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I. Introduction

Arkansas' Class I areas, the Caney Creek Wilderness Area ("Caney Creek") and the Upper Buffalo Wilderness Area ("Upper Buffalo"), have seen marked improvement in visibility since the start of regional haze monitoring. Based on the Interagency Monitoring of Protected Visual Environment (IMPROVE) data, which reflects monitored visibility impairment in Class I areas, the haze index for the twenty percent worst days of visibility has been steadily improving as a result of reduced emissions within Arkansas and because of broader industrial and energy trends in other states. According to modeling performed by the Central Regional Air Planning Association (CENRAP)[1], all of Arkansas' elevated point sources (including all power plants and large industrial sources) account for only about 2.7% and 2.3% of total light extinction within Caney Creek and Upper Buffalo, respectively. The overwhelming visibility impact comes from non-Arkansas point sources and mobile sources. Because of the Mercury and Air Toxic Standards (MATS) rule[2], the continuing benefits of the Clean Air Interstate Rule (CAIR), the next phase of the Cross State Air Pollution Rule (CSAPR), and the national ambient air quality standards (NAAQS), along with continuing reductions in emissions from mobile sources, the visibility at Caney Creek and Upper Buffalo will continue to improve. Based on the visibility trends in both Class I areas and the imposition of the State Implementation Plan (SIP) controls, no further action will be necessary to ensure that Arkansas' Class I areas remain below the Uniform Rate of Progress (URP) until at least 2028 and likely even longer as a result of emissions controls that will be required by future regulatory programs and planned retirements of numerous electric generating units.[3]

A. Arkansas State Implementation Plan Revision

Arkansas has made significant improvements in air quality in recent years. Arkansas is currently in attainment for all of the NAAQS and is well below both the State's and the U.S. Environmental Protection Agency's (EPA) 2018 regional haze reasonable progress goals. Arkansas is taking steps to revise its regional haze SIP to return control of the Regional Haze Program to the state.

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[1] CENRAP is a regional planning organization that includes nine states–Nebraska, Kansas, Oklahoma, Texas, Minnesota, Iowa, Missouri, Arkansas, and Louisiana. Five such regional organizations are funded by EPA to address the interstate transport nature of the regional haze pollutants. The primary objective of these organizations is to evaluate technical information to better understand the impact of the affiliated states on national strategy and to develop regional strategies to reduce emissions of particulate matter and other pollutants leading to regional haze.

[2] In spite of the Supreme Court decision in Michigan v. EPA, 135 S. Ct. 2699 (2015), which held that EPA must evaluate costs in determining whether it is appropriate and necessary to regulate hazardous air pollutant emissions from electric generating units (EGUs), several EGUs already have installed controls to comply with MATS or have undertaken other steps to reduce their emissions. Even if the rule is stayed or vacated while EPA undertakes its cost analysis, ADEQ expects that the rule will go forward before the end of this planning period along with the associated emission reductions.

[3] 2016 monitored haze index values for Caney Creek and Upper Buffalo wilderness areas were less than the URP value associated with 2028. Five year average values for these Class I areas from the period 2012–2016 were less than 0.2 deciviews higher than the URP values associated with 2028. See Visibility Progress Update 2016 Datasheet in Appendix F.

Specifically, Arkansas has included in this SIP revisions to address disapproved portions of the Arkansas Regional Haze State Implementation Plan (AR RH SIP), submitted to the EPA in 2008. In 2012, EPA partially approved and partially disapproved the 2008 AR RH SIP.[4] Specifically, the following elements are being submitted to EPA for approval:

- Best available retrofit technology (BART) compliance dates;
- BART eligible sources and subject-to-BART sources;
- Select BART determinations:
    - Sulfur dioxide (SO_2) and particulate matter (PM) BART determinations for Arkansas Electric Cooperative Corporation (AECC) Bailey Plant Unit 1;
    - SO_2 and PM BART determinations for AECC McClellan Plant Unit 1;
    - SO_2 BART determination for Southwestern Power Company (SWEPCO) Flint Creek Plant Boiler No. 1;
    - SO_2 BART determination under both bituminous and sub-bituminous coal firing scenarios for Entergy White Bluff Units 1 and 2;
    - BART determination for Entergy White Bluff Plant Auxiliary Boiler;
- Reasonable progress goals (RPGs); and
- Long-term strategy.

Revisions to disapproved BART requirements for Domtar Ashdown Mill are not included in this SIP revision. Arkansas is not revising determinations included in the 2008 AR RH SIP that were approved.

B. Arkansas SIP Components Included in this Revision

The following Administrative Orders (AOs) are included in this SIP revision:

- LIS No. 18-073 between Entergy and ADEQ
- LIS No. 18-072 between SWEPCO and ADEQ
- LIS No. 18-071 between AECC and ADEQ

Inclusion of permanently enforceable emissions limitations and compliance schedules in the included AOs is consistent with and allowable under federal programs. The AOs contain rescission clauses, which are intended to effect any changes to the AO's provisions by federal court or legislative actions. These clauses would ensure that the effect of any such changes to the AO would be consistent with federal court or legislative action. ADEQ will review any federal guidance and consult with EPA as needed to ensure consistency with federal policy prior taking any actions affecting the AOs or SIP based on federal court or legislative action. Any changes affecting the SIP or AOs would be taken after notice and comment period for any such revisions, which would provide reasonable notice of any change.

Sampling, monitoring, and reporting requirements that are generally applicable to stationary sources, including sources for which emissions limitations are established in this SIP, are

[4] Approval and Promulgation of Implementation Plans; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze. (77 FR 14604, March 12, 2012)

contained in SIP-approved Arkansas Pollution Control and Ecology Commission (APC&EC) Regulation No. 19 Chapter 7. No revisions to requirements in Regulation No. 19 Chapter 7 were necessary for this SIP revision.

II. **Background**

In 1977, Congress added § 169A to the Clean Air Act (CAA), which set forth the following goal for restoring pristine conditions in national parks and wilderness areas:

Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from man-made air pollution.

In 1980, EPA issued regulations to address visibility degradation that is "reasonably attributable" to a single source or small group of sources. These regulations primarily addressed "plume blight"—visual impairment of air quality that manifests itself as a coherent plume—rather than overall haze. In 1988, EPA, the states, and federal land managers (FLMs) began monitoring fine particulate matter concentrations and visibility in thirty Class I areas to better understand the species of particulates causing visibility impairment.

When the CAA was amended in 1990, Congress added § 169B which authorized research and regular assessments of progress toward restoring visibility in Class I areas and authorized the creation of visibility transport regions and commissions. Specifically, CAA § 169B(f) mandated the creation of the Grand Canyon Visibility Transport Commission (GCVTC) to make recommendations to EPA for regions affecting the visibility of the Grand Canyon National Park. EPA relied upon the recommendations of GCVTC and research reports to develop the 1999 "Regional Haze Regulations: Final Rule" (RHR).[5]

The 1999 RHR sought to address the combined visibility effects of various pollution sources over a wide geographic region with the goal of achieving natural visibility conditions at designated Class I areas by 2064. This required all states, including those that did not have Class I areas to participate in planning, analysis, and emission control programs under the RHR. States with Class I areas were required to conduct certain analyses to establish goals for each Class I area in the state to 1) improve visibility on the haziest days and 2) ensure no degradation occurs on the clearest days. These goals and long-term strategies to achieve these goals were to be included in SIPs covering each ten-year period leading up to 2064. States were also required to submit progress reports in the form of SIP revisions every five years. The 1999 RHR also expanded the existing Class I visibility monitoring network to 108 Class I areas.

For the purposes of assisting with coordination and cooperation among states to address visibility issues, EPA designated five regional planning organizations (RPOs) to assist with coordination and cooperation among states in addressing visibility issues the states have in common. Arkansas

[5] *Regional Haze Rule* (64 FR 35714, July 1, 1999)

was located in the CENRAP RPO. Figure 1 is a map depicting the five RPO regions designated by EPA.

Figure 1 Regional Planning Organizations

In SIPs covering the first ten-year period, states were also specifically required to evaluate controls for certain sources that were not in operation prior to 1962, were in existence in 1977, and had the potential to emit 250 tons per year or more of any air pollutant. These sources were referred to as “BART-eligible sources.” States were required to make BART determinations for all BART-eligible sources or consider exempting some sources from BART requirements because they did not cause or contribute to visibility impairment in a Class I area. BART-eligible sources that were determined to cause or contribute to visibility impairment in a Class I area were subject to BART controls. In determining BART emissions limitations for each subject-to-BART source, states were required to take into account the existing control technology in place at the source, the cost of compliance, energy and nonair environmental impacts of compliance, remaining useful life of the source, and the degree of visibility improvement that was reasonably anticipated from use of each technology considered. States also had the flexibility to choose an alternative to BART—such as an emissions trading program—that would achieve greater reasonable progress in visibility protection than implementation of source-by-source BART controls. SIPs for the first ten-year planning period were due on December 17, 2007.

In 2005, EPA issued a revised BART rule pursuant to a partial remand of the 1999 RHR by the U.S. Court of Appeals of the DC District Court in 2002.[6] The Court had remanded the BART provisions of the 1999 RHR to EPA and denied industry’s challenge to the RHR goals of natural

[6] American Corn Growers Assn. v. EPA, 291 F.3d.1 (D.C. Cir. 2002)

visibility and no degradation. The revised BART rule included guidelines for states to use in determining which facilities must install controls and the type of controls the facilities must use.

In addition to revisions to BART, EPA has also issued rulemakings establishing the CAIR and its successor the CSAPR as approvable alternatives to source-by-source BART controls.[7] EPA has also amended regulatory requirements for state regional haze plans for the second planning period and beyond.[8]

On September 9, 2008, Arkansas submitted a SIP for the 2008–2018 planning period to comply with regional haze regulations promulgated as of 2005 codified at 40 C.F.R. Part 51. In a 2012 action on the 2008 AR RH SIP, EPA partially approved and partially disapproved the SIP.[9] This partial approval/partial disapproval of the 2008 AR RH SIP triggered a requirement for EPA to either approve a SIP revision by Arkansas or promulgate a federal implementation plan (FIP) within twenty-four months of the final rule partially approving and partially disapproving the 2008 AR RH SIP.

In the 2012 partial approval/partial disapproval of the 2008 AR RH SIP, EPA approved the following elements of the 2008 AR RH SIP:

- Identification of Class I areas affected by sources in Arkansas;
- Determination of baseline and natural visibility conditions;
- Determination of a uniform rate of progress (URP);
- Select BART determinations:
    - PM determination on SWEPCO Flint Creek Plant Boiler No. 1;
    - SO_2 and PM determinations for the natural gas firing scenario for Entergy Lake Catherine Plant Unit 4;
    - PM determinations for both bituminous and sub-bituminous coal firing scenarios for Entergy White Bluff Plant Units 1 and 2; and
    - PM determination for Domtar Ashdown Mill Power Boiler No. 1;
- Consultation with FLMs and other states regarding RPGs and long-term strategy;
- Coordination of regional haze and reasonably attributable visibility impairment (RAVI);
- Regional haze monitoring strategy and other SIP requirements under 40 C.F.R. 51.308(d)(4);
- A commitment to submit periodic regional haze SIP revisions; and
- A commitment to submit periodic progress reports that include a description of progress toward RPG and a determination of adequacy of the existing SIP.

