action. We recognize that the comments submitted by Entergy indicate that some of the assumptions used to calculate the cost effectiveness of NO_X controls for White Bluff may not exactly apply to future operations. However, because we found LNB/SOFA controls to be very cost effective, we expect that even if the change in operation of the source were known more precisely and were taken into account in our calculation of the cost ($/ton), these controls would continue to be cost effective. Therefore, we are not revising our cost effectiveness calculations or visibility improvement modeling of LNB/SOFA for White Bluff Units 1 and 2.

[44] 80 FR at 18972.

TABLE 10—ENTERGY WHITE BLUFF UNITS 1 AND 2—SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT OF LNB/SOFA—Continued

Class I area	White Bluff Unit 1		White Bluff Unit 2	
	Baseline visibility impact (Δdv)	Visibility improvement from baseline (Δdv)	Baseline visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Hercules-Glades	1.041	0.176	1.060	0.190
Mingo	0.887	0.038	0.903	0.047
Cumulative Visibility Improvement (Δdv)		0.481		0.601

In our proposal, we also solicited public comment on any alternative SO_2 and NO_X control measures that could address the regional haze requirements for Entergy White Bluff Units 1 and 2 and Entergy Independence Units 1 and 2 for this planning period. We received comments from the company during the public comment period that proposed one alternative strategy,[45] but we determined that this alternative strategy would not adequately address the BART and reasonable progress requirements for the affected units. We discuss this issue in more detail elsewhere in this final rule and in our RTC document.

e. White Bluff Auxiliary Boiler

We are finalizing our determination 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. We do not expect these emission limits to require the installation of additional controls. We are requiring the White Bluff Auxiliary Boiler to comply with these emission limits as of the effective date of this final rule.

f. Entergy Lake Catherine Unit 4

Taking into consideration the BART factors, we are finalizing our determination that BART for NO_X for the natural gas-firing scenario is an emission limit of 0.22 lb/MMBtu on a 30 boiler-operating-day rolling average, consistent with the installation and operation of BOOS. As discussed in more detail in our RTC document, we are not making changes to the analysis presented in our proposal of the cost and visibility improvement of this control measure. We discussed in our proposal that the cost of BOOS on Lake Catherine Unit 4 is estimated to be \$138/NO_X ton removed, which we consider to be very cost effective, and it is also projected to result in considerable visibility improvement at the affected Class I areas (see Table 11).[46] Therefore, we are finalizing the NO_X BART emission limit as proposed. We are requiring the source to comply with this emission limit no later than 3 years from the effective date of this final rule.

TABLE 11—ENTERGY LAKE CATHERINE UNIT 4—SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT OF BOOS

Class I area	Baseline visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	1.371	0.596
Upper Buffalo	0.532	0.248
Hercules-Glades	0.387	0.175
Mingo	0.429	0.196
Cumulative Visibility Improvement (Δdv)		1.215

We are also finalizing our determination that Lake Catherine Unit 4 shall not burn any fuel oil unless or until Arkansas submits a SIP revision that contains BART determinations for SO_2, NO_X, and PM for the fuel oil-firing scenario for Unit 4 and we approve these BART determinations into the SIP or we promulgate such BART determinations in a FIP. We are finalizing this determination in light of the fact that Unit 4 has not combusted any fuel oil in over 10 years and the company's commitment to not burn any fuel oil at Unit 4 until Arkansas submits the SIP revision described above.

g. Domtar Ashdown Mill Power Boiler No. 1

In response to comments received from the company, we are finalizing an SO_2 BART emission limit in the form of lb/day instead of lb/hr for Power Boiler No. 1. Specifically, we are finalizing an SO_2 BART emission limit of 504 lb/day averaged over a rolling 30 boiler-operating-day period instead of the proposed emission limit of 21.0 lb/hr averaged over a rolling 30 boiler-operating-day period. According to the company, the calculation of hourly SO_2 emissions using hourly fuel throughput information is not a workable approach for Power Boiler No. 1, where the practice is to use monthly fuel throughput information that is reconciled at the end of each month to determine monthly fuel usage. The company believes an emission limit in terms of lb/day is better suited to the mill's methodology for determining fuel usage at Power Boiler No. 1. We agree

[45] As described in section I. of this notice, Entergy also submitted a comment after the close of the comment period, indicating that Entergy intends that a second alternative described in the late comment, involving only White Bluff, is a replacement for the multi-unit alternative previously described in its timely comments. Because the late comment is not a basis for our decision making in this final rule, we are responding in this final rule and in our RTC document to the alternative proposal described in the comments that Entergy filed during the comment period.

[46] 80 FR 18944, 18978.

with the company and are finalizing an SO_2 BART emission limit of 504 lb/day averaged over a rolling 30 boiler-operating-day period. This emission limit is consistent with the Power Boiler's baseline emissions and would not necessitate additional controls.[47] We are also finalizing our determination that the mill must demonstrate compliance with the SO_2 BART emission limit by using a site-specific curve equation (provided to us by the facility) to calculate SO_2 emissions from Power Boiler No. 1 when combusting bark, and that the mill must confirm the accuracy of the site-specific curve equation using stack testing.[48] Further, we are finalizing our determination that for purposes of demonstrating compliance with the emission limit for BART for SO_2 when combusting fuel oil, the mill shall assume that the SO_2 inlet is equal to the SO_2 being emitted at the stack, where SO_2 inlet is defined to be the SO_2 content of the fuel delivered to the fuel inlet of the combustion chamber.

We are finalizing a NO_X BART emission limit of 207.4 lb/hr for Power Boiler No. 1 as proposed. This emission limit is consistent with the Power Boiler's baseline emissions, and we expect that compliance with this emission limit will not necessitate the installation of additional controls. In response to comments we received from the company, we are revising our proposed method for demonstrating compliance with the NO_X BART emission limit. We proposed that, to demonstrate compliance with the NO_X BART emission limit, the facility must conduct annual stack testing. The company submitted comments stating that it generally agreed that stack testing was an appropriate method for demonstrating compliance, but it disagreed that our proposed frequency of an annual stack testing was appropriate. The company noted that historical NO_X stack test data from 2001–2005 and 2010 for Power Boiler 1 showed the NO_X emissions were fairly consistent. After carefully considering the company's comments, we agree that the results of these previous stack tests demonstrate that an annual stack test is not warranted. Therefore, we are finalizing a requirement that the facility demonstrate compliance with the NO_X BART emission limit for Power Boiler No. 1 by conducting stack testing once every 5 years, beginning no later than 1 year from the effective date of our final action.

In response to comments we received from the company, we are finalizing one alternative method for demonstrating compliance with the SO_2 and NO_X BART emission limits for Power Boiler No. 1. The company submitted comments stating that it may decide in the near future to convert Power Boiler No. 1 to burn only natural gas. After carefully considering the company's comments, we are making the determination that if the company makes the decision to convert Power Boiler No. 1 to burn only pipeline quality natural gas and its preconstruction air permit is revised to reflect that Power Boiler No. 1 is permitted to burn only pipeline quality natural gas, the company will have demonstrated that the boiler is complying with the SO_2 BART emission limit. Once the air permit is revised to reflect that Power Boiler No. 1 is allowed to burn only pipeline quality natural gas, the reporting and recordkeeping requirements associated with our SO_2 BART emission limit would no longer be applicable. We find this alternative method for demonstrating compliance with the SO_2 BART emission limit to be appropriate given that SO_2 emissions due to natural gas combustion are negligible. This alternative method for compliance demonstration will ensure that the facility is not unnecessarily burdened with calculating SO_2 emissions and with recordkeeping and reporting requirements when SO_2 emissions from Power Boiler No. 1 are anticipated to be negligible. We are also making the determination that if the preconstruction air permit is revised to reflect that Power Boiler No. 1 is permitted to burn only pipeline quality natural gas, the facility may demonstrate compliance with the NO_X emission limit by calculating NO_X emissions using AP–42 emission factors and fuel usage records. Under this scenario, the facility would not be required to demonstrate compliance with the NO_X BART emission limit for Power Boiler No. 1 through stack testing. We also note that after the close of the comment period for our proposal, we became aware that Power Boiler No. 1 has already switched to burn only natural gas and that the facility submitted a permit renewal application to ADEQ that will reflect that the power boiler is permitted to burn only natural gas. We believe that the alternative methods for compliance demonstration we are finalizing are appropriate and addresses the mill's concerns.[49]

In response to comments we received from the company, we are revising our definition of ''boiler-operating-day'' as it applies to Power Boilers Nos. 1 and 2 under this FIP. The company commented that for mill operation purposes, it defines boiler-operating-day as ''a 24-hr period between 6 a.m. and 6 a.m. the following day during which any fuel is fed into and/or combusted at any time in the power boiler.'' After carefully considering the comment, we agree with the company that it is reasonable and appropriate to harmonize our definition of a boiler-operating day with that of the mill to avoid any unnecessary modification or reprogramming of Power Boilers 1 and 2. Therefore, for purposes of BART for Power Boilers No. 1 and 2, we are defining a boiler-operating-day as a 24-hour period between 6 a.m. and 6 a.m. the following day during which any fuel is fed into and/or combusted at any time in the power boiler. The 30-day rolling average for Power Boiler No. 1 shall be determined by adding together the pounds of SO_2 from that boiler-operating-day and the preceding 29 boiler-operating-days and dividing the total pounds of SO_2 by the sum of the total number of boiler operating days (*i.e.,* 30). The result will be the 30 boiler-operating-day rolling average in terms of lb/day emissions of SO_2.[50]

In response to comments we received from the company, we are also revising our proposed compliance dates for SO_2 and NO_X BART for Power Boiler No. 1. The company submitted comments requesting that we finalize a compliance date of 30 days after the effective date of the final rule instead of requiring the source to comply with BART as of the effective date of the final rule. The company noted this would provide additional time for it to prepare compliance records. We determined that the company's request is reasonable and

[47] The lb/day emission limit we are finalizing is a logical outgrowth of our proposal based on the company's comments, which are discussed in more detail elsewhere in the final rule and our RTC document. *See Int'l Union, UMW,* 407 F.3d at 1259; *Fertilizer Inst.,* 935 F.2d at 1311; *Chocolate Mfrs. Ass'n,* 755 F.2d 1098.

[48] 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.

[49] The alternative methods for demonstrating compliance we are finalizing for Power Boiler No. 1 are a logical outgrowth of our proposal based on the company's comments, which are discussed in more detail elsewhere in the final rule and our RTC document. *See Int'l Union,UMW,* 407 F.3d at 1259; *Fertilizer Inst.,* 935 F.2d at 1311; *Chocolate Mfrs. Ass'n,* 755 F.2d 1098.

[50] The revised definition of ''boiler operating day'' as it applies to these two units is a logical outgrowth of our proposal based on the company's comments, which are discussed in more detail elsewhere in the final rule and our RTC document. *See Int'l Union,UMW,* 407 F.3d at 1259; *Fertilizer Inst.* v. *EPA,* 935 F.2d at 1311; *and Chocolate Mfrs. Ass'n,* 755 F.2d 1098.

would allow the mill to prepare applicable compliance records and adjust recordkeeping systems without unduly delaying compliance with the BART emission limits. Therefore, we are requiring Power Boiler No. 1 to comply with the SO_2 and NO_X BART emission limits no later than 30 days from the effective date of this final rule.[51]

h. Domtar Ashdown Mill Power Boiler No. 2

In response to comments we received from the company, we are finalizing an emission limit of 91.5 lb/hr based on a 30 boiler-operating-day rolling average instead of 0.11 lb/MMBtu. As discussed in our proposal, 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.[52] Based on the information provided by Domtar, we found that the monthly average SO_2 control efficiency of the existing venturi scrubbers for the 2011–2013 period ranged from 57% to 90%. The information provided also indicated that the facility could add more scrubbing solution to achieve greater SO_2 removal than what is currently being achieved. We proposed 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 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 average control efficiency (*i.e.,* baseline control efficiency) of approximately 69%. Based on the emissions data provided by Domtar, we determined that Power Boiler No. 2's annual average SO_2 emission rate for the years 2011–2013 was 280.9 lb/hr. 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 a 90% control efficiency to the uncontrolled rate 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.[53] We thus proposed that BART for SO_2 for Power Boiler No. 2 is an emission limit of 0.11 lb/MMBtu on a 30 boiler-operating-day rolling average.

During the public comment period, the company submitted comments requesting that we finalize an SO_2 BART emission limit that is on a lb/hr basis instead of lb/MMBtu. The company correctly noted that we used the boiler's maximum heat input rating of 820 MMBtu/hr to determine the proposed emission limit in terms of lb/MMBtu. The company brought to our attention that the use of the maximum heat input rating is not representative of typical boiler operating conditions, which are lower than the maximum heat input capability. We have determined that finalizing an emission limit in terms of lb/hr is appropriate and will address the company's concern.[54] Therefore, we are finalizing an SO_2 emission limit of 91.5 lb/hr on a 30 boiler-operating-day rolling average for Power Boiler No. 2. Because the SO_2 emission limit we are finalizing is based on converting our proposed emission limit of 0.11 lb/MMBtu to an emission limit in the form of lb/hr, we find that our final emission limit is expected to achieve the same level of SO_2 reduction as 0.11 lb/MMBtu, which is what we assumed in our analysis of cost and visibility improvement. Therefore, we are not making changes to the analysis we presented in our proposal of the cost and visibility improvement of this control measure.[55] The use of additional scrubbing reagent with scrubber pump upgrades on the existing venturi scrubbers to meet an emission limit of 91.5 lb/hr is estimated to cost $1,411/$SO_2$ ton removed, and it is projected to result in considerable visibility improvement at the affected Class I areas (see Table 12). Taking into consideration the BART factors, we are finalizing this SO_2 emission limit. In response to comments we received from the company, we are also revising our definition of ''boiler-operating-day'' as it applies to Power Boilers No. 1 and 2 for BART purposes.

TABLE 12—DOMTAR POWER BOILER NO. 2—SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT OF USING ADDITIONAL SCRUBBING REAGENT/SCRUBBER PUMP UPGRADES

Class I area	Baseline visibility impact (Δdv)	Estimated visibility improvement from baseline (Δdv)
Caney Creek	0.844	0.139
Upper Buffalo	0.146	0.05
Hercules-Glades	0.105	0.048
Mingo	0.065	0.025
Cumulative Visibility Improvement (Δdv)	....	0.262

We also received comments from Domtar expressing uncertainty as to whether our proposed SO_2 emission limit for Power Boiler No. 2 can be met by upgrading the scrubber pumps and using additional scrubbing solution to consistently achieve our proposed SO_2 emission limit. However, we have determined that aside from expressing general uncertainty, Domtar did not provide any information that demonstrates that it is not technically feasible to meet our proposed SO_2 emission limit, which is based on a 30 boiler-operating-day rolling average. We also received comments from Domtar disagreeing with our use of 2011–2013 as the baseline years for calculating our proposed SO_2 emission limit for Power Boiler No. 2. Domtar asked that we instead use 2001–2003 as the baseline period for calculating the SO_2 emission limit, which would result in an emission limit of 155 lb/hr instead of

[51] The revised compliance date is a logical outgrowth of our proposal based on the company's comments. *See Int'l Union,UMW,* 407 F.3d at 1259; *Fertilizer Inst,* 935 F.2d at 1311; *and Chocolate Mfrs. Ass'n,* 755 F.2d 1098.

[52] 80 FR 18944, 18984.

[53] 80 FR at 18984.

[54] The lb/hr emission limits we are finalizing is a logical outgrowth of our proposal based on the company's comments, which are discussed in more detail elsewhere in the final rule and our RTC document. *See Int'l Union,UMW,* 407 F.3d at 1259; *Fertilizer Inst,* 935 F.2d at 1311; *and Chocolate Mfrs. Ass'n,* 755 F.2d 1098.

[55] 80 FR at 18984, 18985.

91.5 lb/hr. Domtar pointed out that in more recent years (after the 2001–2003 period), the mill voluntarily reduced its SO_2 emissions and that using a more recent period to calculate the BART emission limit results in a more stringent emission limit.

As discussed in more detail elsewhere in this final rule and in our RTC document, we disagree that it is appropriate to use 2001–2003 as the baseline period for purposes of calculating the SO_2 BART emission limit for Power Boiler No. 2. One of the factors we are required to take into consideration in making a BART determination is whether there is any existing pollution control equipment in use at the source. Power Boiler No. 2 is currently equipped with venturi scrubbers for control of SO_2 emissions, and in our BART analysis, we evaluated upgrades to the existing scrubbers. As we discussed in our proposal, in determining whether upgrades to the existing scrubbers are technically feasible and whether additional SO_2 control could be achieved, it was necessary for us to first determine the current control efficiency of the scrubbers. For purposes of determining the current control efficiency of the scrubbers, we believe the most reasonable and appropriate approach is to rely on recent data instead of older data from the 2001–2003 period. Therefore, we relied on 2011–2013 monthly average data on monitored SO_2 emissions, records of mass of fuel burned for each fuel type, and the percent sulfur content of each fuel type burned to estimate the current average control efficiency (*i.e.,* baseline control efficiency) of the scrubbers, which we found to be approximately 69%. We find that because the baseline control efficiency of the existing scrubbers (*i.e.,* 69%) corresponds to emissions data from 2011–2013, it is reasonable and appropriate to rely on emissions data from the same period to calculate the emission limit that corresponds to increasing the control efficiency from the baseline level of approximately 69% up to 90%. Therefore, we are not using 2001–2003 as the baseline period for purposes of calculating the SO_2 emission limit for Power Boiler No. 2.

We proposed to require the facility to demonstrate compliance with the SO_2 emission limit for Power Boiler No. 2 using the existing CEMS. We are finalizing this method for demonstrating compliance with the SO_2 BART emission limit for Power Boiler No. 2. During the public comment period for our proposal, Domtar submitted comments stating that due to a repurposing project the mill is currently undergoing, the mill's steam demands may change and Power Boiler No. 2 may be converted to burn only natural gas, mothballed, or shut down in the near future. After carefully considering the comments submitted to us, we have determined that in light of the repurposing project the mill is currently undergoing and the possibility of Power Boiler No. 2 being converted to burn only natural gas, it is appropriate to provide the facility with flexibility in how it must demonstrate compliance with the SO_2 emission limit for Power Boiler No. 2. Therefore, we are providing one alternative method for demonstrating compliance with the SO_2 BART emission limit: The owner or operator may demonstrate compliance with this emission limit by switching Power Boiler No. 2 to burn only pipeline quality natural gas provided that the preconstruction air permit is revised so as to permit combustion of only pipeline quality natural gas at Power Boiler No. 2. Therefore, if Power Boiler No. 2 is switched to burn only pipeline quality natural gas and the company's air permit is revised to reflect this, it would satisfy the requirement for demonstrating compliance with the boiler's SO_2 BART emission limit, and the related reporting and recordkeeping requirements would not be applicable.[56]

Taking into consideration the BART factors, we are finalizing our determination that BART for NO_X for Power Boiler No. 2 is an emission limit of 345 lb/hr on a 30 boiler-operating-day rolling average basis, which is consistent with the installation and operation of LNB. We are not making changes to the analysis we presented in our proposal of the cost and visibility improvement of this control measure.[57] As discussed in our proposal, the cost of LNB on Power Boiler No. 2 is estimated to cost \$1,951/NO_X ton removed, and it is projected to result in considerable visibility improvement at the most impacted Class I area (see Table 13). We are finalizing this NO_X emission limit as proposed.

TABLE 13—DOMTAR POWER BOILER NO. 2—SUMMARY OF THE 98TH PERCENTILE VISIBILITY IMPACTS AND IMPROVEMENT OF LNB

Class I area	Baseline visibility impact (Δdv)	Estimated visibility improvement from baseline (Δdv)
Caney Creek	0.844	0.181
Upper Buffalo	0.146	0.014
Hercules-Glades	0.105	0.011
Mingo	0.065	0.005
Cumulative Visibility Improvement (Δdv)		0.211

We proposed to require the facility to demonstrate compliance with this NO_X emission limit using the existing CEMS. We are finalizing this method for demonstrating compliance. As discussed above, during the public comment period for our proposal, Domtar submitted comments stating that due to a repurposing project the mill is currently undergoing, the mill's steam demands may change and Power Boiler No. 2 may be converted to burn only natural gas, mothballed, or shut down in the near future. After carefully considering the comments submitted to us, we have determined that it is appropriate to provide the facility with flexibility in how it must demonstrate compliance with the NO_X emission limit for Power Boiler No. 2. Therefore, we are providing one alternative method

[56] The alternative method to demonstrate compliance with the SO_2 emission limit is a logical outgrowth of our proposal based on the company's comments, which are discussed in more detail elsewhere in the final rule and our RTC document. *See Int'l Union, UMW,* 407 F.3d at 1259; *Fertilizer Inst,* 935 F.2d at 1311; *and Chocolate Mfrs. Ass'n,* 755 F.2d 1098.

[57] 80 FR 18944, 18987.

for demonstrating compliance with the NO_X BART emission limit: If Power Boiler No. 2 is switched to burn only natural gas and the facility's preconstruction air permit is revised such that Power Boiler No. 2 is permitted to burn only natural gas, the facility may demonstrate compliance with the NO_X emission limit by calculating emissions using AP–42 emission factors and fuel usage records provided that the operation of the CEMS is no longer required by any other applicable requirements. Under these circumstances, the facility would not be required to use the existing CEMS to demonstrate compliance with the NO_X BART emission limit.[58]

As discussed above, in response to comments we received from Domtar, we are also revising our definition of ''boiler-operating-day'' as it applies to Power Boilers No. 1 and 2 for BART purposes. For purposes of SO_2 and NO_X BART for Power Boilers No. 1 and 2, we are defining a boiler-operating-day as a 24-hour period between 6 a.m. and 6 a.m. the following day during which any fuel is fed into and/or combusted at any time in the power boiler.

We proposed to require the Domtar Ashdown Mill to comply with the SO_2 and NO_X BART emission limits no later than 3 years from the effective date of our final action, but invited public comment on this issue in our proposal. We received comments from Domtar requesting that we finalize a 5-year compliance date in light of the repurposing project the mill is currently undergoing. The repurposing project involves converting a non-BART paper machine at the mill into a fluff pulp line and may significantly affect the mill's steam demands and ultimately determine the future operating scenario for Power Boiler No. 2. The comments submitted by Domtar indicate that after the repurposing and reconfiguration of the mill systems is complete and fully operational and the mill has learned how to operate and optimize in its newly configured state, it will be able to determine steam demands and will then decide the future operating scenario for Power Boiler No. 2. Our understanding from the comments submitted is that this decision is expected to be made in late 2018, but that additional time will be needed after this to implement the future operating scenario selected by the mill for Power Boiler No. 2, which could include switching fuels, mothballing or retiring the boilers, or continued operation under current operating conditions. It is not EPA's intention to place an undue burden on the Domtar Ashdown Mill by requiring a compliance date that may not provide sufficient time for the mill to install controls or otherwise make the necessary operating changes to meet the boiler's BART emission limits after it has made a final decision on the future operating scenario for Power Boiler No. 2. We believe that a 3-year compliance date is generally sufficient for installation of the controls that the SO_2 and NO_X BART emission limits we are requiring can be achieved with. However, due to the special circumstances in this case, which we discuss in section V.E of this final rule, we believe it is reasonable and appropriate to establish a longer compliance date. Therefore, we are requiring the mill to comply with the SO_2 and NO_X BART emission limits no later than 5 years from the effective date of this final rule. We believe that this adequately addresses the commenter's concerns while complying with the CAA mandate that compliance with BART requirements must be as expeditiously as practicable, but in no event later than 5 years after promulgation of this FIP.

We are finalizing our determination that Domtar must satisfy the PM BART requirement by relying on the applicable Boiler MACT PM standard as revised.[59] We proposed that the same method for demonstrating compliance with the Boiler MACT PM standard must be used for demonstrating compliance with the PM BART emission limit. We proposed to require the source to comply with this emission limit for BART purposes as of the effective date of the final rule. During the public comment period, we received comments from Domtar seeking clarification regarding the requirements for compliance demonstration, reporting, and recordkeeping for our proposed PM BART determination for Power Boiler No. 2. Domtar requested that we ensure that the requirements for compliance demonstration, testing, reporting, and recordkeeping under the Boiler MACT standard for PM are consistent with those associated with the PM BART emission limit for Power Boiler No. 2. As the Domtar Ashdown Mill will be relying on compliance with the Boiler MACT PM standard to satisfy the PM BART requirement for Power Boiler No. 2, we believe that there is no need for a separate set of requirements for compliance demonstration, testing, monitoring, recordkeeping, and reporting to satisfy the PM BART requirement. This was our position at proposal, but we recognize that the regulatory text in our proposal may not have conveyed this clearly. Therefore, to provide clarification, we are revising the regulatory requirements of our FIP found under 40 CFR 52.173(c) that apply to Power Boiler No. 2 for PM BART to state that the mill shall rely on compliance with the Boiler MACT PM standard under 40 CFR part 63 Subpart DDDDD to satisfy the PM BART requirement for Power Boiler No. 2. In other words, compliance with the Boiler MACT PM standard applicable to Power Boiler No. 2 is sufficient to demonstrate compliance with the PM BART requirement. Additionally, we are also clarifying that Power Boiler No. 2 must satisfy the PM BART requirement by relying on the Boiler MACT PM standard that it is subject to at any given time, such that if the MACT PM standard and/or the compliance demonstration and recordkeeping requirements are revised in the future, the boiler must rely on those revised requirements to satisfy the PM BART requirement.

In response to comments we received from the company, we are revising our proposed compliance date for PM BART for Power Boiler No. 2. The company submitted comments requesting that we finalize a compliance date of 30 days after the effective date of the final rule instead of requiring the source to comply with BART as of the effective date of the final rule. The company noted that this would provide additional time for it to prepare compliance records. We determined that the company's request is reasonable and would provide the mill with additional time to understand the applicable BART requirements and to prepare compliance records and adjust recordkeeping systems without unduly delaying compliance with the BART emission limit. Therefore, we are requiring Power Boiler No. 2 to comply with the PM BART emission limit no later than 30 days from the effective date of this final rule.[60]

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[58] The alternative method to demonstrate compliance with the NO_X emission limit is a logical outgrowth of our proposal based on the company's comments, which are discussed in more detail elsewhere in the final rule and our RTC document. *See Int'l Union, UMW,* 407 F.3d at 1259; *Fertilizer Inst,* 935 F.2d at 1311; *and Chocolate Mfrs. Ass'n,* 755 F.2d 1098.

[59] Boiler MACT standards are required under CAA section 112, and are 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.

[60] The revised compliance date is a logical outgrowth of our proposal based on the company's comments, which are discussed in more detail elsewhere in the final rule and our RTC document.

3. Reasonable Progress Analysis

a. Four-Factor Analysis

In our proposed rule, we explained that the CENRAP CAMx modeling with PSAT showed that sulfate from all source categories combined contributed 87.05 inverse megameters (Mm^{-1}) out of 133.93 Mm^{-1} of light extinction at Caney Creek on the average across the 20% worst days in 2002, which is approximately 65% of the total light extinction. At Upper Buffalo, sulfate from all source categories combined contributed 83.18 Mm^{-1} out of 131.79 Mm^{-1} of light extinction at Upper Buffalo on the average across the 20% worst days in 2002, which is approximately 63% of the total light extinction. 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 at each Class I area on the average across the 20% worst days in 2002. The CENRAP CAMx modeling showed that on most of the 20% worst days in 2002, total extinction was dominated by sulfate at both Caney Creek and Upper Buffalo.[61] Additionally, total extinction at Caney Creek was dominated by nitrate on 4 of the days that comprise the 20% worst days in 2002, while a significant portion of the total extinction at Upper Buffalo on 2 of the days that comprise the 20% worst days in 2002 was due to nitrate.[62] Given their contribution to visibility impairment on the 20% worst days, we consider both SO_2 and NO_X to be key pollutants contributing to visibility impairment at Arkansas Class I areas, so it is appropriate to consider both SO_2 and NO_X controls in our reasonable progress analysis.

In our proposal, we explained that point sources are responsible for a majority of the total light extinction at each Class I area, contributing approximately 60% of the total light extinction. 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 average across the 20% worst days in 2002. Because other source types (*i.e.,* natural, on-road, non-road, and area) each contributed a much smaller proportion of the total light extinction at each Class I area, we decided to focus only on point sources in our reasonable progress analysis for this 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 on the average across the 20% worst days in 2002, 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. 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. We explained in our proposal that SO_2 emissions (a 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 was largely due to sulfate from point sources. We also explained that 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, while 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. Based on the CENRAP 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.

As a starting point in our analysis to determine whether additional controls on Arkansas sources are necessary to make reasonable progress in the first regional haze planning period, we examined the most recent SO_2 and NO_X emissions inventories for point sources in Arkansas. In our examination of the SO_2 and NO_X emissions inventories for Arkansas' point sources, we found that the number of point sources in Arkansas that emit SO_2 and NO_X emissions is relatively small. Furthermore, a very small portion of the point sources in the state are responsible for a large portion of the statewide SO_2 and NO_X point-source emissions. Specifically, White Bluff, Independence, and Flint Creek are the three largest emitters of SO_2 and NO_X point-source emissions in the state and are collectively responsible for approximately 84% of the SO_2 point source emissions and 55% of the NO_X point-source emissions in the state.[63] As our proposed rule included SO_2 and NO_X emission limits under BART for White Bluff Units 1 and 2 and Flint Creek Unit 1 that are anticipated to result in a substantial reduction in SO_2 and NO_X emissions from these facilities, we proposed to determine that it is appropriate to eliminate these two facilities from further consideration of additional controls under the reasonable progress requirements for the first planning period. The Entergy Independence Plant is not subject to BART, and 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. In our proposal, we explained that it was appropriate to focus our reasonable progress analysis on the Entergy Independence Power Plant because it is a significant source of SO_2 and NO_X as the second largest emitter of NO_X and SO_2 point-source emissions in the State. Consequently, addressing White Bluff and AEP Flint Creek under the BART requirements and Independence under the reasonable progress requirements will address a large proportion of the visibility impacts due to Arkansas point sources at Caney Creek and Upper Buffalo.

We also found that the remaining point sources in the state had much lower SO_2 and NO_X emissions than these facilities. For example, the point source with the fourth highest SO_2 emissions is Future Fuel Chemical Company, which contributes approximately 4.1% of the total SO_2 point-source emissions in the state (*i.e.,* 3,420 SO_2 tons out of statewide SO_2 point source emissions of 83,883 SO_2 tons). The point source with the fourth highest NO_X emissions is the Natural Gas Pipeline Company of America #308, which contributes approximately 5.1% of the total NO_X point source emissions in the state (*i.e.,* 3,194 NO_X tons out of statewide NO_X point source emissions of 62,984 NO_X tons). Based on the much smaller magnitude of these sources'

[61] See Arkansas Regional Haze SIP, Appendix 8.1—''Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans,'' sections 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas Regional Haze SIP.

[62] See Arkansas Regional Haze SIP, Appendix 8.1—''Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans,'' section 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas Regional Haze SIP.

[63] 80 FR 18944, 18991.

emissions, we determined that the remaining point sources in the state are less likely to be significant contributors to regional haze (both on an actual and percentage basis) and thus did not warrant closer evaluation during this planning period. Because such a small number of point sources in Arkansas are responsible for a such large portion of the statewide SO_2 and NO_X point-source emissions in the state, we concluded that photochemical modeling or other more exhaustive analyses that we have performed in other regional haze actions were unnecessary to identify sources in Arkansas to evaluate under reasonable progress. In contrast, in states such as Texas where the universe of point sources is much larger and the distribution of SO_2 and NO_X emissions is very widespread, an evaluation of the state's emissions inventory alone was not sufficient to reveal the best potential candidates for evaluation under reasonable progress. For this reason, we explained in our Texas Regional Haze FIP that, due to the challenges presented by the geographic distribution and number of sources in Texas, the CAMx photochemical model was best suited for identifying sources to evaluate for reasonable progress controls.[64] We did not encounter these challenges in our Arkansas Regional Haze FIP and therefore did not conduct photochemical modeling.

In our reasonable progress analysis for Independence, we considered the four statutory factors under CAA section 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A): The costs of compliance, the time necessary for compliance, the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements. Alongside the four statutory factors, we also considered the visibility improvement of controls. Although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states or EPA have the option of considering the projected visibility benefits of controls in determining if the controls are necessary to make reasonable progress. In our proposal, we explained that SO_2 emissions are the principal driver of regional haze on the 20% worst days in Arkansas' Class I areas. While point source NO_X emissions are not the principal contributor to visibility extinction on the 20% worst days at Arkansas' Class I areas, NO_X is nevertheless a key pollutant since NO_X emissions contributed considerably to visibility impairment on a portion of the 20% worst days in 2002 based on CENRAP's CAMx source apportionment modeling. Further, our assessment of the Independence facility using CALPUFF dispersion modeling, which assesses the 98th percentile visibility impairment caused by the facility, indicated that Independence is potentially one of the largest single contributors to visibility impairment at Class I areas in Arkansas.[65] Therefore, we determined that it was appropriate to evaluate the Independence facility for both SO_2 and NO_X controls under reasonable progress.

Based on our reasonable progress analysis under 40 CFR 51.308(d)(1), we discussed in our proposal that SO_2 and NO_X controls at Independence would be cost-effective and would result in meaningful visibility benefits at Arkansas' Class I areas based on the maximum (98th percentile) facility impacts using CALPUFF dispersion modeling. Although the reasonable progress provisions of the Regional Haze Rule place emphasis on the 20% worst days, the CAA goal of remedying visibility impairment due to anthropogenic emissions encompasses all days. Thus, states and EPA have the discretion to consider the visibility impacts of sources and the visibility benefit of controls on days other than the 20% worst days in making their decisions, such as the days on which a given facility has its own largest impacts. Even if the days on which a given facility has its largest impacts are not the same as the 20% of days with the worst visibility overall, the facility's impacts will still need to be addressed for Arkansas' Class I areas to achieve the goal of natural visibility conditions. The Eighth Circuit previously addressed state and EPA use of CALPUFF for reasonable progress purposes.[66]

Based on our consideration of the four reasonable progress factors and the visibility impacts from Independence and the visibility improvement of controls, we proposed two alternative options for reducing emissions at Independence Units 1 and 2. Under Option 1, we proposed to require both SO_2 and NO_X controls. Under Option 2, we proposed to require only SO_2 controls. We solicited public comment on our two proposed options. In addition to Options 1 and 2, we also solicited public comment on any alternative SO_2 and NO_X control measures that could address the regional haze requirements for White Bluff Units 1 and 2 and Independence Units 1 and 2 for this planning period.

We received many comments opposed to our proposal to establish *any* controls on Independence to achieve reasonable progress. Many of these comments stated that it was not necessary to control or even evaluate Arkansas' sources under the CAA and Regional Haze Rule's reasonable progress requirements because Arkansas' Class I areas are projected to be below the uniform rate of progress (URP) in 2018 and because Arkansas' Class I areas are on track to meet the RPGs established by the state in the Arkansas Regional Haze SIP. As discussed in section V.C. of this final rule and in our RTC document, we have an obligation under the CAA and the Regional Haze Rule to conduct an analysis of the four reasonable progress factors. This obligation applies even when a Class I area is below the URP and even when monitoring data show that a Class I area is meeting or is projected to meet the RPG previously established by the state. The CAA and Regional Haze Rule are clear that the determination of what controls are necessary to make reasonable progress (and whose emission reductions dictate the RPGs) must be determined based on the four-factor analysis. *See* CAA section 169A(b)(2) & (g)(1); 40 CFR 51.308(d)(1)(i). Neither the CAA nor the Regional Haze Rule divest states or EPA of the authority and obligation to conduct a four-factor analysis for sources contributing significantly to visibility impairment based on existing or projected future visibility conditions at affected Class I areas. We discussed above and also in section V of this final rule that our four factor analysis focused on the Independence Plant because it is a significant source of visibility impairing pollutants, as it is the second largest source of SO_2 and NO_X point-source emissions in Arkansas.[67] The largest and third largest sources of SO_2 and NO_X point-source emissions in Arkansas are White Bluff and Flint Creek, for which we are requiring controls under the BART requirements in this final rule. In comparison to the SO_2 and NO_X emissions from the three largest point sources (*i.e.,* White Bluff, Independence, and Flint Creek), emissions from the remaining point sources in the state are relatively small and are less likely to be significant contributors to regional haze, both on an actual and percentage basis. Therefore,

[64] 81 FR 296 (January 5, 2016).

[65] 80 FR 24872.

[66] *North Dakota* v. *EPA,* 730 F.3d 750, 764–66 (8th Cir. 2013) (discussing reasonable progress determination for the Antelope Valley station).

[67] The Independence Plant accounts for approximately 36% of the SO_2 point-source emissions and 21% of the NO_X point-source emissions in Arkansas (2011 NEI).

our reasonable progress analysis focused on the Independence Plant. As discussed in our proposal and throughout this final notice, based on our analysis of the four reasonable progress factors and our consideration of the baseline visibility impacts from Independence and the visibility improvement of potential controls, we determined that SO_2 and NO_X controls at Independence would be cost-effective and would result in meaningful visibility benefits at Arkansas' Class I areas, and therefore find that they are reasonable controls and are necessary to make reasonable progress.

Other comments we received stated that Arkansas' point sources have a very small impact on visibility impairment at Arkansas' Class I areas on the 20% worst days and that we should therefore not require any controls at Independence under the reasonable progress requirements. At a minimum, these commenters argued, the contribution to visibility impairment at Arkansas' Class I areas on the 20% worst days from point-source nitrate emissions was insignificant, so NO_X controls for Independence were unnecessary. After carefully considering these comments, we continue to believe that Arkansas' point sources have a significant contribution to visibility impairment at Arkansas Class I areas on the 20% worst days. As we discuss in section V.J. of this final rule, CAMx source apportionment modeling conducted by Entergy Arkansas Inc.[68] (Entergy) and submitted to us during the public comment period showed that the contribution to visibility impairment due to emissions from the Independence facility alone are projected to be approximately 1.3% of the total visibility impairment during the 20% worst days in 2018 at each Arkansas Class I area. Considering that the CAMx photochemical modeling takes into account the emissions of thousands of sources, both in Arkansas and outside of the state, we consider this to be a significant contribution to visibility impairment at each Class I area and a large portion (approximately one-third) of the total contribution from all Arkansas point sources that can be addressed through installation of controls on two units at a single facility. The CAMx modeling also showed that at Upper Buffalo, the Independence facility's contribution to visibility impairment is greater than the contribution from all of the subject-to-BART sources addressed in this final action combined. In terms of deciviews, the average impact from Independence over the 20% worst days, based on Entergy's CAMx modeling and adjusted to natural background conditions, is over 0.5 dv at each of the Arkansas Class I areas. Together, the modeling results from Entergy's CAMx modeling and the CALPUFF modeling demonstrate that controls will provide meaningful visibility benefits toward the goal of natural visibility conditions.

While the majority of the visibility impacts due to Independence on the 20% worst days are due to SO_2, we note that NO_X emissions from the facility also have impacts on the 20% worst days. The CAMx source apportionment modeling submitted by Entergy showed that NO_X emissions from Independence are responsible for 30–40% of the visibility impairment in Arkansas' Class I areas on 2 of the 20% worst days (*i.e.,* 2 out of the 21 days that are the 20% worst of the days with Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data). We expect that installation of NO_X controls on Independence will provide visibility improvement on this portion of the 20% worst days and will also provide meaningful visibility improvement on the 98th percentile day, as shown by the CALPUFF dispersion modeling. After carefully considering all comments submitted to us during the comment period, we are finalizing both SO_2 and NO_X controls for Independence Units 1 and 2 to make reasonable progress at Arkansas' Class I areas (*i.e.,* proposed Option 1), because both SO_2 and NO_X are key pollutants contributing to visibility impairment, and because we have determined that these controls are cost effective and will provide for significant visibility benefits towards the goal of natural visibility conditions at Arkansas' Class I areas.

In response to comments we received on our initial cost analysis presented in our proposal, we have revised our cost estimate for dry FGD for Independence Units 1 and 2. Based on this revision to our cost analysis, we find that dry FGD is estimated to cost \$2,853/SO_2 ton removed at Unit 1 and \$2,634/SO_2 ton removed. Although these cost estimates are slightly higher than we estimated in our proposal, we continue to find these controls to be cost effective and well within the range of cost of controls found to be reasonable by EPA and the States in other regional haze actions. Dry FGD controls on Independence are also expected to result in considerable visibility improvement at Arkansas' Class I areas based on CALPUFF modeling of the maximum (98th percentile) visibility impacts from the facility (see Table 14).[69] As dry FGD will eliminate a majority of the SO_2 emissions from Independence,[70] we anticipate that on the 20% worst days these controls will also accordingly eliminate a majority of the visibility impairment due to SO_2 emissions from Independence. Taking into consideration the four reasonable progress factors and the visibility benefit of dry FGD controls, we conclude that these are reasonable controls and are therefore necessary to make reasonable progress. We are finalizing an SO_2 emission limit of 0.06 lb/MMBtu for Independence Units 1 and 2 based on a 30 boiler-operating-day rolling average basis, which is consistent with the installation and operation of dry FGD. We are requiring the facility to comply with this emission limit no later than 5 years from the effective date of this final rule.

[68] Entergy Arkansas Inc. is one of the owners of White Bluff Units 1 and 2 and Independence Units 1 and 2. The company submitted CAMx photochemical modeling as part of its comments submitted during the public comment period. These and all other comments we received are found in the docket associated with this rulemaking.

[69] 80 FR 24872.

[70] As discussed in our proposal, dry FGD controls on Independence Units 1 and 2 are expected to reduce facility-wide SO_2 emissions by 26,902 tpy from a baseline emission rate of 29,780 tpy (*i.e.,* Units 1 and 2 combined). See 80 FR 18944, 18993.

TABLE 14—ENTERGY INDEPENDENCE PLANT—SUMMARY OF THE 98TH PERCENTILE BASELINE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO DRY FGD

[Facility-wide]

Class I area	Facility-wide baseline visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	2.512	1.096
Upper Buffalo	2.264	1.178
Cumulative Visibility Improvement at Arkansas' Class I areas (Δdv)		2.274

As discussed in our proposal, LNB/SOFA controls on Independence are estimated to cost $401/$NO_X$ ton removed at Unit 1 and $436/$NO_X$ ton removed at Unit 2,[71] which we consider to be very cost effective and well within the range of cost of controls found to be reasonable by EPA and the States in other regional haze actions. LNB/SOFA controls on Independence are also expected to provide considerable visibility benefits based on CALPUFF modeling of the maximum (98th percentile) visibility impacts from the facility (see Table 15).[72] As LNB controls will eliminate a large portion of the NO_X emissions from Independence,[73] we anticipate that these controls will also accordingly eliminate a large portion of the visibility impairment due to NO_X emissions from Independence on a portion of the 20% worst days. Taking into consideration the four reasonable progress factors and the visibility benefit of LNB/SOFA controls, we conclude that these are reasonable controls and are therefore necessary to make reasonable progress. As such, we are requiring NO_X controls for Independence Units 1 and 2 under the reasonable progress requirements.

TABLE 15—ENTERGY INDEPENDENCE PLANT—SUMMARY OF THE 98TH PERCENTILE BASELINE VISIBILITY IMPACTS AND IMPROVEMENT DUE TO LNB/SOFA

[Facility-wide]

Class I area	Facility-wide baseline visibility impact (Δdv)	Visibility improvement from baseline (Δdv)
Caney Creek	2.028	0.459
Upper Buffalo	2.003	0.198
Cumulative Visibility Improvement at Arkansas' Class I areas (Δdv)		0.657

We received comments from the company stating that Independence Units 1 and 2 are no longer expected to be able to consistently meet our proposed NO_X emission limit of 0.15 lb/MMBtu over a 30-boiler-operating-day period based on LNB/SOFA controls.[74] We have determined that the company has provided sufficient information to substantiate that the units are not expected to be able to meet our proposed NO_X emission limit of 0.15 lb/MMBtu when the units are primarily operated at less than 50% of their operating capacity. Therefore, we are finalizing a ''bifurcated'' NO_X emission limit for each unit.[75] We are requiring Independence Units 1 and 2 to meet a NO_X emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average, where the average is to be calculated by including only the hours during which the unit was dispatched at 50% or greater of maximum capacity. In this particular case, the 30 boiler-operating-day rolling average is to be calculated for each unit by the following procedure: (1) Summing the total pounds of NO_X emitted during the current boiler operating day and the preceding 29 boiler operating days, including only emissions during hours when the unit was dispatched at 50% or greater of maximum capacity; (2) summing the total heat input in MMBtu to the unit during the current boiler operating day and the preceding 29 boiler operating days, including only the heat input during hours when the unit was dispatched at 50% or greater of maximum capacity; and (3) dividing the total pounds of NO_X emitted as

[71] Our cost analysis and visibility modeling analysis for LNB/SOFA for Independence Units 1 and 2, as presented in our proposal, is based on an emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average. As discussed in this final action, we received new information from Entergy that indicates that the source expects to be operating at less than 50% load more frequently and therefore no longer expects to be able to meet our proposed NO_X emission limit. We are therefore finalizing the bifurcated NO_X emission limit described in this final action. We recognize that the comments submitted by Entergy indicate that some of the assumptions used to calculate the cost effectiveness of NO_X controls for Independence may not exactly apply to future operations. However, because we found LNB/SOFA controls to be very cost effective, we expect that even if the change in operation of the source were known more precisely and were taken into account in our calculation of the cost ($/ton), these controls would continue to be cost effective. Therefore, we are not revising our cost effectiveness calculations or visibility improvement modeling of LNB/SOFA for Independence Units 1 and 2.

[72] 80 FR 24872.

[73] As discussed in our proposal, LNB/SOFA controls on Independence Units 1 and 2 are expected to reduce facility-wide NO_X emissions by 5,927 tpy from a baseline emission rate of 12,713 tpy (*i.e.,* Units 1 and 2 combined). See 80 FR 18944, 18996.

[74] Entergy submitted comments on this issue that are applicable to both White Bluff and Independence. We discuss and address these comments in more detail elsewhere in this final rule.

[75] The bifurcated emission limit is a logical outgrowth of our proposal based on the company's comments, which are discussed in more detail elsewhere in the final rule and our RTC document. *See Int'l Union, UMW,* 407 F.3d at 1259; *Fertilizer Inst,* 935 F.2d at 1311; *and Chocolate Mfrs. Ass'n,* 755 F.2d 1098.

calculated in step 1 by the total heat input to the unit as calculated in step 2. In addition to this limit that is intended to control NO_X emissions when the units are operated at 50% or greater of maximum capacity, we are also establishing a limit in lb/hr that applies only when the units are operated at lower capacity. We are requiring Independence Units 1 and 2 to meet an emission limit of 671 lb/hr on a rolling 3-hour average, where the average is to be calculated by including emissions only for the hours during which the unit was dispatched at less than 50% of the unit's maximum heat input rating (*i.e.,* hours when the heat input to the unit is less than 4,475 MMBtu). We calculated this emission limit by multiplying 0.15 lb/MMBtu by 50% of the maximum heat input rating for each unit (*i.e.,* 50% of 8,950 MMBtu/hr, or 4,475 MMBtu/hr). As discussed in section V.F. in this final rule, in response to comments we received, we are shortening the compliance date for the NO_X emission limit for Independence Units 1 and 2 from our proposed 3 years to 18 months.

We also received comments during the public comment period from Entergy that presented an alternative multi-unit approach to address the regional haze requirements for White Bluff Units 1 and 2 and Independence Units 1 and 2.[76] The company's alternative approach consisted of the following: Requiring White Bluff Units 1 and 2 and Independence Units 1 and 2 to comply with an SO_2 emission limit of 0.60 lb/MMBtu on a 30 boiler-operating-day rolling average beginning in 2018; requiring White Bluff Units 1 and 2 and Independence Units 1 and 2 to comply with a NO_X emission limit of 1,342.5 lb/hr on a 30 boiler-operating-day rolling average based on the installation of LNB/SOFA within 3 years; and ceasing coal combustion at White Bluff Units 1 and 2 in 2027 and 2028. We note that we do not interpret Entergy's comments as suggesting that we adopt the elements in its alternative that are unique to White Bluff as an alternative to our proposed BART emission limits at the facility unless we also conclude that the remaining elements address any reasonable progress requirements for Independence. After carefully considering the comments we received specifically on this issue, we do not believe the comprehensive multi-unit strategy as presented by the company has potential to satisfy the BART requirements for White Bluff Units 1 and 2 and the reasonable progress requirements for Independence Units 1 and 2. We address this in more detail elsewhere in this final rule.

b. RPGs for Caney Creek and Upper Buffalo

We proposed RPGs for the 20% worst days for Caney Creek and Upper Buffalo of 22.27 dv and 22.33 dv, respectively that reflected the anticipated visibility conditions resulting from the combination of control measures from the approved portion of the 2008 Arkansas Regional Haze SIP and our FIP proposal. We received comments on our proposal indicating that our proposed RPGs for the 20% worst days for Caney Creek and Upper Buffalo improperly incorporated visibility improvements that would not occur until after 2018. After considering these comments, we agree that the RPGs should reflect anticipated visibility conditions at the end of the implementation period in 2018 rather than the anticipated visibility conditions once the FIP has been fully implemented. This approach is consistent with the purpose of RPGs and the direction provided in our 2007 Reasonable Progress Guidance.[77]

Section 169B(e)(1) of the CAA directed the Administrator to promulgate regulations that ''include[e] criteria for measuring 'reasonable progress' toward the national goal.'' Consequently, we promulgated 40 CFR 51.308(d)(1) as part of the Regional Haze Rule. This provision directs states to develop RPGs for the most and least impaired days to ''measure'' the progress that will be achieved by the control measures in the state's long-term strategy ''over the period of the implementation plan.'' [78] The current implementation period ends in 2018. RPGs ''are not directly enforceable'' like the emission limitations in the long-term strategy.[79] Rather, they fulfill two key purposes: (1) Allowing for comparisons between the progress that will be achieved by the state's long-term strategy and the URP,[80] and (2) providing a benchmark for assessing the adequacy of a state's SIP in 5-year periodic reports.[81] Consequently, in our 2007 Reasonable Progress Guidance, we indicated that states could consider the ''time necessary for compliance'' factor by ''adjust[ing] the RPG to reflect the degree of improvement in visibility achievable within the period of the first SIP if the time needed for full implementation of a control measure (or measures) will extend beyond 2018.'' [82] In other words, RPGs need not reflect the visibility improvement anticipated from all of the control measures deemed necessary to make reasonable progress (as a result of the four-factor analysis) and included in the long-term strategy.

In this instance, we are taking final action on the Arkansas Regional Haze FIP 9 years after the state's initial SIP submission was due.[83] As a result, only some of the control measures that we have determined are necessary to satisfy the BART and reasonable progress requirements will be installed by the end of 2018. Some controls will not be installed until 2021. Because RPGs are only unenforceable analytical benchmarks, we think that it is appropriate to follow the recommendation in our 2007 Reasonable Progress Guidance and finalize RPGs that represent the visibility conditions anticipated on the 20% worst days at Caney Creek and Upper Buffalo by 2018. These RPGs are listed in the table below: [84] [85]

TABLE 16—REASONABLE PROGRESS GOALS FOR 2018 FOR CANEY CREEK AND UPPER BUFFALO

Class I area	2018 RPG 20% Worst days (dv)
Caney Creek	22.47
Upper Buffalo	22.51

[76] As described in section I. of this notice, Entergy also submitted a comment after the close of the comment period, indicating that Entergy intends that a second alternative described in the late comment, involving only White Bluff, is a replacement for the multi-unit alternative previously described in its timely comments. Because the late comment is not a basis for our decision making in this final rule, we are responding in this final rule and in our RTC document to the alternative proposal described in the comments that Entergy filed during the comment period.

[77] ''Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program,'' dated June 1, 2007. We refer to this guidance as the ''2007 Reasonable Progress Guidance'' throughout this final notice.

[78] 40 CFR 51.308(d)(1).

[79] 40 CFR 51.308(d)(1)(iv).

[80] 40 CFR 51.308(d)(1)(ii).

[81] 40 CFR 51.308(g)–(h).

[82] ''Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program,'' at 5–2.

[83] We discuss in section II.A of this final rule the history of the state's submittals and our actions.

[84] These RPGs are calculated using the same methodology described in our proposal and TSD. See ''CACR UPBU RPG analysis 2018.xlsx'' for additional information on the calculation of the RPGs.

[85] The RPGs we are finalizing in this rulemaking for Caney Creek and Upper Buffalo are a logical outgrowth of our proposed RPGs based on comments we received, which are discussed in more detail elsewhere in the final rule and our RTC document. *See Int'l Union, UMW,* 407 F.3d at 1259; *Fertilizer Inst.,* 935 F.2d at 1311; *and Chocolate Mfrs. Ass'n* v. *Block,* 755 F.2d 1098.

