**ENVIRONMENTAL PROTECTION AGENCY**

**40 CFR Part 52**

**[EPA–R06–OAR–2022–0735; FRL–9405–01–R6]**

## Air Plan Approval; Arkansas; Regional Haze State Implementation Plan for the Second Implementation Period

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Proposed rule.

**SUMMARY:** Pursuant to the Clean Air Act (CAA or the Act), the Environmental Protection Agency (EPA) is proposing to approve a State Implementation Plan (SIP) revision submitted by the State of Arkansas through the Division of Environmental Quality (DEQ) on August 8, 2022, and clarified by DEQ on July 29, 2025, as satisfying the requirements of the Act and the EPA's Regional Haze Rule (RHR) for visibility protection in mandatory Class I Federal areas (Class I areas) for the program's second implementation period. Arkansas' SIP submission addresses the requirement that states must revise their long-term strategies for making reasonable progress to prevent any future and remedy any existing man-made visibility impairment in the Class I areas. The EPA is taking this action pursuant to sections 110 and 169A of the CAA.

**DATES:** Written comments must be received on or before October 6, 2025.

**ADDRESSES:** Submit comments, identified by Docket No. EPA–R06–OAR–2022–0735, at *https://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov.* The EPA may publish any comment received to its public docket. Do not submit electronically any information that is considered to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment with multimedia submissions and should include all discussion points desired. The EPA will generally not consider comments or their contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). For additional submission methods, please contact James E. Grady, 214–665–6745, *grady.james@epa.gov.* For the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets.*

*Docket:* The index to the docket for this action is available electronically at *www.regulations.gov.* While all documents in the docket are listed in the index, some information may not be publicly available due to docket file size restrictions or content (*e.g.,* CBI).

**FOR FURTHER INFORMATION CONTACT:** James E. Grady, EPA Region 6 Office, Regional Haze and $SO_2$ Section, (214) 665–6745; *grady.james@epa.gov.* We encourage the public to submit comments via *https://www.regulations.gov.* Please call or email Mr. Grady or call Mr. Bill Deese at 214–665–7253 if you need alternative access to material indexed but not provided in the docket.

**SUPPLEMENTARY INFORMATION:** Throughout this document "we," "us," and "our" mean the EPA.

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### I. What action is the EPA proposing?

On August 8, 2022, DEQ submitted its 2022 Arkansas Regional Haze Planning Period II SIP submission to the EPA to satisfy the regional haze program requirements for the second implementation period. The EPA is proposing to find that the Arkansas regional haze SIP submission for the second implementation period meets the applicable statutory and regulatory requirements and, therefore, is proposing to approve Arkansas' submission into its SIP. Specifically, the EPA is proposing to approve Arkansas' 2022 SIP submission, clarified by DEQ on July 29, 2025, as satisfying the requirements of (1) 40 CFR 51.308(f)(1): calculations of baseline, current, and natural visibility conditions, progress to date, and the uniform rate of progress (URP); (2) 40 CFR 51.308(f)(2): long-term strategy; (3) 40 CFR 51.308(f)(3): reasonable progress goals (RPGs); (4) 40 CFR 51.308(f)(4): reasonably attributable visibility impairment (RAVI); (5) 40 CFR 51.308(f)(5) and 40 CFR 51.308(g)(1) through (5): progress report requirements; (6) 40 CFR 51.308(f)(6): monitoring strategy and other implementation plan requirements; and (7) 40 CFR 51.308(i): Federal Land Manager (FLM) consultation. The State's submission can be found in the docket of this action.

### II. Background and Requirements for Regional Haze Plans

A detailed history and background of the regional haze program is provided in multiple prior EPA proposal actions.[1] For additional background, please refer to Section III, "Overview of Visibility Protection Statutory Authority, Regulation, and Implementation" of the 2017 RHR revisions titled, "Protection of Visibility: Amendments to Requirements for State Plans."[2] The following is an abbreviated history and background of the regional haze

[1] *See* 90 FR 13516 (March 24, 2025).

[2] *See* 82 FR 3078 (January 10, 2017) located at *https://www.federalregister.gov/documents/2017/01/10/2017-00268/protection-of-visibility-amendments-to-requirements-for-State-plans#h-16.*

program and 2017 RHR as it applies to the current action.

*A. Regional Haze Background*

In the 1977 CAA Amendments, Congress created a program for protecting visibility in the nation's mandatory Class I Federal areas, which include certain national parks and wilderness areas.[3] CAA section 169A(a)(1) establishes 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.''

Regional haze is visibility impairment that is produced by a multitude of anthropogenic sources and activities which are located across a broad geographic area that emit pollutants that impair visibility. Visibility impairing pollutants predominantly include fine particulates ($PM_{2.5}$) and their precursors but also coarse mass.[4] $(PM)_{2.5}$ particles consist of sulfates ($SO_4{}^{2-}$), nitrates ($NO_3{}^{minus;}$), organic carbon, elemental carbon, and soil dust. Precursors that react in the atmosphere to form $PM_{2.5}$ consist of sulfur dioxide ($SO_2$), nitrogen oxides ($NO_X$), and, in some cases, volatile organic compounds (VOC) and ammonia ($NH_3$). $PM_{2.5}$ impairs visibility by scattering and absorbing light, which reduces the perception of clarity and color, as well as visible distance.[5]

To address regional haze visibility impairment, the 1999 RHR established an iterative planning process to implement CAA section 169(A)(b)(2) that requires a state in which any Class I area is located or for a state ''the emissions from which may reasonably be anticipated to cause or contribute to any impairment of visibility'' in a Class I area to each periodically submit comprehensive SIP revisions to address such impairment.[6] On January 10, 2017, the EPA promulgated revisions to the RHR, that apply for the second and subsequent implementation periods. *See* 82 FR 3078 (January 10, 2017). The reasonable progress requirements as revised in the 2017 rulemaking (referred to here as the 2017 RHR Revisions) are codified at 40 CFR 51.308(f).

*B. Roles of Agencies in Addressing Regional Haze*

Because the air pollutants and pollution affecting visibility in Class I areas can be transported over long distances, successful implementation of the regional haze program requires long-term, regional coordination among multiple jurisdictions and agencies that have responsibility for Class I areas and the emissions that impact visibility in those areas. In order to address regional haze, states need to develop strategies in coordination with one another, considering the effect of emissions from one jurisdiction on the air quality in another. Five regional planning organizations (RPOs),[7] which include representation from state and tribal governments, the EPA, and Federal Land Managers, were developed in the lead-up to the first implementation period to address regional haze. RPOs evaluate technical information to better understand how emissions from state and tribal land impact Class I areas across the country, pursue the development of regional strategies to reduce emissions of particulate matter and other pollutants leading to regional haze, and help states meet the consultation requirements of the RHR.

The Central Regional Air Planning Association (CENRAP), one of the five RPOs referred to, was a collaborative effort of tribal governments, state governments and various federal agencies representing the central states for the first planning period. Due to lack of funding in 2011, CENRAP subsequently ceased to function, and Arkansas now communicates through the Central States Air Resource Agencies (CenSARA) with the other states that were part of CENRAP. The CenSARA region includes the states of Arkansas, Iowa, Kansas, Louisiana, Missouri, Nebraska, Oklahoma, Texas, and the local agencies within these states. CenSARA promotes the exchange of ideas, information, knowledge, experience and data, and develops strategies for addressing air quality issues that may affect the CenSARA states. CenSARA also conducts research and undertakes other activities as necessary to provide CenSARA states with information to support the development of sound air pollution control policy.

*C. Previous Actions on Arkansas Regional Haze*

The State of Arkansas submitted a regional haze SIP on September 9, 2008, intended to address the requirements of the first regional haze implementation period. On August 3, 2010, the State submitted a SIP revision with mostly non-substantive changes that addressed Arkansas Pollution Control and Ecology Commission (APCEC) Regulation 19, Chapter 15. On September 27, 2011, the State submitted a supplemental letter that clarified several aspects of the 2008 submittal. The EPA collectively refers to the original 2008 submittal, the supplemental letter, and the 2010 revision together as the 2008 Arkansas Regional Haze SIP. On March 12, 2012, the EPA partially approved and partially disapproved the 2008 Arkansas Regional Haze SIP.[8] Specifically, the EPA disapproved certain BART compliance dates; the State's identification of certain BART-eligible sources and subject-to-BART sources; certain BART determinations for $NO_X$, $SO_2$, and $PM_{10}$; the State's reasonable progress analysis; and a portion of the State's long-term strategy. The remaining provisions of the 2008 Arkansas Regional Haze SIP were approved. The final partial disapproval started a 2-year FIP clock that obligated the EPA to either approve a SIP revision and/or promulgate a FIP to address the disapproved portions of the action.[9] Because a SIP revision addressing the deficiencies was not approved and the FIP clock expired in April 2014, the EPA promulgated a FIP (the Arkansas

[3] CAA 169A establishes visibility protection for mandatory Class I Federal areas and CAA 162(a) statutorily designates these areas as consisting of all national parks exceeding 6,000 acres, all national wilderness areas and memorial parks exceeding 5,000 acres, and all international parks that were in existence on August 7, 1977. There are 156 mandatory Class I areas. The list of areas to which the requirements of the visibility protection program apply is in 40 CFR part 81, subpart D.

[4] Particles greater than $PM_{2.5}$ but less than $PM_{10}$ are referred to as coarse mass.

[5] 40 CFR 51.301 states that there are several ways to measure the amount of visibility impairment, *i.e.,* haze. One such measurement is the deciview, which is the principal metric used by the RHR. Under many circumstances, a change in 1 deciview will be perceived by the human eye to be the same on both clear and hazy days. The deciview is unitless. It is proportional to the logarithm of the atmospheric extinction of light, which is the perceived dimming of light due to its being scattered and absorbed as it passes through the atmosphere. Atmospheric light extinction ($b^{ext}$) is a metric used for expressing visibility and is measured in inverse megameters ($Mm^{-1}$). The formula for the deciview is dv=10*ln ($b^{ext}$/10 $Mm^{-1}$).

[6] 40 CFR 51.308(d), (f) expresses the statutory requirement for states to submit plans addressing out-of-state class I areas by providing that states must address visibility impairment ''in each mandatory Class I Federal area located outside the State that may be affected by emissions from within the State.'' *See also* 40 CFR 51.308(b), (f) which establishes submission dates for iterative regional haze SIP revisions; 64 FR 35714, 35768 (July 1, 1999).

[7] RPOs are sometimes also referred to as ''multi-jurisdictional organizations,'' or MJOs. For the purposes of this notice, the terms RPO and MJO are synonymous.

[8] 77 FR 14604 (March 12, 2012).

[9] Under CAA section 110(c), the EPA is required to promulgate a FIP 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 effective date that the EPA disapproves a SIP in whole or in part. The FIP requirement is terminated only if a state submits a SIP, and the EPA approves that SIP as meeting applicable CAA requirements before promulgating a FIP.

Regional Haze FIP) on September 27, 2016, to address the disapproved portions of the 2008 Arkansas Regional Haze SIP.[10] Among other things, the FIP established $SO_2$, $NO_X$, and $PM_{10}$ emission limits under the BART requirements for nine units at six facilities: Arkansas Electric Cooperative Corporation (AECC) Carl E. Bailey Plant Unit 1 Boiler; AECC John L. McClellan Plant Unit 1 Boiler; American Electric Power/Southwestern Electric Power Company (AEP/SWEPCO) Flint Creek Plant Boiler No. 1; Entergy Lake Catherine Plant Unit 4 Boiler; Entergy White Bluff Plant Units 1 and 2 Boilers and the Auxiliary Boiler; and the Domtar Ashdown Mill Power Boilers No. 1 and 2. The FIP also established $SO_2$ and $NO_X$ emission limits under the reasonable progress requirements for the Entergy Independence Plant Units 1 and 2.

Following petitions for reconsideration submitted by the State, industry, and ratepayers, on April 25, 2017, the EPA issued a partial administrative stay of the effectiveness of the FIP for 90 days.[11] During that period, Arkansas started to address the disapproved portions of its regional haze SIP through several phases of SIP revisions. On July 12, 2017, the State submitted its proposed Phase I SIP revision (the Arkansas Regional Haze $NO_X$ SIP revision) to address $NO_X$ BART requirements for all electric generating units (EGUs) and the reasonable progress requirements with respect to $NO_X$. The Arkansas Regional Haze $NO_X$ SIP submittal replaced all source-specific $NO_X$ BART determinations for EGUs established in the FIP with reliance upon the Cross-State Air Pollution Rule (CSAPR) emissions trading program for ozone ($O_3$) season $NO_X$ as an alternative to $NO_X$ BART. The SIP submittal addressed the $NO_X$ BART requirements for Bailey Unit 1, McClellan Unit 1, Flint Creek Boiler No. 1, Lake Catherine Unit 4; White Bluff Units 1 and 2, and the Auxiliary Boiler. The revision did not address $NO_X$ BART for Domtar Ashdown Mill Power Boilers No. 1 and 2. On February 12, 2018, we took final action to approve the Arkansas Regional Haze $NO_X$ SIP revision and to withdraw the corresponding $NO_X$ provisions of the FIP.[12]

The State submitted its Phase II SIP revision (the Arkansas Regional Haze $SO_2$ and PM SIP revision) on August 8, 2018, that addressed most of the remaining parts of the 2008 Arkansas Regional Haze SIP that were disapproved in the March 12, 2012, action. The August 8, 2018, SIP submittal was intended to replace the federal $SO_2$ and $PM_{10}$ BART determinations as well as the reasonable progress determinations established in the FIP with the State's own determinations. Specifically, the SIP revision addressed the applicable $SO_2$ and $PM_{10}$ BART requirements for Bailey Unit 1; $SO_2$ and $PM_{10}$ BART requirements for McClellan Unit 1; $SO_2$ BART requirements for Flint Creek Boiler No. 1; $SO_2$ BART requirements for White Bluff Units 1 and 2; $SO_2$, $NO_X$, and $PM_{10}$ BART requirements for the White Bluff Auxiliary Boiler; and included a requirement that Lake Catherine Unit 4 not burn fuel oil until $SO_2$ and PM BART determinations for the fuel oil firing scenario are approved into the SIP by the EPA. The submittal addressed the reasonable progress requirements with respect to $SO_2$ and $PM_{10}$ emissions for Independence Units 1 and 2 and all other sources in Arkansas. In addition, it established revised reasonable progress goals (RPGs) for Arkansas' two Class I areas and revised the State's long-term strategy provisions. The submittal did not address BART and associated long-term strategy requirements for Domtar Ashdown Mill Power Boilers No. 1 and 2. On September 27, 2019, we took final action to approve a portion of the Arkansas Regional Haze $SO_2$ and PM SIP revision and to withdraw the corresponding parts of the FIP.[13]

On August 13, 2019, DEQ submitted the Arkansas Regional Haze Phase III SIP (Phase III SIP revision). The submittal contained a BART alternative measure to address BART and the associated long-term strategy requirements for two subject-to-BART sources (Power Boilers No. 1 and 2) at the Domtar Ashdown Mill located in Ashdown, Arkansas. On March 22, 2021, we withdrew the remaining portions of the 2016 FIP and in a separate action approved the Arkansas Regional Haze Phase III SIP revision as meeting the applicable regional haze BART alternative provisions set forth in 40 CFR 51.308(e)(2) for the Domtar Ashdown Mill.[14] We also approved the reasonable progress components under 40 CFR 51.308(d)(1) relating to Domtar Power Boilers No. 1 and 2. With the approved Phase III SIP revision addressing BART alternative requirements and the previously approved Phase I and II SIP revision requirements, Arkansas addressed all reasonable progress requirements under section 51.308(d)(1) that were previously disapproved and achieved a fully approved regional haze SIP for the first implementation period.

Pursuant to 40 CFR 51.308(g), Arkansas was responsible for submitting a 5-year progress report as a SIP revision for the first implementation period, which it did on June 2, 2015. DEQ was also required to include a determination of adequacy of the regional haze SIP for the first implementation period as required under 40 CFR 51.308(h), at the same time as the progress report. On October 1, 2019, the EPA approved the progress report into the Arkansas SIP as meeting the applicable regional haze requirements set forth in section 51.308(g), and also approved the State's determination of adequacy under 40 CFR 51.308(h) that no additional controls were needed.[15]

### *D. Arkansas Regional Haze Planning Period II SIP Submittal*

On August 8, 2022, DEQ submitted to the EPA the 2022 Arkansas Regional Haze Planning Period II SIP revision (2022 Planning Period II SIP) which is the subject of this action. It addresses the State's regional haze obligations for the second implementation period (2018–2028) under CAA sections 169A and 169B and the RHR at 40 CFR 51.308(f) and (i). The 2022 Planning Period II SIP submittal contains: the State's long-term strategy which includes analyses by DEQ and CenSARA and assesses potential controls needed for selected sources to meet reasonable progress, an assessment of progress made since the first implementation period in reducing emissions of visibility impairing pollutants, and the visibility improvement progress at its Class I areas and nearby Class I areas. On July 29, 2025, DEQ submitted a letter[16] clarifying that its 2022 Planning Period II SIP submittal demonstrates reasonable progress under the RHR and CAA without the Administrative Order (LIS No. 22–084) for Entergy Independence. DEQ requested in the letter for EPA to act on its submittal without the inclusion of that Administrative Order.

[10] 81 FR 66332 (September 27,2016) as corrected on October 4, 2016 (81 FR 68319).

[11] 82 FR 18994 (April 25, 2017).

[12] *See* 83 FR 5927 (February 12, 2018) final action. *See also* 82 FR 42627 (September 11, 2017) for the proposed approval.

[13] *See* 84 FR 51033 (September 27, 2019) for final approval. *See also* 83 FR 62204 (November 30, 2018) for proposed action and 84 FR 51056 (September 27, 2019) for the final FIP withdrawal action.

[14] *See* 86 FR 15104 (March 22, 2021) final action (effective April 21, 2021). *See also* 85 FR 14847 (March 16, 2020) for proposed approval.

[15] 84 FR 51986 (October 1, 2019).

[16] *See* letter sent to EPA from DEQ signed by Secretary Khoury (dated July 28, 2025) and included in the docket of this action.

This action provides EPA's evaluation of the 2022 SIP submittal which we are proposing to approve as meeting the requirements of the CAA and RHR for the second implementation period of the regional haze program.

## III. Requirements for Regional Haze Plans for the Second Implementation Period

### *A. Long-Term Strategy*

Under the CAA and EPA's regulations, all 50 states, the District of Columbia, and the U.S. Virgin Islands are required to submit regional haze SIPs satisfying the applicable requirements for the second implementation period of the regional haze program by July 31, 2021. Each state's SIP must contain a long-term strategy for making reasonable progress toward meeting the national goal of remedying any existing and preventing any future anthropogenic visibility impairment in Class I areas. *See* CAA 169A(b)(2)(B). To this end, 40 CFR 51.308(f) lays out the process by which states determine what constitutes their long-term strategies, with the order of the requirements in 40 CFR 51.308(f)(1) through (f)(3) generally mirroring the order of the steps in the reasonable progress analysis [17] and (f)(4) through (f)(6) containing additional, related requirements. Broadly speaking, a state first must identify the Class I areas within the state and determine the Class I areas outside the state in which visibility may be affected by emissions from the state. These are the Class I areas that must be addressed in the state's long-term strategy. *See* 40 CFR 51.308(f), (f)(2). For each Class I area within its borders, a state must calculate the baseline (five-year average period of 2000–2004), current, and natural visibility conditions (*i.e.,* visibility conditions without anthropogenic visibility impairment) for that area, as well as the visibility improvement made to date and the uniform rate of progress (URP). The URP is the linear rate of progress needed to attain natural visibility conditions, assuming a starting point of baseline visibility conditions in 2004 and ending with natural conditions in 2064. This linear interpolation is used as a tracking metric to help states assess the amount of progress they are making towards the national visibility goal over time in each Class I area. *See* 40 CFR 51.308(f)(1). Each state having a Class I area and/or emissions that may affect visibility in a Class I area must then develop a long-term strategy that includes the enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress in such areas. A reasonable progress determination is based on applying the four factors in CAA section 169A(g)(1) to sources of visibility-impairing pollutants that the state has selected to assess for controls for the second implementation period. Additionally, the RHR at 40 CFR 51.308(f)(2)(iv) separately provides five "additional factors" [18] that states must consider in developing their long-term strategies. A state evaluates potential emission reduction measures for those selected sources and determines which are necessary to make reasonable progress. Those measures are then incorporated into the state's long-term strategy.

While states have discretion to choose any source selection methodology that is reasonable, whatever choices they make should be reasonably explained. To this end, 40 CFR 51.308(f)(2)(i) requires that a state's SIP submission include "a description of the criteria it used to determine which sources or groups of sources it evaluated." The technical basis for source selection, which may include methods for quantifying potential visibility impacts such as emissions divided by distance metrics, trajectory analyses, residence time analyses, and/or photochemical modeling, must also be appropriately documented, as required by 40 CFR 51.308(f)(2)(iii). Once a state has selected the set of sources, the next step is to determine the emissions reduction measures for those sources that are necessary to make reasonable progress for the second implementation period.[19] This is accomplished by considering the four reasonable progress factors—"the costs of compliance, the time necessary for compliance, and the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements." *See* CAA 169A(g)(1). The EPA has explained that the four-factor analysis is an assessment of potential emission reduction measures (*i.e.,* control options) for sources; "use of the terms 'compliance' and 'subject to such requirements' in section 169A(g)(1) strongly indicates that Congress intended the relevant determination to be the requirements with which sources would have to comply in order to satisfy the CAA's reasonable progress mandate." [20] Thus, for each source selected for four-factor analysis, a state must consider a "meaningful set" of technically feasible control options for reducing emissions of visibility impairing pollutants.[21] The EPA has also explained that, in addition to the four statutory factors, states have flexibility under the CAA and RHR to reasonably consider visibility benefits as an additional factor alongside the four statutory factors.[22] Ultimately, while states have discretion to reasonably weigh the factors and to determine what level of control is needed, 40 CFR 51.308(f)(2)(i) provides that a state "must include in its implementation plan a description of . . . how the four factors were taken into consideration in selecting the measure for inclusion in its long-term strategy."

As explained previously, 40 CFR 51.308(f)(2)(i) requires states to determine the emission reduction measures for sources that are necessary to make reasonable progress by considering the four factors. Pursuant to 40 CFR 51.308(f)(2), measures that are necessary to make reasonable progress toward the national visibility goal must be included in a state's long-term strategy and in its SIP.[23] If the outcome

[17] The EPA explained in the 2017 RHR Revision that we were adopting new regulatory language in 40 CFR 51.308(f) that, unlike the structure in 51.308(d), "tracked the actual planning sequence." *See* 82 FR 3078, 3091 (January 10, 2017).

[18] The five "additional factors" for consideration in 40 CFR 51.308(f)(2)(iv) are distinct from the four factors listed in CAA section 169A(g)(1) and 40 CFR 51.308(f)(2)(i) that states must consider and apply to sources in determining reasonable progress.

[19] CAA 169A(g)(1) provides that, "in determining reasonable progress there shall be taken into consideration" the four statutory factors. However, in addition to four-factor analyses for selected sources, groups of sources, or source categories, a state may also consider additional emission reduction measures for inclusion in its long-term strategy, *e.g.,* from other newly adopted, on-the-books, or on-the-way rules and measures for sources not selected for four-factor analysis for the second planning period.

[20] 82 FR 3078, 3091 (January 10, 2017).

[21] "Each source" or "particular source" is used here as shorthand. While a source-specific analysis is one way of applying the four factors, neither the statute nor the RHR requires states to evaluate individual sources. Rather, the 2017 RHR Revision (82 FR 3078, 3088) explains that states have "the flexibility to conduct four-factor analyses for specific sources, groups of sources or even entire source categories, depending on state policy preferences and the specific circumstances of each state."

[22] *See, e.g.,* Responses to Comments on Protection of Visibility: Amendments to Requirements for State Plans; Proposed Rule (81 FR 26942, May 4, 2016) (December 2016), Docket Number EPA–HQ–OAR–2015–0531, U.S. Environmental Protection Agency at 186.

[23] States may choose to, but are not required to, include measures in their long-term strategies beyond just the emission reduction measures that are necessary for reasonable progress. For example, states with smoke management programs may choose to submit their smoke management plans to the EPA for inclusion in their SIPs but are not required to do so. *See, e.g.,* 82 FR at 3108–09 (requirement to consider smoke management practices and smoke management programs under 40 CFR 51.308(f)(2)(iv) does not require states to

Continued

of a four-factor analysis is that an emission reduction measure is necessary to make reasonable progress toward remedying existing or preventing future anthropogenic visibility impairment, that measure must be included in the SIP.

The characterization of information on each of the factors is also subject to the documentation requirement in 40 CFR 51.308(f)(2)(iii). The reasonable progress analysis is a technically complex exercise and also a flexible one that provides states with bounded discretion to design and implement approaches appropriate to their circumstances. Given this flexibility, 40 CFR 51.308(f)(2)(iii) plays an important function in requiring a state to document the technical basis for its decision making so that the public and the EPA can comprehend and evaluate the information and analysis the state relied upon to determine what emission reduction measures must be in place to make reasonable progress. The technical documentation must include the modeling, monitoring, cost, engineering, and emissions information on which the state relied to determine the measures necessary to make reasonable progress. Additionally, the RHR at 40 CFR 51.3108(f)(2)(iv) separately provides five ''additional factors'' [24] that states must consider in developing their long-term strategies: (1) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment; (2) measures to reduce the impacts of construction activities; (3) source retirement and replacement schedules; (4) basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs; and (5) the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

Because the air pollution that causes regional haze crosses state boundaries, 40 CFR 51.308(f)(2)(ii) requires a state to consult with other states that also have emissions that are reasonably anticipated to contribute to visibility impairment in a given Class I area. 40 CFR 51.308(f)(2)(ii)(A) requires that if a state, pursuant to consultation, agrees that certain measures (*e.g.,* a certain emission limitation) are necessary to make reasonable progress at a Class I area, it must include those measures in its SIP. Additionally, 40 CFR 51.308(f)(2)(ii)(B) requires states that contribute to visibility impairment at the same Class I area consider the emission reduction measures the other contributing states have identified as being necessary to make reasonable progress for their own sources. If a state has been asked to consider or adopt certain emission reduction measures, but ultimately determines those measures are not necessary to make reasonable progress, 40 CFR 51.308(f)(2)(ii)(C) requires that a state must document in its SIP the actions taken to resolve the disagreement. Under all circumstances, a state must document in its SIP submission all substantive consultations with other contributing states.

### *B. RPGs*

RPGs ''measure the progress that is projected to be achieved by the control measures states have determined are necessary to make reasonable progress based on a four-factor analysis.'' [25] After a state has developed its long-term strategy, it then establishes RPGs for each Class I area within its borders by modeling the visibility impacts of all reasonable progress controls at the end of the second implementation period (*i.e.,* in 2028) as well as the impacts of other requirements of the CAA. The RPGs include reasonable progress controls not only for sources in the state in which the Class I area is located, but also for sources in other states that contribute to visibility impairment in that area. The RPGs are then compared to the baseline visibility conditions and the URP to ensure that progress is being made toward the statutory goal of preventing any future and remedying any existing anthropogenic visibility impairment in the Class I areas. *See* 40 CFR 51.308(f)(2) to (3). While states are not legally obligated to achieve the visibility conditions described in their RPGs, 40 CFR 51.308(f)(3)(i) requires that ''the long-term strategy and the RPGs must provide for an improvement in visibility for the most impaired days since the baseline period and ensure no degradation in visibility for the clearest days since the baseline period.'' RPGs may also serve as a metric for assessing the amount of progress a state is making toward the national visibility goal. To support this approach, the RHR requires states with Class I areas to compare the 2028 RPG on the most impaired days to the corresponding 2028 point on the URP line (representing visibility conditions in 2028 if visibility were to improve at a linear rate from conditions in the 2000–2004 baseline period to 2064 natural visibility conditions). If the 2028 RPG on the most impaired days is above the 2028 URP point (*i.e.,* if visibility conditions are improving slower than the rate described by the URP), each state that contributes to visibility impairment in the Class I area must demonstrate, based on the four-factor analysis required under section 51.308(f)(2)(i), that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the state that would be reasonable to include in the long-term strategy. *See* 40 CFR 51.308(f)(3)(ii). To this end, 40 CFR 51.308(f)(3)(ii) requires that each state contributing to visibility impairment in a Class I area that is projected to improve slower than the URP must provide ''a robust demonstration, including documenting the criteria used to determine which sources or groups of sources were evaluated and how the four factors required by paragraph (f)(2)(i) were taken into consideration in selecting the measures for inclusion in its long-term strategy.''

### *C. Monitoring Strategy and Other State Implementation Plan Requirements*

Section 51.308(f)(6) requires states to have certain strategies and elements in place for assessing and reporting on visibility. Individual requirements under this subsection apply either to states with Class I areas within their borders, states with no Class I areas but that are reasonably anticipated to cause or contribute to visibility impairment in any Class I area, or both. Compliance with the monitoring strategy requirement may be met through a state's participation in the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring network, which is used to measure visibility impairment caused by air pollution at the 156 Class I areas covered by the visibility program. *See* 40 CFR 51.308(f)(6), (f)(6)(i), and (f)(6)(iv). All states' SIPs must provide for procedures by which monitoring data and other information are used to determine the contribution of emissions from within the state to regional haze visibility impairment in affected Class I areas, as well as a statewide inventory documenting such emissions. *See* 40 CFR 51.308(f)(6)(ii), (iii) and (v). All states' SIPs must also provide for any other elements, including reporting, recordkeeping, and other measures, that are necessary for states to assess and report on visibility. *See* 40 CFR 51.308(f)(6)(vi).

adopt such practices or programs into their SIPs, although they may elect to do so).