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[7] Regional Haze Regulations; Revisions to Provisions Governing Alternative to Source-Specific Best Available Retrofit Technology (BART) Determinations (71, FR 60612, October 13, 2006)
Regional Haze Regulations; Revisions to Provisions Governing Alternative to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans (77 FR 33642, June 7, 2012).
[8] Protection of Visibility: Amendments to Requirements for State Plans (82 FR 3078, January 10, 2017)
[9] Approval and Promulgation of Implementation Plans; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze. (77 FR 14604, March 12, 2012)

EPA disapproved the following elements of the 2008 AR RH SIP:

- BART compliance dates;
- BART-eligible sources and subject-to-BART sources;
- Select BART determinations:
  - SO_2, NOx, and PM BART determinations for AECC Bailey Plant Unit 1;
  - SO_2, NOx, and PM BART determinations for AECC McClellan Plant Unit 1;
  - SO_2 and NOx BART determinations for SWEPCO Flint Creek Plant Boiler No. 1;
  - SO_2, NOx, and PM BART determinations for the fuel oil firing scenario and NOx BART determination for the natural gas firing scenario at Entergy Lake Catherine Plant Unit 4;
  - SO_2 and NOx BART determinations under both bituminous and sub-bituminous coal firing scenarios for Entergy White Bluff Units 1 and 2;
  - BART determination for Entergy White Bluff Plant Auxiliary Boiler;
  - SO_2 and NOx BART determinations for Domtar Ashdown Mill Power Boiler No. 1; and
  - SO_2, NOx, and PM BART determinations for Domtar Ashdown Mill Power Boiler No. 2;
- RPGs; and
- Long-term strategy.

On September 27, 2016, EPA finalized a regional haze FIP for Arkansas (AR RH FIP).[10] This FIP established new BART requirements for those sources whose BART determinations in the 2008 AR RH SIP were disapproved. The FIP also required the installation of controls at Entergy Independence Units 1 and 2. Despite the previous disapproval of ADEQ's determination in the 2008 AR RH SIP that Georgia Pacific Crossett Mill Boiler 6A and 9A did not cause or contribute to visibility impairment in a Class I area, EPA reversed its decision and concurred with ADEQ that Georgia Pacific Crossett Mill Boiler 6A and 9A are not subject to BART.

On November 22, 2016, the State of Arkansas filed a Petition for Reconsideration and Administrative Stay of the AR RH FIP. In the petition, the State of Arkansas requested that EPA reconsider the AR RH FIP based on new information not raised during the comment period that was of central relevance to the outcome of the FIP. Arkansas asserted that EPA should reconsider controls on Entergy Independence in light of recent data from the IMPROVE monitoring network that shows that Arkansas has already achieved the amount of progress required for the 2008–2018 planning period without having implemented the controls required in the FIP. Arkansas requested that EPA reconsider NOx emissions limitations placed on BART-eligible facilities in light of the recent rulemaking that increased the stringency of the CSAPR. Arkansas also requested reconsideration of BART for SO_2 at Entergy White Bluff during the 2008–2018 planning period. Lastly, Arkansas requested an immediate administrative stay pending completion of EPA's reconsideration of the AR RH FIP.

[10] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule (81 FR 66332, September 27, 2016)

On February 3, 2017, the State of Arkansas filed a Petition for Review of the AR RH FIP with the United States Court of Appeals for the Eighth Circuit. On March 8, 2017, the Court held the case in abeyance for ninety days. On April 14, 2017, EPA issued a letter notifying Arkansas that the Agency was convening the reconsideration process for the following:

- Compliance dates for NOx emissions limitations for Flint Creek Unit 1, White Bluff Units 1 and 2, and Independence Units 1 and 2;
- Low-load NOx limitations applicable to White Bluff Units 1 and 2 and Independence Units 1 and 2 during periods of operation at less than fifty percent of the unit's maximum heat input rating;
- SO_2 emissions limitations for White Bluff Units 1 and 2; and
- Compliance dates for SO_2 emissions limitations for Independence Units 1 and 2.

On April 25, 2017, EPA published in the Federal Register a partial stay of the effectiveness of the AR RH FIP.[11] Specifically, EPA stayed from April 25, 2017 until July 24, 2017 (ninety days) the compliance dates for the NOx emissions limitations at Flint Creek Unit 1, White Bluff Units 1 and 2, and Independence Units 1 and 2, as well as the compliance dates for the SO_2 emissions limitations for White Bluff units 1 and 2 and Independence Units 1 and 2. This action did not alter or extend the ultimate compliance dates for these units nor did it stay requirements for other units subject to the FIP.

On July 8, 2017, ADEQ proposed revisions to the State's Regional Haze SIP specifically to address NOx from electric generating units (NOx Regional Haze SIP). The NOx Regional Haze SIP revision sought to replace source-specific NOx BART determinations included in the 2008 AR RH SIP, as well as the NOx limitations promulgated under the AR RH FIP, with reliance on the CSAPR trading program. The NOx Regional Haze SIP revision proposal demonstrated that Arkansas meets all of the current requirements under 40 C.F.R. § 51.308(e)(4) for an alternative to NOx BART. ADEQ submitted the proposed NOx Regional Haze SIP to EPA Region 6 on July 12, 2017 and requested parallel processing. EPA proposed approval of the NOx Regional Haze SIP on September 11, 2017. ADEQ submitted the final NOx Regional Haze SIP on October 31, 2017 and EPA finalized approval on February 12, 2018.[12]

On July 13, 2017, EPA proposed revisions to the AR RH FIP that would extend the compliance dates for the NOx emissions limitations at Flint Creek Unit 1, White Bluff Units 1 and 2, and Independence Units 1 and 2.[13] In the proposal, EPA stated that the Petition for Reconsideration submitted by the State of Arkansas on November 22, 2016, as well as the petitions submitted by the owners of the five units, raised certain arguments regarding the feasibility of eighteen-month

[11] 82 FR 18994

[12] Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision and Withdrawal of Federal Implementation Plan: Proposed Rule (82 FR 42627, September 11, 2017)

Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision for NOx for Electric Generating Units in Arkansas: Final Rule (83 FR 5927, February 12, 2018)

[13] Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Revision of Federal Implementation Plan (82 FR 32284, July 13, 2017)

NOx compliance dates for the five units that have merit and warrant proposal of a revision to the AR RH FIP with respect to those compliance dates. Therefore, EPA proposed extension of the NOx compliance dates by twenty-one months; however, this extension was not finalized due to EPA's September 11, 2017proposal to withdraw NOx emission limits from the AR RH FIP for EGUs in concert with their proposed approval of the NOx Regional Haze SIP revision.[14] The action to withdraw the AR RH FIP EGU NOx emission limits action was finalized on February 12, 2018.[15]

On July 31, 2017, the Eighth Circuit Court of Appeals granted a motion by the parties to hold the case in which the EPA's FIP is at issue in abeyance until September 26, 2017. The Court has continued holding the case in abeyance, as requested by the parties, while ADEQ works on issuing a replacement SIP. On March 7, 2018, the AR RH FIP SO_2 emission limits for Entergy White Bluff and Independence were judicially stayed.

III. Revisions to BART-Eligible and Subject-to-BART Sources

EPA disapproved the list of BART-eligible and subject-to-BART sources included in the 2008 AR RH SIP. The 2008 AR RH SIP inadvertently omitted Georgia Pacific Crossett Mill Boiler 6A and 9A from the list of BART-eligible sources in Table 9.1 on page 45; however, Georgia Pacific Crossett Mill 6A and 9A were included in the list of BART-eligible sources adopted into APC&EC Regulation No. 19 and submitted with the 2008 AR RH SIP.

Table 1 below is a correction to the list of BART-eligible units in Arkansas in the SIP.

Table 1 Facilities with BART-Eligible Units in the State of Arkansas

BART Source Category Number and Name	Facility Name	Arkansas Facility Identification Number	Unit ID	Unit Description
1. Fossil fuel-fired Electric Plants > 250 million British thermal units (MMbtu)/hour – Electric Generating	AECC Carl E. Bailey	74-00024	SN-01	Boiler
	AECC McClellan	52-00055	SN-01	Boiler
	Entergy Lake Catherine	30-00011	SN-03	Unit 4 Boiler

[14] Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision and Withdrawal of Federal Implementation Plan: Proposed Rule (82 FR 42627, September 11, 2017)
[15] Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan Revisions; Withdrawal of Federal Implementing Plan for NOx for Electric Generating Units in Arkansas: Final Rule (83 FR 5915, February 12, 2018)

BART Source Category Number and Name	Facility Name	Arkansas Facility Identification Number	Unit ID	Unit Description
Units (EGUs)	Plant			
	Entergy Ritchie	54-00017	SN-02	Unit 2
	Entergy White Bluff	35-00110	SN-01	Unit 1 Boiler
			SN-02	Unit 2 Boiler
			SN-05	Auxiliary Boiler
	SWEPCO Flint Creek Power Plant	04-00107	SN-01	Boiler
3. Kraft Pulp Mills	Domtar Industries, Inc. Ashdown Mill	41-00002	SN-03	#1 Power Boiler
			SN-05	#2 Power Boiler
	Delta Natural Kraft and Mid America Packaging, LLC.	35-00017	SN-02	Recovery Boiler
	Evergreen Packaging Inc., Pine Bluff Mill	35-00016	SN-04	#4 Recovery Boiler
	Georgia-Pacific Corporation Crossett Paper Operations	02-00013	SN-19	6A Boiler
			SN-22	9A Boiler
	Green Bay Packaging, Inc. Arkansas Kraft Division	15-00001	SN-05A	Recovery Boiler
	Potlatch Forest Products Corporation – Cypress Bend	21-00036	SN-04	Power Boiler

BART Source Category Number and Name	Facility Name	Arkansas Facility Identification Number	Unit ID	Unit Description
	Mill			
11. Petroleum Refineries	Lion Oil Company	70-00016	SN-809	#7 Catalyst Regenerator
15. Sulfur Recovery Plant	Albemarle Corporation South Plant	14-00028	SR-01	Tail Gas Incinerator
19. Sintering Plants	Big River Industries	18-00082	SN-01	Kiln A
21. Chemical Processing Plants	Albemarle Corporation South Plant	14-00028	BH-01	Boiler #1
			BH-02	Boiler #2
	FutureFuel Chemical Co.	32-00036	6M01-01	3 Coal Boilers
	El Dorado Chemical Company	70-00040	SN-08	West Nitric Acid Plant
			SN-09	East Nitric Acid Plant
			SN-10	Nitric Acid Concentrator

Although EPA initially disapproved ADEQ's determination in the 2008 AR RH SIP that Georgia Pacific-Crossett Mill Boiler 6A and 9A did not cause or contribute to visibility impairment in a Class I area and were not subject to BART, EPA reversed its decision in the 2016 AR RH FIP and concurred with ADEQ that Georgia-Pacific Crossett Mill Boiler 6A and 9A are not subject to BART. This reversal was supported by information provided by Georgia-Pacific regarding revisions to emission limits included in their Title V permit and additional dispersion modeling conducted using those revised limits.[16] The results of this modeling demonstrated that the maximum impact of Georgia-Pacific Crossett's boilers on any Class I area was less than the 0.5 deciview threshold used by ADEQ to determine whether a BART-eligible source should be considered subject-to-BART. Georgia-Pacific provided further information regarding fuel usage during the 2001–2003 baseline and performed calculations using AP-42, Compilation of Air Pollutant Emission Factors, that demonstrated that emission rates during the 2001–2003 baseline were lower than the rates modeled in Georgia Pacific's 2011 BART screening modeling and lower than their currently enforceable Title V permit limits.[17][18] Therefore, EPA concluded that, based upon the additional information provided by Georgia-Pacific, Georgia-Pacific Crossett Mill 6A Boiler and 9A Boiler are not subject to BART. ADEQ concurs that Georgia-Pacific Crossett Mill 6A Boiler and 9A Boiler are not subject to BART; therefore, no revisions are necessary to the list of subject-to-BART sources in Arkansas included in the 2008 AR RH SIP. Documentation in support of the determination that Georgia-Pacific Crossett Mill 6A Boiler and 9A Boiler are not subject to BART can be found in Appendix A. Table 2 lists the subject-to-BART sources in Arkansas.