4. Long-Term Strategy

We are finalizing our determination that the provisions in this final rule, in combination with provisions in the approved portion of the Arkansas Regional Haze SIP, fulfill the Regional Haze Rule's long-term strategy requirements. The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve reasonable progress at Class I areas impacted by emissions from Arkansas. In this final rule, we are promulgating emission limits, compliance schedules, and other requirements for nine units subject to BART and for two reasonable progress units.

B. Interstate Visibility Transport

We are finalizing our determination that the control measures in the approved portion of the Arkansas Regional Haze SIP and our final FIP are adequate to prevent Arkansas' emissions from interfering with other states' required measures to protect visibility. Thus, the combined measures from both plans satisfy the interstate transport visibility requirement of CAA section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and the 1997 $PM_{2.5}$ NAAQS.

V. Summary and Analysis of Major Issues Raised by Commenters

We received comments at the public hearing held in Little Rock, as well as comments submitted electronically on *www.regulations.gov* and through the mail. The full text of comments we received from commenters is included in the publicly posted docket associated with this action at *www.regulations.gov*. Our RTC document, which is also included in the docket associated with this action, provides detailed responses to all significant comments received, and is a part of the administrative record for this action. Below we provide summaries of the more significant comments received and our responses to them. Our RTC document is organized similarly to the structure of this section (*e.g.,* Cost, Modeling, etc.). Therefore, if additional information is desired concerning how we addressed a particular comment, the reader should refer to the appropriate section in the RTC document.

A. General Comments

Comment: We received 238 comments in support of our rulemaking, specifically regarding the requirements to control SO_2, NO_X, and PM emissions from Arkansas' subject-to-BART sources, and to control emissions from the Independence facility pursuant to the Regional Haze Rule's reasonable progress requirements. Most of these commenters also expressed support for our proposed Option 1, which consists of both SO_2 and NO_X controls for Independence Units 1 and 2. These comments were from members representing various organizations and members of the general public. At the public hearing in Little Rock, Arkansas, 40 people expressed general support for the plan. The speakers at the public hearings included members of various organizations and members of the general public. Some of these commenters also stated that we should transition away from coal-fired power and that retrofitting these plants and allowing them to continue operating is not a sound long-term solution, but does signal progress in Arkansas towards cleaner energy sources.

Response: We thank the commenters for participating in the rulemaking and acknowledge their support of this action. As discussed in section IV. of this final rule, we are finalizing SO_2, NO_X, and PM controls for six facilities under the BART requirements and we are finalizing both SO_2 and NO_X controls for Independence under the reasonable progress requirements (proposed Option 1). Under the Regional Haze Rule, we are authorized to require affected sources to meet emission limits for visibility impairing pollutants (*i.e.,* SO_2, NO_X, and PM), but we are not authorized to dictate what type of technology the source must employ to meet those emission limits and we are not authorized to force sources to retire or to stop burning fossil fuels. However, sources may choose to voluntarily retire or switch fuels in order to comply with our emission limits.

Comment: We received one email from a citizen that opposed our proposal. The commenter expressed that it is not fair that we are requiring sources in Arkansas to spend a large amount of money in retrofits when other countries are not held to the same standards. The commenter questioned why other countries are given additional time to meet requirements. The commenter also expressed concern that our proposed controls would result in a higher electric bill that could mean no electricity for some people.

Response: We acknowledge the commenter's concerns. Consistent with the CAA, the regional haze program is concerned with remedying existing and preventing future impairment of visibility caused by manmade air pollution in mandatory Class I Federal areas (located in this country). Our action requires particular Arkansas sources to control emissions that impact visibility at Arkansas and Missouri Class I areas. Our action does not in any way expect Arkansas to make up for emissions from international sources. On the other hand, as we discussed in the preamble to the Regional Haze Rule, "the States should not consider the presence of emissions from foreign sources as a reason not to strive to ensure reasonable progress in reducing any visibility impairment caused by sources located within their jurisdiction." [86] While the goal of the regional haze program is to restore natural visibility conditions at Class I areas by 2064, the rule requires only that reasonable progress be made towards the goal during each planning period. In cases where it is not reasonable to meet the rate of progress needed to attain the goal by 2064, the Regional Haze Rule requires a state to demonstrate that this rate of progress is not reasonable, and that the state's selected rate of progress is reasonable for that planning period. While there is no indication at this time that emissions from international sources are anticipated to prevent Arkansas from attaining the goal of natural visibility conditions at its Class I areas, we recognize that in some cases it may not be possible to attain the goal by 2064 because of impacts from new or persistent international emissions sources or impacts from sources where reasonable controls are not available. However, states are still required to demonstrate that they are establishing a reasonable rate of progress that includes implementation of reasonable measures within the state to address visibility impairment in an effort to make progress towards the natural visibility goal during each planning period. We acknowledge the commenter's concern regarding potential increases in electricity rates. While our consideration of cost under the Regional Haze Rule is limited to the direct costs incurred by sources, consistent with the CAA's and Rule's source-specific focus, we are very sensitive to the ramifications of our actions and we seek to select the most cost-effective options when we propose and finalize these controls.

Comment: ADEQ submitted comments stating that it concurs with our proposed determination that the Georgia Pacific-Crossett Mill 6A and 9A Boilers are not subject to BART.

Response: We appreciate ADEQ's support of our proposed determination. As discussed in section IV. of this final action, we are finalizing our determination that the Georgia Pacific-

[86] 64 FR 35714, 35755 (July 1, 1999).

Crossett Mill 6A and 9A Power Boilers are not subject to BART.

B. Entergy's Alternative Strategy for White Bluff and Independence

Comment: Entergy proposes an alternative multi-unit strategy to address the regional haze requirements for four units that it states EPA should adopt instead of finalizing the proposed controls for the four units. The alternative multi-unit strategy involves meeting an emission limit of 0.60 lb/MMBtu on a 30-day rolling average at White Bluff Units 1 and 2 and Independence Units 1 and 2 by 2018; ceasing coal combustion at White Bluff Units 1 and 2 by 2027 and 2028; and installing LNB/SOFA at White Bluff Units 1 and 2 and Independence Units 1 and 2 within 3 years. Based on Entergy's modeling, the company says it believes its alternative multi-unit proposal achieves virtually the same visibility benefit as the FIP proposal and that the alternative proposal would ensure that Arkansas' Class I areas remain below the URP glidepath. Entergy argues that the difference in the haze index between the proposed FIP controls and Entergy's alternative multi-unit strategy is too trivial to justify a $2 billion investment at White Bluff and Independence for the installation of dry FGD.

Response: After carefully considering the comments we received, we have determined that we cannot approve Entergy's alternative proposal consistent with the Clean Air Act and Regional Haze rule. This determination is based on our conclusion that the alternative is not a better than BART alternative, does not meet the BART requirement for White Bluff Units 1 and 2, does not meet the reasonable progress requirements, and does not provide for the same visibility benefits as the FIP while delaying a majority of the visibility benefits until several years later than the FIP. Below, we discuss our assessment of the merits of Entergy's alternative proposal as an alternative approach for both meeting the BART requirements of section 308(e) for White Bluff and meeting the requirements of sections 308(d)(1) and 308(d)(3) regarding reasonable progress.

As an initial matter, we note that Entergy does not appear to be proposing that we apply the provisions of sections 308(e)(2) and 308(e)(3) to determine that its multi-unit strategy is an alternative program that provides more reasonable progress than BART. To the extent that this is Entergy's proposal, we cannot approve Entergy's multi-unit plan as an alternative to BART because it does not meet the requirements of section 308(e)(2)(iii) that ''all necessary emission reductions take place during the first planning period,'' *i.e.,* by December 31, 2018. Moreover, Entergy does not argue that its alternative would provide for ''greater'' reasonable progress towards achieving natural visibility conditions, only that its proposal would result in ''virtually the same'' visibility benefits. Thus, our assessment discussed below considers only the requirements of section 308(e)(1), which contains the source-specific BART requirements, in considering the provisions of Entergy's alternative proposal applicable to White Bluff.

Entergy proposes that White Bluff Units 1 and 2 would meet an SO_2 interim emission limit of 0.6 lb/MMBtu on a rolling 30-day average from 2018 through 2027/2028, when coal combustion at the two units would cease.[87] We note that the 0.6 lb/MMBtu interim emission limit is only slightly lower than the units' current SO_2 emission rates. The maximum monthly SO_2 emission rates for White Bluff Units 1 and 2 in 2009–2013 were 0.653 lb/MMBtu and 0.679 lb/MMBtu, respectively.[88] Thus, under Entergy's alternative proposal, White Bluff Units 1 and 2 would continue to operate for the remainder of the first planning period and throughout most of the second planning period at near the current emission rate, with only a slight actual reduction in SO_2 emissions. Because section 308(e)(1) and the BART guidelines require that a subject-to-BART source install and operate the best available emission reduction technology based on the five statutory factors, it is necessary to consider whether there are any additional SO_2 control measures, such as dry sorbent injection (DSI), that constitute BART during this interim period. Entergy has argued that with this limited remaining period of coal combustion, the cost per ton of SO_2 emissions reduction for dry scrubbers would be too high for it to be selected as BART for White Bluff. While we agree that a shorter remaining useful life might result in a conclusion that dry scrubbers are not cost effective, as part of the BART analysis, technically feasible control technologies beyond the interim SO_2 emission limit the company has proposed must be evaluated to determine if they are cost effective for use in the period before coal combustion ceases. In particular, DSI has a relatively low capital cost and may be cost effective even if operated for a short period of time.[89] Under Entergy's proposed strategy, White Bluff Units 1 and 2 would cease coal combustion towards the end of the second planning period. Therefore, it would be necessary to consider and evaluate DSI as a possible interim BART control option for White Bluff Units 1 and 2. Because Entergy has provided no analysis to demonstrate that there is no more effective interim SO_2 control that would constitute BART, the company's proposed strategy is not adequate to ensure that the BART requirements for White Bluff Units 1 and 2 will be met.

Even if it were not necessary to evaluate DSI or if we found it to not be cost effective for use at White Bluff in the interim period before coal combustion ceases, Entergy's alternative proposal would still not satisfy the BART requirements for White Bluff because it does not propose SO_2 and NO_X emission limits after coal combustion ceases or otherwise propose adopting a binding requirement to burn only natural gas or completely shut down the units. Entergy proposes to cease coal combustion at White Bluff Units 1 and 2 in 2027/2028, but its comments do not specify the operating conditions of White Bluff Units 1 and 2 after coal combustion ceases. The type of fuel White Bluff is permitted to burn after ceasing coal combustion will impact the emissions reductions actually achieved under Entergy's alternative proposal. Exhibit C to Entergy's comments indicates that the company assumes in its visibility modeling that SO_2 and NO_X emissions from White Bluff Units 1 and 2 will be zero under the company's alternative proposal (*i.e.,* ''Entergy's proposed controls'' scenario).[90] If Entergy's alternative proposal had included accepting a binding requirement to burn only natural gas at White Bluff Units 1 and 2 after coal combustion ceases, or a binding requirement to completely shut down the units, then we would

[87] Although not specified in Entergy's written comments, the company met with us and confirmed that the interim emission limit would be met by combusting lower sulfur coal. See file titled ''Record of Meeting October 27 2015,'' which is found in the docket for this rulemaking.

[88] 80 FR 18944, 18970; see also the spreadsheet titled ''White Bluff R6 cost revisions2,'' which is found in the docket for this rulemaking.''

[89] For example, Florida evaluated a shutdown option by December 31, 2020 for two BART units. After reviewing the Florida Regional Haze SIP, we concluded that the State should have evaluated DSI as a as a possible interim BART control option during the interim before the units shut down. We ultimately approved Florida's determination after evaluating the cost-effectiveness of DSI and concluding that such controls were not cost-effective in light of the remaining useful life of the units. See 78 FR 53250, 53261 (August 29, 2013).

[90] See ''Regional Haze Modeling Assessment Report,'' dated August 4, 2015, submitted as Exhibit C to Entergy Arkansas Inc.'s comments.

agree that it would be appropriate to assume that SO_2 emissions from White Bluff will be zero beginning in 2027/2028. Similarly, if Entergy's alternative proposal had included accepting a binding requirement to completely shut down White Bluff, then we would agree that it would be appropriate to assume that NO_X emissions from White Bluff will be zero beginning in 2027/2028.

Although, as we have already established, Entergy's alternative proposal cannot constitute a BART alternative because all necessary emission reductions will not take place during the first implementation period and the alternative proposal also does not satisfy the source-specific BART requirements of section 308(e)(1) for White Bluff, in response to Entergy's comment that its alternative proposal would achieve almost the same level of visibility benefit as the FIP, we compared the potential impacts of Entergy's proposal to our FIP. Despite the ambiguity in the comments submitted by Entergy regarding its alternative proposal, for purposes of assessing the visibility impacts of the company's proposed approach we have assumed that post-2028 SO_2 and NO_X emissions from White Bluff Units 1 and 2 will be zero under Entergy's alternative proposal. In Table 17, we compare the total annual SO_2 emissions reductions that would result under our FIP and under Entergy's alternative proposal when the alternative proposal is fully implemented in 2028 (*i.e.,* when coal combustion has ceased at White Bluff).[91] For consistency and to allow for direct comparison to our FIP proposal, in estimating the SO_2 emissions reductions anticipated to result from Entergy's alternative proposal we have assumed the same SO_2 baseline emissions we used for White Bluff and Independence in our proposal.[92] As shown in Table 17, although Entergy's alternative proposal would, after 2027/2028, achieve slightly greater SO_2 reductions at White Bluff Units 1 and 2 than our FIP proposal, it would achieve substantially lower SO_2 reductions at Independence Units 1 and 2. Under Entergy's proposed approach, Independence Units 1 and 2 would be subject to an SO_2 emission limit of 0.6 lb/MMBtu on a rolling 30-day average beginning in 2018.[93] This emission limit is only slightly lower than the current SO_2 emission rates from Independence Units 1 and 2. The maximum monthly SO_2 emission rates for Independence Units 1 and 2 in 2009–2013 were 0.631 lb/MMBtu and 0.612 lb/MMBtu, respectively.[94] We have no basis to assume that future emissions would be different from current rates in the absence of new SIP or FIP requirements, and so these current emission rates are the appropriate baseline for comparing strategies, rather than the currently permitted emission rates, which are higher. As such, under Entergy's proposal these units would continue to operate with minimal SO_2 emissions reductions. Unlike Entergy's proposed approach with respect to White Bluff, the proposed limits for Independence would not be interim emission limits. The company's alternative proposal does not include any further SO_2 controls for Independence Units 1 and 2, such as DSI or the eventual cessation of coal combustion. In contrast, we expect our proposed SO_2 emission limit of 0.06 lb/MMBtu would significantly and permanently reduce SO_2 emissions from Independence Units 1 and 2. As shown in Table 17, our FIP proposal would achieve substantially greater SO_2 emissions reductions at Independence than Entergy's alternative proposal. We estimate that the additional SO_2 emissions reductions that our FIP proposal would achieve at Independence compared to Entergy's alternative strategy are 11,621 SO_2 tpy at Unit 1 and 12,591 SO_2 tpy at Unit 2. In light of the minimal SO_2 emissions reductions that would be achieved at Independence under the company's proposed strategy, we expect that there would be correspondingly minimal visibility improvement with respect to the SO_2 controls it proposes for Independence.

TABLE 17—COMPARISON OF ANNUAL SO_2 EMISSIONS REDUCTIONS FROM WHITE BLUFF UNITS 1 AND 2 AND INDEPENDENCE UNITS 1 AND 2

[Post-2028]

Unit	SO_2 Baseline emissions (tpy)	FIP Proposal—annual SO_2 reductions [1]	Entergy alternative proposal—annual SO_2 reductions [2]	Additional SO_2 emissions reductions achieved by FIP proposal
White Bluff Unit 1	15,816	14,363	15,816	(1,453)
White Bluff Unit 2	16,697	15,221	16,697	(1,476)
Independence Unit 1	14,269	12,912	1,291	11,621
Independence Unit 2	15,511	13,990	1,399	12,591
Total—All four units combined (SO_2 tpy)	62,293	56,486	35,203	21,283

[1] These SO_2 reductions will begin taking place no later than 5 years from the effective date of this final FIP.
[2] This takes into account the full SO_2 reductions that would take place under Entergy's alternative proposal; a small amount of SO_2 reductions would begin taking place in 2018, but the majority of these SO_2 reductions would begin taking place in 2027/2028.

As shown in Table 17, considering the four units combined, we estimate that our FIP proposal would achieve annual emissions reductions of 21,283 SO_2 tpy more than Entergy's alternative proposal. With regard to visibility benefits, Entergy does not assert that its alternative proposal would provide equal or greater visibility benefits

[91] The SO_2 emissions reductions expected to result from our FIP will take place several years earlier than any significant SO_2 reductions under Entergy's alternative proposal. However, for purposes of comparing the long-term emissions reductions under the FIP and under the Entergy alternative, we are assessing the annual emissions reductions that will take place beginning in 2028, when the Entergy alternative would be fully implemented.

[92] In our proposal, for purposes of estimating the annual SO_2 emissions reductions due to controls on White Bluff Units 1 and 2 and Independence Units 1 and 2, we assumed an SO_2 emissions baseline that was 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. See 80 FR 18944, 18971, and 18992.

[93] Although not specified in Entergy's written comments, the company met with us and confirmed that this emission limit would be met by combusting lower sulfur coal. See file titled ''Record of Meeting October 27 2015,'' which is found in the docket for this rulemaking.

[94] See the spreadsheet titled ''White Bluff R6 cost revisions2,'' which is found in the docket for this rulemaking.

relative to our proposed FIP once the alternative is fully realized in the period after 2027/2028. Entergy states only that its alternative proposal would provide almost the same visibility benefit as our proposed FIP post-2027/2028. However, as illustrated in Table 17, it is clear that annual emissions would be significantly higher under the Entergy alternative and that the long-term visibility benefits of the Entergy alternative proposal would be significantly smaller than those of the proposed and final FIP. As we explained above, Entergy assumes in its visibility improvement projections that SO_2 and NO_X emissions from White Bluff Units 1 and 2 will be zero under the company's alternative proposal. The assumption of zero SO_2 emissions from White Bluff after coal combustion ceases would be appropriate only if Entergy's alternative proposal involves accepting a binding requirement to burn only natural gas or permanently shut down after coal combustion ceases. With respect to NO_X emissions from all four units of White Bluff and Independence, Entergy's multi-unit strategy includes the same level of NO_X control as our FIP proposal prior to the cessation of coal combustion at White Bluff in 2027/2028. Since Entergy's explanation of its alternative proposal does not specify the operating conditions of White Bluff Units 1 and 2 when coal combustion ceases in 2027/2028, we find that the assumption of zero NO_X emissions is also not adequately supported. However, even if we accept Entergy's assumption that NO_X emissions from White Bluff will be zero after coal combustion ceases and that its alternative proposal would thus achieve greater NO_X reductions compared to our FIP proposal, given the dominance of visibility impact from sulfate compared to nitrate at the affected Class I areas in Arkansas, the higher visibility impacts due to sulfate under the Entergy alternative proposal would more than outweigh any extra nitrate-related visibility benefit. Entergy's own CAMx modeling shows that even assuming zero SO_2 and NO_X emissions from White Bluff once it ceases coal combustion, its multi-unit alternative proposal would achieve less visibility benefit than the FIP controls at Arkansas' Class I areas, most significantly at Upper Buffalo where the benefit from Entergy's proposal is approximately only 66% of the benefit from the FIP (*i.e.,* 1.54 dv visibility benefit from the FIP compared to 0.97 dv from Entergy's alternative proposal).[95]

We also note that Entergy does not appear to be requesting in the comments submitted during the comment period that we adopt the elements in its alternative proposal that are unique to White Bluff as an alternative to our proposed BART emission limits at the facility unless we also conclude that the remaining elements address any reasonable progress requirements for Independence. In other words, Entergy's comments provide no indication that it is willing to accept a binding requirement to cease coal combustion at White Bluff by 2027/2028, unless we also accept the elements of its alternative proposal that are applicable to Independence as satisfying the reasonable progress requirements. Even if we had interpreted Entergy's comments as requesting that we adopt the elements in its alternative proposal that are unique to White Bluff as an alternative to our proposed BART emission limits at the facility without these elements being linked to the remaining elements addressing the reasonable progress requirements for Independence, we conclude that we would not be able to incorporate the Entergy alternative proposal into the final FIP as a way of meeting the BART requirement for White Bluff for the reasons already discussed above.[96]

Similarly, we also conclude that we cannot consider Entergy's proposal to meet the reasonable progress requirements with respect to Independence if Independence is considered in isolation. SO_2 emissions are the primary driver of regional haze in Arkansas' Class I areas on the 20% worst days and Independence is the second largest source of SO_2 emissions in Arkansas.[97] As explained in our proposal, our consideration of the four reasonable progress factors and consideration of visibility impacts and visibility improvement of controls for Independence revealed that dry scrubbers on Independence Units 1 and 2 are cost effective. These controls would provide significant visibility improvement as projected by our CALPUFF modeling focusing on the 98th percentile impacts from the source. We also discuss in section V.J. of this final rule and in our RTC document that the results of Entergy's CAMx photochemical modeling, which estimates the visibility impacts from Independence during the average of the 20% worst days, confirm and provide additional support to our determination that Independence significantly impacts visibility at Arkansas' Class I areas. Since Entergy's alternative proposal includes minimal SO_2 control for Independence, thus omitting controls that we found to be cost effective and that are anticipated to result in considerable visibility benefits at Arkansas' Class I areas, we conclude that the elements of Entergy's alternative proposal that are specific to Independence do not satisfy the reasonable progress requirements.

We recognize that ceasing coal combustion at White Bluff Units 1 and 2 could result in greater nonair environmental benefits and in more emission reductions of mercury and other hazardous air pollutants and CO_2/CO_{2e} than our proposed FIP. However, in assessing Entergy's alternative proposal, we do not find it necessary to weigh the nonair quality environmental benefits with the other statutory factors since we ultimately find that we cannot accept Entergy's alternative proposal because it does not satisfy the requirements of the Regional Haze Rule. As discussed earlier in our response, we conclude that Entergy's proposal does not satisfy the requirements to be considered a better-than-BART alternative under sections 308(e)(2) and 308(e)(3); does not satisfy the source-specific BART requirements under section 308(e)(1) for White Bluff; does not satisfy the reasonable progress requirements under section 308(d)(1); and does not provide for the same visibility benefits as the FIP, while delaying a majority of the visibility benefits until several years later than the FIP. For these reasons, we cannot adopt Entergy's alternative approach in lieu of our FIP.

In response to Entergy's comment regarding the cost to install dry FGD and as discussed in more detail in our RTC document, we have revised our cost calculations of SO_2 controls for White Bluff Units 1 and 2 in response to the comments received on our initial cost

[95] We discuss this, as well as Entergy's ranked statistical analysis and its photochemical modeling, in more detail elsewhere in this final rule and in our RTC document.

[96] We explain in an earlier part of our response why Entergy's alternative proposal does not satisfy the source-specific BART requirements of section 308(e)(1) for White Bluff.

[97] CENRAP CAMx modeling shows that on most of the 20% worst days in 2002, total extinction is dominated by sulfate at both Caney Creek and Upper Buffalo. Therefore, SO_2 emissions are considered the primary driver of haze in Arkansas' Class I areas. However, as discussed elsewhere in this final rule and in our RTC document, we consider both SO_2 and NO_X to be key visibility impairing pollutants in Arkansas' Class I areas. See Arkansas Regional Haze SIP, Appendix 8.1—''Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans,'' sections 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas Regional Haze SIP.

analysis.[98] As we discuss in more detail elsewhere in this final rule, based on our consideration of the five BART factors, we have determined that controls consistent with dry scrubber and LNB/SOFA installation are BART for White Bluff Units 1 and 2. After revising our cost estimates, we continue to believe that dry scrubber controls and LNB/SOFA controls are cost effective at White Bluff Units 1 and 2 and would result in significant visibility improvement at Arkansas' Class I areas based on our CALPUFF modeling of the 98th percentile visibility impacts from the facility.[99]

As we discuss in more detail elsewhere in this final rule, based on our consideration of the four reasonable progress factors and of the visibility impacts and visibility improvement of controls on Independence, we have determined that dry scrubbers and LNB/SOFA controls on Independence Units 1 and 2 are necessary to make reasonable progress at Arkansas' Class I areas. We have also revised our cost calculations of SO_2 controls for these units in response to the comments received on our initial cost analysis, and we continue to believe that both dry scrubber and LNB/SOFA controls are cost effective.[100] We also find that these controls on Independence would provide significant visibility improvement as projected by our CALPUFF modeling that focuses on the 98th percentile impacts from the facility.[101] Additionally, the CAMx photochemical modeling submitted by Entergy shows that the contribution to visibility impairment due to baseline emissions from the Independence facility alone are projected to be approximately 1.3% of the total visibility impairment during the average 20% worst days in 2018 at each Arkansas Class I area. We consider this to be a significant contribution to visibility impairment at each Class I area and a large portion (approximately one-third) of the total contribution from all Arkansas point sources. The results of Entergy's CAMx modeling confirm and provide additional support to our determination that Independence significantly impacts visibility at Arkansas' Class I areas. While the majority of the visibility impacts due to Independence on the 20% worst days are due to SO_2, we note that NO_X emissions from the facility also have impacts on the 20% worst days. Entergy's CAMx modeling shows that nitrate from Independence is responsible for 30–40% of the visibility impairment in Arkansas' Class I areas on 2 of the 20% worst days.[102] We expect that installation of cost-effective NO_X controls on Independence would provide visibility improvement on this portion of the 20% worst days, and as such, are requiring both SO_2 and NO_X controls under the reasonable progress requirements.

We are requiring White Bluff Units 1 and 2 under BART and Independence Units 1 and 2 under reasonable progress to each meet an SO_2 emission limit of 0.06 lb/MMBtu on a 30 boiler-operating-day rolling average. We are requiring White Bluff Units 1 and 2 under BART and Independence Units 1 and 2 under reasonable progress to each meet a NO_X emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average, where the average is to be calculated by including only the hours during which the unit is dispatched at 50% or greater of maximum capacity. In addition, we are requiring White Bluff Units 1 and 2 under BART and Independence Units 1 and 2 under reasonable progress to each meet a NO_X emission limit of 671 lb/hr on a rolling 3-hour average, where the average is to be calculated by including emissions only for the hours during which the unit was dispatched at less than 50% of the unit's maximum heat input rating (*i.e.,* hours when the heat input to the unit is less than 4,475 MMBtu).

We do note that if Arkansas submits a regional haze SIP revision to replace our FIP, the state has the discretion to consider an approach to address the BART requirements for White Bluff that involves ceasing coal combustion at Units 1 and 2 by 2027/2028, but an approvable SIP revision must also include consideration and evaluation of DSI as a possible interim BART control option. With respect to Independence, a strategy that includes controls for Independence similar to the elements of Entergy's alternative proposal that are specific to White Bluff (*i.e.,* interim SO_2 controls, ceasing coal combustion in the near future, and NO_X controls) would also have potential merit with respect to addressing the reasonable progress requirements for Independence Units 1 and 2. The state may consider submitting a SIP revision that includes such a strategy for Independence to replace our FIP.

With regard to the comment that Entergy's alternative multi-unit strategy would ensure that Arkansas' Class I areas remain below the URP glidepath, we discuss in section V.C. of this final rule and in our RTC document that being on or below the URP glidepath does not mean that the BART requirements for White Bluff Units 1 and 2 and the reasonable progress requirements for Independence Units 1 and 2 are automatically satisfied.

Comment: Several commenters noted that as part of a multi-unit plan to improve visibility and to better manage its generation assets for reliability and costs, Entergy proposed in comments submitted to EPA to cease burning coal at White Bluff Units 1 and 2 by 2027 and 2028, one unit per year, and is prepared to take an enforceable commitment to that effect. The commenters stated that the CAA and the Regional Haze Rule require EPA and states to consider the remaining useful life of a source in BART determinations, which factors into the cost of compliance in the BART analysis. The commenters argue that as a result of Entergy's alternative proposal, EPA's proposed BART determination for White Bluff Units 1 and 2 has been rendered inapplicable, requiring EPA to undertake a new BART analysis to address the now reduced remaining useful coal-fired life of the units. The commenters noted that comments submitted by Entergy contain a revised dry FGD cost analysis from Sargent & Lundy (S&L) that takes into account current costs for dry FGD installation and argue that when the appropriate dry scrubber costs from the S&L analysis are considered, operating the dry FGD systems at White Bluff for only 6 or 7 years would result in a cost effectiveness of over $7,500 to $8,500 per ton at the White Bluff units, which is several times higher than EPA estimates and not cost effective.

Response: Entergy's comments propose a multi-unit strategy as an alternative to the proposed FIP. As discussed above, we do not interpret Entergy's comments submitted during the comment period as requesting that we adopt the elements in its alternative that are unique to White Bluff as an alternative to our proposed BART emission limits for the facility unless we also conclude that the remaining elements address any reasonable progress requirements for

[98] Based on our revised cost analysis, we have found that dry scrubbers on White Bluff are estimated to cost \$2,565/SO_2 ton removed at Unit 1 and \$2,421/SO_2 ton removed at Unit 2.

[99] See 80 FR at 18972, 18974. Our FIP proposal provides a detailed discussion of the visibility improvement of these controls based on our CALPUFF modeling.

[100] Based on our revised cost analysis, we have found that dry scrubbers on Independence are estimated to cost \$2,853/SO_2 ton removed at Unit 1 and \$2,634/SO_2 ton removed at Unit 2. After revising our cost estimates, we continue to believe that these controls are cost effective.

[101] 80 FR 24872.

[102] This means 2 out of the 21 days that are the 20% worst of the days with IMPROVE monitoring data.

Independence. As we discuss in a previous response, we do not find that the comprehensive multi-unit alternative proposal as presented by the company satisfies the BART requirements for White Bluff Units 1 and 2 and the reasonable progress requirements for Independence Units 1 and 2. A chief element of Entergy's alternative is its proposal to cease coal combustion at White Bluff Units 1 and 2. It is unclear whether this would mean the shutdown or the repowering of White Bluff Units 1 and 2. Regardless of this ambiguity, a number of commenters have argued that because of Entergy's proposal, we should use a shorter remaining life in assessing the costs of controls at White Bluff. If we were to assume that Entergy were proposing changes at White Bluff regardless of our action regarding Independence, we could include in our final FIP an enforceable requirement for the shutdown (or repowering) and take that change into consideration as part of a BART determination. The BART Guidelines state that where unit shutdown affects the BART determination, the shutdown date should be assured by a federally or state-enforceable restriction preventing further operation.[103] Although we could include such a requirement in our FIP, the comments we received from Entergy during the public comment period do not indicate that it intends to cease coal combustion at White Bluff Units 1 and 2 at this time absent a broader agreement on appropriate controls for both White Bluff and Independence. As such, we do not consider it appropriate to include a requirement in our FIP to cease coal combustion at White Bluff Units 1 and 2 in our rule unless we were to also accept the Entergy proposal as meeting all requirements with respect to Independence.[104] Therefore, we consider it appropriate to assume a remaining useful life of 30 years for White Bluff Units 1 and 2 when determining BART for these units. We address specific comments regarding the White Bluff cost analysis in the section of this final rule where we discuss cost issues.

C. Reasonable Progress Goals and Reasonable Progress Analysis

Comment: Several commenters stated that EPA lacks evidence of a sufficient need to evaluate additional controls under reasonable progress for Arkansas point sources. These commenters argued that before evaluating controls under reasonable progress, EPA must first determine that further actions are necessary in Arkansas beyond BART to ensure that visibility improvement is continuing on or below the glide path for each affected Class I area. These commenters cited to the CAA and EPA guidance which they believe support their position that reductions beyond BART should not be required because the impacted Class I areas are at or below their glide paths. The commenters also pointed to ADEQ's "State Implementation Plan Review for the Five-Year Regional Haze Progress Report"[105] as evidence that Caney Creek and Upper Buffalo will be below the glide path in 2018. They claimed that EPA ignores ADEQ's Five-Year Progress SIP revision, which they argued demonstrates that Arkansas has achieved 73% of the 2018 RPG it established for Caney Creek (3.88 dv of improvement) and 66% of the 2018 RPG it established for Upper Buffalo (3.75 dv of improvement). The commenters argued that as a result of emission reductions achieved through regional and national programs, including MATS, CAIR, and CSAPR, future Clean Air Act programs such as implementation of the 1-hour SO_2 NAAQS, the revised ozone NAAQS and the Clean Power Plan, as well as the reductions for White Bluff and Independence that Entergy is proposing and the BART controls that EPA has proposed for the other sources in Arkansas, there is every reason to project continued improvement in visibility in Caney Creek and Upper Buffalo well beyond 2018.

Response: EPA disagrees with the comment that we can only evaluate controls under reasonable progress if further controls beyond BART are needed to be on or below the URP glidepath for a Class I area. Specifically, commenters cited section 169A(b)(2) of the Act, which requires regional haze regulations to "contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal." These commenters interpret the term "reasonable progress" to be defined as being on or below the URP glidepath, and that as long as a Class I area is on or below the URP glidepath, additional controls are not necessary under the reasonable progress requirements. This interpretation is incorrect and does not take into account other, more explicit, statutory and regulatory language. The CAA requires reasonable progress determinations to be based on consideration of "the costs of compliance, the time necessary for compliance, the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements." CAA section 169A(g)(1). The regional haze regulations under 40 CFR 51.308(d)(1)(i)(A) also require consideration of these four statutory factors in establishing the RPGs and a demonstration showing how these factors were taken into account.

We commonly refer to the evaluation of these four statutory factors as the "four-factor analysis" or "reasonable progress analysis." The statute and regulations are both clear that the states or EPA in a FIP have the authority and obligation to evaluate the four reasonable progress factors and that the decision regarding the controls required to make reasonable progress and the establishment of the RPG must be based on these factors identified in the CAA section 169A(g)(1) and the Regional Haze regulations under § 51.308(d)(1)(i)(A). While the regulations require that a state must also consider the URP glidepath in establishing the RPGs, this should not be interpreted to mean that the URP can or should be automatically adopted as the RPG without completing the requisite analysis of the four statutory factors. It also should not be interpreted to mean that a set of controls sufficient to achieve the URP is automatically sufficient for an approvable long-term strategy. Clearly, a state's obligation to set reasonable progress goals based on CAA section 169A(g)(1) and § 51.308(d)(1) applies in all cases, without regard to the Class I area's position on the URP. Since an evaluation of the factors is required regardless of the Class I area's position on the glidepath, this necessarily means that the CAA and the Regional Haze regulations envisioned that controls could be required under reasonable progress even when a Class I area is on or below the URP glidepath. There is nothing in the CAA or Regional Haze regulations that suggests that a State's obligation, or EPA's in a FIP, to ensure reasonable progress can be met by just meeting the URP.[106]

Some commenters also argue that the EPA's 2007 Reasonable Progress

[103] See Appendix Y to 40 CFR part 51—Guidelines for BART Determinations Under the Regional Haze Rule, section IV.D.4.k.

[104] Additionally, as discussed above, Entergy did not submit sufficient information to demonstrate that there are no additional SO_2 control measures, such as DSI, that constitute BART even in light of a limited remaining useful life for White Bluff.

[105] Available at *http://www.adeq.state.ar.us/air/planning/pdfs/ar_5yr_prog_rep_review-final-6-2-2015.pdf.*

[106] 77 FR 14604, 14629.

Guidance suggests that controls under reasonable progress are not necessary if a Class I area is on or below the URP glidepath. The specific part of the Reasonable Progress Guidance that some of the commenters point to states that:

Given the significant emissions reductions that we anticipate to result from BART, the CAIR, and the implementation of other CAA programs, including the ozone and $PM_{2.5}$ NAAQS, for many States [determining the amount of emission reductions that can be expected from identified sources or source categories as a result of requirements at the local, State, and federal levels during the planning period of the SIP and the resulting improvements in visibility at Class I areas] will be an important step in determining your RPG, and it may be all that is necessary to achieve reasonable progress in the first planning period for some States.[107]

We see nothing in the Reasonable Progress Guidance indicating that additional controls can only be required if further action beyond BART is needed to remain on or below the URP glidepath. Nor do we see anything in the Reasonable Progress Guidance indicating that a state (or EPA) is exempt from completing the four factor analysis if a Class I area is on or below the URP glidepath. As discussed above, the CAA and Regional Haze regulations are clear that an evaluation of the four statutory factors is required, and this requirement applies regardless of the Class I area's position on the glidepath. We noted in our FIP proposal that the preamble to the Regional Haze Rule states that the URP does not establish a ''safe harbor'' for the state in setting its progress goals:

If the State determines that the amount of progress identified through the [URP] analysis is reasonable based upon the statutory factors, the State 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 determines that additional progress is reasonable based on the statutory factors, the State should adopt that amount of progress as its goal for the first long-term strategy.[108]

Being projected to meet the URP for 2018 does not justify dismissing the analysis required under CAA section 169A(g)(1) and § 51.308(d)(1) in determining reasonable progress and establishing the RPGs, nor does it automatically mean that no additional controls beyond BART are required under reasonable progress. The URP is an analytical requirement created by regulation to ensure that states consider the possibility of setting an ambitious reasonable progress goal. Its purpose is to complement, not usurp, the reasonable progress analysis. Based on the analysis of the four statutory factors required under the CAA and Regional Haze regulations, a state (or EPA in a FIP) may determine that a greater or lesser amount of visibility improvement than what is reflected in the URP is necessary to demonstrate reasonable progress.[109] Based on our analysis of the factors under CAA section 169A(g)(1) and § 51.308(d)(1), along with consideration of the visibility improvement of controls, we determined that there are reasonable controls available for Independence that would be cost-effective and would result in meaningful visibility benefit at Arkansas' Class I areas. Because we have identified that additional progress (beyond the amount reflected in the URP) is reasonable based on the statutory factors and our consideration of the visibility impacts, we are required to adopt that amount of progress under the reasonable progress requirements. It is for this reason, we are requiring controls on Independence. It is not, as some commenters contend, ''for the sole purpose of achieving emissions reductions.''

We note that our conclusion here is consistent with our final action on the Arkansas Regional Haze SIP, where we disapproved Arkansas' RPGs specifically because the state established its RPGs without conducting an evaluation of the four statutory factors and did so based on the fact that its Class I areas are below the URP glidepath. In the preamble to our final action on the Arkansas Regional Haze SIP, we were clear that an evaluation of the four statutory factors is required regardless of the Class I area's position on the URP glidepath:

[B]eing on the ''glidepath'' does not mean a state is allowed to forego an evaluation of the four statutory factors when establishing its RPGs. Based on an evaluation of the four statutory factors, states may determine that RPGs that provide for a greater rate of visibility improvement than would be achieved with the URP for the first implementation period are reasonable.[110]

Our final action on the Arkansas Regional Haze SIP was published in the **Federal Register** on March 12, 2012, and became effective on April 11, 2012. We reiterate in this final action that the CAA and Regional Haze regulations require an analysis of the four reasonable progress factors regardless of a Class I area's position on the URP and that being below the glide path does not automatically mean that no controls are necessary under reasonable progress.

With regard to the comment contending that we are ignoring data from ADEQ's Five-Year Progress Report SIP revision, we note that Arkansas submitted the first 5-year report to EPA in June 2015, and that we are not addressing that SIP revision within this action.[111] The 5-year progress report is a separate requirement from the regional haze SIP required for the first and subsequent planning periods, and it has separate content and criteria for review. We are therefore not obligated to consider or take action on the 5-year progress report at the same time we promulgate our FIP.

We acknowledge that recent IMPROVE monitoring data indicate there has been visibility improvement in Arkansas' Class I areas. But even assuming that the current trend in visibility improvement will continue, as the commenter argues, this does not divest us from our authority and obligation to conduct a reasonable progress analysis, nor does it justify the dismissal of controls for Independence that we have determined, pursuant to that analysis, are cost-effective and would result in meaningful visibility benefit at Arkansas' Class I areas. The commenters point out that even without the BART and reasonable progress controls required by our FIP, Caney Creek has achieved 73% and Upper Buffalo has achieved 66% of their respective 2018 RPGs established by Arkansas based on 5-year average data from IMPROVE monitors as of 2011. However, even if we had approved these RPGs (which we did not), achieving or being projected to achieve the RPG does not necessarily demonstrate that a state has satisfied its requirements under BART and reasonable progress. The state or EPA must complete the requisite analyses to determine appropriate controls and emission limits under the BART and reasonable progress requirements, and must adopt and enforce these controls and emission limits. The numeric RPGs are calculated by taking into account the visibility improvement anticipated from these enforceable emission limitations and other control measures (including BART, reasonable progress, and other ''on the books'' controls). The Regional Haze Rule provides that these emission limitations and control measures are what is enforceable, not the RPGs

[107] ''Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program,'' at 4–1.

[108] 80 FR at 18992.

[109] 64 FR 35714, 35732.

[110] 77 FR at 14629.

[111] We anticipate taking action on ADEQ's Five Year Progress Report SIP revision in a separate, future action.

themselves.[112] Thus, the RPGs are intended to provide a degree of transparency regarding the rate of improvement in visibility anticipated for each Class I area over the planning period of the SIP.[113]

As noted above, we disapproved Arkansas' RPGs in our March 12, 2012 final action on the Arkansas Regional Haze SIP [114] because the state did not complete the required four-factor analysis in establishing the RPGs. Further, the state's RPGs were based on BART determinations that were not in accordance with the CAA and Regional Haze regulations. As such, the State's RPGs are not a reflection of the controls necessary to make reasonable progress, and any arguments upholding or suggesting that the state's RPGs are appropriate or adequate are outside the scope of this action. That Arkansas' Class I areas are on track to achieve the disapproved RPGs by 2018 does not mean that the reasonable progress requirements have been satisfied, nor does it justify no additional controls under reasonable progress.

Comment: Some commenters argued that our FIP proposal was improper because it adopted an individual source-based approach to setting RPGs, and that this is inconsistent with the CAA. Another commenter claimed that EPA failed to explain how factors required to be considered in setting the RPGs, which are themselves not enforceable, could somehow be used to require specific enforceable limits for a single plant.

Response: While our FIP does consider and ultimately apply controls on an individual source basis to assure reasonable progress, this is consistent with the CAA, our regulations, and past EPA guidance. The four statutory factors under CAA Section 169A(g) and 40 CFR 51.308(d)(1)(i)(A) are directed to the listed possible features or consequences of potential emission control measures for sources, including individual stationary sources. The CAA and the Regional Haze regulations expressly set forth that the reasonable progress analysis must consider the ''compliance'' time and costs for ''potentially affected sources.'' A state determines the rate of progress that is reasonable for a Class I area after taking into account the four statutory factors—as applied to specific sources or groups of sources—to determine what additional controls should be required in its regional haze SIP. Thus, individual stationary sources may be subject to emission limits and source specific analysis when determining whether additional controls are necessary to make reasonable progress.

The commenter's suggestion that because the RPGs are not themselves enforceable we cannot require specific enforceable limits for a single plant is not consistent with the requirement that each regional haze SIP or FIP include enforceable emissions limitations as necessary to ensure that the SIP or FIP will provide reasonable progress toward the national goal of natural visibility conditions. The numeric RPGs established by the state or EPA represent the best estimate of the degree of visibility improvement that will result in 2018 from changes in emissions inventories, changes driven by the particular set of control measures the state has adopted in its regional haze SIP or EPA in a regional haze FIP to address visibility, as well as all other enforceable measures expected to reduce emissions over the period of the SIP from 2002 to 2018.[115] Thus, the RPGs are intended to provide a degree of transparency regarding the rate of improvement in visibility anticipated for each Class I area over the planning period of the SIP. But the RPGs themselves are not enforceable.[116] EPA cannot enforce an RPG in the sense of seeking to apply penalties on a state for failing to meet the RPG or obtaining injunctive relief to require a state to achieve its RPG. However, the long-term strategy can and must contain emission limits and other control measures that apply to specific sources under the reasonable progress requirements, and that are themselves enforceable. The fact that the RPGs are not enforceable does not mean that we cannot conduct a source-specific evaluation of the reasonable progress factors or require source-specific emission limits under the reasonable progress requirements.

Comment: EPA treated Independence Units 1 and 2 as if they were subject-to-BART units by ignoring whether controls at the units are needed to improve visibility and looking only at whether controls are cost effective. EPA's failure to assess and document the contribution to visibility impairment at any relevant Class I area from any Arkansas point source, including Independence, is contrary to past rulemakings and is inconsistent with the detailed approach taken by EPA Region 6 in its promulgation of the Texas Regional Haze FIP. The Independence plant was apparently singled out by EPA for additional pollution controls under reasonable progress, while other non-BART emission sources were not. EPA does not provide any explanation for its selective treatment in this case other than noting that the Independence is among the top three largest point sources in the state. EPA's justification for imposing SO_2 and NO_X emission limits on Independence is not based on rational policy, legal, or environmental grounds and, as a result, it is arbitrary and capricious. EPA's primary justification for proposing reasonable progress limits at Independence is that ''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.'' EPA further supports its conclusion that emission limits based on the installation of major control technology are justified based on a finding that the proposed controls at Independence are cost effective. However, the fact that a source, which is not subject to BART, may have significant SO_2 or NO_X emissions, or that it would be cost effective to control such emissions, is irrelevant for reasonable progress purposes. This is an inapplicable and inadequate justification to identify sources for control under a reasonable progress analysis. EPA did not appropriately analyze which sources, if any, should be controlled for reasonable progress and did not follow the procedures it has regularly used in other regional haze FIPs.

Response: We did not treat Independence as if it were a subject-to-BART source, nor did we ignore whether controls at the facility are needed to improve visibility, or only look at whether controls are cost effective. Under the CAA and 40 CFR 51.308(d)(1), we must consider the following four factors in our reasonable progress analysis: (1) The costs of compliance; (2) the time necessary for compliance; (3) the energy and nonair quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. These are the factors we took into consideration in our proposal. As we discuss in our proposal and elsewhere in this final rule, although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states or EPA have the option of considering the projected visibility

[112] 64 FR 35714, 35733.

[113] The RPGs are intended to provide the state or EPA's best estimate of the amount of visibility improvement in deciviews anticipated for each Class I area over the planning period of the SIP or FIP.

[114] 77 FR 14604.

[115] 64 FR at 35733.

[116] See 51.308(d)(1)(v).

benefits of controls in determining if the controls are necessary to make reasonable progress. We modeled both the baseline visibility impacts from the Independence facility and the visibility benefit of controls using CALPUFF dispersion modeling. Based on our consideration of the four reasonable progress factors as well as the baseline visibility impacts from Independence and the visibility improvement of potential controls, we determined that reasonable controls for SO_2 and NO_X are available for Independence Units 1 and 2 that are cost effective and would result in a large amount of visibility improvement in Arkansas' Class I areas in terms of the 98th percentile impacts from the source.[117] Therefore, the claim that we ignored whether controls at the units are needed to improve visibility is incorrect.

We also disagree that the fact that a non-BART source has significant SO_2 or NO_X emissions, or that it would be cost-effective to control such emissions, is irrelevant in determining what sources to take a closer look at and evaluate under reasonable progress. As noted above, the cost of compliance is one of the statutory factors that EPA is required to consider in a reasonable progress analysis, meaning that the cost effectiveness of potential controls is not irrelevant for reasonable progress purposes. Significant SO_2 or NO_X emissions from a source is generally an indication that there may be significant visibility impacts at nearby Class I areas and that installation of more effective controls, if any are available, may result in substantial emissions reductions and meaningful visibility improvement. As noted above, states and EPA have the option of considering the projected visibility benefits of controls in determining if the controls are necessary to make reasonable progress. Therefore, we find that consideration of a source's emissions and whether it would be cost-effective to control such emissions is appropriate and relevant for reasonable progress purposes.

The commenter makes the incorrect claim that our primary justification for imposing emission limits under reasonable progress for Independence Units 1 and 2 is that 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. While we did state in our FIP proposal that 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 commenters took this statement out of context. The full citation from our FIP proposal referenced by the commenters is the following:

> 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.[118]

As evidenced by the full citation from our FIP proposal, the fact that we considered it 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 was our primary justification for looking more closely and evaluating the Independence plant in our reasonable progress analysis. It was not, as the commenter contends, our justification for imposing controls on Independence. As we discuss in our FIP proposal and elsewhere in this final action, our decision to require controls on Independence is based on our analysis under § 51.308(d)(1), as required by the CAA and Regional Haze Rule.

We do not agree with the commenter's allegation that we did not appropriately analyze what sources, if any, should be controlled under reasonable progress. To the extent that the commenter contends that our process for determining which sources should be evaluated under reasonable progress was incorrect because we did not conduct photochemical modeling, such argument is incorrect. To the extent that the commenter contends that we treated the Independence facility like a BART source because we evaluated it under the reasonable progress requirements without conducting photochemical modeling to identify potential sources to evaluate under reasonable progress, this is also incorrect. We are not required to conduct photochemical modeling in a reasonable progress analysis. Our 2007 Reasonable Progress Guidance states that ''The RHR gives States wide latitude to determine additional control requirements, and there are many ways to approach identifying additional reasonable measures; however, you must at a minimum, consider the four statutory factors.'' [119] The states or EPA in the context of a FIP have wide discretion in deciding what approaches, methods, and tools to use in identifying source categories, specific point sources, or pollutants to evaluate for additional controls under the reasonable progress requirements, provided that a reasonable rationale for the approach used is provided. There are a number of different approaches states or EPA in the context of a FIP have used in identifying sources for reasonable progress evaluation, but they usually center around the general premise of evaluating the biggest sources and/or the biggest impactors on visibility. While the states or EPA have the discretion to consider visibility in a reasonable progress analysis, photochemical modeling is not required for purposes of conducting a reasonable progress analysis.

Our FIP proposal provided a detailed explanation of how we determined what sources to evaluate for controls under reasonable progress, and we provided a reasonable rationale for the approach we used. The first step in our analysis involved determining what source categories or specific point sources it would be appropriate to look at more closely and evaluate under the reasonable progress requirements in § 51.308(d)(1) to determine if additional controls are necessary. We explained in our proposal that it was appropriate to focus our analysis on point sources since the other source categories (*i.e.,* natural, on-road, non-road, and area) each contribute a much smaller proportion of the total light extinction at each Class I area in Arkansas based on the CENRAP CAMx modeling.[120] At Caney Creek, point sources contribute 81.04 Mm^{-1} out of a total light extinction of 133.93 Mm^{-1} on the average across the 20% worst days in 2002, or approximately 60.5% of the total light extinction. At Upper Buffalo, point sources contribute 77.80 Mm^{-1} out of a total light extinction of 131.79 Mm^{-1} on the average across the 20% worst days in 2002, or approximately 59% of the total light extinction. In comparison, area sources, which are the source category with the next highest contribution to the total light extinction at each Class I area, contribute approximately 13.3% of the total light

[117] CAMx source apportionment modeling was submitted to us by Entergy Arkansas Inc. during the comment period. This modeling shows that Independence has significant visibility impacts in Arkansas Class I areas on the 20% worst days, and further supports our decision to require controls for Independence under reasonable progress. We discuss Entergy Arkansas Inc.'s photochemical modeling and the visibility impacts due to SO_2 and NO_X from Independence on the 20% worst days elsewhere in this final rule.

[118] 80 FR at 18992.

[119] ''Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program,'' at 4–2.

[120] See 80 FR 18944, 18989.

extinction at Caney Creek and 15.5% at Upper Buffalo. The remaining source categories each contribute less than 6% of the total light extinction at each Class I area. Therefore, we concluded that it was appropriate to focus our analysis on point sources.

The CENRAP CAMx modeling shows that on most of the 20% worst days in 2002, total extinction was dominated by sulfate at both Caney Creek and Upper Buffalo.[121] Additionally, total extinction at Caney Creek was dominated by nitrate on 4 of the days that comprise the 20% worst days in 2002 and a significant portion of the total extinction at Upper Buffalo on 2 of the days that comprise the 20% worst days in 2002 was due to nitrate.[122] The CENRAP CAMx modeling also shows that sulfate from point sources was responsible for approximately 54.8% of the total visibility impairment at Upper Buffalo and 56.1% at Caney Creek on the 20% worst days in 2002. Nitrate from point sources was responsible for approximately 3% of the total visibility impairment at each Class I area on the 20% worst days in 2002. As such, although SO_2 emissions are the primary contributor to regional haze in Arkansas' Class I areas on the 20% worst days, NO_X emissions are also a key contributor. Thus, consistent with our Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program,[123] we found it appropriate to evaluate both SO_2 and NO_X controls under reasonable progress.