[24] The five ''additional factors'' for consideration in section 51.308(f)(2)(iv) are distinct from the four factors listed in CAA section 169A(g)(1) and 40 CFR 51.308(f)(2)(i) that states must consider and apply to sources in determining reasonable progress.

[25] 82 FR 3078, 3091 (January 10, 2017).

*D. Requirements for Periodic Reports Describing Progress Toward the RPGs*

Section 51.308(f)(5) requires a state's regional haze SIP revision to address the requirements of paragraphs 40 CFR 51.308(g)(1) through (5) so that the plan revision due in 2021 will serve also as a progress report addressing the period since submission of the progress report for the first implementation period. The regional haze progress report requirement is designed to inform the public and the EPA about a state's implementation of its existing long-term strategy and whether such implementation is in fact resulting in the expected visibility improvement.[26] To this end, every state's SIP revision for the second implementation period is required to assess changes in visibility conditions and describe the status of implementation of all measures included in the state's long-term strategy, including BART and reasonable progress emission reduction measures from the first implementation period, and the resulting emissions reductions. *See* 40 CFR 51.308(g)(1) and (2).

*E. Requirements for State and FLM Coordination*

CAA section 169A(d) requires that before a state holds a public hearing on a proposed regional haze SIP revision, it must consult with the appropriate FLM; pursuant to that consultation, the state must include a summary of the FLM conclusions and recommendations in the notice to the public. Consistent with this statutory requirement, 40 CFR 51.308(i) provides the requirements for State and FLM coordination. Specifically, 40 CFR 51.308(i)(2) requires that states must ''provide the FLM with an opportunity for consultation, in person and at a point early enough in the State's policy analyses of its long-term strategy emission reduction obligation so that information and recommendations provided by the FLM can meaningfully inform the State's decisions on the long-term strategy.'' In order for the EPA to evaluate whether FLM consultation meeting the requirements of the RHR has occurred, the SIP submission should include documentation of the timing and content of such consultation. The SIP revision submitted to the EPA must also describe how the state addressed any comments provided by the FLMs. *See* 40 CFR 51.308(i)(3). Finally, a SIP revision must provide procedures for continuing consultation between the state and FLMs regarding the state's visibility protection program, including development and review of SIP revisions, 5-year progress reports, and the implementation of other programs having the potential to contribute to impairment of visibility in Class I areas. *See* 40 CFR 51.308(i)(4).

## IV. EPA's Evaluation of Arkansas' Regional Haze Planning Period II SIP Submittal

Inthis section of this document, we describe Arkansas' 2022 SIP submission and evaluate it against the requirements of the CAA and RHR for the second implementation period of the regional haze program.

*A. Identification of Class I Areas*

Section 169A(b)(2) of the CAA requires a state in which any Class I area is located or for a state ''the emissions from which may reasonably be anticipated to cause or contribute to any impairment of visibility'' in a Class I area to each have a plan for making reasonable progress toward the national visibility goal. The RHR implements this statutory requirement at 40 CFR 51.308(f), which provides that each state's plan ''must address regional haze in each mandatory Class I Federal area located within the State and in each mandatory Class I Federal area located outside the State that may be affected by emissions from within the State,'' and (f)(2), which requires each state's plan to include a long-term strategy that addresses regional haze in such Class I areas.

The EPA concluded in the 1999 RHR that ''all states contain sources whose emissions are reasonably anticipated to contribute to regional haze in a Class I area,'' 64 FR 35721, and this determination was not changed in the 2017 RHR. Critically, the statute and regulation both require that the cause-or-contribute assessment consider all emissions of visibility impairing pollutants from a state, as opposed to emissions of a particular pollutant or emissions from a certain set of sources.

1. Arkansas Class I Areas

To address 40 CFR 51.308(f), Arkansas identified two Class I areas within its borders: the Caney Creek and Upper Buffalo Wilderness Areas. Caney Creek Wilderness is located in Polk County, Arkansas, and covers 14,460 acres on the southern edge of the Ouachita National Forest and protects a rugged portion of the Ouachita Mountains. The Caney Creek Wilderness Area monitor (CACR1) is located at latitude 34.4544, longitude −94.1429 in Polk County, Arkansas at an elevation of 683 meters (m) above mean sea level (MSL). Upper Buffalo Wilderness area, located in Newton County, Arkansas, is an oak-hickory forest with intermittent portions of shortleaf pine located in the Ozark National Forest and offers 12,108 acres of boulder strewn and rugged scenery along the Buffalo River. The Upper Buffalo Wilderness monitor (UPBU1) is located 1 mile north of the U.S. Forest Service workstation near Deer, AR at an elevation of 722 m above MSL.

2. Other State Class I Areas Affected by Arkansas Emissions

In addition to the two Class I areas in Arkansas, DEQ used an area of influence analysis by Ramboll (*see* section IV.C.2.b for further details)[27] to identify Class I areas in and near the CenSARA region that may be influenced by emissions from Arkansas. DEQ examined distance-weighted residence time plots by Ramboll and applied a 0.05 percent threshold to the plots as a cutoff to identify areas of influence. Based on the contour plot qualitative results,[28] DEQ identified the following four Class I areas for which emissions from Arkansas sources may be reasonably anticipated to contribute to visibility impairment: Hercules Glades Wilderness (Hercules Glades) in Missouri;[29] Mammoth Cave National Park (Mammoth Cave) in Kentucky;[30] Sipsey Wilderness (Sipsey) in Alabama;[31] and Wichita Mountains Wildlife Refuge (Wichita Mountains) in Oklahoma.[32] In addition to the Class I

[26] 81 FR 26942, 26950 (May 4, 2016); 82 FR 3078, 3119 (January 10, 2017).

[27] *See* area of influence report in Appendix B of 2022 Planning Period II SIP submittal called 7AppB_Area of Influence Report Prepared by Ramboll.pdf.

[28] *See* All Trajectories Distance-Weighted Residence Times contour plots for EWRT $NO_3$ and EWRT $SO_4$ for the 20 percent Most Impaired Days in the 2022 Planning Period II SIP: Figure III–10 for Hercules Glades; Figure III–20 for Mammoth Cave; Figure III–29 for Mingo; Figure III–48 for Sipsey; and Figure III–58 for Wichita Mountains. Note that air masses from Arkansas were not within the 0.05 percent distance-weighted residence time contour for Mingo on the most impaired days.

[29] The Hercules Glades Wilderness Area located in southwestern Missouri consists of 12,413 acres of open grasslands, forested knobs, steep rocky hillsides, and narrow drainages. The area is characterized by shallow, droughty soils and limestone outcrops. The Hercules Glades monitor (HEGL1) is located at latitude 36.6137, longitude −92.9220 in Missouri.

[30] The Mammoth Cave National Park in south central Kentucky consists of 51,303 acres in the Green River valley and contains the world's longest known cave system. The Mammoth Cave monitor (MACA1) is located at latitude 37.1317, longitude −86.1478 in Kentucky.

[31] The Sipsey Wilderness consists of 12,646 acres in the Bankhead National Forest. The Sipsey monitor (SIPS1) is located at latitude 34.3433, longitude −87.3387 in Alabama.

[32] The Wichita Mountains Wildlife Refuge in southwestern Oklahoma consists of 8,900 acres of

Continued

areas DEQ identified using distance-weighted residence times, DEQ also identified two additional Class I areas for which a particular source within Arkansas may contribute to visibility impairment: Mingo National Wildlife Refuge (Mingo) [33] in Missouri was identified using the 2016 visibility impact surrogate (*see* section IV.C.2.b for further details) and Shining Rock Wilderness (Shining Rock) [34] in North Carolina was identified through photochemical modeling. DEQ identified the Entergy Independence Power Plant in Arkansas as meeting its threshold for a reasonable progress analysis for Mingo in Missouri. The Visibility Improvement State and Tribal Association of the Southeast (VISTAS) [35] RPO also made a request of DEQ to perform a reasonable progress analysis for the Entergy Independence Power Plant in Arkansas, as their modeling showed impacts at Shining Rock in North Carolina. DEQ, therefore, identified both Mingo and Shining Rock as Class I areas to consider for its source selection. Mingo was included in the analysis performed by Ramboll but Shining Rock in North Carolina was not included since that Class I area is not in the CenSARA region or adjacent to a CenSARA state. DEQ assessed state-by-state source contributions to visibility impairment for the two Class I areas in Arkansas (Caney Creek and Upper Buffalo) and also for the six Class I areas in other states (Hercules Glades, Mammoth Cave, Mingo, Shining Rock, Sipsey, and Wichita Mountains) affected by emissions from Arkansas for the second planning period. DEQ also provided further evaluation of the sources from these Class I areas in and outside Arkansas by analyzing the key pollutants and then screening the main sources contributing toward visibility impairment for possible emission reduction controls. EPA provides our evaluation of DEQ's source selection process [36] and the overall long-term strategy [37] for these areas in section IV.C of this proposed action.

The EPA finds that DEQ has met the requirement in its 2022 Planning Period II SIP submittal of identifying the Class I areas located both within and outside Arkansas that may be affected by emissions from within Arkansas.

### *B. Calculations of Baseline, Current, and Natural Visibility Conditions; Progress to Date; and the URP for Arkansas' Class I Areas*

Section 51.308(f)(1)(i) to (vi) requires DEQ to determine the following for each Class I area located within Arkansas: (i) baseline visibility conditions for the most impaired and clearest days, (ii) natural visibility conditions for the most impaired and clearest days, (iii) current visibility conditions for the most impaired and clearest days, (iv) progress to date for the most impaired and clearest days, (v) the differences between current visibility conditions and natural visibility conditions, (vi) and the URP for each Class I area in the state. This section also provides the option for states to propose adjustments to the URP line for a Class I area to account for visibility impacts from anthropogenic sources outside the United States and/or the impacts from wildland prescribed fires that were conducted for certain, specified objectives. *See* 40 CFR 51.308(f)(1)(vi)(B).

DEQ reported the current visibility conditions and improvement realized at Arkansas' Class I areas in its 2022 Planning Period II SIP as required by 40 CFR 51.308(f)(1) and the 2018 Visibility Tracking Guidance.[38] DEQ relied on available IMPROVE monitoring data [39] at Caney Creek and Upper Buffalo Wilderness Areas and developed figures showing visibility impairment trends. DEQ reported 2000–2019 annual observed visibility data and 5-year rolling average data in deciviews on the 20 percent clearest days and the 20 percent most impaired days as compared to the glidepaths at these areas.[40] DEQ also compared charts of baseline (2000–2004), current (2015–2019),[41] and natural (2064) visibility conditions as measured by the IMPROVE monitors and determined that current visibility (2015–2019) at each Class I area for both the clearest and most impaired days has improved since the baseline period (*see* Tables 1 and 2).[42]

TABLE 1—VISIBILITY AT ARKANSAS CLASS I AREAS FOR 20 PERCENT CLEAREST DAYS

| Class I areas | Visibility (dv) | | |
|---|---|---|---|
| | Baseline (2000–2004) | Current (2015–2019) | Natural conditions (2064) |
| Caney Creek Wilderness | 11.24 | 7.79 | 4.23 |
| Upper Buffalo Wilderness | 11.71 | 8.17 | 4.18 |

canyons and grasslands that embrace the ancient Wichita Mountains. The Wichita Mountain monitor (WIMO1) is located at latitude 34.7322, longitude −98.7129 Oklahoma.

[33] The Mingo National Wildlife Refuge Wilderness Area in southeastern Missouri consists of 7,730 acres of swamp, riparian areas, and Ozark Plateau uplands. The Mingo monitor (MING1) is located at latitude 36.9716, longitude −90.1432 in Missouri.

[34] The Shining Rock Wilderness area consists of over 18,000 acres on the north side of the Pisgah Ledge in the Blue Ridge Mountains in North Carolina. The Shining Rock monitor (SHRO1) is located at latitude 35.3936, longitude −82.7743 in North Carolina.

[35] VISTAS is responsible for convening and collaborating on regional air quality analysis work necessary to support the development of regional haze SIPs. It is made up of 10 states (Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia), the Eastern Band of Cherokee Indians, and Knox County, Tennessee (representing the 17 Southeastern local air agencies).

[36] *See* source screening spreadsheet in Appendix C of 2022 Planning Period II SIP submittal called 7AppC_Arkansas Source Screening Method Spreadsheet-v8.xlsx.

[37] *See* 40 CFR 51.308(f)(2) for the long-term strategy requirements. *See also* CAA 169A(b)(2)(B).

[38] *See* December 20, 2018, memo, "Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program" from Richard A. Wayland at the EPA Office of Air Quality Planning and Standards, Research Triangle Park. *https://www.epa.gov/sites/default/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf.*

[39] The Caney Creek IMPROVE monitor (CACR1) is located at latitude 34.4544, longitude −94.1429 in Polk County, AR at an elevation of 683 m above mean sea level (MSL). The Upper Buffalo Wilderness IMPROVE monitor (UPBU1) is located 1 mile north of the U.S. Forest Service workstation near Deer, AR at an elevation of 722 meters above MSL.

[40] *See* Figures II–2 and II–3 (pages II–5 to 6) for visibility progress at Caney Creek and Figures II–14 and II–15 (pages II–19 to 20) for visibility progress at Upper Buffalo in the 2022 Planning Period II SIP.

[41] The period for calculating "current" visibility conditions is the most recent 5-year period for which data are available.

[42] *See* Tables II–1 and II–2 (page II–4) for Caney Creek and Tables II–3 and II–4 (page II–18) for Upper Buffalo in the 2022 Planning Period II SIP for comparison of baseline, current, and natural visibility conditions.

TABLE 2—VISIBILITY AT ARKANSAS CLASS I AREAS FOR 20 PERCENT MOST IMPAIRED DAYS

| Class I areas | Visibility (dv) | | |
|---|---|---|---|
| | Baseline (2000–2004) | Current (2015–2019) | Natural conditions (2064) |
| Caney Creek Wilderness | 23.99 | 17.65 | 9.54 |
| Upper Buffalo Wilderness | 24.21 | 17.52 | 9.41 |

DEQ reported, for the most impaired and clearest days, the progress made toward natural visibility conditions during the first planning period from the baseline period (2000–2004) to the last 5-year average from that period (2014–2018); and total progress made to date toward natural visibility conditions from the baseline period (2000–2004) to the current 5-year average period (2015–2019). The State also included the visibility improvement that is still required at Caney Creek and Upper Buffalo in order to meet natural conditions by 2064 (*see* Tables 3 and 4).

TABLE 3—VISIBILITY IMPROVEMENT PROGRESS TOWARD NATURAL VISIBILITY FOR 20 PERCENT CLEAREST DAYS AT ARKANSAS' CLASS I AREAS

| Class I areas | Progress during planning period I * (dv) | Total progress to date ** (dv) | Additional progress needed for natural conditions † (dv) |
|---|---|---|---|
| Caney Creek Wilderness | 3.22 | 3.46 | 3.56 |
| Upper Buffalo Wilderness | 3.51 | 3.54 | 3.99 |

* Difference between baseline (2000–2004) average conditions and 2014–2018 average conditions.
** Difference between baseline (2000–2004) average conditions and 2015–2019 average conditions.
† Difference between 2015–2019 average conditions and 2064 natural conditions.

TABLE 4—VISIBILITY IMPROVEMENT PROGRESS TOWARD NATURAL VISIBILITY FOR 20 PERCENT MOST IMPAIRED DAYS AT ARKANSAS' CLASS I AREAS

| Class I areas | Progress during planning period I * (dv) | Total progress to date ** (dv) | Additional progress needed for natural conditions † (dv) |
|---|---|---|---|
| Caney Creek Wilderness | 5.70 | 6.34 | 8.11 |
| Upper Buffalo Wilderness | 6.26 | 6.70 | 8.11 |

* Difference between baseline (2000–2004) average conditions and 2014–2018 average conditions.
** Difference between baseline (2000–2004) average conditions and 2015–2019 average conditions.
† Difference between 2015–2019 average conditions and 2064 natural conditions.

The URP is the uniform rate of visibility improvement (measured in deciviews of improvement per year) that would need to be maintained during each implementation period for the most impaired days in order to attain natural visibility conditions by the end of 2064. The State calculated the URP for Caney Creek and Upper Buffalo for the 20 percent most impaired days, and developed linear glidepaths for each area assuming a starting point of baseline visibility conditions in 2004 and ending with natural conditions in 2064.[43] The RHR allows states the option to adjust the 2064 glidepath endpoints to account for both international anthropogenic emissions and certain prescribed fire impacts at each Class I area. In the EPA's September 2019 memo and associated technical support document (EPA 2019 Memo and Modeling TSD),[44] the EPA used 2028 modeling results to quantify the international anthropogenic and prescribed fire impacts [45] at Class I areas on the 20 percent most anthropogenically impaired days. This linear tracking metric was used by the State to assess the amount of progress toward visibility improvement over time in each Class I area by comparing annual observed data and 5-year average visibility data to the URP glidepath. Caney Creek's URP was revised to be −0.212 dv per year based on an adjusted 2064 endpoint of 11.26 dv. Upper Buffalo's URP was revised to be −0.206 dv per year based on an adjusted 2064 endpoint of 11.83 dv. The adjusted URP glidepath 2064 endpoints were calculated by adding the contribution of international anthropogenic emissions as modeled by EPA [46] to the natural visibility conditions. The total international anthropogenic contributions for Caney

[43] *See* Figures II–2 and II–14 in the 2022 Planning Period II SIP for Caney Creek and Upper Buffalo's URP glidepaths on the 20 percent most impaired days.

[44] *See* Memorandum titled, ''Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling,'' from Richard A. Wayland, Director of EPA's Air Quality Assessment Division, to EPA Regional Air Division Directors (September 19, 2019). *https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling.*

[45] *See* EPA 2019 Modeling Memo (page 2, footnote 4). The Regional Haze Rule also allows an adjustment of the glidepath endpoint to account for certain prescribed fire impacts. Modeled prescribed fire contributions were calculated by EPA, with results presented in the modeling TSD. However, consistent with the focus of the December 2018 Technical Guidance and the Administrator's Regional Haze Roadmap, the glidepath adjustments presented only include the international anthropogenic contributions. Additionally, the prescribed fire impacts are relatively small (~0–5 $Mm^{-1}$) compared to the international anthropogenic impacts (~3–19 $Mm^{-1}$). *See* the 2019 Modeling TSD at Table 5–1 (pages 44 and 52) for the impacts from prescribed fires at Caney Creek (1.88 $Mm^{-1}$) and at Upper Buffalo (3.68 $Mm^{-1}$).

[46] See EPA 2019 Modeling TSD, Table 5–2.

Creek and Upper Buffalo Wilderness are 4.88 $Mm^{-1}$ and 7.02 $Mm^{-1}$, respectively. Table 5 shows the current 5-year rolling average on the 20 percent most impaired days for 2015–2019 and the adjusted 2028 URP value for the Arkansas Class I areas.

TABLE 5—CURRENT VISIBILITY CONDITIONS AND 2028 ADJUSTED URP VALUES FOR 20 PERCENT MOST IMPAIRED DAYS AT ARKANSAS' CLASS I AREAS

| Class I areas | Most current (2015–2019) (dv) | 2028 Adjusted URP (dv) |
|---|---|---|
| Caney Creek Wilderness | 17.65 | * 18.90 |
| Upper Buffalo Wilderness | 17.52 | ** 19.26 |

* The unadjusted 2028 URP value at Caney Creek is 18.18 dv without accounting for international anthropogenic and prescribed fire contributions. *See* EPA 2019 Modeling TSD at 57, Table 5–2.

** The unadjusted 2028 URP value at Upper Buffalo is 18.32 dv without accounting for international anthropogenic and prescribed fire contributions. *See* EPA 2019 Modeling TSD at 64, Table 5–2.

The EPA is proposing to find that DEQ has met the requirements under 40 CFR 51.308(f)(1) in the 2022 Planning Period II SIP submittal for the two Class I areas located within Arkansas (the Caney Creek and Upper Buffalo Wilderness areas) related to the calculations of baseline, current, and natural visibility conditions for the most impaired and clearest days; progress to date for the most impaired and clearest days; differences between current and natural visibility conditions; and the URP for the second implementation period.

*C. Long-Term Strategy*

Each state that has a Class I area within its borders or has emissions that may affect visibility in a Class I area must develop a long-term strategy for making reasonable progress toward the national visibility goal. CAA 169A(b)(2)(B). The long-term strategy must include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress, as determined pursuant to 51.308(f)(2)(i) through (iv). 40 CFR 51.308(f)(2). A reasonable progress determination is based on applying the four statutory factors in CAA section 169A(g)(1) to sources of visibility-impairing pollutants that the state has selected to assess for controls for the second implementation period. After considering the four statutory factors, all measures that are determined to be necessary to make reasonable progress must be in the long-term strategy. Section 51.308(f)(2)(i) provides the requirements for the four-factor analysis. The first step of this analysis entails selecting the sources to be evaluated for emission reduction measures. The RHR provides states flexibility in selecting sources, and to that end, section 51.308(f)(2)(i) requires States to provide a description of the criteria used to determine which sources or group of sources were evaluated (*i.e.,* subjected to four-factor analysis) for the second implementation period and how the four factors were taken into consideration in selecting the emission reduction measures for inclusion in the long-term strategy. In developing its long-term strategy, a state must also consider the five additional factors in section 51.308(f)(2)(iv). Each State must also document the technical basis on which it is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I area it affects. 40 CFR 51.308(f)(2)(iii). States may rely on technical information developed by the RPOs of which they are members to select sources for four-factor analysis and to conduct that analysis, as well as to satisfy the documentation requirements under 40 CFR 51.308(f). Where an RPO has performed source selection and/or four-factor analyses (or considered the five additional factors in 40 CFR 51.308(f)(2)(iv)) for its member states, those states may rely on the RPO's analyses for the purpose of satisfying the requirements of 40 CFR 51.308(f)(2)(i) so long as the states have a reasonable basis to do so and all state participants in the RPO process have approved the technical analyses. 40 CFR 51.308(f)(2)(iii). States may also satisfy the requirement of 40 CFR 51.308(f)(2)(ii) to engage in interstate consultation with other states that have emissions that are reasonably anticipated to contribute to visibility impairment in a given Class I area under the auspices of intra- and inter-RPO engagement.

1. EPA's Rationale To Evaluate the Long-Term Strategy

In this section of this document, we summarize and evaluate Arkansas' long-term strategy against the requirements of the CAA and RHR for the second implementation period of the regional haze program. As detailed further in sections IV.C.2 through 6 that follow, EPA is proposing to approve Arkansas' long-term strategy under 40 CFR 51.308(f)(2), including the source selection methodology (*see* section IV.C.2), the four factor analysis and determinations of the measures necessary to make reasonable progress under section 51.308(f)(2)(i) (*see* section IV.C.3); and other regional haze requirements for the long-term strategy (51.308(f)(2)(ii) through (iv)) such as consultation requirements (*see* section IV.C.4), documentation requirements (*see* section IV.C.5), and analysis of the five additional factors (*see* section IV.C.6).

In this proposed action, we note that it is the Agency's policy, as announced in our recent approval of the West Virginia Regional Haze SIP,[47] that where visibility conditions for a Class I area impacted by a State are below the 2028 URP and the State has also evaluated potential control measures by considering the four statutory factors, the State will have presumptively demonstrated reasonable progress for the second planning period for that area. We acknowledge that this reflects a change in policy as to how the URP should be used in the evaluation of regional haze second planning period SIPs. However, we find that this policy better aligns with the purpose of the statute and RHR, which is achieving ''reasonable'' progress, not maximal progress, toward Congress's natural visibility goal. We also note that we have the discretion and authority to change policy.[48]

[47] *See* EPA's final action for West Virginia's regional haze SIP at 90 FR 29737 (July 7, 2025), and our notice of proposed rulemaking at 90 FR 16478, 16483 (April 18, 2025) which describes the policy. *See also* EPA's notice of proposed rulemaking for South Dakota at 90 FR 20425 (May 14, 2025).

[48] In *FCC* v. *Fox Television Stations, Inc.,* the U.S. Supreme Court plainly stated that an agency is free to change a prior policy and ''need not demonstrate . . . that the reasons for the new policy are better

In developing the regulations required by CAA section 169A(b), we established the concept of the URP for each Class I area. As previously discussed, for each Class I area, there is a regulatory requirement to compare the projected visibility impairment represented by the RPG at the end of each planning period to the URP (*e.g.,* in 2028 for the second planning period).[49] In the 2017 RHR Revisions, we also addressed the role of the URP as it relates to a state's development of its second planning period SIP.[50] Specifically, in response to comments suggesting that the URP should be considered a ''safe harbor'' and relieve states of any obligation to consider the four statutory factors, we explained that the URP was not intended to be such a safe harbor.[51] Some commenters stated a desire for corresponding rule text dealing with situations where RPGs are equal to or below the URP glidepath. Several commenters stated that the URP glidepath should be a ''safe harbor,'' opining that states should be permitted to analyze whether projected visibility conditions for the end of the implementation period will be on or below the glidepath based on on-the-way control measures, and that in such cases a four-factor analysis should not be required.[52] Other 2017 RHR comments indicated a similar approach, such as ''a somewhat narrower entrance to a 'safe harbor,''' by suggesting that if current visibility conditions are already below the end-of-planning-period point on the URP glidepath, a four-factor analysis should not be required.[53] We stated in our response that we do not agree with either of these recommendations. The CAA requires that each SIP revision contain long-term strategies for making reasonable progress, and that in determining reasonable progress states must consider the four statutory factors. Treating the URP as a safe harbor would be inconsistent with the statutory requirement that states assess the potential to make further reasonable progress towards natural visibility goal in every implementation period.[54]

Our policy is that as long as the visibility conditions, as reflected in the projected 2028 RPGs, of the Class I areas impacted by a state are below the 2028 URP values and the State evaluates the four factors, the State has presumptively demonstrated that it has already made reasonable progress for the second planning period for that area.[55] Indeed, we believe this policy also recognizes the considerable improvements in visibility impairment that have been made by a wide variety of state and federal programs in recent decades.

Applying this policy in our evaluation of Arkansas' SIP submission and as further detailed in the sections that follow, the EPA is proposing to approve that the long-term strategy outlined in Arkansas' 2022 Planning Period II SIP submission is adequate to demonstrate reasonable progress towards natural visibility at the Class I areas impacted by emissions from Arkansas sources.

2. Source Selection Methodology

a. Key Pollutants and Source Categories

Section 51.308(f)(2)(i) provides the requirements for the four-factor analysis. The first step of this analysis entails selecting the sources to be evaluated for emission reduction measures. DEQ analyzed key pollutants and source categories contributing toward visibility impairment for the two Class I areas in Arkansas and for the Class I areas in other states affected by emissions from Arkansas. DEQ's selection of key pollutants and source categories for evaluation in its reasonable progress analysis was based on examination of the particulate species from anthropogenic emissions that dominate visibility at the different Class I areas; relative contributions of various sectors to the Arkansas emission inventory; and projected 2028 sector-based source apportionment results from EPA's modeling.[56] DEQ noted that this approach is consistent with the 2019 guidance which provides that a state may focus on particulate species that contribute the most to visibility impairment and then select only sources with emissions of those dominant pollutants and their precursors.[57]

DEQ relied on IMPROVE monitoring data at each Class I area and developed figures showing annual visibility impairment trends from 2002–2019 tracked in deciviews and included the relative light extinction compositions from contributing pollutant species for the most impaired and clearest days. DEQ also developed figures showing trends of selected daily light extinction data for 2019 with estimated pollutant contributions corresponding to anthropogenic sources and natural sources.[58] The pollutant extinction compositions were made up of varying amounts of ammonium sulfate, ammonium nitrate, coarse mass, organic mass, elemental carbon, soil, and sea salt at each Class I area. The 2002–2019 extinction data showed that visibility impairment on the most impaired days at all of the identified Class I areas in and outside of Arkansas were consistently dominated by ammonium sulfate, ammonium nitrate, or both.[59] In addition, the 2002–2019 data showed that light-extinction on the most impaired days from ammonium nitrate and ammonium sulfate was primarily attributable to anthropogenic sources. Elemental carbon, which is primarily from anthropogenic sources, makes up a small contribution to visibility impairment at the Class I areas. The State reported that organic mass contributed more than ammonium nitrate at Caney Creek but most of the organic mass was attributable to natural sources.[60] DEQ did not put weight on relative contributions to visibility impairment on the clearest days in its consideration of source selection since visibility impairment on the clearest days has remained below baseline conditions. Based on these monitor data observations, the State's strategy for addressing visibility impairment focused on ammonium nitrate and ammonium sulfate from anthropogenic sources in all Class I areas identified in

than the reasons for the old one; it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency believes it to be better.'' 566 U.S. 502, 515 (2009) (referencing *Motor Vehicle Mfrs. Ass'n of United States, Inc.* v. *State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29 (1983)). See also *Perez* v. *Mortgage Bankers Assn.,* 135 S. Ct. 1199 (2015). However, the EPA believes that this policy aligns with the purpose of the statute and RHR, which is achieving ''reasonable'' progress, not maximal progress, toward Congress' natural visibility goal.