Table 2 Facilities with Subject-to-BART Units in the State of Arkansas

BART Source Category Number and Name	Facility Name	Arkansas Facility Identification Number	Unit ID	Unit Description
1. Fossil fuel-fired Electric Plants > 250 million British thermal units (MMBtu)/hour – Electric Generating Units (EGUs)	AECC Carl E. Bailey	74-00024	SN-01	Boiler
	AECC McClellan	52-00055	SN-01	Boiler
	Entergy Lake Catherine Plant	30-00011	SN-03	Unit 4 Boiler
	Entergy White Bluff	35-00110	SN-01	Unit 1 Boiler
			SN-02	Unit 2 Boiler
			SN-05	Auxiliary Boiler
	SWEPCO Flint Creek	04-00107	SN-01	Boiler

16 May 18, 2012 letter from Georgia Pacific Crossett Paper Operations to ADEQ. A copy of this letter is included in Appendix A of this SIP.
17 April 1, 2013 letter from Georgia-Pacific-Crossett to ADEQ and associated supporting attachments.
18 ADEQ Operating Permit 0597-AOP-R-18

	Power Plant			
3. Kraft Pulp Mills	Domtar Industries, Inc. Ashdown Mill	41-00002	SN-03	#1 Power Boiler
			SN-05	#2 Power Boiler

IV. Revisions to BART Determinations

Among the provisions disapproved in EPA's 2012 action on the 2008 AR RH SIP, were several BART determinations, including the following BART determinations that are addressed in this SIP revision:

- SO_2 and PM BART determinations for AECC Bailey Plant Unit 1;
- SO_2 and PM BART determinations for AECC McClellan Plant Unit 1;
- SO_2 BART determinations for SWEPCO Flint Creek Plant Boiler No. 1;
- SO_2 BART determinations under both bituminous and sub-bituminous coal firing scenarios for Entergy White Bluff Units 1 and 2;
- BART determination for Entergy White Bluff Plant Auxiliary Boiler;

In this SIP revision, ADEQ is addressing disapproved emissions limitations and compliance schedules for the subject-to-BART sources listed above. All emissions limitations included in this SIP revision will be rendered enforceable through AOs included with this SIP revision.

The statutory five factors established in U.S.C. § 7491(g)(2) were analyzed for each subject-to-BART unit. These analyses and the emissions limitations determined thereupon are summarized in Sections IV.A–D of this SIP. The analyses are provided in Appendices B–E. Pursuant to Ark. Code Ann. § 8-4-317, ADEQ also considered the factors set forth in Ark. Code Ann. § 8-4-312 for emissions limitations included in this SIP revision to satisfy BART requirements. The emissions limitations included in this SIP are based upon generally accepted scientific knowledge and engineering practices. The need for each measure in attaining or maintaining the NAAQS is not applicable to the Regional Haze Program. Table 3 describes how each factor set forth in Ark. Code Ann. § 8-4-312 was considered.

Table 3 Consideration of Ark. Code Ann. § 8-4-312 for BART Limitations

Ark. Code Ann. § 8-4-312 Factor	Consideration of the Factor
(1) The quantity and characteristics of air contaminants and the duration of their presence in the atmosphere that may cause air pollution in a particular area of the state;	These characteristics were considered in modeling conducted for each source's BART analysis.
(2) Existing physical conditions and topography;	Modeling in support of the emissions limitations established in this SIP utilizes these

Ark. Code Ann. § 8-4-312 Factor	Consideration of the Factor
	factors as inputs.
(3) Prevailing wind directions and velocities;	Modeling in support of the emissions limitations established in this SIP utilizes these factors as inputs.
(4) Temperatures and temperature-inversion periods, humidity, and other atmospheric conditions;	Modeling in support of the emissions limitations established in this SIP utilizes these factors as inputs.
(5) Possible chemical reactions between air contaminants or between such air contaminants and air gases, moisture, or sunlight;	Modeling in support of the emissions limitations established in this SIP utilizes these factors as inputs.
(6) The predominant character of development of the area of the state such as residential, highly developed industrial, commercial, or other characteristics	The predominant character of development of the area of the state impacted by this SIP includes Class I areas—specifically Upper Buffalo and Caney Creek. The Class I areas are protected and remain deliberately undeveloped. Furthermore enhanced visibility in these areas will benefit the primary driver of development around Class I areas: tourism.
(7) Availability of air-cleaning devices;	Availability of air cleaning devices was considered as part of each BART analysis.
(8) Economic feasibility of air-cleaning devices	Economic feasibility of air cleaning devices was considered as part of each BART analysis.
(9) Effect on normal human health of particular air contaminants	This factor is not applicable to the regional haze program, which targets visibility improvements.
(10) Effect on efficiency of industrial operation resulting from use of air-cleaning devices;	Effect on efficiency of air cleaning devices was considered as part of each BART analysis.
(11) The extent of danger to property in the area reasonably to be expected from any particular air contaminant;	This factor is not applicable to the regional haze program, which targets visibility improvements.
(12) Interference with reasonable enjoyment of life by persons in the area and conduct of established enterprises that can reasonably be expected from air contaminants;	Visibility improvements are expected to occur at Arkansas Class I areas in the State as a result of the emissions limitations included in this SIP. Visitors to Caney Creek and Upper Buffalo are expected to enjoy these improvements. Persons that conduct tourism enterprises may also benefit as a result of the BART controls required in this SIP. Costs of control may be passed on to customers of the sources for which ADEQ is establishing emissions limitations; however, these costs are anticipated to be lower in this SIP than in the AR RH FIP that this SIP seeks to replace.
(13) The volume of air contaminants emitted from a particular class of air contamination	The volume of air contaminants emitted from subject-to-BART sources for which controls

Ark. Code Ann. § 8-4-312 Factor	Consideration of the Factor
sources;	are included in this SIP are factored into the BART analysis.
(14) The economic and industrial development of the state and the social and economic value of the air contamination sources;	Costs of control may be passed on to customers of the sources for which ADEQ is establishing emissions limitations. This may have a negative impact on economic and industrial development in the State. However, these costs are anticipated to be lower in this SIP than in the AR RH FIP that this SIP seeks to replace.
(15) The maintenance of public enjoyment of the state's natural resources; and	Visibility improvements are expected to occur at Arkansas Class I areas in the State as a result of the emissions limitations included in this SIP. Visitors to Caney Creek and Upper Buffalo are expected to enjoy these improvements. Persons that conduct tourism enterprises may also benefit as a result of the BART controls required in this SIP.
(16) Other factors that the department or the commission may find applicable.	Other factors considered by the Department in setting BART controls for subject-to-BART sources are contained in the Sections IV.A–D and Appendices B–E of this SIP.

A. Arkansas Electric Cooperative Corporation Carl E. Bailey Generating Station

AECC produced a BART analysis (dated March 2014, Version 4) for the Carl E. Bailey Generating Station. EPA used this analysis in the development of the AR RH FIP and ADEQ has made its BART determination included in this SIP based on the analysis provided by AECC. This analysis is included in Appendix B of this SIP and summarized below.

AECC Bailey Plant Unit 1 is a 122 megawatt wall-fired boiler installed in 1966. Unit 1 has a maximum heat input of 1,350 million British thermal units per hour (MMBtu/hr). AECC Bailey Plant Unit 1 burns pipeline quality natural gas as the primary fuel and No. 6 fuel oil as a secondary fuel. AECC Bailey Plant Unit 1 meets the BART-eligibility criteria. Also, ADEQ determined, based on results of previous air dispersion modeling, that the AECC Bailey Plant Unit 1 contributes greater than 0.5 deciviews to visibility impairment in at least one Class I area. Although, more recent modeling conducted by Trinity Consultants (Trinity) shows impacts for AECC Bailey Unit 1 that are less than 0.5 deciviews, AECC conducted a complete BART analysis and identified the AECC Bailey Plant Unit 1 source as the sole AECC Bailey source subject to BART. Consequently, the five BART statutory factors were considered for AECC Bailey Unit 1.

1. Summary of BART Analysis and Requirements for SO_2

The available control options for AECC Bailey Plant Unit 1 when burning fuel oil are flue gas desulfurization (FGD) systems and fuel switching. No control technologies were evaluated for natural gas burning scenarios due to the intrinsically low sulfur content of natural gas. FGD systems were considered technically infeasible. Fuel switching was the only technically feasible control option.

Fuel oil stored at AECC Bailey since 2006 had an average sulfur content of 1.81% by weight, therefore one percent sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, and diesel were considered. Fuel switching to one percent sulfur fuel oil at AECC Bailey Plant Unit 1 would result in up to a forty-five percent control efficiency for SO_2. Switching to 0.5% fuel oil would result in a seventy-two percent control efficiency and switching to 0.05% sulfur diesel would result in a ninety-seven percent control efficiency.

a. Existing Controls in Use at the Source

AECC Bailey does not have existing SO_2 control technology.

b. Cost of Compliance

The fuel switching options evaluated do not require capital investments in equipment; therefore, annual costs are based upon operation and maintenance costs associated with the different fuels. The cost-effectiveness of switching to one percent sulfur No. 6 fuel oil is $1,198/ton of SO_2 reduced. The cost-effectiveness of switching to 0.5% sulfur No. 6 fuel oil is $2,559/ton. The cost-effectiveness of switching to diesel is $5,382/ton, which is out of the range typically identified as cost-effective. Both 0.5% sulfur No. 6 fuel oil and one percent sulfur No. 6 fuel oil were within the range typically considered cost-effective.

c. Energy and Nonair Quality Environmental Impacts

AECC concluded that there are no energy or nonair quality impacts associated with fuel switching.

d. Remaining Useful Life

The remaining useful life of Bailey Unit 1 does not impact the annualized costs of evaluated control technologies since it is assumed that fuel switching will not require any significant capital costs.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated technologies are included in Table 5-13 at page 5-12 of AECC's BART analysis. Fuel switching to one percent sulfur No. 6 fuel oil would result in a 41.52% reduction in visibility impairment from AECC Bailey at Caney Creek, a 44.25% reduction at Upper Buffalo, a 44.02% reduction at Hercules Glades Wilderness Area (Hercules Glades), and a 45.65% reduction at Mingo Wilderness Area (Mingo). Fuel switching to 0.5% sulfur No. 6 fuel oil would result in a 56.97% reduction in visibility impairment from AECC Bailey at Caney Creek, a 63.51% reduction at Upper Buffalo, a 63.32% reduction at Hercules Glades, and a 55.15% reduction at Mingo.

f. BART Requirements for SO_2

Based on cost/ton of SO_2 emissions reduced and visibility improvement among low sulfur fuels, AECC determined that SO_2 BART for AECC Bailey Plant Unit 1 is using fuel oil and natural gas with 0.5% sulfur or less. ADEQ concurs with AECC's BART determination for SO_2 at Bailey Plant Unit 1.

AO LIS No. 18-071 includes enforceable limitations and compliance dates consistent with ADEQ's BART determination.