We explained in our FIP proposal that as a starting point in our analysis to determine whether additional controls on Arkansas point 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 (NEI 2011 v1).[124] We reasoned that examination of the emissions inventories is appropriate because significant SO_2 or NO_X emissions from a source are generally an indication that it may be having significant visibility impacts at nearby Class I areas and that installation of controls may result in substantial emissions reductions and meaningful visibility improvement. We did not conduct photochemical modeling or other more exhaustive analyses to identify potential candidates to evaluate under reasonable progress, and while we recognize that this approach is different from the approaches and methods that we have used or approved in other regional haze actions, we find that the approach we are taking in this action is appropriate given the specific circumstances. In particular, our examination of the SO_2 and NO_X emissions inventories for Arkansas' point sources revealed that the number of point sources that emit SO_2 and NO_X emissions is relatively small. Furthermore, a very small portion of the point sources in the state is responsible for a large portion of the statewide SO_2 and NO_X point source emissions. Specifically, White Bluff, Independence, and Flint Creek are collectively responsible for approximately 84% of the SO_2 point source emissions and 55% of the NO_X point source emissions in the state. Consequently, addressing these sources under the regional haze program will address a large proportion of the visibility impacts due to Arkansas point sources. We are requiring SO_2 and NO_X controls for White Bluff and Flint Creek under the BART requirements in this final action, which will substantially reduce emissions from these two facilities. The Independence Plant, which is not a subject-to-BART source, contributes approximately 36.2% of the total SO_2 point source emissions in the state (30,398 SO_2 tons out of total SO_2 point source emissions of 83,883 SO_2 tons, based on the 2011 NEI).[125] This source also contributes approximately 21.3% of the total NO_X point source emission in the state (13,411 NO_X tons out of total NO_X point source emissions of 62,984 NO_X tons). Based on this examination, we determined that the magnitude of emissions from the Independence Plant warranted further evaluation of the source to determine if it is a significant contributor to regional haze in Arkansas' Class I areas and whether controls at the facility are needed based on an analysis under § 51.308(d)(1).

After White Bluff, Independence, and Flint Creek, the remaining point sources in the state have much lower SO_2 and NO_X emissions than these facilities. In other words, the magnitude of SO_2 and NO_X emissions from point sources in Arkansas drops off considerably after the top 3 emitters. We stated the following in our proposal:

> 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.[126]

Future Fuel Chemical Company, the point source with the fourth highest SO_2 emissions (after White Buff, Independence, and Flint Creek), contributes approximately 4.1% of the total SO_2 point source emissions in the state (3,420 SO_2 tons out of total SO_2 point source emissions of 83,883 SO_2 tons, based on the 2011 NEI). The Natural Gas Pipeline Company of America #308, the point source with the fourth highest NO_X emissions, contributes approximately 5.1% of the total NO_X point source emission in the state 3,194 NO_X tons out of total NO_X point source emissions of 62,984 NO_X tons, based on the 2011 NEI). Based on the much smaller magnitude of these sources' emissions, we determined that the remaining point sources in the state are less likely to be significant contributors to regional haze, and thus did not warrant closer evaluation under reasonable progress in this planning period. As such, we found that it is appropriate to evaluate Independence for controls under reasonable progress. The claim that we arbitrarily singled out Independence and that we provided no explanation as to why we did not evaluate other point sources under reasonable progress is not supported by the record in this action.

Because our examination of the Arkansas emissions inventory revealed that the number of point sources that emit SO_2 and NO_X emissions is relatively small and that a very small portion of the point sources in the state are responsible for a large portion of the statewide SO_2 and NO_X point source emissions, we concluded that photochemical modeling or other more exhaustive analyses that we have performed in other regional haze actions were unnecessary to identify point sources to evaluate under reasonable progress. In contrast, in states such as Texas, where the universe of point

[121] See Arkansas Regional Haze SIP, Appendix 8.1—''Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans,'' sections 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas Regional Haze SIP.

[122] See Arkansas Regional Haze SIP, Appendix 8.1—''Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans,'' section 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas Regional Haze SIP.

[123] ''Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program,'' at 2–3 and 3–1.

[124] 80 FR at 18991.

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

[126] 80 FR at 18992.

sources is much larger and the distribution of SO_2 and NO_X emissions is very widespread, an evaluation of the state's emissions inventory alone was not sufficient to reveal the best potential candidates for evaluation under reasonable progress. For this reason, we explained in our Texas Regional Haze FIP that due to the challenges presented by the geographic distribution and number of sources in Texas, the CAMx photochemical model was best suited for identifying sources to evaluate for reasonable progress controls.[127] We did not encounter these challenges in the development of our reasonable progress analysis for Arkansas and therefore did not conduct photochemical modeling.

We do note that while we did not conduct photochemical modeling to identify Arkansas point sources to evaluate under reasonable progress, Entergy conducted CAMx source-apportionment modeling and submitted it during the comment period. Entergy's CAMx source apportionment modeling showed that emissions from the Independence facility alone are projected to contribute approximately 1.3% of the total visibility impairment in 2018 on the 20% worst days at each Arkansas Class I area. This is a large portion (approximately one-third) of the total contribution from all Arkansas point sources, and we consider it to be a significant contribution to visibility impairment Arkansas' Class I areas on the 20% worst days. The CAMx modeling also showed that at Upper Buffalo, the Independence facility's contribution to visibility impairment is greater than the contribution from all of the subject-to-BART sources addressed in this final action combined. In terms of deciviews, the average impact from Independence over the 20% worst days, based on Entergy's CAMx modeling and adjusted to natural background conditions, is over 0.5 dv at the Arkansas Class I areas. The results of Entergy's CAMx modeling confirm and provide additional support to our determination that Independence significantly impacts visibility at Arkansas' Class I areas.

Additionally, we note that because of the controls required during this planning period, we expect that the impact from the facilities in Arkansas that were not controlled and not specifically evaluated in the first planning period will become larger on a percentage basis. These sources will become the largest impacting sources and should be considered for analysis under reasonable progress in future planning periods. The methodology we used here thus allows a consistent procedure to identify facilities for additional control analysis in this and future planning periods and ensures continuing progress towards the goal of natural visibility conditions.

To the extent the commenter contends that additional controls under reasonable progress cannot or should not be evaluated or required unless controls beyond BART are needed for Arkansas to be on or below the URP glidepath or to meet the RPGs established by the state (which, in the case of Arkansas, we disapproved in a previous final action), this is incorrect. As we discuss elsewhere in this section of the final rule and in our RTC document, there is nothing in the CAA or Regional Haze regulations that suggests that a State's obligations to ensure reasonable progress can be met simply by being on or below the URP glidepath or meeting the state's RPGs.[128]

Comment: EPA's own analysis counsels against imposing additional controls on the Independence Plant. EPA asserts that CENRAP modeling shows that sulfate from all point sources is projected to contribute to 57% of the total light extinction at Caney Creek on the worst 20% days in 2018 and 43% of the total light extinction at Upper Buffalo. Nitrate from all point sources is projected to account for only 3% of the total light extinction at the Class I areas. However, the CENRAP modeling also projects that sulfate from Arkansas point sources will be responsible for only 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo. The contribution of nitrate from Arkansas point sources to visibility impairment is even more insignificant, accounting for only 0.29% of the total light extinction at Caney Creek and 0.25% at Upper Buffalo. The Independence Plant's share of emissions to this minimal contribution from Arkansas point sources is even smaller. Despite these very small contributions, EPA's proposal concludes that SO_2 and NO_X controls at the Independence Plant are warranted and reasonable. EPA lacks evidence of a sufficient need to evaluate additional controls for Arkansas point sources and lacks a sufficient basis to justify additional controls.

Response: The commenter appears to believe that the CENRAP modeling shows that the visibility impacts on the 20% worst days from Arkansas point sources, and from Independence in particular, are very small. We disagree that these visibility impacts are insignificant. As we discuss above, Entergy's CAMx source apportionment modeling showed that the contribution to visibility impairment due to emissions from the Independence facility alone are projected to be approximately 1.3% of the total visibility impairment during the 20% worst days in 2018 at each Arkansas Class I area. This is a large portion (approximately one-third) of the total contribution from all Arkansas point sources, and we consider this to be a significant contribution to visibility impairment. Entergy's CAMx modeling also showed that at Upper Buffalo, the Independence facility's contribution to visibility impairment is greater than the contribution from all of the subject-to-BART sources addressed in this final action combined. In terms of deciviews, the average impact from Independence over the 20% worst days, based on Entergy's CAMx modeling and adjusted to natural background conditions, is over 0.5 dv at the Arkansas Class I areas. The results from Entergy's CAMx modeling confirm and provide additional support to our determination that the source significantly impacts visibility at Arkansas' Class I areas and should be evaluated for controls under reasonable progress.

As discussed in our proposal and elsewhere in this final rule, we have found that dry scrubbers for SO_2 control are cost effective and are expected to provide significant visibility improvements to the facility's 98th percentile visibility impacts as shown by our CALPUFF modeling. We have also found that NO_X controls in the form of LNB/SOFA on Independence are very cost effective and are expected to provide considerable visibility improvements to the 98th percentile visibility impacts.

Based on Entergy's CAMx modeling, SO_2 emissions are responsible for a majority of the visibility impacts from Independence on the 20% worst days and NO_X emissions are responsible for 30–40% of the visibility impairment on 2 of the 20% worst days.[129] The controls we are requiring will significantly reduce SO_2 and NO_X emissions from Independence, and accordingly, we expect that they will also significantly reduce the significant visibility impacts from the facility on the 20% worst days. Therefore, we disagree that these controls are not necessary and/or that they would not improve visibility in Arkansas Class I areas. Based on our consideration of the four reasonable progress factors and of the visibility improvement of controls, we are

[127] 81 FR 296.

[128] See 77 FR at 14629.

[129] This means 2 out of the 21 days that are the 20% worst of the days with IMPROVE monitoring data.

requiring both SO_2 and NO_X controls for Independence Units 1 and 2 under the reasonable progress requirements.

Comment: The RPG and URP in the Arkansas Regional Haze SIP should be accepted as presented by the State since ADEQ's Five Year Progress Report SIP revision demonstrates that Arkansas is on track to achieve its RPGs and is below the URP glidepath. EPA's disapproval of the Arkansas Regional Haze SIP submitted to EPA in 2008 was not due to lack of reasonable progress to achieve visibility improvement or for missing the URP. It was disapproved primarily because the underlying emissions were based on presumptive limits and no BART evaluations had been conducted. EPA's proposed FIP and the controls for Independence only serve to achieve greater emissions reductions than in the Arkansas Regional Haze SIP. Therefore, EPA should not look beyond BART eligible units to achieve greater visibility improvements. EPA should not simply use the regional haze program as leverage to impose emissions reductions that have little benefit to the purpose of the rule to improve visibility.

Response: We disagree that we should accept Arkansas' RPGs as presented in the Arkansas Regional Haze SIP submitted to us in 2008. We partially approved and partially disapproved the Arkansas Regional Haze SIP in our final action published on March 12, 2012.[130] In that final action, we disapproved a large portion of the state's BART determinations, as well as the state established RPGs. We disapproved the state's RPGs because they were based on BART determinations that were not made in accordance with the CAA and Regional Haze regulations and also because in establishing the RPGs, the state did not conduct the reasonable progress analysis required under the CAA and § 51.308(d)(1). As discussed in a separate response, the state decided to forego an evaluation of the four statutory factors, stating that there was no need for such an evaluation since Arkansas' Class I areas are below the URP glidepath. In foregoing the reasonable progress analysis, the state did not demonstrate that the RPGs it established were a reflection of the amount of visibility improvement necessary to make reasonable progress. Our final action disapproving Arkansas' RPGs for Caney Creek and Upper Buffalo became effective on April 11, 2012. Any arguments upholding or suggesting that the state's RPGs are appropriate or adequate are outside the scope of this action.

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 two years unless we approve a SIP revision correcting the deficiencies before promulgating a FIP. To date, Arkansas has not submitted a SIP revision following our partial disapproval, and EPA is already past-due on its action per the statutory deadlines. In addition, EPA is under an August 31, 2016 court ordered deadline to either finalize a FIP or approve a SIP to address the regional haze requirements and the interstate visibility transport requirements. Therefore, the purpose of our FIP is to correct the deficiencies in the SIP and conduct the required analyses and establish emission limits in accordance with the CAA and the Regional Haze Rule. One of the required analyses we must conduct in this FIP is the consideration of the four statutory factors to determine if additional controls are needed to make reasonable progress. We discuss in a separate response that the reasonable progress requirements under CAA section 169A(g)(1) and our Regional Haze regulations at § 51.308(d)(1) cannot be satisfied by merely being below the URP glidepath and/or meeting the RPGs previously established by the state. The states or EPA in a FIP must conduct an analysis of the four statutory factors regardless of the Class I area's position on the URP glidepath. Based on our consideration of the four statutory factors and of the baseline visibility impacts from Independence and the visibility improvement of potential controls, we determined that reasonable controls for SO_2 and NO_X are available for Independence Units 1 and 2 that are cost effective and would result in a large amount of visibility improvement in Arkansas' Class I areas in terms of the 98th percentile impacts from the source. Additionally, as we discuss in section V.J of this final rule, CAMx source apportionment modeling submitted to us by Entergy during the comment period shows that Independence has significant visibility impacts in Arkansas' Class I areas on the 20% worst days, and further supports our decision to require controls for Independence under reasonable progress. Therefore, the claim that the SO_2 and NO_X controls we are requiring for Independence Units 1 and 2 only serve to achieve greater emissions reductions that have little benefit to the purpose of the Regional Haze Rule to improve visibility are incorrect. Because we have identified through our reasonable progress analysis that additional controls are reasonable, we are requiring these controls for Independence Units 1 and 2. We address elsewhere in this final rule and in the RTC document comments related to ADEQ's 5-year Progress Report SIP revision.

Comment: EPA's imposition of costly controls on BART-ineligible sources like the Independence plant, based only on what it claims is ''reasonable,'' is economically wasteful and effectively re-writes the definition of what sources are BART eligible. Under the regional haze program, BART controls may be imposed on (1) major stationary sources in 26 listed categories, (2) that existed on August 7, 1977, (3) but were not in operation prior to August 7, 1962, and (4) emit air pollutants ''which may reasonably be anticipated to cause or contribute to any impairment of visibility'' at Class I areas. Under the proposed rule, the first three of these statutory and regulatory criteria would be rendered a nullity. According to EPA, it may impose BART controls on any facility, regardless of when it was built or when it began operating, so long as EPA determines it to be ''reasonable.'' EPA has effectively adopted a presumption that at least some BART-ineligible sources should be subject to BART unless those pollution controls are cost prohibitive. Such a presumption ignores the statute and re-writes EPA's own regulations.

Response: We are requiring controls on Independence under the reasonable progress requirements, not under the BART requirements. Clean Air Act section 169A required us to promulgate regulations directing the States to revise their SIPs to include emission limits and other measures as necessary to make ''reasonable progress.'' [131] Congress defined reasonable progress based on the consideration of four statutory factors: The costs of compliance, the time necessary for compliance, the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements.[132] We commonly refer to our analysis of these four statutory factors as a reasonable progress analysis. Congress also directed EPA to promulgate regulations requiring BART for a specific universe of older sources, and again provided a set of statutory factors States must consider: The costs of compliance, the energy and nonair

[130] 77 FR 14604.

[131] CAA section 169A(b)(2).

[132] CAA section 169A(g)(1).

quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[133] We note that many of the factors that must be considered in a BART analysis must also be considered in the reasonable progress analysis. Therefore, some commenters may mistakenly believe that we are somehow stretching the BART analysis to impose BART controls on Independence Units 1 and 2. This is not the case. As discussed in our proposal and elsewhere in this final rule, in our reasonable progress analysis, we considered the reasonable progress statutory factors as well as the visibility improvement of potential controls. Although visibility is not one of the four mandatory factors explicitly listed for consideration under CAA section 169A(g)(1) or 40 CFR 51.308(d)(1)(i)(A), states and EPA have the option of considering the projected visibility benefits of controls in determining if the controls are necessary to make reasonable progress. We discuss this in more detail in our proposal and in our RTC document. Based on our analysis of the four statutory factors and consideration of the visibility improvement of controls, we have determined that there are SO_2 and NO_X controls available for Independence Units 1 and 2 that are cost-effective and would result in considerable visibility benefit at Arkansas' Class I areas, and are therefore requiring these controls under reasonable progress.

To the extent the commenter believes that we treated the Independence Plant as if it were subject to BART in performing a source-specific reasonable progress analysis, this is incorrect. As we discuss elsewhere in this section of the final rule, individual stationary sources may be subject to source-specific analysis when determining whether additional controls are necessary to make reasonable progress. To the extent the commenter believes that only sources subject to BART can be looked to for emission reductions to promote reasonable progress, this is incorrect. If that were the case, then States, or EPA acting as necessary in the place of a State, would have little to no room for additional progress and even less need for sequential planning periods to build on past progress.

Comment: Some commenters claim that we inappropriately took a ''cut and paste'' approach in estimating the cost of controls for Independence in our reasonable progress analysis.

Response: We explained in our FIP proposal that White Bluff and Independence are sister facilities with nearly identical units. We explained that we verified that the two plants are sister facilities by constructing a master spreadsheet that contains information concerning ownership, location, boiler type, environmental controls, and other pertinent information.[134] The cost of compliance is a factor that is required for consideration under both a BART and a reasonable progress analysis. Due to the similarities in the facilities and the identical requirement for consideration of the cost of controls under reasonable progress and BART, our use of the total annualized costs of controls on White Bluff Units 1 and 2 in our cost analysis for Independence Units 1 and 2 was a reasonable approach. We do note that we used actual emissions data from Independence Units 1 and 2 to estimate the emission reductions expected to take place from the controls we evaluated and to calculate the cost effectiveness ($/ton removed) of controls for Independence Units 1 and 2. Thus, the total annual cost of controls on Independence was the only aspect of our reasonable progress analysis where we relied on our cost analysis for White Bluff. Our consideration of the remaining reasonable progress factors (time necessary for compliance, energy and nonair quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources), as well as the visibility impacts of Independence and improvement due to controls on the facility, was specific to the Independence facility.[135] We modeled both the baseline visibility impacts from the Independence facility and the visibility benefit of controls using CALPUFF dispersion modeling. Based on our consideration of the four reasonable progress factors and the modeled visibility improvement of controls, we determined that reasonable controls for SO_2 and NO_X are available for Independence Units 1 and 2 that are cost effective and would result in a large amount of visibility improvement in Arkansas' Class I areas in terms of the 98th percentile impacts from the source.[136]

Comment: The CAA's regional haze program tasks states with making reasonable progress toward the elimination of man-made visibility impairment, for which EPA has set a goal of 2064 with required progress milestones. Accordingly, the CAA's regional haze program contemplates gradual visibility improvements along a ''glide path'' toward the 2064 goal. This program does not require immediate and costly reductions in the first planning period or any subsequent planning period that go beyond what is needed to make ''reasonable progress,'' as determined by a state based on its assessment of the four statutory factors. Thus, it neither requires nor authorizes the front-loading of extensive control requirements. Delaying consideration of controls on Independence until the next planning period is a more reasonable approach that would allow for the consideration of updated information, such as control equipment characteristics and costs, emissions reductions attributable to other regulatory and market drivers, and contemporaneous monitoring and meteorological conditions, which would allow the coordination of these important investment and regulatory decisions with the implementation of other pending regulations. This approach would also give states and regulated entities the opportunity to conduct integrated compliance planning in ways that are consistent with provision of reliable and affordable electric power. EPA should withdraw its proposed controls for Independence Units 1 and 2.

Response: We agree that the regional haze program contemplates gradual visibility improvements over several planning periods. Those gradual improvements are guided by the principle that controls found to be reasonable in a given planning period should be required now, rather than in some unspecified future planning period. That is the very nature of ''reasonable progress.'' For that reason, we do not consider the controls we proposed and those we finalize in this action as being frontloading. As we discuss in several sections throughout this final rule, our cost analysis indicates that the SO_2 and NO_X controls we are requiring for Independence Units 1 and 2 are cost effective and well within the range of cost of controls found to be reasonable by EPA and the

[133] CAA section 169A(b)(2)(A), (g)(2).

[134] 80 FR at 18992.

[135] 80 FR at 18996.

[136] Entergy Arkansas Inc. submitted CAMx source apportionment modeling during the comment period. This modeling shows that Independence has significant visibility impacts in Arkansas Class I areas on the 20% worst days, and further supports our decision to require controls for Independence under reasonable progress. We discuss Entergy Arkansas Inc.'s photochemical modeling and the visibility impacts due to SO_2 and NO_X from Independence on the 20% worst days elsewhere in this final rule and in our RTC document.

states in other regional haze actions for this first planning period. Arkansas did not comply with certain aspects of the Regional Haze Rule and thus portions of its Regional Haze SIP submitted to us in 2008 were not approvable, including the state's reasonable progress determinations and RPGs.[137] We therefore have an obligation to promulgate this FIP to address the disapproved portions of the State's SIP submission. Pursuant to CAA section 169A(g)(1) and our Regional Haze regulations at § 51.308(d)(i)(A), we conducted an evaluation of additional controls under a reasonable progress analysis that considered the four statutory factors. As discussed in our proposal and throughout this final rule, based on the demonstrations we developed pursuant to the CAA and § 51.308(d)(1) and our consideration of the visibility impacts from Independence and the visibility improvement of potential controls, we determined that there are reasonable and cost-effective SO_2 and NO_X controls available for Independence that would result in considerable visibility benefit at Arkansas' Class I areas. Under the CAA and the Regional Haze regulations, if we determine that additional controls are reasonable based on the consideration of the four statutory factors, we must require those controls. Therefore, we are requiring SO_2 and NO_X controls for Independence Units 1 and 2 under reasonable progress.

Comment: EPA applied dollar per ton cost-effectiveness estimates and visibility improvement rates for the proposed controls on Independence that are out of line with the standards applied in other regional haze actions. Specifically, EPA's proposal attempts to justify a cost-effectiveness of dry FGD at Independence Plant totaling $2,477/$SO_2$ ton removed for Unit 1 and $2,686/$SO_2$ ton removed for Unit 2. This far exceeds the cost-effectiveness standards reviewed and approved by EPA for the Kentucky[138] and North Carolina Regional Haze SIPs.[139] In its approval of the Kentucky Regional Haze SIP, EPA approved the use of a $2,000 per ton SO_2 screening threshold. In its approval of the North Carolina Regional Haze SIP, EPA approved the state's decision not to implement additional controls under reasonable progress despite the finding that there are potential controls with cost effectiveness ranging from $912 to $1,922 per ton of SO_2 removed. EPA's proposed controls for Independence are inconsistent with these other regional haze actions.

Response: In response to comments we received during the comment period, we have revised our cost analysis for SO_2 controls for Independence and estimate that these controls cost $2,853/$SO_2$ ton removed for Unit 1 and $2,634/$SO_2$ ton removed for Unit 2. Although slightly higher than the cost effectiveness estimates we presented in our proposal, we continue to consider these controls to be cost effective and well within the range of cost of controls found to be reasonable by EPA and the states in other regional haze actions. We disagree with the statement that our proposal to require SO_2 controls for Independence is inconsistent with our approvals of the Kentucky and North Carolina Regional Haze SIPs. Additionally, the factual contexts of both of these actions are easily distinguished from context in which we assessed potential reasonable progress controls for Independence.

The commenter contends that in our proposed approval of the Kentucky Regional Haze SIP, we approved the state's use of a $2,000/$SO_2$ ton threshold. This is incorrect. In the preamble of our proposed approval of the Kentucky Regional Haze SIP, we discussed that the state identified 10 units for evaluation under reasonable progress, and that 9 of these were EGUs subject to CAIR. The remaining facility, Century Aluminum, is not an EGU. We further discussed that for the limited purpose of evaluating the cost of compliance for the reasonable progress assessment in this first regional haze SIP for the non-EGU Century Aluminum, Kentucky concluded that it was not equitable to require non-EGUs to bear a greater economic burden than EGUs for a given control strategy. As a result, Kentucky decided to use CAIR as a guide, using a cost of $2,000/ton of SO_2 reduced as a threshold for cost-effectiveness for that particular non-EGU source. Kentucky found that the cost effectiveness of the SO_2 control as suggested by the VISTAS control cost spreadsheet for potlines 1–4 at Century Aluminum is $14,207/ton of SO_2 removed. The State thus concluded that, based on the high cost on a $/ton basis, there are no cost-effective SO_2 reasonable progress controls available for the Century Aluminum units for the first implementation period. We proposed to approve Kentucky's determination, but we also stated the following concerning our position on Kentucky's use of a $2,000/$SO_2$ ton threshold:

> Although the use of a specific threshold for assessing costs means that a state may not fully consider available emissions reduction measures above its threshold that would result in meaningful visibility improvement, EPA believes that the Kentucky SIP still ensures reasonable progress. In proposing to approve Kentucky's reasonable progress analysis, EPA is placing great weight on the fact that there is no indication in the SIP submittal that Kentucky, as a result of using a specific cost effectiveness threshold, rejected potential reasonable progress measures that would have had a meaningful impact on visibility in its Class I area.[140]

It is clear in our proposed approval that we were not approving or otherwise advocating Kentucky's use of a $2,000/$SO_2$ ton threshold in the reasonable progress analysis. On the contrary, we expressed concern that the use of a specific threshold for assessing cost may result in a state not fully considering potential reasonable control measures above that threshold that would have meaningful visibility improvement on its Class I areas. Furthermore, our statements in the proposal indicate that had there been evidence of more affordable controls available above the $2,000/$SO_2$ ton threshold used by the state that provide meaningful visibility improvement at the Class I areas, we might have arrived at a different decision concerning the approvability of Kentucky's reasonable progress analysis for SO_2.

North Carolina took a similar approach to that of Kentucky in its SO_2 reasonable progress analysis by relying on a cost threshold when deciding on measures for its non-EGUs. North Carolina set this threshold based on the estimated cost of compliance with its Clean Smokestacks Act, a law establishing a state-wide cap on SO_2 and NO_X emissions from the State's two major utilities. In our proposed approval of the North Carolina Regional Haze SIP, we discussed that the state identified 11 units (non-EGU) for evaluation. We noted that North Carolina decided that for the limited purpose of evaluating the cost of compliance for non-EGUs in the SO_2 reasonable progress assessment for the first implementation period, it was not equitable to require non-EGUs to bear a greater economic burden than EGUs for a given control strategy and therefore also used a cost-effectiveness threshold for its non-EGUs. North Carolina's threshold was based on ''[t]he facility-by-facility cost for EGUs under [the Clean Smokestacks Act which] ranged from 912 to 1,922 dollars per ton of SO_2 removed,'' a statement which the commenters appear to have misinterpreted to mean that North

[137] 77 FR 14604.

[138] 76 FR 78194, 78206 (December 16, 2011).

[139] 77 FR 11858, 11870 (February 28, 2012).

[140] 76 FR at 78206.

Carolina rejected potential reasonable progress measures with costs falling within this range.[141] Rather, upon conducting cost evaluations for the non-EGUs and determining that the costs of controls exceeded its threshold, North Carolina concluded that there were no cost-effective reasonable progress SO_2 controls available for the first implementation period. We proposed to approve North Carolina's determination, but we also stated the following concerning our position on North Carolina's use of a specific cost-effectiveness threshold:

> Although the use of a specific threshold for assessing costs means that a state may not fully consider available emissions reduction measures above its threshold that would result in meaningful visibility improvement, EPA believes that the North Carolina SIP still ensures reasonable progress. In proposing to approve North Carolina's reasonable progress analysis, EPA is placing great weight on the fact that there is no indication in the SIP submittal that North Carolina, as a result of using a specific cost effectiveness threshold, rejected potential reasonable progress measures that would have had a meaningful impact on visibility in its Class I areas.[142]

As in the case of Kentucky, it is clear that in our proposed approval of North Carolina's reasonable progress determination, we were not approving or otherwise advocating North Carolina's use of that specific cost-effectiveness threshold in the reasonable progress analysis. Therefore, we disagree that our requirement of SO_2 controls for Independence Units 1 and 2 under reasonable progress is inconsistent with our actions on the Kentucky and North Carolina Regional Haze SIPs.

Comment: EPA's decision to evaluate and propose NO_X controls at the Independence Plant stands completely opposite its decision not to even evaluate similar controls for Texas' point sources despite similar visibility conditions. EPA elected not to evaluate Texas point sources for NO_X controls because modeling suggested that impacts from the sources on the 20% worst days were ''primarily due to sulfate emissions.'' [143] In Arkansas, EPA was even more explicit in stating that ''visibility impairment is not projected to be significantly impacted by nitrate on the 20% worst days at Caney Creek or Upper Buffalo.'' [144] However, the agency nevertheless evaluated and proposed NO_X controls for the Independence Plant Units 1 and 2. The arbitrary nature of this aspect of EPA's proposal is further evidenced by the low projection for anticipated visibility improvement due to the NO_X controls. For instance, EPA rejected installation of SCR controls under reasonable progress where it was projected to result in 0.41 dv improvement at affected Class I areas in the Arizona Regional Haze FIP proposal, whereas it is proposing to require NO_X controls on Independence that are projected to result in visibility improvement of 0.461 dv in the Arkansas Regional Haze FIP proposal.

Response: This comment, and our response to it, illustrate the very fact-specific nature of individual evaluations and decisions under the regional haze program. It is critical to understand the full context of each decision. In each one, the EPA applies the requirements of the statute and regulations in a consistent manner, but the different facts—unique to each state and facility—inevitably lead to different outcomes. We agree that in our Texas FIP action we noted that on the 20% worst days, the impacts from the EGUs we evaluated under reasonable progress were primarily due to sulfate emissions. We also agree that in our Arkansas FIP proposal we acknowledged that the CENRAP modeling demonstrates that sulfate is the primary driver of regional haze in Arkansas' Class I areas on the 20% worst days. This does not mean that NO_X is not a key pollutant contributing to regional haze impairment in both states. For instance, the CENRAP CAMx modeling shows that total extinction at Caney Creek is dominated by nitrate on 4 of the days that comprise the 20% worst days in 2002, and a significant portion of the total extinction at Upper Buffalo on 2 of the days that comprise the 20% worst days in 2002 is due to nitrate.[145]

As a key pollutant, we considered NO_X controls under reasonable progress in both Texas and Arkansas. In our Texas FIP, we considered NO_X controls under reasonable progress for the Works No. 4 Glass Plant but ultimately did not require those controls based on the emission reductions already occurring at the facility, the anticipated lifetime of the furnaces, and the fact that Furnace No. 2 had undergone rebricking within the past few years. Although we determined it was reasonable to not require additional controls for Works No. 4 Glass Plant at this time, we encouraged Texas to consider additional controls when Furnace No. 2 is scheduled for its next rebricking. We also found that in Texas all the EGUs that we evaluated for controls under reasonable progress had existing LNB for control of NO_X emissions. This is in contrast to Independence, which is the second largest source of NO_X point source emissions in Arkansas and is not currently equipped with any NO_X controls. As such, Independence was a more compelling candidate for evaluation of NO_X controls than were the EGUs in Texas that we evaluated for controls under reasonable progress.

As NO_X is a visibility impairing pollutant and Independence is responsible for a very large portion of the point source NO_X emissions in the state (approximately 21.3%),[146] we determined that it was reasonable to evaluate NO_X controls under reasonable progress in our Arkansas FIP proposal. We conducted CALPUFF modeling and found that the Independence Plant has significant visibility impacts in Arkansas' Class I areas due to NO_X emissions based on the 98th percentile visibility impacts from the facility, and also found that LNB/SOFA would improve these visibility impacts.[147] We also found that LNB/SOFA is very cost effective ($401/ton removed for Unit 1 and $436/ton removed for Unit 2). For these reasons, we proposed LNB/SOFA for Independence Units 1 and 2 under Option 1. In addition, we discuss in more detail elsewhere in this final rule and in our RTC document that Entergy submitted CAMx photochemical modeling during the public comment period showing that nitrate from Independence is responsible for 30–40% of the visibility impairment in Arkansas' Class I areas on 2 out of the 20% worst days in 2018. We expect that the installation of NO_X controls at Independence, which we found to be very cost effective, would provide visibility improvement on this portion of the 20% worst days, thereby assuring reasonable progress toward the goal of natural visibility conditions. Based on

[141] 77 FR at 11870.

[142] 77 FR 11858, 11872.

[143] 79 FR 74818, 74873 (December 16, 2014).

[144] 80 FR at 18966.

[145] See Arkansas Regional Haze SIP, Appendix 8.1— ''Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans,'' section 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas Regional Haze SIP.

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

[147] Although the reasonable progress provisions of the Regional Haze Rule place emphasis on the 20% worst days, the CAA goal of remedying visibility impairment due to anthropogenic emissions encompasses all days. Thus, states and EPA have the discretion to consider the visibility impacts of sources and the visibility benefit of controls on days other than the 20% worst days in making their decisions, such as the days on which a given facility has its own largest (98th percentile) impacts. Because Independence has significant 98th percentile visibility impacts, these impacts will need to be addressed to achieve the CAA goal of remedying visibility impairment due to anthropogenic emissions.

our consideration of the four statutory factors and the visibility improvement available from controls, we have determined that there are reasonable NO_X controls available for Independence that are cost effective and would result in considerable visibility improvement. Therefore, we are requiring these controls.

We disagree that our decision to require NO_X controls for Independence is inconsistent with our Arizona FIP proposal. In that action, we proposed that neither SCR nor SNCR was required to achieve reasonable progress for Springerville Units 1 and 2 in this regional haze planning period because:

> [w]hile the cost per ton for SNCR may be reasonable, the projected visibility benefits are relatively small (0.18 dv at the most affected area). The projected visibility benefits of SCR are larger (0.41 dv at the most affected area), but we do not consider them sufficient to warrant the relatively high cost of controls for purposes of RP in this planning period. However, these units should be considered for additional NO_X controls in future planning periods.[148]

The ''relatively high cost'' of SCR controls we refer to in that statement is $6,829/ton NO_X removed for Springerville Unit 1 and $6,085/ton NO_X removed for Springerville Units 2.[149] Thus, our decision to not propose SCR at Springerville Units 1 and 2 was not because we considered the visibility benefits to be too small, as the commenter appears to believe. Instead, it was because we determined that, under these circumstances, this level of visibility improvement was not sufficient to warrant the cost per ton of emissions reduced. In contrast, we found that the cost of LNB/SOFA at Independence Units 1 and 2 is significantly lower ($401/ton removed for Unit 1 and $436/ton removed for Unit 2), and we determined that 0.459 dv visibility improvement on a facility wide basis warranted the cost of these controls. Therefore, we disagree that the NO_X controls we proposed and are finalizing in this action for Independence Units 1 and 2 in any way contradict our proposed Arizona Regional Haze FIP.

Comment: The overarching requirement of the CAA's haze provisions is for each state's plan to include ''emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress.'' CAA section 169A(b)(2). The statute defines reasonable progress to account for four factors: The cost of controls, the time needed to install controls, energy and nonair quality environmental impacts of controls, and the remaining useful life of the source. CAA section 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A). EPA's implementing regulations require each state with a Class I area to set an RPG for each area within its borders based on considering the four statutory factors for reasonable progress. Each state must also determine the uniform rate of progress. If a state sets a reasonable progress goal that provides for less progress than the URP, the state must demonstrate that achieving the URP is unreasonable and that its alternative goal is reasonable. Moreover, each state must consult with other states that contribute to haze in the host state's Class I areas. Neither the statute nor the regulations exempts states from the required reasonable progress analysis merely because a Class I area is on the glidepath to achieving the URP. To the contrary, EPA's long-standing interpretation of the regional haze rule is that ''the URP does not establish a 'safe harbor' for the state in setting its progress goals.'' [150] If it is reasonable to make more progress than the URP, a state must do so, as EPA explained in the 1999 Regional Haze Rule.[151] Having disapproved Arkansas' regional haze plan, EPA has an obligation to conduct a reasonable progress analysis for Caney Creek and Upper Buffalo based on a consideration of the four statutory factors for reasonable progress. 40 CFR 51.308(d)(1).

Response: We agree with this comment with regard to our obligation to conduct a reasonable progress analysis for sources in Arkansas regardless of the Class I areas' position on the URP glidepath.

D. Control Levels and Emission Limits

Comment: Assuming EPA proceeds with BART for the Ashdown Mill, EPA should revise the proposed SO_2 limit for Power Boiler 2 from 0.11 lb/MMBTU to 155 lb/hr on a 30-day boiler operating day. There are a number of concerns with EPA's proposed limit of 0.11 lb/MMBTU: It is too stringent, it is based on the use of an inappropriate baseline (2011–2013), and assumes the existing control equipment can continuously operate at the upper range of its capability (90% efficiency) over long periods of time, without supporting data or other documentation. First, in the methodology to calculate the proposed BART limit, EPA used data from 2011–2013 for determining the proposed BART limit, instead of using 2001–2003 as the baseline. No justification is given for not using 2001–2003 as the baseline, or why the particular years EPA selected are better than the BART baseline years or legally appropriate. Deviating from the 2001–2003 BART baseline is appropriate if significant changes were made to the emission units or permit conditions were imposed that prevent a unit from operating at the BART baseline emission value. However, this is not the case for Power Boiler 2. The BART 2001–2003 baseline information is representative of Power Boiler 2's potential operations. The fact that the Ashdown Mill voluntarily elected to operate at a lower SO_2 level subsequent to the 2001–2003 baseline period is not relevant. Moreover, by not utilizing the BART 2001–2003 baseline actual emissions in establishing the proposed BART SO_2 limit, EPA penalizes the Ashdown Mill for its voluntary SO_2 emission reductions undertaken on its own initiative since the BART baseline period. Here, the mill voluntarily reduced SO_2 emissions by over 40% since the BART baseline years prior to the proposed BART requirements. Using the actual emission data from the BART baseline period of 2001–2003, gives the mill credit for its early voluntary action. Second, EPA wrongly applied the maximum rated heat input capacity of 820 MMBTU/hr when it converted from a lb/hr limit to a lb/MMBTU limit. The use of the maximum heat input rating is not representative of average (typical) boiler operating conditions, which are lower than the maximum heat input capability. The actual average heat input during the 2001–2003 baseline period is 586 MMBTU/hr. In this situation, the use of actual emission data and maximum rated heat input to calculate the proposed SO_2 BART limit is inappropriate and an inaccurate methodology which creates significant concerns. EPA should instead establish an SO_2 emission limit in terms of lb/hr. Third, based on monthly SO_2 information for the 2011–2013 period, EPA estimated that the SO_2 control efficiency for the existing scrubber on Power Boiler 2 to be approximately 69% and that the existing scrubber may achieve on a short-term basis an SO_2 control efficiency of 90%. However, there is no documentation showing that the scrubber can sustain this maximum performance level on a long term basis. EPA should revise the methodology for calculating the SO_2 BART emission limit for Power Boiler No. 2 by using 2001–2003 actual emissions as the baseline; assuming the existing scrubbers operated at a 69% control efficiency during the 2001–2003

[148] 79 FR 9318, 9360 (February 18, 2014).

[149] 79 FR 9318, 9359.

[150] 79 FR 74818, 74834.

[151] 64 FR at 35714, 35732.

baseline period; calculating an SO_2 emission limit in lb/hr based on 2001–2003 baseline actual emissions and a 90% control efficiency. Based on this approach, EPA should revise the proposed SO_2 limit for Power Boiler 2 from 0.11 lb/MMBTU to 155 lb/hr on a 30-day boiler operating day.

Response: We disagree that an emission limit of in an emission limit of 155 lb/hr on a 30 boiler-operating-day satisfies the SO_2 BART requirement for Power Boiler No. 2. As discussed in our proposal, we requested information from the facility to determine if upgrades to the existing scrubbers are technically feasible and if they would be cost effective and provide meaningful visibility benefit. This assessment first required us to determine the current control efficiency of the scrubbers. Because our BART analysis involved determining the current control efficiency of the existing scrubbers, we found that the most reasonable approach was to use data that reflect the current control efficiency of the existing scrubbers, as opposed to 2001–2003 data. In order to conduct our BART analysis, we requested 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.[152] These were the three most recent full calendar years of data available at the time we conducted our BART analysis. For these reasons, our use of 2011–2013 as the baseline for calculating the current control efficiency of the existing scrubbers and our proposed SO_2 BART limit for Power Boiler No. 2 was appropriate and justified. As discussed in detail in our proposal, based on the emissions data and fuel usage data Domtar provided to us, we estimated that the current control efficiency of the existing scrubbers is approximately 69% based on 2011–2013 data.[153] The data also indicated that the existing scrubbers could achieve up to 90% removal efficiency. As discussed in our proposal, Domtar indicated that the scrubbers are currently operated in a manner that allows for compliance with permitted emission limits.[154] In other words, the facility generally uses only the amount of scrubbing solution needed to comply with permitted emission limits. The information the facility provided indicated that it would be possible to add more scrubbing solution to achieve greater SO_2 removal than required to meet the boiler's existing SO_2 permit limit; specifically, the information indicated that additional scrubbing reagent can be added to increase the control efficiency of the existing scrubbers to 90%.[155]

We agree that we applied the boiler's maximum heat input rating of 820 MMBtu/hr when we calculated our proposed limit of 0.11 lb/MMBtu, and based on information provided by the commenter, we acknowledge that use of the maximum heat input rating is not representative of average (typical) boiler operating conditions. To address the commenter's concern, we are finalizing an SO_2 BART limit for Power Boiler No. 2 in terms of lb/hr. As we discussed in our proposal, based on the emissions data we obtained from Domtar, we determined that the No. 2 Power Boiler's annual average SO_2 emission rate for the years 2011–2013 was 280.9 lb/hr.[156] 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 to this emission rate results in a controlled emission rate of 91.5 lb/hr.[157] We recognize that the boiler's SO_2 emissions are currently lower than they were in the 2001–2003 period, and that had we used 2001–2003 data to calculate the current control efficiency and SO_2 BART emission limit, as the commenter requests, this would have resulted in a less stringent emission limit. However, as discussed above, the most reasonable approach is to use recent data in our calculation of an appropriate SO_2 BART emission limit.

As Domtar is requesting an emission limit in terms of lb/hr, we are finalizing for SO_2 BART for Power Boiler No. 2 an emission limit of 91.5 lb/hr on a 30 boiler operating day. We believe this emission limit reflects operation of the scrubbers at 90% control efficiency and addresses the SO_2 BART requirement for Power Boiler No. 2.

We believe it reasonable to set the emission limit using baseline emissions resulting from recent/current fuels. Given that we don't find it appropriate to use emissions from the 2001–2003 period to calculate the SO_2 emission limit, the control efficiency from that period is irrelevant. What is relevant are the current uncontrolled SO_2 emissions and the possible control efficiency of the existing scrubbers, which is what we considered in our BART analysis. We found in our analysis that during the 2011–2013 period, the company was able to achieve an average monthly control efficiency of 90% and find that this level of control is reasonable, and can be achieved by the use of sufficient reagent to achieve the lower level. We also note that the commenter did not provide additional information to support the claim that the existing scrubbers cannot consistently achieve the level of control efficiency necessary to meet an emission limit of 91.5 lb/hr.

Comment: The NO_X emission limits proposed for the units at White Bluff and Independence are based on the emission rate for LNB/SOFA of 0.15 lb/MMBtu that Entergy proposed in the Revised White Bluff BART Analysis. At the time Entergy submitted the Revised White Bluff BART Analysis in October 2013, which EPA relied on in developing its FIP proposal, all four of the coal-fired units at White Bluff and Independence were operated as base load units and spent the overwhelming majority of their operating time at loads of greater than 50% of unit capacity. Since submitting the Revised White Bluff BART Analysis, Entergy transitioned to MISO in December 2013. MISO utilizes an economic dispatch model to determine which EGUs within its service territory are dispatched to operate and the operating load (MW) for each unit. Beginning in December 2014, the units at both White Bluff and Independence began to be dispatched primarily as load-following units. Since December 2014, the White Bluff and Independence units have been dispatched less frequently and, when dispatched, have spent significantly more time at low operating rates of less than 50% of unit capacity. The data for 2015 (through June 30) reflects a significant increase in the percentage of time that each unit is dispatched at less

[152] See 80 FR at 18984. See also 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.

[153] See 80 FR at 18984. See also 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.

[154] 80 FR at 18983, 18984.

[155] 80 FR at 18984.

[156] See 80 FR at 18984. See also 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 our rulemaking.

[157] See 80 FR at 18984. See also 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 our rulemaking.

than 50% of operating capacity. Three of the four units have spent greater than 40% of their 2015 operating hours at less than 50% of capacity, and the two Independence units have spent nearly half of their operating time at less than 50% of capacity. This change in dispatch coincided with a sharp drop in natural gas prices. This drop in gas prices to near $3 per MMBtu has been sustained since December 2014, and Entergy has no reason to expect any significant increase in gas pricing in the near future. This change in dispatch for the units at both White Bluff and Independence is significant with regard to NO_X emissions as the LNB/SOFA system is designed to operate primarily in the range of 50–100% of unit load. Entergy has selected Foster Wheeler as the LNB/SOFA vendor for White Bluff and has only been able to obtain a guarantee of less than 0.15 lb/MMBtu for operating loads in the range of 50–100% of unit capacity. Since the available emission guarantee does not cover unit operation at less than 50% of capacity, Entergy requested a memorandum from Foster Wheeler regarding the impact of unit operation at less than 50% capacity on NO_X emission rates. Based on input from the LNB/SOFA vendor, Entergy does not believe that the proposed emission rate of 0.15 lb/MMBtu is consistently achievable under all operating conditions. Even with a 30-day averaging period for the proposed limit, a unit which is frequently dispatched at less than 50% of capacity may not be able to achieve compliance. This was not perceived as an issue at the time that the Revised White Bluff BART Analysis was prepared and submitted to ADEQ by Entergy as, historically and at that time, the units were operated almost exclusively as base-load units and spent less than 10% of their operating time at less than 50% of unit capacity. In the current dispatch environment, with some units spending nearly 50% of their operating time outside of the control range for LNB/SOFA, Entergy can no longer be confident that the units will be able to achieve compliance with a limit of 0.15 lb/MMBtu on a 30-day rolling average basis. The concern arises from low-load operation during which periods of higher NO_X emissions, on a lb/MMBtu basis, would not be expected to correspond to an increase in the maximum mass emission rate (lb/hr) from the units as any increase in the emission rate on a lb/MMBtu basis would be expected to be more than offset by the lower unit operating rate in MMBtu/hr to arrive at a mass emission rate (lb/hr).

To address the potential for a higher NO_X emission rate (lb/MMBtu basis) at operating rates of less than 50% of unit capacity, Entergy proposes a rolling 30-boiler operating day average emission rate of 1,342.5 lb NO_X/hr at each coal-fired unit at White Bluff and Independence. In the alternative, if EPA believes that a lb/MMBtu limit is necessary for the units, Entergy proposes a bifurcated NO_X emission limit for each unit at both White Bluff and Independence as follows: (1) For all unit operation (0–100% of capacity) require an emission limit of 1,342.5 lb NO_X/hr, based on a rolling 30-boiler operating day average; and (2) for unit operation at 50–100% of capacity, require an emission limit of 0.15 lb NO_X/MMBtu, based on a rolling 30-boiler operating day average, to include only those hours for which the unit was dispatched at 50% or greater of maximum capacity. This alternative approach would ensure that the units are operated in compliance with the LNB/SOFA design within the control range of 50–100% of capacity while providing Entergy with flexibility in demonstrating compliance. The lb/hr limit, which would apply to all operating hours, will ensure that the 30-day average emission rates remain below those on which both EPA and Entergy relied to project visibility improvements from the proposed NO_X emission reductions.

Response: We acknowledge the information provided by the commenter. We understand the commenter's concerns that because of recent changes in dispatch of the units, White Bluff Units 1 and 2 and Independence Units 1 and 2 are no longer expected to be able to consistently meet our proposed NO_X emission limit of 0.15 lb/MMBtu over a 30-boiler-operating-day period based on LNB/SOFA controls. We believe the commenter has provided sufficient information to substantiate that the units are not expected to be able to meet our proposed NO_X emission limit of 0.15 lb/MMBtu when the units are primarily operated at less than 50% of their operating capacity. In particular, the information provided by the commenter indicates that LNB/SOFA achieves optimal NO_X control when the boiler is operated from 50 to 100% steam flow because the heat input across this range is sufficient to safely redirect a substantial portion of combustion air through the overfire air registers.[158] This allows the combustion zone airflow to be sub-stoichiometric and oxygen to be reduced to the point where much of the elemental nitrogen in the fuel and combustion air can pass through the boiler without oxidizing (*i.e.,* converting to NO_X). When a boiler is operated below the 50 to 100% capacity range, NO_X concentrations on a lb/MMBtu basis can be elevated due to the lower heat input rating, even though the pounds of NO_X emitted (*i.e.,* on a mass basis) is less due to the reduced amount of fuel and air. In light of the information provided by the commenter, we believe it is appropriate to promulgate a bifurcated NO_X emission limit for each unit, as suggested by the commenter.

Therefore, in this FIP we are requiring White Bluff Units 1 and 2 and Independence Units 1 and 2 to each meet a NO_X emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average, where the average is to be calculated by including only the hours during which the unit was dispatched at 50% or greater of maximum capacity, as requested by the commenter. Specifically, the 30 boiler-operating-day rolling average is to be calculated for each unit by the following procedure: (1) Summing the total pounds of NO_X emitted during the current boiler-operating-day and the preceding 29 boiler-operating-days, including only emissions during hours when the unit was dispatched at 50% or greater of maximum capacity; (2) summing the total heat input in MMBtu to the unit during the current boiler-operating-day and the preceding 29 boiler-operating-days, including only the heat input during hours when the unit was dispatched at 50% or greater of maximum capacity; and (3) dividing the total pounds of NO_X emitted as calculated in step 1 by the total heat input to the unit as calculated in step 2. In addition to this limit that is intended to control NO_X emissions when the units are operated at 50% or greater of maximum capacity, we are establishing a limit in lb/hr for periods in which the units are operated at less than 50% capacity. However, the 1,342.5 lb/hr emission limit suggested by the commenter is too high to appropriately control NO_X emissions when the units are operated at low capacities. There is no indication in the comments submitted that the 1,342.5 lb/hr emission limit suggested by the

[158] See comments submitted during the comment period by Entergy Arkansas Inc., including Exhibit G to Entergy's comments. These and all other comments and associated attachments submitted during the public comment period are found in the docket associated with this rulemaking.

commenter was based on a vendor guarantee. The commenter did not explain how the 1,342.5 lb/hr limit was calculated, but it appears that it was calculated by multiplying the 0.15 lb/MMBtu limit by the maximum heat input rating for each unit (8,950 MMBtu/hr), which yielded 1,342.5 lb/hr. An emission limit of 1,342.5 lb/hr would be appropriate when the unit is operated at high capacities considering that the limit was calculated based on the unit's maximum heat input rating. However, such an emission limit would not be sufficiently protective or appropriate when the unit is operated at lower capacities when it is expected that NO_X emissions on a mass basis would be lower compared to operation at high capacity. To address this concern, we have calculated a new emission limit of 671 lb/hr that is based on 50% of the unit's maximum heat input rating, and is applicable only when the unit is being operated at less than 50% of the unit's maximum heat input rating. We calculated this limit by multiplying 0.15 lb/MMBtu by 50% of the maximum heat input rating for each unit (*i.e.,* 50% of 8,950 MMBtu/hr, or 4,475 MMBtu/hr). This limit is on a rolling 3-hour average, where the average is to be calculated by including emissions only from the hours during which the unit was operated at less than 50% of the unit's maximum heat input rating (*i.e.,* hours when the heat input to the unit is less than 4,475 MMBtu). We are not establishing a lb/hr emission limit that applies when the units are operated at 50% or greater of the unit's maximum heat input rating because there is no need for it since the 0.15 lb/MMBtu limit will address NO_X emission during those operating conditions.

As such, we are requiring White Bluff Units 1 and 2 and Independence Units 1 and 2 to each meet a NO_X emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average, where the average is to be calculated by including only the hours during which the unit was dispatched at 50% or greater of maximum capacity, as requested by the commenter. In addition, we are requiring White Bluff Units 1 and 2 and Independence Units 1 and 2 to each meet a NO_X emission limit of 671 lb/hr on a rolling 3-hour average that applies only to the hours when the unit is operated at less than 50% of the unit's maximum heat input rating. We believe that these limits address the commenter's concern of not being able to meet the lb/MMBtu emission limit when the unit is being operated at lower capacities, and will also ensure that NO_X emissions are appropriately controlled when the units are operated at higher capacities, as well as when they are operated at lower capacities.

Comment: Assuming EPA proceeds with BART for the Domtar Ashdown Mill, the mill conceptually agrees with the proposed BART SO_2 limit for Power Boiler 1 of 21.0 lb/hr on a 30-day averaging basis with no add-on control. However, based on the methodology the mill uses to determine fuel usage, the emission limit needs to be expressed in an alternative form to better match with the compliance averaging time of 30 days. Calculation of hourly SO_2 emissions using hourly fuel usage information is not a workable approach for Power Boiler 1, where the facility's practice is to use monthly fuel usage information that is reconciled at the end of each month based on fuel inventory records. Records of daily fuel usage may be adjusted at the end of the month as part of the reconciliation process. Therefore, Domtar requests the BART limit of 21.0 lb/hr be expressed as 504 lb/day.