[49] *See* 82 FR 3078, 3091–3092 (January 10, 2017). RPGs are a regulatory construct that we developed to address statutory mandate in section 169B(e)(1), which required our regulations to include ''criteria for measuring 'reasonable progress' toward the national goal.'' Under 40 CFR 51.308(f)(3)(ii), RPGs measure the progress that is projected to be achieved by the control measures a state has determined are necessary to make reasonable progress. Consistent with the 1999 RHR, the RPGs are unenforceable, though they create a benchmark that allows for analytical comparisons to the URP and mid-implementation-period course corrections if necessary.

[50] *Id.*

[51] 82 FR 3099 (January 10, 2017).

[52] *Id.*

[53] *Id.*

[54] *Id.*

[55] *See* EPA's final action for West Virginia's regional haze SIP at 90 FR 29737 (July 7, 2025), and our notice of proposed rulemaking at 90 FR 16478, 16483 (April 18, 2025) which describes the policy.

[56] *See* page V–1 of the 2022 Planning Period II SIP.

[57] *See* 2019 Guidance at 11.

[58] *See* chapter II and III of 2022 Planning Period II SIP for the specific figures of light extinction data at each class I area: Figures II–4 to 7 for Caney Creek; Figures II–16 to 19 for Upper Buffalo; Figures III–2 to 5 for Hercules Glades; Figures III–12 to 15 for Mammoth Cave; Figures III–22 to 25 for Mingo Wilderness; Figures III–31 to 34 for Shining Rock; Figures III–40 to 43 for Sipsey; and Figures III–50 to 53 for Wichita Mountains.

[59] *See* Table V–1 of 2022 Planning Period II SIP (page V–2): Summary of Key Anthropogenic Particulate Species at each Class I area.

[60] *See* 2022 Planning Period II SIP (page V–2).

and outside Arkansas with the exceptions of Sipsey and Shining Rock where its strategy focused on ammonium sulfate only since it was the main contributing pollutant in those areas. The State focused on target precursor pollutants for potential control as a strategy for reducing these pollutants. The State identified $SO_2$ and $NH_3$ precursor emissions for control since they are associated with ammonium sulfate, and $NO_X$ precursor emissions for control since it is associated with ammonium nitrate.

DEQ reviewed categorized NEI state-wide emissions by sector for 2011, 2014, and 2017 as well as 2020 continuous emissions monitoring system (CEMS) emissions for EGUs.[61] The pollutants inventoried were $SO_2$, $NO_X$, and $NH_3$ (the targeted precursor pollutants); as well as VOC (a precursor to a lesser extent), and primary $PM_{2.5}$ which was not speciated but included all particulate species directly emitted rather than just ammonium sulfate and ammonium nitrate. These five pollutant inventories were categorized under major anthropogenic source groupings but also included biogenic sources. The anthropogenic source categories included EGU and non-EGU point; nonpoint; on and non-road mobile sources; off-road mobile sources (marine and rail); fires (agricultural, prescribed, wildfires, residential wood combustion); oil and gas; anthropogenic dust; and agricultural $NH_3$. The 2017 NEI inventory was the most recent comprehensive inventory of updated actual emissions available at the time DEQ prepared its SIP. For source selection, DEQ emphasized the 2017 NEI emissions from these NEI datasets and summarized the relative contribution of each sector to the total emissions in each pollutant inventory. DEQ eliminated $NH_3$ and VOC as well as directly emitted $PM_{2.5}$ from consideration because the majority of emission categories in those inventories could not be controlled by the State. Nearly all of the 2017 $NH_3$ emissions (98 percent) came from sectors that DEQ does not have authority to regulate under Arkansas law or from which DEQ is pre-empted from regulating by EPA.[62] As a result, DEQ eliminated $NH_3$ as a potential precursor pollutant control to reduce ammonium sulfate in the State's long-term strategy. Similarly, DEQ eliminated primary $PM_{2.5}$ as a potential pollutant to control since 85 percent of primary $PM_{2.5}$ emissions in 2017 came from sectors outside its regulatory authority.[63] DEQ also eliminated VOC controls since the vast majority of 2017 annual VOC emissions in Arkansas are made up of biogenic emissions (79%) which are not anthropogenic or controllable. VOC emissions decreased from 2011 to 2017 across all other categories. DEQ focused on $SO_2$ and $NO_X$ emissions for control as a result. For 2017 $SO_2$ and $NO_X$ emissions, DEQ reported that 89% (57,213 tpy) of the total 64,284 tpy $SO_2$ emissions and 35% (68,608 tpy) of the total 196,022 tpy $NO_X$ emissions in Arkansas came from sectors that DEQ does have authority to regulate under Arkansas law, and that EGUs and non-EGU point source sectors make up a large portion of these $SO_2$ and $NO_X$ emissions.[64]

DEQ also relied on EPA modeling analysis that provided projected 2028 visibility conditions and source sector contribution information. Based on the EPA's 2028 modeling projections, DEQ included source apportionment pie charts that represented the specific anthropogenic emission sector contributions at the different Class I areas on the most impaired days.[65] DEQ indicated that the 2028 sector-wide projections showed that the most prominent source categories contributing to visibility impairment at the Class I areas in and outside Arkansas are EGUs and non-EGU point sources with smaller contributions coming from other U.S. anthropogenic sources. DEQ also included the oil and gas sector as being a contributor at Wichita Mountains. As a result, DEQ concluded that the source apportionment data presented in the pie charts suggest that its strategy should focus on emissions from EGUs, non-EGU point, and the oil and gas sector.[66] Based on this modeling analysis; the 2002–2019 IMPROVE extinction data; and the 2011, 2014, and 2017 categorized NEI state-wide emissions; DEQ focused its reasonable progress analysis on stationary sources of $SO_2$ and $NO_X$ for planning period II.

The EPA finds that DEQ's strategy to focus its reasonable progress evaluation on stationary sources of $NO_X$ and $SO_2$ in its 2022 Planning Period II SIP is reasonable for the second planning period. DEQ adequately assessed the key pollutants and source categories and formed the basis of its decision after weighing the monitoring data, emission inventory trends of key precursor pollutants, and projected 2028 source apportionment data.

b. Area of Influence Analysis

Through collaboration with CenSARA, Arkansas assessed state-by-state contributions to visibility impairment for the two Class I areas in Arkansas and for Class I areas in other states affected by emissions from Arkansas. Arkansas relied on an area of influence (AOI) analysis performed by Ramboll US Corporation (Ramboll) for the CenSARA states in its 2022 Planning Period II SIP to identify possible regional source locations impacting visibility. Ramboll performed the AOI analysis for CenSARA Class I areas and for neighboring Class I areas that might potentially be impacted by emissions from the CenSARA states. Ramboll produced an AOI report[67] that summarizes the approach of the analysis and an AOI spreadsheet[68] that the CenSARA states could use to evaluate the results for specific Class I areas. The AOI analysis used back-trajectory modeling[69] to identify the geographic

[61] *See* 2022 Planning Period II SIP, Tables IV–4 to IV–7.

[62] *See* Figure V–2 (page V–4) in the 2022 Planning Period II SIP. The pie chart shows sector contributions to the $NH_3$ inventory consisting of agricultural $NH_3$ (78 percent), prescribed fire (11 percent), agricultural fire (6 percent), wildfire (2 percent), and other (1 percent) for 98 percent total. The chart also lists non-EGU point (1 percent) and on-road (1 percent).

[63] *See* Figure V–1 (page V–3) in the 2022 Planning Period II SIP. The pie chart shows sector contributions to the $PM_{2.5}$ inventory consisting of prescribed fire (39 percent), anthropogenic dust (32 percent), non-EGU point (11 percent), wildfire (6 percent), nonpoint (4 percent), residential wood combustion (4 percent), agricultural fires (1 percent), on-road (1 percent), non-road (1 percent), and other (1 percent).

[64] *See* Figures V–3 and V–4 (pages V–5 to 6) for a breakdown of percent sector contributions to $NO_X$ and $SO_2$ inventories; and Tables IV–4 and IV–5 showing the 2011, 2014, and 2017 categorized emissions of $NO_X$ and $SO_2$ (pages IV–18 and IV–20) in the 2022 Planning Period II SIP.

[65] *See* chapters II and III of 2022 Planning Period II SIP for figures of projected 2028 emission sectors: Figures II–8, II–20, III–6, III–16, III–26, III–35, III–44, and III–53.

[66] *See* 2022 Planning Period II SIP Table V–2: Summary of Key Sectors Affecting Visibility Impairment in 2028

[67] *See* area of influence report in Appendix B of 2022 Planning Period II SIP submittal called 7AppB_Area of Influence Report Prepared by Ramboll.pdf.

[68] *See* screening spreadsheet in Appendix C of the 2022 Planning Period II SIP called 7AppC_Arkansas Source Screening Method Spreadsheet-v8.xlsx. DEQ developed this from the CenSARA AOI Analysis EWRT.QD 2016 All Trajectories Spreadsheet provided to CenSARA states.

[69] Back trajectory analyses estimate the most likely central path of air masses that would arrive at a receptor at a given time by accounting for the impact of wind direction and wind speed on delivery of emissions to the receptor. A back trajectory analysis for certain emissions starts at the Class I area and go backwards in time to examine the path that emissions took to get to the Class I areas. Ramboll ran HYSPLIT model for the 20 percent most anthropogenically impaired days and developed 72-hour back trajectories arriving at each of the IMPROVE sites at 06:00, 12:00, 18:00 and 24:00 from each Class I area following trajectory

areas and anthropogenic emission sources with a high probability of impacting visibility at Class I areas within the CenSARA region and in nearby states. The analysis focused on $SO_2$ and $NO_X$ as the primary anthropogenic particulate species precursors (for $SO_4^{2-}$ and $NO_3^-$, respectively) that impair visibility at the Class I areas in the CenSARA region. The AOI analysis report generated several metrics that states could use. Based on the individual back trajectories on the 20 percent most impaired visibility days, Ramboll carried out residence time analysis [70] generating residence time plots which graphically mapped trajectory paths for each IMPROVE monitoring site. Ramboll extended the analysis by weighting the residence times using various metrics like emissions, visibility extinction, and distance-weighted approaches. Distance-weighted residence time generally assessed the probability of air parcels originating outside a given Class I area to reach a particular area following a straight-line trajectory with constant speed from all directions. Extinction-weighted residence time (EWRT) assessed visibility extinction values attributable to specific pollutants ($NO_X$ and $SO_2$ in this case) to help identify geographical areas of influence for each pollutant at each Class I area. The Ramboll report also examined the EWRT*Q/d metric which the report identifies as the most comprehensive residence time metric because it combines visibility extinction values and also considers the distance-weighted emissions from the source to the Class I area. More specifically, this metric considered point source emission contributions from each facility to visibility impairment at each Class I area by matching the EWRT with the facility-level emissions (Q) over distance (d) of the 2016 actual and 2028 projected point source emission inventories.[71] To determine the total potential impact from sources of $SO_2$ and $NO_X$ (precursors of $SO_4^{2}$ and $NO_3$ , respectively), the EWRT values for $SO_4^{2-1}$ and $NO^{3-}$ were combined with emissions from sources of $SO_2$ and $NO_X$. CenSARA states chose to focus on EGU and non-EGU point sources since these sources comprise major fractions of the $NO_X$ and $SO_2$ emissions inventory. The EWRT*Q/d values for each grid cell were normalized by the domain total and then plotted for both 2016 and 2028 emissions. Arkansas applied a 0.05 percent extinction-weighted screening threshold to the 2016 EWRT $NO_X$ results and 2016 EWRT $SO_2$ results for all trajectory heights combined to identify pollutant-specific areas of influence for each Class I area included in the AOI analysis.[72] DEQ included those sources for screening in the AOI for each Class I area with an EWRT value greater than or equal to 0.05 percent for either pollutant. DEQ summed the combined EWRT*Q/d values for $NO_X$ and $SO_2$ to produce a surrogate value for total visibility impact (the visibility impact surrogate) for each source in the AOI and then ranked them from largest to smallest for each Class I area. This allowed DEQ to identify the sources having the largest impact at each Class I area by comprehensively considering all combinations of impacts from the key pollutants from all stationary sources. DEQ used the AOI analysis and EWRT*Q/d to identify sources that impact the Class I areas in and around Arkansas and used that information to inform consultations with other states and to select Arkansas sources for additional analysis.

DEQ's evaluation of the visibility impact surrogate results for all $SO_2$ and $NO_X$ sources in the 2016 AOI for Caney Creek Wilderness Area indicates that stationary sources in 16 states potentially contributed to visibility impairment on the most impaired days, with sources in Texas, Arkansas, Louisiana, and Oklahoma contributing the majority with 94 percent of the total visibility impact surrogate in the 2016 AOI analysis results (46, 23, 13, and 12 percent, respectively).[73] Stationary sources in 12 other states combined for the remaining 6 percent contribution: Missouri, Illinois, and Indiana contributed 3, 1, and 0.5 percent each while the remaining nine states [74] all combined to contribute 0.7 percent. DEQ's evaluation of the visibility impact surrogate results for all sources in the 2016 AOI for Upper Buffalo Wilderness Area indicated that stationary sources in 16 states potentially contributed to visibility impairment on the most impaired days, with Arkansas, Missouri, Texas, Oklahoma, contributing the majority with 81 percent (48, 15, 9, and 9 percent, respectively).[75] Louisiana and Illinois contributed 5 and 4 percent each while sources in the remaining ten states each contributed 3 percent or less: Iowa, Indiana, Kansas, Kentucky, Nebraska Minnesota, Mississippi, South Dakota, Tennessee, and Wisconsin.

DEQ used the 2016 results from the AOI analysis to select stationary sources of $SO_2$ and $NO_X$ for consideration for four-factor analyses. DEQ calculated the cumulative percentage of AOI source impacts for each source and applied a screening threshold of 70 percent of the cumulative percentage of 2016 AOI source impacts for $NO_X$ and $SO_2$ combined.[76] Using this methodology, the stationary sources comprising 70 percent of the cumulative percentage of AOI source impacts at each Arkansas Class I area were identified for four-factor evaluation. The State reported five facilities in Arkansas (three EGU power plants and two non-EGU facilities) that were brought forward for further analysis by applying the 70 percent screening threshold: [77] White Bluff Power Plant, Independence Power Plant, FutureFuel Chemical Co., Domtar Ashdown Mill, and Flint Creek Power Plant. Out of Arkansas' total AOI sources impacts at Caney Creek—Independence, White Bluff, and Domtar contributed 16 percent out of the 23 percent Arkansas total state contributions (69 percent of total Arkansas impacts).[78] [79] Out of Arkansas' total AOI sources impacts at Upper Buffalo—Independence, White Bluff,

ending altitudes of 100 m, 200 m, 500 m, and 1000 m.

[70] A more sophisticated trajectory-based analysis technique combines emissions, ambient PM data, and trajectory information. Residence time represents the cumulative time that emission trajectories would reside in each 36-km by 36-km grid square. This approach selects sources for analysis using an approach that gives each point source a score that takes into account the source's emissions, the daily values of light extinction at a Class I area, the distance between the source and a Class I area, and the relative frequency with which wind trajectories indicate that each source is upwind of the IMPROVE monitoring site.

[71] The IMPROVE ''most anthropogenically impaired days'' data for 2017 was not available at the time the area of interest report was developed so the 2013–2017 period could not be used and the 2012–2016 period was used instead.

[72] The RHR has no specific guidance on threshold values for residence time, so Ramboll chose normalized percentages across selected Class I areas and altitudes that represented a reasonable range.

[73] *See* Figure II–12 in the 2022 Planning Period II SIP (page II–16) which shows each state's percent contribution to the total visibility impact surrogate from all stationary sources in the 2016 AOI for Caney Creek Wilderness Area.

[74] Iowa, Kansas, Kentucky, Minnesota, Mississippi, Nebraska, North Dakota, Tennessee, and Wisconsin all combined contributed 0.7 percent of the total visibility impact surrogate from all stationary sources.

[75] *See* Figure II–24 in the 2022 Planning Period II SIP (page II–27) which shows each state's percent contribution to the total visibility impact surrogate from all stationary sources in the 2016 AOI for Upper Buffalo Wilderness Area.

[76] *See* 2022 Planning Period II SIP Appendix C spreadsheet: 7AppC_Arkansas Source Screening Method Spreadsheet-v8.xlsx.

[77] *See* Table V–3 of 2022 Planning Period II SIP.

[78] *See* Figure II–12 in the 2022 Planning Period II SIP (page II–16) which shows each state's percent contributions to visibility impairment at Caney Creek Wilderness Area for all sources in the AOI.

[79] *See* 2022 Planning Period II SIP Appendix C spreadsheet 7AppC_Arkansas Source Screening Method Spreadsheet-v8.xlsx.

FutureFuel, and Flint Creek contributed 40 percent out of the 48 percent Arkansas total state contributions (85 percent of total Arkansas impacts).[80] [81]

DEQ reported that it also considered a higher threshold of 80 percent for source selection during the early stages of the SIP development process. The State noted that application of an 80 percent threshold would result in additional Arkansas sources being brought forward for analysis when compared to the 70 percent threshold, but those additional sources would not have the potential to meaningfully reduce contributions to visibility impairment because they would all have minimal visibility impacts relative to the sources selected. In contrast, the 70 percent threshold occurred at a natural break in the data distribution and included the highest contributors to visibility impairment at the Class I areas without ''unnecessarily'' bringing forward additional sources with minimal-impact for four-factor analysis. An 80 percent threshold would bring forward three additional Arkansas sources forward for Caney Creek—Weyerhaeuser NR Company-Dierks Mill, Albemarle Corporation-South Plant, and Ash Grove Cement Company—Foreman Cement Plant—but each would only contribute 1 percent or less to the AOI source impacts (1.13, 1.06, and 0.85 percent, respectively).[82] Similarly, an 80 percent threshold would bring forward six additional Arkansas sources forward for Upper Buffalo—Dunn Compressor Station, Domtar Ashdown Mill (which has already been selected for four-factor analysis due to impacts at Caney Creek), Green Bay Packaging-AR Kraft-Morrilton, Albemarle Corporation-South Plant, SGL Carbon, LLC, and Plum Point Energy Station Unit 1—but each would only contribute 0.5 percent or less to the AOI source impacts (0.53, 0.49, 0.48, 0.48, 0.46, and 0.43 percent, respectively).[83]

DEQ reported that the 70 percent threshold would also bring forward 18 sources in other states that impact Arkansas' Class I areas (*see* Table 6).[84] Therefore, DEQ considered those sources and sent out consultation letters (''ask'' letters) to those states where the 18 facilities are located and requested that those states consider whether performing a four-factor analysis was appropriate for each of those sources in accordance with 40 CFR 51.308(f)(2)(i); and, if so, whether any control measures for $SO_2$ or $NO_X$ would be necessary to make reasonable progress toward natural visibility at Caney Creek and Upper Buffalo during the second planning period. DEQ also requested that each state share with them the results of any analyses, including technical supporting documentation, and provide an opportunity for consultation on the analyses and each state's long-term strategy early enough in the process for DEQ to provide feedback. *See* section IV.C.4 of this action which discusses Consultation Requirements with States for further information.

TABLE 6—SOURCES IN OTHER STATES IMPACTING ARKANSAS' CLASS I AREAS

| State | Facility | Class I areas impacted |
|---|---|---|
| Texas | Martin Lake Electrical Station | —Caney Creek.<br>—Upper Buffalo. |
| | AEP Pirkey | —Caney Creek.<br>—Upper Buffalo. |
| | Welsh Power Plant | —Caney Creek<br>—Upper Buffalo. |
| | WA Parish Electric Generating Station | —Caney Creek. |
| Louisiana | CLECO Power LLC Dolet Hills | —Caney Creek.<br>—Upper Buffalo. |
| | Entergy Louisiana LLC—Roy S Nelson Plant | —Caney Creek. |
| Oklahoma | Muskogee Generating Station | —Caney Creek.<br>—Upper Buffalo. |
| | Hugo Generating Station | —Caney Creek.<br>—Upper Buffalo. |
| | Grand River Energy Center | —Upper Buffalo. |
| Missouri | Ameren Missouri Labadie Plant | —Upper Buffalo. |
| | Ameren Missouri Rush Island Plant | —Upper Buffalo. |
| | New Madrid Power Plant Marston | —Upper Buffalo. |
| | City Utilities of Springfield Missouri John Twitty Energy Center | —Upper Buffalo. |
| | Thomas Hill Energy Center Power Division | —Upper Buffalo. |
| Illinois | Prairie Generating Station | —Upper Buffalo. |
| Indiana | Indiana Michigan Power DBA AEP Rockport | —Upper Buffalo. |
| | Duke Energy Indiana LLC—Gibson Genera | —Upper Buffalo. |
| Kentucky | Tennessee Valley Authority (TVA)—Shawnee Fossil Plant | —Upper Buffalo. |

DEQ performed a source screening sensitivity analysis which omitted recently controlled or shut down $SO_2$ and $NO_X$ emissions sources in Oklahoma and Texas from the 2016 inventory in the AOI analysis to see if those changes (which occurred after 2016) would impact the source selection results while maintaining the remainder of the inventory.[85] Specifically, DEQ zeroed out the emissions of three major point sources in Texas that shutdown in 2018—the Sandow Steam Electric Station, the Big Brown Steam Electric Station, and Monticello Steam Electric Stations—and then used the 2019 emissions for the Muskogee and Sooner Generating Stations in Oklahoma to reflect $SO_2$ reductions from installed 2018 controls. DEQ performed this sensitivity analysis for each Class I area

[80] *See* Figure II–24 of the 2022 Planning Period II SIP (page II–27) which shows each state's percent contributions to visibility impairment at Upper Buffalo Wilderness Area for all sources in the AOI.

[81] *See* 2022 Planning Period II SIP Appendix C spreadsheet: 7AppC_Arkansas Source Screening Method Spreadsheet-v8.xlsx.

[82] *Id.*

[83] *Id.*

[84] *See* Table V–4 of 2022 Planning Period II SIP.

[85] *See* 2022 Planning Period II SIP Appendix E spreadsheet: AppE_AR Screening Method_V32_2016_InventoryOK_TX_Sensitivity_v9.xlsx.

that contained at least one Arkansas source in the 2016 AOI and at least one of the five revised emission sources. This included Caney Creek and Upper Buffalo in Arkansas, Hercules Glades in Missouri, and Wichita Mountains in Oklahoma. The State applied a 70 percent screening threshold to the cumulative percentage of AOI impacts for $NO_X$ and $SO_2$ combined based on the revised 2016 inventory. The AOI sensitivity analysis identified two additional Arkansas sources that would be brought forward for consideration for four-factor analysis based on adjustments to the 2016 inventory—Weyerhaeuser NR Company—Dierks Mill (Dierks Mill) and Albemarle Corporation—South Plant (Albemarle South). Dierks Mill is a sawmill that processes lumber and wood residuals. It is 40 km from Caney Creek and has one major $NO_X$ unit (100 tons per year (tpy) or greater) and none for $SO_2$. The $NO_X$ unit is a wood-fired boiler with a rate of 249.0 MMBtu/hr. Albemarle South is a chemical manufacturer that extracts bromine-containing brine from geologic formations. It has one major $SO_2$ emission unit (100 tpy or greater) and none for $NO_X$. Albemarle South burns tail gas from a sulfur recovery plant that removes sulfur from sour gas created from bromine separation from extracted brine. DEQ explained for Dierks Mill that the wood-fired boiler has not operated since 2017 and was removed from the permit in May 2020.[86] DEQ does not anticipate that retrofitting $NO_X$ post-combustion controls to be reasonable even if operation had continued at Dierks Mill. DEQ also explained that after a review of the RACT/BACT/LAER Clearinghouse (RBLC) database,[87] it could not identify technically feasible $SO_2$ controls for Albemarle South that could be implemented in conjunction with the existing tail gas incinerator. Based on this assessment, DEQ determined that the revised 2016 inventory used in the sensitivity analysis would not produce more potential for meaningfully reducing contributions from Arkansas sources at Caney Creek or Upper Buffalo. EPA notes that Dierks Mill and Albemarle South contribute 1.43 and 1.35 percent of the AOI source impacts at Caney Creek, and negligible AOI source impacts at Upper Buffalo (0.03 and 0 percent, respectively). Based on the State's assessment of the lack of technically feasible controls as well as low contributing emissions, DEQ concluded that source selection sensitivity adjustments would not make a difference in the sources that DEQ would analyze. Therefore, DEQ did not make adjustments to the emissions inventory used in the AOI analysis and its source selection methodology.

After considering all of the sources screened in the AOI study from the different thresholds applied, and after considering potential adjustments to the 2016 emission inventory used in the AOI analysis, DEQ selected five Arkansas facilities to be included for four-factor analysis (*see* Table 7). Originally, DEQ brought forward White Bluff in its list of sources selected for a full four-factor analysis from the 70 percent screening threshold. However, after a partial four-factor analysis evaluating the existing control measures for White Bluff, DEQ determined in its 2022 Planning Period II SIP submittal that existing control measures at White Bluff Power Plant are sufficient for reasonable progress (*see* section IV.C.2.a for more details).[88] For each selected facility, DEQ identified the emission units that emit $SO_2$ and/or $NO_X$ and identified existing controls in place at each emission unit.

TABLE 7—ARKANSAS SOURCES SELECTED FOR FOUR-FACTOR ANALYSIS AND EXISTING CONTROLS

| Facility | Class I areas impacted | Units | Existing $SO_2$ controls | Existing $NO_X$ controls |
|---|---|---|---|---|
| Entergy White Bluff Power Plant. | —Caney Creek<br>—Upper Buffalo.<br>—Hercules Glades. | Two Coal-fired EGU Boilers: (SN–01 and SN–02). | —Low Sulfur Coal<br>—0.60 lb/MMBtu $SO_2$ limit for each unit. | Low $NO_X$ Burners with Overfire Air. |
| Entergy Independence Power Plant. | —Upper Buffalo (26%)<br>—Hercules Glades (20%).<br>—Caney Creek (5%).<br>—Mingo (3%).<br>—Sipsey (1%). | Two Coal-Fired EGU Boilers: (SN–01 and SN–02). | Low Sulfur Coal | Low $NO_X$ Burners with Overfire Air. |
| FutureFuel Chemical Co | —Upper Buffalo (3%)<br>—Hercules Glades (2%).<br>—Caney Creek (<1%).<br>—Mingo (<1%).<br>—Sipsey (<1%). | Three Coal-Fired Industrial Boilers: (6M01–01). | None | None. |
| Domtar Ashdown Mill | —Caney Creek (5%)<br>—Upper Buffalo (<1%).<br>—Hercules Glades (<1%).<br>—Wichita Mtns (<1%). | No. 2 Power Boiler<br>No. 3 Power Boiler<br>No. 2 Recovery Boiler<br>No. 3 Recovery Boiler. | Venturi Scrubbers<br>None. | Overfire Air.<br><br>None. |
| SWEPCO Flint Creek Power Plant. | —Upper Buffalo (1%)<br>—Hercules Glades (1%).<br>—Caney Creek (<1%). | One Coal-Fired EGU Boiler (SN–01 Boiler). | —Novel Integrated Desulfurization (Dry FGD).<br>—0.06 lb/MMBtu $SO_2$ limit. | —Low $NO_X$ Burners with Overfire Air.<br>—0.23 lb/MMBtu. |

EPA finds that the State's source selection methodology and the criteria it used to determine which sources to select for four-factor evaluation is reasonable for the second implementation period. DEQ relied on a comprehensive robust approach for its source selection to identify the geographic areas with anthropogenic emission sources with a high probability of impacting visibility at the different Class I areas. DEQ used the EWRT*Q/d metric which is the most comprehensive residence time metric that combines visibility extinction values and also considers the distance-weighted emissions from the source to the Class I area. DEQ also relied on total

[86] *See* DEQ air permit No. 0023–AOP–R14 issued May 11, 2020.

[87] RACT, or Reasonably Available Control Technology, is required on existing sources in areas that are not meeting national ambient air quality standards (*i.e.,* non-attainment areas). BACT, or Best Available Control Technology, is required on major new or modified sources in clean areas (*i.e.,* attainment areas). LAER, or Lowest Achievable Emission Rate, is required on major new or modified sources in non-attainment areas.