2. Summary of BART Analysis and Requirements for PM

Available PM retrofit control technologies include: dry electrostatic precipitator (Dry ESP), wet electrostatic precipitator (Wet ESP), fabric filter, wet scrubber, a cyclone, and fuel switching. Dry ESP and fabric filters were considered technically infeasible.

A Wet ESP, with an estimated PM control efficiency of up to ninety percent, is a technically feasible option for PM control.

The use of a wet scrubber, with an estimated PM removal efficiency of around fifty-five percent, is a technically feasible option.

A cyclone is a technically feasible option. When clean oil is combusted, a high percentage of small particles are emitted and cyclones are not effective at controlling the smaller particles that are the primary source of visibility impairment, although when including the larger particles an eighty-five percent reduction in PM can be expected.

Fuel switching to lower sulfur content fuel is a technically feasible option. Reductions in filterable PM for No. 6 fuel oil are directly related to the sulfur content of the fuel and greater than a ninety-nine percent reduction of PM is expected solely from a fuel switch to natural gas.

a. Existing Controls in Use at the Source

AECC Bailey does not have existing PM control technology.

b. Cost of Compliance

The cost of compliance differs among the control technologies evaluated. Add-on controls such as Wet ESP, wet scrubber, and cyclone systems involve capital costs for new equipment that were annualized over a fifteen year period for the analysis. Fuel switching options have associated operation and maintenance costs, but no capital costs. The cost-effectiveness values of all evaluated options exceed $22,000/ton of PM removed, which is higher than the range typically considered cost-effective.

c. Energy and Nonair Quality Environmental Impacts

AECC concluded that there are no energy or nonair quality impacts associated with fuel switching; however, there are impacts associated with wet ESPs and wet scrubbers. These impacts were factored into the cost of compliance.

d. Remaining Useful Live

AECC anticipated that the remaining useful life of the AECC Bailey Plant Unit 1 is at least as long as the capital cost recovery period of fifteen years.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated add-on technologies are included in Table 7-8 at page 7-9 of AECC's BART analysis and improvements that would be anticipated from fuel switching are included in Table 5-13 at page 5-12. Although no control options were considered cost-effective for PM, AECC determined that switching to 0.5% sulfur No. 6 fuel oil was cost-effective for SO_2. Visibility improvements anticipated from fuel switching to a lower sulfur content fuel oil are discussed in section IV.A.1.e. above.

f. BART Requirements for PM

AECC proposed that no fuel changes or add-on controls constitute PM BART for AECC Bailey Unit 1. In addition, the BART determination for SO_2 of fuel switching to 0.5 % sulfur No. 6 fuel oil will also result in PM reductions. ADEQ concurs with this AECC's BART determination for PM at Bailey Plant Unit 1 that no additional controls are necessary to satisfy PM BART beyond fuel switching to 0.5 % sulfur No. 6 fuel oil consistent with the SO_2 BART determination.

B. Arkansas Electric Cooperative Corporation John L. McClellan Generating Station

AECC produced a BART analysis (dated March 2014, Version 4) for the John L. McClellan Generating Station. EPA used this analysis in the development of the AR RH FIP and ADEQ has made its BART determination included in this SIP based on the analysis provided by AECC. This analysis is included in Appendix B of this SIP and summarized below.

AECC McClellan Plant Unit 1 is a 122 megawatt wall-fired boiler installed in 1971. AECC McClellan Plant Unit 1 has a maximum heat input of 1,436 MMBtu/hr. AECC McClellan Plant Unit 1 burns pipeline quality natural gas as the primary fuel and No. 6 fuel oil as a secondary fuel. AECC McClellan Plant Unit 1 meets the BART-eligibility criteria. Also, ADEQ determined, based on results of previous air dispersion modeling, that the AECC McClellan Plant Unit 1 contributes greater than 0.5 deciview to visibility impairment in at least one Class I area. Therefore, AECC conducted a complete BART analysis and identified the AECC McClellan Plant Unit 1 source as the sole AECC McClellan source subject to BART. Consequently, the five BART statutory factors were considered for AECC McClellan Unit 1.

1. Summary of BART Analysis and Requirements for SO_2

The available control options for AECC McClellan Unit 1 when burning fuel oil are FGD systems and fuel switching. No control technologies were evaluated for natural gas burning scenarios due to the intrinsically low sulfur content of natural gas. FGD systems were considered technically infeasible. Fuel switching was the only technically feasible control option.

Fuel oil stored at AECC McClellan since 2009 had an average sulfur content of 1.38% by weight, therefore one percent sulfur No. 6 fuel oil, 0.5% sulfur No. 6 fuel oil, and diesel were considered. Fuel switching to one percent sulfur fuel oil at AECC McClellan Plant Unit 1 would result in up to a twenty-eight percent control efficiency for SO_2. Switching to 0.5% fuel oil would result in a sixty-four percent control efficiency and switching to 0.05% sulfur diesel would result in a ninety-six percent control efficiency.

a. Existing Controls in Use at the Source

AECC McClellan does not have existing SO_2 control technology.

b. Cost of Compliance

The fuel switching options evaluated do not require capital investments in equipment; therefore, annual costs are based upon operation and maintenance costs associated with the different fuels. The cost-effectiveness of switching to one percent sulfur No. 6 fuel oil is $2,457/ton of SO_2 reduced. The cost-effectiveness of switching to 0.5% sulfur No. 6 fuel oil is $4,553/ton. The cost-effectiveness of switching to diesel is $10,698/ton, which is out of the range typically identified as cost-effective. Both 0.5% sulfur No. 6 fuel oil and one percent sulfur No. 6 fuel oil were within the range typically considered cost-effective.

c. Energy and Nonair Quality Environmental Impacts

AECC concluded that there are no energy or nonair quality impacts associated with fuel switching.

d. Remaining Useful Life

The remaining useful life of McClellan Unit 1 does not impact the annualized costs of evaluated control technologies since it is assumed that fuel switching will not require capital investments in new equipment.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated technologies are included in Table 5-13 at page 5-12 of AECC's BART analysis. Fuel switching to one percent sulfur No. 6 fuel oil would result in a 13.67% reduction in visibility impairment from AECC McClellan at Caney Creek, a 13.16% reduction at Upper Buffalo, a 12.55% reduction at Hercules Glades, and a 15.35% reduction at Mingo. Fuel switching to 0.5% sulfur No. 6 fuel oil would result in a 48.23% reduction in visibility impairment from AECC McClellan at Caney Creek, a 45.11% reduction at Upper Buffalo, a 50.22% reduction at Hercules Glades, and a 40.35% reduction at Mingo.

f. BART Requirements for SO_2

Based on cost/ton of SO_2 emissions reduced and visibility improvement among low sulfur fuels, AECC proposed that SO_2 BART for AECC McClellan Plant Unit 1 is using fuel oil and natural gas with 0.5% sulfur or less. ADEQ concurs with AECC's BART determination for SO_2 at McClellan Plant Unit 1.

AO LIS No. 18-071 includes enforceable limitations and compliance dates consistent with ADEQ's BART determination.

2. Summary of BART Analysis and Requirements for PM

Available PM retrofit control technologies include: Dry ESP, Wet ESP, fabric filters, wet scrubber, a Cyclone, and fuel switching. Dry ESP and fabric filters were considered technically infeasible.

A Wet ESP, with an estimated PM control efficiency of up to ninety percent, is a technically feasible option for PM control.

The use of a wet scrubber, with an estimated PM removal efficiency of around fifty-five percent, is a technically feasible option.

A cyclone is a technically feasible option. When clean oil is combusted, a high percentage of small particles are emitted and cyclones are not effective at controlling the smaller particles that are the primary source of visibility impairment, although when including the larger particles an eighty-five percent reduction in PM can be expected.

Fuel switching to lower sulfur content fuel is a technically feasible option. Reductions in filterable PM for No. 6 fuel oil are directly related to the sulfur content of the fuel and greater than a ninety-nine percent reduction of PM is expected solely from a fuel switch to natural gas.

a. Existing Controls in Use at the Source

AECC McClellan does not have existing PM control technology.

b. Cost of Compliance

The cost of compliance differs among the control technologies evaluated. Add-on controls such as Wet ESP, wet scrubber, and cyclone systems involve capital costs for new equipment that were annualized over a fifteen year period for the analysis. Fuel switching options have associated operation and maintenance costs, but no capital costs. The cost-effectiveness of all evaluated options exceeds $14,000/ton of PM removed, which is higher than the range typically considered cost-effective.

c. Energy and Nonair Quality Environmental Impacts

AECC concluded that there are no energy or nonair quality impacts associated with fuel switching; however, there are impacts associated with wet ESPs and wet scrubbers. These impacts were factored into the cost of compliance.

d. Remaining Useful Live

AECC anticipated that the remaining useful life of the AECC McClellan Plant Unit 1 is at least as long as the capital cost recovery period of fifteen years.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated add-on technologies are included in Table 7-9 at page 7-10 of AECC BART analysis and improvements that would be anticipated from fuel switching are included in Table 5-14 at page 5-13. Although no control options were considered cost-effective for PM, AECC determined that switching to 0.5% sulfur No. 6 fuel oil was cost-effective for SO_2. Visibility improvements anticipated from fuel switching to a lower sulfur content fuel oil are discussed in section IV.A.1.e. above.

f. BART Requirements for PM

AECC proposed that no fuel changes or add-on controls constitute PM BART for AECC McClellan Unit 1. In addition, the BART determination for SO_2 of fuel switching to 0.5 % sulfur No. 6 fuel oil will result in PM reductions. ADEQ concurs with this AECC's BART determination for PM at McClellan Plant Unit 1 that no additional controls are necessary to satisfy PM BART beyond fuel switching to 0.5 % sulfur No. 6 fuel oil consistent with the SO_2 BART determination.

C. Entergy Arkansas, Inc. Lake Catherine Plant

Entergy provided a BART analysis (dated June 2013) for burning of natural gas at the Entergy Lake Catherine Generating Station. EPA used this analysis in the construction of the AR RH FIP and ADEQ has made its BART determination included in this SIP based on the analysis provided by Entergy. This analysis is included in Appendix C of this SIP and summarized below.

Entergy Lake Catherine Plant Unit 4 is a 558 megawatt tangentially-fired boiler installed in 1970. Entergy Lake Catherine Plant Unit 4 has a maximum heat input of 5,850 MMBtu/hr. Entergy Lake Catherine Plant Unit 4 burns pipeline quality natural gas and was capable of burning No. 6 fuel oil as a secondary fuel at the time the BART analysis was submitted; however, Entergy has committed to not burning fuel oil at this unit. Therefore, emissions from fuel oil were not considered in the BART analysis and the Entergy Lake Catherine Plant Unit 4 must not burn fuel oil until BART determinations are promulgated for this unit for SO_2 and PM for the fuel oil firing scenario through EPA action upon and approval of revised BART determinations submitted by the State as a SIP revision. Entergy Lake Catherine Plant Unit 4 meets the BART-eligibility criteria. Also, ADEQ determined, based on results of previous air dispersion modeling, that the Entergy Lake Catherine Plant Unit 4 contributes an existing visibility impairment of greater than 0.5 deciview in at least one Class I area. Therefore, Entergy conducted a complete BART analysis and identified the Entergy Lake Catherine Plant Unit 4 source as the sole Entergy Lake Catherine unit subject to BART. Consequently, the five BART statutory factors were considered for Entergy Lake Catherine Plant Unit 4.