Response: After carefully considering this comment we have determined that Domtar's request for an SO_2 BART emission limit in terms of lb/day is reasonable. An emission limit in terms of lb/day will be better suited for the mill's methodology of using monthly fuel throughput information. Therefore, as requested by the facility, we are finalizing an SO_2 BART emission limit of 504 lb/day for Power Boiler No. 1.

E. Domtar Ashdown Mill Repurposing Project

Comment: The Domtar Ashdown Mill is in the process of re-purposing and is in a state of transition. Once the re-purposing and re-configuration is complete and the mill is fully operational, the mill will need to decide if Power Boiler 1 will continue with full or intermittent operation, and if so what fuels will be used, or will be retired. If the boiler is fuel switched to natural gas or the boiler retired, the SO_2 BART limit will be unnecessary along with the associated monitoring, recordkeeping and reporting requirements for the SO_2 BART limit. The Ashdown Mill is requesting EPA include in the FIP final rule an alternate compliance option that removes all of SO_2 BART related requirements for Power Boiler 1 if this boiler is switched to burn only natural gas. If Power Boiler 1 is switched to burn only natural gas, requirements for NOx testing also need to be removed and an alternate NO_X BART compliance option needs to be developed to allow compliance to be based on the use of AP–42 emission factors and fuel use records. If Power Boiler 1 is retired, there is no need to retain the SO_2 and NO_X BART limits and associated requirements, and an alternate BART compliance option should address this retirement scenario as well.

Response: We proposed an SO_2 BART emission limit of 21.0 lb/hr for Power Boiler No. 1. As discussed in section IV. of this final rule, we are finalizing an emission limit in terms of lb/day, as requested by Domtar. We proposed to find that to demonstrate compliance with this SO_2 BART emission limit, the facility was required to use a site-specific curve equation (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.[159] We also proposed to find that to calculate the SO_2 emissions from Power Boiler No. 1 when combusting fuel oil, the facility must assume that the SO_2 inlet is equal to the SO_2 being emitted at the stack.[160] In our proposal we invited public comment specifically on the issue of whether our proposed method of demonstrating compliance is appropriate.

We note that we became aware that Power Boiler No. 1 wished to burn only natural gas after the end of the comment period for our proposal, and that the facility has submitted a permit renewal application to ADEQ that will reflect this enforceable change.[161] We do not agree that the SO_2 BART emission limit becomes ''unnecessary'' when a unit is switched to burn only natural gas. The Regional Haze regulations define BART as an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility.[162] Therefore, a BART emission limit is still applicable and is required regardless if the unit switches to natural gas. However, the repurposing project the mill is currently undergoing and the fact that the facility's air permit will be revised such that Power Boiler No. 1 will be permitted to burn only natural gas render it appropriate to provide the facility with flexibility in demonstrating compliance with the SO_2 emission limit. Therefore, in addition to the method we proposed for demonstrating compliance with the SO_2 BART emission limit for Power Boiler No. 1, we are also finalizing one alternative method for

[159] 80 FR 18944, 18980.

[160] 80 FR at 18980.

[161] See file ''Record of Meeting_March 10 2016,'' which can be found in the docket for this rulemaking.

[162] 40 CFR 51.301.

demonstrating compliance: The owner or operator may demonstrate compliance with the SO_2 emission limit by switching Power Boiler No. 1 to burn only pipeline quality natural gas. Therefore, if the facility's air permit is revised to reflect that Power Boiler No. 1 is permitted to burn only pipeline quality natural gas, this would satisfy the requirement for demonstrating compliance with the boiler's SO_2 BART emission limit, and the reporting and recordkeeping requirements would be waived. We are revising proposed § 52.173 to reflect this.

We are finalizing our determination that NO_X BART for Power Boiler No. 1 is an emission limit of 207.4 lb/hr. We proposed that to demonstrate compliance with this NO_X BART emission limit, the facility was required to conduct annual stack testing. In response to a separate comment provided by Domtar, in our final FIP we are requiring stack testing every five years instead of annually to demonstrate compliance with the NO_X BART emission limit. The repurposing project the mill is currently undergoing and the fact that the facility's air permit will be revised such that Power Boiler No. 1 will be permitted to burn only natural gas render it appropriate to provide the facility with flexibility in demonstrating compliance with the NO_X emission limit. Therefore, we are also providing one alternative method for demonstrating compliance with the NO_X emission limit: If the facility's air permit is revised to reflect that Power Boiler No. 1 is permitted to burn only pipeline quality natural gas, the facility may demonstrate compliance with the NO_X emission limit by calculating emissions using AP–42 emission factors and fuel usage records. Under these circumstances, the facility would not be required to demonstrate compliance with the NO_X BART emission limit for Power Boiler No. 1 through stack testing. We are revising proposed § 52.173 to reflect this.

With regard to the request that we include a provision in our FIP that removes all SO_2 and NO_X BART related requirements for Power Boiler 1 if this boiler is permanently retired in the future, we noted above that the Regional Haze regulations define BART as an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The BART emission limits and applicable requirements continue to apply regardless if a BART source is mothballed or retired/shut down without being dismantled, decommissioned, and having the air permit revoked. In the event that the BART source is permanently shut down, dismantled, decommissioned, and the permit revoked in the future, the process for removing the BART emission limits and applicable requirements would necessarily involve a request by the company for partial FIP withdrawal or a SIP revision from the State in the event that we have approved a SIP revision that replaces our FIP. We are committed to work with ADEQ and the facility to partially withdraw our FIP with respect to the emission limits for the BART unit or revise the SIP if at some point in the future the company decides to permanently shut down, dismantle, and decommission the boiler and surrender the air permit.

Further, we consider the conditions under which a unit is permanently retired and the mechanism by which this is made enforceable to be critical. Because the company has not decided if and when Power Boiler No. 1 will be permanently retired or decided what the conditions of the retirement will be, we believe that it is reasonable and appropriate to wait until the company makes these decisions instead of including a provision in our FIP that waives the BART recordkeeping requirements in anticipation that the unit's permanent retirement will take place under certain conditions and made enforceable through a particular mechanism that may be different from what ultimately takes place.

Comment: If Power Boiler 2 is fuel switched to natural gas or retired as part of the Domtar Ashdown Mill's repurposing project, there is no need to retain the SO_2 and PM BART limits and the associated monitoring, recordkeeping and reporting requirements for the SO_2 and PM BART limits. The Ashdown Mill requests that EPA include in the FIP final rule an alternative compliance option which removes the SO_2 and PM BART limits and the associated requirements if the boiler is fuel switched to natural gas or permanently retired. Additionally, if Power Boiler 2 is fuel switched to natural gas as part of the Domtar Ashdown Mill's repurposing project, the NO_X BART requirements need to be modified to require compliance based on the use of AP–42 emission factors and fuel use records. The requirement to operate and maintain a NO_X CEM needs to be removed. If Power Boiler 2 is retired, all the BART requirements are unnecessary. The Ashdown Mill requests that EPA include alternate compliance options in the FIP final rule provisions to address these potential scenarios.

Response: We are finalizing an SO_2 BART emission limit of 91.5 lb/hr and we are finalizing our determination that compliance with the Boiler MACT PM standard as revised satisfies the PM BART requirement for Power Boiler No. 2. We proposed to require the facility to demonstrate compliance with the SO_2 emission limit for Power Boiler No. 2 using the existing CEMS, and to demonstrate compliance with the PM emission limit using the same method that is used for demonstrating compliance with the Boiler MACT PM standard. We are finalizing these methods for demonstrating compliance with the SO_2 and PM emission limits for Power Boiler No. 2. With regard to the commenter's request that we include an alternate compliance option in our FIP that removes the SO_2 and PM BART limits if the boiler is switched to natural gas, we do not have the authority to do this. The Regional Haze regulations define BART as an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility.[163] The BART emission limits are still applicable and are required regardless if the unit is switched to natural gas. However, the repurposing project the mill is currently undergoing and the possibility of Power Boiler No. 2 being converted to burn only natural gas render it appropriate to provide the facility with flexibility in demonstrating compliance with the SO_2 and PM emission limits for Power Boiler No. 2. Therefore, we are providing one alternative method for demonstrating compliance with the SO_2 and PM emission limits: The owner or operator may demonstrate compliance with these emission limits by switching Power Boiler No. 2 to burn only natural gas. Therefore, if Power Boiler No. 2 is switched to burn only pipeline quality natural gas, and the air permit is revised to reflect this change, this would satisfy the requirement for demonstrating compliance with the boiler's SO_2 and PM BART emission limits, and the related reporting and recordkeeping requirements would be waived. Under these circumstances, the SO_2 and PM BART determinations for Power Boiler No. 2 would continue to apply but the facility would be able to demonstrate compliance with these emission limits by virtue of switching to natural gas and it would not be required to use the existing CEMS to demonstrate

[163] 40 CFR 51.301.

compliance with the SO_2 BART emission limit. We are revising proposed § 52.173 to reflect this.

We are requiring Power Boiler No. 2 to meet an emission limit of 345 lb/hr to satisfy the NO_X BART requirement. We proposed to require the facility to demonstrate compliance with this NO_X emission limit using the existing CEMS, and we are finalizing this method for demonstrating compliance. However, the repurposing project the mill is currently undergoing and the possibility of Power Boiler No. 2 being converted to burn natural gas only render it appropriate to provide the facility with flexibility in demonstrating compliance with the NO_X emission limit. Therefore, we are providing one alternative method for demonstrating compliance with the NO_X emission limit: If Power Boiler No. 2 is switched to burn only pipeline quality natural gas, and the air permit is revised to reflect this, the facility may demonstrate compliance with the NO_X emission limit by calculating emissions using AP–42 emission factors and fuel usage records. Under these circumstances, the facility would not be required to use the existing CEMS to demonstrate compliance with the NO_X BART emission limit. We are revising proposed § 52.173 to reflect this.

We do not have the authority to include in our FIP a provision that removes all SO_2, NO_X, and PM BART requirements for Power Boiler No. 2 if it is permanently retired in the future. As noted above, the Regional Haze regulations define BART as an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The BART emission limits and applicable requirements continue to apply regardless if a BART source is mothballed or retired/shut down without being dismantled, decommissioned, and having the air permit revoked. In the event that the BART source is permanently shut down, dismantled, decommissioned, and the permit revoked in the future, the process for removing the BART emission limits and applicable requirements would necessarily involve a request for a partial FIP withdrawal or a SIP revision in the event that we have approved a SIP revision that replaces our FIP. We are committed to work with ADEQ and the facility to partially withdraw our FIP with respect to the emission limits for the BART unit or revise the SIP if at some point in the future the company decides to permanently shut down, dismantle, and decommission the boiler and surrender the air permit.

Further, we consider the conditions under which a unit is permanently retired and the mechanism by which this is made enforceable to be critical. Because the company has not decided if and when Power Boiler No. 2 will be permanently retired or decided what the conditions of the retirement will be, we believe that it is reasonable and appropriate to wait until the company makes these decisions instead of including a provision in our FIP that waives the BART recordkeeping requirements in anticipation that the unit's permanent retirement will take place under certain conditions and made enforceable through a particular mechanism that may be different from what ultimately takes place.

Comment: EPA proposes to require compliance with the SO_2 BART emission limit for Power Boiler 2 within 3 years of the effective date of the final rule. EPA also proposes compliance with the NO_X BART emission limit within 3 years of the effective date of the final rule. With the mill transformation and re-purposing project and all of the work associated with this huge undertaking, the Ashdown Mill needs a 5-year compliance window from the effective date of the final rule for the SO_2 and NO_X BART requirements for Power Boiler 2 (assuming EPA decides to proceed with BART for the mill). As announced in late 2014, the mill is converting a paper machine to produce fluff pulp. This transformation project is being driven by the continued decline in the demand for paper products. Power 1 and Power Boiler 2 are part of the mill's steam generating components, and are operated to produce steam that is needed for the manufacturing of pulp and paper products. It is anticipated that this mill transformation project may significantly affect mill steam demands reducing the amount of steam needed from Power Boiler 1 and 2. Ultimately, this transformation project may determine future use of Power Boiler 2. Once the re-purposing and re-configuration of the mill systems is complete and fully operational, the mill will decide whether Power Boiler 2 will continue with full or intermittent operation, if so, using what fuels, or will it be permanently retired. In order to make this decision, the mill will need to go through the startup, initial operation and a shakedown period with the new fluff pulp process. Since this is a significant change for the mill it is uncertain how long it will take to learn how to operate and to optimize in this newly configured state. The mill will then need at least 2 winter cycles to understand what the maximum steam demand requirements will be for the newly configured mill. The re-purposing project is scheduled to be completed and the newly configured mill is anticipated to start-up in late 2016. The mill will operate through the winter of 2016–2017 and will be learning how to operate and optimize the new process. The winter of 2017–2018 will be the first real indicator of what winter steam demands will be in the re-purposed state. For the purposes of selecting an appropriate BART compliance schedule and future mill operations, the understanding of how the Power Boilers will operate and on what fuels is essential. The project schedule will set these key decision points in late 2018. Once the decision on mill steam needs and boiler utilization is made, additional time is required to implement the boiler scenario selected by the mill. These scenarios could range from the mothballing or retiring Power Boilers 1 or 2 to shifting fuels. In addition, changes involving the combustion of the NCG gases and the shared biomass feed system also need to be determined and new systems engineered and permitted, as needed. Another factor to be considered is determining the ability of the existing SO_2 scrubber to continuously operate at 90% removal on a long-term basis. If Power Boiler 2 continues to use solid fuels, additional time is needed to optimize the existing scrubber to consistently perform at this higher level of control efficiency on a long-term basis. Given the mill's interconnected nature as well as the complex aspects of the re-purposing project, a 5-year compliance schedule for achieving the SO_2 BART and NO_X BART requirements for Power Boiler 2 is essential.

Response: We have reconsidered the SO_2 and NO_X BART compliance dates for Power Boiler No. 2 in response to this comment. We understand the commenter's concerns with respect to how the transformation and repurposing project the mill is currently undertaking may significantly affect mill steam demands and may ultimately determine future use of Power Boiler No. 2. We understand that the mill will decide the future use of Power Boiler No. 2, including whether it will be converted to other fuels or permanently retired, after the repurposing and reconfiguration of the mill systems is complete and fully operational and after the mill has learned how to operate and to optimize in its newly configured state. Our understanding from the comments is that Ashdown Mill expects to make this decision in late 2018, but that additional time will be needed to implement the boiler scenario selected by the mill, which could include switching fuels, mothballing or retiring the boilers, or continued operation and combustion of solid fuels and installation of air pollution controls to meet the BART emission limits. It is not EPA's intention to place an undue burden on the Domtar Ashdown Mill by requiring a compliance date that may not provide sufficient time for the mill to install controls or otherwise make the necessary operating changes to meet the boiler's BART emission limits. While we believe that a 3-year compliance date is generally sufficient for installation of the controls on which the BART emission limits are based, due to the special circumstances in this case we believe that it is reasonable and appropriate to establish a longer compliance date particularly since it could avoid unnecessary investment in a scrubber that may be no longer needed due shutdown or fuel switch. Therefore, we are requiring that the mill comply with the SO_2 and NO_X BART emission limits no later than 5 years from the effective date of this final rule and have amended the proposed regulatory text to reflect this change. We believe that this adequately addresses the commenter's concerns while in keeping with the CAA mandate that compliance with BART requirements must be as expeditiously as practicable but in no event later than 5 years after promulgation of this FIP.

F. Other Compliance Dates

Comment: EPA proposed compliance with the SO_2 and NO_X BART limits for Power Boiler 1 and for the PM BART limit for Power Boiler No. 2 to be on the effective date of the final rule. Should EPA proceed with imposing these BART limits, the Ashdown Mill requests the compliance date be changed to 30 calendar days after effective date of the final rule. That will give the mill additional time to prepare the compliance records if there is a short period between when the rule is promulgated and the effective date, especially if the effective date of the final rule falls on a weekend or a holiday. In addition, if any confusion exists regarding exactly when the effective date is, the cushion of 30 days helps to provide more certainty. This extra time will be needed if EPA finalizes any changes to definitions or other requirements that require the Ashdown to adjust recordkeeping systems.

Response: We are finalizing a NO_X BART emission limit of 207.4 lb/hr for Power Boiler No. 1, which is what we proposed. We proposed an SO_2 BART emission limit of 21.0 lb/hr for Power Boiler No. 1, and as discussed in section IV. of this final rule, we are finalizing an emission limit of 504 lb/day. We are finalizing our determination that compliance with the Boiler MACT PM standard satisfies the PM BART requirement for Power Boiler No. 2. As discussed elsewhere in this section of the final rule, we are finalizing some changes to the definitions and BART requirements for Power Boiler No. 1. After carefully considering this comment, we have determined that extending the compliance dates associated with the aforementioned BART emission limits for Power Boiler No. 1 is appropriate because it is a reasonable request that will allow the owner or operator of the affected facility to prepare applicable compliance records and adjust recordkeeping systems without unduly delaying compliance with the BART requirement. Therefore, we are revising the compliance dates we proposed for the SO_2 and NO_X BART emission limits for Power Boiler No. 1 and the PM BART requirement for Power Boiler No. 2 such that the owner or operator must comply with these emission limits no later than 30 calendar days from the effective date of the final rule.

Comment: EPA's proposed BART requirements will require installation of new emission controls on utility electric generation resources at a significant cost. The utilities will pass these costs on to Arkansas ratepayers. The Ashdown Mill, like other energy intensive manufacturers, will be affected by the increasing cost of electric power needed to operate our processes. EPA should also consider other emerging regulatory initiatives that will be driving substantial changes to major coal burning facilities. Manufacturing facilities, such as the Ashdown Mill, are undertaking major transformation projects that potentially may result in a move away from coal and other emerging regulations targeting utilities are likely to further reduce coal burning and further remove visibility concerns. A practical alternative to EPA's proposed compliance dates is for EPA to use its discretion under the Regional Haze Rule and delay the Arkansas BART requirements for all sources for five years. This will align compliance timelines so that the full effects of all of these regulatory changes will be known. Facilities affected by these other requirements can plan holistic compliance strategies rather than being compelled to follow an expensive and potentially wasteful piecemeal approach. Using the maximum 5-year window allowed under BART will provide the Ashdown Mill the time to determine if coal will continue as a fuel for the facility. It will also provide the other affected sources in Arkansas with time to address the Clean Power Plan strategies and other significant regulatory programs that may also remove coal as a fuel. The effect of allowing a full 5-year compliance program will thereby minimize the potential for stranded assets and minimize the cost increases on companies and on ratepayers. This approach is further compelled by the fact that Arkansas is more than meeting its ''glide path'' as discussed above.

Response: We acknowledge the commenter's concerns related to the potential increase in utility rates for Arkansas ratepayers as well as to potential requirements related to other CAA and EPA regulatory actions. We agree that multiple regulatory actions are pending that will affect the power sector and that regulatory development should be coordinated when possible while still meeting the statutory and regulatory requirements for compliance. We also recognize the importance of long-term and coordinated planning on the parts of owners of industrial sources that are subject to BART. However, we disagree that our FIP presents a tight or unreasonable regulatory timeline. It is an appropriate timeline for cost-effective control measures needed to meet the regional haze requirements.

The CAA and Regional Haze Rule require the installation and operation of BART, in particular, to be carried out expeditiously. The CAA defines the term ''as expeditiously as practicable'' to mean ''as expeditiously as practicable but in no event later than five years after the date of approval of a [Regional Haze] plan revision. . . .''[164] Therefore, we do not have the authority to delay compliance dates across the board for all subject-to-BART sources in Arkansas to allow time for greater certainty regarding requirements associated with other CAA and regulatory requirements. We also disagree that ADEQ's finding that Arkansas Class I areas are projected to be below the URP glidepath in 2018 is sufficient justification for delaying the compliance dates for all subject-to-BART sources in Arkansas. We address other more specific comments related to this issue in a separate response.

In determining what is ''as expeditiously as practicable'' for installation and operation of a particular control technology, the states and EPA

[164] CAA section 169A(b)(2)(A) and (g)(4).

usually consider the amount of time it generally takes to install and operate that type of technology at similar sources and the compliance dates that have been required for the installation and operation of the same type of control technology at similar sources in other regional haze actions, especially if there are no source-specific considerations or other special circumstances that would prevent the source from installing and operating the control technology within the same amount of time. For example, where a particular control technology can generally be installed and operated in 3 years, and where there are no source-specific considerations or other special circumstances that would affect the facility's ability to install and operate the control technology within that time frame, it would not be in accordance with the CAA and the Regional Haze Rule to allow a 5-year compliance period because that would not be as expeditiously as practicable. Additionally, considering that most other states already have plans in place that fully address the regional haze requirements, it would be inequitable and contrary to the intent of the CAA and the Regional Haze Rule to further delay implementation of regional haze requirements in Arkansas by allowing a 5-year compliance date across the board for all of Arkansas' subject-to-BART sources. Therefore, we disagree that it is appropriate for us to allow a 5-year compliance date for all subject-to-BART sources in Arkansas, rather than establishing deadlines consistent with the facts and regulatory requirements in each instance.

We do note that we are revising some of the compliance dates we proposed in response to source-specific considerations raised in other comments. We address these comments in separate responses.

Comment: If EPA's final SO_2 BART determination for Flint Creek Unit 1 is based on installation of a NID dry scrubber, EPA should impose a shorter compliance deadline, as required by the Act. EPA's proposed FIP requires Flint Creek Unit 1 to comply with the SO_2 BART determination within five years from the effective date of the final rule. Yet the statute requires a source to comply with BART as expeditiously as possible, but no later than five years from the effective date of EPA's action on the regional haze plan.[165] AEP could install a NID scrubber at Flint Creek much more expeditiously than five years from the effective date of the rule. The utility has already obtained an Arkansas PSC order finding that NID dry scrubber installation is in the public interest.[166] ADEQ has already issued a Title V air permit for scrubber construction and operation at Flint Creek.[167] Further, it appears that on-site construction of the NID scrubber has begun, and that the Flint Creek owners intend to operate it by May 29, 2016, in order to comply with EPA's MATS rule.[168] Thus, given that AEP is currently installing the NID scrubber with a May 2016 planned operation date, EPA's five-year SO_2 BART compliance deadline does not comply with the statutory requirement that BART controls be installed ''as expeditiously as practicable,'' [169] Since AEP is installing the NID scrubber for MATS as well as BART compliance, EPA should require SO_2 BART compliance at Flint Creek by no later than May 29, 2016.

Response: We acknowledge the information provided by the commenter regarding AEP Flint Creek's plans to complete installation of the NID system in 2016 in order to comply with 40 CFR part 63, subpart UUUUU—National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, otherwise known as the Utility MATS Rule. MATS establishes emission limits for three categories of pollutants: Mercury, acid gases (HCl and SO_2), and non-mercury hazardous air pollutant (HAP) metals. To address acid gases, an EGU must comply with an HCl emission limit unless it is equipped with a wet or dry FGD or DSI and an SO_2 CEMS, in which case it has the option of complying with an alternative SO_2 emission limit. The applicable alternative SO_2 emission limit is 0.2 lb/MMBtu.

The commenter has made us aware that the Arkansas PSC has determined that dry scrubber installation at Flint Creek is in the public interest and that the installation of those controls is already underway and anticipated by the company to be complete by May 29, 2016. The commenter also points to the air permit issued to Flint Creek by ADEQ on October 25, 2013, which allows for the installation and operation of new control equipment and associated material handling systems to comply with the requirements of the Utility MATS Rule. These controls include a NID system on Unit 1. The AEP–SWEPCO Web site also indicates that the installation of these scrubber controls is driven by MATS and future Regional Haze rules.[170] A timeline provided on the Web site states that construction of these controls began in October 2013 and that installation will be complete and the facility will be operating with these controls by the end of May 2016. In addition, the commenter has made us aware that the Arkansas PSC requires Flint Creek to provide quarterly reports on the progress of the installation of these controls. The first report the company submitted to the Arkansas PSC is dated March 26, 2014, and stated that the FGD project includes the installation of an Alstom NID system to comply with MATS and in anticipation of the BART requirements. The report also stated that the NID system and associated equipment are to be constructed at Flint Creek Unit 1, and that the company established design, procurement, and construction schedules to bring the upgraded plant fully on line by May 29, 2016. The commenter provided the report as an attachment to the comments submitted, but this and all other quarterly reports the company submitted to the Arkansas PSC are available online.[171] The most recent quarterly report available on the Arkansas PSC Web site is dated March 10, 2016, and covers the fourth quarter in 2015. This report indicated that the company still expected the upgraded plant to be fully on line by May 29, 2016. We verified the status of the installation of the controls with the company, who confirmed that installation of the NID controls was completed in June 2016, and that the plant is now operating with those controls.[172]

After carefully considering the information the commenter has brought to our attention, we no longer believe that a 5-year compliance date is appropriate for the SO_2 BART controls

[165] 40 CFR 51.308(e)(1)(iv).

[166] See 7/10/2013 SWEPCO News Release, SWEPCO Receives Arkansas Commission Approval for Flint Creek Plant Project, at *https://www.swepco.com/info/news/viewRelease.aspx?releaseID=1424*.

[167] See Stamper Report at 14 (citing October 25, 2013 Permit No. 0276–AOP–R6 at 5 (Ex. 29 to Stamper Report)).

[168] Stamper Report at 14 (citing Flint Creek Retrofit Project, SWEPCO News & Info Site at *https://swepco.com/info/projects/FlintCreek/*; March 26, 2014 Independent Monitor Report for AEP Flint Creek Plant Unit 1, submitted to the Arkansas Public Service Commission under Docket No. 12–008–U, at (Ex. 30 to Stamper Report)).

[169] CAA section 169A(b)(2)(A).

[170] *https://www.swepco.com/info/projects/FlintCreek/*.

[171] See the Arkansas PSC Web site at *http://www.apscservices.info/efilings/docket_search.asp*. The quarterly reports the company is required to submit to the Arkansas PSC are available by searching for docket No. 12–008–U.

[172] See file titled ''Record of Call- Flint Creek_August 10 2016,'' which is found in the docket for this rulemaking.

we are requiring for Flint Creek. We agree with the commenter that BART controls must be installed as expeditiously as practicable. CAA section 169A(b)(2)(A). Therefore, we are finalizing a shorter compliance date. The information made available to us during the comment period, as discussed above, indicates that Flint Creek intends to operate the NID system to comply with the alternative SO_2 emission limit under the Utility MATS rule. The applicable SO_2 emission limit is 0.2 lb/MMBtu. The SO_2 emission limit we are requiring in our FIP to satisfy the BART requirement is 0.06 lb/MMBtu. As indicated in the information and other documentation the commenter provided, the company plans to use the same NID system to comply with MATS and to comply with the facility's SO_2 BART requirement. We expect that to achieve an emission rate of 0.06 lb/MMBtu, additional scrubbing reagent would be needed beyond that required to meet the 0.2 lb/MMBtu emission limit the company is required to meet by April 2016 under MATS. We also recognize that it is possible that the reagent handling system installed to meet the 0.2 lb/MMBtu emission limit would need some upgrades in order to accommodate the additional scrubbing reagent that would be needed to achieve the more stringent 0.06 lb/MMBtu emission limit we are requiring in this FIP. Therefore, to allow the facility sufficient time to secure the additional scrubbing reagent that would be needed to comply with the SO_2 BART emission limit and to make any necessary upgrades to the reagent handling system, we are finalizing an 18-month compliance date for Flint Creek Unit 1 to comply with the SO_2 BART requirement. We believe this is will provide sufficient time for the facility to be able to achieve the SO_2 BART requirement while still meeting the statutory mandate that BART controls be installed as expeditiously as practicable.

Comment: If EPA's final NO_X BART determination for White Bluff is based on installation of a SCR with LNB/SOFA, EPA should require a NO_X BART compliance date for SCR at White Bluff of no later than within 3 years of the final rule's effective date, which would represent the expeditious implementation required by CAA section 169A(b)(2)(A). The NO_X BART compliance date for LNB/SOFA should be 8 months from the final rule's effective date. If EPA finalizes its proposal to require LNB/SOFA only as NO_X BART for White Bluff, EPA should require compliance within 8 months of the final rule's effective date. Eight months is sufficient time for installation of these controls. These same comments apply and should be extended to EPA's reasonable progress determination for NO_X for Independence Units 1 and 2.

Response: We are requiring White Bluff Units 1 and 2 and Independence Units 1 and 2 to each meet a NO_X emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average, where the average is to be calculated by including only the hours during which the unit was dispatched at 50% or greater of maximum capacity. In addition, we are requiring each unit to meet a NO_X emission limit of 671 lb/hr on a rolling 3-hour average that is applicable only when the unit is being operated at less than 50% of the unit's maximum heat input rating. These emission limits are consistent with the installation and operation of LNB/SOFA controls. In light of the comment, we have reconsidered the compliance date for the NO_X BART requirements for White Bluff Units 1 and 2 and for the NO_X controls under reasonable progress for Independence Units 1 and 2. Based on the supporting information provided by the commenter, we agree with the commenter that 6–8 months is the typical installation timeframe for LNB/OFA controls.[173] However, in determining the appropriate compliance date for these NO_X controls, we have also taken into consideration that we are finalizing NO_X emission limits that are based on LNB/OFA or LNB/SOFA controls for a total of five EGUs in this FIP and that the installation of these controls will require outage time. These five EGUs are Flint Creek Unit 1, White Bluff Units 1 and 2, and Independence Units 1 and 2, and combined they accounted for approximately 45% of the state's 2015 heat input. Because of the heavy reliance on these EGUs for electricity generation in the state, we recognize that it may be difficult to schedule outage time to install LNB/OFA or LNB/SOFA on all five of these Arkansas units within the typical installation timeframe of 6–8 months and at the same time supply adequate electricity to meet demand in the state. In light of these unique circumstances, we find that it is appropriate to finalize an 18-month compliance date for White Bluff Units 1 and 2, Independence Units 1 and 2, and Flint Creek Unit 1 to comply with the NO_X emission limits required by this FIP. This compliance date provides the affected utilities sufficient time beyond typical LNB/OFA installation timeframes to install these controls and comply with their NO_X emission limits, while safeguarding the continuity of Arkansas' electricity supply.

We address comments contending that we should require SCR controls on White Bluff and Independence elsewhere in this final rule and in our RTC document.

Comment: One commenter noted that the proposed FIP would require Flint Creek Unit 1 to comply with the NO_X BART requirement within 3 years of the effective date of the rule. The commenter argued that if EPA's final NO_X BART determination for Flint Creek is based on installation of LNB/OFA, EPA should establish a shorter compliance deadline since compliance with BART is required as expeditiously as practicable.[174] The commenter contends that AEP has been planning for the installation of LNB/OFA and that construction has already begun. The commenter argues that since the utility is currently installing LNB/OFA with a May 2016 planned operation date, EPA should require a NO_X BART compliance date of no later than May 2016 in order to ensure the expeditious implementation required by law.

AEP/SWEPCO, which is one of the owners of Flint Creek, also commented on our proposed NO_X BART compliance date for Flint Creek Unit 1. The company stated that if EPA does not rely on CSAPR to satisfy the NO_X BART requirement for EGUs in Arkansas, it supports EPA's determination of LNB/OFA controls as BART and the associated limits proposed by EPA. But the company stated that the proposed 3-year compliance timeframe is unreasonable. The company stated that the compliance time frame must allow for planning, selection of engineering and design professionals, vendors, contractors, permitting, start up and commissioning, and coordinating and scheduling unit outages. The company also argued that since EPA has allowed installation schedules up to 5 years in other states, we should allow such a time frame here.

Response: We are finalizing our determination that NO_X BART for AEP Flint Creek Unit 1 is an emission limit of 0.23 lb/MMBtu on a 30 boiler-operating-day rolling average, which is consistent with the installation and operation of LNB/OFA. The commenter has not provided sufficient information to corroborate the claim that installation of LNB/OFA at Flint Creek Unit 1 is

[173] See comments and exhibits submitted by Earthjustice, the National Parks Conservation Association, and Sierra Club, dated August 7, 2015. These and all other comments submitted during the public comment period are found in the docket associated with this rulemaking.

[174] 40 CFR 51.308(e)(1)(iv).

expected to be completed by May 2016. We acknowledge that on July 10, 2013, the Arkansas PSC filed an order agreeing that the installation of additional environmental controls at Flint Creek Unit 1, including LNB/OFA to meet the NO_X BART requirement, is in the public interest.[175] In the attachments to the comment, the commenter points to a news article that references a January 21, 2014 report submitted by AEP/SWEPCO to the Arkansas PSC.[176] In that January 21, 2014 report, AEP/SWEPCO announces that construction of environmental controls at Flint Creek commenced on January 20, 2014.[177] However, the January 21, 2014 report does not specify if this includes construction of LNB/OFA. While we acknowledge that there is publicly available information indicating that the company planned to complete installation of a NID system and activated carbon injection by May 2016 to comply with the Utility MATS rule, there is no information available to us corroborating that the expected date of LNB/OFA installation was also May 2016. In fact, the comments submitted by AEP/SWEPCO indicate that the company has not begun installation of these controls.[178] With regard to AEP/SWEPCO's request that we extend the compliance date to 5 years, we have determined that the company has not provided any information regarding any special circumstances specific to the facility that sets it apart from other facilities and that would prevent it from completing installation of controls within typical 3-year LNB/OFA installation timeframes.

Additionally, as discussed in a previous response, we agree that LNB/OFA can typically be installed within a 6–8 month timeframe. However, in determining the appropriate compliance date for these NO_X controls, we have also taken into consideration that we are finalizing NO_X emission limits that can be achieved by the installation of LNB/OFA or LNB/SOFA controls for a total of 5 EGUs in this FIP. Because of the heavy reliance on these EGUs for electricity generation in the state and because it may be difficult to schedule outage time to install these controls on all five of these units within the typical installation timeframe of 6–8 months without disrupting the supply of electricity in the state, we are finalizing an 18-month compliance date for Flint Creek Unit 1 and the other EGUs to comply with the NO_X emission limits required by this FIP.

G. Compliance Demonstration Requirements

Comment: For purposes of BART for the Domtar Ashdown Mill Power Boiler No. 1 and Power Boiler No. 2, EPA is 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, consistent with the guidelines for utility boilers. However, the Ashdown Mill boilers are industrial boilers, not utility boilers. The Ashdown Mill defines a mill operating day to be a 24-hour period between 6 a.m. and 6 a.m. the following day. All of the mill's systems for Power Boilers No. 1 and 2 are programmed around this definition of a mill operating day and modification of these systems would require a significant amount of effort and would require the gathering and maintaining of multiple sets of records. Assuming EPA proceeds with BART for the Ashdown Mill, the mill requests that for Power Boiler No. 1 and Power Boiler No. 2 a boiler operating day be defined as ''a 24-hr period between 6 a.m. and 6 a.m. the following day during which any fuel is fed into and/or combusted at any time in the power boiler.'' Harmonizing the definitions of a boiler operating day and a mill operating day does not increase costs for the mill, reduces confusion for the mill operators, eliminates the need for maintaining multiple sets of records, and eliminates the need for changes to existing monitoring systems. We believe EPA is authorized or can use its discretion to define a boiler operating day for the Ashdown Mill to be consistent with the mill's boiler operating day definition.

Response: After carefully considering the comment, we agree that Domtar's request is reasonable and that it is appropriate to harmonize the definitions of a boiler operating day and a mill operating day to avoid any unnecessary modification or reprogramming of Power Boilers 1 and 2. To accommodate Domtar's request, for purposes of Power Boiler 1 and Power Boiler 2, in this final action we are defining a boiler operating day as ''a 24-hr period between 6 a.m. and 6 a.m. the following day during which any fuel is fed into and/or combusted at any time in the power boiler.'' We are revising proposed § 52.173 to reflect this.

Comment: EPA proposed to require compliance with the BART NO_X limit for the Domtar Ashdown mill Power Boiler No. 1 be demonstrated with an annual stack test. Domtar agrees in general that stack testing is an appropriate method for demonstrating compliance. However, EPA's proposal to require stack testing annually is not appropriate. Historical NO_X stack test data from 2001, 2002, 2003, 2004, 2005, and 2010 for Power Boiler 1 show NO_X emissions to be fairly consistent. Based on the numerous previous stack tests, conducting stack tests annually is not warranted. Should EPA proceed with BART for the Ashdown Mill, the facility is requesting that stack testing to demonstrate compliance with the BART NO_X limit be required every 5 years instead of annually, which is consistent with the Ashdown Mill's Title V permit requirements.

Response: After carefully considering the comment, we have reconsidered our proposed requirement of annual stack testing. We agree that the results of the NO_X stack testing conducted by Domtar for Power Boiler No. 1 demonstrate that NO_X emissions have historically remained well below the NO_X emission limit we are finalizing for the boiler.[179] Therefore, we agree with the company that it is appropriate to require stack testing every 5 years instead of annually. In our final action we are requiring that the facility demonstrate compliance with the NO_X BART emission limit for Power Boiler No. 1 by conducting stack testing every five years, beginning no later than 1 year from the effective date of our final action. As discussed in a separate response, we are also providing one alternative method for demonstrating compliance with the NO_X BART emission limit for Power Boiler No. 1. Specifically, if the facility's air permit is revised to reflect that Power Boiler No. 1 is permitted to burn only natural gas, the facility may demonstrate compliance with the NO_X emission limit by calculating emissions using AP–42 emission factors and fuel usage records. Under these circumstances, the

[175] See Arkansas Public Service Commission, Docket No. 12–008–U, Order No. 14, dated July 10, 2013. A copy of the order can be found at *http://www.apscservices.info/pdf/12/12-008-u_227_1.pdf.*

[176] See the document titled ''Technical Support Document to Comments of Conservation Organizations,'' which is an attachment to the comments submitted by Earthjustice, the National Parks Conservation Association, and Sierra Club. These and all other comments submitted during the public comment period are found in the docket associated with this rulemaking.

[177] *http://www.apscservices.info/pdf/12/12-008-u_238_1.pdf.*

[178] See the comments submitted by AEP–SWEPCO, dated July 15, 2015 and August 7, 2015. These and all other comments submitted during the public comment period are found in the docket associated with this rulemaking.

[179] See Excel file titled ''Email from Domtar Regarding NOx Stack Test for PB1,'' found in the docket for this final rule. The data provided by Domtar indicate that out of the stack testing conducted in 2001, 2002, 2003, 2004, 2005, and 2010, the highest NO_X emission rate from Power Boiler No. 1 was 171.3 lb/hr, compared to the 207.4 lb/hr NO_X emission limit we are finalizing.

facility would not be required to demonstrate compliance with the NO_X BART emission limit for Power Boiler No. 1 through stack testing. We are revising proposed § 52.173 to reflect this.

Comment: Assuming EPA proceeds with BART for the Domtar Ashdown Mill, the mill agrees with the proposed BART PM limit of 0.44 lb/MMBTU for Power Boiler No. 2 based on the MACT standard for the ''biomass hybrid suspension grate'' sub-category contained in the 2013 Boiler MACT final rule. The Ashdown Mill agrees with EPA's approach of relying on the Boiler MACT standards for PM to satisfy the PM BART requirement. However, for this streamlined BART approach, EPA must also ensure that the monitoring, recordkeeping, reporting requirements for PM BART are consistent with the monitoring, recordkeeping and reporting requirements under Boiler MACT. Deviating from the MACT requirements will result in additional administrative burden for the facility in maintaining ''multiple sets of compliance books.'' It also will create confusion for external stakeholders if different values and information are being reported.

Response: We generally agree with the comment. We proposed to find that the Domtar Ashdown Mill may rely on compliance with the Boiler MACT PM standard to satisfy the PM BART requirement for Power Boiler No. 2, and we did not intend for our FIP to establish requirements for compliance demonstration, monitoring, recordkeeping, and reporting different from those the mill is already required to comply with under the Boiler MACT PM standard. In our proposal, our intent was to propose requirements for compliance demonstration, monitoring, recordkeeping, and reporting for the PM BART limit for Power Boiler No. 2 that are consistent with those under the Boiler MACT PM standard. However, the commenter has brought to our attention that only some of the compliance demonstration, monitoring, recordkeeping, and reporting requirements associated with the Boiler MACT PM standard were included under our proposed § 52.173(c)(21) and (22) and that it appeared that we were proposing a separate and distinct set of requirements associated with our PM BART determination for Power Boiler No.2. Therefore, to ensure clarity and consistency, we are revising the regulatory text found under 40 CFR 52.173(c) that applies to Power Boiler No. 2 for PM BART to state that the mill shall rely on compliance with the Boiler MACT PM standard under 40 CFR part 63 Subpart DDDDD as revised to satisfy the PM BART requirement for Power Boiler No. 2. We interpret this to mean that compliance with the applicable Boiler MACT PM standard as revised is sufficient to demonstrate compliance with the PM BART requirement. We are not establishing a separate set of requirements for compliance demonstration, monitoring, recordkeeping, and reporting (*i.e.,* in addition to those already required under the Boiler MACT PM standard, as revised), that Power Boiler No. 2 is required to comply with to satisfy the PM BART requirement.

H. Reliance on CSAPR Better Than BART

Comment: Arkansas is subject to a Cross-State Air Pollution Rule (CSAPR, also referred to as the Transport Rule) FIP for ozone-season NO_X. EPA should not require sources that are subject to the CSAPR FIP to also install BART or additional emissions controls based on a reasonable progress analysis. The Regional Haze Rule allows states to implement an alternative program in lieu of BART so long as the alternative program has been demonstrated to achieve greater reasonable progress toward the national visibility goal than would BART.[180] EPA published CSAPR as a replacement to CAIR on August 8, 2011.[181] In the final Transport rule, EPA demonstrated that CSAPR would make greater reasonable progress toward national visibility goals than would BART.[182] EPA concluded in the final Transport rule that a state in the CSAPR region whose EGUs are subject to the requirements of the CSAPR trading program for ozone season NO_X may rely on EPA's finding that CSAPR makes greater reasonable progress than source-specific NO_X BART. Despite EPA's demonstration that CSAPR makes greater reasonable progress than source-specific BART, EPA makes no mention of CSAPR emissions controls in the FIP proposal and requires source specific NO_X BART for Arkansas EGUs that are covered by CSAPR. The approach that EPA has proposed for Arkansas is inconsistent with that taken for other states. EPA promulgated FIPs to replace reliance on CAIR with reliance on CSAPR for the following states: Georgia, Indiana, Iowa, Kentucky, Michigan, Missouri, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia and West Virginia. Similarly, Virginia is revising the Virginia Regional Haze SIP to rely on the Virginia CSAPR FIP to meet BART and reasonable progress requirements for SO_2 and NO_X. Perhaps most noteworthy, EPA has proposed reliance on CSAPR in states that border Arkansas. The Texas-Oklahoma Regional Haze FIP proposal does not require BART for sources that are subject to CSAPR.[183] In that FIP proposal, EPA reiterates its position that ''CSAPR, like CAIR, provides for greater reasonable progress towards the national goal than would BART,''[184] and proposes replacing reliance on CAIR with reliance on the trading programs of CSAPR as an alternative to SO_2 and NO_X BART for Texas EGUs.[185] Not only is EPA requiring Arkansas EGUs covered by CSAPR to control emissions under BART in the FIP proposal, but EPA has not even considered CSAPR as an option for making reasonable progress. Even if EPA ultimately rejected CSAPR as a means to meet the reasonable progress requirements under the Regional Haze Rule, EPA is required to cogently explain why it has exercised its discretion in a given manner. EPA's failure to consider CSAPR is arbitrary and capricious in light of its treatment of other states. EPA should withdraw the FIP proposal and remove the source-specific NO_X BART requirements for Arkansas EGUs that are covered by CSAPR in any subsequently proposed plan.

Response: Arkansas EGUs are subject to CSAPR for ozone season NO_X, and we acknowledge that a state in the CSAPR region whose EGUs are subject to the requirements of the CSAPR trading program for ozone season NO_X may rely on CSAPR to satisfy the NO_X BART requirement for its EGUs. However, when standing in the shoes of a state and promulgating a FIP, EPA has the same discretion as the state to choose to either conduct source-specific BART determinations or to rely on EPA's 2012 finding that CSAPR is better than BART. Our decision to make source-specific NO_X BART determinations for Arkansas is reasonable for multiple reasons: It is the approach Congress chose in the statute itself;[186] it is consistent with Arkansas' earlier decision to conduct

[180] 40 CFR 51.308(e); 77 FR 33642.

[181] 76 FR 48208.

[182] 77 FR 33642 (June 7, 2012).

[183] Approval and Promulgation of Implementation Plans; Texas and Oklahoma; Regional Haze State Implementation Plans; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze; Federal Implementation Plan for Regional Haze and Interstate Transport of Pollution Affecting Visibility, 79 FR 74818.

[184] 79 FR 74818, 74851.

[185] 79 FR 74818, 74853.

[186] See CAA section 169A(g)(2) in which Congress defined the five factor analysis for determining BART but did not expressly provide for an alternative to source by source BART.

source-specific NO_X BART determinations in lieu of relying on CAIR to meet the BART requirements; and at the time of our proposed action, it properly accounted for uncertainty in the CSAPR better-than-BART regulation created by ongoing litigation regarding the CSAPR program. Further explanation of these reasons is given below.

The Regional Haze regulations provide generally that ''[a] State may opt'' to rely on an emissions trading program rather than to require source-specific BART controls.[187] More specifically, in 2005 EPA revised the Regional Haze regulations to provide that a state subject to CAIR ''need not require affected BART-eligible EGUs to install, operate, and maintain BART.'' [188] Following the D.C. Circuit's vacatur and remand of CAIR,[189] EPA issued CSAPR as a replacement rule. EPA revised its regulations in 2012 to allow states to rely on CSAPR in lieu of source-specific BART.[190]

In its 2008 regional haze SIP submittal, Arkansas decided to not rely on CAIR to satisfy the NO_X BART requirement for its EGUs.[191] In our Regional Haze FIP proposal for Arkansas, we did not rely on CSAPR (the follow up rule to CAIR) to satisfy the NO_X BART requirement for EGUs because we chose to follow the same source-specific approach to NO_X BART that Arkansas selected in its Regional Haze SIP submittal. In addition, litigation surrounding CSAPR was ongoing at the time that we issued our proposed Arkansas Regional Haze FIP. CSAPR was issued in 2011, but on December 30, 2011, the D.C. Circuit stayed the rule prior to implementation. The D.C. Circuit subsequently vacated CSAPR, an action later reversed by the Supreme Court in 2014. The case was then remanded to the D.C. Circuit. Then, after our April 2015 Regional Haze FIP proposal, the D.C. Circuit issued a July 2015 decision in *EME Homer City Generation* v. *EPA* [192] upholding CSAPR but remanding without vacatur a number of the Rule's state NO_X and SO_2 emissions budgets. Arkansas' ozone season NO_X budget is not itself affected by the remand. However, the Court's remand of the affected states' emissions budgets has implications for CSAPR better-than BART, since the demonstration underlying that rulemaking relied on the emission budgets of all states subject to CSAPR, including those that the D.C. Circuit remanded, to establish that CSAPR provides for greater reasonable progress than BART. As of the time EPA is taking this action to finalize Arkansas' Regional Haze FIP, we are in the process of acting on the Court's remand consistent with the planned response we outlined in a June 2016 memorandum.[193]

Our final action on the Arkansas Regional Haze FIP is consistent with our final action on the Texas Regional Haze FIP. Although we proposed to rely on CSAPR to address the NO_X BART requirements for EGUs in Texas, we did not finalize that portion of our proposed Texas FIP given the uncertainty arising from the remand of the CSAPR budgets for Texas and other states.[194] In light of the above, the comments that we are treating Arkansas differently than other states where EPA relied on CSAPR to meet the BART requirements are no longer applicable.

As we have noted throughout this document, we are willing to work with ADEQ to develop a SIP revision that could replace our FIP. Such a SIP revision will need to meet the CAA and EPA's Regional Haze regulations. In its SIP revision, ADEQ may elect to rely on CSAPR to satisfy the NO_X BART requirements for Arkansas' EGUs instead of doing source-specific NO_X BART determinations. Such an approach could be appropriate if, as we expect, the uncertainty created by the D.C. Circuit's remand of the affected states' emission budgets will shortly be resolved.

With regard to the comment that we should not require EGUs that are covered under CSAPR to also install additional emissions controls under reasonable progress analysis, we disagree. In our 2012 finding that CSAPR is better than BART, we stated that states with EGUs covered under CSAPR may rely on CSAPR to satisfy the BART requirement. However, controls under reasonable progress are a separate requirement from BART, and we disagree that states can rely on CSAPR to satisfy the reasonable progress requirements under § 51.308(d)(1). As explained in the 2005 rulemaking addressing reliance on CAIR, our determination that a trading program provides for greater reasonable progress than BART is not a determination that the trading program satisfies all reasonable progress requirements.[195]

I. Cost

We received numerous comments related to the cost analyses we proposed. These comments were received from both industry and environmental groups, and covered all aspects of our cost analyses.

We received comments from industry concerning our proposed scrubber cost analyses that objected to our use of the IPM cost algorithms that Sargent and Lundy (S&L) developed under contract to us. As we discuss in our TSD, we programmed the Spray Dryer Absorber (SDA—a type of dry scrubber), and wet FGD cost algorithms, as employed in version 5.13 of our IPM model, into spreadsheets in our analysis of various aspects of the Entergy White Bluff and Independence scrubber cost analyses.[196] Industry stated these cost algorithms were not accurate enough to warrant their use in individual unit-by-unit cost analyses, do not consider site-specific costs, and that our use of them violated our Control Cost Manual. Environmental groups supported our use of the IPM cost algorithms, and employed them as well in costing scrubber and SCR control costs to support their own comments. In response, we conclude that the IPM cost algorithms provide reliable, study-level, unit-specific costs for regulatory cost analysis such as required for BART and reasonable progress.[197]

We received comments relating to our critique of Entergy's White Bluff dry scrubber cost analysis. These primarily involved claims that we (1) improperly escalated Entergy's own cost analyses, (2) improperly excluded costs, (3) under-estimated O&M costs, (4) improperly calculated the SO_2 baseline, (5) improperly excluded ''Allowance for Funds Used During Construction''

[187] 40 CFR 51.308(e)(2).

[188] 70 FR 39104, 39156 (July 6, 2005).

[189] *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir. 2008).

[190] 77 FR 33642.

[191] As Arkansas did not rely on CAIR to satisfy requirements in the regional haze SIP, Arkansas is not included in the EPA's limited disapproval of regional haze SIPs that relied on CAIR to satisfy certain regional haze requirements. See 77 FR 33642, at 33654. In that same rulemaking, the EPA promulgated FIPs to replace reliance on CAIR with reliance on CSAPR in many of those regional haze SIPs; however, Arkansas was likewise not included in that FIP action.

[192] 795 F.3d 118 (DC Cir 2015).

[193] *https://www3.epa.gov/airtransport/CSAPR/pdfs/CSAPR_SO₂_Remand_Memo.pdf.*

[194] 81 FR 296, 302.

[195] 70 FR 39104, 39143; see also 77 FR 33642, 33653.

[196] See discussion beginning on pages 9 and 20 of our TSD Appendix A.

[197] We believe that the IPM cost algorithms provide study level accuracy. See pdf page 17 of our Control Cost Manual: ''[a]''study'' level estimate [has] a nominal accuracy of ± 30% percent. According to Perry's Chemical Engineer's Handbook, a study estimate is '. . . used to estimate the economic feasibility of a project before expending significant funds for piloting, marketing, land surveys, and acquisition . . . [However] it can be prepared at relatively low cost with minimum data.'''

(AFUDC) and owner's costs, and (6) improperly extended our White Bluff scrubber cost analyses to the Independence facility. In response to these comments, we have made some minor adjustments to our White Bluff scrubber cost analyses, but those changes do not change our proposal that scrubbers remain cost-effective for the White Bluff facility, and by extension to the Independence facility.

We received comments from environmental groups concerning the White Bluff, Independence, and Flint Creek facilities that (1) generally supported our proposed control suite, (2) criticized us in some cases for not proposing stricter control levels, (3) criticized our control cost analyses for being too conservative in some cases and/or containing errors, and (4) criticized us in some cases for not requiring earlier compliance. These groups also generally opposed our BART determination for Lake Catherine Unit 4.

Below we present a summary of our responses to the more significant comments we received that relate to our proposed cost analyses.

Comment: S&L states we significantly under-estimated the direct Operating and Maintenance (''O&M'') costs projected for the scrubbers by using its Integrated Planning Model (''IPM'') Spray Dryer Absorber (''SDA'') cost model to scale the O&M costs rather than estimating these costs using current utility pricing information. S&L stated that our use of the IPM cost algorithms was not in keeping with our Control Cost Manual and because of the limited number of site-specific inputs, the IPM cost algorithms provide order-of-magnitude control system cost estimates, but do not provide case-by-case project-specific cost estimates meeting the requirements of the BART Guidelines, nor do the IPM equations incorporate the cost estimating methodology described in the Control Cost Manual.