[88] 2022 Planning Period II SIP (pages V–16 to 17).

visibility impact surrogate values for each source (summed EWRT*Q/d values for $NO_X$ and $SO_2$) in the areas of influence, which enabled the State to identify each state's percent contribution to visibility impairment and the respective sources that have the largest impact at each Class I area. DEQ appropriately selected five facilities in Arkansas (Entergy White Bluff, Entergy Independence, FutureFuel, Domtar Ashdown Mill, and Flint Creek) for further analysis of potential emission reduction controls and documented its rationale in selecting those sources after analyzing the total source impacts from all contributing sources in Ramboll's AOI source screening analysis. We find that the State adequately weighed its decision after considering all sources screened from two different applied thresholds (70 and 80 percent) and then considering potential emission adjustments to the 2016 inventory. The State determined that the 70 percent threshold was more reasonable compared to the 80 percent threshold because it occurred at a natural break in the distribution and included the highest contributors to visibility impairment at the Class I areas. The 70 percent threshold also did not ''unnecessarily'' bring forward minimal-impact sources for four-factor analysis like the 80 percent threshold did. Any additional sources added above a 70 percent threshold would only contribute 1 percent or less to the AOI source impacts at either of the two Arkansas Class I areas. The five facilities selected with the 70 percent threshold represented a high proportion of the emission impacts at each Class I area in Arkansas. EPA notes that these sources contributed 16 out of the 23 percent AOI source impacts at Caney Creek and 40 out of the 48 percent AOI source impacts at Upper Buffalo. DEQ also performed a source screening sensitivity analysis which omitted recently controlled or shut down $SO_2$ and $NO_X$ emissions sources in Oklahoma and Texas from the 2016 inventory, but those adjustments were not incorporated because they did not impact source selection. The two additional sources considered in the sensitivity analysis had minimal potential impacts relative to the five initially selected sources and the State did not identify any technically feasible controls for these two sources. These analyses show that the five sources brought forward from the 70 percent screening threshold represent a reasonable set of sources to evaluate for potential control within Arkansas.

3. Four Factor Analyses

For each facility selected to undergo four-factor analysis, the State identified potential emission reduction control strategies and asked each selected facility (through information collection request letters dated January 8, 2020)[89] to assess whether the identified controls by the State were technically feasible or not. If a strategy was not technically feasible, facilities were to provide a robust explanation explaining why.

For each technically feasible control, facilities were directed to provide information about the control effectiveness of each technology for each emission unit ranked from highest to lowest control efficiency (*i.e.,* percentage $SO_2$ and/or $NO_X$ reduced).[90] Facilities were asked to include resulting actual annual emission reduction estimates (in tpy) that would be achieved through implementation of each control strategy. This was determined by calculating the difference in baseline and controlled emission rates in pounds per hour (pph) or pounds per million British thermal units (lb/MMBtu). Facilities were asked to provide baseline emission rates annualized on a maximum monthly basis for the 2017–2019 period[91] to ensure that cost estimates would be based on appropriately sized equipment. DEQ also directed facilities to provide additional information for baseline emission rates annualized on an average monthly emission rate basis to estimate the typical emission reductions that may be achievable from each control. DEQ included a description of the criteria it required for the facilities to use to evaluate the four factors for each control measure being considered in its long-term strategy and the underlying assumptions for each factor.

For cost of compliance, DEQ instructed facilities to follow the EPA Pollution Control Cost Manual overnight methodology[92] which estimates capital costs, annual operating/maintenance costs, and annualized costs as if the project is completed ''overnight'' with no interest incurring during construction. Facilities expressed the costs in terms of annualized cost per ton of emissions reduced per year to compare the different control options for the same source and across different sources. DEQ noted that the amortization period should be based on the time between when the strategy could reasonably be in place and the remaining useful life of the emission control system. DEQ reviewed the cost per ton information provided by the facilities for the different identified control strategies and compared those results to different cost thresholds based on dollar per ton ($/ton) values that were incurred from past BART and reasonable progress determinations from the first planning period.[93] DEQ adjusted those $/ton values to 2019 dollars using the Chemical Engineering Plant Cost Index and then selected the 98th percentile[94] as the threshold for each emission unit type (see Table 8). The State selected the 98th percentile $/ton metric because it is a robust approach that does not give undue weight to the extreme tail of a distribution and ensures that costs that have incurred multiple times from the first planning period by sources of a similar type are captured. DEQ noted that the different thresholds consider how imposed costs are financed and how investments are recovered from the different emission unit types. DEQ originally proposed to use a bank prime rate of 3.25 percent after considering EPA comments received during the public comment period concerning the rate at the time, but because of more recent upward trends of the federal interest rate, DEQ revised its analyses and calculated the annualized capital costs using the information provided by the different facilities and a 7 percent interest rate.

[89] *See* Appendices F through I of the 2022 Planning Period II SIP for the regional haze four-factor analysis information collection requests by DEQ which includes the identified technologies to Independence, FutureFuel, Domtar, and Flint Creek. DEQ did not send an information collection request to White Bluff for the two coal-fired EGU Boilers (SN–01 and SN–02). As mentioned, after a partial four-factor analysis evaluating the existing control measures for White Bluff, DEQ determined in its 2022 Planning Period II SIP submittal that existing control measures at White Bluff Power Plant are sufficient for reasonable progress.

[90] From EPA Menu of Control Measures which provides states with information on a broad, though not comprehensive, listing of potential emissions reduction measures, as well as relevant information concerning the efficiency and cost effectiveness of the measures. *See https://www.epa.gov/sites/default/files/2016-02/menuofcontrolmeasures.xlsx.*

[91] A shorter baseline period (June 1, 2018–December 31, 2019) was provided for Flint Creek because construction of low $NO_X$ burners with separated over fire air was completed on May 18, 2018, which reduced $NO_X$ emissions from the SN–01 Boiler.

[92] *See* EPA Air Pollution Cost Control Manual Section 1—Introduction, Chapter 2—Cost Estimation: Concepts and Methodology (page 11). An alternate way of describing this method is the present value cost that would have to be paid as a lump sum up front to completely pay for a construction project.

[93] *See* spreadsheet in Appendix J of 2022 Planning Period II SIP called 7AppJ_DescStats_PP1 DetermCosts-v9.xlsx.

[94] The 98th percentile means that for a given distribution, it is equal to or higher than 98 percent of the rest of the distribution.

TABLE 8—COST EFFECTIVENESS THRESHOLDS FOR DIFFERENT EMISSION UNIT TYPES IN 2019 DOLLARS

| Equipment type | Cost threshold ($/ton—98th percentile) |
| --- | --- |
| EGU Boiler | 5,086 |
| Industrial Boiler | 3,328 |
| Kiln | 4,419 |
| Smelter | 1,041 |

For the time necessary for compliance, DEQ directed facilities to consider the time needed for a source to comply with a potential control measure and to justify the time needed to install a control measure as being reasonable. DEQ noted in its SIP submittal that a reasonable time period to establish a compliance deadline is one in which the source comes into compliance in an efficient manner without unusual amounts of overtime, above-market wages and prices, or premium charges for expedited delivery of control equipment. DEQ mentioned that, in addition to establishing compliance schedules, the time necessary for compliance may influence how capital costs of control measures are annualized if the remaining useful life of an emission unit is less than the life of the equipment involved.[95]

For remaining useful life, DEQ instructed facilities to follow the EPA Pollution Control Cost Manual on typical useful life values of various emission control systems or should be based on enforceable shutdown dates. DEQ noted that for purposes of its evaluation, the remaining useful life was factored into the cost of compliance. DEQ based the annualization of capital costs on the expected life of the equipment involved for the potential control measures under evaluation and consideration of any other requirements.[96]

For energy and non-air quality environmental impacts of compliance, DEQ directed facilities to factor any costs associated with these impacts into the cost of implementing the strategy, including without limitation: permitting costs if other regulatory requirements are triggered by the controls; costs associated with compliance with any other regulatory requirements triggered by the controls; and cost of waste disposal for wastes generated by proposed controls.

In addition to the four statutory factors, DEQ also included in its evaluation of potential controls the context of historical visibility improvement that has been achieved at the Arkansas' Class I areas, and future 2028 anticipated visibility impairment in those areas.[97]

The facilities responded to DEQ's information collection requests and provided reports with the requested information for each technically feasible control.[98] DEQ relied on the information provided in the facility reports in its 2022 Planning Period II SIP submittal and, based on the information provided, determined which control measures would be necessary for each facility to make reasonable progress for the second implementation period.

a. Entergy White Bluff Power Plant

*Facility Information.* DEQ selected the White Bluff Power Plant located in Jefferson County, Arkansas for further analysis. The State identified two boilers (SN–01 and SN–02 Boilers) as major sources that emitted a total of 18,336 tpy $SO_2$ emissions and a total of 9,719 tpy $NO_X$ emissions in 2016.

The boiler units are identical tangentially-fired 850 megawatt (MW) boilers that have a maximum heat input capacity of 8,950 MMBtu/hr. Both units burn sub-bituminous coal as a primary fuel and No. 2 fuel oil or bio-diesel as the startup fuel at a maximum rate of 1,000 MMBtu/hr. The boilers supply steam which feed turbine generators to produce electricity.

*Proposed Reasonable Progress Control Determination for Entergy White Bluff.* In the State's evaluation of controls for White Bluff,[99] DEQ reported that both boilers burn low-sulfur coal to control $SO_2$ emissions, are equipped with low $NO_X$ burners with separated overfire air to control $NO_X$ emissions, and are equipped with electrostatic precipitators[100] to control PM emissions. For $SO_2$ control, both boilers are subject to BART and are required to comply with an $SO_2$ emission limit of 0.60 lb/MMBtu for each boiler on a thirty-boiler-operating-day rolling average. This is based on fuel switching to lower sulfur coal by August 7, 2021, pursuant to an Administrative Order[101] between DEQ and Entergy as part of the approved 2018 Phase II SIP revision from the first planning period.[102] This state- and federally-enforceable Administrative Order incorporates the requirements of a Settlement Agreement and Consent Judgement (Consent Decree)[103] that resolves CAA claims brought by the Sierra Club. The Consent Decree and Administrative Order also require both boilers to cease coal-fired operations by no later than December 31, 2028, and was approved into the State's SIP as a source-specific SIP requirement in the first implementation period.[104] DEQ considered that enforceable requirement to cease coal-fired operations at White Bluff to be sufficient reason to not perform a four-factor analysis for this source for the second planning period. DEQ stated that additional $NO_X$ control measures beyond the low $NO_X$ burners and low sulfur coal, which have already been implemented at White Bluff to meet its obligations under CSAPR for $O_3$ season $NO_X$ allocations, are not cost-effective due to the plant's remaining useful life. The annual cost of control measures evaluated during the first planning period[105] would only be expected to increase in an updated reasonable progress analysis because White Bluff is nearer to its termination of coal-fired operations date than it was in the previous analysis. The technologies available to reduce $NO_X$ and $SO_2$ at power plants, such as White Bluff, have not changed since 2018. Because the low $NO_X$ burners installed at White Bluff cannot be shut down temporarily, being an inherent part of the equipment design, no separate emission limit is necessary for inclusion in the SIP to ensure operation of the low $NO_X$

[95] *See* 2022 Planning Period II SIP submittal (page V–15). *See also* 2019 Guidance at 45.

[96] *Id.*

[97] *See* 2022 Planning Period II SIP submittal (page V–16).

[98] *See* Appendices F through I of the 2022 Planning Period II SIP for the regional haze four-factor analysis information collection requests by DEQ and the corresponding responses including four-factor analyses for the identified technologies from Independence, FutureFuel, Domtar, and Flint Creek. As mentioned, after a partial four-factor analysis evaluating the existing control measures for White Bluff, DEQ determined in its 2022 Planning Period II SIP submittal that existing control measures at White Bluff Power Plant are sufficient for reasonable progress. Therefore, DEQ did not send an information collection request to White Bluff for the two coal-fired EGU Boilers (SN–01 and SN–02).

[99] *See* 2022 Planning Period II SIP (pages V–16 to V–17).

[100] *See* EPA Air Pollution Cost Control Manual Section 6—Particulate Matter Controls Chapter 3—Electrostatic Precipitators (page 3–4). An electrostatic precipitator is an air pollution control device that functions by electrostatically charging particles in a gas stream that passes through collection plates with wires. The ionized particulate matter is attracted to and deposited on the plates as the cleaner air passes through. A wet electrostatic precipitator is designed to operate with water vapor saturated air streams to remove liquid droplets such as sulfuric acid.

[101] *See* Administrative Order (LIS No. 18–073), dated August 7, 2018.

[102] *See* 84 FR 51033 (September 27, 2019) final approval.

[103] *Sierra Club and National Parks Conservation Association* v. *Entergy Arkansas, inc., Entergy Power, LLC, and Entergy Mississippi, Inc.* Case No. 4:18–cv–00854–KGB (ED Ark., March 11, 2021).

[104] *See* 84 FR 51033 (September 27, 2019).

[105] *Id.* at 51033, 51040.

burners. Lastly, if Entergy chooses to continue operations of the White Bluff units after December 31, 2028, they must apply for a permit revision to burn a different fuel. Such a permit revision would be subject to new source review (NSR) requirements. If the change would result in a significant increase in emissions, Prevention of Significant Deterioration (PSD) and BACT requirements would be triggered. The most likely fuel switch would be to natural gas, which inherently emits much less $SO_2$ and $NO_X$ relative to coal. Because of this reasoning, DEQ chose not to require White Bluff to perform additional analysis on potential control technologies.

DEQ considered the potential cost of controls and the remaining useful life of the SN–01 and SN–02 boilers and concluded that no additional analysis is required, and no additional measures are necessary to make reasonable progress for the second planning period at Entergy White Bluff. In addition, the projected 2028 visibility conditions at all Class I areas to which White Bluff contributes (Caney Creek, Upper Buffalo, and Hercules Glades) are all below their respective 2028 URP values. The EPA is proposing to find that Arkansas demonstrated that it is making reasonable progress for the second planning period without requiring any additional measures for White Bluff.

b. Entergy Independence Power Plant

*Facility Information:* DEQ selected the Entergy Independence Power Plant located in Independence County, Arkansas for further analysis. Two coal-fired boilers (SN–01 and SN–02) were identified by the State as major sources that emitted a total of 22,570 tpy $SO_2$ emissions and a total of 9,864 tpy $NO_X$ emissions in 2016. DEQ identified potential $SO_2$ and $NO_X$ control technologies for each of these boilers in its January 8, 2020, information collection request letter to Entergy Services LLC.[106]

The SN–01 and SN–02 Boilers are identical 900 MW boilers that were installed in 1978. The SN–01 Boiler was placed into operation in 1983, and the SN–02 Boiler was placed into operation in 1985. The boilers operate using sub-bituminous coal as their primary fuel and no. 2 fuel oil or bio-diesel as the start-up fuel. For $NO_X$ emissions, both boilers operate with low $NO_X$ burners and separated overfire air systems, which were installed in 2017 in order to assist the facility in meeting its obligations under CSAPR for $O_3$ season $NO_X$ allocations. The permit[107] contains limits of 6,090 pph $NO_X$ and 0.7 lb/MMBtu $NO_X$ that apply to both boilers. In addition, PM emissions are controlled with electrostatic precipitators and subject to a PSD limit of 0.04 lb/MMBtu.[108] $SO_2$ emissions are subject to a limit of 0.60 lb/MMBtu based on using low sulfur coal on a 30-boiler-operating-day averaging period, which became effective on August 7, 2021, and was incorporated into the SIP in the 2018 Phase II SIP revision from the first planning period.[109] CEMS measures $SO_2$ and $NO_X$ emissions for these boilers.

*Technically Feasible Controls.* Entergy responded to DEQ's information collection request in a response letter dated April 7, 2020 (revised on July 24, 2020),[110] which provided the facility's evaluation of seven potential controls identified by DEQ. Based on the information provided by Entergy, DEQ determined that four $SO_2$ control options and two $NO_X$ controls would be technically feasible for the boilers (*see* Table 9).

TABLE 9—IDENTIFIED CONTROLS AT ENTERGY INDEPENDENCE POWER PLANT FOR SN–01 AND SN–02 BOILERS AND FEASIBILITY DETERMINATIONS

| Unit | Pollutant controlled | Identified control technologies | Technically feasible? |
|---|---|---|---|
| SN–01 and 02 Boilers | $SO_2$ and $NO_X$ | Fuel Switch from Coal to Gas | No. |
| | $SO_2$ | Wet Flue Gas Desulfurization (WFGD)[111] | Yes. |
| | | Spray Dry Absorber (SDA)[112] | Yes. |
| | | Dry Sorbent Injection (DSI)[113] | Yes. |
| | | Enhanced DSI[114] | Yes. |
| | $NO_X$ | Select Catalytic Reduction (SCR)[115] | Yes. |
| | | Select Non-Catalytic Reduction (SNCR)[116] | Yes. |

[106] *See* Appendix F–1 of the document: 7AppF_ _Entergy Independence.pdf in Appendix F of the 2022 Planning Period II SIP for DEQ's Information Collection Request to Entergy Independence.

[107] *See* DEQ air permit No. 0449–AOP–R18 issued January 17, 2023.

[108] This limit is for total suspended particulate (TSP), but guidance makes clear that $PM_{10}$ is the appropriate metric for the Title V permit threshold since TSP is no longer a regulated pollutant. *See* EPA Memorandum from Deputy Director L.N. Wegman dated October 16, 1995: ''Definition of Regulated Pollutant for Particulate Matter for Purposes of Title V.''

[109] *See* 83 FR 5927 (February 12, 2018) final action. *See also* 82 FR 42627 (September 11, 2017) for the proposed approval.

[110] *See* Appendix F–2 of the document: 7AppF_ _Entergy Independence.pdf in Appendix F of 2022 Planning Period II SIP for the Entergy Independence Power Plant regional haze four-factor analysis response letter to DEQ prepared by Trinity Consultants (dated April 7, 2020). For follow up consultations and revisions (*see* Appendices F–3 to F–7), DEQ requested that Entergy Services LLC (July 21, 2020, email) review revised cost control calculations and Entergy provided feedback in a July 24, 2020, email with an updated version of the four factor analysis response to DEQ (dated July 23, 2020).

[111] *See* EPA Air Pollution Cost Control Manual (seventh edition) Section 5—$SO_2$ and Acid Gas Controls Chapter 1—Wet and Dry Scrubbers for Acid Gas Control (page 1–9 to 1–10). WFGD systems control $SO_2$ emissions using solutions containing alkali reagents or sorbents such as limestone, lime, sodium-based alkaline, or dual alkali-based sorbents. The sorbent reacts with the $SO_2$ and falls to the bottom of the absorber tower where it is collected and disposed of or recycled back into the system. WFGD systems generally have the highest control efficiencies. New WFGD systems can achieve $SO_2$ removal of 99 percent and HCl removal of over 95 percent. Packed tower WFGD systems may achieve efficiencies over 99 percent for some pollutant-solvent systems.

[112] *See* EPA Air Pollution Cost Control Manual (seventh edition) Section 5—$SO_2$ and Acid Gas Controls Chapter 1—Wet and Dry Scrubbers for Acid Gas Control (pages 1–4, 1–7, 1–10 to 1–11). SDA systems consist of an absorber vessel, a bag house filter, an absorbent feeding tank, and an absorbent feeding system. Absorbents such as lime and sodium bicarbonate are often used and sprayed as a slurry into an absorber vessel. At high temperatures, the water is rapidly vaporized and exits the stack. The absorbent reacts with the acidic gases in the waste stream to form a byproduct that is collected in a fabric filter. Spray dryers can achieve typical $SO_2$ removal efficiencies of 85–95 percent and up to 98 percent for new systems.

[113] *See* EPA Air Pollution Cost Control Manual (seventh edition) Section 5—$SO_2$ and Acid Gas Controls Chapter 1 (pages 1–11 to 1–12). DSI is a type of dry FGD system that is not a standalone, add-on air pollution control system but a modification to the combustion unit or ductwork where dry sorbent is injected directly into the furnace or into the ductwork following the furnace. Unlike the three other FGD systems, DSI can typically achieve $SO_2$ control efficiencies ranging from 50 to 70 percent and has been used in power plants, biomass boilers, and industrial applications.

Fuel switchin from coal to natural gas was determined to be not technically feasible because it would involve significant modifications to the plant that have not been demonstrated in similarly sized units. A switch to natural gas would also require constructing a new natural gas supply pipeline to serve the site. For these reasons, fuel switching to natural gas was not further evaluated as a potential control strategy.

*Control Effectiveness.* DEQ determined the anticipated emission reductions and control effectiveness for each of the six technically feasible control technologies identified for the SN–01 and SN–02 Boilers as presented in Entergy's report (*see* Table 10).[117] Entergy provided baseline $SO_2$ and $NO_X$ emission rates on both an annualized maximum monthly emission rate basis and an annualized average monthly emission rate basis from the baseline period of November 1, 2018, to December 31, 2019, for the SN–01 Boiler; and January 1, 2018, to December 31, 2019, for the SN–02 Boiler. The average monthly emission rate basis was used by DEQ to estimate the potential emission reductions.

TABLE 10—CONTROL EFFECTIVENESS AND EXPECTED EMISSION REDUCTIONS FOR THE TECHNICALLY FEASIBLE CONTROLS FOR THE SN–01 AND SN–02 BOILERS AT ENTERGY INDEPENDENCE POWER PLANT

| Unit | Identified technology | Pollutant | Control efficiency (%) † | Baseline rate (avg. monthly basis) (tpy) | Controlled rates | | Emission reduction (tpy) |
|---|---|---|---|---|---|---|---|
| | | | | | lb/MMBtu ** | tpy † | |
| SN–01 Boiler | WFGD | $SO_2$ | 92 | 9,945 | 0.04 | 841 | 9,104 |
| | SDA | | 87 | 9,945 | 0.06 | 1,261 | * 8,684 |
| | Enhanced DSI | | 68 | 9,945 | 0.15 | 3,153 | 6,792 |
| | DSI | | 26 | 9,945 | 0.35 | 7,358 | 2,587 |
| | SCR | $NO_X$ | 66 | 3,423 | 0.055 | 1,156 | 2,267 |
| | SNCR | | 20 | 3,423 | 0.13 | 2,733 | 690 |
| SN–02 Boiler | WFGD | $SO_2$ | 92 | 10,672 | 0.04 | 887 | 9,786 |
| | SDA | | 88 | 10,672 | 0.06 | 1,330 | 9,342 |
| | Enhanced DSI | | 69 | 10,672 | 0.15 | 3,325 | 7,347 |
| | DSI | $NO_X$ | 27 | 10,672 | 0.35 | 7,759 | 2,914 |
| | SCR | | 62 | 3,180 | 0.055 | 1,219 | 1,961 |
| | SNCR | | 9 | 3,180 | 0.13 | 2,882 | 298 |

* EPA corrected this value in the table which was a typo by the State. *See* the revised cost spreadsheet in Appendix F of the 2022 Planning Period II SIP: 7AppF_7 Entergy Independence Post-Comment Period Cost Calculation Revisions.xlsx.

** The bases for the controlled rates in lb/MMBtu were determined in previous analyses as stated in Entergy's revised July 2020 report (pages 2–2, 2–3, and 3–1) for WFGD,[118] SDA,[119] DSI and enhanced DSI,[120] and $NO_X$ Controls (SCR and SNCR).[121]

† EPA provided controlled rates in tpy (and resulting control efficiencies) from Entergy's revised report (pages 2–4 and 3–2) for a direct comparison to the baseline tpy values provided by DEQ in Table V–8 of the 2022 Planning Period II SIP.

*Cost of Compliance.* DEQ reviewed the cost information of the different identified control strategies provided by Entergy for the SN–01 and SN–02 Boilers and compared the $/ton values to DEQ's $5,086/ton cost threshold for EGU boilers (*see* Table 11). DEQ presented estimated costs for the control strategies using Entergy's assumptions for remaining useful life and equipment life in 2019 dollars.[122] Entergy

[114] DEQ considered DSI with and without a fabric filter in its SIP. ''Enhanced DSI'' refers to DSI with a fabric filter and ''DSI'' refers to DSI without a fabric filter.

[115] *See* EPA Air Pollution Cost Control Manual (seventh edition) Section 4—$NO_X$ Controls Chapter 2—Selective Catalytic Reduction (page 2–9). SCR systems include a $NH_3$ storage and delivery system, $NH_3$ injection grid, and a catalyst reactor. A nitrogen-based reducing agent, such as $NH_3$ or urea-derived $NH_3$, is injected into the post-combustion flue gas. The reagent reacts selectively with the flue gas $NO_X$ within a specific temperature range and in the presence of the catalyst and oxygen to reduce the $NO_X$ into molecular nitrogen ($N_2$) and water vapor. SCR systems can be designed for $NO_X$ removal efficiencies up close to 100 percent. In practice, commercial coal-, oil-, and natural gas-fired SCR systems are often designed to meet control targets of over 90 percent. However, the reduction may be less than 90 percent when SCR follows other $NO_X$ controls.

[116] *See* EPA Air Pollution Cost Control Manual (seventh edition) Section 4—$NO_X$ Controls Chapter 1—Selective Non-Catalytic Reduction (page 1–9). SNCR systems have similar equipment to reduce $NO_X$ emissions as SCR systems and both utilize a reagent like urea or $NH_3$, but SNCR relies on a higher flue gas temperature at the point of injection instead of a catalyst to reduce $NO_X$. Efficiencies typically range from 30–70%.

[117] *See* Tables V–7 and V–8 (pages V–19 to V–20) of the 2022 Planning Period II SIP.

[118] The controlled emission rate of 0.04 lb/MMBtu for WFGD is based on information presented in Entergy's October 2013 *Revised BART Five Factor Analysis for White Bluff Steam Electric Station* (pages 5–3 to 5–4), included in Appendix D of the Phase II SIP revision from the first planning period.

[119] The controlled emission rate for SDA is based on information presented in the following first planning documents: Entergy's August 18, 2017 *Updated BART Five-Factor Analysis for $SO_2$ for Unit 1 and 2,* (pages 4–1 to 4–3), included in Appendix D of the Phase II SIP revision from the first planning period; Sargent & Lundy's (S&L's) August 3, 2017 *White Bluff Dry FGD Cost Estimate and Technical Basis,* SL–01283, included in Appendix A of Entergy's 2020 response to DEQ's information collection request; and S&L's January 31, 2018 *Independence Dry FGD Cost Estimate and Technical Basis,* SL–014308, included in Appendix A of Entergy's 2020 response to DEQ's four-factor information collection request.

[120] The controlled emission rates for DSI and Enhanced DSI are based on information presented in the following first planning period documents: Entergy's August 2017 White Bluff BART report, (pages 4–1 to 4–3); S&L's August 3, 2017, *White Bluff DSI Cost Estimate Basis Document,* SL–014000, and *White Bluff Enhanced DSI Cost Estimate Basis Document,* SL–014001, included in Appendix A of Entergy's 2020 response to DEQ's four-factor information collection request.

[121] The controlled emission rates are based on information presented in Entergy's October 2013 White Bluff BART report, (pages 6–3 to 6–4), and S&L's May 16, 2013, *$NO_X$ Control Technology Cost and Performance Study, Entergy Services, Inc.—White Bluff and Lake Catherine,* SL–011439, which is included in Appendix B of Entergy's 2020 response to DEQ's four-factor information collection request.

[122] *See* Tables V–9 and V–10 (pages V–20 to V–22) of the 2022 Planning Period II SIP.

calculated the cost of compliance based on the assumption that the Independence units will cease coal-fired operations by a cessation date of December 31, 2030, as required in a Settlement Agreement and Consent Judgement (Consent Decree) that was entered between Entergy and Sierra Club.[123] Based on that cessation date, Entergy used 5.42 years remaining useful life for DSI and enhanced DSI; and 3.42 years remaining useful life for all other technologies after consideration of time necessary for compliance of the evaluated controls. DEQ also calculated annual costs based on the expected life of the control equipment in the event that these units would continue to operate with no assumed operation cessation date. For equipment life, Entergy used 30 years for WFGD, SDA, DSI, Enhanced DSI, and SCR; and 20 years for SNCR. In addition, DEQ revised its analyses and calculated the annualized capital costs using the information provided by Entergy and a 7 percent interest rate. Control cost calculations were completed using average-monthly baseline emission rates. Cost effectiveness was also evaluated based on an average of both boiler units because the units perform an identical function and have the same design.

TABLE 11—ESTIMATED COSTS OF CONTROL OPTIONS FOR SN–01 AND SN–02 BOILERS (ESCALATED TO 2019) *

| Unit | Control option | Total annual costs ($MM/year) ** | | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|
| | | Based on remaining useful life | Based on equipment life | Based on remaining useful life | Based on equipment life |
| SN–01 Boiler | WFGD | 173.97 | 69.43 | 19,109 | 7,627 |
| | SDA | 138.35 | 40.09 | 15,931 | 4,616 |
| | Enhanced DSI | 106.45 | 56.61 | 15,673 | 8,335 |
| | DSI | 56.92 | 30.93 | 22,001 | 11,955 |
| | SCR | 67.04 | 18.57 | 29,573 | 8,191 |
| | SNCR | 9.56 | 7.41 | 13,861 | 10,739 |
| SN–02 Boiler | WFGD | 173.97 | 69.43 | 17,778 | 7,095 |
| | SDA | 138.35 | 40.09 | 14,809 | 4,291 |
| | Enhanced DSI | 106.45 | 56.61 | 14,489 | 7,706 |
| | DSI | 56.92 | 30.93 | 19,532 | 10,613 |
| | SCR | 67.04 | 18.57 | 34,188 | 9,469 |
| | SNCR | 9.56 | 7.41 | 32,095 | 24,864 |
| Boiler Average | WFGD | | | 18,444 | 7,361 |
| | SDA | | | 15,370 | 4,454 |
| | Enhanced DSI | | | 15,081 | 8,020 |
| | DSI | | | 20,766 | 11,284 |
| | SCR | | | 31,881 | 8,830 |
| | SNCR | | | 22,978 | 17,802 |

* DEQ revised the cost and cost-effectiveness values obtained from Entergy's report. *See* spreadsheet in Appendix F of the 2022 Planning Period II SIP: 7AppF_7 Entergy Independence Post-Comment Period Cost Calculation Revisions.xlsx.
** The total annual cost values in Table V–9 of the 2022 Planning Period II SIP were transcribed incorrectly. EPA updated the values to reflect the total annual costs from the spreadsheet in Appendix F.