1. Summary of BART Analysis and Requirements for SO_2

A BART determination for SO_2 based on the use of natural gas was included in the 2008 AR RH SIP and approved in EPA's March 12, 2012, final rule (77 FR 14604). The determination resulted in no SO_2 controls needed during natural gas combustion. Because Entergy has committed to not burning fuel oil, no changes are needed to EPA's determinations with respect to the previously approved SO_2 BART limitations included in APC&EC Regulation No. 19.

2. Summary of BART Analysis and Requirements for PM

A BART determination for PM at Lake Catherine Plant Unit 4 based on the use of natural gas was included in the 2008 AR RH SIP and approved in EPA's March 12, 2012, final rule (77 FR 14604). The determination resulted in no PM controls needed during natural gas combustion. Because Entergy has committed to not burning fuel oil, no changes are needed to EPA's determinations with respect to the previously approved PM BART limitation included in APC&EC Regulation No. 19.

D. Entergy Arkansas, Inc. White Bluff

At the request of ADEQ, Entergy provided an updated BART five-factor analysis for SO_2 for White Bluff (dated August 18, 2017) to supplement previous BART analyses (dated February 2013, October 2013, August 2015, and August 2016) submitted to EPA for their consideration in development of the AR RH FIP. This updated analysis provided new information in light of an updated remaining useful life for White Bluff and evaluated three new control scenarios. At the time of proposal of this SIP revision, certain elements, including the remaining useful life, were held confidential. For this reason ADEQ also relied upon additional supplemental information provided by Entergy on April 5, 2017, which detailed cost-effectiveness for Dry FGD with various remaining useful life assumptions, in the proposed SIP. On December 1, 2017, Entergy released confidentiality claims with respect to the August 18, 2017 updated BART analysis for White Bluff. ADEQ released a notice of data availability to provide the public with the opportunity to take the full updated five-factor analysis into consideration as they prepared their comments on the proposed SIP. ADEQ's final BART determination included in this SIP is based on the updated BART five-factor analysis for SO_2, previous BART analyses, and supplemental information provided by Entergy. These analyses are included in Appendix D of this SIP and our evaluation is provided below.

Entergy White Bluff Units 1 and 2 are identical tangentially-fired 850 megawatt boilers, which were in existence in 1974, and they have a maximum heat input capacity of 8,950 MMBtu/hr each. These units are currently equipped with ESPs to control PM emissions. Entergy White Bluff Units 1 and 2 burn sub-bituminous coal as a primary fuel and burn No. 2 fuel oil or biofuel as a start-up fuel. Entergy White Bluff also has a rarely used 183 MMBtu/hr auxiliary boiler that burns only No. 2 fuel oil or biodiesel. Entergy White Bluff Units 1 and 2 and the auxiliary boiler meet the BART eligibility criteria. Because modeling demonstrates that the auxiliary boiler's greatest impact on visibility at any Class 1 area is only 0.01 deciview, EPA determined that existing emissions limitations for the auxiliary boiler in Entergy's permit satisfy BART for SO_2, NOx, and PM. ADEQ concurs with this determination. Entergy White Bluff Units 1 and 2 contribute greater than 0.5 deciview to at least one Class I area. Consequently, the five BART statutory factors were considered for Entergy White Bluff Units 1 and 2.

1. Summary of BART Analyses and Requirements for SO_2

The available SO_2 retrofit control technology options for White Bluff Units 1 and 2 include: fuel switching to low sulfur coal (LSC), dry sorbent injection (DSI), spray dryer absorber (SDA), circulating dry scrubber (CDS), and Wet FGD. All evaluated options were considered technically feasible.

Fuel switching to LSC with a sulfur content of 0.6 lb/MMBtu would result in an 8.75% reduction in SO_2 emissions from baseline levels.

DSI, which is the injection of sorbent into the exhaust gas stream, has a control efficiency that can range from forty to ninety percent based on sorbent particle size, residence time, temperature, and particulate collection equipment. Entergy evaluated two particulate collection methods for DSI at Entergy White Bluff. The first collection method would require retrofits to the currently installed ESP and would achieve a fifty percent SO_2 removal efficiency. The second "enhanced" collection method would require the installation of a baghouse and would achieve an eighty percent SO_2 removal efficiency. Both evaluated DSI technologies would require landfilling of DSI waste.

SDA and CDS, both Dry FGD systems, have control efficiencies ranging from sixty to ninety-five percent. Both systems utilize a fine mist of lime slurry sprayed into an absorption tower to absorb SO_2. The resulting calcium sulfite and calcium sulfate are then collected with a fabric filter.

Wet FGD, scrubbing the exhaust gas stream with a lime or limestone slurry, is capable of achieving eighty to ninety-five percent control of SO_2 emissions. This option was eliminated in previous analyses and in the AR RH FIP due to the small incremental difference in visibility improvement between Wet FGD and Dry FGD relative to the marginal cost difference.

a. Existing Controls in Use at the Source

The current permitted emissions rate for Units 1 and 2 at Entergy White Bluff is a three-hour average emission rate of 1.2 lb SO_2/MMBtu for each unit based on the new source performance standard for fossil-fuel fired steam generators.

b. Cost of Compliance

The cost of compliance differs among the control technologies evaluated. For some technologies, remaining useful life is a significant factor in determining annual cost. The cost of fuel switching to LSC is not dependent on the remaining useful life of White Bluff Units 1 and 2 or equipment because no capital investments in equipment are required. The other evaluated control technologies require capital investments in new equipment or retrofit of existing equipment. These capital investments are amortized over the remaining useful life of White Bluff Units 1 and 2 to determine the annual cost-effectiveness of SO_2 emissions reductions. The remaining useful life assumptions are discussed in section IV(D)(1)(d) below.

Switching to LSC entails an increased annual cost of operation based on purchase contract terms for the specific sulfur content of the coal. Entergy estimates an increase in operation and maintenance costs based on a $0.50 per ton cost premium to guarantee that the sulfur content of coals is less than 0.6 lb/MMBtu.

In Entergy's August 18, 2017 revised BART analysis, Entergy presented two sets of cost-effectiveness values for add-on control technologies: one set based on claimed "actual costs" and another that comports with EPA's control cost methodology for BART determinations. ADEQ's evaluation of controls is based on the latter of the two. Cost-effectiveness of Wet FGD was not calculated in the updated five factor analysis because EPA already determined in the AR RH FIP that Wet FGD is not BART because Wet FGD is more expensive than Dry FGD technologies with a 0.028 deciview or less incremental impact at Class I areas. The incremental cost of Wet FGD would be even greater considering the updated remaining useful life for Entergy White Bluff Units 1 and 2.

Table 4 compares the average and incremental cost-effectiveness versus LSC based on allowed costs of each control technology evaluated in Entergy's updated five factor analysis for White Bluff. Average dollar-per-deciview cost for LSC, DSI and Dry FGD are included in Table 5.

Table 4 Average Cost-Effectiveness and Incremental Cost-Effectiveness for Control Options at White Bluff Units 1 and 2

Control Option	Average Cost Effectiveness ($/ton)	Average Incremental Cost-Effectiveness Relative to LSC ($/ton)
LSC	1,149	
DSI	6,240	7,724
Enhanced DSI	6,406	7,113
Dry FGD	5,404	5,865

Table 5 Average Dollar-Per-Deciview Reduction for Control Options at White Bluff Units 1 and 2[19]

Control Option	Caney Creek	Upper Buffalo	Hercules Glades	Mingo
LSC	14,500,519	11,932,988	10,666,332	13,554,882
DSI	133,341,667	105,417,939	120,512,761	116,126,126
Enhanced DSI	158,855,956	139,165,572	168,897,541	173,433,064
Dry FGD	131,447,683	121,373,255	153,165,608	153,852,117

[19] Total annualized cost, as calculated by ADEQ using information from Entergy's August 18, 2017 revised BART analysis for White Bluff divided by visibility improvements that would be anticipated from evaluated technologies included in Tables 4-6 and 4-7 of Entergy's August 18, 2017 analysis at pages 4-7 and 4-8. Further discussion of those modeled visibility benefits are discussed in Section IV.D.1.e of this SIP.

ADEQ finds that the average cost-effectiveness values for DSI, Enhanced DSI, and Dry FGD at White Bluff exceed what is typically found to be cost-effective for BART based on actions taken in other states.[20] In addition, the dollar-per-deciview values for DSI, Enhanced DSI, and Dry FGD are approximately an order of magnitude greater than for LSC.

c. Energy and Nonair Quality Environmental Impacts

Entergy indicated that there were energy and adverse nonair quality environmental impacts associated with add-on controls under consideration, such as DSI and Dry FGD. These impacts were factored into costs of compliance.

d. Remaining Useful Life

In the August 18, 2017 updated BART analysis for White Bluff, Entergy amortized costs based on their proposal regarding changes in coal-fired operations. The August 18, 2017 analysis redacted Entergy's proposed date to enact these changes; however, Entergy voluntarily released confidentiality claims on those dates on December 1, 2017. On December 18, 2017, ADEQ issued a notice of data availability, including Entergy's unredacted analysis, and extended the public comment period to enable the public to consider this new information as they developed comments on the proposed SIP. In the updated BART analysis, Entergy stated that they anticipate cessation of coal use by White Bluff by the end of the year 2028 and that they are prepared to take an enforceable restriction to that effect.

Under the guidelines for BART determinations, the remaining useful life calculation should begin on "the date that controls will be put in place" (compliance date) and ending on "the date the facility permanently stops operations."[21] The compliance date for BART controls must be be as expeditiously as practicable, but in no event later than five years after approval of the SIP.[22] ADEQ had proposed that the compliance date for Dry FGD at White Bluff would be by 2023 based on five years from the anticipated approval of this SIP in 2018; however, due to comments received during the public comment period and Entergy's use of 2021 in its unredacted analysis , ADEQ is now basing its analysis on a compliance date of October 27, 2021. The shifting of compliance and cessation of coal-fired operations date assumptions by two years results in the same seven year remaining useful life assumption included in the proposed SIP.

The guidelines for BART determinations further specify that the permanent operations cessation date should be "assured by a federally- or State-enforceable restriction preventing further operation."[23] Therefore, ADEQ agrees that Entergy's cost-effectiveness calculations are reasonable based on a remaining useful life of seven years and Entergy's proposal to take an enforceable limit regarding the timing of their planned changes in coal-fired operations.

[20] Cost-effectiveness values included in approved SIPs and FIPs for BART are typically below $5,000/ton. This is illustrated in Exhibit B to the National Parks Conservation Association, Earthjustice, and Sierra Club comments on the Proposed SIP.
[21] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations (70 FR 39104,July 6, 2005)
[22] 40 CFR 51.308(e)(iv)
[23] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations (70 FR 39104, July 6, 2005)

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated technologies are included in Tables 4-6 and 4-7 of Entergy's August 18, 2017 analysis at pages 4-7 and 4-8 and are summarized in Table 6 below. [24]

Table 6 Summary of CALPUFF-Modeled Average Visibility Improvement from Evaluated SO_2 Controls at White Bluff Over Baseline (98th Percentile Impact)

	Average Deciview Improvement over 2001–2003 Baseline (98th Percentile Impact)			
	Caney Creek	Upper Buffalo	Hercules Glades	Mingo
LSC	0.113	0.135	0.152	0.119
DSI	0.291	0.367	0.322	0.333
Enhanced DSI	0.476	0.543	0.448	0.436
SDA	0.589	0.637	0.506	0.503

f. BART Requirements for SO_2

Based on their analysis, Entergy proposed that BART to control SO_2 emissions from Entergy White Bluff Units 1 and 2 is LSC. ADEQ concurs with Entergy's BART determination that LSC is BART for SO_2 at White Bluff Units 1 and 2 given the information presented in their updated five-factor analysis and the remaining useful life of the units. For the remaining useful life assumptions for White Bluff, Dry FGD, DSI, and Enhanced DSI are not within the range typically found to be cost-effective for BART.[25] In addition, the cost-per-deciview improvement for Dry FGD, DSI, and Enhanced DSI are an order of magnitude larger than for LSC. Therefore, ADEQ agrees that BART for White Bluff is LSC based on Entergy's planned cessation of coal-fired operations at White Bluff by the end of 2028. This voluntarily proposed cessation of coal-fired operations date is rendered state-enforceable through an AO.