Response: We disagree with S&L. As we discuss in our TSD,[198] we needed to adjust Entergy's O&M costs for its White Bluff SDA model because of a mismatch between Entergy's SO_2 emission baseline and the SO_2 inlet it assumed in the design of its scrubber (discussed in our response to another comment). Entergy costed a scrubber capable of treating a SO_2 level of 2.0 lbs/MMBtu, when it historically burned coal that averaged less than 0.6 lbs/MMBtu from 2009–2013. This had the effect of worsening the cost effectiveness (increasing the $/ton) over what it would have been had Entergy designed it to treat the coal it historically burned. We could not directly adjust Entergy's O&M costs because Entergy's O&M cost estimates were based on an S&L economic model from May 2008, which it did not supply.[199] These issues, which we discuss in our responses to comments elsewhere, dictated a revision to Entergy's cost estimate. We were left with no choice but to seek an alternative means of estimating Entergy's O&M costs, in order to address the mismatch described above. We utilized the IPM SDA cost model that Entergy's own contractor designed for us.

We disagree that our cost estimates were not in keeping with the Control Cost Manual. As we stated in our TSD Appendix A, we relied on the methods and principles contained within the Control Cost Manual, namely the use of the overnight costing method. In fact, the Control Cost Manual does not include any method for estimating the costs specific to any of the SO_2 control equipment evaluated in this action. We note our technique of relying on a publicly available control cost tool is similar to the strategy the states themselves employed in the development of their SIPs. For instance, as explained in the Texas SIP, the ADEQ used the control strategy analysis completed by the CENRAP, which depended on the EPA AirControlNET tool[200] to develop cost per ton estimates. We have used IPM cost models to estimate BART costs in other similar rulemakings including our Arizona Regional Haze FIPs,[201] the Wyoming Regional Haze FIP,[202] and to supplement our analysis in the Oklahoma FIP.[203] S&L used real world cost data to construct its cost algorithms and confirm their validity. These cost models have been updated and maintained since their introduction in 2010 and we have been continuously using them since that time. These control costs are based on databases of actual control project costs and account for project specifics such as unit size, coal type, gross heat rate, and retrofit factor. The costs further require unit specific inputs such as reagent cost, waste disposal cost, auxiliary power cost, labor cost, gross load, and emission information. We believe that the IPM cost models provide reliable study-level, unit-specific costs for regulatory cost analysis such as required for BART and reasonable progress. We are confident enough in the basic methodology behind the S&L cost algorithms that in our recent update of the SCR chapter of the Control Cost Manual[204] we presented an example costing methodology that is based on the IPM S&L SCR algorithms, which were developed using a similar methodology to the wet FGD, SDA, and DSI cost algorithms discussed herein. Lastly, we note that Entergy used a number of general approximations when estimating the wet scrubbing costs for White Bluff, as we describe in our TSD.[205] We conclude that our approach is in keeping with the Control Cost Manual and is sufficiently accurate for its intended purpose.

Comment: Entergy disagreed with our approach for escalating a 2013 scrubber cost analysis for its White Bluff facility to 2015, rather than obtaining a revised cost estimate. Entergy claims this caused us to underestimate our scrubber cost estimate by $36,322,881 (total for both units). Entergy also disagreed with our application of the Chemical Engineering Plant Cost Index (CEPCI) indices in several instances from 2008 that de-escalated costs, resulting in lower costs in 2013 as compared to 2008. Entergy states that our cost calculations ignored the updated 2012 direct annual costs it provided, and instead included the 2008 costs. In a subsequent comment, Entergy calculates an escalation rate of 4.7%, based on a comparison of a revised 2013 quote to a 2009 quote, and applies that escalation rate along with other corrections to various cost line items in concluding that we underestimated the cost of installing scrubbers at the White Bluff facility by $42,607,547 per unit.

Response: For our proposal, we used Entergy's revised BART analysis for the White Bluff facility, as submitted by it on October 14, 2013, because at the time it was the latest information available to us.[206] In our proposal, our control cost analysis used the same basic information that Entergy previously presented to us in 2013. As we describe in Appendix A of our TSD, Entergy stated that it received two different SDA cost estimates for White Bluff: An early 2009 Sargent and Lundy (S&L) estimate with a total contractor cost of $291,930,000, and a December 2009

[198] See Section 3.1 in Appendix A of our TSD.

[199] See Section 2.7 in Appendix A of our TSD.

[200] Our AirControlNET tool is out of date and no longer supported.

[201] 77 FR 42852 (July 20, 2012).

[202] Memorandum from Jim Staudt to Doug Grano, EPA, Re: Review of Estimated Compliance Costs for Wyoming Electricity Generating Units (EGUs)—Revision of Previous Memo, February 7, 2013, EPA–R08–OAR–2012–0026–0086_Feb 7, 2013.

[203] 76 FR 81728 (December 28, 2011).

[204] *https://www3.epa.gov/ttn/ecas/cost_manual.html.*

[205] See discussion beginning on page 19 of Appendix A to our TSD.

[206] See section 2.1 of Appendix A to our TSD.

estimate from Alstom of $247,856,184. Entergy stated that unlike the S&L quote, the Alstom estimate was not itemized and only included a total price. Entergy used the 2009 Alstom price quote as the basis for its BART cost analysis for White Bluff by increasing it by 10%, and scaling the S&L itemized cost to match the 110% adjusted Alstom total price. As we describe in our RTC, we critiqued certain aspects of Entergy's use of this information. For example, Entergy mistakenly included certain NO_X controls in its 2013 cost analysis. It also failed to document certain BOP costs that we had no choice but to exclude. However, between the 2009 S&L and the 2009 Alstom quotes, and with these corrections, we were able to construct a reasonable control cost estimate. In so doing, we used the same 2009 Alstom total, and the Alstom payment schedule for its quote, as the actual Alstom quote was not supplied and no better information was presented by Entergy. Because Entergy's 2013 cost estimate used 2009 Alstom pricing, we had no choice but to escalate it to 2013—more recent information was not available.

Entergy did not provide its updated 2015 cost estimate, which it references in its comment, until after our proposal. Entergy's 2015 report uses updated 2013 pricing from Alstom as its basis. As we discuss in our RTC, we reviewed this 2015 cost analysis and found that it presents problems that prevent us from using it, primarily because it is undocumented.

In this comment, Entergy attempts to use its newly submitted 2015 cost analysis to discredit the escalation technique we employed to adjust its previous 2013 cost analysis. It does so without even presenting the 2013 Alstom quote on which it states the 2015 cost estimate relies. Thus, we have no basis to conclude that the costs Entergy presents in its first table above even cover the same scope of work. This is an important consideration and a different scope can cause a significant difference in cost. Entergy itself noted this when it used a revised BOP estimate to adjust its 2009 Alstom quote because the scope had changed. Even different cost estimates received in the same year can result in significantly different totals. For instance, as we also note in our TSD, Entergy stated that it received two different SDA cost estimates for White Bluff: An early 2009 S&L estimate with a total contractor cost of $291,930,000, and a December 2009 estimate from Alstom of $247,856,184.[207] We note that the difference between these two quotes is $44,073,816, which is more than Entergy calculates in its first table above is the difference between our escalated 2013 quote ($261,581,119) and its revised 2015 cost estimate, based on the its 2013 Alstom quote ($297,904,000).

Escalation from one year's cost basis to another[208] is not only allowed by the Control Cost Manual, it is a required procedure in order to allow an apples-to-apples comparison between control cost analyses. Our use of the Chemical Engineering Plant Cost Index (CEPCI) is a standard method of escalating costs,[209] and one that power companies have also used on numerous occasions. Entergy itself has used the CEPCI in an attempt to escalate its costs. Unfortunately, as we explain in our TSD, Entergy did so incorrectly and we corrected that error.[210] We certainly prefer revised vendor quotations to escalating older cost estimates. However, when revised vendor quotes are not available as in this case, we have no choice but to escalate older cost estimates in order to bring the cost basis to the present.

Entergy also apparently objects to any escalation technique that results in a reduction in a future year's cost basis, holding it up as evidence of our error.[211] This is a fundamental misunderstanding of escalation. For instance, although the Composite CE index usually increases from year to year, it does occasionally decrease, due to various broad economic factors, such as it did from 2008 to 2009, and again from 2011 to 2013. This is mainly due to broad economic factors that influence the cost of raw materials, supply and demand, vendor profit, etc. Thus, Entergy's objection over the ''de-escalation'' of cost from 2008 to 2013 is entirely misplaced. In other words, escalation is escalation: Most of the time it is positive but sometimes it is negative. We therefore do not agree with Entergy's objections to our escalation technique. We take up the issue of Entergy's 2015 cost estimate in our response to another comment.

Entergy states that our cost calculations ignored the updated 2012 direct annual costs provided by Entergy, and instead included the 2008 costs. As noted in the first sentence of our response to this comment, we were constrained to use Entergy's revised BART analysis for the White Bluff facility, as submitted by Entergy on October 14, 2013 (hereafter referred to as the ''2013 SDA Cost Analysis''). These costs employed a 2008 vintage total direct annual cost, as we indicate in Appendix A of our TSD.[212] Regarding its direct annual costs, Entergy further states, ''The cost estimates were scaled to reflect 2012 dollars.'' [213] We therefore agree that Entergy did provide what it stated was 2012 vintage direct annual costs. We did not use those costs because Entergy incorrectly escalated them from 2008, as we discuss above. For instance, Entergy presented its 2008 direct annual cost as $7,901,369. It then ''scaled'' them to 2012 using a 2008 CEPCI index of 530.7 and a 2012 CEPCI index of 593.6, resulting in a 2012 value of $8,837,861. As we discuss in Appendix A of our TSD, Entergy appears to have incorrectly used the January monthly CEPCI value for each year instead of the annual CEPCI value. Entergy should have used a 2008 CEPCI index of 575.4 and a 2012 CEPCI index of 584.6, resulting in a 2012 escalated direct annual cost of $8,027,703 ($7,901,369 × 584.6/575.4). As we also discuss in our TSD, because we were conducting our analysis later, we escalated Entergy's 2008 direct annual cost to 2013, resulting in a value of $7,790,140 ($7,901,369 × 567.3/575.4). These facts appear to have been ignored by Entergy in its comment. We therefore have no choice but to disagree with Entergy's comment concerning our not using its 2012 direct annual cost.

Comment: Entergy and Nucor stated that we improperly excluded AFUDC and owner's costs from our White Bluff control cost analysis. Entergy also objects to our disallowance of certain BOP costs.

Response: As we have noted in a number of our FIPs, AFUDC and Owner's Costs are not valid costs under our Control Cost Manual methodology. We invite the commenters to examine our response to similar comments we received in response to those actions.[214]

In Appendix A to our TSD, we noted that Entergy used BOP costs from a 2008 S&L quote to supplement its adjusted 2009 Alstom quote in its 2013 SDA cost analysis for the White Bluff BART determination. However, due to a lack of documentation, it appeared that a number of items were either not appropriate for a SO_2 scrubber, or were

[207] See section 2.1 of Appendix A to our TSD.

[208] Note that escalation during the construction period is disallowed, however, because that is not a part of the overnight method.

[209] Vatavuk, William, M., ''Updating the CE Plant Cost Index,'' Chemical Engineering, January 2002.

[210] See section 2.6 of Appendix A to our TSD.

[211] Entergy's reference to de-escalated costs.

[212] See section 2.7 of Appendix A to our TSD.

[213] Revised Bart Five Factor Analysis, White Bluff Steam Electric Station, Redfield, Arkansas (AFIN 35–00110). Appendix A, SDA cost analysis, June 2013, Appendix A.

[214] See, *e.g.,* ''Response to Technical Comments for Sections E through H of the **Federal Register** Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan,'' Docket No. EPA–R06–OAR–2010–0190, 12/13/2011.

already covered as part of the Alstom quote. As discussed in detail in our RTC document, we removed those items from our proposed SDA cost analysis and invited Entergy to supply additional documentation to verify these costs. S&L now points to an S&L Report #012831, which contains a 2015 White Bluff SDA cost estimate, for that documentation. First, Entergy states that its 2015 SDA cost estimate is based on a 2013 Alstom quote. As with the 2009 Alstom quote it used to support its 2013 SDA cost analysis, Entergy did not provide this Alstom quote. Consequently, we have no way of verifying Entergy's 2015 cost calculations or to conclude that their scopes are the same. Therefore, we have no choice but to conclude that Entergy has not demonstrated that our removal of costs associated with the reagent preparation enclosure and reagent handling system and ductwork was incorrect. Similarly, we continue to find that Entergy has not documented certain BOP indirect costs, miscellaneous contract labor, Entergy internal costs, and capital suspense.

We do agree that Entergy has provided documentation for other costs, including demonstrating that recalibration of the CEMS and painting of the chimney are justified, and we have adjusted our White Bluff scrubber cost analysis accordingly. Other costs that were calculated as percentages of the equipment, material, and labor costs were similarly adjusted. We have revised our cost analysis to include these adjustments, and have determined that dry scrubbers are estimated to cost $2,565/SO_2 ton removed at Unit 1 and $2,421/SO_2 ton removed at Unit 2.[215] Revising these costs did not change our final determination that dry scrubbers are cost-effective for the White Bluff facility.

Comment: S&L objects to our approach of calculating an SO_2 baseline for the White Bluff and Independence facilities, in which we eliminated the high and low annual emission values from 2009 to 2013, and averaged the remaining values. S&L presents four alternative approaches in which a straight five year average from 2009 to 2013, and different three year averages from 2009 to 2013 are examined for White Bluff Units 1 and 2 and Independence Units 1 and 2, and concludes that in all cases, at least one of the alternative approaches would have resulted in lower baseline SO_2 emissions for one of the units.

Response: We disagree with S&L that we erred in the procedure we used in estimating baseline emissions for our BART and reasonable progress scrubber upgrade cost analyses. We calculated our baseline SO_2 emissions by first acquiring the 2009 to 2013 emissions as reported to us by the facilities in question.[216] We reasonably eliminated the high and low values from the 2009–2013 emissions to better address potential yearly variations in in coal sulfur data, capacity usage, etc., and to make the baseline more representative of plant operations and thereby provide the basis for a more accurate estimate of the cost effectiveness of controls. The fact that S&L can construct alternative approaches to our baseline calculation that result in lower emissions estimates does not invalidate our BART and reasonable progress approaches. As can be seen from an examination of S&L's own data, regardless of whether a 3-year average or a 5-year average of a particular set of years is employed, the resulting emissions baselines are all similar. In fact, for three out of four units, one of S&L's alternative approaches would have produced higher SO_2 emissions baselines, which if used would have resulted in the cost analyses we performed being even more cost-effective. We believe that the procedure we used is in compliance with the BART Guidelines, which states:

> How do I calculate baseline emissions?
>
> 1. The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period.
>
> 2. When you project that future operating parameters (*e.g.,* limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.[217]

Regarding the baseline used in our Independence reasonable progress analysis, our 2007 Reasonable Progress Guidance notes the similarity between some of the reasonable progress factors and the BART factors contained in § 51.308(e)(1)((ii)(A), and suggests that the BART Guidelines be consulted regarding cost, energy and nonair quality environmental impacts, and remaining useful life.[218] We are therefore relying on our BART Guidelines for assistance in interpreting those reasonable progress factors, as applicable. One of these areas is in the calculation of the baseline emissions in determining cost effectiveness.

The difference between our baseline calculations and any of the alternative procedures S&L outlines is small and would not change our conclusions for the White Bluff BART determinations and the Independence reasonable progress determinations.

Comment: S&L objects to our extending our White Bluff scrubber cost analysis to the Independence facility on the basis of the similarity of the two facilities. S&L states that our use of EIA information, satellite photographs and other points of comparison are inadequate to account for potential site-specific differences between the two facilities, such as operating data, O&M practices, underground utility interferences, geotechnical differences, and seismic differences.

Response: While there are likely differences between the two facilities that would have some minor impact on the scrubber cost analyses, we reasonably concluded based on the information available to us that there were enough similarities between the facilities to make our approach appropriate. As we discuss in our TSD:

> The White Bluff and Independence facilities are sister facilities. According to EIA,[219] the boilers were manufactured by Combustion Engineering with in-service dates of 1980 and 1981 for White Bluff, and 1983 and 1985 for Independence. All four units are tangentially firing boilers having nameplate capacities of 900 MW and similar gross ratings. As we indicate above, all four units burn coal from the Powder River Basin of Wyoming with similar characteristics. All four units employ cold side electrostatic precipitators for particulate collection. Other pertinent characteristics are similar.[220]

We further presented satellite photographs to demonstrate that the layout of these facilities are extremely similar. We consequently expect that the differences Entergy describes in its comments result in minor differences in the cost to install and operate scrubbers. As we have discussed in our response to another comment, the Control Cost Manual explains that the sole input required for making an ''order of magnitude'' estimate is the control

[215] See the file, ''White Bluff_R6 cost *revisions2-revised.xlsx*'' in our docket.

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

[217] 70 FR 39104, 39167.

[218] ''Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program,'' at 5–1.

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

[220] See document titled ''AR RH FIP TSD Appendix A—White Bluff and Independence SO_2 Cost Analysis,'' found in the docket for this rulemaking.

system's capacity (often measured by the maximum volumetric flow rate of the gas passing through the system). Such an estimate, for example, could be obtained from the cost reported in dollars per megawatt ($/MW) or dollars per million BTUs fired ($/MMBtu), metrics that are widely reported in the literature. The Control Cost Manual indicates that ''the costs and estimating methodology in this Manual are directed toward the 'study' estimate with a nominal accuracy of +/−30% percent.'' This is the long-standing rule of thumb for cost estimate accuracy used by the EPA for regulatory cost effectiveness analyses. We see nothing in Entergy's comments that would suggest that the differences between these two facilities are so significant they would impact this required level of accuracy. Indeed, Entergy does not attempt to estimate the capital costs of these differences or otherwise provide a cost estimate specific to the Independence facility in support of its argument that it was inappropriate for us to extend our White Bluff scrubber cost analysis to the Independence facility.

Comment: Entergy objects to our correction to its White Bluff scrubber control cost analysis to adjust the cost for a scrubber designed to treat a 2.0 lb/MMBtu coal to 0.68 lbs/MMBtu to account for the lower sulfur coal it has historically burned. Entergy states that we correctly assumed that the 2.0 lb/MMBtu design basis for the White Bluff scrubber was to preserve fuel flexibility, but our conclusions that, ''either (1) this higher cost be balanced against its greater SO_2 reduction potential, or (2) that the scrubber system's capability and cost be adjusted down to match the facility's historical emissions'' are without basis and inconsistent with the BART guidelines. Entergy also concludes that its assumption that a 2.0 lb/MMBtu scrubber inlet was in error and a 1.2 lb/MMBtu inlet assumption is now appropriate. Entergy presents SO_2 emission data in support of its position that our 0.68 lbs/MMBtu coal assumption was incorrect and recalculates its O&M and capital costs. Lastly, Entergy states that in correcting its scrubber control cost analysis to account for a 0.68 lbs/MMBtu coal, we misapplied a correction factor to our total direct and indirect costs.

Response: As we noted in our TSD, ''either (1) this higher cost be balanced against its greater SO_2 reduction potential, or (2) that the scrubber system's capability and cost be adjusted down to match the facility's historical emissions.'' Entergy chose to do neither and costed a scrubber capable of treating a coal far in excess of what it historically burned, but continued to base the capabilities of the scrubber on its historical SO_2 baseline. Thus, either Entergy's annualized cost (the ''$'') or its tons reduced (the ''tons'') in the $/ton cost effectiveness calculation are misrepresented. Our approach was to recalculate Entergy's scrubber cost to bring its scrubber design in line with the coal it has historically burned. Entergy could have taken the alternative approach of calculating a new baseline on the basis of its higher sulfur design coal, but it chose not to do so. We see nothing in Entergy's comments that would cause us to conclude our reasoning was in error. With regard to Entergy's concerns with the 0.68 lbs/MMBtu baseline that we use, it appears the SO_2 emission data Entergy presented was hourly data, which should not be used to design a scrubber that would have to meet a 30–BOD average. Our analysis indicates the individual hourly data fluctuations Entergy presents are inconsequential. Further, an examination of the running 30–BOD average indicates that our decision to fix the mismatch between Entergy's scrubber costs and its historical SO_2 baseline on the basis of a SO_2 inlet of 0.68 lbs/MMBtu is reasonable.

In apparent agreement with our basic approach, Entergy recalculates its variable and fixed O&M costs on the basis of 0.68 lb/MMBtu fuel sulfur levels. We note that our own variable and fixed O&M costs are actually greater, adding to the conservativeness of our calculation. To illustrate the small difference in capital costs associated with the revised design basis (1.2 lb/MMBtu versus 0.68 lb/MMBtu), Entergy then performs a sensitivity analysis and concedes there is a ''small difference in capital costs associated with the revised design basis (1.2 lb/MMBtu versus 0.68 lb/MMBtu). . . .'' This conclusion is borne out by our own figures, which indicate there is a small difference in capital costs to even the 2.0 lbs/MMBtu case; the capital, engineering and construction costs, which cover the fundamental design parameter of a scrubber—gas flow rate—were only changed by less than 5%. In sum, Entergy's assertion that our cost analysis improperly designed the White Bluff scrubber system is without merit and would make an insignificant difference in the final outcome.

Lastly, we agree with Entergy that we misapplied a correction factor to our total direct and indirect costs. We incorporate that correction in our final SDA cost analysis for the White Bluff and Independence facilities, which we discuss in more detail in our response to other comments. This correction has a relatively minor impact on the overall cost analysis.

Comment: The Sierra Club supported our proposal regarding SO_2 for the White Bluff and Independence facilities, but concluded that our proposed SO_2 emission rate of 0.06 lbs/MMBtu on a 30–BOD average should have been stricter at 0.04 lbs/MMBtu, based on wet scrubbing. The Sierra Club also agrees with our assessment that Entergy included undocumented costs in its White Bluff scrubber cost estimate.

The Sierra Club's consultant performed a cost analysis of dry and wet scrubber systems, including Alstom's NID circulating dry scrubber, and concluded that our White Bluff scrubber cost analysis was conservative, that scrubbers are cost effective compared to controls required pursuant to other BART determinations, and that we should have required compliance in 3 years instead of 5 years.

Response: We confirm that we intended to construct conservative cost estimates. With some minor disagreements with the Sierra Club, we generally agree that an independent cost analysis such as it presents does support our basic position that scrubbers are cost effective at both the White Bluff and Independence facilities. However, as we discuss in our RTC document, we disagree that in this specific instance wet scrubbers are more cost effective than dry scrubbers. Our scrubber cost analyses was built off of the analyses supplied by Entergy, and we determined that wet scrubbers were significantly less cost effective—again, in the specific cases of the White Bluff and Independence facilities for BART and reasonable progress respectively. We disagree with the SO_2 baseline Sierra Club uses in its cost analysis, rendering its scrubber cost analysis and ours not directly comparable. Consequently, we disagree that an SO_2 emission rate of 0.04 lbs/MMBtu averaged over a 30-boiler-operating-day period, based on a wet scrubber cost analysis, is appropriate for either the White Bluff or Independence facilities. We agree that in some cases scrubbers can be installed in less than the 5 years that we proposed. However, this is site-specific and, in this case, we have found that installation within 5 years is as expeditious as practicably possible.

We agree that the Alstom NID circulating dry scrubber is a promising SO_2 control option. We reviewed NID in our preliminary work but ultimately decided not to evaluate it as a control because we had no relevant operating data and no method to estimate costs.

After addressing all comments from Entergy and the Sierra Club concerning our White Bluff and Independence scrubber cost analyses, we made several minor corrections.[221] Below we summarize those corrections:

TABLE 18—CORRECTIONS TO OUR COST-EFFECTIVENESS CALCULATIONS FOR DRY FGD FOR WHITE BLUFF AND INDEPENDENCE

Unit	Proposed cost-effectiveness ($/ton)	Final cost-effectiveness ($/ton)
White Bluff Unit 1	$2,227	$2,565
White Bluff Unit 2	2,101	2,421
Independence Unit 1	2,477	2,853
Independence Unit 2	2,286	2,634

We find that these revised cost-effectiveness calculations do not change our proposed findings for BART and reasonable progress for these units.

In addition, we have examined the effect of adding back in a number of the BOP and other costs we excluded (based on these costs being either disallowed by the Control Cost Manual, or having lacked documentation from Entergy). This exercise also appears in the file ''White Bluff_R6 cost revisions2-revised.xlsx.'' These costs include:

• BOP Costs associated with the reagent prep enclosure and the reagent handling system, totaling $21,229,000.
• BOP Costs associated with the flue gas system ductwork, totaling $1,754,000.
• BOP indirect costs of $8,474,666 (escalated to 2013).
• Miscellaneous contract labor costs of $4,448,074 (escalated to 2013).
• Entergy internal costs of $19,482,518 (escalated to 2013).
• Capital suspense costs of $8,101,226 (escalated to 2013).

TABLE 19—ALTERNATE COST-EFFECTIVE CALCULATIONS FOR DRY FGD ON WHITE BLUFF AND INDEPENDENCE

[Include disallowed costs]

Unit	Alternate cost-effectiveness ($/ton)
White Bluff Unit 1	$3,013
White Bluff Unit 2	2,843
Independence Unit 1	3,351
Independence Unit 2	3,093

We continue to believe that these costs are either disallowed by the Control Cost Manual, or are properly disallowed because they lack documentation from Entergy. We have presented this information to indicate that these disallowed costs have a relatively minor effect on the final cost effectiveness. Although our final decision regarding BART and reasonable progress for the White Bluff and Independence units does not rest upon these cost-effectiveness calculations that include the disallowed costs, had our final decision rested on these cost-effectiveness calculations, we would have reached the same conclusions regarding BART and reasonable progress for these units.

Comment: The Sierra Club stated that the NO_X emission limit of 0.15 lbs/MMBtu based on LNB/SOFA we proposed for White Bluff Units 1 and 2 does not satisfy BART. The Sierra Club asserted that NO_X BART for these units should have been based on SCR. The Sierra Club's consultant concluded that we overestimated the costs of SCR and underestimated the visibility benefits of SNCR and SCR. The consultant's conclusions are based on cost-effectiveness calculations developed by the consultant, which rely on the S&L IPM SCR Cost Module and assume an achievable NO_X emission rate of 0.04 lb/MMBtu for LNB/SOFA plus SCR. The Sierra Club stated that LNB/SOFA can be installed in much shorter timeframe than the 3 years we proposed. The Sierra Club also stated that we should have evaluated SNCR and SCR for the Independence facility.

Response: We have a number of disagreements with the Sierra Club's consultant concerning the SCR cost analysis provided, including the NO_X baseline and the emission limit, which are outlined in detail in our RTC document. After addressing those issues, we do not believe that the cost effectiveness of SCR or SNCR fall within a range that justifies the relatively small incremental visibility improvement (over our NO_X BART determination based on LNB/SOFA) that would result from the installation of SNCR or SCR at the White Bluff facility. As we discussed in our proposal,[222] our modeling indicated that the visibility improvement at several Class I areas from the installation of LNB/SOFA at the Independence facility was of a similar magnitude as the same controls at the White Bluff facility, and cumulatively (*i.e.,* at all Class I areas combined) the visibility improvement of the controls at Independence was lower than at White Bluff. Therefore, we reasoned that since White Bluff and Independence are sister facilities with near identical units, the cost effectiveness of SCR or SNCR at Independence would likely not fall within a range that justifies the relatively small incremental visibility improvement (over LNB/SOFA) that would result from installation of these controls. Therefore, we did not evaluate SCR or SNCR controls for Independence. As we discuss in a separate response, after carefully considering the comments we have received, we are finalizing an 18-month compliance date for the NO_X emission limits we are establishing for White Bluff Units 1 sand 2 under BART and Independence Units 1 and 2 under reasonable progress.

Comment: The Sierra Club and others stated that the costs of both a wet and a dry scrubber are reasonable at the two Independence units. The Sierra noted our proposed costs are reasonable in other reasonable progress determinations that it summarizes. The Sierra Club's consultant independently calculated the costs of scrubbers at Independence Units 1 and 2 and concluded that those calculations confirm that a scrubber is cost-effective. The consultant also noted that the significant visibility improvement from a scrubber at Independence Units 1 and 2 would equal or exceed the visibility improvement from other reasonable

[221] Those corrections are contained in the file, ''White Bluff_R6 cost revisions2-revised.xlsx,'' which appears in our docket.

[222] See our supplemental NO_X modeling results for the Independence facility in 80 FR 24872 vs. our NO_X modeling results for the White Bluff facility in 80 FR at 18974.

progress controls we have previously approved. The Sierra Club's consultant also incorporated comments for the White Bluff facility regarding time for installation and control level.

Response: We take no position on the separate cost analysis that the Sierra Club's consultant has conducted for dry and wet scrubbers and that uses to conclude that our cost analyses are reasonable. We agree that our finding that the control costs are reasonable, given the visibility improvements achieved, is consistent with other EPA actions. We refer the Sierra Club's consultant to our responses to other similar comments regarding the White Bluff facility scrubber concerning control level and installation time.

Comment: The Sierra Club and others stated that our proposal that SO_2 BART for AEP Flint Creek is a NID dry scrubber is appropriate, but argued that a NID dry scrubber is even more cost-effective than what AEP and EPA have estimated. The Sierra Club's consultant presented cost analyses for wet and NID scrubbing for Flint Creek, based on the IPM cost algorithms we used in our recent Texas-Oklahoma FIP. In so doing, the consultant applied the SDA cost algorithm to NID, citing to documentation that indicates that NID may be 1–2% lower in cost to an SDA system. The Sierra Club's consultant argues that both wet and dry scrubbers are capable of even greater levels of control than what we assumed.

Response: As we discuss in our TSD,[223] we noted a number of issues with AEP's NID and wet scrubber cost analyses that if corrected would have resulted in more favorable (lower $/ton) cost-effectiveness values. Nevertheless, even disregarding those errors, we concluded that NID was cost-effective and worth the visibility benefit that will result from its installation. We also determined that wet scrubbing would remain less cost-effective than NID, and was not worth the small additional visibility that would result from its installation in this particular instance.

We extensively analyzed the performance potential of wet scrubbers in our recent Texas-Oklahoma FIP.[224] We concluded that a control level of 98%, not to go below an emission rate of 0.04 lbs/MMBtu on a 30–BOD average, was a reasonable lower level of control. We applied the same reasoning to our Arkansas proposal. As we discuss in our response to another comment, although we regard NID as a promising technology that may in fact be capable of greater levels of control than what we have assumed, there is no real long-term monitoring data to substantiate such a conclusion. Therefore, because we have concluded that in this instance the cost-effectiveness of wet scrubbers is not justified by their relatively small additional visibility benefit, we disagree that SO_2 BART for Flint Creek Unit 1 should be 0.04, based on the performance of a wet scrubber.

Comment: The Sierra Club and others stated that the LNB/OFA proposal for Flint Creek does not satisfy NO_X BART, which should have been based on SCR. The Sierra Club stated that we and AEP used very conservative assumptions that inflated the cost of the SCRs and SNCRs as NO_X BART options for Flint Creek. The Sierra Club's consultant stated that the 20-year life assumed in AEP's SCR cost analysis should have been 30 years, and that the assumed level of control should have been 0.04 lbs/MMBtu. The consultant then performed an SCR control cost analysis and concluded that the cost effectiveness was within a range we have previously found to be acceptable in other BART determinations. The Sierra Club's consultant also stated that AEP overestimated the cost of SNCR because it based it on a reduction of from 0.31 lbs/MMBtu to 0.2 lbs/MMBtu, when in fact, the first-in-line LNB/OFA controls would have already reduced the NO_X to 0.23 lbs/MMBtu, resulting in a lesser loading to the SNCR system and reducing its operating costs.

Response: We note that we provided comments to ADEQ,[225] which included a recommendation that 30 years should be used as an equipment life for SNCR. AEP did not adopt this recommendation in its September 2013 BART analysis for the Flint Creek facility. We agree with the Sierra Club's consultant that AEP overestimated the cost of SNCR because its calculation based it on a reduction of from 0.31 lbs/MMBtu to 0.2 lbs/MMBtu. We have corrected this error, and the error in AEP SWEPCO's assumed 20-year equipment life, and recalculated the SNCR cost effectiveness for Flint Creek. We calculated that SNCR + LNB/OFA has a revised cost-effectiveness of $1,346/ton, as opposed to cost effectiveness of $1,258/ton for LNB/OFA alone. Also, we calculated that the incremental cost effectiveness of SNCR + LNB/OFA over LNB/OFA alone is $1,581/ton. We then re-applied the BART five factors, with emphasis on cost and visibility improvement. The incremental visibility improvement of SNCR + LNB/OFA over LNB/OFA alone is 0.033 dv at Caney Creek and ranges from 0.005 to 0.01 dv at each of the other affected Class I areas. As discussed in our proposal, we consider the incremental visibility improvement of SNCR + LNB/OFA to be relatively small at Caney Creek and to be very small in the remaining three affected Class I areas. We conclude that despite the improvement in the cost-effectiveness of SNCR + LNB/OFA over LNB/OFA alone, under these circumstances the resulting relatively small incremental visibility improvement is still not worth the additional cost of the more stringent controls.

Regarding the Sierra Club's consultant's SCR control cost analysis, we do not believe that a NO_X emission limit of 0.04 lbs/MMBtu has been maintained on a 30 boiler-operating-day average at other similar facilities. We conclude that, as we did in our New Mexico FIP, a 30 boiler-operating-day NO_X average of 0.05 lbs/MMBtu is an appropriate assumption for SCR installation at the Flint Creek facility. We also note that the maximum visibility improvement due to SCR at Flint Creek based on the modeled rate of 0.067 lb/MMBtu was 0.245 dv, which occurred at Caney Creek. If we make reasonable, conservative adjustments to the anticipated visibility benefit, based on a control level of 0.055 lbs/MMBtu rather than the modeled rate of 0.067 lbs/MMBtu,[226] we estimate that the resulting visibility improvement at Caney Creek would be no higher than

[223] See page 65 of our TSD: ''[W]e 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 values. Therefore, we believe a wet scrubber and NID are 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 values 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 a wet scrubber would continue to be higher than the costs associated with NID if the estimates were adjusted, yet the installation and operation of a wet scrubber is projected to result in minimal incremental visibility improvement over NID.

[224] See response to comment beginning on page 310 of our Response to Comments for the **Federal Register** Notice for the Texas and Oklahoma Regional Haze State Implementation Plans; Interstate Visibility Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze; and Federal Implementation Plan for Regional Haze, Docket No. EPA–R06–OAR–2014–0754, 12/9/2015.

[225] See email from Dayana Medina to Mary Pettyjohn on 8/21/13.

[226] Modeled emission rates were based on a maximum heat input of 6,324 MMBtu/hr multiplied by the anticipated control rate (*e.g.* 0.067 lb/MMBtu) Baseline emissions determined from 2001–2003 CAMD data were 1,945 lb/hr, approximately 0.308 lb/MMBtu.

0.26 dv.[227] Based on this adjustment, the incremental visibility improvement of SCR + LNB/OFA over SNCR + LNB/OFA is 0.146 dv. Even accepting the Sierra Club's consultant's SCR cost analysis of $3,511/ton (which would be higher were it revised using a controlled NO_X rate of 0.05 lbs/MMBtu) and taking into consideration the adjustments we have made to the cost analysis for SNCR + LNB/OFA, the incremental cost effectiveness of SCR + LNB/OFA over SNCR + LNB/OFA is $4,969/ton. In the context of this BART determination, we do not consider the relatively small incremental visibility improvement to be worth the incremental cost of the SCR installation.

Comment: The Sierra Club and others stated that the Lake Catherine Unit 4 BART analysis failed to accurately consider compliance costs, non-environmental impacts, and the degree of visibility improvement. The Sierra Club further stated we underestimated the cost of BOOS and overestimated the costs of low NO_X burners, over-fired air, SNCR, and SCR. The Sierra Club's consultant also alleges that the documentation to support the Lake Catherine NO_X BART analysis is incomplete. Lastly, the Sierra Club stated that our cost-effectiveness analysis should be based on a capacity calculation that depends on time of operation, and our proposal to use a 10% capacity is unenforceable. Had we used a higher capacity factor, the Sierra Club reasons that the increase in NO_X emissions removed by the various pollution control equipment would have improved their cost-effectiveness (lower $/ton), making them more attractive.

Response: The Sierra Club's consultant raises a number of issues pertaining to missing documentation or errors in Entergy's NO_X BART analysis for Lake Catherine Unit 4, on which we relied on in making our BART decision. We reviewed the issues raised by the Sierra Club's consultant in detail in our RTC document and conclude they are unfounded or lack documentation. We conducted an analysis of Lake Catherine's data on heat input, operational time, and NO_X emissions to investigate the correlation between heat input and operational time to NO_X emissions, and further conclude that capacity calculations for the Lake Catherine Unit 4 should be based on heat input and not operational time. Lastly, we calculate the historical capacity for the Lake Catherine Unit 4 as follows:

TABLE 20—LAKE CATHERINE UNIT 4 HISTORICAL CAPACITY

Year	Capacity factor (%)
2001	28.2
2002	24.2
2003	11.3
2004	3.7
2005	4.7
2006	0.6
2007	0.8
2008	2.3
2009	2.8
2010	3.5
2011	2.9
2012	14.3
2013	11.1
2014	2.0
2015	3.9

We agree that the Lake Catherine Unit 4 historical capacity has sometimes exceeded the 10% capacity Entergy has assumed in its control cost analyses. However, the average from the last ten years of data (2006 to 2015) has been 4.4%. Typically, we place the most emphasis on the last five years of data, and our recent practice has been to discard the high and low values and average the remaining three years.[228] Applying that procedure to the Lake Catherine Unit 4 capacity factor results in a value of 6.0%. Alternatively, calculating a straight average of the last five years results in a value of 6.8%. Thus, we disagree that we erred in accepting Entergy's assumption of a 10% capacity factor in its control cost analysis. We note that in its response to us, Entergy stated, ''If future capacity factors change, ADEQ and EPA may impose further NO_X emission reductions on Unit 4, if necessary, in later planning periods to show reasonable progress.'' We believe that is an appropriate strategy and we will re-examine Lake Catherine's historical capacity in our review of Arkansas' next regional haze SIP.

Comment: We received comments from Nucor, Entergy and Conway Corporation stating that we should have used the dollar per deciview ($/dv) metric to weigh the cost versus the visibility benefit of controls for the White Bluff and Independence facilities. The Sierra Club supported our position that we are not required to use this metric.

Response: The BART Guidelines require that cost effectiveness be calculated in terms of annualized dollars per ton of pollutant removed, or $/ton.[229] The BART Guidelines list the $/deciview metric as an optional cost effectiveness measure that can be employed along with the required $/ton metric for use in a BART evaluation. The metric can be useful in comparing control strategies or as additional information in the BART determination process; however, due to the complexity of the technical issues surrounding regional haze, we have never recommended the use of this metric as a cutpoint or threshold in making BART determinations or reasonable progress determinations. We note that to use the $/deciview metric as the main determining factor would most likely require the development of thresholds of acceptable costs per deciview of improvement for BART and reasonable progress determinations for both single and multiple Class I analyses. We have not developed such thresholds for use in BART or reasonable progress determinations. Generally speaking, while the $/deciview metric can be useful if thoughtfully applied, we view the use of this metric as suggesting a level of precision in the calculation of visibility impacts that is not justified in many cases. While we did not use a $/deciview metric in the BART and reasonable progress determinations we make in this FIP, we did, however, consider the visibility benefits and costs of control together, as noted above by weighing the costs in light of the predicted visibility improvement. We have addressed this issue in a number of our previous actions since we first discussed this issue in our Oklahoma FIP,[230] and our position with regard to the $/deciview metric was reviewed and upheld in *Oklahoma* v. *EPA,* 723 F.3d 1201 by the Tenth Circuit which ruled:

> Oklahoma first suggests EPA should not have rejected the visibility analysis it conducted in the SIP, which used the dollar-per-deciview method. This argument is misguided. The EPA rejected the SIP because of the flawed cost estimates. When promulgating its own implementation plan, it did not need to use the same metric as Oklahoma. The guidelines merely permit the BART-determining authority to use dollar per deciview as an optional method of evaluating cost effectiveness. *See* 40 CFR pt. 51 app. Y(IV)(E)(1).[231] And in the final rule, the EPA

[227] Modeled visibility benefit at CACR over baseline from SCR at 0.067lb/MMbtu was 0.245 dv. SCR at 0.055 lb/MMBtu would result in an additional reduction in emissions from baseline of only 4%. Assuming a linear relationship between emission and visibility impacts, this would also result in an increase in visibility benefit of only 4%.

[228] This was our approach in calculating the SO_2 baselines used in our recent TX–OK FIP.

[229] 70 FR at 39167.

[230] Response to Technical Comments for Sections E. through H. of the **Federal Register** Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan, Docket No. EPA–R06–OAR–2010–0190, 12/13/2011, pdf 116.

[231] We note, however, that in both its final rule and in its brief the EPA asserts that the guidelines

explained why it did not use the dollar-per-deciview metric used by Oklahoma. ''Generally speaking, while the metric can be useful if thoughtfully applied, we view the use of the $/deciview metric as suggesting a level of precision in the calculation of visibility impacts that is not justified in many cases.'' 76 Fed. Reg. at 81,747. The EPA has never mandated the use of this metric, and has not developed ''thresholds of acceptable costs per deciview improvement.'' *Id.* While the federal land managers have developed thresholds, these thresholds were apparently developed without input from the EPA and without notice-and-comment review. EPA Br. at 54 n. 13. In light of this, we do not find it arbitrary or capricious that the EPA chose not to use the dollar-per-deciview metric in evaluating BART options in creating the FIP. We therefore also conclude that any argument by the petitioners that the dollar-per-deciview measurement proves the scrubbers are not cost effective lacks merit. *See* Pet. Reply Br. at 16.

We see no reason to deviate from our view of the $/deciview metric here.

J. Modeling

1. Cumulative Visibility Impairment

Comment: Several commenters opposed the use of a ''cumulative deciviews'' or ''total'' visibility improvement metric and claim the ''cumulative deciviews'' metric has no basis in the CAA and EPA's regulations. It also allegedly mischaracterizes visibility improvements in Class I areas. Determinations instead should be based on the predicted visibility improvements at individual Class I areas. Furthermore, the cumulative metric is deceptive and provides no information that could be used to assess whether any single Class I area would experience perceivable visibility improvements as a result of BART or reasonable progress controls, and may mask the fact that no individual Class I area would experience any discernible visibility improvement from control of emissions at any particular source. The cumulative metric represents an illusory visibility benefit; it is an improvement that cannot be perceived and therefore provides no indication of whether the proposed controls will contribute to the goal of the regional haze program: To reduce human perception of visibility impairment in Class I areas. The only purpose of the cumulative visibility improvement indicator is to imply that facilities are having a large impact across numerous Class I areas, but this indicator can be deceptive if it includes imperceptible visibility improvements for some Class I areas.

The commenters also suggest that the use of a ''total dv'' metric is inconsistent with BART guidelines (40 CFR part 51 Appendix Y, IV.D.5) that state it is appropriate to model impacts at the nearest Class I area as well as other nearby Class I areas to determine where the impacts are greatest. Modeling at other Class I areas may be unwarranted if the highest modeled effects are observed at the nearest Class I area. The commenters claim the analysis should be focused on the visibility impacts at the most impacted area, not all areas. Other commenters supported the use of the cumulative visibility metric, stating that it is appropriate and lawful, and within the spirit of the statutory mandate and expressly permissible within the regulation to consider cumulative impacts.

Response: We agree with the comments supporting the consideration of cumulative visibility impacts and benefits. We disagree with the other commenters that cumulative improvement over multiple areas is an inappropriate metric, or that examining a single Class I area is sufficient. The cumulative improvement metric (*i.e.,* the simple sum of impacts or improvements over all the affected Class I areas) is not intended to correspond to a single human's perception at a given time and place. The approach is simply one way of assessing improvements at multiple areas, for consideration along with other visibility metrics. Another approach would be to simply list visibility improvements at the various areas, and qualitatively weigh the number of areas and the magnitudes of the improvements. The cumulative sum is simply an easily understood and objective way of weighing cumulative visibility improvement, as part of the overall control evaluation along with the visibility improvement at each impacted Class I area. As noted by some comments, we have calculated cumulative visibility in a number of Regional Haze actions evaluating the benefits of controls under BART and when visibility is considered in the reasonable progress analysis. Furthermore, the FLMs have provided comments in support of the use of this metric in past actions.[232]

The comment opposing cumulative modeling does not provide the full context when citing to the BART guidelines. The portion referred to by the commenter discusses the development of a modeling protocol and establishing the receptors to model. The full portion of the BART Guidelines that the commenter referenced states:

> The receptors that you use should be located in the nearest Class I area with sufficient density to identify the likely visibility effects of the source. For other Class I areas in relatively close proximity to a BART-eligible source, you may model a few strategic receptors to determine whether effects at those areas may be greater than at the nearest Class I area. For example, you might chose to locate receptors at these areas at the closest point to the source, at the highest and lowest elevation in the Class I area, at the IMPROVE monitor, and at the approximate expected plume release height. If the highest modeled effects are observed at the nearest Class I area, you may choose not to analyze the other Class I areas any further as additional analyses might be unwarranted.[233]

This section of the BART Guidelines addresses how to determine visibility impacts as part of the BART determination. Several paragraphs later in the BART Guidelines it states: ''You have flexibility to assess visibility improvements due to BART controls by one or more methods. You may consider the frequency, magnitude, and duration components of impairment,'' emphasizing the flexibility in method and metrics that exists in assessing the net visibility improvement.

In fully considering the visibility benefits anticipated from the use of an available control technology as one of the factors in selection of BART, it is appropriate to account for visibility benefits across all affected Class I areas and the BART guidelines provide the flexibility to do so. One approach as noted above is to qualitatively consider, for example, the frequency, magnitude, and duration of impairment at each and all affected Class I areas. Where a source significantly impacts more than one Class I areas, the cumulative visibility metric is one way to take magnitude of the impacts of the source into account.

With respect to our analysis of controls under reasonable progress, we rely on our Reasonable Progress Guidance.[234] Our Reasonable Progress Guidance notes the similarity between some of the reasonable progress factors and the BART factors contained in § 51.308(e)(1)((ii)(A), and suggests that

require the use of the dollar-per-ton metric in evaluating cost effectiveness. The guidelines themselves are a bit unclear. In the section on cost effectiveness, the guidelines mention only the dollar-per-ton metric. 40 CFR pt. 51 app. Y(IV)(D)(4)(c). However, the guidelines later state that in evaluating alternatives, ''we recommend you develop a chart (or charts) displaying for each of the alternatives'' that includes, among other factors, the cost of compliance defined as ''compliance—total annualized costs ($), cost effectiveness ($/ton), and incremental cost effectiveness ($/ton), and/or any other cost-effectiveness measures (such as $/deciview).'' Id. app.Y(IV)(E)(1) (emphasis added).

[232] For example, see 76 FR 52388, 52429 (August 22, 2011).

[233] 40 CFR 51 Appendix Y, IV.D.5.

[234] ''Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program,'' June 1, 2007.

the BART Guidelines be consulted regarding cost, energy and nonair quality environmental impacts, and remaining useful life. We are therefore relying on our BART Guidelines for assistance in interpreting those reasonable progress factors, as applicable.

Also, similar to a BART analysis, we are also considering the projected visibility benefit in our analysis following the BART guidelines and the use of CALPUFF.[235] We rely on the BART Guidelines here and in other actions evaluating reasonable progress controls because they provide a reasonable and consistent approach regarding visibility modeling. This includes the flexibility in metrics that exists in assessing the net visibility improvement, and the use of cumulative visibility, along with visibility impacts at individual Class I areas, as one way to take magnitude of the impacts of the source into account where a source evaluated under reasonable progress significantly impacts more than one Class I area.

For each subject-to-BART source and the source evaluated for reasonable progress controls, we evaluated the visibility impacts from the source and benefits of controls at four separate Class I areas. In addition to providing the visibility impacts and potential benefits at each Class I area in the proposal, we also summed the impact and improvement across the four Class I areas. The results show that some sources significantly impact visibility at more than one Class I area, emission reductions result in visibility benefits at all impacted class I areas, and in some situations, the largest visibility benefits from controls can occur at Class I areas other than the most impacted.

Therefore, consistent with the BART Guidelines, and based upon these facts, we determined additional analyses were not only warranted but necessary. The BART Guidelines only indicate that additional analyses may be unwarranted at other Class I areas, and in no way exclude such analyses, as the commenter suggests. We concluded that a quantitative analysis of visibility impacts and benefits at only the most impacted area would not be sufficient to fully assess the impacts and benefits of controlling emissions from the sources evaluated for BART and reasonable progress.

Nothing in the Regional Haze Rule suggests that a state (or EPA in issuing a FIP) should ignore the full extent of the visibility impacts and improvements from controls at multiple Class I areas. Given that the national goal of the program is to improve visibility at *all* Class I areas, it would be short-sighted to limit the evaluation of the visibility benefits of a control to only the most impacted Class I area. We believe such information is useful in quantifying the overall benefit of controls. As discussed in our proposal, we evaluated the statutory factor, visibility benefits anticipated due to controls, at each Class I area in making BART determinations and considered the visibility benefits in consideration of controls for reasonable progress.

2. Imperceptible Visibility Improvement

Comment: EPA must withdraw the proposed FIP because the FIP would only achieve visibility improvements below one deciview, which is not discernible to the naked eye. Commenters state that the CAA only provides EPA with the authority to regulate the ''impairment of visibility.''[236] Visibility extends only to things that humans can see with their naked eyes.[237] By extension, EPA only has authority to regulate the impairments of visibility that are perceptible to the human eye. Under both the plain language and dictionary definitions of ''visibility,'' the statute does not provide EPA with the authority to regulate haze below a single deciview, which would be invisible to the naked eye. Since the Proposed FIP will only achieve visibility improvements smaller than one deciview, the EPA lacks authority to revise the RPGs suggested by Arkansas, and it should withdraw the Proposed FIP.

Commenters also state that the EPA may not require a source ''to spend millions of dollars for new technology that will have no appreciable effect on haze in any Class I area.'' *Am. Corn Growers Ass'n.* v. *EPA*[238] (vacating EPA's BART determinations because EPA left open the possibility that it could require a source to install technologies even when those technologies had no appreciable effect on visibility). Yet the EPA requires certain stationary sources of immense value to the State of Arkansas and its citizens to install controls that will cost billions of dollars in order to achieve imperceptible visibility improvements.

Response: We disagree with commenters that the Regional Haze Rule requires that controls on a source or group of sources result in perceptible visibility improvement.[239] We believe, for reasons we have outlined in our proposal and elsewhere in our response to comments, that the controls we proposed under our FIP will result in significant improvements in visibility at a number of Class I areas. In a situation where the installation of BART may not result in a perceptible improvement in visibility, the visibility benefit may still be significant, as explained by the Regional Haze Rule:

> Even though the visibility improvement from an individual source may not be perceptible, it should still be considered in setting BART because the contribution to haze may be significant relative to other source contributions in the Class I area. Thus, we disagree that the degree of improvement should be contingent upon perceptibility. Failing to consider less-than-perceptible contributions to visibility impairment would ignore the CAA's intent to have BART requirements apply to sources that contribute to, as well as cause, such impairment.[240]

Section 169A of the CAA requires that certain major sources that emit any pollutant which may reasonably be anticipated to cause or contribute to visibility impairment in Class I Areas install BART. The following factors must be taken into account in determining BART: The costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[241]

The CAA also requires that in determining reasonable progress there shall be taken into consideration the costs of compliance, the time necessary for compliance, the energy and nonair

[235] As we explain in our proposed action (80 FR at 18993): ''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''. See 79 FR at 74838, 74840, and 74874.

[236] CAA section 169A (''Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, *impairment of visibility* in mandatory class I Federal areas which impairment results from manmade air pollution.) (emphasis added).

[237] *E.g.* Webster's Third New International Dictionary 2557 (1981) (''visible'' means ''capable of being seen''; ''visibility'' means ''the degree or extent to which something is visible . . . [by] the observer's eye unaided by special optical devices'').

[238] *Am. Corn Growers Ass'n* v. *EPA,* 291 F.3d 1, 7 (D.C. Cir. 2002).

[239] It is generally recognized that a change in visibility of 1.0 deciview is humanly perceptible.

[240] 70 FR 39104, 39129.

[241] CAA section 169A(g)(2).

quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements. Our 2007 Reasonable Progress Guidance [242] notes the similarity between some of the reasonable progress factors and the BART factors contained in § 51.308(e)(1)(ii)(A), and suggests that the BART Guidelines be consulted regarding cost, energy and nonair quality environmental impacts, and remaining useful life. We are therefore relying on our BART Guidelines for assistance in interpreting those reasonable progress factors, as applicable, including visibility improvement even though it may not be perceptible from an individual source. Also, similar to a BART analysis, we are also considering the projected visibility benefit in our analysis of reasonable progress controls following the BART guidelines.[243] We rely on the BART Guidelines here and in other actions evaluating reasonable progress controls because they provide a reasonable and consistent approach regarding visibility modeling.