The cost effectiveness based on a 2030 cessation date to end coal operations was greater than the costs estimated based on the life of the different control equipment. Under the assumption of a 2030 cessation date, all of the $/ton values for each of the control strategies exceeded DEQ's $5,086/ton cost threshold for EGU boilers by a large margin. In comparison, the $/ton values based on equipment life all exceeded the cost threshold for EGU boilers except for SDA, which when averaged over both boiler units, had a cost effectiveness of $4,454/ton.

*Time Necessary for Compliance.* DEQ summarized the time estimates provided by Entergy that would be needed for the different control options and the basis for each (*see* Table 12).[124]

TABLE 12—TIME NEEDED TO COMPLY FOR CONTROL OPTIONS FOR SN–01 AND SN–02 BOILERS

| Control technology | Time for compliance (years) | Basis for compliance |
|---|---|---|
| WFGD<br>SDA | 5 | Time determined in 2016 FIP.[125] |
| Enhanced DSI<br>DSI | 3 | Similar estimate in other analyses (FutureFuel's response to DEQ).[126] |
| SCR<br>SNCR | 5 | Precedent in Utah and North Dakota FIPs.[127] |

[123] *Sierra Club and National Parks Conservation Association* v. *Entergy Arkansas, inc., Entergy Power, LLC, and Entergy Mississippi, Inc.* Case No. 4:18–cv–00854–KGB (ED Ark., March 11, 2021).

[124] *See* Table V–11 (page V–23) of the 2022 Planning Period II SIP.

[125] *See* FIP Proposal: 80 FR 18944, 18993 (April 8, 2015).

[126] *See* 2022 Planning Period II SIP Appendix G for the FutureFuel Chemical Company regional haze four-factor analysis response letter prepared by the facility.

[127] 77 FR 20894, 20944 (April 6, 2012) and 81 FR 43894, 43907 (July 5, 2016), respectively.

*The Energy and Non-Air Quality Environmental Impacts of Compliance.* DEQ reported that all of the $SO_2$ and $NO_X$ control options would require waste removal and additional power requirements that were both factored into the cost of compliance. WFGD and SDA require increased water usage. WFGD generates large volumes of wastewater and solid waste/sludge that must be managed and/or treated. SDA utilizes lime slurry that would generate PM emissions that must be controlled through use of a baghouse or ESP and then collected and disposed of through landfilling.[128] DSI processes would require substantial storage and transportation. DSI fly ash could not be resold for beneficial reuse due to the solubility of the sodium salts present in the waste. SCR would require the disposal of spent catalyst waste. SCR and SNCR systems would both require storage and transport of $NH_3$. Accidental release of unreacted $NH_3$ could react with $SO_4^{2-}$ and $NO_3^-$ in the atmosphere to form ammonium sulfate and ammonium nitrate which are the predominant sources of regional haze. SCR and SNCR would both require electricity from ancillary equipment that would increase electrical demand to operate the systems.

*Remaining Useful Life.* As discussed, DEQ used 5.42 years remaining useful life for DSI and enhanced DSI; and 3.42 years remaining useful life for all other control technologies to annualize capital and indirect costs. These assumptions were based on the time necessary for compliance and an assumed 2030 cessation date to end coal-fired operations at the SN–01 and SN–02 Boilers.[129] As mentioned, DEQ also evaluated the cost effectiveness based on equipment life of the different control equipment.[130] As part of the 2022 Planning Period II SIP submittal, DEQ included an Administrative Order[131] that it entered with Entergy that would render the requirement to cease coal-fired operations by no later than December 31, 2030, to be federally enforceable upon final approval by EPA. However, on July 29, 2025,[132] DEQ sent to EPA a letter determining that inclusion of the Administrative Order was not needed to fulfill the CAA and RHR requirements for the second planning period. DEQ requested in the letter for EPA to approve the remainder of the 2022 Planning Period II SIP submittal without the Administrative Order for Independence.

*Visibility Considerations.* DEQ also evaluated Entergy Independence's contribution to visibility impairment at the different Class I areas within and outside Arkansas alongside its consideration of the four statutory factors. DEQ noted that the AOI analysis indicated that emissions from Independence impacted five Class I areas (Caney Creek, Upper Buffalo, Hercules Glades, Mingo, and Sipsey) which are all on track to make greater progress than the URP glidepath in 2028, even before consideration of potential controls for Independence. Source apportionment from VISTAS modeling also indicated that Independence was projected to contribute 1.04 percent of the total $SO_4^{2-}$ point source visibility impacts and 0.01 percent of total $NO_3^-$ point source visibility impacts on the most impaired days in 2028 at Shining Rock. However, Shining Rock is also on track to make greater progress than the URP glidepath in 2028 before consideration of potential controls for Independence.

*Proposed Reasonable Progress Control Determination for Entergy Independence.* DEQ determined in its 2022 Planning Period II SIP and clarified in the July 29, 2025, letter to EPA that no additional controls are necessary for Entergy Independence to make reasonable progress during the second planning period. In making that determination, the 2022 Planning Period II SIP outlines how the four statutory factors were considered for control technologies that the State identified to reduce $SO_2$ and $NO_X$ emissions at the SN–01 and SN–02 Boilers. DEQ initially determined that additional controls would not be cost effective because the cost-effectiveness values for each control option, based on the required December 31, 2030, cessation date from the consent decree and Agreed Order, exceeded the cost threshold for EGU boilers. However, in its July 29, 2025, letter sent to EPA, DEQ indicated that after reconsidering its initial determination to include the Administrative Order (LIS No. 22–084) for Entergy Independence, the SIP submittal would meet the RHR and CAA requirements for the second planning period without the requirements contained in the Administrative Order. DEQ also noted in the letter that the Administrative Order's requirement to cease coal use at Entergy Independence by December 31, 2030, was previously set by a separate 2021 District Court order (Case No. 4:18cv854). In addition to DEQ's determination of no additional controls needed, DEQ noted in its 2022 Planning Period II SIP that all Class I areas for which Independence was within the AOI are on track to make greater reasonable progress than the URP glidepath in 2028 before any additional controls at Independence.

EPA is proposing to find that the State's determination of no additional controls for the SN–01 and SN–02 Boilers at the Entergy Independence Power Plant is reasonable and meets regional haze requirements for the second planning period. After appropriately identifying the boilers for potential controls, the State adequately took into consideration the four statutory factors on the selected control technologies and determined that the evaluated controls were not necessary to make reasonable progress for the second planning period. In addition to the four factor analyses of additional controls, the Class I areas (Upper Buffalo, Hercules Glades, Caney Creek, Mingo, Sipsey)[133] impacted by Entergy Independence are projected to be below their respective 2028 URP glidepath values with existing controls. Therefore, we are proposing to find that Arkansas demonstrated that it is making reasonable progress for the second planning period without requiring any additional controls for the Entergy Independence Power Plant.

c. FutureFuel Chemical Company

*Facility Information.* DEQ selected FutureFuel Chemical Company (FutureFuel), located in Batesville, Arkansas for further analysis. A three-

[128] Per Entergy's September 27, 2017, Analysis of Reasonable Progress Arkansas Regional Haze Program First Planning Period (''Entergy's September 2017 RP Report''), at 6–2, which is included in Appendix F of Phase II of the first planning period SIP revisions. Entergy has not indicated unusual circumstances that would create greater problems than experienced elsewhere that Dry FGD was utilized as BART. *See also* the 2018 Phase II SIP revision at 52.

[129] *See* 2022 Planning Period II SIP Appendix F for Entergy's revised July 23, 2020, response to DEQ's Four-Factor Analysis information collection request (page 2–4 and 3–2). These remaining useful life estimates were based on Entergy's assumption of an EPA approved SIP by July 31, 2022. The SIP is projected to be approved beyond this date so the cost-effectiveness numbers will be even higher than estimated in the SIP.

[130] For equipment life, Entergy used 30 years for WFGD, SDA, DSI, Enhanced DSI, and SCR; and 20 years for SNCR.

[131] *See* Administrative Order (LIS No. 22–084) dated August 2, 2022, and included as part of the 2022 Planning Period II SIP submittal.

[132] *See* letter sent to EPA from DEQ signed by Secretary Khoury (dated July 28, 2025) and included in the docket of this action.

[133] *See* the 2022 Planning Period II SIP (page V–24). The Entergy Independence Power Plant visibility surrogate value was 26 percent of the total source impacts for the Upper Buffalo AOI and 20 percent for the Hercules Glades AOI. Caney Creek, Mingo, and Sipsey AOI total source impacts were each impacted by 5 percent, 3 percent, and 1 percent, respectively, by Independence. *See also* 2022 Planning Period II SIP Appendix C spreadsheet: 7AppC_Arkansas Source Screening Method Spreadsheet-v8.xlsx.

boiler system (collectively known as 6M01–01) was identified by the State as a source that emitted a total of 2,132 tpy $SO_2$ emissions and a total of 323 tpy $NO_X$ emissions in 2016.[134] DEQ identified potential $SO_2$ and $NO_X$ control technologies for each of the three boilers in its January 8, 2020, information request letter to the facility.[135]

The three-boiler system was installed in 1975, and each boiler is rated for 70 MMBtu/hr. All three boilers share a common primary fuel conveying system, a common ash handling system, and a common 200 ft tall stack. The three boilers are balanced draft, coal-fired steam generation boilers that have been fitted with atomizing nozzles to facilitate burning of liquid chemical wastes. Each coal fired boiler is equipped with its own ESP to control PM emissions. The units do not have existing $SO_2$ or $NO_X$ emission controls but are subject to emission limits for the three-boiler system of 1,391 pph $SO_2$ (5,982.9 tpy) and 106 pph $NO_X$ (488.2 tpy), contained in the facility's permit.[136] FutureFuel is also subject to a permit condition that prohibits combustion of coal with sulfur content greater than 3.8 percent by weight. The three coal fired boilers are also subject to 40 CFR part 63, subpart EEE, National Emission Standards for Hazardous Air Pollutants (NESHAP) from Hazardous Waste Combustors. Due to size and installation date, these boilers are not subject to any of the NSPS requirements.

*Technically Feasible Controls.* FutureFuel responded to DEQ's information collection request in a response letter dated April 7, 2020 (with follow up consultations),[137] which provided the facility's evaluation of 15 potential controls identified by DEQ. Based on the information provided by FutureFuel, DEQ determined that 12 of the control measures would be technically feasible for the boilers (*see* Table 13).

TABLE 13—IDENTIFIED CONTROLS FOR THREE COAL FIRED BOILERS AT FUTUREFUEL AND FEASIBILITY DETERMINATIONS

| Pollutant controlled | Identified technology | | Technically feasible? |
|---|---|---|---|
| $SO_2$ and $NO_X$ | Fuel Switch from Coal to Gas | Retrofit 1 boiler | yes |
| | | Retrofit 3 boilers | yes |
| | | Replace 1 boiler | yes |
| | | Replace 3 boilers | yes |
| $SO_2$ | Scrubber Strategies | WFGD with Lime Slurry | yes |
| | | WFGD with Sodium Hydroxide (NaOH) | no |
| | | SDA | yes |
| | | DSI | yes |
| | Fuel Switch to Low Sulfur Coal | 2.5% Sulfur Content | yes. |
| | | 2.0% Sulfur Content | yes |
| | | 1.5% Sulfur Content | yes |
| | | Less than 1.5% Sulfur Content | no |
| $NO_X$ | Post Combustion Control of Flue Gas | SCR | yes |
| | | SNCR | yes |
| | | Low-$NO_X$ Burners | no |

Three of the controls were not technically feasible. DEQ concluded that WFGD utilizing NaOH reagent to scrub $SO_2$ gas in the exit stream was technically infeasible because the facility could exceed its National Pollution Discharge Elimination System (NPDES) $SO_4^{2-}$ permit limit of 70,000 ppd by 3,000 ppd due to salt formation from NaOH addition. DEQ noted that it could accommodate the additional 3,000 ppd $SO_4^{2-}$ with a permit modification but decided to assess lime slurry instead as an alternative reagent since it is similar in cost and efficiency as NaOH. DEQ noted that it considers its assessment of WFGD with lime slurry as sufficient to apply to both reagents. DEQ determined that fuel switching to low sulfur coal with a sulfur content less than 1.5 percent was technically infeasible after considering three coal supply options. FutureFuel considered low sulfur coal from a nearby plant (0.5 percent sulfur content), coal from Wyoming Powder River Basin, and coal from Uinta Basin. The local plant and the Powder River Basin coal supplies were not usable for stoker style boilers because their heating values and fusion temperatures are less than the design requirements of FutureFuel's three coal-fired boilers which requires at least 11,000 Btu/lb and a minimum temperature of 2,550 °F. Uinta Basin coal supply had a sufficient heating value, but the coal did not meet the minimum required fusion temperature and the distance of the plant would require trucking fleet upgrades. Lastly, after reviewing the RBLC database, DEQ determined that low $NO_X$ burners were technically infeasible because they have not been implemented for industrial coal fired stoker boilers as part of NSR. In addition, low $NO_X$ burners are not listed as an available control strategy for industrial coal-fired stoker boilers in EPA's Air Pollution Control Cost Manual.[138]

*Control Effectiveness.* DEQ determined the anticipated emission reductions and control effectiveness for each technically feasible control

[134] The three boilers emit 99 percent of the $SO_2$ and 72 percent of the $NO_X$ from the facility There are other emission units that emit $SO_2$ and $NO_X$, or both including: two natural gas-fired boilers, a regenerative thermal oxidizer, thermal oxidizers and caustic scrubbers, a chemical waste destructor, a flare, two hot oil systems, a diesel glycol pump, two diesel waste disposal pumps, a diesel generator, and a diesel fire water pump.

[135] *See* Appendix G–1 of the document: 7AppG_ _FutureFuel_4-factor.pdf in Appendix G of the 2022 Planning Period II SIP for DEQ's Information Collection Request to Futurefuel Chemical Company.

[136] *See* DEQ air permit No. 1085–AOP–R–16 issued June 21, 2023.

[137] *See* Appendix G–2 of the document: 7AppG_ _FutureFuel_4-factor.pdf in Appendix G of the 2022 Planning Period II SIP for the FutureFuel Chemical Company regional haze four-factor analysis response letter prepared by the facility. For follow up consultations (*see* Appendices G–3 to G–7), DEQ requested FutureFuel (July 20, 2020, email) to review the cost and cost-effectiveness calculations; provide additional technical justifications regarding the NPDES limit for the WFGD option; and provide feedback for not choosing low sulfur coal less than 1.5 percent. The facility provided feedback in a July 23, 2020, email.

[138] *See* EPA Air Pollution Cost Control Manual Section 4—$NO_X$ Controls Chapter 1—Selective Non-Catalytic Reduction (page 1–2). Table 1.2, which identifies no available urea-based SNCR for stoker-fired.

[139] *See* Table V–12 (page V–29) of the 2022 Planning Period II SIP.

technology identified for the three coal-fired boilers (*see* Table 14).[139] FutureFuel provided baseline $SO_2$ and $NO_X$ emission rates annualized on both a maximum monthly emission rate basis and an annualized average monthly emission rate basis for the baseline period 2017–2019. Maximum monthly emissions are used to ensure that cost estimates for control technologies have appropriately sized equipment. DEQ used the annualized average monthly emission rate basis to estimate the potential emission reductions for each identified control technology. The average baseline emissions rates for the three coal-fired boilers were calculated to be 2,171 tpy $SO_2$ and 247 tpy $NO_X$.

TABLE 14—CONTROL EFFECTIVENESS AND EXPECTED EMISSION REDUCTIONS FOR POTENTIAL CONTROLS FOR THE THREE BOILER SYSTEM

| Identified technology | Control efficiency (%) | | Baseline rate avg. monthly basis (tpy) | | Emission reductions (tpy) | | |
|---|---|---|---|---|---|---|---|
| | $SO_2$ | $NO_X$ | $SO_2$ | $NO_X$ | $SO_2$ | $NO_X$ | Both |
| Fuel Switch from Coal to Gas: * | | | | | | | |
| Retrofit 1 boiler ** | 32 | 30 | 2,171 | 247 | 690 | 74 | 764 |
| Retrofit 3 boilers | 99 | 90 | 2,171 | 247 | 2,149 | 222 | 2,371 |
| Replace 1 boiler ** | 32 | 30 | 2,171 | 247 | 690 | 74 | 764 |
| Replace 3 boilers | 99 | 90 | 2,171 | 247 | 2,149 | 222 | 2,371 |
| Scrubber Strategies: | | | | | | | |
| WFGD with Lime Slurry | 94 | N/A | 2,171 | N/A | 2,041 | N/A | 2,041 |
| SDA | 92 | N/A | 2,171 | N/A | 1,997 | N/A | 1,997 |
| DSI | 40 | N/A | 2,171 | N/A | 868 | N/A | 868 |
| Fuel Switch to Low Sulfur Coal: | | | | | | | |
| 2.5% Sulfur | 10 | N/A | 2,171 | N/A | 215 | N/A | 215 |
| 2.0% Sulfur | 27 | N/A | 2,171 | N/A | 591 | N/A | 591 |
| 1.5% Sulfur | 44 | N/A | 2,171 | N/A | 966 | N/A | 966 |
| Post Combustion Control: | | | | | | | |
| SCR | N/A | 80 | N/A | 247 | N/A | 197 | 197 |
| SNCR | N/A | 40 | N/A | 247 | N/A | 99 | 99 |

* DEQ revised the cost of fuel for natural gas scenarios to reflect the incremental change in cost of using natural gas compared to coals currently in use for boilers based on EIA data. *See* FutureFuel's revised cost spreadsheets in Appendix G of the 2022 Planning Period II SIP: 7AppG_7_Futurefuel Post-Comment Period Cost Calculation Revisions.xlsx.

** The $SO_2$ emissions are estimated from fuel usage records based on feed stream analysis that assumes all sulfur entering the boilers through fuel is emitted as $SO_2$. The average emission rate for coal burned was 5.1 lb/MMBtu (2,092 tons) and the average emission rate for all fuels burned during the baseline was 4.6 lb/MMBtu (2,171 tons). For the option of retrofitting or replacing one boiler for natural gas, DEQ took the baseline rate of 2,092 tpy for 'coal burned' and multiplied that by a 33 percent control efficiency to give 690 tpy $SO_2$ reduced. DEQ then applied the baseline rate of 2,171 tpy 'for all fuels burned' to determine the $SO_2$ control efficiency for these options: 690 tpy ÷ 2,171 tpy = 32 percent. Note that the values are rounded. *See* spreadsheet in Appendix G of the 2022 Planning Period II SIP for details.

*Cost of Compliance.* DEQ reviewed the cost information of the different identified control strategies provided by FutureFuel for the three coal-fired boilers and compared the $/ton values to DEQ's $3,328/ton cost threshold for industrial boilers (*see* Table 15).[140] DEQ revised its analyses and calculated the annualized capital costs using the information provided by FutureFuel and a 7 percent interest rate. After consultation with EPA and other states, DEQ also calculated cost-effectiveness based on annual average emission rates for the three coil-fired boilers instead of a max monthly basis. DEQ made various revisions to the cost calculations provided by FutureFuel for consistency with the EPA control cost manual and similar technology assessments made during the first planning period for regional haze:[141]

- Contingency costs were revised to 20 percent of total capital investment.[142]
- AFUDC and owner's costs were removed consistent with EPA Control Cost Manual overnight estimation methodology.[143]
- All line-item costs estimated using total capital investment were revised to reflect changes in contingency and removal of the disallowed costs.[144]
- The cost of fuel for natural gas scenarios was revised to reflect the incremental change in cost of using natural gas compared to coal currently in use for boilers based on EIA data. The costs associated with electrical, maintenance, operating and support labor, permitting and compliance were removed because they do not represent cost increases above the current cost of using coal.[145]
- Costs for each lower sulfur content coal scenario were revised to reflect the incremental cost of the scenario above current costs for coal. The tax associated with the 1.5 percent sulfur coal control scenario was adjusted to remove cost of transportation from the taxable amount and costs were adjusted to reflect the incremental increase in cost above current stocks for each of the lower sulfur coal strategies (2.5, 2, and 1.5 percent).[146]
- Lastly, equipment life for each control technology was revised to be consistent with EPA control cost manual and similar technology assessments made during the first planning period for regional haze.[147]

[140] *See* Tables V–13 and V–14 (pages V–31 to V–32) of the 2022 Planning Period II SIP.

[141] *See* FutureFuel's revised cost spreadsheets in Appendix G of the 2022 Planning Period II SIP: 7AppG_7_Futurefuel Post-Comment Period Cost Calculation Revisions.xlsx.

[142] The EPA Control Cost Manual (Chapter 2, page 30) suggests using 20 percent of total capital investment for contingency for study level cost estimates and 5–15 percent for "mature control technologies."

[143] EPA Control Cost Manual overnight estimation methodology (Chapter 2, pages 11 and 17).

[144] Using formulas provided by the EPA Control Cost Manual (Chapter 2, page 35): Administrative costs = 2 percent of capital investment; Property tax = 1 percent of capital investment; Insurance = 1 percent of capital investment.

[145] *See* email from Philip Antici on July 23, 2020, in Appendix G for follow-up consultation about cost and cost-effectiveness.

[146] *See* email from Philip Antici on 7/23/2020 in Appendix G for follow-up consultation about cost and cost-effectiveness; *see also* spreadsheet titled 7AppG–5_FutureFuel Baseline Heat Input.xlsx

[147] WFGD: 30 years; SDA: 30 years; DSI: 30 years; SCR: 30 years; and SNCR: 20 years.

TABLE 15—ESTIMATED COSTS OF CONTROLS OF THREE COAL-FIRED BOILERS (ESCALATED TO 2019) [148]

| Identified technology | Annualized capital investment ($/year) ** | Annual operating & maintenance costs ($/year) ** | Indirect annual costs ($/year) ** | Total annual costs ($/year) | Cost effectiveness ($/ton) |
|---|---|---|---|---|---|
| Fuel Switch from Coal to Gas: | | | | | |
| Retrofit 1 boiler | 532,814 | 8,267,445 | 280,024 | 9,080,283 | † 11,881 |
| Retrofit 3 boilers | 1,029,535 | 24,758,948 | 588,801 | 26,377,284 | † 11,124 |
| Replace 1 boiler | 680,133 | 8,267,445 | 353,147 | 9,300,725 | † 12,170 |
| Replace 3 boilers | 1,082,258 | 24,758,948 | 614,970 | 26,456,177 | † 11,156 |
| Scrubber Strategies: | | | | | |
| WFGD with Lime Slurry | 5,594,635 | 3,043,215 | 4,388,002 | 13,025,851 | 6,383 |
| SDA | 4,808,346 | 2,067,599 | 3,384,422 | 10,260,367 | 5,137 |
| DSI | 4,737,737 | 921,467 | 2,643,393 | 8,302,597 | 9,561 |
| Fuel Switch to Low Sulfur Coal: | | | | | |
| 2.5% Sulfur | N/A | 738,720 | N/A | ‡ 738,720 | 3,430 |
| 2.0% Sulfur | N/A | 1,282,500 | N/A | ‡ 1,282,500 | 2,171 |
| 1.5% Sulfur | N/A | 2,679,500 | N/A | ‡ 2,679,500 | 2,774 |
| Post Combustion Control: | | | | | |
| SCR | 3,725,537 | 541,053 | 1,992,806 | 6,259,396 | 31,720 |
| SNCR | * 2,424,063 | 413,695 | 6,584 | * 2,844,342 | * 28,828 |

* EPA is correcting these cost values to reflect the revised 20-year life instead for SNCR. DEQ mentioned revising the SNCR cost values to reflect a 20-year life but reported the cost/ton values in Table V–14 (page V–32) of the 2022 Planning Period II SIP using a 30-year life instead.

** EPA is including these columns from DEQ's revised cost spreadsheet to give a breakdown of the total costs.

† DEQ reported the cost/ton values for fuel switching from coal to gas for $SO_2$ only in Table V–14 (page V–31) of the 2022 Planning Period II SIP. EPA is correcting these to reflect combined $SO_2$ and $NO_X$ values in DEQ's revised cost spreadsheet in Appendix G.

‡ DEQ provided total annual cost calculations for switching to low sulfur coal based on quotes from coal brokers in $/ton for each coal ($13.68/ton for 2.5 percent sulfur coal; $23.75/ton for 2 percent sulfur coal; and $50.39/ton for 1.5 percent sulfur coal) and assuming a max usage of 50,000 tons each and an 8 percent usage tax. For example, 2 percent sulfur coal total annual cost = $23.75/ton × 50,000 tons × 1.08 = $1,282,500/year.

The cost effectiveness values showed that fuel switching to 2 percent sulfur content coal and fuel switching to 1.5 percent sulfur content coal were below DEQ's $3,328/ton cost threshold for industrial boilers and were found to be cost-effective strategies for FutureFuel. The $/ton values of all other potential control strategies were above DEQ's cost threshold. DEQ concluded that switching to 2 percent sulfur content coal was the most cost-effective strategy. However, after discussions with FutureFuel representatives and consideration of public comments received on the proposed SIP, DEQ concluded that a commitment by FutureFuel to switch to 1.5 percent sulfur content coal also offered a cost-effective control with even greater visibility benefits for Upper Buffalo and Hercules Glades Class I areas.

*Time Necessary for Compliance.* DEQ reviewed the time estimates provided by FutureFuel that would be needed for the different control options to meet compliance deadlines for the three coal-fired boilers and provided the times of compliance that were reasonable along with the basis for each (*see* Table 16).[149]

TABLE 16—TIME NEEDED TO COMPLY FOR CONTROL OPTIONS FOR THE COAL-FIRED BOILERS

| Identified technology | Time for compliance (years) | Basis for compliance |
|---|---|---|
| Fuel Switch from Coal to Gas: | | |
| Retrofit one boiler | 2 | • All options require time for engineering design, DEQ review and approval, and logistics for shipping waste off-site. |
| Replace one boiler | | • Retrofitting options also require time for demolition of old feed system, installation of natural gas system, and optimization. |
| Retrofit all three boilers | 4 | • Replacing options also require time for equipment fabrication, delivery, and construction. |
| Replace all three boilers | 2.5 | |
| $SO_2$ Scrubber Strategies: | | |
| WFGD with Lime Slurry | 6 | Time for engineering design, DEQ review and approval, vendor and equipment selection, demolition, delivery, construction, training, and startup. |
| SDA | 4 | |
| DSI | 3 | |
| Fuel Switch to Low Sulfur Coal: | | |
| 2.5% Sulfur | 3 | Time to complete contracts and exhaust existing coal stockpile. |
| 2.0% Sulfur | | |
| 1.5% Sulfur | | |
| $NO_X$ Post Combustion Controls: | | |

[148] DEQ revised the cost values obtained from FutureFuel's report in response to public comments. *See* DEQ's revised cost spreadsheet in Appendix G of the 2022 Planning Period II SIP: 7AppG_7_Futurefuel Post-Comment Period Cost Calculation Revisions.xlsx.

[149] *See* Table V–15 (pages V–32 to V–33) of the 2022 Planning Period II SIP.

TABLE 16—TIME NEEDED TO COMPLY FOR CONTROL OPTIONS FOR THE COAL-FIRED BOILERS—Continued

| Identified technology | Time for compliance (years) | Basis for compliance |
|---|---|---|
| SCR<br>SNCR | * 4 | Time necessary for engineering design, DEQ review and approval, vendor and equipment selection, demolition or movement of an existing building, purchase and installation of equipment, training, and start-up. |

* This was recommended as 5 years in FutureFuel's Response to DEQ in Appendix G of 2022 Planning Period II SIP (pages 43 and 46).

*The Energy and Non-Air Quality Environmental Impacts of Compliance.* DEQ reported that all of the control strategies except fuel-switching to lower sulfur coal would require waste disposal and would impact the boiler system's ability to burn waste for energy recovery. The impacted waste recovery costs and waste removal costs (including hazardous waste closure costs) were all factored into the cost of compliance for each control strategy. Fuel switching to gas would require solvent wastes that produce steam, including hazardous waste, to be shipped off-site for disposal. All three $SO_2$ scrubber strategies and both $NO_X$ controls would require renting portable gas boilers for tie-ins during installation and shipping unburned wastes off-site. Additionally, WFGD would require lime slurry removal while SDA and DSI would require spent sorbent disposal.

*Remaining Useful Life.* DEQ reported that since there is no enforceable limit on the useful life of the three coal-fired boilers, FutureFuel revised the remaining useful life of each control technology evaluated to be consistent with the EPA control cost manual and similar technology assessments made during the first planning period. FutureFuel annualized the total capital investment based on the following recommended equipment life of each control strategy: WFGD: 30 years; SDA: 30 years; DSI: 30 years; SCR: 30 years; and SNCR: 20 years.