[24] Entergy's modeled visibility improvement from evaluated SO_2 controls are based on an updated baseline of 2009–2013 emissions rather than the 2001–2003 baseline emissions EPA used in the AR RH FIP to project visibility improvements from Dry FGD and Wet FGD. This change in baseline emissions impacts the modeled visibility benefit from Dry FGD. The modeled visibility benefit of Dry FGD at each unit is 15% to 26% lower in Entergy's updated analysis than estimated in the AR RH FIP. EPA did not evaluate visibility improvements associated with DSI, enhanced DSI, and LSC in the AR RH FIP; however, ADEQ expects that the relative difference in cost-per-deciview among the control options evaluated would be similar across both baseline emissions periods. The difference in visibility impact estimates due to differences in estimated baseline emissions between the AR RH FIP and Entergy's updated five factor analysis does not change ADEQ's ultimate decision for its SO_2 BART determination for White Bluff, which is discussed in Section IV.D.1.e of this SIP and was based on an assessment of all five statutory BART factors.

[25] Cost-effectiveness values included in approved SIPs and FIPs for BART are typically below $5,000/ton. This is illustrated in Exhibit B to the National Parks Conservation Association, Earthjustice, and Sierra Club comments on the Proposed SIP.

In communication with ADEQ, Entergy indicated that it is their practice to project how much coal will be needed in future years and to contract for a portion of their coal supply up to three years in advance. Furthermore, Entergy keeps a reserve supply of coals at White Bluff to ensure that the units can operate in the event of a fuel supply disruption. In response to comments received during the public comment period, ADEQ requested that Entergy provide additional information regarding the time necessary for compliance with an emission limit based on LSC. On April 3, 2018, Entergy submitted a letter to ADEQ providing additional information with regards to current coal contracts, coal blending capabilities at White Bluff.[26] Entergy detailed how site-specific circumstances preclude the ability to guarantee an emission rate of 0.6 lb/MMBTU. Specifically, the sulfur content limits of Entergy's existing coal contracts for the next three years exceed this emission rate. In addition, Entergy cannot accurately calculate expected SO_2 emissions from blending of coals from their stockpile and new deliveries from a train because stockpile coal sulfur content is not tracked. Given the site-specific circumstances for White Bluff, ADEQ finds Entergy's explanation as to why three years is necessary to guarantee compliance with an emission limit of 0.6 lb/MMBTU to be reasonable.

The emission rate for LSC proposed by Entergy was 0.6 lb/MMBtu. During the public comment period, commenters pointed out that the significant digits of this limit, as proposed, could result in smaller reductions than assumed because it is typical to round to the nearest significant digit when demonstrating compliance. For instance, an emission rate as high as 0.64 lb/MMBtu could be rounded down to 0.6 lb SO_2/MMBtu. Based on this comment, ADEQ finds that it is appropriate to revise the number of significant digits associated with the enforceable emission rate for LSC to preclude emission rates higher than evaluated for LSC in Entergy's updated five-factor analysis for White Bluff. Therefore, ADEQ finds that it is reasonable to require Entergy to comply with the requirement to meet an emission rate of 0.60 lb/MMBtu at Entergy White Bluff Unit 1 and Unit 2 no later than three years after approval of this SIP revision.

AO LIS No. 18-073 includes enforceable limitations and compliance dates consistent with ADEQ's determination.

2. Summary of BART Analysis and Requirements for PM

A BART determination for PM for Entergy White Bluff Units 1 and 2 was included in the 2008 AR RH SIP and approved in EPA's March 12, 2012, final rule (77 FR 14604). No changes are needed to EPA's determinations with respect to previously approved PM BART limitations (0.10 lb/MMBtu) included in APC&EC Regulation No. 19.

E. Southwestern Electric Power Company Flint Creek Power Plant

SWEPCO, a subsidiary of AEP, provided a BART analysis (dated September 2013, Version 4) for the Flint Creek Power Plant. EPA used this analysis in the development of the AR RH FIP and ADEQ has made its BART determination included in this SIP based on the analysis

[26] The April 3, 2018 letter from Entergy regarding time necessary for compliance with LSC is included in Appendix D.

provided by SWEPCO. This analysis is provided in Appendix E of this SIP and summarized below.

SWEPCO Flint Creek Plant Boiler No. 1 is a 558 megawatt dry bottom wall-fired boiler that commenced operation in 1978. SWEPCO Flint Creek Plant Boiler No. 1 has a maximum heat input of 6,324 MMBtu/hr. SWEPCO Flint Creek Plant Boiler No. 1 is equipped with Dry FGD with a Pulse Jet Fabric Filter (PJFF) and Activated Carbon Injection (ACI). SWEPCO Flint Creek Plant Boiler No. 1 burns low sulfur western coal as a primary fuel, but can also combust fuel oil and tire-derived fuels. Fuel oil firing is only allowed during unit startup and shutdown, during startup and shutdown of pulverizer mills, for flame stabilization when coal is frozen, for No. 2 fuel oil tank maintenance, to prevent boiler tube failure in extreme cold weather when the unit is offline for maintenance, and during malfunction. SWEPCO Flint Creek Plant Boiler No. 1 meets the BART-eligibility criteria. Also, based on results of air dispersion modeling, the SWEPCO Flint Creek Plant Boiler No. 1 contributes greater than 0.5 deciview to visibility impairment in at least one Class I area. Consequently, the five BART statutory factors were considered for SWEPCO Flint Creek Plant Boiler No. 1.

1. Summary of BART Analysis and Requirements for SO_2

The available SO_2 retrofit control technology options include DSI, Dry FGD, and Wet FGD. DSI, a form of FGD, has a control efficiency of forty to sixty percent and was considered technically feasible in SWEPCO's BART analysis for the SWEPCO Flint Creek Plant Boiler No. 1. A Dry FGD was also deemed a technically feasible option and has a control efficiency of sixty to ninety-five. Novel integrated deacidification (NID), a form of Dry FGD, was predicted to have an achievable ninety-two percent control efficiency on the SWEPCO Flint Creek Plant Boiler No. 1. Wet FGD was also considered a technically feasible option and has an eighty to ninety-five percent control efficiency.

a. Existing Controls in Use at the Source

At the time SWEPCO performed a BART analysis, no SO_2 controls were in place at Flint Creek Plant Boiler No. 1. Since that time, SWEPCO has installed an NID system to comply with SO_2 BART requirements included in the AR RH FIP. Cost-effectiveness and visibility improvement data included in SWEPCO's BART analysis are based on the 2001–2003 baseline, not current SO_2 controls in place at Flint Creek Plant Boiler No. 1.

b. Cost of Compliance

SWEPCO determined the cost effectiveness of a Wet FGD at an SO_2 rate of 0.04 lb/MMBtu (ninety-five percent control of baseline emissions) is $4,919/ton of SO_2 removed, while cost effectiveness of a NID system at an SO_2 rate of 0.06 lb/MMBtu (ninety-two percent control of baseline emissions) is $3,845/ton of SO_2 removed. Because technologies with higher control efficiencies were within the range considered cost-effective, the costs of DSI were not evaluated.

c. Energy and Nonair Quality Environmental Impacts

SWEPCO concluded that although Wet FGD was expected to achieve a slightly higher level of SO_2 control compared to NID technology, a negative energy or nonair quality impact associated with Wet FGD was the generation of large volumes of wastewater and solid waste/sludge that must be treated. Also, Wet FGD systems have increased power requirements and increased reagent usage over Dry FGD, as well as the potential for increased particulate and sulfuric acid mist releases.

d. Remaining Useful Life

The remaining useful life of SWEPCO Flint Creek Plant Boiler No. 1 does not impact the annualized capital costs because the useful life of the unit is anticipated to be at least as long as the capital cost recovery period.

e. Degree of Visibility Improvement as a Result of Controls

Visibility improvements that would be anticipated from evaluated control technologies are included in Table 5-7 on page 5-9 of SWEPCO's 2013 BART analysis. Operation of NID at SWEPCO Flint Creek Plant Boiler No. 1 will result in up to a 0.647 deciview improvement to the existing visibility impairment and Wet FGD does not add additional visibility improvement over Dry FGD because Wet FGD results in other visibility impairing emissions.

f. BART Requirements for SO_2

SWEPCO proposed that BART to control SO_2 emissions from SWEPCO Flint Creek Plant Boiler No. 1 was NID technology with an expected emissions rate of 0.06 lb/MMBtu calculated as a 30-day rolling average over each boiler operating day. ADEQ concurs with this determination.

AO LIS No. 18-072 includes enforceable limitations and compliance dates consistent with ADEQ's BART determination.

2. Summary of BART Analysis and Requirements for PM

A BART determination for PM based on the existing ESP controls was included in the 2008 AR RH SIP and approved in EPA's March 12, 2012, final rule (77 FR 14604). This determination also approved the existing PM emissions rate of 0.10 lb/MMBtu. No changes are needed to EPA's determination with respect to the previously approved PM BART limit included in Regulation No. 19.

V. <u>Reasonable Progress Analysis Framework for Arkansas in the First Planning Period</u>

The 1999 RHR requires states to establish RPGs for each Class I area within the state. These goals must ensure reasonable progress consistent with the URP necessary to achieve natural visibility conditions by 2064 on the twenty percent worst days and no degradation on the twenty percent best days. The URP is also referred to as the "glidepath."

In establishing RPGs, the RHR requires states to consider four factors: (1) cost of compliance, (2) the time necessary for compliance, (3) the energy and nonair quality environmental impacts of compliance, and (4) the remaining useful life of potentially affected sources. If a state determines that additional progress beyond what is necessary to achieve the URP is reasonable, the RHR rule states that "the State should adopt that amount of progress as its goal for the first-long-term strategy.” The RHR also requires states to provide a demonstration as part of the SIP if the State determines that the URP needed to reach natural conditions is not reasonable. In its 2007 reasonable progress guidance, EPA states that the “glidepath is not a presumptive limit and states may establish an RPG that provides for greater, lesser, or equivalent visibility improvement as that described by the glidepath.”[27] The guidance also instructs the states in the following manner:

> In deciding what amount of emissions reduction is appropriate in setting the RPG, you should take into account the fact that the long-term goal of no manmade impairment encompasses several planning periods. It is reasonable for you to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal.[28]

In the 2008 AR RH SIP, ADEQ established a URP for Caney Creek and Upper Buffalo based on the progress needed to reach natural conditions by 2064 in each area. The 2008 AR RH SIP established RPGs based on a combination of mandated controls, including BART requirements, and demonstrated that these measures would provide for a rate of progress that improves visibility conditions on the worst days at a rate that surpasses the URP and would prevent degradation on the best days. ADEQ reasoned that no four factor analysis was required because the State determined that no additional controls were necessary to ensure reasonable progress toward natural visibility by 2064 beyond those controls required for sources subject to BART requirements. Therefore, the 2008 AR RH SIP did not include a four-factor analysis.