We accordingly disagree that selection of control measures under BART or for reasonable progress should be contingent upon perceptible visibility improvement. As we stated in our previous rulemaking addressing the BART determinations in Oklahoma:

> Given that sources are subject to BART based on a contribution threshold of no greater than 0.5 deciviews, it would be inconsistent to automatically rule out additional controls where the improvement in visibility may be less than 1.0 deciview or even 0.5 deciviews. A perceptible visibility improvement is not a requirement of the BART determination because visibility improvements that are not perceptible may still be determined to be significant.[244]

The Regional Haze Rule provides that BART–eligible sources with a 0.5 dv impact at a Class I area ''contribute'' to visibility impairment and must be analyzed for BART controls. BART determining authorities, however, are free to establish thresholds less than 0.5 dv. Consequently, even though the visibility improvement from controlling an individual source may not be perceptible, it should still be considered because the contribution to haze may be significant when the aggregate contribution of other sources in the Class I area is taken into account and because the contribution to haze from the source may be significant relative to other source contributions in the Class I area. Thus, in our visibility improvement analysis for BART sources and in consideration of visibility benefits from controls under our reasonable progress analysis, we have not considered perceptibility as a threshold criterion for considering improvements in visibility to be meaningful.

We have considered visibility improvement in a holistic manner, taking into account all reasonably anticipated improvements in visibility, and the fact that, in the aggregate, improvements from controls on multiple sources (either under BART or reasonable progress) will contribute to visibility progress towards the goal of natural visibility conditions. Visibility impacts below the thresholds of perceptibility cannot be ignored because regional haze is produced by a multitude of sources and activities which are located across a broad geographic area. In this action, we found that the required cost-effective controls reduce visibility impairment from those BART sources that contribute or cause visibility impairment at nearby Class I areas and result in meaningful visibility benefits towards the goal of natural visibility conditions. Similarly, we also found that the required cost-effective controls at the Entergy Independence facility reduce visibility impairment from the source with the largest potential visibility impacts (among all Non-BART sources) and result in meaningful visibility benefits towards the goal of natural visibility conditions.

The commenter mischaracterizes a statement made by the D.C. Circuit Court of Appeals in *Am. Corn Growers Ass'n.* v. *EPA.* The statement made by the Court is as follows: ''[U]nder EPA's take on the statute, it is therefore entirely possible that a source may be forced to spend millions of dollars for new technology that will have no appreciable effect on the haze in any Class I area.'' [245] The Court made this statement in reviewing EPA's approach to the BART requirements in the Regional Haze Rule promulgated in 1999 which did not require the source-specific assessment of a BART eligible source's visibility impacts at any step of the BART process.[246]

The Court disagreed with the approach used by EPA to determine what BART eligible sources are reasonably anticipated to cause or contribute to regional haze and therefore subject to BART.[247] The approach in the Regional Haze Rule required a State to analyze ''the degree of visibility improvement that would be achieved in each mandatory Class I Federal area as a result of the emission reductions achievable from all sources subject to BART located within the region that contributes to visibility impairment in the Class I area.'' [248] The Court held that the Rule's treatment of ''the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology'' factor infringed on states' authority with respect to BART determinations under the Act.[249] The Court noted that the Act does not assign a specific weight with which to consider each factor, it solely mandates that all the factors be considered in making a BART determination.[250] The Court's issue was not with the weight, or lack thereof, placed on this factor by EPA. It found issue with what it considered to be ''dramatically'' different treatment of the visibility factor by EPA. Id. While the court in *American Corn Growers Ass'n.* v. *EPA* found that we had impermissibly constrained State authority, it did so because it found that we forced States to require BART controls without first assessing a source's particular contribution to visibility impairment. This is not the case with our action in Arkansas. In response to this court decision and to address these concerns we finalized revised Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations.[251]

Our analysis does not give greater weight to one factor over another; rather, we considered all five BART factors fully, revealing that the cost and visibility factors were the two most important factors in our decisions. In *American Corn Growers Ass'n.* v. *EPA,* the D.C. Circuit Court faulted how EPA assessed the statutory fifth factor of visibility improvement in a BART determination by using a regional, multi-source, group approach to assessing the visibility improvement factor, while assessing the other four

[242] ''Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program,'' June 1, 2007.

[243] As we explain in our proposed action (80 FR at 18993): ''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''. See also 79 FR at 74838, 74840, and 74874.

[244] 76 FR 81728, 81739.

[245] *Am. Corn Growers Ass'n* v. *EPA,* 291 F.3d 1, 7 (D.C. Cir. 2002).

[246] Id.

[247] Id. at 7–8.

[248] 40 CFR 51.308(e)(1)(ii)(B).

[249] Id.

[250] 291 F.3d at 6.

[251] 70 FR 39104.

statutory BART factors on a source-specific basis. Here, we did not give greater weight to our consideration of visibility improvement or consider the visibility in a different fashion from the other factors. All BART factors were evaluated on a source-specific basis.

The Court also noted that it is the State's and not EPA's duty to determine what BART is (provided that the State's determination complies with the Act and EPA guidelines.[252]). When EPA promulgates a FIP, it is acting in the place of the State, and thus has the same authority a state has when the state promulgates a SIP. It is therefore our duty to determine what BART is since we are proposing a FIP for Arkansas. We must also consider the same factors that the State is mandated to consider by the CAA. The ''degree of improvement in visibility which may reasonably be anticipated to result from the use of such [best available retrofit] technology'' is just one of several factors the State, or EPA in the case of a FIP, must consider in determining what BART is for a specific source.

We also disagree with commenter's statement that we required emissions reductions just for the sake of doing so under the guise of imperceptible visibility improvements or solely for the sake of reducing emissions. As discussed above, we considered all the statutory factors, including the ''degree of improvement in visibility which may reasonably be anticipated to result from the use of such [best available retrofit] technology'' in our BART determinations. We do not consider perceptibility as a threshold criterion for considering improvements in visibility to be meaningful. Failing to consider less-than-perceptible contributions to visibility impairment would ignore the CAA's intent to have BART requirements apply to sources that contribute to, as well as cause, such impairment.

Comment: One commenter stated that the visibility benefits of some of the required controls either individually or in combination will result in perceptible visibility benefits. They also comment that the regional haze regulations reflect EPA's finding that the Congressional goal of eliminating haze can be achieved only by tackling the multitude of sources that contribute to haze in national parks and wilderness areas. For this reason, EPA has stated that ''visibility improvement does not need to be perceptible to be deemed significant for BART purposes.'' [253]

Response: We agree with the commenter. As we discuss in response to comments above, the Regional Haze Rule does not require that controls on a source or group of sources result in perceptible visibility improvement. We also agree that in some cases required controls either individually or in combination with other required controls will result in perceptible visibility improvements at impacted Class I areas on some days.

3. Model Selection

Comment: CALPUFF modeling cannot be used to justify controls at Independence under the reasonable progress requirements. Using CALPUFF, a single source model, for evaluating the reasonable progress benefits of installing controls at Independence is misplaced and clearly in error. EPA must demonstrate that additional controls are rational and economically justifiable and that the amount of progress that would result will be ''reasonable based upon the statutory factors.'' CALPUFF is overly simplistic and greatly overstates the effect of single source emissions.[254] CALPUFF also fails to show the effects of multiple sources, and is much less sophisticated in its treatment of the chemical interactions of the different pollutants in the atmosphere than CAMx. The commenters also state that the use of CALPUFF does not reflect the interaction of pollutants in the atmosphere as accurately as CAMx does.

EPA used CALPUFF and did not perform refined, multi-state modeling to determine the amount of visibility improvements that would be achieved through the installation of controls because it would be difficult, time-consuming, and expensive. Instead, the Agency took a ''thumbnail'' approach in an attempt to justify the proposed controls based on how long it would take to achieve background levels.

EPA recognized in their action on Texas regional haze that CAMx, a photochemical transport 3-dimensional grid model, is a more appropriate modeling tool for reasonable progress purposes.[255] BART analyses assess the impact of a single facility based on the maximum or 98th percentile impacts, regardless of whether the Class I area was actually experiencing high visibility impairment on any given day. Since CALPUFF does not conduct an analysis considering all the emissions from all potential sources, some of the days with the worst model-predicted concentrations could be days that are not significantly impaired. Reasonable progress modeling using a photochemical model, such as CAMx, allows EPA to evaluate impacts from a source (with all other sources included in the modeling) on a Class I area's best and worst days.[256]

The draft *EPA Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$*, and Regional Haze (Dec. 2014) (''Draft Modeling Guidance'') discusses the use of photochemical grid models. The Draft Modeling Guidance specifically notes that ''a modeling based demonstration of the impacts of an emissions control scenario . . . as part of a regional haze assessment usually necessitates the application of a chemical transport grid model.'' [257] Throughout the Draft Modeling Guidance, the discussion is focused on items specific to photochemical grid models such as CAMx, including emissions inventories, supporting models, pre-processors, and applying a model to changes in visibility.

Notably, EPA recently issued a proposal, which would remove CALPUFF from EPA's preferred list of air dispersion models in its *Guideline on Air Quality Models* [258] (''Guideline''). Although EPA states that the proposed changes to the Guideline would not affect its recommendation that CALPUFF be used in the BART determination process, EPA made no such assurances regarding the use of CALPUFF for a reasonable progress analysis. EPA's proposal emphasizes the use of chemical transport models for assessing visibility impacts from a single source or small group of sources.

EPA's *Interagency Workgroup on Air Quality Modeling Phase 3 Summary Report: Long Range Transport and Air Quality Related Values* [259] makes clear that CALPUFF should not be used for a reasonable progress analysis.

Another commenter, EarthJustice, states that the other commenter's assessment of the methodology used for Texas sources is incorrect. In fact, EPA also used an emission ''scaling'' approach to determine the effects of various control scenarios for their evaluation of Texas sources that is

[252] 291 F. 3d at 8–9.

[253] 79 FR 5032, 5120 (January 30, 2014).

[254] BART Guidelines, 70 FR 39104, 39121 (''there are other features of our recommended modeling approach that are likely to overstate the actual visibility effects of an individual source. Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source.'')

[255] Proposed Texas Regional Haze FIP, 79 FR 74818, 74877, 74878.

[256] *Id.* at 74878.

[257] Draft Modeling Guidance at 22. The Draft Modeling Guidance is available at *http://www.epa.gov/scram001/guidance/guide/Draft_O3-PMRH_Modeling_Guidance-2014.pdf*.

[258] Appendix W to 40 CFR part 51.

[259] Docket ID EPA–HQ–OAR–2015–0310–0004.

similar to that currently being applied for the evaluation of the sources in Arkansas. EPA Region 6 did not run the CAMx model repeatedly to determine the overall visibility effects of controlling individual sources.

Response: The commenters confuse the single source analysis for evaluating the visibility impact and benefits of controls on units at the Independence facility and the analysis to estimate the visibility benefits of all controls on the 20% worst days in establishing a new reasonable progress goal for 2018. We utilized CALPUFF modeling following the same modeling protocol relied on for the BART analyses to assess the visibility impacts and potential benefits of controls for the units at the Independence facility. For estimating the total visibility benefit from all controls and estimating a new reasonable progress goal that reflects those controls, we relied on the CENRAP's 2018 CAMx modeling results, including source apportionment results, and the projected emission inventories, and scaled the results as described in the TSD. While we acknowledge that this approach is not as refined an estimate as would be attained in performing a new photochemical modeling run, it is based on scaling of earlier photochemical modeling results and not on CALPUFF modeling, as the commenter suggests. We disagree with the commenter's characterization of our analysis as a ''thumbnail'' approach and noted in our proposal that similar approaches have been used in other actions in Hawaii and Arizona. As discussed in the proposed action, our determination that controls were reasonable for the Independence units was based on our evaluation of the four factors and including consideration of the visibility benefit of controls. For consideration of the visibility benefits, we relied on the results of our CALPUFF modeling, the CENRAP CAMx source apportionment results, and point source emission inventory data that initially identified the Independence facility as having the greatest potential to impact visibility at nearby Class I areas among all sources not already controlled under the BART requirements.

The 2005 BART Guidelines recommended the use of CALPUFF for assessing visibility (secondary chemical impacts) but noted that CALPUFF's chemistry was fairly simple. The visibility results from CALPUFF could be used as one of the five factors in a BART evaluation and the impacts should be utilized in a somewhat relative sense because CALPUFF was not explicitly approved for full chemistry calculations.[260] The BART guidelines also provided the option to potentially use photochemical grid models (such as CAMx) in the future if modeling tools available were appropriate and EPA approved of the technical approaches and how the model would be utilized.[261] Appendix W gives us discretionary authority in the selection of what models to use for visibility assessments with modeling systems, and models such as CALPUFF, CMAQ, REMSAD, and CAMx have all been used for that purpose. Specifically for single-source reasonable progress assessments similar to that done here for Independence, CALPUFF has been used for the majority of sources, while CAMx has been used in some situations, most notably and as noted by the commenter, in evaluating specific Texas sources for reasonable progress. In 2006/7, EPA OAQPS and EPA Region 6 consulted with FLM representatives and approved Texas' BART screening modeling protocol using source apportionment tools in CAMx.[262]

Under the BART guidelines, CALPUFF should be used as a screening tool and appropriate consultation with the reviewing authority is required to use CALPUFF in a BART determination as part of a SIP or FIP. The BART Guideline cited and referred to EPA's Guideline on Air Quality Models (Appendix W) [263] which includes provisions to obtain approval through consultation with the reviewing authority. Moreover, we also note that in EPA's document entitled Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze (EPA–454/B–07–002), that Appendix W does not identify a particular modeling system as 'preferred' for modeling conducted in support of state implementation plans under 40 CFR 51.308(b). A model should meet several general criteria for it to be a candidate for consideration. These general criteria are consistent with the requirements of 40 CFR 51.112 and 40 CFR 51, Appendix W. Therefore, it is correct to interpret that no model system is considered 'preferred' under 40 CFR 51, Appendix W, Section 3.1.1 (b) for either secondary particulate matter or for visibility assessments. Under this general framework, we followed the general recommendation in Appendix Y to use CALPUFF as a screening technique since the modeling system has not been specifically approved for chemistry. The use of CALPUFF is subject to Appendix W requirements in section 3.0(b), 4, and 6.2.1(e) which includes an approved protocol to use the current version.

We and some states have used CALPUFF to model visibility benefits as part of the reasonable progress analysis, and have used largely the same methodology as in BART modeling (*i.e.* use of 24 hour or hourly maximum emissions, a ''clean'' background condition, and a maximum or 98th percentile metric).[264] This approach provides information on the relative visibility benefits of controls to inform the evaluation of cost-effectiveness as part of the four factor analysis and has the benefit that it is immediately comparable to modeling used for BART determinations. Compared to a CAMx modeling exercise, CALPUFF modeling of one or more sources requires much less resources and time. However, the CALPUFF approach models the impacts from the single facility with limited chemistry and focuses on the maximum impacts from the source rather than the visibility impairment on the 20% worst days. We agree with the commenter that the CAMx model may be better suited for evaluating the average visibility impairment due to individual sources during the 20% worst days as part of reasonable progress analysis. Photochemical models, like the CAMx model, provide a complete representation of emissions, chemistry, transport, and deposition, while CALPUFF treats a single source with simplified chemistry and parameterized physical processes. Furthermore, the

[260] 70 FR 39104, 39123, 39124. ''We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. To date, no other modeling applications with updated chemistry have been approved by EPA to estimate single source pollutant concentrations from long range transport.'' and in discussion of using other models with more advanced chemistry it continues, ''A discussion of the use of alternative models is given in the Guideline on Air Quality in appendix W, section 3.2.''

[261] 70 FR at 39123, 39124. ''The use of other models and techniques to estimate if a source causes or contributes to visibility impairment may be considered by the State, and the BART guidelines preserve a State's ability to use other models. Regional scale photochemical grid models may have merit, but such models have been designed to assess cumulative impacts, not impacts from individual sources. Such models are very resource intensive and time consuming relative to CALPUFF, but States may consider their use for SIP development in the future as they are adapted and demonstrated to be appropriate for single source applications.''

[262] See Appendix 9–4: CAMx Modeling Protocol, Screening Analysis of Potentially BART-Eligible Sources in Texas of the Texas regional haze SIP.

[263] 40 CFR part 51 Appendix W, Guideline on Air Quality Models, 70 FR 68218 (November 9, 2005).

[264] For example see summary of the reasonable progress analyses for specific sources in Arizona (79 FR 9353), North Dakota (76 FR 58631), Montana (77 FR 24065), and Wyoming (78 FR 34785).

CAMx model can be used to evaluate a large number of individual sources, and there are concerns in using CALPUFF for modeling impacts at distances much greater than 300 km from the source. In our analysis of source-specific impacts of Texas sources, we determined that CAMx was best suited for the complex analysis that we needed to perform in evaluating a large number of sources (38 separate facilities for our initial analysis) at distances from impacted Class I areas much larger than 300km, and in focusing on the 20% worst days. We discuss our selection of CAMx modeling in our Texas analysis in depth in the RTC document that accompanies that action.[265] As noted by EarthJustice, we did not perform a final CAMx model scenario to obtain the new RPGs in our Texas action, and instead relied on a scaling analysis similar to the methodology used in this action to adjust the CENRAP modeled RPG values based on the source apportionment data and emissions data available. As discussed above, RPGs were adjusted in actions in Arizona, Hawaii, Texas/Oklahoma and in this action by estimating the visibility improvement due to required controls based on scaling the anticipated emission reductions and the source apportionment modeling. In Texas/Oklahoma, source-specific source apportionment data and emissions were utilized. In the other states, emissions and source-apportionment data on a state and source category level were utilized.

Consistent with the examples discussed above,[266] in evaluating the sources in Arkansas, we determined that CALPUFF was adequate since we determined that only one source needed to be assessed for a reasonable progress evaluation, and that source was well within the recommended range for CALPUFF modeling of under 300km from the Class I areas of interest. In fact, three of the four impacted Class I areas lie within 200km of the source. We discuss comments concerning why our reasonable progress screening analysis focused on NO_X and SO_2 emissions from Arkansas point sources and our determination that additional analysis was necessary for the Independence facility in response to comments elsewhere in this document. In evaluating visibility impacts and benefits for those sources subject to BART, we relied on CALPUFF modeling prepared by the facilities. Utilizing CALPUFF for the reasonable progress analysis on Independence provided for a consistent approach for all facilities and allowed for direct comparison of the visibility impacts and benefits across all facilities impacted by the proposed rulemaking. In some situations, the CALPUFF modeled maximum or 98th percentile impacts of the facility may not coincide with the days that make up the worst 20% monitored days at the Class I area. Therefore, the visibility benefits modeled by CALPUFF are not directly comparable to the visibility benefits that would be anticipated on the 20% worst days from those specific controls. However, our analysis of the CENRAP 2018 CAMx photochemical modeling showed that: On the 20% worst days, Arkansas point sources contribute significantly to visibility impairment at Arkansas' Class I areas (greater than 4% of total visibility impairment at each Arkansas Class I area); review of the emission inventory revealed that a very small number of point sources are responsible for the majority of the point source emissions of NO_X and SO_2 and therefore a very small number of point sources are responsible for the portion of visibility impairment due to Arkansas point sources on the 20% worst days; and the Independence facility is one of the very largest emission sources and it is located relatively close (under 200 km) to three Class I areas. Therefore, we identified Independence as having the greatest potential to impact visibility on the 20% worst days based on emissions and location and should be evaluated for reasonable progress controls. We determined that CALPUFF modeling was appropriate and sufficient to provide information on the degree of visibility benefits of controls on Independence to inform the reasonable progress assessment. Through our evaluation of the four statutory factors, we identified cost-effective controls. We then considered visibility benefits of the cost-effective controls. We conducted CALPUFF modeling to determine the level of visibility impacts and benefits anticipated by SO_2 and NO_X controls at nearby impacted Class I areas, evaluating the 98th percentile visibility impacts.[267]

As we discuss elsewhere in this final rule, Entergy submitted CAMx model results as part of their comments. The modeled contribution to visibility impairment due to baseline emissions from the Independence facility alone were approximately 1.3% of the total visibility impairment at each Arkansas Class I area. In terms of deciviews, the average impact over the 20% worst days based on Entergy's CAMx modeling (adjusting to natural background conditions) is over 0.5 dv at the Arkansas Class I areas and even larger at the Class I areas in Missouri. These results estimate the visibility impacts from the source on the 20% worst days and confirm and provide additional support to our determination that Independence significantly impacts visibility, both in terms of maximum visibility impairment and visibility impairment on the 20% worst days, and that emissions controls provide for meaningful visibility benefits towards the goal of natural visibility conditions. In conclusion, both approaches, CALPUFF and CAMx, support the determination that the required controls are reasonable.

The commenter cites the BART guidelines and asserts that EPA recognizes that the CALPUFF model is overly simplistic and overstates the effect of single-source emissions. This is not an accurate characterization. EPA recognized the uncertainty in the CALPUFF modeling results when EPA made the decision, in the final BART Guidelines, to recommend that the model be used to estimate the 98th percentile visibility impairment rather than the highest daily impact value. We made the decision to consider the less conservative 98th percentile primarily because the chemistry modules in the CALPUFF model are simplified and likely to provide conservative (higher) results for peak impacts. Since CALPUFF's simplified chemistry could lead to model over predictions and thus be conservative, EPA decided to use the less conservative 98th percentile.[268] While recognizing the limitations of the CALPUFF model in the preamble, EPA concluded that, for the specific purposes of the Regional Haze Rule's BART provisions, CALPUFF is sufficiently reliable to inform the decision making process.[269] More recent evaluations demonstrate that the CALPUFF model can both under-predict and over-predict visibility impacts. For example, the 2012 ENVIRON report on

[265] Texas Regional Haze FIP, EPA Response to Comments Document, available at *www.regulations.gov*, Document ID: EPA–R06–OAR–2014–0754–0087.

[266] For example see summary of the reasonable progress analyses for specific sources in Arizona (79 FR 9321, 9353), North Dakota (76 FR 58570, 58631 (September 21, 2011)), Montana (77 FR 23988, 24065 (April 20, 2012)), and Wyoming (78 FR 34738, 34785 (June 10, 2013)).

[267] See Summary of Additional Modeling for Entergy Independence and Appendix C to the TSD.

[268] "Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source. Because of these features and the uncertainties associated with the model, we believe it is appropriate to use the 98th percentile—a more robust approach that does not give undue weight to the extreme tail of the distribution."

[269] 70 FR at 39123.

Comparison of Single-Source Air Quality Assessment Techniques for Ozone, $PM_{2.5,}$ other criteria pollutants and AQRVs found that CALPUFF predicted highest 24-hr nitrate and sulfate concentrations lower than those predicted by the CAMx photochemical grid model in some areas within the modeling domain.[270] In a presentation for the 2010 annual Community Modeling and Analysis System conference, Anderson et al. (2010) [271] found that the CALPUFF model frequently predicted lower nitrate concentrations compared to the CAMx photochemical grid model which has a much more rigorous treatment of photochemical reactions. As we stated in promulgating the BART Guidelines, we are confident that CALPUFF distinguishes, comparatively, the relative contributions from sources such that the differences in source configurations, sizes, emission rates, and visibility impacts are well-reflected in the model results.[272]

With regard to comments concerning the draft *EPA modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze* (Dec. 2014), the commenter confuses the single-source analysis to evaluate visibility impacts and benefits of controls on an individual source with the analysis of overall visibility conditions at a Class I area due to the complete emission control strategy for all sources developed under the reasonable progress and long-term strategy requirements. The draft modeling guidance (as does the current guidance [273]) discusses the projection of overall visibility conditions and the need for photochemical grid modeling to account for all emission sources to model current visibility conditions and project future visibility conditions in response to the overall emission control scenarios. The section of the modeling guidance on regional haze [274] describes the recommended modeling analysis to assess overall future visibility improvement relative to the uniform rate of progress or ''glidepath'' (for each Class I area) as part of a reasonable progress analysis, and does not discuss source-specific analyses that may be completed to inform a reasonable progress assessment.[275] Because the CALPUFF model only evaluates visibility impacts from a single-source or a limited group of sources, it is not capable of projecting overall visibility conditions due to all sources and controls. Consistent with this draft guidance and the current guidance, CENRAP and Arkansas utilized CAMx and CMAQ modeling to project future visibility conditions for 2018 for establishment of the RPGs and comparison with the URP. Similarly, we utilized the CENRAP CAMx model results and adjusted them based on source apportionment and emissions data, to estimate the new RPGs for the Arkansas Class I areas considering the anticipated changes in emissions due to all required controls. We discuss the selection of models for assessing individual visibility impacts and benefits of controls above.

The commenters cite to the proposed revisions to the Guideline on Air Quality Models (Appendix W) [276] and the IWAQM Phase 3 modeling report [277] and assert that they support the conclusion that the use of CALPUFF for Independence was inappropriate. We disagree with the commenter. As we discuss above, we agree with the commenter that the CAMx model, may be better suited for a reasonable progress analysis in certain situations. Proposed revisions to Appendix W discuss removing the requirement to use CALPUFF for long-range transport assessments and as a preferred model due to the need to provide flexibility in estimating single-source secondary pollutant impacts and concerns about management and maintenance of the CALPUFF modeling code.[278] These proposed changes do not affect EPA's recommendation that States use CALPUFF to determine the applicability and level of BART in regional haze implementation plans. The proposed changes also do not preclude the use of CALPUFF for any other non-BART analysis, such as long-range transport PSD increment assessment, but recognize that modern chemical transport models have evolved sufficiently and provide a credible platform for estimating potential visibility impacts from a single or small group of emission sources.[279] The proposed Appendix W rule simply proposes to remove CALPUFF as a preferred model. If the proposed changes are finalized, CALPUFF or any other model can still be used for non-BART analyses with the appropriate justification as an ''alternative model''.

The IWAQM Phase 3 modeling report [280] discusses in detail the difference between the CALPUFF analysis typically followed under BART and the use of photochemical grid models for assessing reasonable progress and overall visibility conditions. The report does not identify a preferred model for single-source analysis but rather identifies the difference between the modeling approaches and cautions that the model results are not directly comparable.[281] The report also states

[270] Comparison of Single-Source Air Quality Assessment Techniques for Ozone, $PM_{2.5}$, other Criteria Pollutants and AQRVs, ENVIRON, September 2012.

[271] Anderson, B., K. Baker, R. Morris, C. Emery, A. Hawkins, E. Snyder ''Proof-of-Concept Evaluation of Use of Photochemical Grid Model Source Apportionment Techniques for Prevention of Significant Deterioration of Air Quality Analysis Requirements'' Presentation for Community Modeling and Analysis System (CMAS) 2010 Annual Conference, (October 11–15, 2010) can be found at *http://www.cmascenter.org/conference/2010/agenda.cfm*.

[272] 70 FR 39104, 39122.

[273] 2007 EPA modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze.

[274] Draft EPA modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze (December 2014) Section 4.8 ''What Is The Recommended Modeling Analysis for Regional Haze?''

[275] Draft *EPA modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze* (December 2014) at 173: ''The modeling can be used to determine the predicted improvement in visibility and whether the visibility levels are on, above, or below the glidepath. It cannot by itself determine the reasonable progress goals or determine whether the reasonable progress goal is met, and it does not satisfy the requirements for the statutory four factor analysis. See the Regional Haze Rule and related guidance documents for more information on the four factor analysis, including control strategy analysis for single sources.''

[276] 80 FR 45340 (July 29, 2015).

[277] *Interagency Workgroup on Air Quality Modeling Phase 3 Summary Report: Long Range Transport and Air Quality Related Values.*

[278] 80 CFR 45340, 45349: ''In order to provide the user community flexibility in estimating single-source secondary pollutant impacts and given the availability of more appropriate modeling techniques, such as photochemical transport models (which address limitations of models like CALPUFF [37]), the EPA is proposing that the Guideline no longer contain language that requires the use of CALPUFF or another Lagrangian puff model for long-range transport assessments. Additionally, the EPA is proposing to remove the CALPUFF modeling system as an EPA-preferred model for long-range transport due to concerns about the management and maintenance of the model code given the frequent change in ownership of the model code since promulgation in the previous version of the Guideline. [38] The EPA recognizes that long-range transport assessments may be necessary in certain limited situations for PSD increment. For these situations, the EPA is proposing a screening approach where CALPUFF along with other appropriate screening tools and methods may be used to support long-range transport PSD increment assessments''

[279] 80 FR at 45349.

[280] Interagency Workgroup on Air Quality Modeling Phase 3 Summary Report: Long Range Transport and Air Quality Related Values (July 2015).

[281] IWAQM Phase 3 Report (July 2015) at 9: ''In sum, the differences in the types of models, the inputs to the models, and how the models and model results are used means that the results from a BART determination or similar modeling using CALPUFF cannot be directly compared to estimated impacts of emissions controls from a single source on a reasonable progress goal. If recommended

Continued

that puff-models, such as CALPUFF, are not suited for reasonable progress demonstrations assessing overall visibility conditions and improvement because they are only able to model a single or small group of sources. Accordingly, we utilized CAMx model results to project overall future visibility conditions and establish the new RPGs in our reasonable progress demonstration. We used CALPUFF visibility modeling along with our evaluation of the costs of controls to inform our decision on the reasonableness of controls at the Independence facility. We also used CALPUFF visibility modeling as only one factor to inform our decisions on BART for subject-to-BART facilities. We also note that both the proposed revisions and the IWAQM report were published after the proposed rule for Arkansas regional haze was published and well before the technical analysis and modeling were completed.

We address comments concerning the contribution to visibility impairment from Arkansas point sources and the benefit of controls on Independence on Arkansas Class I areas elsewhere. We find that the contribution to visibility impairment from Arkansas point sources to be significant and that controls on Independence will result in meaningful visibility improvements towards the goal of natural visibility conditions and addresses a significant portion of the visibility impairment due to Arkansas sources.

Comment: Use of CALPUFF modeling does not support EPA's determination to require controls at the three coal-fired power plants. EPA's reliance on CALPUFF modeling results to make regulatory decisions in this case is not justified due to CALPUFF's well-known overestimation of visibility impacts.[282] Under the circumstances here, it is highly likely that CALPUFF overestimated the visibility impacts of White Bluff, Flint Creek and Independence by at least five (5) times. One component of this overestimation is the failure to incorporate the puff splitting option within the CALPUFF model into the development of visibility results. CALPUFF's overestimation of visibility impacts by a factor of 2–10 times under similar circumstances has been previously identified [283] and is described with specific reference to EPA's Proposed FIP for Arkansas in a report by Dr. Richard T. McNider.[284] Dr. McNider's report explains that the CALPUFF protocols used in the Proposed FIP fail to account for several well-known meteorological phenomena and processes, and causes it to overestimate visibility impacts. The Hoffnagle report demonstrates that CALPUFF modeling has not been validated by real world observations and that the current regulatory version of CALPUFF used by EPA is outdated.[285] Consequently, CALPUFF is not ''sufficiently accurate to make determinations of deciview differences of 1 deciview.'' [286]

It is inappropriate to utilize CALPUFF as a screening tool to qualify a source as subject to BART and subsequently use it to determine a facility's required implementation of a control technology at a significant financial cost. EPA in its final regional haze rules stated that ''because of the scale of the predicted impacts from these sources, CALPUFF is an appropriate or a reasonable application to determine whether such a facility can reasonably be anticipated to cause or contribute to any impairment of visibility. In other words, to find that a source with a predicted maximum impact greater than 2 to 3 deciviews meets the contribution threshold adopted by the States does not require the degree of certainty in the results of the model that might be required for other regulatory purposes.'' [287]

EPA's visibility analysis in the Proposed FIP systematically overstates both the baseline visibility impacts of White Bluff, Flint Creek and Independence, and the visibility benefits that would result from installation of EPA's required controls.[288] EPA's Proposed FIP presumes greater accuracy and precision than is reasonable or that may be expected from CALPUFF under the circumstances here. EPA has failed to update its model or to address any of these deficiencies considering currently available state-of-the-art modeling science. EPA's consideration of visibility impacts is fundamentally flawed and should be withdrawn and corrected.

EPA's admission that CALPUFF is a reasonable tool to evaluate a facility's visibility impacts only if those impacts exceed 2 to 3 deciviews, combined with the inability of the model to make accurate determinations below the 1 deciview threshold of perceptibility, discredits the results of the visibility analyses in the Proposed FIP. For these reasons, EPA has not adequately explained how the baseline and subsequent controlled visibility analyses in the Proposed FIP justify the selected control technologies.

Response: In promulgating the 2005 BART guidelines, we responded to comments concerning the limitations and appropriateness of using CALPUFF. There we respond:

> CALPUFF is the best modeling application available for predicting a single source's contribution to visibility impairment. It is the only EPA-approved model for use in estimating single source pollutant concentrations resulting from the long range transport of primary pollutants. In addition, it can also be used for some purposes, such as the visibility assessments addressed in today's rule, to account for the chemical transformation of SO_2 and NO_X. As explained above, simulating the effect of precursor pollutant emissions on $PM_{2.5}$ concentrations requires air quality modeling that not only addresses transport and diffusion, but also chemical transformations. CALPUFF incorporates algorithms for predicting both. At a minimum, CALPUFF can be used to estimate the relative impacts of BART-eligible sources. *We are confident that CALPUFF distinguishes, comparatively, the relative contributions from sources such that the differences in source configurations, sizes, emission rates, and visibility impacts are well-reflected in the model results.*

The use of CALPUFF in the context of the Regional Haze rule provides results that can be used in a relative manner and are only one factor in the overall BART determination. We determined the visibility results from CALPUFF could be used as one of the five factors in a BART evaluation and the impacts should be utilized somewhat in a relative sense because CALPUFF was not explicitly approved for full chemistry calculations.[289]

procedures change for either BART determination impact assessments or reasonable progress goal impact assessments the comparability between approaches would also change. Photochemical grid models could be applied to estimate single source impacts and post-processed in a manner consistent with requirements for a BART-like assessment but Lagrangian puff models are not ideal for reasonable progress demonstrations since they typically characterize one or a small group of sources''

[282] Coincidentally, the EPA Administrator on July 14, 2015, signed a proposed notice to remove CALPUFF as a model for long-range transport in EPA's Guideline on Air Quality Models in Docket No. EPA–HQ–OAR–2015–0310.

[283] See Exhibit 19 to Nucor's comments, Hoffnagle, G., ''Accuracy of Visibility Protocol Modeling in BART Evaluations'' (June 15, 2012); EPA Docket EPA–R08–OAR–2011–0851.

[284] See, McNider, R. ''Inadequacy of CALPUFF and CALMET Protocols for Visibility Impact Analysis in the Arkansas RHR FIP,'' July 13, 2015, attached hereto as Exhibit 20 to Nucor's comments.

[285] Hoffnagle, Exhibit 19 at p. 4.

[286] Hoffnagle, Exhibit 19 at p. 23.

[287] 70 FR 39104, 39123.

[288] As well as the other sources that were modeled using CALPUFF.

[289] 70 FR at 39123, 39124. ''We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. To date, no other modeling applications with updated chemistry have been approved by EPA to estimate single source pollutant concentrations from long range

EPA's modeling in this action was consistent with the BART Guidelines and Appendix W. In recommending the use of CALPUFF for assessing source specific visibility impacts, EPA recognized that the model had certain limitations but concluded that ''[f]or purposes of the regional haze rule's BART provisions . . . CALPUFF is sufficiently reliable to inform the decision-making process.'' [290] To the extent that the comment takes issue with the provisions in the BART Guidelines for use of CALPUFF, the legal deadline for challenging the use of CALPUFF has passed.

The commenters also refer to the 2005 Rule where we discuss the use of CALPUFF as a screening tool to qualify a source as subject to BART [291] and claim that we state that CALPUFF is only a reasonable tool when impacts exceed 2 to 3 deciviews. This is incorrect. The commenters fail to note that later in that same section we also discuss the recommended use of CALPUFF to evaluate visibility benefits of controls. There we state:

''. . . we *also* recommend that the States use CALPUFF as a screening application in estimating the degree of visibility improvement that may reasonably be expected from controlling a single source in order to inform the BART determination. As we noted in 2004, this estimate of visibility improvement does not by itself dictate the level of control a State would impose on a source; ''the degree of improvement in visibility which may reasonably be anticipated to result from the use of [BART]'' is only one of five criteria that the State must consider together in making a BART determination.'' [292]

With respect to our analysis of controls under reasonable progress, we rely on our Reasonable Progress Guidance.[293] Our Reasonable Progress Guidance notes the similarity between some of the reasonable progress 4 statutory factors and the BART 5 statutory factors contained in the Act and repeated in the Guidance, and suggests that the BART Guidelines be consulted regarding cost, energy and nonair quality environmental impacts, and remaining useful life. We are therefore relying on our BART Guidelines for assistance in interpreting those reasonable progress factors, as applicable.

Also, similar to a BART analysis, we are considering the projected visibility benefit in our reasonable progress analysis following the BART guidelines and the use of CALPUFF.[294] We rely on the BART Guidelines here and in other actions evaluating reasonable progress controls because they provide a reasonable and consistent approach regarding visibility modeling.

We also disagree with the commenters conclusions concerning CALPUFF model performance and assertions that model predictions are overestimated by a factor of 5. We note that our regulations do not allow for the calibration of model results to try to adjust for potential biases as suggested by the commenter.[295]

As discussed more fully in the RTC document, the CALPUFF model can both under-predict and over-predict visibility impacts. While recognizing the limitations of the CALPUFF model in the Preamble of the Regional Haze Rule EPA concluded that, for the specific purposes of the Regional Haze Rule's BART provisions, CALPUFF is sufficiently reliable to inform the decision making process.[296]

We disagree with the commenter's assertion that we were incorrect in not utilizing the puff-splitting option [297] and that this resulted in an overestimation of model results. Tests conducted by the EPA and the FLM's have shown that the CALPUFF puff-splitting algorithm does not behave in the manner posited in Dr. McNider's document.[298] As discussed in detail in the RTC document, multiple evaluations of puff-splitting show that visibility impacts (and thus concentrations) both increased and decreased across various Class I areas impacted by the source. These results are contrary to the claims of the commenter that CALPUFF overpredicts downwind concentrations at distances beyond 100 km and that the use of puff-splitting would result in lower concentrations. Furthermore, commenters have not provided any additional CALPUFF modeling to support their claims concerning model performance using the non-default puff splitting option.

The commenter refers to the Hoffnagle report (Ex. 19 of Nucor comments) to support claims that the CALPUFF model overpredicts concentrations, that the model is unreliable beyond 200km, and that the modeling is not sufficiently accurate to make determinations of deciview differences of 1 dv. We disagree with the conclusions of the Hoffnagle report and note significant flaws in that analysis. We also note that all the large EGU sources modeled in this action are less than 200 km for at least one Class I area. We specifically address Hoffnagle's analysis of modeled to measured results in response to comments elsewhere where we address comments concerning the ''margin of error'' of the model and case study comparisons of CALPUFF modeled values to measured values.

We disagree with the commenter that the model we utilized is outdated. We used the regulatory version of the CALPUFF model.[299] We disagree that the newer versions of CALPUFF should be used in this action to determine potential visibility impacts. The newer version(s) of CALPUFF have not received the level of review required for use in regulatory actions subject to EPA approval and consideration in a BART decision making process. Based on our review of the available evidence we do not consider these newer versions of CALPUFF to have been shown to be sufficiently documented, technically valid, and reliable for use in a BART decision making process.

The commenters also refer to the proposed revisions to the Guideline on Air Quality Models (Appendix W). Proposed revisions to Appendix W discuss removing the requirement to use CALPUFF for long-range transport assessments and as a preferred model due to the need to provide flexibility in estimating single-source secondary pollutant impacts and concerns about management and maintenance of the CALPUFF modeling code.[300] These

transport.'' and in discussion of using other models with more advanced chemistry it continues, ''A discussion of the use of alternative models is given in the Guideline on Air Quality in appendix W, section 3.2.''

[290] 70 FR at 39123.

[291] 70 FR at 39123.

[292] 70 FR at 39123.

[293] ''Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program,'' June 1, 2007.

[294] As we explain in our proposed action (80 FR at 18993): ''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''. See 79 FR at 74838, 74840, and 74874.

[295] App. W, Section 7.2.9(a) ''. . . Therefore, model calibration is unacceptable.''

[296] 70 FR at 39123.

[297] CALPUFF contains an optional puff splitting algorithm that can further account for vertical wind shear effects across individual puffs when this is of specific concern. Dispersion and transport can act on separate puffs generated from the original puff. This option is not part of the regulatory default set-up.

[298] See CALPUFF_SJGS_SPLIT_summary.xls.

[299] On December 4, 2013, EPA approved an update to v5.8.4 that contains bug fixes to the previous version. See December 3, 2013 CALPUFF Update Memo for a discussion of model changes.

[300] 80 CFR at 45349: ''In order to provide the user community flexibility in estimating single-source secondary pollutant impacts and given the availability of more appropriate modeling

Continued

proposed changes do not affect EPA's recommendation that States use CALPUFF to determine the applicability and level of BART in regional haze implementation plans. The proposed changes also do not preclude the use of CALPUFF for any other non-BART analysis. The proposed changes to the Appendix W rule simply propose to remove CALPUFF as a preferred model for long-range transport assessments. If the proposed changes are finalized, CALPUFF or any other model can still be used with the appropriate justification as an ''alternative model'' for long-range transport assessments.

Finally, the CAMx modeling provided by Entergy Arkansas provides additional information that directly contradicts the commenter's assertion that CALPUFF greatly overestimates visibility impacts by at least a factor of 5. As we discuss elsewhere in this final rule, the CAMx visibility modeling estimates a maximum visibility impact (limited to only the days comprising the 20% worst days and based on annual emissions) of over 1.5 dv from the Independence facility at both Caney Creek and Upper Buffalo. For the White Bluff facility, the CAMx maximum visibility impact is approximately 3.5 dv at Caney Creek and 0.8 dv at Upper Buffalo. In some situations, the CALPUFF modeled maximum or 98th percentile impacts of the facility may not coincide with the days that make up the worst 20% monitored days at the Class I area, therefore the true maximum impact considering all days based on CAMx modeling could be even higher. This compares to a CALPUFF modeled visibility 98th percentile impact (based on maximum emissions) due to the Independence facility of 2.5 dv at Caney Creek and 2.3 at Upper Buffalo. For White Bluff, the CALPUFF modeled impact (98th percentile) is approximately 3.3 dv at Caney Creek and 2.3 dv at Upper Buffalo.

We address more general comments concerning the use of CALPUFF modeling and model uncertainty in separate response to comments.

4. Margin of Error in CALPUFF Modeling

Comment: Commenters stated that BART requires that states (or EPA in the case of a federal implementation plan) consider ''the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.'' [301] The Ninth Circuit, in *National Parks Conservation Association* v. *EPA,* Case No. 12–73710, 2015 WL 3559149 at 8 (9th Cir. June 9, 2015), held that the estimated visibility improvement was less than CALPUFF's margin of error, and thus, EPA had no basis to believe that BART controls in that case could ''reasonably be anticipated'' to improve visibility. The Clean Air Act does not require visibility improvements that cannot be reasonable anticipated. Visibility improvements that are less than the margin of error are not ''reasonably anticipated'' and found to be invalid by the Ninth Circuit in *National Parks Conservation Association*.[302] In the proposal, EPA dictates the imposition of control equipment for emissions reduction under BART in instances where CALPUFF predicted minor visibility improvements. EPA did so without first undertaking any site specific analytical analysis to determine if the visibility improvements were in fact within the CALPUFF margin of error.

The CAA does not require visibility improvements that cannot be reasonably anticipated. Conversely, visibility improvements that are less than the margin of error were expressly found to be invalid. Until such time as EPA can provide assurance that the CALPUFF model is a reliable indicator of visibility projections, many of the numerical projections contained in the Proposed FIP are themselves, unreliable. For this reason, the Proposed FIP is flawed and is overly expansive and should be withdrawn.

Response: We disagree with the commenter's characterization of the Ninth Circuit decision regarding the ''margin of error'' of the CALPUFF model. The Ninth Circuit decision cited did not rule on any specific issue related to CALPUFF or the ''margin of error.'' Rather, the court ruled on a procedural error that EPA did not respond to the comment received regarding the CALPUFF margin of error in its rulemaking as required under the law.[303]

In response to the court's finding in *American Corn Growers Ass'n.* v. *EPA* [304] that we failed to provide an option for BART evaluations on an individual source-by-source basis, we had to identify the appropriate analytical tools to estimate single-source visibility impacts. The 2005 BART Guidelines recommended the use of CALPUFF for assessing visibility (secondary chemical impacts) but noted that CALPUFF's chemistry was fairly simple and the model has not been fully tested for secondary formation and thus is not fully approved for secondary-formed particulate. In the preamble of the final 2005 BART guidelines we identify CALPUFF as the best available tool for analyzing the visibility effects of individual sources, but we also recognized that it is a model that includes certain assumptions and uncertainties.[305] Evaluation of CALPUFF model performance for dispersion (no chemistry) to case studies using inert tracers has been performed.[306] It was concluded from these case studies the CALPUFF dispersion model had performed in a reasonable manner, and had no apparent bias toward over or under prediction, so long as the transport distance was limited to less than 300km.[307] [308]

In promulgating the 2005 BART guidelines, we responded to comments concerning the limitations and

techniques, such as photochemical transport models (which address limitations of models like CALPUFF [37]), the EPA is proposing that the Guideline no longer contain language that requires the use of CALPUFF or another Lagrangian puff model for long-range transport assessments. Additionally, the EPA is proposing to remove the CALPUFF modeling system as an EPA-preferred model for long-range transport due to concerns about the management and maintenance of the model code given the frequent change in ownership of the model code since promulgation in the previous version of the Guideline. [38] The EPA recognizes that long-range transport assessments may be necessary in certain limited situations for PSD increment. For these situations, the EPA is proposing a screening approach where CALPUFF along with other appropriate screening tools and methods may be used to support long-range transport PSD increment assessments.''

[301] CAA section 169A(g)(2).

[302] 80 FR at 18968.

[303] ''Concurring, Judge Berzon wrote separately to emphasize her understanding that the lead opinion is not impugning the EPA's use of the CALPUFF model generally, but only requiring a sufficiently reasoned response to a particular comment regarding CALPUFF's usefulness in these specific circumstances.'' Nat'l Parks Conservation Ass'n vs. EPA.

[304] *Am. Corn Growers Ass'n* v. *EPA,* 291 F.3d 1 (D.C. Cir. 2002).

[305] 70 FR at 39121.

[306] See ''more recent series of comparisons has been completed for a new model, CALPUFF (Section A.3). Several of these field studies involved three-to-four hour releases of tracer gas sampled along arcs of receptors at distances greater than 50km downwind. In some cases, short-term concentration sampling was available, such that the transport of the tracer puff as it passed the arc could be monitored. Differences on the order of 10 to 20 degrees were found between the location of the simulated and observed center of mass of the tracer puff. Most of the simulated centerline concentration maxima along each arc were within a factor of two of those observed.'' 68 FR 18440, 18458 (April 15, 2003), 2003 Revisions to Appendix W, Guideline on Air Quality Models

[307] Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts. Publication No. EPA–454/R–98–019. Office of Air Quality Planning & Standards, Research Triangle Park, NC. 1998.

[308] 68 FR 18440, 18458, 2003 Revisions to Appendix W, Guideline on Air Quality Models.

appropriateness of using CALPUFF. There we respond:

CALPUFF is the best modeling application available for predicting a single source's contribution to visibility impairment. It is the only EPA-approved model for use in estimating single source pollutant concentrations resulting from the long range transport of primary pollutants. In addition, it can also be used for some purposes, such as the visibility assessments addressed in today's rule, to account for the chemical transformation of SO_2 and NO_X. As explained above, simulating the effect of precursor pollutant emissions on $PM_{2.5}$ concentrations requires air quality modeling that not only addresses transport and diffusion, but also chemical transformations. CALPUFF incorporates algorithms for predicting both. At a minimum, CALPUFF can be used to estimate the relative impacts of BART-eligible sources. *We are confident that CALPUFF distinguishes, comparatively, the relative contributions from sources such that the differences in source configurations, sizes, emission rates, and visibility impacts are well-reflected in the model results.*

In the 2003 revisions to the Guideline on Air Quality Models, CALPUFF was added as an approved model for long-range transport of primary pollutants. At that time, we considered approving CALPUFF for assessing the impact from secondary pollutants but determined that it was not appropriate in the context of a PSD review because the impact results could be used as the sole determinant in denying a permit.[309] However, the use of CALPUFF in the context of the Regional Haze rule provides results that can be used in a relative manner and are only one factor in the overall BART determination. We determined the visibility results from CALPUFF could be used as one of the five factors in a BART evaluation and the impacts should be utilized somewhat in a relative sense because CALPUFF was not explicitly approved for full chemistry calculations.[310]

We also recognized the uncertainty in the CALPUFF modeling results when we made the decision, in the final BART Guidelines, to recommend that the model be used to estimate the 98th percentile visibility impairment rather than the highest daily impact value. We made the decision to consider the less conservative 98th percentile primarily because the chemistry modules in the CALPUFF model are simplified and likely to provide conservative (higher) results for peak impacts. Since CALPUFF's simplified chemistry could lead to model over predictions and thus be conservative, EPA decided to use the less conservative 98th percentile.[311] Examining the distribution of CALPUFF modeled visibility impacts, it can be seen that the few values at the extreme of the distribution are much higher than the rest of the values.[312] Therefore, in recognizing some of the limitations of the CALPUFF model, we determined that use of the maximum modeled impact may be overly conservative and recommended the use of the 98th percentile value.

We disagree with the commenter's general statement that there is an acknowledged over-prediction of the CALPUFF model or an acknowledged inaccuracy at low levels, and that the actual visibility impacts from the BART sources are lower. The CALPUFF model can both under-predict and over-predict visibility impacts when compared to photochemical grid model. For example, the 2012 ENVIRON report on *Comparison of Single-Source Air Quality Assessment Techniques for Ozone, $PM_{2.5}$, other criteria pollutants and AQRVs* found that CALPUFF predicted highest 24-hr nitrate and sulfate concentrations lower than those predicted by the CAMx photochemical grid model in some areas within the modeling domain.[313] In a presentation for the 2010 annual Community Modeling and Analysis System conference, Anderson et al. (2010)[314] found that the CALPUFF model frequently predicted lower nitrate concentrations compared to the CAMx photochemical grid model, which has a much more rigorous treatment of photochemical reactions. As discussed above, model evaluations examining how the model captures the transport and diffusion of pollutants showed that the model performed in a reasonable manner for modelled distances less than 300 km.[315] The selection of the 98th percentile value rather than the maximum value was made to address concerns that the maximum may be overly conservative.

The CALPUFF modeling following the BART guidelines and using the 98th percentile value does not lend itself to model performance evaluations of the type suggested by the commenters (see comments below concerning the ''Margin of error'' analysis), comparing measured visibility impairment at a specific time and place to modeled impairment at that same time and place to derive some ''margin of error'' in the modeled estimates. The BART modeling is a worst case assessment, utilizing maximum emissions,[316] assumptions of background ammonia and ozone, and simplified chemistry, modeled over a period of three years.[317] The modeling also does not capture the effect of competition with other emission sources for the available ammonia. The goal of this modeling is to estimate the maximum anticipated impact from the source in the vicinity of a Class I area (typically an area on the order of several hundred square miles or more), and not to provide an estimate of downwind concentrations or visibility conditions for a specific place at a specific time.

CALPUFF uses a pseudo-first-order chemical reaction mechanism to model the conversion of SO_2 to SO_4 and NO_X ($NO + NO_2$) to NO_3. We find the representation of key chemical conversions of precursors to $PM_{2.5}$ in CALPUFF are appropriate for estimating a worst-case scenario for this particular source and region. We note that small changes in emission levels will not significantly perturb the available ammonia. Therefore, the relative difference between two scenarios with similar emissions will not be overly

[309] 68 FR 18440.

[310] 70 FR at 39123, 39124. ''We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. To date, no other modeling applications with updated chemistry have been approved by EPA to estimate single source pollutant concentrations from long range transport,'' and in discussion of using other models with more advanced chemistry it continues, ''A discussion of the use of alternative models is given in the Guideline on Air Quality in appendix W, section 3.2.''

[311] ''Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source. Because of these features and the uncertainties associated with the model, we believe it is appropriate to use the 98th percentile—a more robust approach that does not give undue weight to the extreme tail of the distribution.'' 70 FR 39104, 39121.

[312] See figures for Lake Catherine and Domtar in our response to comments on the ''Margin of Error'' analysis in the RTC document

[313] Comparison of Single-Source Air Quality Assessment Techniques for Ozone, $PM_{2.5}$, other Criteria Pollutants and AQRVs, ENVIRON, September 2012.