*Visibility Considerations.* DEQ evaluated FutureFuel's contribution to visibility impairment at the different Class I areas within and outside Arkansas alongside its consideration of the four statutory factors. DEQ noted that the AOI analysis indicated that emissions from FutureFuel impacted five Class I areas (Caney Creek, Upper Buffalo, Hercules Glades, Mingo, and Sipsey) which are all on track to make greater progress than the URP glidepath in 2028, even before consideration of potential controls for FutureFuel. FutureFuel did not meet the distance-weighted screening threshold of 0.05 percent for Mammoth Cave or Wichita Mountains. FutureFuel was not identified as a source reasonably anticipated to contribute to visibility impairment at other Class I areas by modeling from other RPOs.

*Proposed Reasonable Progress Control Determination for FutureFuel Chemical Company.* DEQ determined in its 2022 Planning Period II SIP that fuel switching from coal with 3 percent sulfur content by weight to a low sulfur coal with 1.5 percent sulfur content (equating to 2.93 lb/MMBtu $SO_2$) for the three coal-fired boilers (SN:6M01–01) would be reasonable to ensure continued progress toward natural visibility conditions for the second regional haze planning period. DEQ's determination was based on considering the four statutory factors on the control technologies that the State identified to reduce $SO_2$ and $NO_X$ emissions at the three-boiler system. The State put particular emphasis on the cost of controls because the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and remaining useful life were all factored into the cost of compliance. The State noted that all of the control strategies except fuel switching exceeded DEQ's cost threshold of $3,328/ton for industrial boilers. DEQ determined that fuel switching offers a cost-effective control that results in improved visibility benefits for Upper Buffalo and Hercules Glades Class I areas; and also allows for greater reasonable progress than projected in Arkansas's RPGs. DEQ entered into an Administrative Order [150] with FutureFuel that would render the use of 1.5 percent sulfur content coal and the resulting $SO_2$ emission limit enforceable by DEQ, which would become federally enforceable by EPA upon approval of the 2022 Planning Period II SIP. DEQ included a contingency in the Administrative Order that allows for a time-limited temporary variance. In the event that coal that meets the prescribed sulfur concentration and other boiler requirements becomes temporarily unavailable to FutureFuel, 2 percent sulfur content coal (equating to 3.69 lb/MMBtu $SO_2$) shall be used to temporarily satisfy the RHR requirements during the period that coal meeting a limit of 2.93 lb/MMBtu $SO_2$ is unavailable.

EPA is proposing to find that the State's determination of switching to 1.5 percent sulfur content coal (equal to 2.93 lb/MMBtu $SO_2$) for the three coal-fired boilers (SN:6M01–01) at the FutureFuel plant is reasonable and meets regional haze requirements for the second planning period. After appropriately identifying the three boilers for potential controls, the State adequately took into consideration the four statutory factors on the selected control technologies. The State sufficiently determined that all of the evaluated controls for these three boilers except fuel switching to low sulfur coal were not cost effective because all other $/ton values exceeded DEQ's $3,328/ton cost threshold for industrial boilers. The $3,328/ton threshold was based on $/ton values incurred from past BART and reasonable progress determinations from the first planning period and represents the 98th percentile of all costs incurred by sources to control emissions for that timeframe.[151] The cost effectiveness of this fuel switch option was estimated by DEQ to be $2,774/ton. Therefore, we are proposing to find that the determination by the State to implement a switch to low sulfur coal with 1.5 percent sulfur content is reasonable and demonstrates reasonable progress for the second planning period.

This control option of fuel switching to coal with 1.5 percent sulfur content has also been made enforceable by the State through an Administrative Order that has been adopted and incorporated in the 2022 Planning Period II SIP revision.[152] We are proposing to approve the State's Administrative Order into the Arkansas SIP which will

[150] *See* Administrative Order (LIS No. 22–085) dated August 3, 2022, and included as part of the 2022 Planning Period II SIP submittal.

[151] *See* spreadsheet in Appendix J of 2022 Planning Period II SIP called 7AppJ_DescStats_PP1 DetermCosts-v9.xlsx.

[152] *See* Administrative Order (LIS No. 22–085) dated August 3, 2022, included as part of the 2022 Planning Period II SIP revision.

make the switch to 1.5 percent sulfur content coal and the $SO_2$ emission limit of 2.93 lb/MMBtu at the three coal-fired boilers (SN:6M01–01) federally enforceable upon approval of the 2022 Planning Period II SIP revision. The Administrative Order contains the compliance demonstration requirements for the 1.5 percent sulfur content coal which will be based on fuel usage records and feed stream analysis. It also includes demonstration requirements for a temporary variance to use 2 percent sulfur content coal during periods that coal meeting a limit of 2.93 lb/MMBtu $SO_2$ is unavailable. We are proposing to approve all of the specific provisions in the Administrative Order for the three coal-fired boilers (SN:6M01–01) as source-specific SIP requirements as part of the 2022 Planning Period II SIP revision.

d. Domtar Ashdown Mill

*Facility Information.* DEQ selected the Domtar Ashdown Mill located in Ashdown, Arkansas for further analysis. Four boilers were identified by the State (No. 2 Power Boiler, No. 3 Power Boiler, No. 2 Recovery Boiler, and No. 3 Recovery Boiler) as existing major sources [153] that emitted a total of 1,550 tpy $SO_2$ emissions and a total of 2,238 tpy $NO_X$ emissions in 2016. DEQ identified potential $SO_2$ and $NO_X$ control technologies for each of the four boilers in its January 8, 2020, information request letter to the facility (*see* Table 17).[154]

The No. 2 Power Boiler was installed in 1975 and has a heat input rating of 820 MMBtu/hr with possible steam generation ranging from 100,000–300,000 pph. The No. 2 Power Boiler falls under the ''biomass hybrid suspension grate'' subcategory for the Boiler MACT at 40 CFR part 63, subpart DDDDD–NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. It is capable of burning a variety of fuels including coal, petroleum coke, tire derived fuel,[155] natural gas, clean cellulosic biomass (*e.g.,* bark, wood residuals, and other woody biomass materials), and wood chips used to absorb oil spills. It is equipped with a traveling grate,[156] a combustion air system that includes over-fire air, multi-clones for $PM_{10}$ removal,[157] and two venturi scrubbers in parallel for removal of $SO_2$ and remaining particulates.[158] The No. 2 Power Boiler was subject to BART for the first planning period and DEQ finalized a BART alternative that included limits for the No. 1 and No. 2 Power Boilers in the 2019 Phase III SIP revision. EPA approved that BART alternative (86 FR 15104) to replace the 2016 FIP BART limits [159] on March 22, 2021 (effective on April 12, 2021), making them federally enforceable. The BART alternative limits are also specified in the permit for the facility.[160] The BART alternative limits for the No. 1 Power Boiler are 5.2 pph $PM_{10}$, 0.5 pph $SO_2$, and 191.1 pph NOx; and for the No. 2 Power Boiler are 81.6 pph $PM_{10}$, 435 pph $SO_2$, and 293 pph $NO_X$. The No. 2 Power Boiler's actual 2016 emissions were 1,453 tpy $SO_2$ and 528 tpy $NO_X$.

The No. 3 Power Boiler was originally a recovery boiler, but was converted to a power boiler in 1990–91 and has a heat input rating of 790 MMBtu/hr with possible steam generation ranging 100,000–300,000 pph. It also falls under the ''biomass hybrid suspension grate'' subcategory for the Boiler MACT at 40 CFR part 63, subpart DDDDD–NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. It is capable of burning a variety of fuels (except coal) including clean cellulosic biomass (*e.g.,* bark, wood residuals, and other woody biomass materials), wood chips used to absorb oil spills, tire derived fuel, and natural gas. Currently, the No.3 Power Boiler does not burn any non-condensable gases (including VOCs). It is equipped with a moving grate (hydragrate), combustion air system including over fire air, and a two chamber ESP for PM control. The No. 3 Power Boiler does not have existing combustion or post-combustion controls for $NO_X$ or $SO_2$. However, the No. 3 Power Boiler is subject to emission limits of 0.30 lb/MMBtu $NO_X$ and 0.10 lb/MMBtu $SO_2$ in the Ashdown Mill permit. The No. 3 Power Boiler's actual 2016 emissions were 44 tpy $SO_2$ and 189 tpy $NO_X$.

The No. 2 and 3 Recovery Boilers were both last modified in 1989 and have heat input capacities of 1,160 MMBtu/hr and 1,088 MMBtu/hr, respectively. Each recovery boiler combusts black liquor solids to recover inorganic chemicals and natural gas. Neither recovery boiler has any combustion or post-combustion controls for $NO_X$ or $SO_2$. The No. 2 Recovery Boiler is equipped with an ESP for PM control and is subject to emission limits of 309.2 pph NOx and 286 pph $SO_2$ in the Ashdown Mill permit. The No. 3 Recovery Boiler is subject to emission limits of 270 pph NOx and 425 pph $SO_2$ in the permit. The No. 2 and 3 Recovery Boiler's actual 2016 emissions for $SO_2$ were 1.2 and 1.1tpy; and for $NO_X$ were 485 and 589 tpy, respectively.

*Technically Feasible Controls.* The Domtar Ashdown Mill responded to DEQ's information collection request in a response letter dated April 6, 2020 (revised on May 7, 2020, and August 14, 2020),[161] which provided the facility's evaluation of five potential $SO_2$ scrubber options and 12 potential $NO_X$ control options identified by DEQ for the four boilers. Based on the information provided by the Domtar Ashdown Mill, DEQ determined that four of the $SO_2$ scrubber controls and two of the $NO_X$ controls would be technically feasible for the No. 2 and No. 3 Power Boilers (*see* Table 17).

[153] This facility is considered an existing major source under 40 CFR 52.21, PSD regulations because the facility is a Kraft Pulp Mill (one of the 28 listed industrial source categories) and has the potential to emit more than 100 tpy of a regulated NSR pollutant.

[154] *See* Appendix H–1 of the document: 7AppH__Domtar Ashdown Mill_4-factor-v9.pdf in Appendix H of the 2022 Planning Period II SIP for DEQ's Information Collection Request to the Domtar Ashdown Mill.

[155] These are tires that are not discarded and are managed under the oversight of established tire collection programs.

[156] A traveling grate is a moving grate used to feed fuel to the boiler for combustion.

[157] A cyclone separator is an air pollution control device shaped like a conical tube that creates an air vortex as air moves through it causing larger particles ($PM_{10}$) to settle as the cleaner air passes through. Multi-clones are a sequence of cyclone separators in parallel used to treat a higher volume of air. In this particular case, the cleaner air travels to the venturi scrubbers to remove the smaller remaining particles like $PM_{2.5}$ and $SO_2$.

[158] The two scrubbers operate in parallel to control $SO_2$ and particulate emissions by absorption and chemical reaction with scrubbing fluid composed of NaOH, water, and pulp mill extraction stage filtrate.

[159] *See* FIP final action on September 27, 2016 (81 FR 66332) as corrected on October 4, 2016 (81 FR 68319).

[160] *See* current DEQ Air Permit No. 0287–AOP–R24 issued June 23, 2022, which renewed Permit No. 0287–AOP–R23 issued April 15, 2020.

[161] *See* Appendices H–2 to H–4 of the document: 7AppH__Domtar Ashdown Mill_4-factor-v9.pdf in Appendix H of the 2022 Planning Period II SIP for the Domtar Ashdown Mill regional haze four-factor analysis response letter to DEQ prepared by Trinity Consultants (dated April 6, 2020, and revised on May 7, 2020, to update emission reductions to be based on actual hours of operation and include average emission rate for baseline period). For follow-up consultations and revisions (*see* Appendices H–5 to H–6), DEQ requested (July 20, 2020, email) that Domtar review revised control efficiency and cost assumptions made by the State and Domtar provided feedback in a July 24, 2020, email. Domtar submitted another revised four factor response letter to DEQ on August 14, 2020.

TABLE 17—IDENTIFIED CONTROLS AT DOMTAR ASHDOWN MILL AND FEASIBILITY DETERMINATIONS

| Units | $SO_2$ controls | | $NO_X$ controls | |
|---|---|---|---|---|
| | Identified technology | Technically feasible? | Identified technology | Technically feasible? |
| No. 2 Power Boiler | Install new add-on spray scrubber downstream of existing venturi scrubbers. | yes | SCR | no |
| | Increase reagent usage in existing venturi scrubbers. | | Regenerative SCR (RSCR) [162]. | |
| | Upgrade existing venturi scrubbers | no | SNCR | yes * |
| No. 3 Power Boiler | WFGD | yes | SCR | no |
| | SDA. | | RSCR. | |
| | | | SNCR | yes |
| No. 2 Recovery Boiler | None | N/A | SCR | no |
| | | | RSCR. | |
| | | | SNCR. | |
| No. 3 Recovery Boiler | None | N/A | SCR | no |
| | | | RSCR. | |
| | | | SNCR. | |

* DEQ noted that while SNCR is technically feasible for the No. 2 Power Boiler, the emission reduction capability of this technology is limited due to the wide variability in temperature at the unit.

DEQ concluded that none of the other potential $SO_2$ and $NO_X$ controls for the four boilers were technically feasible. Specifically, the $SO_2$ control option to upgrade the existing venturi scrubbers at the No. 2 Power Boiler was not considered further because that option does not provide for any quantifiable decrease in $SO_2$ emissions. For both power boilers, SCR was determined to be technically infeasible in a previous analysis submitted in the first planning period; [163] and RSCR was determined to be technically infeasible since there is no comparable-type emission unit successfully implemented, and also because there are space and temperature constraints at the mill. DEQ determined that SCR, RSCR, and SNCR were not technically feasible for the recovery boilers based on information available in EPA's RBLC Clearinghouse, the National Council for Air and Stream Improvement information (NCASI),[164] and Trinity Consultants' library of air pollution control assessments. An RBLC query indicated that SCR and SNCR have not been applied to recovery boilers before.[165] DEQ reported that complex chemical reactions could potentially damage the system, and there could be potential difficulty injecting SNCR reagent due to varying loading. Although DEQ's information collection request did not list any specific $SO_2$ emission reduction options for consideration for the recovery boilers, Domtar's report considered FGD. DEQ concluded from the report that FGD was not technically feasible for the recovery boilers either because it is capital-intensive, energy-intensive, and its efficacy is unproven when considering the generally low but rapidly fluctuating levels of $SO_2$ in the kraft recovery furnace flue gases. Because no technically feasible control technologies were identified for the No. 2 and 3 Recovery Boilers, DEQ did not perform additional analysis for those emission units for emission reductions, control effectiveness, or characterizing the four reasonable progress factors.

*Control Effectiveness.* DEQ determined the anticipated emission reductions and control effectiveness for each technically feasible control technology identified for the No. 2 and No. 3 Power Boilers (*see* Table 18).[166] Domtar presented monthly average $SO_2$ and $NO_X$ emission rates from 2017–2019 for the boilers based on CEMS records. Domtar provided baseline emission rates on both an annualized maximum monthly emission rate basis and an annualized average monthly emission rate basis from the baseline period of 2017–2019. The average monthly emission rate basis was used by DEQ to estimate the potential emission reductions.

TABLE 18—CONTROL EFFECTIVENESS AND EXPECTED EMISSION REDUCTIONS FOR POTENTIAL CONTROLS FOR THE NO. 2 AND 3 POWER BOILERS

| Unit | Identified technology | Pollutant | Control efficiency (%) | Baseline rate (avg. monthly basis) (tpy) | Controlled rate (tpy) | Emission reductions (tpy) |
|---|---|---|---|---|---|---|
| No. 2 Power Boiler | New scrubber downstream | $SO_2$ | 90 | ** 858.9 | * 279.8 | 579.1 |
| | Increase reagent in existing venturi scrubbers. | | 90 | ** 858.9 | * 279.8 | 579.1 |
| | SNCR | $NO_X$ | † 3 | 559.9 | 543.1 | 16.8 |
| | | | ‡ 27.5 | 559.9 | 406 | 154 |

[162] RSCR, also known as tail-end SCR, is placed downstream of a PM control device. It incorporates a regenerator which pre-heats the cool gas stream from the PM control device outlet before it enters the RSCR using the RSCR outlet gas that has been heated to within the optimal SCR temperature range. Space constraints often make retrofitting with an RSCR impossible.

[163] *See* 7AppH__Domtar Ashdown Mill_4-factor-v9.pdf in Appendix H of the 2022 Planning Period II SIP for the relevant first planning period SIP package information related to the No. 2 Power Boiler $SO_2$ emission reduction options (at 127–133 and 510–512) included as Appendix A to that report.

[164] NCASI Handbook of Environmental Regulations and Control, Volume 1: Pulp and Paper Manufacturing, April 2013, Sections 6.8.3.3 and 6.8.3.4.

[165] RBLC searches were completed on February 3, 2020, for Process Types 30.211, 30.219, 30.290, 11.190, 11.290, and 11.900 and for process names that include the word "recovery."

[166] *See* Tables V–16 and V–17 (pages V–40 to V–41) of the 2022 Planning Period II SIP.

TABLE 18—CONTROL EFFECTIVENESS AND EXPECTED EMISSION REDUCTIONS FOR POTENTIAL CONTROLS FOR THE NO. 2 AND 3 POWER BOILERS—Continued

| Unit | Identified technology | Pollutant | Control efficiency (%) | Baseline rate (avg. monthly basis) (tpy) | Controlled rate (tpy) | Emission reductions (tpy) |
|---|---|---|---|---|---|---|
| No. 3 Power Boiler | WFGD | $SO_2$ | 90 | 46.9 | 4.7 | 42.2 |
| | SDA | | 90 | 46.9 | 4.7 | 42.2 |
| | SNCR | $NO_X$ | 3 | 290.1 | 281.4 | 8.7 |
| | | | ‡27.5 | 290.1 | 210.3 | 79.8 |

* Based on calculations presented in the February 2015 Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze FIP (2015 FIP TSD), (page 120). The controlled emission rate calculation for the two scrubber options for the No. 2 Power Boiler are the same as described by EPA in the 2015 FIP TSD: 858.9 tpy ÷ (1–0.693) × (1–0.90) = 279.8 tpy.

** DEQ reported the baseline emissions of 858.9 tpy $SO_2$ as already representing 69.3 percent control from uncontrolled $SO_2$ emissions of approximately 2,800 tpy $SO_2$.[167] Therefore, 90 percent overall control represents 20.7 percent more emission reduction (579.1 tpy) than is currently being achieved for a total reduction of 2,520 tpy $SO_2$ from the uncontrolled rate. The 579.1 tpy $SO_2$ reduced represents an effective incremental control efficiency of 67 percent from the current 858.9 $SO_2$ baseline.

‡ DEQ performed a sensitivity case study using a 27.5 percent control efficiency assumption which was used in the EPA 2016 FIP but was determined to be infeasible. Using this efficiency could result in stack emissions of 1,700 tpy or greater of unreacted urea due to variability in exit gas temperature that limits when an SNCR system can function.

† This was based on assumptions from the 2015 FIP TSD (page 120) that recommended operating the boiler at 40 percent efficiency for 7 percent of the total boiler operating time. EPA concluded that because of the wide variability in steam demand and wide range in furnace temperature observed at Power Boiler No. 2, the $NO_X$ control efficiency of SNCR at the boiler would not reach optimal control levels on a long-term basis. Therefore, there was uncertainty as to the level of control efficiency that SNCR would be able to achieve on a long-term basis for Power Boiler No. 2.

*Cost of Compliance.* DEQ reviewed the cost information of the different identified control strategies provided by Domtar for the No. 2 and 3 Power Boilers and compared the $/ton values to DEQ's $3,328/ton cost threshold for industrial boilers (*see* Table 19).[168] DEQ revised its analyses and calculated the annualized capital costs using the information provided by Domtar and a 7 percent interest rate.

TABLE 19—ESTIMATED COSTS OF CONTROL OPTIONS FOR NO. 2 AND 3 POWER BOILERS

[Escalated to 2019]

| Unit | Control option | Annualized capital costs ($/year) | Annual direct and indirect/operations and maintenance costs ($/year) | Total annual costs ($/year) | Cost effectiveness ($/ton) * |
|---|---|---|---|---|---|
| No. 2 Power Boiler | New scrubber downstream | 609,722 | 9,759,619 | 10,369,341 | 17,914 |
| | Increased reagent at existing scrubbers | 16,996 | 2,066,829 | 2,083,824 | 3,600 |
| | SNCR—3% option | 99,390 | 294,560 | 393,950 | 25,129 |
| | SNCR—27.5% option | 793,042 | 263,545 | 1,056,587 | 6,862 |
| No. 3 Power Boiler | WFGD—low | 2,452,158 | 973,726 | 3,425,883 | 81,182 |
| | WFGD—high | 14,712,946 | 2,190,883 | 16,903,828 | 400,565 |
| | SDA—low | 2,942,589 | 1,217,157 | 4,159,746 | 98,572 |
| | SDA—high | 14,712,946 | 36,514,710 | 51,227,655 | 1,213,925 |
| | SNCR—3% option | 99,390 | 294,560 | 393,950 | 48,499 |
| | SNCR—27.5% option | 793,042 | 263,545 | 1,056,587 | 13,244 |

* DEQ revised the cost-effectiveness values obtained from Domtar's report post comment period utilizing a 7 percent interest rate (changed back from 3.25 percent). *See* Domtar cost spreadsheet in Appendix H of the 2022 Planning Period II SIP: 7AppH_7_Domtar Ashdown Mill_Post Comment Period Revised Cost Calculations.xlsx.

DEQ reported that all of the $/ton values for the control strategies exceeded DEQ's $3,328/ton cost threshold for industrial boilers.

*Time Necessary for Compliance.* DEQ presented the time estimates provided by Domtar that would be needed for the different control options to meet compliance deadlines for the No. 2 and 3 Power Boilers and the basis for each (*see* Table 20).[169]

[167] *See* spreadsheet 7AppH_7_Domtar Ashdown Mill_Post Comment Period Revised Cost Calculations.xlsx in Appendix H of 2022 Planning Period II SIP.

[168] *See* Table V–18 (page V–42) of 2022 Planning Period II SIP.

[169] *See* Table V–19 (pages V–42 to V–43) of the 2022 Planning Period II SIP.

TABLE 20—TIME NEEDED TO COMPLY FOR CONTROL OPTIONS FOR NO. 2 AND 3 POWER BOILERS

| Unit | Control technology | Time for compliance (years) | Basis for compliance |
| --- | --- | --- | --- |
| No. 2 Power Boiler | New scrubber downstream | 3 | • Both options require an 18-month outage for No. 2 Power Boiler. |
| | Increased reagent at existing venturi scrubbers. | 2 | • The new scrubber option also requires 34 weeks for shipment and construction. • The increased reagent option also requires time to procure and install two new pumps. |
| | SNCR | 5 | Precedent in Utah and North Dakota FIPs.[170] |
| No. 3 Power Boiler | WFGD | 5 | Determinations for numerous SIPs for the first planning period. |
| | SDA | | |
| | SNCR | 5 | Precedent in Utah and North Dakota FIPs. |

*The Energy and Non-Air Quality Environmental Impacts of Compliance.* DEQ reported that installation of a new scrubber downstream of the existing scrubber would increase water usage and wastewater generation and also require additional power requirements. These were all factored into the cost of compliance. Energy and non-air quality impacts from increased reagent usage at the existing scrubbers are expected to be minimal. For WFGD or SDA, Entergy noted that the inherent scrubbing option represents no new energy or non-air quality environmental impacts.[171] For SNCR, Entergy noted that storage and handling of $NH_3$/urea is required.[172] DEQ noted that accidental release of unreacted urea could be emitted through the stack if operated outside of the optimal temperature window that is effective for only 7 percent of the boiler operating time.

*Remaining Useful Life.* DEQ reported that Domtar has no plans to cease operations of the No. 2 and 3 Power Boilers. The useful life values of the different control equipment (WFGD: 30 years; SDA: 30 years; and SNCR: 20 years) were determined from EPA's Air Pollution Control Costs Manual. The capital costs were annualized over amortization periods based on these respective useful life values and then added to the annual operating costs to determine the total annual costs.

*Visibility Considerations.* DEQ also evaluated Domtar Ashdown Mill's contribution to visibility impairment at the different Class I areas within and outside Arkansas alongside its consideration of the four statutory factors. DEQ noted that the AOI analysis indicated that emissions from Domtar are anticipated to only contribute to Caney Creek which is on track to make greater progress than the URP glidepath in 2028, even before consideration of potential controls for Domtar. Three other Class I areas (Hercules Glades, Upper Buffalo, and Wichita Mountains) were impacted by less than 1 percent each and are not anticipated to have significant contributions to visibility impairment.

*Proposed Reasonable Progress Control Determination for Domtar Ashdown Mill.* DEQ determined in its 2022 Planning Period II SIP that no additional controls are necessary for the Domtar Ashdown Mill to make reasonable progress during the second planning period. DEQ's determination was based on considering the four reasonable progress factors on the control technologies that the State identified to reduce $SO_2$ and $NO_X$ emissions at the No. 2 and 3 Power Boilers; and the No. 2 and 3 Recovery Boilers. The State put particular emphasis on the cost of controls and noted that all of the control strategies evaluated for the Domtar Ashdown Mill exceed DEQ's cost threshold of $3,328/ton for industrial boilers. While the State emphasized cost, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and remaining useful life were all factored into the cost of compliance factor. In addition to DEQ's four-factor evaluation, the State concluded that the impacts from Domtar Ashdown Mill are smaller relative to other point sources.

EPA is proposing to find that the State's determination of no additional controls for the two power boilers at the Domtar Ashdown Mill is reasonable and meets regional haze requirements for the second planning period. Based on DEQ's consideration of the four statutory factors in its assessment of potential additional controls for reasonable progress and because the projected 2028 visibility conditions for the affected Class I areas are below the 2028 URP glidepath values, Arkansas demonstrated reasonable progress toward the national visibility goal for the second planning period. After appropriately identifying the two power boilers (the recovery boilers were eliminated from consideration) for potential controls, the State adequately took into consideration the four statutory factors on the selected control technologies and determined that none of the evaluated controls were cost effective because each $/ton value evaluated exceeded DEQ's $3,328/ton cost threshold for industrial boilers. In addition to the four factor analyses of additional controls, the projected 2028 visibility improvement at the Class I areas (Caney Creek, Hercules Glades, Upper Buffalo, and Wichita Mountains)[173] impacted by the Domtar Ashdown Mill are all on track to make greater progress and be below their respective 2028 URP glidepath values with existing controls. Therefore, we are proposing to find that Arkansas demonstrated that it is making reasonable progress for the second planning period without requiring any additional controls for the Domtar Ashdown Mill.

e. SWEPCO Flint Creek Power Plant

*Facility Information.* DEQ selected the Flint Creek Power Plant located in Gentry, Arkansas for further analysis. One coal-fired boiler (SN–01) was identified by the State as a major source that emitted a total of 3,056 tpy $NO_X$ emissions and a total of 1,637 tpy $SO_2$ in 2016. DEQ identified potential $SO_2$

[170] 77 FR 20894, 20944 (April 6, 2012) and 81 FR 43894, 43907 (July 5, 2016), respectively.

[171] *See* Appendices H–2 in Appendix H of 7AppH__Domtar Ashdown Mill_4-factor-v9.pdf of the 2022 Planning Period II SIP (page 4–3).

[172] *See* Appendices H–2 in Appendix H of 7AppH__Domtar Ashdown Mill_4-factor-v9.pdf of the 2022 Planning Period II SIP (page 3–4).

[173] *See* the 2022 Planning Period II SIP (page V–43). The Domtar Ashdown Mill visibility surrogate value was 5 percent of the total source impacts for Caney Creek's AOI, while it impacted the AOI's for Hercules Glades, Upper Buffalo, and Wichita Mountains by less than 1 percent each. *See also* 2022 Planning Period II SIP Appendix C spreadsheet: 7AppC_Arkansas Source Screening Method Spreadsheet-v8.xlsx.

and $NO_X$ control technologies for this boiler in its January 8, 2020, information request letter to the Flint Creek Power Plant.[174]

The SN–01 Boiler is a dry bottom wall-fired boiler that utilizes pulverized coal combustion technology to produce steam that generates a nominal 558 megawatts (MW) of electricity to operate a turbine generator. The boiler primarily burns low sulfur coal, but can also combust fuel oil and tire-derived fuels. The SWEPCO boiler is equipped with low-NOx burners with separated overfire air to control NOx emissions (completed May 8, 2018) in order to assist the facility in meeting its obligations under CSAPR for $O_3$ season $NO_X$ allocations; dry FGD with a pulse jet fabric filter and activated carbon injection to control $SO_2$ emissions; and electrostatic precipitators to control PM emissions. The SWEPCO boiler is subject to BART and an $SO_2$ emission limit of 0.06 lb/MMBtu on a thirty-day rolling average. This $SO_2$ BART limit was established in EPA's 2016 FIP and was replaced with the State's own identical limit after final approval of the Phase II SIP revision from the first implementation period.[175] Flint Creek is subject to a NOx emission limit of 4,426.8 pph in its permit.[176] However, the low-NOx burners with over-fire air are guaranteed to achieve an emission rate of 0.23 lb/MMBtu or less. DEQ noted that because the low NOx burners are an inherent part of equipment design, they cannot be shut down temporarily, as is the case with a post-combustion control.