In 2012, EPA issued a partial approval and a partial disapproval of the 2008 AR RH SIP. In this action, EPA approved the URP, but disapproved the RPGs because Arkansas did not complete a four-factor analysis to demonstrate that additional controls were not reasonable under 40 CFR 51.308(d)(1)(i)(A).[29] EPA’s 2016 AR RH FIP included requirements for an additional non-BART facility, Entergy Independence, based on a four factor analysis of this single facility. EPA selected Independence for a four factor analysis due to the magnitude of its SO_2 and NOx emissions.

This submittal addresses EPA’s disapproval of the reasonable progress analysis included in the 2008 AR RH SIP by considering key pollutants that contribute to visibility impairment in Arkansas Class I areas and using the four factors, as well as other factors relevant to reasonable progress, to assess whether controls on sources that are not subject to BART are reasonable. Technical supporting information for the reasonable progress analysis can be found in Appendix F.

CAA § 169A requires States to adopt a strategy for making reasonable progress toward improving visibility taking into account the statutory four reasonable progress factors. The 2007

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[27] EPA (2007) Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program
[28] *Id.*
[29] Approval and Promulgation of Implementation Plans; Arkansas Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze: Proposed Rule (76 FR 64186 at 64195, October 17, 2011)

reasonable progress guidance provides that states have “flexibility in how to take into consideration these statutory factors that [the State] has determined to be relevant.”[30] ADEQ has determined that these four statutory factors are appropriately applied broadly to an array of sources state-wide rather than in a source-specific manner. However, due to the circumstances of the 2016 AR RH FIP, which applied the factors to a single facility, Independence, ADEQ has determined that application of the four factors to the specific source analyzed by EPA is also “relevant.” Therefore, ADEQ has performed both a broader analysis using the four factors as well as a more narrow analysis specific to Independence before determining whether any controls are necessary.

A. Identification of Key Pollutants and Source Categories That Contribute to Visibility Impairment in Arkansas Class I Areas

Included with the 2008 AR RH SIP, ADEQ provided emissions and air quality modeling performed by CENRAP in support of SIP development in the central states region.[31] As part of this modeling, the Particulate Source Apportionment Technology Tool (PSAT), included with CAMx Version 4.4, was used to provide source apportionment by geographic regions and major source categories for pollutants that contribute to visibility impairment at each of the Class I areas in the central states region.[32] The PSAT results demonstrate that sulfate (SO_4) from point sources is the principle driver of light extinction at both Arkansas Class I areas on the twenty percent worst days.

1. Regional Particulate Source Apportionment for Caney Creek and Upper Buffalo

Table 7 shows the modeled relative contributions to light extinction for each source category at Caney Creek and Upper Buffalo on the twenty-percent worst days in 2002. Point sources, responsible for approximately sixty percent of total light extinction at each Arkansas Class I area, are the primary contributor to light extinction on the twenty percent worst days. Area sources are the next largest contributor to light extinction at Arkansas Class I areas; however, area sources only contribute thirteen percent and sixteen percent of total light extinction at Caney Creek and Upper Buffalo, respectively. The other source categories each contribute between two percent and seven percent of total light extinction at Arkansas Class I areas.

Table 7 Modeled Light Extinction for the 20% Worst Days at Caney Creek and Upper Buffalo in 2002 (Mm^{-1})

	Point	Natural	On-Road	Non-Road	Area
Caney Creek	81.04	2.45	7.26	7.31	17.81
Upper Buffalo	77.8	2.39	6.62	7.72	20.46

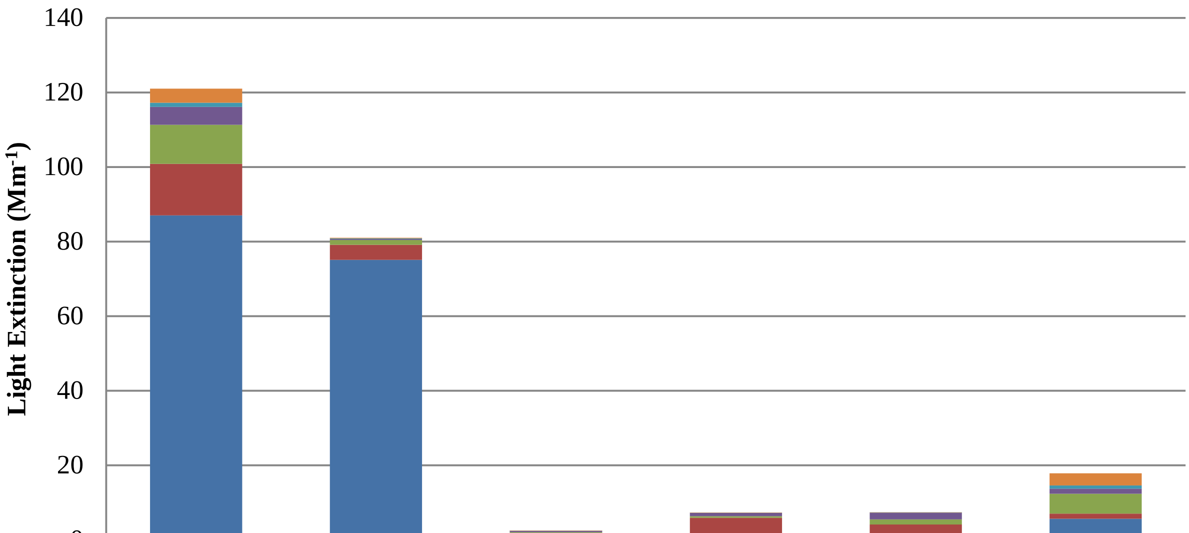
[30] EPA (2007) Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program

[31] The central states region includes Texas, Oklahoma, Louisiana, Arkansas, Kansas, Missouri, Nebraska, Iowa, Minnesota; and tribal governments included in these states.

[32] August 27, 2007 CENRAP PSAT tool: W20% Projected Bext;

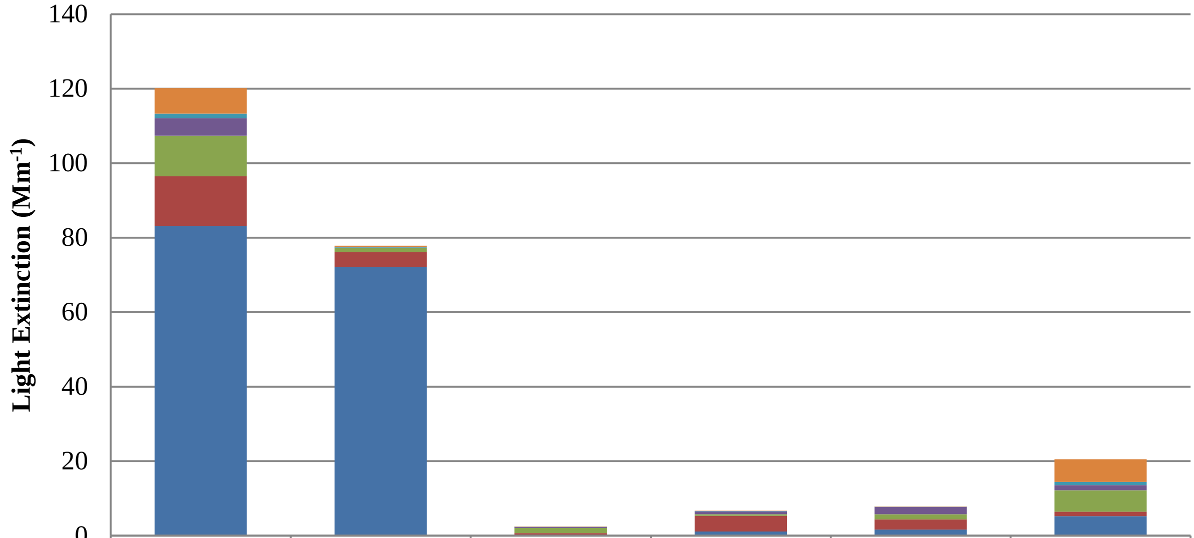
Figure 2 and Figure 3 show the modeled relative contributions to light extinction for each species and source category at Caney Creek and Upper Buffalo on the twenty percent worst days in 2002. According to the 2002 PSAT results, SO_4 contributed approximately sixty-five percent and sixty-three percent of modeled light extinction at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2002. The point source category contributed eighty-six percent and eighty-seven percent of light extinction due to SO_4 at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days. The other source categories contribute much smaller proportions of light extinction due to SO_4. In fact, point sources of SO_4 contributed fifty-five to fifty-six percent of total light extinction at Arkansas Class I areas. By contrast, nitrate (NO_3) contributed approximately ten percent, primary organic aerosols (POA) contributed approximately eight percent, elemental carbon (EC) contributed approximately four percent, and soil contributed approximately one percent of modeled light extinction at both wilderness areas in 2002 on the twenty percent worst days. Crustal material (CM) contributed approximately three percent and five percent of modeled light extinction at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days. Relative contributions from on-road and point sources each represent approximately a third of light extinction attributed to NO_3. Area sources were the primary driver of light extinction attributed to POA, soil, and CM. Light extinction attributed to EC is primarily driven by non-road and area sources.

Figure 2 Modeled Light Extinction for the 20% Worst Days at Caney Creek in 2002



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	3.73	0.21	0.04	0.03	0.02	3.19
SOIL	1.12	0.19	0.01	0.01	0.01	0.87
EC	4.8	0.19	0.33	0.86	1.79	1.4
POA	10.5	1.29	1.33	0.46	1.34	5.32
NO3	13.78	4.06	0.64	4.7	2.45	1.37
SO4	87.05	75.1	0.09	1.19	1.7	5.66

Figure 3 Modeled Light Extinction for the 20% Worst Days at Upper Buffalo in 2002



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	6.85	0.29	0.05	0.05	0.02	6.02
SOIL	1.21	0.2	0.02	0.01	0.01	0.93
EC	4.72	0.16	0.31	0.8	1.93	1.3
POA	10.85	1.06	1.33	0.47	1.38	5.75
NO3	13.3	3.93	0.61	4.14	2.71	1.23
SO4	83.18	72.17	0.08	1.15	1.67	5.24

Table 8 shows the modeled relative contributions to light extinction for each source category at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2018. Point sources are projected to remain the primary contributor to light extinction at Arkansas Class I areas. Point sources are projected to contribute approximately fifty-three percent of total light extinction at Caney Creek and fifty percent of total light extinction at Upper Buffalo on the twenty percent worst days in 2018. Area sources are also projected to continue to be the second largest contributor to light extinction with contributions of twenty percent of total light extinction at Caney Creek and twenty-three percent of total light extinction at Upper Buffalo on the twenty percent worst days in 2018. Natural, on-road, and non-road sources are projected to continue to contribute five percent of total light extinction at Arkansas Class I areas on the twenty percent worst days in 2018.