[314] Anderson, B., K. Baker, R. Morris, C. Emery, A. Hawkins, E. Snyder ''Proof-of-Concept Evaluation of Use of Photochemical Grid Model Source Apportionment Techniques for Prevention of Significant Deterioration of Air Quality Analysis Requirements'' Presentation for Community Modeling and Analysis System (CMAS) 2010 Annual Conference, (October 11–15, 2010) can be found at *http://www.cmascenter.org/conference/2010/agenda.cfm*.

[315] 68 FR at 18458, 2003 Revisions to Appendix W, Guideline on Air Quality Models.

[316] 70 FR at 39129, ''We believe the maximum 24hour modeled impact can be an appropriate measure in determining the degree of visibility improvement expected from BART reductions (or for BART applicability)''

[317] 70 FR 39104, 39107–3918 of BART Rule. For assessing the fifth factor, the degree of improvement in visibility from various BART control options, the States may run CALPUFF or another appropriate dispersion model to predict visibility impacts. Scenarios would be run for the pre-controlled and post-controlled emission rates for each of the BART control options under review. The maximum 24-hour emission rates would be modeled for a period of three or five years of meteorological data.

influenced by assumptions of background concentrations of ammonia.

The utility of the model used must be judged based on the available data, the known limitations or simplifications inherent to the model, and the purpose of the modeling or manner in which the model results are used in informing decisions. The use of the 98th percentile value and considering a minimum of three years of meteorological data within CALPUFF provides a snapshot of the worst case visibility impacts, simulating impacts (based on maximum emissions and assumed ammonia concentrations) on a day when modeled meteorological conditions are most conducive to formation and transport of visibility impairing pollutants to a receptor within a Class I area. While there is some uncertainty in the absolute visibility impacts and benefits due to the model and some of the simplifications and assumptions used in the BART guideline modeling approach, the relative level of impact is a reliable assessment of the degree of visibility impacts and benefit from controls. Any uncertainties in meteorological conditions that govern the transport and diffusion of pollutants are less important in comparing impacts between two control scenarios, since the same effects will be included in both the base and the control scenario model simulations. CALPUFF modeling will be better at predicting changes in visibility impairment due to the application of controls than at predicting the absolute visibility impacts. BART determinations are only made for sources that have already been shown to reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. Modeling of control scenarios is used to estimate the amount that this visibility impact can be reduced due to a reduction in emissions. The modeling of these control scenarios is done in a manner that holds all variables constant except for the emissions of the pollutant of interest. A relative reduction in visibility impact due to a change in emissions is an indication that visibility benefits are reasonably anticipated to occur. The modeled magnitude of the visibility improvement is not a determinative factor in the BART determination, but only one factor and is considered on a relative basis to the baseline impact and the benefits of other controls. The relative visibility benefit of all controls is weighed along with the absolute and relative costs of controls, energy and nonair environmental impacts, any existing controls, and the remaining useful life of the source. As stated above, we are confident that CALPUFF distinguishes, comparatively, the relative contributions from sources such that the differences in source configurations, sizes, emission rates, and visibility impacts are well-reflected in the model results.

CALPUFF visibility modeling, performed using the regulatory CALPUFF model version and following all applicable guidance and EPA/FLM recommendations, provides a consistent tool for comparison with the 0.5 dv subject-to-BART threshold. The CALPUFF model, as recommended in the BART guidelines, has been used for almost every single-source BART analysis in the country and has provided a consistent basis for assessing the degree of visibility benefit anticipated from controls as one of the factors under consideration in a five-factor BART analysis. Since almost all states have completed their BART analyses and have either approved SIPs or FIPs in place, there is a large set of available data on modeled visibility impacts and benefits, and how those model results were utilized to screen out sources and as part of the five-factor analysis in making BART control determinations for comparison with.

Comment: Trinity Consultants completed a quantitative analysis to evaluate the margin of error in the CALPUFF model for Lake Catherine Unit 4 and Domtar Ashdown Mill.[318] Trinity calculated the average difference between modeled values obtained using CALPUFF (including the CENRAP background) and IMPROVE monitored values for Caney Creek and Upper Buffalo. Trinity compared the regional haze design value format of average W20 days visibility for this analysis.

In its analysis, the pre-BART impact from Lake Catherine Unit 4 at Caney Creek and Upper Buffalo is inconsequential when compared with the IMPROVE measurements, which capture the impact of all other sources, including Lake Catherine, on the Class I areas.

The proposed NO_X BART controls for Lake Catherine Unit 4 will result in visibility improvements that are even more inconsequential and cannot accurately be predicted by CALPUFF. Based on Trinity's analysis, the minimum calculated margin of error for CALPUFF for Lake Catherine Unit 4 is 0.93 dv. The CALPUFF modeling predicted visibility improvement associated with EPA's proposed BART controls for Lake Catherine Unit 4 at Caney Creek and Upper Buffalo falls within the minimum calculated margin of error for CALPUFF for Lake Catherine Unit 4. Similarly, the predicted visibility improvements associated with the imposition of the proposed BART requirements for Power Boiler 2 at the Domtar Ashdown Mill fall within the CALPUFF model's margin of error. As such, the visibility improvements at each of these Class I areas associated with the proposed BART controls cannot ''reasonably be anticipated.'' [319] Accordingly, EPA has not adequately demonstrated that it is appropriate to require controls on Lake Catherine Unit 4 or Power Boiler 2 at the Domtar Ashdown Mill.

These analyses include a discussion of work performed by TRC Environmental Corporation, including a June 2012 paper prepared by Gale Hoffnagle that discusses several case studies that compared CALPUFF modeled values to measured values from the IMPROVE monitoring network.[320] The commenters state that PPL Montana relied on this study in its successful challenge to the Montana FIP for its argument that EPA failed to explain why it could reasonably anticipate a visibility improvement when the improvement was within CALPUFF's margin of error.[321]

Response: The commenters mischaracterize the Ninth Circuit decision regarding the ''margin of error'' of the model. The commenter suggests that the Court agreed that the anticipated visibility benefits in that case were within the margin of error of the model. This is incorrect. The Ninth Circuit decision cited did not rule on any specific issue related to CALPUFF. Rather, the court ruled on a procedural error that EPA did not respond to the comment received regarding the CALPUFF margin of error in its rulemaking as required under the law.[322] Here and elsewhere in our response to comments we address a very similar comment with respect to

[318] ''Evaluation of the CALPUFF Modeling System Margin of Error Report for BART Analysis, Domtar A. W. LLC, Ashdown Mill'' Prepared by Trinity Consultants, August 2015 and ''Evaluation of the CALPUFF Modeling System Margin of Error Report for BART Analysis, Entergy Arkansas, Inc., Lake Catherine Plant'' Prepared by Trinity Consultants, August 2015.

[319] CAA section 169A(g)(2); *see NPCA,* 788 F.3d 1134, 1146–47.

[320] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[321] *National Parks Conservation Ass'n* v. *EPA,* 788 F.3d 1134, 1146–47 (9th Cir. 2015).

[322] ''Concurring, Judge Berzon wrote separately to emphasize her understanding that the lead opinion is not impugning the EPA's use of the CALPUFF model generally, but only requiring a sufficiently reasoned response to a particular comment regarding CALPUFF's usefulness in these specific circumstances.'' *Nat'l Parks Conservation Ass'n* vs. *EPA.*

CALPUFF modeling for Arkansas sources, as well as the commenter's analysis claiming to estimate the ''margin of error''.

The Trinity analysis [323] purports to calculate a ''margin of error'' of the CALPUFF modeling for Lake Catherine. In general, the commenter's analysis adds CALPUFF model results for a specific source or sources with CAMx model results and compares this value to visibility conditions derived from monitored data at each Class I area. This analysis is flawed for many reasons as discussed in detail in our RTC document and fails to provide any assessment of the ability of the CALPUFF model to evaluate the degree of visibility improvement that may be expected from available control technology to inform BART and reasonable progress evaluations. Whether or not the modeled visibility impacts or benefits lie below this calculated ''margin of error'' is immaterial to any assessment of whether or not the visibility impairment or benefits from controls can reasonably be anticipated to occur. BART determinations are only made for sources that have already been shown to reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. Modeling of control scenarios is used to estimate the amount that this visibility impact can be reduced due to a reduction in emissions. The modeling of these control scenarios is done in a manner that holds all variables constant except for the emissions of the pollutant of interest. A relative reduction in visibility impact due to a change in emissions is an indication that visibility benefits are reasonably anticipated to occur. The modeled magnitude of the visibility improvement is not the determinative factor in the BART determination, but only one factor and is considered on a relative basis to the baseline impact and the benefits of other controls. The relative visibility benefit of all controls is weighed along with the absolute and relative costs of controls, energy and nonair environmental impacts, any existing controls, and the remaining useful life of the source. As discussed elsewhere in this section of the final rule, we are confident that CALPUFF distinguishes, comparatively, the relative contributions from sources such that the differences in source configurations, sizes, emission rates, and visibility impacts are well-reflected in the model results.

We respond to specific comments concerning each separate case study in our RTC document.

5. Reasonable Progress Analysis for Entergy Independence

Comment: Entergy contracted with Trinity to perform regional haze modeling using CAMx and PSAT based on the modeling originally developed for CENRAP. This modeling was performed to assess the proposed control options for Independence units 1 and 2, as well as White Bluff units 1 and 2. In addition to the baseline scenario modeling, the FIP scenario (proposed controls in EPA's FIP) and Entergy's proposed control approach consisting of installed LNB/SOFA on Independence, and the cessation of coal combustion at White Bluff were modeled.

Entergy stated that EPA's own analysis counsels against imposing emission limits on Independence. EPA asserts that CENRAP modeling shows that sulfate from *all* point sources included in the regional modeling is projected to contribute to 57% of the total light extinction at Caney Creek on the W20 days in 2018 and 43% of the total light extinction at Upper Buffalo.[324] However, EPA recognizes that the CENRAP modeling also demonstrates that sulfate from all (elevated and low level) *Arkansas* point sources is projected to be responsible for only 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo.[325] The contribution of Arkansas point sources' nitrate emissions to visibility impairment at Arkansas' Class I areas is even more insignificant. According to EPA's analysis, nitrate from *all* point sources included in the regional modeling is projected to account for only 3% of the total light extinction at the Caney Creek and Upper Buffalo Class I areas, with nitrate from *Arkansas* point sources being responsible for only 0.29% of the total light extinction at Caney Creek and 0.25% at Upper Buffalo.[326] The Independence units' share of emissions to this minimal contribution from Arkansas point sources to visibility impairment at Caney Creek and Upper Buffalo is even less.

Entergy's CAMx modeling confirms that Independence's contribution to visibility impairment is insignificant in both Class I areas. Independence is projected to contribute to only 0.119 dv of visibility impairment at Caney Creek and Upper Buffalo on W20 days in 2018.[327] This reflects only one half of one percent of the visibility impairment, based on modeling, on the W20 days in either Caney Creek or Upper Buffalo. Yet, based on such a miniscule contribution and with no credible explanation, EPA arbitrarily concludes that SO_2 and NO_X controls at Independence are warranted.

Response: We disagree with the commenter's assertion that the contribution to visibility impairment from Entergy Independence is ''insignificant'' or ''minimal.'' For example, as the commenter states, the CENRAP source apportionment data show that sulfate from Arkansas point sources are projected to be responsible for 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo in 2018. As we discuss in our proposal, based on 2011 NEI data, the Entergy Independence Plant is the second largest source of both 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 point source NO_X emissions in the State.[328] Therefore, a significant portion of the total visibility impairment on the 20% worst days, on the order of 1% or more, can be expected to be attributable to SO_2 emissions from a single facility, the Independence facility. As we discuss in more detail elsewhere, given their contribution to visibility impairment on the 20% worst days, we consider both SO_2 and NO_X to be key pollutants contributing to visibility impairment at Arkansas' Class I areas. Our CALPUFF modeling evaluating the baseline 98th percentile impacts confirmed that the Independence facility was estimated to impact visibility at levels much larger than the level considered to ''cause'' visibility impairment (greater than 1 dv) at nearby Class I areas, ranging from 2.512 dv at Caney Creek, to 1.859 dv at Mingo. CALPUFF modeling also showed that anticipated visibility benefits from SO_2 and NO_X controls at the facility exceeded 1 dv at each of the four impacted Class I areas. Although we recognize that Independence is not a subject to BART source, for comparison purposes we note that the threshold used for visibility impacts to

[323] Evaluation of the CALPUFF Modeling System Margin of Error for a BART Analysis, Entergy Services, Inc.—Lake Catherine Plant, available as Exhibit H to comments submitted by Entergy Arkansas, Inc.

[324] 80 FR 18944, 18990.

[325] *Id.*

[326] *Id.*

[327] See Figures 9 and 10 of Entergy Arkansas Inc. Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas available in the docket for this action.

[328] 80 FR at 18991.

determine whether facilities are subject to BART is 0.5 dv.[329]

We disagree with the commenter that the CAMx modeling submitted by the commenter confirms that contributions to visibility impairment from the Independence facility are insignificant. When properly assessed, as detailed in the RTC document, the commenter's CAMx modeling supports and reinforces our finding that visibility impairment from Entergy Independence is significant and emission reductions will result in meaningful visibility benefits towards the goal of natural visibility conditions. Entergy's CAMx modeling shows a visibility impact of 0.12 dv at both Caney Creek and Upper Buffalo when compared to 2018 ''dirty'' or ''degraded'' background conditions. The commenter then calculates that this 0.12 dv impact is 0.5% of the total 23 dv visibility impairment. As discussed in the RTC document, the deciview scale is a logarithmic function of extinction, and therefore the calculations by the commenter are incorrect because they are based on deciview values and must be performed based on light extinction to properly calculate the percent contribution to visibility impairment. Spreadsheets submitted by the commenter present the light extinction attributable to each source (in inverse megameters) based on the results of their CAMx source apportionment modeling and calculate the percent contribution to total visibility impairment at each Class I area.[330] The commenter is incorrect in its statement that the impact from the Independence facility is one half of one percent; it is in fact, based on their own modeling and calculation, approximately 1.3% of the total visibility impairment at each Arkansas Class I area. Considering that the CAMx photochemical modeling takes into account the emissions of thousands of sources, both in Arkansas and outside of the state, we consider this to be a significant contribution to visibility impairment at each Class I area and a large portion (approximately one-third) of the total contribution from all Arkansas point sources that can be addressed through installation of controls on two units at a single facility. The CAMx modeling also showed that at Upper Buffalo, the Independence facility's contribution to visibility impairment is greater than the contribution from all of the subject-to-BART sources addressed in this final action combined.

Furthermore, the deciview visibility impacts for individual sources should be assessed based on natural ''clean'' background visibility conditions. The deciview improvement based on the 2018 background conditions provides an estimate of the amount of benefit that can be anticipated in 2018 and the impact a control/emission reduction may have on the established RPG for 2018. However, this estimate based on degraded or ''dirty'' background conditions underestimates the visibility improvement that would be realized for the control options under consideration. The source impacts and the potential benefits of controls must be considered relative to a light extinction level that represents a clean/natural background, rather than the current visibility conditions or projected visibility conditions at the end of the planning period.[331] The need for consideration of visibility impacts and benefits relative to clean/natural conditions was explained in the preamble to the final BART Guidelines:

> Using existing conditions as the baseline for single source visibility impact determinations would create the following paradox: The dirtier the existing air, the less likely it would be that any control is required. This is true because of the nonlinear nature of visibility impairment. In other words, as a Class I area becomes more polluted, any individual source's contribution to changes in impairment becomes geometrically less. Therefore the more polluted the Class I area would become, the less control would seem to be needed from an individual source. . . . Such a reading would render the visibility provisions meaningless, as EPA and the States would be prevented from assuring ''reasonable progress'' and fulfilling the statutorily-defined goals of the visibility program. Conversely, measuring improvement against clean conditions would ensure reasonable progress toward those clean conditions.[332]

The same logic applies to the evaluation of visibility impacts and benefits for sources examined for controls for reasonable progress. Accordingly, the EPA has used clean background conditions in evaluating the benefits of controls on individual reasonable progress sources and has disapproved reasonable progress decisions by states that relied on modeling employing dirty background conditions.[333] This approach has been upheld by the Eighth Circuit.[334]

We note that while CALPUFF results are not directly comparable to CAMx model results due to differences in metrics, models and model inputs,[335] CALPUFF visibility impacts are also calculated based on natural or ''clean'' background conditions.

We recalculated the average modeled visibility impact for the 20% worst days based on the commenter's CAMx modeled average visibility impact for the 20% worst days using a clean background approach (using annual average natural conditions background).[336] The Independence facility (units 1 and 2 combined) has impacts greater than 0.5 dv at both

[329] ''As a general matter, any threshold that you use for determining whether a source ''contributes'' to visibility impairment should not be higher than 0.5 deciviews.'' BART Guidelines, App. Y to 40 CFR 51.

[330] See ''Entergy Scenario 01 Contribution 2015–1124_FINAL.xlsx,'' ''Avg_Impacts'' tab, column ''AA'' for Caney Creek and Upper Buffalo Class I areas. We summarize these results in the RTC document.

[331] This recommended approach to the treatment of background air quality when quantifying source impacts and potential benefits from additional measures is different than the approach to background air quality when projecting how all emission reductions measures combined will determine visibility conditions at the end of the implementation period, *i.e.,* how background assumptions relate to the RPGs. It is not appropriate to consider only the amount by which a potential measure or combination of measures would change the projected overall deciview index value as of the end of the implementation period, *i.e.,* the degree by which the RPGs would differ with and without the control being included in the LTS. The RPGs are values that will be compared in a progress report to actual visibility conditions, and accordingly must represent the expected actual overall visibility conditions. Estimates of source impacts and measure benefits have a different purpose, which is to help guide decisions on the control of individual sources.

[332] 70 FR at 39124.

[333] The EPA has followed this logic in the North Dakota (77 FR 20894, April 6, 2012), Montana (77 FR 57864, September 18, 2012), Arizona (79 FR 52420, September 3, 2014), and Texas (81 FR 296, January 5, 2016) FIPs and partial disapprovals of North Dakota (77 FR 20894, April 6, 2012) and Texas (81 FR 296, January 5, 2016).

[334] *North Dakota* v. *EPA,* 730 F.3d 750, 764–766 (8th Cir. 2013). ''Although the State was free to employ its own visibility model and to consider visibility improvement in its reasonable progress determinations, it was not free to do so in a manner that was inconsistent with the CAA. Because the goal of § 169A is to attain natural visibility conditions in mandatory Class I Federal areas, see CAA section 169A(a)(1), and EPA has demonstrated that the visibility model used by the State would serve instead to maintain current degraded conditions, we cannot say that EPA acted in a manner that was arbitrary, capricious, or an abuse of discretion by disapproving the State's reasonable progress determination based upon its cumulative source visibility modeling.''

[335] Some of the major differences are: (1) CALPUFF uses maximum 24-hour emission rates, while CAMx uses annual average emission rates; (2) CALPUFF focuses on the day with the 98th percentile highest visibility impact from the source being evaluated, whereas CAMx focuses on the average visibility impacts across the 20% worst days regardless of whether the impacts from a specific facility are large or small; and (3) CAMx models all sources of emissions in the modeling domain, which includes all of the continental U.S., whereas CALPUFF only models the impact of emissions from one facility without explicit chemical interaction with other sources' emissions.

[336] Deciview impacts are calculated using the following equation: $\Delta dv = 10 \ln((b_{background} + b_{source})/b_{background})$, where b is extinction (Mm^{-1}) and Δdv is the delta-deciview visibility impact.

Caney Creek and Upper Buffalo on average across the 20% worst days on a ''clean'' background basis based on CAMx modeling submitted by the commenter.[337] These CAMx model results for the average across the 20% worst days show that the Independence facility contributes significantly to visibility impairment on the 20% worst days and controls will result in meaningful visibility benefit towards the goal of natural visibility conditions. Furthermore, the maximum visibility impact on an individual day within the subset of days that make up the 20% worst days are much larger. Facility-wide visibility impacts from Independence exceed 1 dv at each Arkansas Class I area. We note that in some situations, the days that CALPUFF model maximum or 98th percentile value impacts of the facility occur may not coincide with any of the days that make up the days in the worst 20% days at the Class I area and the visibility impacts modeled by CALPUFF are not directly comparable to the visibility benefits that would be anticipated on the 20% worst days. See our complete RTC document for additional information on calculated visibility impacts from the Entergy facilities based on the commenter's CAMx modeling results.

Comment: The level of improvement expected from EPA's proposed controls for Independence is virtually insignificant and does not justify the costs of controls. The BART-type evaluation for NO_X for the Independence Power Plant Units 1 and 2 would result in visibility improvements ranging from 0.148 to 0.459 dv with a cumulative improvement of 0.978 dv. EPA recognized that these improvements were relatively small and proposed an option (Option 2) that did not include the LNB/SOFA NO_X controls for Units 1 and 2. EPA, however, did not recognize that the Independence facility is subject to CSAPR and that NO_X reductions ''better than BART'' would already be achieved by participation in that program without specifically requiring the LNB/SOFA in the FIP.

For SO_2 emissions for Independence Units 1 and 2, EPA estimated improvements with dry FGD ranging from 1.045 to 1.178 dv with a cumulative benefit of 4.375 dv. Three of the four class I areas would realize visibility improvements barely discernible to the human eye (<1.1 dv). The best improvement is for Upper Buffalo and is only 1.178 dv. It is not appropriate to use the cumulative values as a representation of the visibility benefit of adding controls since only the improvement at each particular Class I area could actually be recognized. This level of visibility improvement is virtually insignificant and does not justify the costs associated with adding a dry FGD and, therefore, does not meet the statutory RPG requirement for proper consideration of the cost of controls and so is not ''reasonable.''

Response: We disagree with the commenter and do not believe that visibility improvements from NO_X controls ranging from 0.128 to 0.459 dv are relatively small. Given that sources are subject to BART based on a contribution threshold of no greater than 0.5 deciviews, it would be inconsistent to consider an improvement in visibility of nearly 0.5 dv to be insignificant or small for reasonable progress. In our proposed action, we noted that ''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.'' [338] Furthermore, total modeled extinction at Caney Creek is dominated by nitrate on 4 of the days that comprise the 20% worst days in 2002, and a significant portion of the total extinction at Upper Buffalo on 2 of the days that comprise the 20% worst days in 2002 is due to nitrate.[339] Both NO_X and SO_2 are key pollutants that contribute to visibility impairment at the Arkansas Class I areas. Because we have identified these two pollutants as key, we are obligated to determine which sources or source categories are responsible for emitting these pollutants and evaluate them for reasonable progress. Independence is the second largest point source of both SO_2 and NO_X in the State.[340] Therefore, we evaluated it for reasonable progress controls for both pollutants. We recognized, however, that at this time, even though NO_X emissions are a key pollutant, point source NO_X emissions are not the main contributors to visibility impairment on the average of the 20% worst days at Arkansas' Class I areas in 2018, as projected by CAMx source apportionment modeling.'' [341] Even though we recognized that NO_X emissions are a key pollutant to reaching the regional haze goals, and that the visibility benefits from NO_X controls were sizeable, we took comment on two options because the visibility impairment due to Arkansas point source emissions on the average of the 20% worst days were primarily due to sulfate emissions. We also found that significant reductions could be achieved very cost effectively through the implementation of low NO_X burners. In our final action, we have determined that it is appropriate to require the NO_X controls as proposed under Option 1 because the goal of the long-term strategy and reasonable progress requirements is to improve visibility and make progress towards natural conditions and NO_X is a key pollutant impacting visibility at the Arkansas Class I areas. We used a shorthand term, ''driver,'' in our proposal discussing SO_2, and did not mean to imply that NO_X was not also a key pollutant. While point source NO_X emissions are not the primary contributor to impairment on most of the 20% worst days, NO_X is a key contributor to visibility on other days of the year and on some days that make up the 20% worst days (in 2002, IMPROVE monitor data shows that two days that make up the 20% worst days at Upper Buffalo and three days at Caney Creek are more significantly impacted by nitrate than sulfate). So in considering reasonable progress factors, we have determined that because NO_X and SO_2 are both key visibility impairing pollutants, for Independence there are technically feasible and cost effective controls available for both SO_2 and NO_X and those controls will provide significant visibility improvement. Therefore, both SO_2 and NO_X controls are reasonable and necessary to eventually achieve the national goal. We have determined that it is appropriate to reduce NO_X emissions and finalize Option 1. As to the comment that we did not recognize ''better than BART'' coverage due to CSAPR, we address this comment elsewhere in a separate response to comment.

With respect to the anticipated visibility improvement due to SO_2 controls, we consider visibility benefits ranging from 1.045 to 1.178 dv at each Class I area to be significant. We note that the Regional Haze Rule provides that sources with a 0.5 dv impact at a Class I area ''contribute'' to visibility impairment and must be analyzed for BART controls, and that source with a 1.0 dv impact at a Class I area to ''cause'' visibility impairment. Given

[337] See ''Entergy Arkansas CAMx—EPA calcs max and clean background.xlsx,'' available in the docket for this action.

[338] 80 FR at 18995.

[339] See Arkansas Regional Haze SIP, Appendix 8.1— ''Technical Support Document for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation Plans,'' section 3.7.1 and 3.7.2. See the docket for this rulemaking for a copy of the Arkansas Regional Haze SIP.

[340] See 80 FR at 18991, Table 59.

[341] 80 FR at 18995.

that sources are subject to BART based on a contribution threshold of no greater than 0.5 deciviews and visibility impacts greater than 1.0 deciview are considered a level to be ''causing'' visibility impairment, it would be inconsistent to consider a potential improvement in visibility of greater than twice the BART threshold to be insignificant.

Furthermore, as discussed elsewhere throughout this final rule, results of Entergy Arkansas' CAMx modeling with source apportionment provide additional support that the Independence facility has significant impacts on visibility at nearby Class I areas on the 20% worst days and that controlling these units would result in significant visibility benefits towards the goal of natural visibility conditions. We address comments concerning the consideration of cumulative visibility benefits and imperceptible visibility benefits elsewhere.

Comment: EPA's CALPUFF modeling indicates that the SO_2 and NO_X emission limits proposed for Independence will result in a 1.952 dv improvement in Caney Creek and a 1.782 dv improvement in Upper Buffalo. However, this range is vastly overstated. Based on the current monitored visibility levels in Caney Creek and Upper Buffalo, the W20 days show that the visibility impairment in 2018 will be approximately 23 to 24 dv. EPA recognizes that sulfate from all of Arkansas' point sources are projected to be responsible for only about 3.6% of total light extinction at Arkansas' Class I areas based on CENRAP modeling.[342] This means that sulfate from *all* Arkansas point sources are projected to be responsible for only about 0.81–0.86 dv of impairment (23–24 dv × 3.6%). For nitrates, EPA projects that Arkansas point source emissions will account for, at most, 0.29% of the total light extinction at Arkansas' Class I areas. Independence's SO_2 and NO_X emissions contribute only a portion to the sulfate and nitrate percentages estimated from Arkansas point sources. It would, therefore, be impossible for the SO_2 and NO_X limits proposed for Independence to result in deciview improvements at Caney Creek and Upper Buffalo of 1.952 dv and 1.782 dv, respectively. This simple example demonstrates the obvious flaw in EPA's use of CALPUFF for its reasonable progress analysis and, thus, its justification for imposing emission limits on Independence despite the fact that the Class I areas are below the URP.

[342] 80 FR at 18990.

Based on CALPUFF modeling, EPA's proposed BART limits will result in projected combined visibility benefits of approximately 4.3 dv at Caney Creek. Based on Entergy's statistical projection of the haze index in Caney Creek, that would result in a haze index of 15.76 dv, which would put Caney Creek closer to natural background levels than the glide path. The URP would not reach that haze level until approximately 2048.[343] Indeed, even if you ascribed the CALPUFF-projected benefits to Caney Creek based on the recent IMPROVE levels (approximately 22 dv between 2009 and 2012), the projected haze index would drop to 17.7 dv, which indicates no further action should be needed to remain below the URP until approximately 2038.

If EPA insists on relying on CALPUFF to evaluate the projected visibility benefits of requiring controls on Independence, it must be consistent and use CALPUFF to evaluate the need for such controls for purposes of demonstrating reasonable progress. As demonstrated in Figures 11 and 12, controls at Independence cannot be justified for reasonable progress based on the CALPUFF results, which predict an improvement of several deciviews solely from BART controls.

Response: As more fully explained above and in the RTC Document, the commenter's analysis fails to account for the fact that deciviews are a logarithmic function of extinction, that CALPUFF results are for the maximum impact (98th percentile impact from each source) in contrast to the CENRAP projected visibility conditions that are for the average visibility over the 20% worst days, and also fails to differentiate between deciview values calculated based on natural background conditions (as the CALPUFF results are) and the deciview values relative to a degraded or dirty background.

First, the commenter incorrectly estimates that the impact from sulfate point source emissions in Arkansas is 0.81–0.86 dv. Because the deciview metric is a logarithmic function of extinction, the percent extinction cannot be directly applied to the total deciview impairment. Recalculating the impact from sulfate point sources to correct for this error yields approximately a 0.32 dv impact based on a ''dirty'' background 2018 projected visibility conditions and 0.92 dv based on a natural background approach.

[343] The projected haze index at Upper Buffalo of 18.05 dv would keep Upper Buffalo below the glide path until approximately 2038—the end of the third planning period.

Second, 0.92 dv represents the estimated deciview improvement from eliminating sulfate emissions at all point sources in Arkansas (based on typical or average emissions) on average across the 20% worst days, as defined by the 20% worst days of monitored visibility at Caney Creek. This CAMx derived value is not directly comparable to the CALPUFF modeled 1.952 dv improvement from controls on both units at Independence, due to differences in models, model inputs and metrics. CALPUFF modeling following the BART guidelines and recommended protocol provides an estimate of the maximum (98th percentile) visibility benefit based on 24-hr maximum actual emissions modeled over a period of three years. The CAMx modeling results presented by the commenter represent the average visibility impacts over the 20% worst days (as defined by monitored data) based on modeling actual emissions levels. In addition, CALPUFF uses an estimated constant background ammonia level and does not account for the competition for ammonia due to emissions from other sources. A maximum value of 1.952 dv for visibility benefits of controlling Independence based on CALPUFF modeling is not inconsistent with an estimated 0.92 dv impact from all sulfate point source emissions averaged over the 20% worst days. In general, the maximum value could be several times larger than the average over the 20% worst days (representing the average visibility over the 73 days, or 24 monitored days with the worst visibility). Furthermore, the maximum value as modeled by CALPUFF is based on maximum 24-hr emissions, which may be much higher than the average emissions. As discussed in a separate response to comment above, CAMx modeling using source apportionment provided by the commenter (Entergy) modeled a facility-wide impact from Entergy Independence of 1.64 dv on the maximum day within the subset of days that make up the 20% worst days. The maximum modeled impact across the full 365 days modeled could be much larger. Furthermore, this modeling is based on actual emissions and not maximum 24-hr emissions as modeled by CALPUFF. Therefore, the 1.952 dv visibility benefit estimated by CALPUFF is not ''impossible'' and is in fact in line with the visibility impacts estimated using the CAMx model as supplied by the commenter.

Third, the commenter is incorrect in estimating a 4.3 dv improvement from all BART controls and using this value to adjust projected visibility conditions in 2018 on the 20% worst days in the above figures. The cumulative visibility impacts cited to by the commenter (*e.g.,* 4.3 dv improvement at Caney Creek due to all BART controls) combines the maximum visibility improvements from each facility that would result from required NO_X or SO_2 controls without any consideration of the location of the source or if the impacts and benefits would occur on the same day. The commenter's approach overstates the combined impact at a given Class I area and does not contemplate if sources are located near each other and would likely impact a Class I area at the same time. Contrary to the commenter's description of the methodology used to estimate the total visibility benefits of BART controls,[344] the commenter simply added the CALPUFF modeled deciview visibility benefits for each control. These benefits represent the maximum (98th percentile) visibility benefits at each source based on reductions to the maximum 24-hr emissions modeled over a period of three years. The maximum benefits from controlling one source cannot be added to the maximum benefits of controlling another source as these benefits are not likely to occur on the same day since the sources are not collocated. In addition, the maximum benefits from NO_X controls and SO_2 controls at the same facility cannot be added as they may not occur on the same day. Furthermore, these values represent the benefit on an individual day and not the average visibility benefit on the 20% worst days so it is not appropriate to adjust the visibility conditions on the 20% worst days by this amount as the commenter does in the above figures. In some situations, the days that CALPUFF model maximum or 98th percentile value impacts of the facility occur may not coincide with any of the days that make up the days in the worst 20% days at the Class I area and the visibility benefits modeled by CALPUFF are not directly comparable to the visibility benefits that would be anticipated on the 20% worst days from those specific controls. Furthermore, as discussed elsewhere in this section of the final rule, because deciviews are a logarithmic function of extinction, they cannot be added as the commenter does here. The CALPUFF modeled visibility benefits represent the visibility benefits of controls based on a clean background approach, and not the amount of benefit that would occur from degraded conditions, which would be needed to estimate the improvement in overall visibility conditions in 2018. We estimated the amount of visibility benefit anticipated from all controls against 2018 visibility conditions in estimating the proposed RPGs for 2018. In this calculation we estimated the benefit from all required controls to be 0.21 dv at Caney Creek and 0.19 dv at Upper Buffalo.

Comment: CALPUFF overstates the visibility improvement expected from EPA's proposed controls on Independence, EPA concluded that the cumulative benefit of installing all of the controls in the Proposed FIP—all BART controls plus controls at Independence—would result in visibility benefits at Caney Creek of only 0.21 dv and at Upper Buffalo of only 0.19 dv. Since Independence represents only approximately 36% of the SO_2 point source emissions and 21% of the point source NO_X emissions in Arkansas, one can ascribe only a minor portion of this projected insignificant deciview improvement to controls on Independence (approximately 0.08 dv at Caney Creek and 0.07 dv at Upper Buffalo).[345] Based on this, installation of controls on Independence will yield no discernible visibility improvements.

This demonstrates the illogic of relying on CALPUFF for reasonable progress. Independence's contribution to the deciview improvements EPA projects based on the CENRAP modeling would be much less than the total deciview improvement at Caney Creek of 0.21 dv from the installation of controls at all of the proposed FIP sources and 0.19 dv at Upper Buffalo would not be perceptible to the human eye; nowhere close to the 1.95 dv and 1.78 dv improvement that EPA is claiming based on CALPUFF. Requiring imperceptible visibility improvements is simply unreasonable. The CAA requires only ''reasonable progress, not the *most* reasonable progress.'' [346]

Response: As we discuss in depth elsewhere, visibility improvements from controls must be evaluated on a ''clean'' background basis to fully assess the benefits from controls. It is not appropriate to consider only the amount by which a potential measure or combination of measures would change the projected overall deciview index value as of the end of the implementation period, *i.e.,* the degree by which the RPGs would differ with and without the control being included in the LTS, as the commenter does here. We also discuss elsewhere in this section of the final rule that the deciview scale is a logarithmic function of extinction and calculations to determine benefits or amount of contribution to visibility impairment must be based on extinction and then converted into deciviews. Nevertheless, the commenter's estimated visibility benefits of 0.08 dv at Caney Creek and 0.07 dv at Upper Buffalo on average across the 20% worst days are approximately a reduction in extinction of 0.8 Mm^{-1} at Caney Creek and 0.7 Mm^{-1} at Upper Buffalo, which is 0.37 dv and 0.32 dv based on a clean background approach for the 20% worst days. In our response to a separate comment above, we discuss that due to the differences in models, model inputs, and metrics, the estimated visibility benefits estimated from CAMx modeling cannot be directly compared to CALPUFF modeled visibility benefits. For one, CALPUFF modeling is used to estimate the maximum visibility benefit based on maximum emissions whereas the CAMx modeling estimates the average visibility benefit over the 20% worst days (as defined by the monitored data) using actual or typical emission levels. As we also discuss above in a separate response to comment, CAMx visibility modeling with source apportionment submitted by Entergy estimates a maximum visibility impact (limited to only the days comprising the 20% worst days) of over 1.5 dv from the Independence facility at both Caney Creek and Upper Buffalo. In some situations, the CALPUFF modeled maximum or 98th percentile impacts of the facility may not coincide with the days that make up the worst 20% monitored days at the Class I area, therefore the maximum impact based on CAMx modeling could be even higher.

With regard to the quote the commenter reproduced from the Eighth Circuit Court's decision in *North Dakota* v. *EPA,*[347] several environmental groups challenged a portion of our final action on North Dakota's regional haze SIP that ultimately approved North Dakota's reasonable progress determination for

[344] Commenter states: ''Trinity derived the 4.3 dv improvement from the CALPUFF modeling by determining the total extinction (in inverse megameters) from each proposed BART source, adding them together, and then calculating the deciview improvement. The resulting 4.3 dv improvement is over five times the total visibility impact attributed to all point sources in Arkansas based on CENRAP's CAMx modeling and 14 times the impact attributed to point sources based on Entergy's current CAMx modeling.''

[345] These values are the calculated improvement based on EPA's ''scaling methodology.'' See 80 FR at 18997.

[346] *North Dakota* v. *EPA,* 730 F.3d 750, 767 (8th Cir. 2013).

[347] The commenter states that requiring imperceptible visibility improvements is simply unreasonable and refers to the 8th circuit decision that the CAA requires only ''reasonable progress, not the *most* reasonable progress.'' *North Dakota* v. *EPA,* 730 F.3d 750, 767 (8th Cir. 2013).

NO_X controls for the Coyote Station.[348] The environmental groups objected to North Dakota's decision to reject a control it had evaluated, after having applied the four reasonable progress factors, and subsequently approving another NO_X control as reasonable progress.

We interpret the Court's statement as meaning broadly that just because a more stringent level of control could be technically feasible in a particular instance, it does not mean it necessarily must be required under reasonable progress. We see no conflict with this determination and our proposed Arkansas FIP and requiring controls that may not result in perceptible visibility improvements. In North Dakota's case, we noted technical flaws in North Dakota's analysis, and we noted that we could have reached a different conclusion had we conducted the analysis ourselves, but we ultimately determined these issues did not prevent us from accepting North Dakota's reasonable progress determination. The Court did not find that our conclusions on the issue were arbitrary, stating in part that, ''[e]ven if [the control in question] were perhaps the most reasonable technology available, the CAA requires only that a state establish reasonable progress, not the most reasonable progress. In contrast, and as explained in greater detail elsewhere, in our 2012 rulemaking,[349] we made a finding that Arkansas did not complete a reasonable progress analysis and therefore did not properly demonstrate that additional controls were not reasonable under 40 CFR 51.308(d)(1)(i)(A). Thus we disapproved the RPGs Arkansas established for Caney Creek and Upper Buffalo. Our proposed rulemaking completed the reasonable progress analysis and established revised RPGs, since we have not received a revised SIP to correct the portions of the SIP submittal we disapproved. We determined that cost effective controls were in fact available that would have very significant visibility benefits.

Comment: EPA's assessment demonstrates that the Independence Power Plant's emissions have, and will continue to have, very little effect on visibility in any Class I area. EPA's reasonable progress analysis shows that ''[o]n 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.'' 80 FR at 18989 (footnote omitted). According to EPA, these very small percentages reflect contributions from *all* ''Arkansas point sources,'' not from the Independence Power Plant alone, whose emissions of course contribute only a fraction of these small amounts.

Response: We disagree with the commenter's assertion that the contribution to visibility impairment from Independence is ''insignificant'' or ''minimal.'' We agree with the commenter's description of the 2002 CENRAP source apportionment data. The CENRAP modeling also projects that Arkansas point sources will be responsible for 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo in 2018. As we discuss in our proposal, based on 2011 NEI data 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 point-source NO_X emissions in the State.[350] Therefore, a significant portion of the total projected visibility impairment on the 20% worst days, on the order of 1% or more, can be expected to be attributable to SO_2 emissions from a single facility, the Independence facility, based on the CERNAP modeling. We discuss in a separate response to comment that results of our CALPUFF modeling, as well as the results of additional CAMx modeling submitted by Entergy, confirm and support that the visibility impairment due to the Independence facility is significant and that emission reductions will result in meaningful visibility benefits towards natural visibility conditions.

6. Visibility Benefit of Entergy Arkansas Proposal

Comment: Entergy's proposed combination of controls and lower SO_2 emission rates will ensure that the Class I areas achieve virtually the same reasonable progress as EPA's proposal but at a cost of over $2 billion less than the proposal.[351] Based on Entergy's CAMx modeling and Ranked Statistical Analysis, the difference in the haze index between the proposed FIP controls and Entergy's proposal is 0.05 dv at Caney Creek and 0.07 dv at Upper Buffalo.

Response: We discuss the ''ranked statistical analysis'' submitted by the commenter in the response to comments elsewhere. We disagree with the commenter that the Entergy proposed control scenario achieves ''virtually'' the same visibility benefits as the controls required in this FIP. We examined the estimated visibility benefits of the FIP and Entergy's proposal from the commenter's CAMx photochemical modeling. We note that both scenarios include benefits from all required BART controls at all subject-to-BART facilities with the exception of White Bluff. The modeled FIP scenario also includes SO_2 and NO_X controls at both Independence and White Bluff. The modeled Entergy proposal scenario includes the elimination of emissions from White Bluff, an approximate 15% reduction in SO_2 emissions from Independence and roughly similar NO_X reductions at Independence as required in the FIP.

Entergy's proposal achieves less visibility benefit than the FIP controls at Arkansas' Class I areas, most significantly at Upper Buffalo where the benefit from Entergy's proposal is approximately only 63% of the benefit from the FIP ($1.54\ Mm^{-1}$ from the FIP compared to $0.97\ Mm^{-1}$ from Entergy's Proposal, see the RTC document for additional information). As discussed above, CAMx source apportionment modeling submitted by Entergy shows that Entergy Independence has significant visibility impacts at both Arkansas Class I areas. At Upper Buffalo, the Independence facility contributes more to visibility impairment than all the subject-to-BART sources addressed in this action combined. Additional reductions from the elimination of emissions from the White Bluff facility under Entergy's proposal are much too small to compensate for the lack of significant SO_2 reductions at Independence. Furthermore, Entergy's proposal does not achieve these benefits until 2028, seven years after the full benefits from the FIP would be realized. We discuss other aspects of Entergy's proposal, including uncertainty in emissions at White Bluff after the cessation of coal-burning, and issues concerning the BART requirements for White Bluff in separate responses to comment elsewhere in this document.

[348] See EPA's final rule at 77 FR 20894, 20945 (April 6, 2012).

[349] 64 FR at 35732.

[350] 80 FR at 18991.

[351] Entergy Arkansas Inc. stated that it is proposing near-term interim controls and the cessation of coal combustion at White Bluff by 2028. Entergy is proposing to meet lower SO_2 emission rates at White Bluff Units 1 and 2 and Independence Units 1 and 2 by 2018, and is willing to install LNB/SOFA at all four units and meet a 30-day rolling average NO_X emission rate of 1,342.5 lb NO_X/hr, within three years after the effective date of the final FIP as part of its multi-unit approach. Entergy's comments with regard to the proposed NO_X rate are discussed elsewhere in this final rule.

We also disagree with the commenter's use of the results of their ranked statistical analysis (the ''projected haze index'' shown in the Entergy Arkansas Inc.'s submitted comments in figures 13 and 14) as the starting point for calculating the overall visibility benefits from the FIP or the commenter's proposed alternative. As discussed elsewhere in this section of the final rule, the ranked statistical analysis is simply a projection of future visibility conditions based on past improvement and is not directly tied to any additional required emission reductions in the next few years that would result in this future visibility improvement from current conditions to this projected value in 2018.

7. Observed Visibility Improvements

Comment: Trinity was tasked by Entergy Arkansas with conducting a statistical analysis of observed visibility data gathered through the IMPROVE program to statistically determine the future trends in the regional haze index values. Trinity conducted a simple Trend Statistical Analysis and more robust Ranked Statistical Analysis to determine the projected haze index in 2018.[352]

For Caney Creek and Upper Buffalo, respectively, the observed values are well below the glide path with a consistent downward trend in the observations. This downward trend is consistent with the historical (2002–2011) trend in decreasing sulfur dioxide (SO_2) emissions from tier 1 sources located in the states contributing significantly to the Caney Creek and Upper Buffalo Class I Areas.[353] Pursuant to the NEI emissions data, the SO_2 emissions have significantly decreased since 2005 to 2011 in all source categories, including especially a more than 50% drop due to fuel combustion from electric utilities and a 67% drop in the fuel combustion from industrial sources. Based on the significant downward trend in the observed data and the actual SO_2 emissions data, the future haze index value in 2018 is expected to be lower than the currently predicted glide path. The lower haze index value in 2018 will be additionally supported by the anticipated implementation of regulations further curbing emissions.

In order to statistically calculate the future deciview haze index values using observed data instead of relying on the CENRAP modeling, two statistical analyses were performed and evaluated to determine the most appropriate analysis for predicting the haze index values based on observed data: Trend Analysis, and Ranked Statistical Analysis. The 2018 average of the 20% worst days for visibility was calculated to be 20.07 dv for Caney Creek and 20.91 dv for Upper Buffalo. These numbers are far below the URP for the first planning period and demonstrate that no source in Arkansas, including Independence, needs to install controls for Arkansas to remain below the glide path.

Response: As we discuss in section V.C of this final rule, being projected to be on or below the URP glidepath in 2018 (or even beyond) does not automatically mean that no controls or evaluation under reasonable progress is needed in this planning period. The commenter presents SO_2 emissions data from 2002, 2005, 2008, and 2011 for states identified by the commenter as impacting visibility at the Arkansas Class I areas. These data show significant emissions reductions over this time period and are consistent with observed visibility improvement at the Arkansas Class I areas. However, most of the visibility improvement currently observed in Arkansas appears to be due to emissions reductions that have taken place outside the state. Arkansas emissions do not exhibit the same downward trend as presented for the other states that impact visibility at the Arkansas Class I areas.[354] More recent annual emissions from 2012–2014 are actually higher than emissions from the 2008–2011 period and there is no downward trend in emissions from those point sources with the largest visibility impacts, those from fuel combustion at electric utilities. To the extent that the commenters are suggesting that Arkansas should be relieved of its regional haze obligations because other states' emission reduction efforts have already resulted in significant visibility improvement at Arkansas' Class I areas, this is incorrect. Rather Arkansas, and EPA in standing in Arkansas' shoes, must consider the statutory factors in addressing the long term strategy and reasonable progress requirements.

We disagree with the commenter that the CENRAP CAMx predicted 2018 haze index is overly conservative. The comments indicate a lack of understanding of how reasonable progress goals are established, as well as the imports of the goals as opposed to the measures adopted to ensure reasonable progress. As we state in the Regional Haze Rule, the reasonable progress goal(s) set by the state, or EPA when promulgating a FIP, are not enforceable. The reasonable progress goals are an analytical tool used by EPA and the states to estimate future visibility conditions and track progress towards the goal of natural visibility conditions. Accordingly, the RPGs must represent an estimate of the degree of visibility improvement that will result in a future year from changes in emissions inventories, changes driven by the particular set of control measures adopted in the regional haze SIP or FIP to address visibility, as well as all other enforceable measures expected to reduce emissions. Given the forward-looking nature of reasonable progress goals and the range of assumptions that must be made as to emissions in the future, we expect there to be some uncertainty in the estimates of future visibility.

The statistical analyses provided by the commenter are simply extrapolations of future visibility conditions based on observed reductions in visibility impairment in the past. Future visibility projections must be directly tied to projections of future emissions, and anticipated reductions due to federal and state requirements. Current 5-yr average (2010–2014) observed visibility conditions are 21.8 dv at Caney Creek and 21.6 dv at Upper Buffalo. Any future improvements in overall visibility conditions at the Arkansas Class I areas between now and 2018 will be due to future emission reductions during that time period. Commenters have not provided any specific information suggesting anticipated enforceable emission reductions from those Arkansas point sources with significant visibility impacts or other sources that would result in the almost 2 dv visibility improvement by 2018 projected by the commenter at Caney Creek in their statistical analysis. Furthermore, as discussed above, any anticipated emission reductions from sources in other states do not relieve Arkansas of its regional haze obligations. The BART requirements under § 51.308(e) must be met for those specific sources that meet the BART criteria and contribute to visibility impairment. The determination of whether an RPG and the emission limitations and other control measures upon which it is based constitute reasonable progress is made by conducting certain analyses and

[352] Trinity's report is included as Exhibit D *IMPROVE Data Statistical Analysis,* Trinity Consultants (July 2015) to Entergy Arkansas, Inc.'s comments.

[353] See Figure 2–3 of Exhibit D to Entergy Arkansas, Inc.'s comments.

[354] See RTC document for additional information on Arkansas source category SO_2 emissions from 2004 to 2014.

meeting the requirements under § 51.308(d)(1).

The RPGs are an analytical tool the state and we use to evaluate whether the measures in the implementation plan are sufficient to achieve reasonable progress. What is enforceable under the RH rule are the emission limitations and other control measures that apply to specific sources, and upon which the RPGs are based. Since the emission limitations we are requiring in our FIP for specific Arkansas sources (which is what our revised RPGs are based upon) are not currently being achieved, we disagree that visibility at the Class I areas has already improved beyond what we would require in our FIP and that our FIP is therefore unjustified and unwarranted. The emission reductions required in this action will result in significant visibility improvements at the Class I areas beyond what is currently being achieved or observed. As discussed elsewhere throughout this final rule, the commenter's photochemical modeling analysis provides an additional demonstration that the controls required in this action result in visibility benefits beyond current observed visibility conditions and serve to accelerate progress towards natural visibility conditions.

8. Reasonable Progress Goals

Comment: EPA's proposed RPGs are more stringent than Arkansas' proposed RPGs in its 2008 Regional Haze SIP, which would have ensured that Arkansas is on track to achieve natural visibility conditions by 2064. Arkansas is reducing regional haze in its Class I areas at a higher rate than both the URP, which was approved by EPA, and Arkansas' initial proposed RPGs. As indicated by the URP, Arkansas is well on track to reaching natural visibility conditions by 2064 and more stringent RPGs than those in Arkansas' 2008 Regional Haze SIP are not necessary. EPA should withdraw the Proposed FIP and ensure that revised RPGs in any subsequent plan are within the scope of EPA's authority to address impairment of visibility.

The differences in projected 2018 visibility conditions at Caney Creek and Upper Buffalo that are attributable to all of the proposed FIP controls—including both FIP BART and FIP reasonable progress requirements—will be imperceptibly small (*i.e.,* improvements of, at most, 0.21 dv and 0.19 dv, respectively, at Caney Creek and Upper Buffalo). The minimal visibility improvements that EPA's proposed reasonable progress emission control requirements would produce would come at exorbitant costs. Additionally, even the negligible changes in visibility represented by EPA's proposed revised RPGs are greatly overstated because some controls will not be in place until after 2018.

Commenters also state that the methodology utilized by EPA in estimating the RPGs is oversimplified and inaccurate. EPA chose a method of determining RPGs that is admittedly inferior and less sophisticated than the alternative approach, which EPA rejected in Arkansas but used in Texas: CAMx photochemical modeling. EPA admits that it has not performed its own modeling in a manner adequate to develop "refined numerical RPGs." Some commenters stated that EPA used CALPUFF, which is not a photochemical grid model, to develop a "quick-and-dirty" RPG analysis in the proposed Rule.

Response: As we discuss in more detail elsewhere in our response to comments, we agree that Arkansas proposed RPGs in its 2008 regional haze SIP that fell below the URP. However, in our 2012 rulemaking,[355] we made a finding that Arkansas did not complete a reasonable progress analysis and therefore did not properly demonstrate that additional controls were not reasonable under 40 CFR 51.308(d)(1)(i)(A). Thus we disapproved the RPGs Arkansas established for Caney Creek and Upper Buffalo. In our proposed rulemaking, we completed the reasonable progress analysis and established revised RPGs, since we have not received a revised SIP to correct the portions of the SIP submittal we disapproved. As discussed in our proposal and in our RTC document, we focused our reasonable progress analysis on the Entergy Independence facility because of its significant emissions of NO_X and SO_2 and its large potential to impact visibility at nearby Class I areas. We determined that cost-effective controls were available for units at this facility and that they would result in significant visibility benefits. We respond to specific comments concerning the visibility benefits from controls on the Independence facility in separate responses to comments. We also completed five-factor BART analyses and determinations for subject-to-BART facilities where we had previously disapproved the BART determination in the 2008 Arkansas regional haze SIP. Our proposed RPGs reflected the visibility benefits anticipated from the implementation of controls across the subject-to-BART facilities and the Independence facility required in this action. As we discuss in our proposal and in response to comments, we have determined that these controls are cost-effective and result in significant visibility benefits that provide for progress towards the goal of natural visibility conditions. As we discuss below in a separate response to comment, after considering comments received, we agree that the RPGs should reflect anticipated visibility conditions at the end of the implementation period in 2018 rather than the anticipated visibility conditions once the FIP has been fully implemented. We are finalizing RPGs that represent the visibility conditions anticipated on the 20% worst days at Caney Creek and Upper Buffalo by 2018.