*Technically Feasible Controls.* SWEPCO responded to DEQ's information collection request in a response letter dated March 25, 2020 (with follow up consultations),[177] which provided the facility's evaluation of two potential $NO_X$ controls (SCR and SNCR) identified by DEQ. Based on the information provided by SWEPCO, DEQ determined that both $NO_X$ control measures would be technically feasible for the SN–01 Boiler to make reasonable progress for the second implementation period.

DEQ determined that no further analysis of potential $SO_2$ controls was necessary for the second planning period based on existing $SO_2$ controls and limits contained in the Arkansas SIP.[178] The SN–01 Boiler already operates under a more stringent $SO_2$ BART limit of 0.06 lb/MMBtu than the 0.2 lb/MMBtu limit specified in the 2012 Mercury Air Toxics Standards (MATS) rule.[179] DEQ concluded that it is unlikely that an analysis of control measures for a source already equipped with a scrubber and meeting the MATS limit would conclude that an even more stringent control of $SO_2$ is necessary to make reasonable progress. Therefore, DEQ's information request focused solely on potential $NO_X$ emission control strategies.

*Control Effectiveness.* DEQ determined the anticipated emission reductions and control effectiveness for each technically feasible control identified for the SN–01 Boiler (*see* Table 21).[180] Based on monthly data in EPA's Air Markets Program Data (AMPD) from the period between June 1, 2018, to December 31, 2019, for the SN–01 Boiler, SWEPCO provided baseline $NO_X$ emission rates on both an annualized maximum monthly emission rate basis and an annualized average monthly emission rate basis. The average monthly baseline emission rate of 0.186 lb/MMBtu (or 2,868 tpy) was used by DEQ in the 2022 Planning Period II SIP to estimate potential emission reductions. This baseline rate represents the rate achieved in practice after installation of low $NO_X$ burners with overfire air on May 8, 2018. Additionally, for the purpose of calculating the control cost estimates, the maximum monthly total emissions (0.2 lb/MMBtu) value during the baseline period was used.

TABLE 21—CONTROL EFFECTIVENESS AND EXPECTED $NO_X$ EMISSION REDUCTIONS FOR POTENTIAL CONTROLS FOR THE SN–01 BOILER [181]

| Identified technology | Control efficiency (%)* | $NO_X$ baseline rate (Avg Monthly Basis) | | $NO_X$ controlled rate (lb/MMBtu)** | $NO_X$ emission reductions (tpy) |
|---|---|---|---|---|---|
| | | (tpy) | (lb/MMBtu) ‡ | | |
| SCR | 70.4 | 2,868 | 0.186 | 0.055 | 2,020 |
| SNCR | 3.22 | 2,868 | 0.186 | 0.18 | 92.5 |

* *See* spreadsheet 7AppI_5_Flint Creek Post-Comment Period Cost Calculation Revisions_SCR.xlsx. The control efficiency is calculated as follows: 100 × (baseline rate − controlled rate) ÷ baseline rate.

** DEQ relied on the EPA $NO_X$ BART evaluations from the 2016 FIP which used controlled emission rates of 0.055 lb/MMBtu for SCR and 0.2 lb/MMBtu for SNCR. DEQ adjusted the SNCR control rate in its SIP to be 0.18 lb/MMBtu which is at the lower end of the range provided by the vendor from the FIP (0.18 to 0.23 lb/MMBtu) but is more in line with current practice of the existing low $NO_X$ burners with overfire air after their installation in 2018.

‡ The FIP used a maximum monthly baseline of 0.2 lb/MMBtu which was before low $NO_X$ burners with overfire air were installed which is represented now with the average monthly baseline of 0.186 lb/MMBtu.

[174] *See* Appendix I–1 of the document: 7AppI_SWEPCO Flint Creek-v9.pdf in Appendix I of the 2022 Planning Period II SIP for DEQ's Information Collection Request to the SWEPCO Flint Creek Power Plant.

[175] *See* 84 FR 51033 (September 27, 2019).

[176] *See* DEQ air permit No. 0276–AOP–R10 issued June 28, 2022.

[177] *See* Appendix I–2 of the document: 7AppI_SWEPCO Flint Creek-v9.pdf in the 2022 Planning Period II SIP for the SWEPCO Flint Creek Power Plant regional haze four-factor analysis response letter to DEQ prepared by American Electric Power (AEP). For follow up consultations (*see* Appendices I–3 to I–5), DEQ requested AEP (July 20, 2020, email) to review the cost and cost-effectiveness calculations and the facility provided feedback in a July 23, 2020, email.

[178] *See* 84 FR 51033 (September 27, 2019). *See also* DEQ's Title V air permit (No. 027–AOP–R10) which also incorporates this $SO_2$ limit into its Specific Conditions for the SN–01 Boiler and became effective August 7, 2018.

[179] *See* 2019 Guidance at 23. For the purpose of $SO_2$ control measures, if an EGU that has add-on FGD and already meets the applicable alternative $SO_2$ emission limit of the 2012 MATS rule for power plants, it may be reasonable for a state not to select that particular source for further analysis. The two limits in the rule (0.2 lb/MMBtu for coal-fired EGUs or 0.3 lb/MMBtu for EGUs fired with oil-derived solid fuel) are low enough that it is unlikely that an analysis of control measures for a source already equipped with a scrubber and meeting one of these limits would conclude that even more stringent control of $SO_2$ is necessary to make reasonable progress.

[180] *See* 2022 Planning Period II SIP (pages V–45 to V–46).

[181] *See* Cost Calculation spreadsheets for SCR and SNCR for control efficiency calculations in Appendix I of the 2022 Planning Period II SIP: 7AppI_5_Flint Creek Post-Comment Period Cost Calculation Revisions_SCRxlsx and 7AppI_5_Flint Creek Post-Comment Period Cost Calculation Revisions_SNCR.xlsx.

*Cost of Compliance.* DEQ reviewed the cost information of SCR and SNCR provided by SWEPCO for the SN–01 Boiler and compared the $/ton values to DEQ's $5,086/ton cost threshold for EGU boilers (*see* Table 22).[182] DEQ revised its analyses and calculated the annualized capital costs using the information provided by SWEPCO and a 7 percent interest rate.

TABLE 22—ESTIMATED COSTS OF CONTROL OPTIONS FOR SN–01 BOILER

[Escalated to 2019]

| Control option | Direct annualized costs ($/year) | Indirect annualized costs ($/year) | Total annual costs ($/year) | Cost effectiveness ($/ton) * |
|---|---|---|---|---|
| SCR | 2,080,085 | 13,756,224 | 15,836,308 | 8,641 |
| SNCR ** | 480,382 | 998,556 | 1,478,938 | 17,620 |

* *See* Flint Creek's revised cost spreadsheets in Appendix I of the 2022 Planning Period II SIP that reflect changes to the cost effectiveness: 7Appl_5_Flint Creek Post-Comment Period Cost Calculation Revisions_SCR.xlsx and 7Appl_5_Flint Creek Post-Comment Period Cost Calculation Revisions_SNCR.xlsx.

** DEQ revised the cost calculations for SNCR obtained from SWEPCO's report to reflect the maximum $NO_X$ inlet rate of 0.2 lb/MMBtu and a 10 percent maximum control efficiency. The previous analysis was based on a much higher $NO_X$ inlet rate (0.33 lb/MMBtu) than the emission baseline used to calculate emission reductions.

The cost effectiveness values in $/ton for both $NO_X$ controls exceeded DEQ's $5,086/ton cost threshold for EGU boilers.

*Time Necessary for Compliance.* DEQ reported that 3 years would be needed to implement SCR or SNCR to meet compliance deadlines for the SN–01 Boiler following engineering design, procurement, construction, testing, and SIP approval by EPA.

*The Energy and Non-Air Quality Environmental Impacts of Compliance.* DEQ reported that SCR and SNCR systems would both require storage and transport of $NH_3$. Accidental release of unreacted $NH_3$ could react with $SO_4^{2-}$ and $NO_3^-$ in the atmosphere to form ammonium sulfate and ammonium nitrate which are the predominant sources of regional haze. SCR and SNCR would both require electricity from ancillary equipment that would increase electrical demand to operate the systems. The anticipated costs on energy and non-air quality impacts for each system were factored into the cost of compliance.

*Remaining Useful Life.* DEQ reported that there are no effective limitations on remaining useful life of the SN–01 Boiler; therefore, the default useful life values for SCR and SNCR from the EPA's Air Pollution Control Cost Manual were assumed to be 30 years and 20 years, respectively.

*Visibility Considerations.* DEQ considered SWEPCO Flint Creek's contribution to visibility impairment at the different Class I areas within and outside Arkansas. DEQ noted that the AOI analysis indicated that emissions from the SWEPCO Flint Creek power plant impacted three Class I areas (Caney Creek, Hercules Glades, and Upper Buffalo). Hercules Glades and Upper Buffalo are both on track to make greater progress than the URP glidepath in 2028, even before consideration of potential controls for Flint Creek. Caney Creek was impacted by less than 1 percent and is not anticipated to have significant contributions to visibility impairment.

*Proposed Reasonable Progress Control Determination for SWEPCO Flint Creek Power Plant.* DEQ determined in its 2022 Planning Period II SIP that no additional controls are necessary for the SN–01 Boiler at the SWEPCO Flint Creek Power Plant to make reasonable progress during the second planning period. DEQ's determination was based on weighing the four reasonable progress factors on the control technologies that the State identified to reduce $NO_X$ emissions at the SN–01 Boiler. The State put particular emphasis on the cost of controls and noted that all of the control strategies evaluated for the SWEPCO Flint Creek Power Plant exceed DEQ's cost threshold of $5,086/ton for EGU boilers. While the State emphasized cost, the time necessary for compliance, the energy and non-air quality environmental impacts, and remaining useful life were all factored into the cost of compliance. In addition to DEQ's four-factor evaluation, DEQ pointed out that Hercules Glades and Upper Buffalo Class I areas, of which Flint Creek is within the $SO_4^{2-}$ or $NO_3^-$ specific areas of influence, are both on track to make greater progress than the URP glidepath in 2028 with existing controls. DEQ also stressed that Flint Creek recently installed $SO_2$ and $NO_X$ controls and those emissions are well controlled.

EPA is proposing to find that the State's determination of no additional controls for the SN–01 Boiler at the SWEPCO Flint Creek Power Plant is reasonable and meets regional haze requirements for the second planning period. Based on DEQ's consideration of the four statutory factors in its assessment of potential additional controls for reasonable progress and because the projected 2028 visibility conditions for the affected Class I areas are below the 2028 URP glidepath values, Arkansas demonstrated reasonable progress toward the national visibility goal for the second planning period. After appropriately identifying the SN–01 Boiler for potential controls, the State adequately took into consideration the four statutory factors on the selected control technologies and determined that none of the evaluated controls were cost effective because each $/ton value exceeded DEQ's $5,086/ton cost threshold for EGU boilers. In addition to the four factor analyses of additional controls, the projected 2028 visibility improvement at the Class I areas (Hercules Glades, Upper Buffalo, and Caney Creek)[183] impacted by Flint Creek are all on track to make greater progress and be below their respective 2028 URP glidepath values with existing controls. EPA agrees with the State that the SN–01 Boiler is adequately controlled with recent existing measures. In particular, the SN–01 Boiler is subject to BART and an $SO_2$ emission limit of 0.06 lb/MMBtu on a thirty-day rolling average from the

[182] *See* Table V–20 (page V–46) from 2022 Planning Period II SIP.

[183] *See* the 2022 Planning Period II SIP (page V–47). The SWEPCO Flint Creek Power Plant visibility surrogate value was 1 percent of the total source impacts for both Hercules Glades and Upper Buffalo for their respective AOIs, while it was less than 1 percent for Caney Creek's AOI. *See also* 2022 Planning Period II SIP Appendix C spreadsheet: 7AppC_Arkansas Source Screening Method Spreadsheet-v8.xlsx.

first implementation period. Also, the SN–01 Boiler is equipped with low-$NO_X$ burners with separated overfire air for $NO_X$ control that completed installation on May 8, 2018. Therefore, we are proposing to find that Arkansas demonstrated that it is making reasonable progress for the second planning period without requiring any additional controls for the SWEPCO Flint Creek Power Plant.

f. Conclusion

EPA is proposing to find that DEQ has met the requirements under 40 CFR 51.308(f)(2)(i) in its 2022 Planning Period II SIP submittal by evaluating the five sources brought forward for additional analyses (Entergy White Bluff Power Plant, Entergy Independence Power Plant, FutureFuel Chemical Company, Domtar Ashdown Mill, and SWEPCO Flint Creek Power Plant) and determining the emission reduction measures that are necessary for each source to make reasonable progress for the second planning period after considering the four statutory factors.

4. Consultation Requirement With States

The consultation requirement of section 51.308(f)(2)(ii) provides that the State must consult with other states that are reasonably anticipated to contribute to visibility impairment in a Class I area in order to develop coordinated emission management strategies containing the emission reduction measures that are necessary to make reasonable progress. Section 51.308(f)(2)(ii)(A) requires that the State must demonstrate that it has included in its SIP all measures agreed to during state-to-state consultations or regional planning processes, or measures that will provide equivalent visibility improvement. The State must also consider the emission reduction measures identified by other states for their sources as being necessary to make reasonable progress. 40 CFR 51.308(f)(2)(ii)(B). Lastly, the State must describe the actions taken to resolve any disagreements if states cannot agree on the measures necessary to make reasonable progress. 40 CFR 51.308(f)(2)(ii)(C).

DEQ noted that it consulted regularly with neighboring states through CenSARA facilitated meetings and also had direct consultations with individual states. The CenSARA meetings consisted of regional haze conference calls where DEQ shared and received feedback regarding reasonable progress, monitoring efforts, and other strategies relevant to regional haze planning and program implementation. DEQ consulted with individual states via conference, video calls, and emails/ formal letters.[184] On February 4, 2020, DEQ sent interstate consultation ''ask letters'' to Illinois, Indiana, Kentucky, Louisiana, Missouri, Oklahoma, and Texas requesting that these neighboring states consider whether performing a four-factor analysis was appropriate for sources that DEQ identified as impacting Caney Creek and Upper Buffalo (*see* Table 6) in accordance with 40 CFR 51.308(f)(2)(i); and, if so, whether any additional control measures for $NO_X$ and $SO_2$ were necessary to make reasonable progress towards natural visibility during the second planning period. DEQ requested that each state share with DEQ the results of any analyses, including technical supporting documentation, and provide an opportunity for consultation on each state's long-term strategy early enough in the process for DEQ to provide feedback. On March 1, 2021, DEQ submitted additional consultation ''ask letters'' to these seven states and also to North Carolina to notify them of the availability of its pre-proposal draft SIP and provide them with the opportunity to discuss and provide feedback. Availability of the pre-proposal draft SIP was also announced during CenSARA planning calls that occurred on March 2, 2021, and April 12, 2021; which included state agency partners from Alabama, Georgia, Iowa, Kansas, and Nebraska. Texas was the only state that commented on the pre-proposal draft SIP but none of Texas' comments disagreed with any of the Arkansas measures listed as needed for reasonable progress for the second planning period. DEQ noted that Arkansas had follow up conversations with Texas in CenSARA monthly meetings to fully meet the consultation requirements between the two states.

DEQ considered impacts to other state's Class I areas from Arkansas sources and quantified the relative contribution of those sources using the 2016 AOI analysis. The AOI analysis indicated that Arkansas sources had a relatively small impact on Class I areas in other states with the exception of Hercules Glades in Missouri. Arkansas's relative impacts were identified as 2 percent for Sipsey in Alabama; 4 percent for Mingo in Missouri; and less than 1 percent for Mammoth Cave and Wichita Mountains. No state identified any specific controls for DEQ to consider during consultation after reviewing the AOI analysis. Therefore, DEQ limited its consideration of potential controls to the five facilities in Arkansas brought forward after applying the 70 percent screening threshold previously discussed. In addition to the CenSARA states, DEQ received a request from the VISTAS on behalf of North Carolina to perform a four-factor analysis on Entergy Independence because their modeling showed impacts at Shining Rock in North Carolina. However, VISTAS did not request specific controls for DEQ to consider.

EPA is proposing to find that DEQ has satisfied the consultation requirement of 40 CFR 51.308(f)(2)(ii) in its 2022 Planning Period II SIP. No states disagreed with the Arkansas proposed measures necessary for reasonable progress for the second implementation period and no other measures were identified or agreed upon by the other states for DEQ to include in its SIP.

5. Documentation Requirement for Emission Reduction Measures

The documentation requirement of 40 CFR 51.308(f)(2)(iii) provides that states must meet their obligations to document the technical basis on which they are relying to determine the emission reductions measures that are necessary to make reasonable progress. The State may meet this requirement by relying on technical analyses developed by an RPO, as long as the process has been approved by all State participants. Section 51.308(f)(2)(iii) also requires that the emission information considered to determine the measures that are necessary to make reasonable progress include information on emissions for the most recent year for which the State has submitted triennial emissions data to the EPA (or a more recent year), with a 12-month exemption period for newly submitted data.

All documentation that the State is relying on to determine the emission reduction measures necessary to make reasonable progress were included in the SIP submission in the various appendices. Arkansas included an AOI analysis performed by Ramboll for the CenSARA states in its 2022 Planning Period II SIP to identify possible regional source locations impacting visibility. Ramboll produced an AOI report that summarized the approach of its analysis and an AOI spreadsheet that DEQ used to evaluate the results for its specific Class I areas. DEQ assessed 2019 IMPROVE monitoring extinction data, 2017 NEI emission inventory trends for precursor pollutants, and EPA-projected 2028 source

[184] *See* Appendix D–2 Communication Log of the 2022 Planning Period II SIP that outlines DEQ communications on specific regional haze topics and the outcome of any associated conversations.

apportionment data.[185] DEQ evaluated four-factor analysis reports from the five sources brought forward for potential controls which included cost and emission reduction calculations (later supplemented by DEQ).[186] DEQ included Administrative Orders for SWEPCO FutureFuel[187] and Entergy Independence[188] as part of the 2022 Planning Period II SIP submittal to make emission reduction measures federally enforceable upon final approval of the SIP. However, based on the State's July 29, 2025 letter, the State clarified that after further consideration, the 2022 SIP submittal fulfills RHR and CAA requirements without the inclusion of the Administrative Order for Independence. Therefore, EPA's approval will not incorporate this Administrative Order by reference.

The EPA is proposing to find that DEQ has satisfied the requirements of 40 CFR 51.308(f)(2)(iii) in its 2022 Planning Period II SIP. Based on the documentation provided by the State, DEQ has demonstrated the technical bases and emission information on which it is relying to determine the emission reductions measures that are necessary to make reasonable progress for its long-term strategy for the second planning period.

6. Five Additional Factors for Long-Term Strategy

In developing its long-term strategy, a state must also consider the five additional factors in section 51.308(f)(2)(iv). As mentioned, the five additional factors for consideration in section 51.308(f)(2)(iv) are distinct from the four factors listed in CAA section 169A(g)(1) and 40 CFR 51.308(f)(2)(i) that states must consider and apply to sources in determining reasonable progress.

40 CFR 51.308(f)(2)(iv)(A) requires states to consider emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment. DEQ explained in the 2022 Planning Period II SIP that ongoing programs for the second planning period include NSPS, NESHAPs, national on-road and nonroad emissions standards, reliance upon CSAPR, and other national rules that limit the emissions of pollutants that may contribute to visibility impairment.[189] The emission reductions achieved by these programs were factored into the 2028 emission projections used to develop the RPGs for Arkansas' Class I areas.[190] DEQ noted that the federal rules mentioned in the 2008 SIP submittal, as updated in 2018 Phase II SIP for the first planning period, reflect the list of ongoing state and federal air pollution control programs that have been implemented since the 2008 SIP submittal. Those rules remain in effect for the second planning period, so the emission reductions from those first planning period controls and ongoing state and federal programs are reflected in the emissions inventory information for Arkansas and the surrounding states.[191]

DEQ also performed an analysis of energy efficiency programs implemented by electric utilities. As an ongoing measure, DEQ is implementing Arkansas' energy efficiency resource standard as a part of its long-term strategy for the second planning period.[192] DEQ's analysis projected that the implementation of the energy efficiency program by electric utilities will result in increased emission reductions of visibility impairing pollutants each year from 2021–2028 in Arkansas and throughout the Southeast and Lower Midwest. Based on analysis using estimated emissions reductions from EPA's ''AVoided Emissions and geneRation Tool'' (AVERT), DEQ projected that Arkansas' energy efficiency program will reduce annual emissions by 1,451 tons $SO_2$, 1,478 tons $NO_X$, and 150 tons $PM_{2.5}$ across the lower Midwest and Southeast combined by 2028.[193]

40 CFR 51.308(f)(2)(iv)(B) requires states to consider measures to mitigate the impacts of construction activities. DEQ noted that the Arkansas Water and Pollution Control Act[194] limits DEQ's authority with respect to certain construction activities, such as land clearing operations, land grading, and road construction. Therefore, as noted in Arkansas's 2008 Regional Haze SIP,[195] current and future federal programs result in some mitigation through incentive offerings for voluntary emission reduction measures and through tier standards for nonroad equipment. DEQ also provides funding opportunities for voluntary emission reduction projects for nonroad equipment used for construction through its ''Go RED! program.''

40 CFR 51.308(f)(2)(iv)(C) requires states to consider source retirement and replacement schedules. DEQ identifies in the 2022 Planning Period II SIP that Entergy Lake Catherine and Entergy White Bluff are two stationary sources in Arkansas that are anticipated to retire during the second planning period. Entergy Lake Catherine is listed in EPA's Emissions & Generation Resource Integrated Database (eGRID) as having a generator planned retirement in 2025.[196] The Consent Decree[197] also requires Entergy to cease operations of existing units at Lake Catherine by December 31, 2027, and requires Entergy White Bluff to cease coal-fired operations of all units by December 31, 2028. DEQ's AOI source screening analysis identified Dolet Hills (in Louisiana) and Indiana Michigan Power (in Indiana), but DEQ states that they are anticipated to retire during the second planning period. Cleco Power LLC notified LDEQ of the projected retirement of Dolet Hills Power Station.[198] In addition, DEQ noted publicly announced closures of sources in Texas. DEQ noted that it will manage new and modified sources in conformance with existing SIP

[185] *See* EPA's 2019 TSD ''Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling.'' The goal of this modeling effort was to project 2028 visibility conditions and source sector contribution information, including international anthropogenic visibility impacts, for each mandatory Class I federal area. EPA conducted this visibility modeling to inform the regional haze SIP development process for the second implementation period under EPA's Regional Haze Rule.

[186] *See* Appendices F through I of the 2022 Planning Period II SIP for the four-factor analysis reports and all associated documents from Independence, FutureFuel, Domtar, and Flint Creek.

[187] *See* Administrative Order (LIS No. 22–085) dated August 3, 2022, and included as part of the 2022 Planning Period II SIP submittal.

[188] *See* Administrative Order (LIS No. 22–084) dated August 2, 2022, and included as part of the 2022 Planning Period II SIP submittal.

[189] *See* 2022 Planning Period II SIP (page VI–1).

[190] *See* EPA's 2019 Technical Support Document, ''Preparation of Emissions Inventories for the Version 7.2 2016 North American Emissions Modeling Platform'' (Pages 14–17).

[191] *See* 2022 Planning Period II SIP (pages IV–8 to 9).

[192] *See* 2022 Planning Period II SIP (pages VI–1 to 10).

[193] *See* Tables VI–1 and VI–2 in the 2022 Planning Period II SIP (pages VI–2 to 3). *See also* Energy Efficiency as a Haze Reduction Strategy in Appendix K of the 2022 Planning Period II SIP (page K–16).

[194] Section 8–4–305 of The Arkansas Water and Air Pollution Control Act states that ''The provisions of this subchapter do not apply to: —; (4) Land clearing operations or land grading; (5) Road construction operations and the use of mobile and portable equipment and machinery incident thereto; —.'' It would require legislative action for these exceptions to be removed from the Act and to give DEQ explicit regulatory authority over these activities.

[195] *See* Arkansas' 2008 Regional Haze SIP (page 73).

[196] Planned retirement year for Entergy Lake Catherine: *https://www.epa.gov/sites/production/files/2020-03/egrid2018_data_v2.xlsx.*

[197] Sierra Club and National Parks Conservation Association v. Entergy Arkansas, inc., Entergy Power, LLC, and Entergy Mississippi, Inc. Case No. 4:18-cv-00854–KGB (ED Ark., March 11, 2021).

[198] *http://edms.deq.louisiana.gov/app/doc/view.aspx?doc=12235418&ob=yes&child=yes* and Energy Information Administration Form 860.

requirements pertaining to PSD and minor NSR. DEQ will also track source retirement and replacement through ongoing point source inventories and permitting actions.

40 CFR 51.308(f)(2)(iv)(D) requires states to consider basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes, and smoke management programs. Arkansas has adopted voluntary smoke management plans for both prescribed fire and agricultural burning.[199] These plans are implemented by Arkansas foresters and farmers on a voluntary basis with the assistance of the Arkansas Department of Agriculture. The Arkansas Department of Agriculture coordinates prescribed fire activities, reports fire weather, and assists with voluntary smoke management.[200]

40 CFR 51.308(f)(2)(iv)(E) requires states to consider the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy. DEQ performed air quality photochemical modeling to support the development of the 2022 Planning Period II SIP for the 2018–2028 implementation period. DEQ used Comprehensive Air Quality Model with Extensions (CAMx) to simulate visibility conditions at the Arkansas Class I areas, taking into consideration the control strategy in the Arkansas Planning Period II SIP, to establish RPGs for 2028 and to evaluate the effect of Arkansas's control strategy on the Class I areas in other states that are reasonably anticipated to be impacted by sources in Arkansas. The modeling setup for DEQ's CAMx modeling followed the same approach as the 2016 EPA modeling platform for regional haze. DEQ processed emissions using CAMx by simulating air quality conditions for the 2016 base year and the 2028 future year. DEQ post-processed CAMx outputs to evaluate the two Arkansas Class I areas and the six Class I areas outside Arkansas.[201] Further details on model assumptions, performance, results, and methodology are described in Appendix L. DEQ compared current visibility conditions in 2016 to projected visibility conditions in 2028 as a result of DEQ's long-term strategy.[202] All of the modeled Class I areas show visibility improvement on the most impaired and clearest days from the 2016 base year to the 2028 future year. DEQ noted that its modeling does not take into account emission reductions that other states have determined necessary as a result of their reasonable progress analysis. Any emission reduction measures that other states may determine necessary to ensure reasonable progress would be anticipated to further improve visibility conditions in 2028. The modeling also does not take into account the change in long-term strategy for FutureFuel to a more stringent limit based on the use of 1.5 percent sulfur content coal. DEQ's modeling instead used an assumption of a 2 percent sulfur content coal limit for FutureFuel. Therefore, DEQ anticipates greater reductions of visibility impairment should be realized than projected by DEQ's RPGs.

The EPA is proposing to find that DEQ has met the requirements of 40 CFR 51.308(f)(2)(iv) in its 2022 Planning Period II SIP by reasonably considering the five ''additional factors'' in developing its long-term strategy for the second implementation period. DEQ adequately considered emission reductions due to ongoing air pollution control programs; measures to mitigate impacts of construction activities; source retirements and replacement schedules; smoke management practices and programs; and anticipated visibility conditions in 2028 resulting from implementation of its long-term strategy.

*D. RPGs*

Section 51.308(f)(3) contains the requirements pertaining to RPGs for each Class I area. Section 51.308(f)(3)(i) requires a state in which a Class I area is located to establish RPGs—one each for the most impaired and clearest days—reflecting the visibility conditions that will be achieved at the end of the implementation period as a result of the emission limitations, compliance schedules and other measures required under paragraph (f)(2) to be in states' long-term strategies, as well as implementation of other CAA requirements. The long-term strategy and the RPGs must provide for an improvement in visibility for the most impaired days since the baseline period and ensure no degradation in visibility for the clearest days since the baseline period. Section 51.308(f)(3)(ii) applies in circumstances in which a Class I area's RPG for the most impaired days represents a slower rate of visibility improvement than the URP calculated under 40 CFR 51.308(f)(1)(vi). Under section 51.308(f)(3)(ii)(A), if a state in which a Class I area is located establishes an RPG for the most impaired days that provides for a slower rate of visibility improvement than the URP, the state must demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the state that would be reasonable to include in its long-term strategy. The State must provide a robust demonstration, including documenting the criteria used to determine which sources or groups or sources were evaluated and how the four factors required by paragraph (f)(2)(i) were taken into consideration in selecting the measures for inclusion in its long-term strategy. Section 51.308(f)(3)(ii)(B) requires that if a state contains sources that are reasonably anticipated to contribute to visibility impairment in a Class I area in another state, and the RPG for the most impaired days in that Class I area is above the URP, the upwind state must provide the same robust demonstration.

The State calculated the URPs for Caney Creek and Upper Buffalo for the 20 percent most impaired days, and developed linear glidepaths for each area assuming starting baseline visibility conditions in 2004 and ending with natural conditions in 2064.[203] The URP glidepath results in section IV.B of this proposed action (*see* Table 5) help gauge how far visibility has improved so far in Arkansas for the most impaired days from the baseline period and represent the control measures already required or anticipated before the four-factor analyses have been conducted for the second planning period. DEQ expanded on those visibility results in its SIP by making RPG determinations using CAMx modeling that incorporated the control strategies and resulted in even greater visibility progress than what the URPs established for each Class I area in Arkansas. DEQ determined that the 2028 modeled RPGs for the 20 percent most impaired days for Caney Creek and Upper Buffalo Wilderness Areas are 16.31 dv and 16.49 dv, respectively (*see* Table 23).[204] DEQ noted that these modeled RPG values do not include any

[199] *See* 2022 Planning Period II SIP (pages IV–9).