We disagree with the commenter that the amount of visibility improvement due to our proposed FIP is "insignificant." We address comments concerning the perceptibility of visibility improvements in response to comments elsewhere. The required controls are estimated to improve overall visibility benefits compared to the CENRAP projected visibility conditions for 2018 by approximately 0.2 deciviews, a reduction in light extinction of about 2 Mm^{-1} at Caney Creek and 1.8 Mm^{-1} at Upper Buffalo. Once fully implemented, the required controls to meet the BART requirements, as well as required controls on the Independence facility result in an approximate 2% improvement in overall visibility conditions projected by CENRAP at both Caney Creek and Upper Buffalo on the 20% worst days. Our technical record demonstrates that the required controls reduce impacts from these sources and result in meaningful visibility benefits towards the goal of natural visibility conditions. The required controls reduce the projected visibility impairment due to all Arkansas point sources by 50% at Caney Creek and 50% at Upper Buffalo. We note that the required controls actually result in larger visibility improvements than calculated here because the CENRAP projections already included an assumption of large emission reductions due to SO_2 BART at Flint Creek, as well as NO_X controls at White Bluff and Flint Creek.[356]

We disagree with the commenter that our proposed RPGs overstated the visibility benefit of controls or that they are inaccurate. In our proposal, we acknowledged that the methodology we utilized to estimate the revised RPGs is

[355] 64 FR at 35732.

[356] 2002 CENRAP modeled SO_2 emissions for Flint Creek were 11,165 tpy and 2018 CENRAP modeled SO_2 emissions were 2,896 tpy, an assumed 75% reduction in emissions.

not as refined as developing an updated model projection. However, it allows us to translate the emission reductions contained in the proposed FIP into quantitative RPGs, based on modeling previously performed by the CENRAP. These proposed RPGs provided an estimate of the visibility benefit of all the required controls compared to the 2018 visibility conditions projected by the state and established in their SIP that would result without the required controls. After considering comments received, we agree that the RPGs should reflect anticipated visibility conditions at the end of the implementation period in 2018 rather than the anticipated visibility conditions once the FIP has been fully implemented, and have accordingly revised the 2018 RPGs. RPGs, unlike the emission limits that apply to specific reasonable progress and BART sources, are not directly enforceable. Rather, the RPGs are an analytical framework considered by us in evaluating whether measures in the implementation plan are sufficient to achieve reasonable progress. Our FIP imposes emissions limitations that we conclude to be necessary under the CAA for the first planning period. Ideally, these controls would be installed and the emission limitations achieved, so the visibility improvements can be realized and built on in a subsequent comprehensive periodic SIP revision (see 40 CFR 51.308(f)). Arkansas may choose to use these RPGs for purposes of its progress report (along with a consideration for what controls had already been implemented and what controls would be implemented in the near future), 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) in evaluating the adequacy of their SIP (or this FIP) to meet the established RPGs.

We discuss our selection of the CALPUFF model for evaluating single-source visibility impacts in a separate response to comment above. In the response, we also explain the model selection for our Texas action and refer the reader to our detailed explanation in the RTC that accompanies that action. Commenters are incorrect and confuse the single-source visibility analysis used to evaluate the visibility benefit of controls on a specific source with the assessment of overall visibility conditions. We did not use the CALPUFF modeling to develop the new reasonable progress goals we establish in this rulemaking. The RPGs are based on adjusting the CENRAP 2018 CAMx photochemical modeling based on source apportionment modeling results and emission inventory data. As we stated in the proposed rulemaking, we did not perform additional photochemical modeling to directly model the new projected visibility goals due to the time and resource demands associated with photochemical modeling. The commenters are also incorrect in their comparison of approaches for establishing new RPGs between this action for Arkansas and our previous action in Texas. For both Texas and Arkansas, we utilized the CENRAP 2018 CAMx modeling that estimated the 2018 RPGs and then adjusted those RPGs to account for estimated visibility improvement due to required controls. In neither case did we perform a full photochemical modeling analysis to model all the required controls and project the future visibility conditions. In both cases, the 2018 RPGs were adjusted based on a scaling of the source apportionment model results and emission inventory changes.

Comment: The demonstration methodology used by EPA is unscientific. EPA used a ratio of emission rates from BART sources to Arkansas point sources to scale the modeled predicted haze index. First, there is no evidence to prove that the CAMx predicted modeling results are linearly correlated with emission rates. In fact, the CAMx modeling fundamentally is based on photochemical reactions. Therefore, the relationship between variation in the emission rates and predicted concentration is complicated. Second, a deciview is a logarithmic scale based on the concept that one deciview is the minimum change in the visibility perceptible to a human observer. As such, deciviews cannot be added or subtracted directly. Therefore, fractioning or scaling deciviews based on emission rates is illogical.

Another commenter was supportive of our approach, stating that in Texas, the model results were used to demonstrate that the overall change in species concentrations was very nearly linearly proportional to the change in emission levels for an individual source (with very high linear correlation coefficients near 1.0). This strongly supports the use of the emission scaling approach for Arkansas. If the CAMx model were used to determine the impact of emission controls on a single source in Arkansas (such as Independence), it is therefore expected that the modeled reductions in sulfate and nitrate concentrations at each of the Class I areas will be very nearly proportional to the SO_2 and NO_X concentration reductions. In other words, the emission scaling approach has been shown to be mathematically sound and quite appropriate, especially considering the resources that would be required to exercise CAMx separately for each control measure at each evaluated source.

Response: We disagree with the comments that the methodology used to estimate overall visibility benefits from all required controls control level emissions was unreasonable or unscientific. We agree with comments that the approach we followed is reasonable and based on a scaling of visibility extinction components due to Arkansas point sources in proportion to emission changes from the required controls at Arkansas point sources. The commenter is incorrect in suggesting that we developed a linear relationship between emissions and deciviews and then commenting that this ‘‘fractioning or scaling of deciviews’’ is flawed because the relationship between light extinction and deciviews is exponential. We properly developed a linear relationship between emissions and light extinction (inverse Megameters), not deciviews.

We agree with the commenters, that in general, the relationship between downwind concentrations and emissions can be complicated and non-linear due to complex chemistry, including the fact that reductions in sulfur emissions can result in an increase in ammonium nitrate. For estimating the total visibility benefit from all controls and estimating a new reasonable progress goal that reflects those controls, we relied on the CENRAP's 2018 CAMx modeling results, including source apportionment results, and the projected emission inventories, and scaled the results as described in the TSD, similar to what was done in our previous action in Arizona and Texas. While we acknowledge that this approach is not as refined an estimate as would be attained in performing a new photochemical modeling run, it is based on scaling to adjust earlier photochemical modeling results that took into account the complex chemistry that impacts the overall visibility. The uncertainty in the visibility benefit from these controls introduced by the linear extrapolation does not impact the overall conclusions. Furthermore, in our technical analysis developed to support our action on Texas regional haze, we observed that for each facility and Class I area, the available modeled visibility impact was linear with respect to emissions with high correlation.[357] Following this approach we estimated that when fully implemented, the required controls would result in a reduction in light extinction of about 2 Mm^{-1} at Caney Creek and 1.8 Mm^{-1} at Upper Buffalo on the 20% worst days. As discussed elsewhere, Entergy Arkansas submitted additional CAMx modeling with their comments. This photochemical modeling projects a 2.95 Mm^{-1} reduction at Caney Creek and 1.54 Mm^{-1} reduction at Upper Buffalo when compared to the Entergy's base case modeling for 2018 for the 20% worst days.[358]

Comment: Even the negligible changes in visibility represented by EPA's proposed revised RPGs are greatly overstated because the bulk of the EPA-projected visibility improvements are due to proposed SO_2 emission limits for BART and reasonable progress that have a five-year compliance deadline and thus will not become operative until at least 2020. No sound basis exists for the projections of visibility improvements by 2018 that EPA sets out in the proposed rule. Those EPA projections are inaccurate and unsupportable.

In this regard, EPA fails to explain why (a) the Agency may permissibly use a concededly oversimplified and inaccurate shortcut methodology for calculating RPGs in its FIP, on the grounds that EPA otherwise would have to conduct time-consuming and complicated modeling, *see id.,* but (b) Arkansas and other states apparently are held to a much higher standard for *their* RPG analyses, *see id.* In proposing and promulgating a FIP for Arkansas, EPA merely stands in the state's shoes. Accordingly, if EPA may lawfully comply with the CAA and the regional haze rules by conducting and relying on this sort of analysis that is ''not refined'' but (purportedly) sufficient to support its FIP's RPGs, then states also may do so to support their SIPs' RPGs. On the other hand, to the extent EPA does not believe that RPGs based on such an abbreviated analysis would be approvable if submitted by a state in a SIP, EPA cannot lawfully promulgate the RPGs that it proposes based on the analysis presented in its proposed rule.

Response: We proposed RPGs for the 20% worst days for Caney Creek and Upper Buffalo of 22.27 dv and 22.33 dv, respectively that reflected the anticipated visibility conditions resulting from the combination of control measures from the approved portion of the 2008 Arkansas Regional Haze SIP and our FIP proposal. After considering these comments, we agree that the RPGs should reflect anticipated visibility conditions at the end of the implementation period in 2018 rather than the anticipated visibility conditions once the FIP has been fully implemented. This approach is consistent with the purpose of RPGs and the direction provided in our 2007 Reasonable Progress Guidance.

Section 169B(e)(1) of the CAA directed the Administrator to promulgate regulations that ''include[e] criteria for measuring 'reasonable progress' toward the national goal.'' Consequently, we promulgated 40 CFR 51.308(d)(1) as part of the Regional Haze Rule. This provision directs states to develop RPGs for the most and least impaired days to ''measure'' the progress that will be achieved by the control measures in the state's long-term strategy ''over the period of the implementation plan.'' [359] The current implementation period ends in 2018. RPGs ''are not directly enforceable'' like the emission limitations in the long-term strategy.[360] Rather, they fulfill two key purposes: (1) Allowing for comparisons between the progress that will be achieved by the state's long-term strategy and the URP,[361] and (2) providing a benchmark for assessing the adequacy of a state's SIP in 5-year periodic reports.[362] Consequently, in our 2007 Reasonable Progress Guidance, we indicated that states could consider the ''time necessary for compliance'' factor by ''adjust[ing] the RPG to reflect the degree of improvement in visibility achievable within the period of the first SIP if the time needed for full implementation of a control measure (or measures) will extend beyond 2018.'' [363] In other words, RPGs need not reflect the visibility improvement anticipated from all of the control measures deemed necessary to make reasonable progress (as a result of the four-factor analysis) and included in the long-term strategy.

In this instance, we are taking final action on the Arkansas Regional Haze FIP 9 years after the state's initial SIP submission was due.[364] As a result, only some of the control measures that we have determined are necessary to satisfy the BART and reasonable progress requirements will be installed by the end of 2018. Some controls will not be installed until 2021. Because RPGs are unenforceable analytical benchmarks, we think that it is appropriate to follow the recommendation in our 2007 Reasonable Progress Guidance and finalize RPGs that represent the visibility conditions anticipated on the 20% worst days at Caney Creek and Upper Buffalo by 2018. These RPGs are listed in the table below: [365]

TABLE 21—REASONABLE PROGRESS GOALS FOR 2018 FOR CANEY CREEK AND UPPER BUFFALO

Class I area	2018 RPG 20% Worst days (dv)
Caney Creek	22.47
Upper Buffalo	22.51

We disagree with the commenter that the proposed RPGs overstated the visibility benefit of controls or that they are inaccurate. In our proposal, we acknowledged that the methodology we utilized to estimate the RPGs is not as refined as developing an updated model projection. However, it allows us to translate the emission reductions contained in the proposed FIP into quantitative RPGs, based on modeling previously performed by the CENRAP.[366] The proposed RPGs provided an estimate of the visibility benefit of all the required controls compared to the 2018 visibility conditions projected by the state and established in their SIP that would result without the required controls. Our final RPGs, calculated using the same methodology, reflect the anticipated visibility conditions at the end of the implementation period in 2018 and the visibility benefit from those controls required to be implemented by the end of 2018. RPGs, unlike the emission limits that apply to specific reasonable progress and BART sources, are not directly enforceable.[367] Rather, the RPGs are an analytical framework considered by us in evaluating whether measures in the implementation plan are sufficient to achieve reasonable progress.[368] Our FIP imposes emissions limitations that we conclude to be necessary under the CAA for the first planning period. Ideally, these controls would be installed and the emission limitations achieved, so

[357] See 81 FR 296, 335 and the FIP TSD (document ID: EPA–R06–OAR–2014–0754–0007).

[358] See Entergy CAMx Results 2015–1124_FINAL.xls.

[359] 40 CFR 51.308(d)(1).

[360] 40 CFR 51.308(d)(1)(iv).

[361] 40 CFR 51.308(d)(1)(ii).

[362] 40 CFR 51.308(g)–(h).

[363] ''Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program,'' at 5–2.

[364] We discuss in section II.A of this final rule the history of the state's submittals and our actions.

[365] These RPGs are calculated using the same methodology described in our proposal and TSD. See ''CACR UPBU RPG analysis 2018.xlsx'' for additional information on the calculation of the RPGs.

[366] 80 FR 18944, 18998.

[367] 40 CFR 51.308(d)(1)(v).

[368] 64 FR at 35733 and 40 CFR 51.308(d)(1)(v).

the visibility improvements can be realized and built on in a subsequent comprehensive periodic SIP revision (see 40 CFR 51.308(f)). Arkansas may choose to use these RPGs for purposes of its progress report (along with a consideration for what controls had already been implemented and what controls would be implemented in the near future), 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) in evaluating the adequacy of their SIP (or this FIP) to meet the established RPGs.

We disagree that Arkansas would be held to a higher standard or that the methodology utilized by EPA to adjust the RPGs would not be approvable if submitted by a state. The approach followed by EPA in this action, using scaling to adjust the modeled RPGs based on photochemical source apportionment model results is reasonable and meets the requirements of the Regional Haze Rule. In our 2012 rulemaking,[369] we made a finding that Arkansas did not complete a reasonable progress analysis and therefore did not properly demonstrate that additional controls were not reasonable under 40 CFR 51.308(d)(1)(i)(A). Thus we disapproved the RPGs Arkansas established for Caney Creek and Upper Buffalo. In our proposed rulemaking, we completed the reasonable progress analysis and established revised RPGs using the methodology described above, since we have not received a revised SIP to correct the portions of the SIP submittal we disapproved.

9. Additional Modeling Comments

Comment: We received additional specific modeling comments concerning emission rates modeled to assess baseline visibility impacts for Independence, White Bluff and Flint Creek. We also received separate comments concerning our modeling analysis and assessment of NO_X controls on Lake Catherine, White Bluff and Independence.

Response: We address these comments in our RTC document.

K. Legal

We received several comments on EPA's legal authority to promulgate a FIP under the Regional Haze Rule, and, more specifically, to address the Rule's reasonable progress requirements. Below is a summary of some of the more significant comments. For a more detailed explanation, please refer to the RTC document that is a part of the docket for this rulemaking.

We received comments that EPA is prohibited from requiring controls for this planning period if they cannot be installed during this planning period. We disagree with these comments. The CAA establishes our authority and responsibility to promulgate a FIP that addresses the requirements of the regional haze program where a State's SIP submission fails to meet the program requirements. Although the first planning period, ending in 2018, includes RPGs specific to that planning period, there is no limitation in the CAA or the Regional Haze Rule that controls contained in a SIP (or a FIP) must be fully implemented by the end of the planning period. As both the long-term strategy and BART requirements may extend beyond the first planning period, it follows that EPA has FIP authority to fill in ''gaps'' or ''inadequacies'' related to those components irrespective of whether controls can be put into place by 2018. In addition, any emission limitations that prove to be required by the CAA for the first planning period need to be achieved at their soonest opportunity, not delayed, deferred, or avoided for later planning periods when even further progress may be required in order to achieve the national visibility goal.

We also received comments that we had no legal basis for requiring alternative proposals for SO_2 and NO_X control measures that would address the regional haze requirements for White Bluff Units 1 and 2 and Independence Units 1 and 2 for this planning period to achieve *greater* reasonable progress than the BART and reasonable progress requirements that EPA has proposed for the first planning period. Our response explains our analysis of Entergy's four-unit approach and clarifies how our evaluation of that approach was consistent with the Regional Haze Rule's BART alternative and reasonable progress requirements.

In addition, we received several comments that our proposed FIP was not in keeping with the legal requirements for reasonable progress and long term strategy as spelled out in the Regional Haze Rule and EPA Guidance. We disagree and explain in more detail in the RTC document that we disapproved the reasonable progress determination Arkansas submitted in 2012 because the State did not conduct the required four-factor analysis. The CAA requires us to stand in the State's shoes and promulgate a FIP that addresses the requirements of the Regional Haze Rule that we disapproved, including reasonable progress and the long term strategy for Arkansas' Class I areas.

We also received comments that our proposed FIP did not take into account the leading role of the state in developing a plan that addresses the regional haze program and thus is not in keeping with cooperative federalism. We disagree that EPA ignored the principles of cooperative federalism. Arkansas did develop a regional haze plan. We reviewed it and partially approved and disapproved the plan in 2012. The CAA creates a mandatory duty for EPA to either approve a state SIP revision submittal that corrects the deficiency or promulgate a FIP within two years of the effective date of the disapproval of a state plan.

We received comments that EPA does not have authority to finalize a FIP after two years have elapsed from our initial disapproval of the Arkansas Regional Haze SIP. We describe in more detail in the RTC document our disagreement with this interpretation of what is required under the Clean Air Act. The Tenth Circuit has upheld EPA's authority to finalize a Regional Haze FIP after the two years have passed for EPA to act on Oklahoma's Regional Haze SIP.

We also received comments that our proposed FIP was not in keeping with Executive Orders 12866 and 13211. Our response is that our proposed action is not subject to Executive Order 13211 because it is not a ''significant regulatory action'' under Executive Order 12866; therefore, the proposed FIP is not a rule of general applicability because its requirements apply and are tailored to only seven individually identified facilities. Thus, it is not a ''rule'' or ''regulation'' within the meaning of E.O. 12866 and this action is not a ''regulatory action'' subject to 12866. Since E.O. 13211 applies only to ''significant regulatory actions'' under E.O. 12866, this action is not subject to review under E.O. 13211.[28] Evaluation of the proposal under E.O. 13211's criteria is therefore not required.

We respond in greater detail in the RTC document to comments that EPA did not adequately consider costs to ratepayers as is required under Arkansas law in developing air regulations. States are under an obligation to submit a Regional Haze SIP to EPA which complies with federal requirements. While states enjoy flexibility in developing a SIP and can meet additional state requirements as long as the federal requirements are satisfied, in the event that EPA must step in and create a Federal Implementation Plan, we must meet all federal requirements. We are not subject to state law requirements related to how the cost

[369] 77 FR 14604.

analyses must be conducted or what specific factors need to be considered. We did consider costs in great detail to ensure that the controls required by the FIP are cost-effective, appropriate in light of the visibility reductions achieved, and consistent with expectations in other SIPs and FIPs.

We received several general comments including a claim that documents that EPA relied for its rulemaking were not in the docket. As explained more fully in our RTC document, the documents referred to are briefing sheets and did not serve as the basis for EPA's decision making. The docket contains all of the documents that serve as our basis for our rulemaking for Arkansas Regional Haze.

L. Interstate Visibility Transport

Comment: The good neighbor visibility provision in 42 U.S.C. 7410(a)(2)(D)(i)(II) prohibits interference with ''measures'' required to be included in another State's implementation plan to protect visibility. EPA has not demonstrated that any of these sources in its FIP proposal are interfering with any visibility control measure in any other state's SIP. In its FIP proposal, EPA states that the Arkansas SIP did not ensure that emissions from Arkansas sources ''do not interfere with other states' visibility programs as required by section 110(a)(2)(D)(i)(II) of the CAA.'' [370] The visibility protection requirement of section 110(a)(2)(D)(i)(II) does not protect against interference with either other states ''efforts'' or other states ''programs.'' Unlike the language in section 110(a)(2)(D)(i)(I), which prohibits emissions that contribute significantly to nonattainment or maintenance of a NAAQS in another state, the visibility protection requirement is narrower and only protects against interference with specific measures, that is, actions included in another state's plan to achieve a visibility goal. Reasonable progress goals, projected deciview improvements from regional efforts, and the like are goals or standards; they are not ''measures'' taken by or enforced by a state. There is nothing in the record demonstrating that any of the sources in the FIP proposal interfere with any measure included in any other state's SIP for the purpose of protecting or improving visibility. To the extent that EPA's proposed interstate visibility transport FIP is not based on direct interference with a control measure in another state's regional haze SIP (in contrast to interference with a regional haze related visibility goal), EPA's interpretation is contrary to the clear and express language of Section 110. EPA's interpretation also is contrary to the CAA's clear direction that each state is to determine its own emission limits, schedules of compliance and other measures for sources in that state for purposes of visibility protection under section 169A. EPA's interpretation would impermissibly give one state the power to control another state's regional haze SIP decisions, including its BART and reasonable progress determinations. Finally, even if the CAA's good neighbor visibility provision required a SIP to contain emission limits for sources that contribute to visibility impairment at a Class I area in another state, EPA has not demonstrated that any of the controls in its FIP proposal are ''necessary'' for that purpose, considering based on the uncertainty in the modeling that these controls will result in actual visibility improvements.

Response: Section 110(a)(2)(D)(i)(II) does not explicitly define what is required in SIPs to prevent the prohibited impact on visibility in other states nor does it explicitly define how to determine if a state's emissions are interfering with another state's measures to protect visibility. We have interpreted this statutory requirement as providing that a Regional Haze SIP that requires emission reductions consistent with the assumptions the relevant RPO used to model the RPGs for Class I areas in other states satisfies a state's obligation to ensure that its own emissions do not interfere with another state's visibility measures. States may rely on a fully approved Regional Haze SIP to demonstrate that a SIP for 8-hour ozone or $PM_{2.5}$ contains adequate provisions to prohibit emissions that interfere with visibility measures in other states.[371]

Arkansas chose to address the interstate visibility transport requirement under section 110(a)(2)(D)(i)(II) by relying on its 2008 Regional Haze SIP submittal to achieve the emissions reductions necessary to meet this requirement. However, due to our previous partial disapproval of this submittal,[372] the Arkansas SIP does not currently include all of the emission reductions Arkansas agreed to achieve in its RPO process. Arkansas is a member state of CENRAP, the regional planning committee on regional haze. Each CENRAP state based its regional haze plan and RPGs on the CENRAP modeling, which was based in part on the emissions reductions each state intended to achieve by 2018. Within the CENRAP process, Arkansas promised to achieve emission reductions corresponding to BART, and these emissions reductions were included in the CENRAP modeling used by the participating states to develop their RPGs and Regional Haze SIPs. However, EPA previously disapproved some of Arkansas' BART determinations; therefore, the State's SIP does not currently provide for all the emissions reductions that Arkansas itself determined to be necessary to meet the interstate visibility transport requirement. Because Arkansas has not provided any other analysis or explanation of how the Arkansas SIP fulfills the requirement of 110(a)(2)(D)(i)(II), it follows that the Arkansas SIP does not contain adequate provisions to prohibit emissions that would interfere with other states' visibility protection measures.

We disagree with the commenter's contention that our interpretation is contrary to the CAA because the Act gives clear direction that each state is to determine its own emission limits, schedules of compliance and other measures for sources in that state for purposes of visibility protection under section 169A. The commenter states that our interpretation would impermissibly give one state the power to control another state's regional haze SIP decisions. However, the commenter's interpretation is inconsistent with section 110(a)(2)(D)(i)(II)'s ''good neighbor'' provision, which requires states to prohibit emissions that interfere with other states' measures to protect visibility. This statutory requirement anticipates that a state may be required to adjust its own emissions based on the impacts of those emissions on other states. Our Regional Haze Rule, which was promulgated through notice-and-comment rulemaking in 1999, also requires that states develop ''coordinated emission management strategies'' when necessary to prevent interstate visibility impairment.[373] Thus, while the CAA and our regulations do not allow one state to ''control'' another's regional haze planning, they do contemplate that a state may be required to prohibit emissions that interfere with visibility in another state's Class I areas.

As stated above, Arkansas elected to address the interstate visibility transport requirement under section 110(a)(2)(D)(i)(II) by relying on the BART determinations that are part of its

[370] 80 FR at 18998.

[371] See ''2006 Guidance for SIP Submissions to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the 8-Hour Ozone and $PM_{2.5}$ NAAQS'' at pages 9–10.

[372] 77 FR 14604.

[373] 40 CFR 51.308(d)(3)(i).

Regional Haze SIP submittal. Arkansas could have elected to address the interstate visibility transport requirement under section 110(a)(2)(D)(i)(II) by other means; we have elsewhere determined that states may also be able to satisfy the requirements of CAA section 110(a)(2)(D)(i)(II) with something less than an approved Regional Haze SIP.[374] In other words, an approved Regional Haze SIP is not the only possible means to satisfy the requirements of CAA section 110(a)(2)(D)(i)(II) with respect to visibility; however such a SIP could be sufficient.[375] The approved portion of the Arkansas Regional Haze SIP and our Regional Haze FIP together will ensure emissions reductions from Arkansas sources consistent with the assumptions used in the CENRAP modeling and meets Arkansas' obligations to address the interstate visibility transport requirement under section 110(a)(2)(D)(i)(II).

We address elsewhere in this document comments contending that there is uncertainty in the CALPUFF modeling and uncertainty that our proposed controls will result in actual visibility improvements.

VI. Final Action

We are finalizing a FIP to remedy the deficiencies in the Arkansas Regional Haze SIP and Interstate Visibility Transport SIP to address the visibility transport requirement under section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and $PM_{2.5}$ NAAQS.

A. Regional Haze

Our final FIP includes SO_2, NO_X, and PM emission limits for specific emission units in Arkansas to address the BART requirements. The affected emission units are the AECC Bailey Unit 1; AECC McClellan Unit 1; AEP Flint Creek Unit 1; Entergy White Bluff Units 1, 2, and Auxiliary Boiler; Entergy Lake Catherine Unit 4; and Domtar Ashdown Mill Power Boilers No. 1 and 2. In addition, we are requiring SO_2 and NO_X controls under reasonable progress for Entergy Independence Units 1 and 2. We are also finalizing compliance schedules and testing, reporting and recordkeeping requirements for these emission units. Our final FIP requires the following emission limits for these emission units:

TABLE 22—FINAL BART EMISSION LIMITS

Unit	Final SO_2 emission limit	Final NO_X emission limit	Final PM emission limit
Bailey Unit 1	0.5% limit on sulfur content of fuel combusted.	887 lb/hr	0.5% limit on sulfur content of fuel combusted.
McClellan Unit 1	0.5% limit on sulfur content of fuel combusted.	869.1 lb/hr [a]/705.8 lb/hr [a]	0.5% limit on sulfur content of fuel combusted.
Flint Creek Unit 1	0.06 lb/MMBtu	0.23 lb/MMBtu	EPA approved the state's BART determination in March 12, 2012 final action (77 FR 14604).
White Bluff Unit 1	0.06 lb/MMBtu	0.15 lb/MMBtu [b]/671 lb/hr [c]	EPA approved the state's BART determination in March 12, 2012 final action (77 FR 14604).
White Bluff Unit 2	0.06 lb/MMBtu	0.15 lb/MMBtu [b]/671 lb/hr [c]	EPA approved the state's BART determination in March 12, 2012 final action (77 FR 14604).
White Bluff Auxiliary Boiler	105.2 lb/hr	32.2 lb/hr	4.5 lb/hr.
Lake Catherine Unit 4 [d]	EPA approved the state's BART determination in March 12, 2012 final action (77 FR 14604).	0.22 lb/MMBtu	EPA approved the state's BART determination in March 12, 2012 final action (77 FR 14604).
Domtar Ashdown Mill Power Boiler No. 1.	504 lb/day	207.4 lb/hr	EPA approved the state's BART determination in March 12, 2012 final action (77 FR 14604).
Domtar Ashdown Mill Power Boiler No. 2.	91.5 lb/hr	345 lb/hr	PM BART shall be satisfied by relying on the applicable PM standard under 40 CFR part 63, subpart DDDDD [e]

[a] Emission limit of 869.1 lb/hr applies to the natural gas-firing scenario; emission limit of 705.8 lb/hr applies to the fuel oil-firing scenario.
[b] Emission limit of 0.15 lb/MMBtu applies when unit is operated at 50% or greater of the unit's maximum heat input rating.
[c] Emission limit of 671 lb/hr applies when the unit is operated at less than 50% of the unit's maximum heat input rating.
[d] Emission limit for NO_X applies to the natural gas-firing scenario. The unit shall not burn fuel oil until BART determinations for SO_2, NO_X, and PM are promulgated for the unit for the fuel oil-firing scenario through EPA approval of a SIP revision or a FIP.
[e] The facility shall rely on the applicable PM standard under 40 CFR part 63, subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, as revised, to satisfy the PM BART requirement.

TABLE 23—FINAL REASONABLE PROGRESS EMISSION LIMITS FOR SOURCES NOT SUBJECT TO BART

Unit	Final SO_2 emission limit	Final NO_X emission limit
Independence Unit 1	0.06 lb/MMBtu	0.15 lb/MMBtu [a]/671 lb/hr [b]

[374] See, *e.g.,* Colorado (76 FR 22036 (April 20, 2011)), Idaho (76 FR 36329 (June 22, 2011)), and New Mexico (76 FR 52388 (August, 22, 2011)).

[375] We've allowed states to rely on their approved regional haze plan to meet the requirements of the visibility component of 110(a)(2)(D)(i)(II) because the regional haze plan achieved at least as much emissions reductions as projected by the RPO modeling. See 76 FR 34608, June 14, 2011 (California); 79 FR 60985, October 9, 2014 (New Mexico); 76 FR 36329, June 22, 2011 (Idaho); and 76 FR 38997, July 5, 2011 (Oregon).

TABLE 23—FINAL REASONABLE PROGRESS EMISSION LIMITS FOR SOURCES NOT SUBJECT TO BART—Continued

Unit	Final SO_2 emission limit	Final NO_X emission limit
Independence Unit 2	0.06 lb/MMBtu	0.15 lb/MMBtu [a]/671 lb/hr [b]

[a] Emission limit of 0.15 lb/MMBtu applies when unit is operated at 50% or greater of the unit's maximum heat input rating.
[b] Emission limit of 671 lb/hr applies when the unit is operated at less than 50% of the unit's maximum heat input rating.

Based on our technical analysis, we have calculated the following RPGs for the 20% worst days for Arkansas' Class I areas:

TABLE 24—REASONABLE PROGRESS GOALS FOR 2018 FOR CANEY CREEK AND UPPER BUFFALO

Class I area	2018 RPG 20% Worst days (dv)
Caney Creek	22.47
Upper Buffalo	22.51

B. Interstate Visibility Transport

We are finalizing our determination that the control measures in the approved portion of the Arkansas Regional Haze SIP and our final FIP are sufficient to prevent Arkansas' emissions from interfering with other states' required measures to protect visibility. Thus, the combined measures from both plans satisfy the interstate transport visibility requirement of CAA section 110(a)(2)(D)(i)(II) for the 1997 8-hour ozone and the 1997 $PM_{2.5}$ NAAQS.

VII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is exempt from review by the Office of Management and Budget (OMB) because it imposes requirements that apply and are tailored to only six individual power plants (AECC Bailey; AECC McClellan; AEP Flint Creek; Entergy White Bluff; Entergy Lake Catherine; and Entergy Independence) and one paper mill in Arkansas (Domtar Ashdown Paper Mill). This FIP is not a rule of general applicability. Thus, it is not a ''rule'' or ''regulation'' within the meaning of E.O. 12866, and this action is not a ''regulatory action'' subject to 12866.

B. Paperwork Reduction Act (PRA)

This action does not impose an information collection burden under the provisions of the PRA, 44 U.S.C. 3501 *et seq.* Under the PRA, a ''collection of information'' is defined as a requirement for ''answers to * * * identical reporting or recordkeeping requirements imposed on ten or more persons * * *'' 44 U.S.C. 3502(3)(A). Because the FIP applies to only seven facilities, the Paperwork Reduction Act does not apply. See 5 CFR 1320.3(c).

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. This FIP will apply to seven facilities, none of which fall under the definition of small entities.

D. Unfunded Mandates Reform Act (UMRA)

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

E. Executive Order 13132: Federalism

This 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. The final rule does not impose significant economic costs on state or local governments. Thus, Executive Order 13132 does not apply to the final rule.

F. Executive Order 13175: Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. This action applies to seven facilities in Arkansas and to Federal Class I areas in Arkansas. This action does not apply on any Indian reservation land, any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction, or non-reservation areas of Indian country. Thus, Executive Order 13175 does not apply to this action.

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

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it implements specific standards established by Congress in statutes.

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

This action is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

This action involves technical standards. Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.,* materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards. This rule would require the seven affected facilities to meet the applicable monitoring requirements of 40 CFR part 75. Part 75 already incorporates a number of voluntary consensus standards. Consistent with the Agency's Performance Based Measurement System (PBMS), part 75 sets forth performance criteria that allow the use of alternative methods to the ones set forth in part 75. The PBMS approach is intended to be more flexible and cost-effective for the regulated community; it is also intended to encourage innovation in analytical technology and improved data quality. At this time, EPA is not recommending any revisions to part 75; however, EPA periodically revises the test procedures set forth in part 75. When EPA revises the test procedures set forth in part 75 in the future, EPA will address the use of any new voluntary consensus standards that are equivalent. Currently, even if a test procedure is not set forth in part 75, EPA is not precluding the use of any method, whether it constitutes a voluntary consensus standard or not, as long as it meets the performance criteria specified; however, any alternative methods must be approved through the petition process under 40 CFR 75.66 before they are used.

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

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income, or indigenous 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 FIP limits emissions of SO_2, NO_X, and PM from seven facilities in Arkansas.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.,* as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2). This rule will be effective on October 27, 2016.

L. Judicial Review

Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by November 28, 2016. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. (See CAA section 307(b)(2).)

List of Subjects in 40 CFR Part 52

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

Dated: August 31, 2016.

Gina McCarthy,

Administrator.

Title 40, chapter I, of the Code of Federal Regulations is 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) *Federal implementation plan for regional haze.* 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 this title. For the purposes of this section:

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

Air pollution control equipment includes selective catalytic control units, baghouses, particulate or gaseous scrubbers, and any other apparatus utilized to control emissions of regulated air contaminants 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 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit, unless otherwise specified. For power boilers listed under paragraph (c)(1) of this section, we define boiler-operating-day as a 24-hr period between 6 a.m. and 6 a.m. the following day 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 are 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 must comply with the SO_2 and PM requirements listed in paragraph (c)(3) of this section by October 27, 2021. As of October 27, 2016, the owner or 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. The owner or operator of each unit must comply with the requirement in paragraph (c)(3) of this section to burn only fuel with a sulfur content limit of 0.5% by weight by October 27, 2021. The owner or operator of each unit must comply with the NO_X emission limits in paragraph (c)(3) of this section by October 27, 2016.

(5) *Compliance determination and reporting and recordkeeping requirements 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 or operator shall sample and analyze each shipment of fuel to determine the sulfur content by weight, 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. All records pertaining to the sampling of each shipment of fuel as described above, including the results of the sulfur content analysis, must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives.

(ii) *NO_X.* To determine compliance with the NO_X emission limits of paragraph (c)(3) of this section, the owner or operator shall determine the average concentration (arithmetic average of three contiguous one hour periods) of NO_X as measured by the CEMS and converted to pounds per hour using corresponding average (arithmetic average of three contiguous one hour periods) stack gas flow rates. Records of the NO_X emissions rates must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives.

(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 are as listed in the following table, as specified in pounds per million British thermal units (lb/MMBtu) or pounds per hour (lb/hr). The SO_2 emission limits of 0.06 lb/MMBtu and the NO_X emission limits of 0.23 lb/MMBtu and 0.15 lb/MMBtu are on a rolling 30 boiler-operating-day averaging period. The NO_X emission limit of 671 lb/hr is on a rolling 3-hour average.

Unit	SO_2 Emission limit (lb/MMBtu)	NO_X Emission limit (lb/MMBtu)	NO_X Emission limit (lb/hr)
AEP Flint Creek Unit 1	0.06	0.23	
Entergy White Bluff Unit 1	0.06	0.15	671
Entergy White Bluff Unit 2	0.06	0.15	671

(7) *Compliance dates for AEP Flint Creek Unit 1 and Entergy White Bluff Units 1 and 2.* The owner or operator of AEP Flint Creek Unit 1 must comply with the SO_2 and NO_X emission limits listed in paragraph (c)(6) of this section by April 27, 2018. The owner or operator of White Bluff Units 1 and 2 must comply with the SO_2 emission limit listed in paragraph (c)(6) of this section by October 27, 2021, and must comply with the NO_X emission limits listed in paragraph (c) (6) of this section by April 27, 2018.

(8) *Compliance determination and reporting and recordkeeping requirements for AEP Flint Creek Unit 1 and Entergy White Bluff Units 1 and 2.* (i) For purposes of determining compliance with the SO_2 and NO_X emissions limits listed in paragraph

(c)(6) of this section for AEP Flint Creek Unit 1 and with the SO_2 emissions limit listed in paragraph (c)(6) of this section for White Bluff Units 1 and 2, the emissions for each boiler-operating-day for each unit 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 30-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. For each day, records of the total SO_2 and NO_X emitted that day by each emission unit and the sum of the hourly heat inputs for that day must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Records of the 30 boiler-operating-day rolling average for SO_2 and NO_X for each unit as described above must be maintained by the owner or operator for each boiler-operating-day and made available upon request to EPA and ADEQ representatives.

(ii) For purposes of determining compliance with the 0.15 lb/MMBtu NO_X emissions limit listed in paragraph (c)(6) of this section for White Bluff Units 1 and 2, the NO_X emissions for each unit shall be determined by the following procedure:

(A) Summing the total pounds of NO_X emitted during the current boiler-operating-day and the preceding 29 boiler-operating-days while including only emissions during hours when the unit was dispatched at 50% or greater of the unit's maximum heat input rating;

(B) Summing the total heat input in MMBtu to the unit during the current boiler-operating-day and the preceding 29 boiler-operating-days while including only the heat input during hours when the unit was dispatched at 50% or greater of the unit's maximum heat input rating; and

(C) Dividing the total pounds of NO_X emitted as calculated in step 1 by the total heat input to the unit as calculated in step 2. 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 a 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. For each day, records for each unit of the hours during which the unit was dispatched at 50% or greater of the unit's maximum heat input rating, as well as NO_X emissions and hourly heat input for each of those hours must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Records of the 30 boiler-operating-day rolling average for NO_X for each unit as described above must be maintained by the owner or operator for each boiler-operating-day and made available upon request to EPA and ADEQ representatives.

(iii) For purposes of determining compliance with the 671 lb/hr NO_X emissions limit listed in paragraph (c)(6) of this section for White Bluff Units 1 and 2, the NO_X emissions for each unit shall be determined by the following procedure:

(A) Summing the total pounds of NO_X emitted during the current hour and the preceding 2 hours during which the unit was dispatched at less than 50% of the unit's maximum heat input rating; and

(B) Dividing the total pounds of NO_X emitted as calculated in step 1 by 3. The result shall be the rolling 3-hour 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 a unit, that NO_X pounds per hour shall not be used in the calculation of the rolling 3-hour average for NO_X. For each day, records for each unit of the hours during which the unit was dispatched at less than 50% of each unit's maximum heat input rating, as well as NO_X emissions and hourly heat input for each of those hours must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Records of the rolling 3-hour averages for NO_X for each unit as described above must be maintained for each day by the owner or operator and made available upon request to EPA and ADEQ representatives.

(iv) 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.

(v) 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 are 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 must comply with the SO_2, NO_X, and PM emission limits listed in paragraph (c)(9) of this section by October 27, 2016.

(11) *Compliance determination and reporting and recordkeeping requirements for Entergy White Bluff Auxiliary Boiler.* For purposes of demonstrating compliance with the emission limits listed in paragraph (c)(9) of this section, records of fuel oil analysis must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives.

(12) *Emissions limitations for Entergy Lake Catherine Unit 4.* The individual NO_X emission limit for the unit for natural gas firing is 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 must 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

(13) *Compliance dates for Entergy Lake Catherine Unit 4.* The owner or operator of the unit must comply with the NO_X emission limit listed in paragraph (c)(12) of this section by October 27, 2019.

(14) *Compliance determination and reporting and recordkeeping requirements for Entergy Lake Catherine Unit 4.* (i) NO_X emissions for each 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. For each day, records of the total NO_X emitted that day by the unit and the sum of the hourly heat inputs for that day must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Records of the 30 boiler-operating-day rolling average for NO_X for the unit as described above must be maintained by the owner or operator for each boiler-operating-day and made available upon request to EPA and ADEQ representatives.

(ii) The owner or operator shall continue to maintain and operate a CEMS on the unit listed in paragraph (c)(12) of this section in accordance with 40 CFR part 75, Appendix E as long as the unit meets the definition of a peaking unit under 40 CFR part 75. The owner or operator shall comply with the quality assurance procedures for CEMS found in 40 CFR part 75.

(iii) Continuous emissions monitoring shall apply during all periods of operation of the unit listed in paragraph (c)(12) of this section, including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments.

(15) *Emissions Limitations for Domtar Ashdown Paper Mill Power Boiler No. 1.* The SO_2 emission limit for the boiler is as listed in the following table in pounds per day (lb/day) as averaged over a rolling 30 boiler-operating-day period. The NO_X emission limit for the boiler is as listed in the following table in pounds per hour (lb/hr).

Unit	SO_2 Emission limit (lb/day)	NO_X Emission limit (lb/hr)
Domtar Ashdown Paper Mill Power Boiler No. 1	504	207.4

(16) *Compliance dates for Domtar Ashdown Mill Power Boiler No. 1.* The owner or operator of the boiler must comply with the SO_2 and NO_X emission limits listed in paragraph (c)(15) of this section by November 28, 2016.

(17) *Compliance determination and reporting and recordkeeping requirements for Domtar Ashdown Paper Mill Power Boiler No. 1.* (i)(A) SO_2 emissions resulting from combustion of fuel oil shall be determined by assuming that the SO_2 content of the fuel delivered to the fuel inlet of the combustion chamber is equal to the SO_2 being emitted at the stack. The owner or operator must maintain records of the sulfur content by weight of each fuel oil shipment, where 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, an outside laboratory, or a fuel supplier. All records pertaining to the sampling of each shipment of fuel oil, including the results of the sulfur content analysis, must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. SO_2 emissions resulting 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

(B) The owner or operator must confirm the site-specific curve equation through stack testing. By October 27, 2017, the owner or operator must provide a report to EPA showing confirmation of the site specific-curve equation accuracy. Records of the quantity of fuel input to the boiler for each fuel type for each day must be compiled no later than 15 days after the end of the month and must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Each boiler-operating-day of the 30-day rolling average for the boiler must be determined by adding together the pounds of SO_2 from that boiler-operating-day and the preceding 29 boiler-operating-days and dividing the total pounds of SO_2 by the sum of the total number of boiler operating days (*i.e.,* 30). The result shall be the 30 boiler-operating-day rolling average in terms of lb/day emissions of SO_2. Records of the total SO_2 emitted for each day must be compiled no later than 15 days after the end of the month and must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Records of the 30 boiler-operating-day rolling averages for SO_2 as described in this paragraph (c)(17)(i) must be maintained by the owner or operator for each boiler-operating-day and made available upon request to EPA and ADEQ representatives.

(ii) If the air permit is revised such that Power Boiler No. 1 is permitted to burn only pipeline quality natural gas, this is sufficient to demonstrate that the boiler is complying with the SO_2 emission limit under paragraph (c)(15) of this section. The compliance determination requirements and the reporting and recordkeeping requirements under paragraph (c)(17)(i) of this section would not apply and confirmation of the accuracy of the site-specific curve equation under paragraph (c)(17)(i)(B) of this section through stack testing would not be required so long as Power Boiler No. 1 is only permitted to burn pipeline quality natural gas.

(iii) To demonstrate compliance with the NO_X emission limit under paragraph (c)(15) of this section, the owner or operator shall conduct stack testing using EPA Reference Method 7E once every 5 years, beginning 1 year from the effective date of our final rule. Records and reports pertaining to the stack testing must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives.

(iv) If the air permit is revised such that Power Boiler No. 1 is permitted to burn only pipeline quality natural gas, the owner or operator may demonstrate compliance with the NO_X emission limit under paragraph (c)(15) of this section by calculating NO_X emissions using fuel usage records and the applicable NO_X emission factor under AP–42, Compilation of Air Pollutant Emission Factors, section 1.4, Table 1.4–1. Records of the quantity of natural gas input to the boiler for each day must be compiled no later than 15 days after the end of the month and must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Records of the calculation of NO_X emissions for each day must be compiled no later than 15 days after the end of the month and must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Each boiler-operating-day of the 30-day rolling average for the boiler must 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. Records of the 30 boiler-operating-day rolling average for NO_X must be maintained by the owner or operator for each boiler-operating-day and made available upon request to EPA and ADEQ representatives. Under these circumstances, the compliance determination requirements and the reporting and recordkeeping requirements under paragraph (c)(17)(iii) of this section would not apply.

(18) *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 boiler are as listed in the following table in pounds per hour (lb/hr) as averaged over a rolling 30 boiler-operating-day period.

Unit	SO_2 Emission Limit (lb/hr)	NO_X Emission Limit (lb/hr)
Domtar Ashdown Paper Mill Power Boiler No. 2	91.5	345

(19) *SO_2 and NO_X Compliance dates for Domtar Ashdown Mill Power Boiler No. 2.* The owner or operator of the boiler must comply with the SO_2 and NO_X emission limits listed in paragraph (c)(18) of this section by October 27, 2021.

(20) *SO_2 and NO_X Compliance determination and reporting and recordkeeping requirements for Domtar Ashdown Mill Power Boiler No. 2.* (i) NO_X and SO_2 emissions for each day shall be determined by summing the hourly emissions measured in pounds of NO_X or pounds of SO_2. Each boiler-operating-day of the 30-day rolling average for the boiler shall be determined by adding together the pounds of NO_X or SO_2 from that day and the preceding 29 boiler-operating-days and dividing the total pounds of NO_X or SO_2 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 or SO_2. If a valid NO_X pounds per hour or SO_2 pounds per hour is not available for any hour for the 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. For each day, records of the total SO_2 and NO_X emitted for that day by the boiler must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Records of the 30 boiler-operating-day rolling average for SO_2 and NO_X for the boiler as described above must be maintained by the owner or operator for each boiler-operating-day and made available upon request to EPA and ADEQ representatives.

(ii) The owner or operator shall continue to maintain and operate a CEMS for SO_2 and NO_X on the boiler listed in paragraph (c)(18) 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 60. 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 boiler listed in paragraph (c)(18) 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.

(iv) If the air permit is revised such that Power Boiler No. 2 is permitted to burn only pipeline quality natural gas, this is sufficient to demonstrate that the boiler is complying with the SO_2 emission limit under paragraph (c)(18) of this section. Under these circumstances, the compliance determination requirements under paragraphs (c)(20)(i) through (iii) of this section would not apply to the SO_2 emission limit listed in paragraph (c)(18) of this section.

(v) If the air permit is revised such that Power Boiler No. 2 is permitted to burn only pipeline quality natural gas and the operation of the CEMS is not required under other applicable requirements, the owner or operator may demonstrate compliance with the NO_X emission limit under paragraph (c)(18) of this section by calculating NO_X emissions using fuel usage records and the applicable NO_X emission factor under AP–42, Compilation of Air Pollutant Emission Factors, section 1.4, Table 1.4–1. Records of the quantity of natural gas input to the boiler for each day must be compiled no later than 15 days after the end of the month and must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Records of the calculation of NO_X emissions for each day must be compiled no later than 15 days after the end of the month and must be maintained and made available upon request to EPA and ADEQ representatives. Each boiler-operating-day of the 30-day rolling average for the boiler must 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. Records of the 30 boiler-operating-day rolling average for NO_X must be maintained by the owner or operator for each boiler-operating-day and made available upon request to EPA and ADEQ representatives. Under these circumstances, the compliance determination requirements under paragraphs (c)(20)(i) through (iii) of this section would not apply to the NO_X emission limit.

(21) *PM BART Requirements for Domtar Ashdown Paper Mill Power Boiler No.2.* The owner or operator must rely on the applicable PM standard required under 40 CFR part 63, subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, as revised, to satisfy the PM BART requirement. Compliance with the applicable PM standard under 40 CFR part 63 subpart DDDDD, as revised, shall demonstrate compliance with the PM BART requirement.

(22) *PM compliance dates for Domtar Ashdown Mill Power Boiler No. 2.* The owner or operator of the boiler must comply with the PM BART requirement listed in paragraph (c)(21) of this section by November 28, 2016.

(23) Alternative *PM Compliance Determination for Domtar Ashdown Paper Mill Power Boiler No.2.* If the air permit is revised such that Power Boiler No. 2 is permitted to burn only pipeline quality natural gas, this is sufficient to demonstrate that the boiler is complying with the PM BART requirement under paragraph (c)(21) of this section.

(24) *Emissions limitations for Entergy Independence Units 1 and 2.* The individual emission limits for each unit are as listed in the following table in pounds per million British thermal units (lb/MMBtu) or pounds per hour (lb/hr). The SO_2 emission limit and the NO_X emission limits listed in the table as lb/MMBtu are on a rolling 30 boiler-operating-day averaging period. The NO_X emission limit of 671 lb/hr is on a rolling 3-hour average.

Unit	SO_2 Emission limit (lb/MMBtu)	NO_X Emission limit (lb/MMBtu)	NO_X Emission Limit (lb/hr)
Entergy Independence Unit 1	0.06	0.15	671
Entergy Independence Unit 2	0.06	0.15	671

(25) *Compliance dates for Entergy Independence Units 1 and 2.* The owner or operator of each unit must comply with the SO_2 emission limit in paragraph (c)(24) of this section by October 27, 2021 and with the NO_X emission limits by April 27, 2018.

(26) *Compliance determination and reporting and recordkeeping requirements for Entergy Independence Units 1 and 2.* (i) For purposes of determining compliance with the SO_2 emissions limit listed in paragraph (c)(24) of this section for each unit, the SO_2 emissions for each boiler-operating-day shall be determined by summing the hourly emissions measured in pounds of SO_2. 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 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 applicable 30 boiler-operating-days rolling average. For each day, records of the total SO_2 emitted that day by each emission unit and the sum of the hourly heat inputs for that day must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. . Records of the 30 boiler-operating-day rolling average for each unit as described above must be maintained by the owner or operator for each boiler-operating-day and made available upon request to EPA and ADEQ representatives.

(ii) For purposes of determining compliance with the 0.15 lb/MMBtu NO_X emissions limit listed in paragraph (c)(24), the NO_X emissions for each unit shall be determined by the following procedure:

(A) Summing the total pounds of NO_X emitted during the current boiler-operating-day and the preceding 29 boiler-operating-days while including only emissions during hours when the unit was dispatched at 50% or greater of the unit's maximum heat input rating;

(B) Summing the total heat input in MMBtu to the unit during the current boiler-operating-day and the preceding 29 boiler operating days while including only the heat input during hours when the unit was dispatched at 50% or greater of the unit's maximum heat input rating; and

(C) Dividing the total pounds of NO_X emitted as calculated in step 1 by the total heat input to the unit as calculated in step 2. 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 a 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. For each day, records for each unit of the hours during which the unit was dispatched at 50% or greater of the unit's maximum heat input rating, as well as NO_X emissions and hourly heat input for each of those hours must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Records of the 30 boiler-operating-day rolling average for NO_X for each unit as described above must be maintained by the owner or operator for each boiler-operating-day and made available upon request to EPA and ADEQ representatives.

(iii) For purposes of determining compliance with the 671 lb/hr NO_X emissions limit listed in paragraph (c)(24), the NO_X emissions for each unit shall be determined by the following procedure:

(A) Summing the total pounds of NO_X emitted during the current hour and the preceding 2 hours during which the unit was dispatched at less than 50% of the unit's maximum heat input rating; and

(B) Dividing the total pounds of NO_X emitted as calculated in step 1 by 3. The result shall be the rolling 3-hour 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 a unit, that NO_X pounds per hour shall not be used in the calculation of the rolling 3-hour average for NO_X. For each day, records for each unit of the hours during which the unit was dispatched at less than 50% of each unit's maximum heat input rating, as well as NO_X emissions and hourly heat input for each of those hours must be maintained by the owner or operator and made available upon request to EPA and ADEQ representatives. Records of the rolling 3-hour averages for NO_X for each unit as described above must be maintained for each day by the owner or operator and made available upon request to EPA and ADEQ representatives.

(iv) 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)(24) 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.

(v) Continuous emissions monitoring shall apply during all periods of operation of the units listed in paragraph (c)(24) 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.

(27) *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, unless otherwise specified:

(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) [Reserved]

(28) *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.

(29) *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.* 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.

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