[200] Copies of the most recent publications of the Arkansas voluntary smoke management plans for prescribed fires and row crops are available at: *https://www.agriculture.arkansas.gov/arkansas-voluntary-smoke-management-guidelines.*

[201] *See* Appendix L of the 2022 Planning Period II SIP for all documents associated with DEQ's CAMx modeling and projected visibility conditions in 2028.

[202] *See* Table VI–3 of the 2022 Planning Period II SIP (page VI–14).

[203] *See* Figures II–2 and II–14 in the 2022 Planning Period II SIP for Caney Creek and Upper Buffalo's URP glidepaths on the 20 percent most impaired days.

[204] *See* Tables VI–4 and VI–5 of the 2022 Planning Period II SIP for the adopted RPGs on the most impaired days; and for URP glidepath checks for Arkansas Class I areas (pages VI–15–16). Details on model assumptions, performance, results, and methodology are described in Appendix L of the 2022 Planning Period II SIP.

emission reductions that may occur as a result of adoption of the 2022 Planning Period II SIP control strategies by other states, except in those instances where there is an enforceable retirement. DEQ compared these 2028 RPG values for Caney Creek and Upper Buffalo to the 2028 URP values on the most impaired days; and also to the (2000–2004) baseline conditions on the clearest days. The results demonstrate that implementation of the long-term strategy will result in faster progress and be below the adjusted URP glidepaths for each area on the most impaired days; and that there will be no degradation from the (2000–2004) baseline on the 20 percent clearest days.

TABLE 23—2028 VISIBILITY PROGRESS CHECK FOR ARKANSAS CLASS I AREAS

| Class I areas | Most impaired days (dv) | | Clearest days (dv) | |
|---|---|---|---|---|
| | 2028 adjusted URP | 2028 RPGs | Baseline (2000–2004) | 2028 RPG |
| Caney Creek | * 18.90 | 16.31 | 11.24 | 7.50 |
| Upper Buffalo | ** 19.26 | 16.49 | 11.71 | 7.72 |

* The unadjusted 2028 URP value at Caney Creek is 18.18 dv without accounting for international anthropogenic and prescribed fire contributions. *See* EPA 2019 Modeling TSD at 57, Table 5–2

** The unadjusted 2028 URP value at Upper Buffalo is 18.32 dv without accounting for international anthropogenic and prescribed fire contributions. *See* EPA 2019 Modeling TSD at 64, Table 5–2

DEQ also compared the 2028 modeled RPGs for the six Class I areas outside the state that were identified as having potential visibility impacts from Arkansas emissions. All six Class I areas had RPG values below their respective unadjusted 2028 URPs for the most impaired days (*see* Table 24).[205] This was before consideration of control measures determined to be necessary to ensure reasonable progress for those state's SIPs. There was also no degradation on the clearest days from the (2000–2004) baseline for all six Class I areas.

DEQ consulted[206] with neighboring states about whether they expected to adjust the glidepath for their respective Class I areas from the unadjusted 2028 URP values. All neighboring states commented that they would not adjust the glidepath for any Class I area. However, some states (Kentucky, Oklahoma, North Carolina) indicated in consultation that they would use the 2028 URP values based on the updated natural conditions value for most impaired days from the 2020 EPA memo.[207] The results in Table 24 do not account for visibility improvement that would be achieved from adoption of control measures in the second planning period by other states. As mentioned, no specific controls were requested from any other state for Arkansas sources, including the states that requested DEQ to perform four-factor analyses, or agreed to as part of consultation.

TABLE 24—URP PROGRESS CHECK FOR CLASS I AREAS OUTSIDE ARKANSAS AFFECTED BY ARKANSAS EMISSIONS

| Class I areas | Most impaired days (dv) | | Clearest days (dv) | |
|---|---|---|---|---|
| | 2028 URP | 2028 modeled RPGs | Baseline (2000–2004) | 2028 modeled RPG |
| Hercules Glades | 18.82 | 17.3 | 12.84 | 9.07 |
| Mingo | 19.48 | 18.83 | 14.29 | 10.47 |
| Mammoth Cave * | 21.82 | 19.37 | 16.51 | 10.47 |
| Sipsey | 20.44 | 17.41 | 15.57 | 10.04 |
| Wichita Mountains * | 17.36 | 16.81 | 9.78 | 8.17 |
| Shining Rock * | 20.98 | 13.83 | 7.7 | 4.0 |

* These states indicated in consultation that they were using the 2028 URP values based on the updated natural conditions value for most impaired days from the 2020 EPA memo.[208]

The EPA is proposing to find that the State adequately addressed the applicable provisions under 40 CFR 51.308(f)(3)(i) in its 2022 Planning Period II SIP by establishing RPGs for Arkansas' Class I areas that reflect the measures necessary for reasonable progress for the second implementation period. Arkansas' RPGs demonstrate that implementation of the long-term strategy will result in faster progress and will be below the adjusted URP glidepaths on the most impaired days. There will also be no degradation from the baseline on the clearest days. The six Class I areas in other states affected by Arkansas emissions are also on track to achieve their visibility reduction goals and will be below their respective URP glidepaths. The EPA is also proposing to find that because the projected visibility conditions at all these impacted Class I areas in and outside Arkansas are below their respective 2028 URP values, additional demonstrations under 40 CFR 51.308(f)(3)(ii) are not required.

[205] *See* Tables VI–6 of the 2022 Planning Period II SIP for the URP glidepath checks for Class I areas affected by Arkansas emissions (pages VI–16).

[206] *See* Arkansas' email correspondence between Alabama, Kentucky, Missouri, North Carolina, and Oklahoma, dated September 29, 2021, through September 30, 2021, included in Appendix D.

[207] ''Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program'' *https://www.epa.gov/sites/default/files/2020-06/documents/memo_data_for_regional_haze_0.pdf.*

[208] *Id.*

*E. Reasonably Attributable Visibility Impairment (RAVI)*

The RHR contains a requirement at 40 CFR 51.308(f)(4) related to any additional monitoring that may be needed to address visibility impairment in Class I areas from a single source or a small group of sources. This is called ''reasonably attributable visibility impairment,'' [209] also known as RAVI. Under this provision, if the EPA or the FLM of an affected Class I area has advised a state that additional monitoring is needed to assess RAVI, the state must include in its SIP revision for the second implementation period an appropriate strategy for evaluating such impairment. The EPA has not advised Arkansas to that effect, nor did the State indicate that FLMs for Caney Creek or Upper Buffalo identified any RAVI from Arkansas sources. For this reason, the EPA is proposing to approve the portions of the 2022 Planning Period II SIP relating to 40 CFR 51.308(f)(4).

*F. Monitoring Strategy and Other Implementation Plan Requirements*

Section 51.308(f)(6) specifies that each comprehensive revision of a state's regional haze SIP must contain or provide for certain elements, including monitoring strategies, emissions inventories, and any reporting, recordkeeping and other measures needed to assess and report on visibility. A main requirement of this section is for states with Class I areas to submit monitoring strategies for measuring, characterizing, and reporting on visibility impairment. Compliance with this requirement may be met through participation in the IMPROVE monitoring network.

Section 51.308(f)(6)(i) requires SIPs to provide for the establishment of any additional monitoring sites or equipment needed to assess whether RPGs to address regional haze for all Class I areas within the state are being achieved. DEQ noted that the monitoring strategy for Arkansas' Class I areas relies upon the IMPROVE monitoring network.[210] DEQ deploys IMPROVE monitors for Caney Creek and Upper Buffalo Wilderness areas to determine the visibility conditions at each area. The IMPROVE monitors consist of four sampling modules that collect $PM_{2.5}$ and $PM_{10}$ data for 24 hours every 3 days. Data collected at the IMPROVE sites includes specific information on the composition of haze-forming particles. This data is used to calculate visibility impairment and indicates the extent to which the visibility impairment is either a result of anthropogenic or natural air pollution. The Caney Creek IMPROVE monitor (CACR) is located in Polk County, Arkansas at an elevation of 683 meters above mean sea level at latitude 34.4544, longitude –94.1429. The Upper Buffalo Wilderness IMPROVE monitor (UPBU) is located 1 mile north of the U.S. Forest Service workstation near Deer, AR at an elevation of 722 meters above mean sea level.

For states with Class I areas (including Arkansas), section 51.308(f)(6)(ii) requires SIPs to provide for procedures by which monitoring data and other information are used in determining the contribution of emissions from within the state to regional haze visibility impairment at Class I areas both within and outside the state. DEQ relied on IMPROVE monitoring extinction data at each Class I area for determining the key pollutants and source categories that contribute within and outside the state. DEQ developed figures showing annual visibility impairment trends from 2002–2019 tracked in deciviews and included the extinction compositions from each contributing pollutant species for the most impaired and clearest days.[211] The pollutant extinction compositions were made up of varying amounts of ammonium sulfate, ammonium nitrate, coarse mass organic mass, elemental carbon, soil, and sea salt at each Class I area. DEQ also developed figures showing trends of annual light extinction data for the same time frame with pollutant contributions corresponding to anthropogenic sources and natural sources. DEQ relied on EPA's 2028 modeling projections and source apportionment charts that represented the specific anthropogenic emission sector contributions at the different Class I areas on the most impaired days.[212] Those 2028 sector-wide projections showed the key sectors which would impact visibility the greatest at the Class I areas. Lastly, Arkansas relied on CenSARA's AOI analysis performed by Ramboll for the CenSARA states to identify possible regional source locations impacting visibility. Ramboll performed the AOI analysis for CenSARA Class I areas and also for neighboring Class I areas that might potentially be impacted by emissions from the CenSARA states. The AOI analysis used back-trajectory modeling to identify the geographic areas and anthropogenic emission sources with a high probability of impacting visibility at Class I areas within the CenSARA region and in nearby states.

Section 51.308(f)(6)(iii) requires states with no Class I areas to have SIPs provide for procedures by which monitoring data and other information are used in determining the contribution of emissions from within the state to regional haze visibility impairment at Class I areas in other States. Section 51.308(f)(6)(iii) does not apply since Arkansas has two Class I areas within the state.

Section 51.308(f)(6)(iv) requires the SIP to provide for the reporting of all visibility monitoring data to the Administrator at least annually for each Class I area in the state. DEQ noted that the monitoring strategy for Arkansas relies upon the continued availability of the IMPROVE network and works collaboratively with state, tribal, and federal agencies, and international partners.

Section 51.308(f)(6)(v) requires SIPs to provide for a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any Class I area. The inventory must include emissions for the most recent year for which data are available, and estimates of future projected emissions. The state must also include a commitment to update the inventory periodically. DEQ noted that it will continue to submit annual inventories of pollutants, including those reasonably anticipated to cause or contribute to visibility impairment, in accordance with EPA Air Emissions Reporting Requirements (AERR) in 40 CFR part 51 Subpart A to satisfy the requirement to provide for an emissions inventory for the most recent year for which data are available. The AERR requires states to submit updated emissions inventories for criteria pollutants to the EPA's Emissions Inventory System (EIS) every 3 years. The emission inventory data is used to develop the NEI, which provides for, among other things, a triennial state-wide inventory of pollutants that are reasonably anticipated to cause or contribute to visibility impairment. DEQ

[209] 40 CFR 51.301 defines ''reasonably attributable visibility impairment'' as ''visibility impairment that is caused by the emission of air pollutants from one, or a small number of sources.''

[210] *See* the 2022 Planning Period II SIP (page VII–1).

[211] *See* chapter II and III of 2022 Planning Period II SIP for the specific figures of light extinction data at each class I area: Figures II–4 to 7 for Caney Creek; Figures II–16 to 19 for Upper Buffalo; Figures III–2 to 5 for Hercules Glades; Figures III–12 to 15 for Mammoth Cave; Figures III–22 to 25 for Mingo Wilderness; Figures III–31 to 34 for Shining Rock; Figures III–40 to 43 for Sipsey; and Figures III–50 to 53 for Wichita Mountains.

[212] *See* chapters II and III of 2022 Planning Period II SIP for figures of projected 2028 emission sectors: Figures II–8, II–20, III–6, III–16, III–26, III–35, III–44, and III–53.

included tables of NEI data in Chapter IV of its 2022 Planning Period II SIP. To satisfy the requirement to provide estimates of future projected emissions, DEQ processed emissions using CAMx by simulating air quality conditions for the 2016 base year and the 2028 future year to establish RPGs for its own and nearby Class I areas. Further details on model assumptions, performance, results, and methodology are described in Appendix L of the 2022 Planning Period II SIP submittal.

Lastly, section 51.308(f)(6)(vi) requires SIPs to provide other elements, including reporting, recordkeeping, and other measures, necessary to assess and report on visibility. Because Arkansas has continued ongoing participation in the IMPROVE network and the CenSARA RPO continues its on-going compliance with the AERR, no further elements are necessary at this time for Arkansas to assess and report on visibility.

The EPA is proposing to find that Arkansas has met the requirements under 40 CFR 51.308(f)(6) in its 2022 Planning Period II SIP by providing an adequate monitoring strategy through its IMPROVE monitoring network that measures, characterizes, and reports regional haze visibility impairment that is representative of all Class I areas within the State for the second implementation period. Therefore, the EPA is proposing to approve the monitoring strategy and other state implementation plan elements of Arkansas' 2022 Planning Period II SIP as meeting the requirements of 40 CFR 51.308(f)(6).

*G. Requirements for Periodic Reports Describing Progress Toward the RPGs*

Section 51.308(f)(5) requires that periodic comprehensive revisions of states' regional haze plans also address the progress report requirements of 40 CFR 51.308(g)(1) through (5). The purpose of these requirements is to evaluate progress toward the applicable RPGs for each Class I area within the state and each Class I area outside the state that may be affected by emissions from within that state. Sections 51.308(g)(1) and (2) apply to all states and require a description of the status of implementation of all measures included in a state's first implementation period regional haze plan and a summary of the emission reductions achieved through implementation of those measures. Section 51.308(g)(3) applies only to states with Class I areas within their borders and requires such states to assess current visibility conditions, changes in visibility relative to baseline (2000–2004) visibility conditions, and changes in visibility conditions relative to the period addressed in the first implementation period progress report. Section 51.308(g)(4) applies to all states and requires an analysis tracking changes in emissions of pollutants contributing to visibility impairment from all sources and sectors since the period addressed by the first implementation period progress report. This provision further specifies the year or years through which the analysis must extend depending on the type of source and the platform through which its emission information is reported. Finally, section 51.308(g)(5), which also applies to all states, requires an assessment of any significant changes in anthropogenic emissions within or outside the state have occurred since the period addressed by the first implementation period progress report, including whether such changes were anticipated and whether they have limited or impeded expected progress toward reducing emissions and improving visibility.

Arkansas described the status of implementation of all measures included in the first implementation period long-term strategy as required by 40 CFR 51.308(g)(1). DEQ noted source specific $SO_2$, $NO_X$, and PM controls determined for seven facilities that are currently all fully implemented and federally enforceable.[213] DEQ listed CSAPR $O_3$ season $NO_X$ emission allocations for 22 facilities.[214] The statewide $O_3$ season $NO_X$ budget for Arkansas in 2017 was 12,048 tons with a variability limit of 2,530 tons and an assurance level of 14,578 tons. The statewide $O_3$ season $NO_X$ budget for Arkansas from 2018 forward is 9,210 tons with a variability limit of 1,934 tons and an assurance level of 11,144 tons. DEQ noted that the ongoing federal programs from the 2008 SIP submittal were incorporated into the modeling to establish the first planning period RPGs (CAIR was replaced with CSAPR) and then updated with the 2018 Phase II SIP submittal. All of these were then incorporated into the emission inventories for emission reductions in the 2022 Planning Period II SIP submission. DEQ reported that Arkansas foresters have been implementing a voluntary smoke management plan for prescribed fires since 2007 and, more recently, the Arkansas Department of Agriculture adopted a voluntary smoke management plan for row croppers.[215] The EPA is proposing to find that the State has adequately addressed the applicable provisions under 40 CFR 51.308(g)(1) in its 2022 Planning Period II SIP by reporting the status of implementation of measures for achieving the RPGs for Class I areas both within and outside the State for the second implementation period. The State also documented the status of all measures from the first implementation period and included a summary of the implementation status associated with each.

Pursuant to 40 CFR 51.308(g)(2), DEQ listed the emission reductions achieved from the first planning period measures. DEQ reported that $SO_2$, $NO_X$, and $PM_{2.5}$ emissions reduced since 2011 due to the source specific measures. In 2019, annual emissions reductions from controlled stationary sources were 49 percent lower for $SO_2$ emissions; 61 percent lower for $NO_X$ emissions; and 10 percent lower for primary $PM_{2.5}$ emissions.[216] DEQ illustrated $NO_X$ emissions trends from 2011–2020 for EGUs subject to CSAPR $O_3$ season $NO_X$. Annual $NO_X$ emissions from Arkansas EGUs decreased by 25,692 tons (67 percent) during this period which was from the installation of low $NO_X$ burners in 2017–2018.[217] DEQ reported changes in emissions from smoke management plans which limited smoke impacts from burning.[218] The EPA is proposing to find that the State has adequately addressed the applicable provisions under 40 CFR 51.308(g)(2) in its 2022 Planning Period II SIP by providing a summary of the emission reductions achieved throughout the State through implementation of measures on all visibility impairing pollutants.

Pursuant to 40 CFR 51.308(g)(3), DEQ provided an assessment of changes in visibility conditions. DEQ compared visibility at Arkansas' two Class I areas for the baseline period (2000–2004), the period included in the last progress report (2007–2011), and current conditions (2015–2019).[219] For progress reports due before January 31, 2025, the metrics for most impaired days and least impaired days are required. For progress reports due on and after January 31,

[213] *See* Table IV–1 of the 2022 Planning Period II SIP.

[214] *See* Table IV–2 of the 2022 Planning Period II SIP.

[215] Available at *https://www.agriculture.arkansas.gov/arkansas-voluntary-smoke-management-guidelines.*

[216] *See* Figures IV–1, IV–2, and IV–3 of the 2022 Planning Period II SIP.

[217] *See* Figures IV–5 of the 2022 Planning Period II SIP.

[218] *See* Figures IV–6, IV–7, and IV–8 of the 2022 Planning Period II SIP.

[219] *See* Table IV–3 of the 2022 Planning Period II SIP.

2025, the metric for most impaired days and clearest days metric are required. The State provided all three metrics for each period (most impaired days, clearest days, and least impaired days) and visibility has improved for all three metrics consecutively from each period to the next since the 2000–2004 baseline to the last period of the last progress report (2007–2011) to the current period (2015–2019) with most recent visibility conditions. The EPA is proposing to find that the State has adequately addressed the applicable provisions under 40 CFR 51.308(g)(3) in its 2022 Planning Period II SIP by assessing the changes in visibility conditions at Arkansas' Class I areas for the second implementation period.

Pursuant to 40 CFR 51.308(g)(4), DEQ presented categorized NEI state-wide emissions by sector for 2011, 2014, and 2017. The State also included 2020 CEMS emissions for EGUs in addition to the NEI data. The three targeted precursor pollutants for control ($SO_2$, $NO_X$, and $NH_3$) were inventoried as well as VOC and primary $PM_{2.5}$. The NEI inventories were categorized for all major visibility-impairing pollutants under various categories. The source categorization included EGU and non-EGU point; nonpoint; on and non-road mobile sources; off-road mobile sources (marine and rail); fires (agricultural, prescribed, wildfires, residential wood combustion); oil and gas; biogenic sources, anthropogenic dust, and agricultural $NH_3$. The 2017 NEI inventory was the most recent comprehensive inventory of updated actual emissions available at the time DEQ prepared its SIP.[220] There was an overall downward trajectory of statewide $NO_X$ emissions in Arkansas between 2011–2017. $NO_X$ emissions in Arkansas have decreased by 69,003 annual tons since 2011. The largest emission decrease came from the on-road mobile sector with 36,938 tons reduced followed by EGUs with 19,843 tons reduced. All $NO_X$ emission categories decreased except marine, residential wood, prescribed fire, and nonpoint sources which exhibited slight increases but only made-up 9 percent of the overall Arkansas $NO_X$ inventory. There was an overall downward trend of statewide $SO_2$ emissions in Arkansas between 2011 and 2017. Overall $SO_2$ emissions in Arkansas decreased by 43,112 annual tons since 2011. The largest annual $SO_2$ emission decrease came from the EGU sector with 36,399 tons reduced. All $SO_2$ emission categories decreased except for residential wood, prescribed fire, and nonpoint sources which increased but only made-up 9 percent of the overall Arkansas $SO_2$ inventory. Primary $PM_{2.5}$ increased between 2011 and 2017 by 613 tons. Annual emissions increased in non-EGU Point, residential wood, prescribed fire, and nonpoint categories. In particular, non-EGU point source annual emissions increased by over 9,000 tons and residential wood annual emissions increased by approximately 4,500 tons. All other categories decreased in emissions of primary $PM_{2.5}$. Overall statewide annual emissions of $NH_3$ decreased since 2011. Overall $NH_3$ emissions in Arkansas decreased by 38,307 tons since 2011. The largest decrease came from the agricultural $NH_3$ category with 44,247 tons. There were increases from EGUs, agricultural fire, oil and gas, non-EGU point, residential wood, and nonpoint annual ammonia emissions with the majority increase coming from agricultural fires at 5,432 tons, but these increases only made-up 8 percent of the total $NH_3$ inventory. Overall statewide annual emissions of VOCs decreased since 2011. Total annual VOC emissions decreased by 374,066 tons. The largest decrease in VOC emissions came from biogenics at 332,701 tons. All other categories decreased with the exception of marine, anthropogenic dust, and nonpoint categories, which exhibited increases but only made-up 4 percent of the Arkansas VOC inventory. The EPA is proposing to find that the State has adequately addressed the applicable provisions under 40 CFR 51.308(g)(4) in its 2022 Planning Period II SIP by tracking changes in emissions by category across the entire emission inventory for the second implementation period. The results show that the emissions from $SO_2$ and $NO_X$, the main contributors of regional haze in Arkansas, have all decreased from 2011 to 2017.

Pursuant to 40 CFR 51.308(g)(5), DEQ provided an assessment of significant changes in anthropogenic emissions. DEQ noted that overall emissions of anthropogenic $NO_X$, $SO_2$, $NH_3$, and VOCs all decreased significantly since the last progress report, with the exception of primary $PM_{2.5}$ emissions increasing by 613 tons. DEQ noted that this emission increase in primary $PM_{2.5}$ is dwarfed by the annual emission reductions in $NO_X$ and $SO_2$ (69,003 tpy and 43,112 tpy, respectively), which contribute the most to visibility impairment at Arkansas' Class I areas. As noted, there were other minor increases in emissions for certain source sectors, but they represent a fairly small portion of the Arkansas inventory. Based on DEQ's evaluation of emissions trends for Arkansas sources and visibility trends at Caney Creek and Upper Buffalo since the last progress report, DEQ concluded that the changes in anthropogenic emissions are facilitating, rather than impeding, progress towards natural visibility conditions at Arkansas Class I areas. The EPA is proposing to find that the State has adequately addressed the applicable provisions under 40 CFR 51.308(g)(5) in its 2022 Planning Period II SIP regarding assessing any anthropogenic emission changes that could impede visibility progress for the second implementation period.

Because Arkansas' 2022 Planning Period II SIP addresses the requirements of 40 CFR 51.308(g)(1) through (5), the EPA is proposing to find that Arkansas met the progress report requirements of 40 CFR 51.308(f)(5). Therefore, we are proposing to approve Arkansas' 2022 Planning Period II SIP as meeting the requirements of 40 CFR 51.308(f)(5) and 40 CFR 51.308(g) for periodic progress reports.

*H. State and FLM Coordination Requirements*

Section 169A(d) of the Clean Air Act requires states to consult with FLMs before holding the public hearing on a proposed regional haze SIP, and to include a summary of the FLMs' conclusions and recommendations in the notice to the public. In addition, the FLM consultation provision in section 51.308(i)(2) requires a state to provide the FLMs with an opportunity for consultation that is early enough in the state's policy analyses of its emission reduction obligation so that information and recommendations provided by the FLMs' can meaningfully inform the state's decisions on its long-term strategy. If the consultation has taken place at least 120 days before a public hearing or public comment period, the opportunity for consultation will be deemed early enough, Regardless, the opportunity for consultation must be provided at least 60 days before a public hearing or public comment period at the state level. Section 51.308(i)(2) also provides two substantive topics on which FLMs must be provided an opportunity to discuss with states: assessment of visibility impairment in any Class I area and recommendations on the development and implementation of strategies to address visibility impairment. Section 51.308(i)(3) requires states, in developing their implementation plans, to include a description of how they

[220] *See* Figures IV–9 to IV–14; and Tables IV–4 to IV–8 of the 2022 Planning Period II SIP for statewide emissions by sector.

addressed FLMs' comments. Lastly, section 51.308(i)(4) requires that the plan must provide procedures for continuing consultation between the State and FLMs on the implementation of the visibility protection program.

DEQ consulted with FLMs on SIP development both formally and informally. DEQ submitted letters to the FLMs on March 1, 2021, to notify them of the availability of the pre-proposal draft SIP and provided them with the opportunity to discuss the FLM's assessment of visibility impairment in any Class I area, and the FLM's recommendations on the development and implementation of strategies for improving visibility. DEQ provided public notice of the final SIP proposal on February 27, 2022, and hosted a public hearing on March 29, 2022, to receive comments on the proposed SIP revision. The public comment period concluded on April 28, 2022. In the appendices of the SIP submittal,[221] DEQ provided the comments received during the public comment period, including FLM recommendations, and a summary of DEQ's responses to those comments, along with records from the public hearing. DEQ noted that it continues to include FLMs in regional haze consultation through monthly regional haze calls with CenSARA states to address ongoing consultation with FLMs under 40 CFR 51.308(i)(4). DEQ has consulted with FLMs throughout this planning period, and will continue to coordinate with FLMs in the implementation of the 2022 planning period II SIP elements.[222] In addition, DEQ's 5-year progress report was due by January 31, 2025, and DEQ anticipates communications regularly occurring prior to the report, which started as early as mid-2023 to ensure that proper consultation is achieved. In conclusion, DEQ is committed to effectively consulting FLMs as required under the RHR.

The EPA is proposing to find that DEQ has satisfied the FLM consultation requirements under section 169A(d) and 40 CFR 51.308(i) in its 2022 Planning Period II SIP for the second implementation period.

## V. Proposed Action

The EPA is proposing to approve Arkansas' 2022 Regional Haze Planning Period II SIP revision, submitted August 8, 2022, and clarified on July 29, 2025, as meeting the applicable regional haze program requirements for the second implementation period contained in 40 CFR 51.308(f), (g)(1) through (5), and (i).

The EPA is proposing to approve the State's determination for FutureFuel Chemical Company to require a fuel switch from coal with 3 percent sulfur content by weight to a low sulfur coal that has 1.5 percent sulfur content (equating to 2.93 lb/MMBtu $SO_2$) for its three coal-fired boilers (SN:6M01–01). This requirement has been made enforceable by the state through an Administrative Order (LIS No. 22–085) dated August 3, 2022, and is included as part of the 2022 Planning Period II SIP submittal. The EPA is proposing to approve all requirements set forth in this Administrative Order for FutureFuel Chemical Company included as part of the 2022 Planning Period II SIP submittal as a source specific revision to be incorporated into the Arkansas SIP.

## VI. Incorporation by Reference

In this action, we are proposing to include in a final rule regulatory text that includes incorporation by reference. In accordance with the requirements of 1 CFR 51.5, we are proposing to incorporate by reference revisions to the Arkansas source specific requirements as described in section V of this preamble, Proposed Action. We have made, and will continue to make, these documents generally available electronically through *www.regulations.gov* (please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section of this preamble for more information).

## VII. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the CAA and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this action merely proposes to approve state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

- Is not a "significant regulatory action" subject to review by the Office of Management and Budget under Executive Orders 12866 (58 FR 51735, October 4, 1993);
- Is not subject to Executive Order 14192 (90 FR 9065, February 6, 2025) because State Implementation Plan approvals under the CAA are exempt from review under Executive Order 12866;
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Is not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the Clean Air Act.

In addition, the SIP is not approved to apply on any Indian reservation land or in any other area where the EPA or an Indian Tribe has demonstrated that a Tribe has jurisdiction. In those areas of Indian country, the proposed rule does not have Tribal implications and will not impose substantial direct costs on Tribal governments or preempt Tribal law as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

## List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

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

Dated: August 26, 2025.

**Walter Mason,**

*Regional Administrator, Region 6.*

[FR Doc. 2025–17041 Filed 9–4–25; 8:45 am]

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[221] *See* Appendix D of the 2022 Planning Period II SIP for the FLM contact list, notification letters, comments received, and DEQ's written consideration of the comments received.

[222] *See* Appendix D–2 Communication Log of the 2022 Planning Period II SIP that outlines DEQ communications on specific regional haze topics and the outcome of any associated conversations.