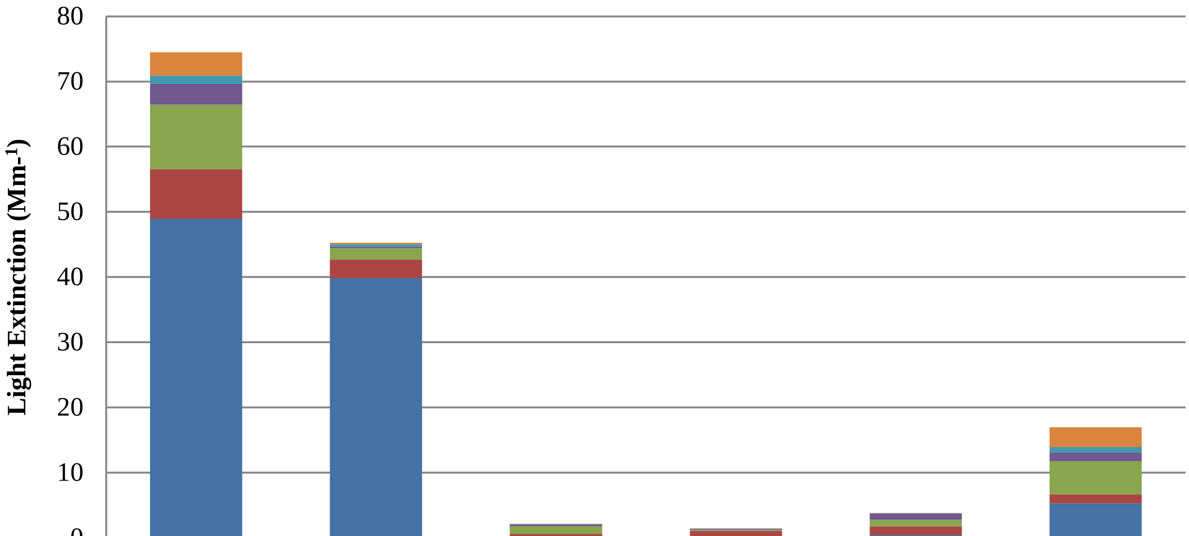
Table 8 Modeled Light Extinction for the 20% Worst Days at Caney Creek and Upper Buffalo in 2018 (Mm^{-1})

	Point	Natural	On-Road	Non-Road	Area
Caney Creek	45.27	2.12	1.44	3.76	16.96
Upper Buffalo	43.02	2.24	1.57	4.25	19.71

Figure 4 and Figure 5 show the modeled relative contributions to light extinction for each species and source category at Caney Creek and Upper Buffalo on the twenty percent worst days in

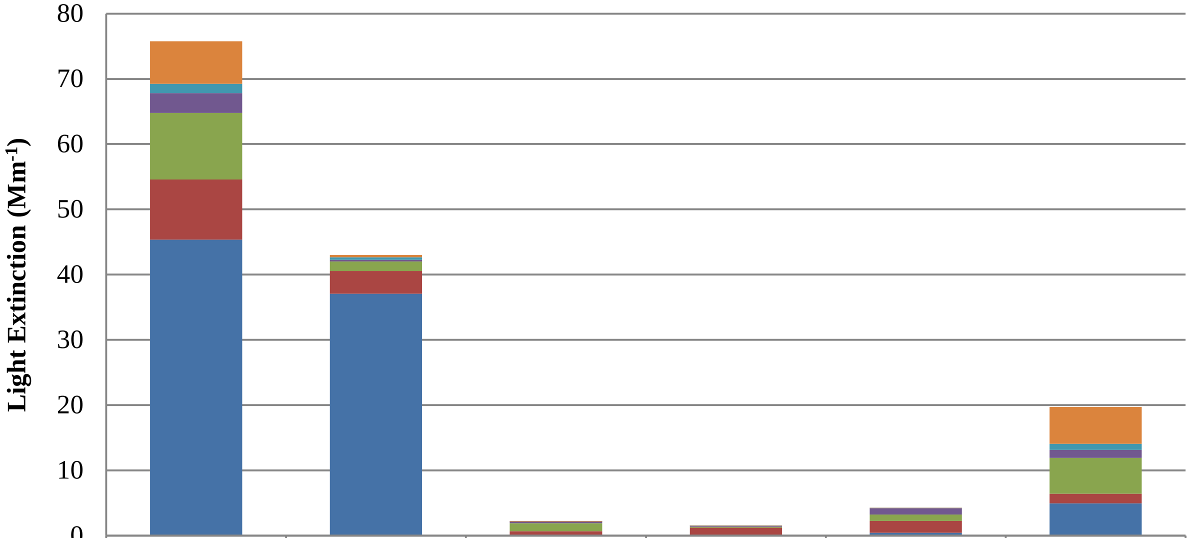
2018. According to the regional PSAT data, light extinction attributed to SO_4 is projected to decrease on the twenty percent worst days by forty-four percent at Caney Creek and by forty-five percent at Upper Buffalo between 2002 and 2018; however, SO_4 is projected to continue to be the primary driver of total light extinction. The 2018 projections show that point sources will continue to be the primary source of light extinction due to SO_4. Point sources of SO_4 are projected to contribute forty-three to forty-six percent of total light extinction on the twenty percent worst days in 2018 in Arkansas Class I areas. The other species are also projected to see reductions in their contribution to total light extinction; however, their relative contributions to total light extinction during 2018 remain much smaller than that of SO_4. Light extinction on the twenty percent worst days attributed to NO_3 from on-road sources is projected to decrease more rapidly than light extinction attributed to NO_3 from point sources; however, point sources of NO_3 will only contribute three to four percent of total light extinction at Arkansas Class I areas on the twenty percent worst days based on 2018 projections.

Figure 4 Modeled Light Extinction for the 20% Worst Days at Caney Creek in 2018



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	3.58	0.24	0.04	0.03	0.01	3.02
SOIL	1.29	0.35	0.01	0.01	0.01	0.87
EC	3.17	0.24	0.3	0.16	0.94	1.31
POA	9.93	1.76	1.18	0.14	1.03	5.09
NO3	7.57	2.84	0.53	0.97	1.33	1.37
SO4	48.95	39.83	0.07	0.12	0.44	5.31

Figure 5 Modeled Light Extinction for the 20% Worst Days at Upper Buffalo in 2018



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	6.53	0.36	0.05	0.04	0.02	5.65
SOIL	1.4	0.4	0.01	0.01	0.01	0.93
EC	3.07	0.21	0.28	0.15	0.99	1.21
POA	10.17	1.48	1.2	0.14	1.01	5.49
NO3	9.22	3.48	0.63	1.1	1.81	1.48
SO4	45.38	37.09	0.06	0.12	0.42	4.95

2. Arkansas Particulate Source Apportionment for Caney Creek and Upper Buffalo

The relative contribution of sources within Arkansas to total light extinction on the twenty percent worst days at both Arkansas Class I areas is small. Species attributed to Arkansas sources contributed approximately ten percent of total light extinction on the twenty percent worst days in Arkansas Class I areas according to 2002 data and are projected to contribute between thirteen and fourteen percent of total light extinction on the twenty percent worst days in Arkansas Class I areas in 2018. Total light extinction is projected to decrease by thirty-five percent on the twenty percent worst days at Arkansas Class I areas between 2002 and 2018. Light extinction on the twenty percent worst days attributed to species from Arkansas sources is projected to decrease by seventeen percent at Caney Creek and to decrease by eleven percent at Upper Buffalo between 2002 and 2018.

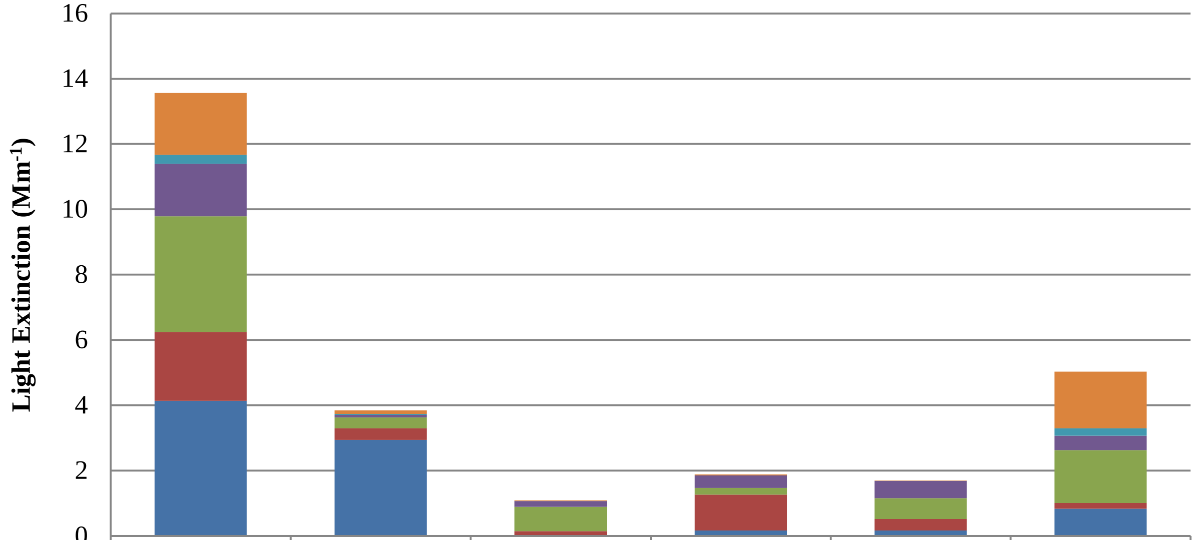
Table 9 shows the relative contributions of sources within Arkansas to light extinction for each source category at Caney Creek and Upper Buffalo on the twenty percent worst days in 2002. Area sources had a larger impact on light extinction than did point sources when only sources within Arkansas were considered. On the twenty percent worst days in 2002, area sources contributed approximately thirty-seven percent of light extinction attributed to Arkansas sources (four percent of total light extinction) at Caney Creek and fifty percent of light extinction attributed to Arkansas sources (five percent of total light extinction) at Upper Buffalo. Point sources contributed approximately twenty-eight percent of light extinction attributed to Arkansas sources (three percent of total light extinction) at Caney Creek and twenty-four percent of light extinction attributed to Arkansas sources (two percent of total light extinction) at Upper Buffalo on the twenty percent worst days. The other sources in Arkansas contributed between seven and fourteen percent each to light extinction attributed to Arkansas sources (approximately one percent each to total light extinction) at Arkansas Class I areas on the twenty percent worst days in 2002.

Table 9 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Caney Creek and Upper Buffalo in 2002 (Mm^{-1})

	Point	Natural	On-Road	Non-Road	Area
Caney Creek	3.85	1.1	1.88	1.72	5.03
Upper Buffalo	3.25	0.94	1.29	1.26	6.72

Figure 6 and Figure 7 show the relative contributions of sources within Arkansas to light extinction for each source category and species at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2002. SO_4 from Arkansas sources contributed approximately three percent of total modeled l extinction at Caney Creek and Upper Buffalo in 2002 on the twenty percent worst days. The point source category contributed approximately two thirds of the light extinction attributed to SO_4 from Arkansas sources at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2002. POA from Arkansas sources contributed approximately three percent and two percent of total light extinction on the twenty percent worst days at Caney Creek and Upper Buffalo, respectively. Area sources were the primary driver of light extinction due to POA. NO_3 from Arkansas sources contributed approximately two percent and one percent to light extinction at Caney Creek and Upper Buffalo on the twenty percent worst days, respectively. On-road sources accounted for approximately fifty percent of the light extinction at Arkansas Class I areas attributed to Arkansas NO_3 sources. EC from Arkansas sources contributed approximately one percent and soil from Arkansas sources contributed approximately 0.2% to total light extinction at both Arkansas Class I areas on the twenty percent worst days. Attribution to light extinction from Arkansas sources of EC was split primarily among on-road, non-road, and area sources. Light extinction from Arkansas sources of soil was primarily attributed to area sources. CM from Arkansas sources, primarily area sources, contributed approximately one and two percent of total light extinction and Caney Creek and Upper Buffalo, respectively.

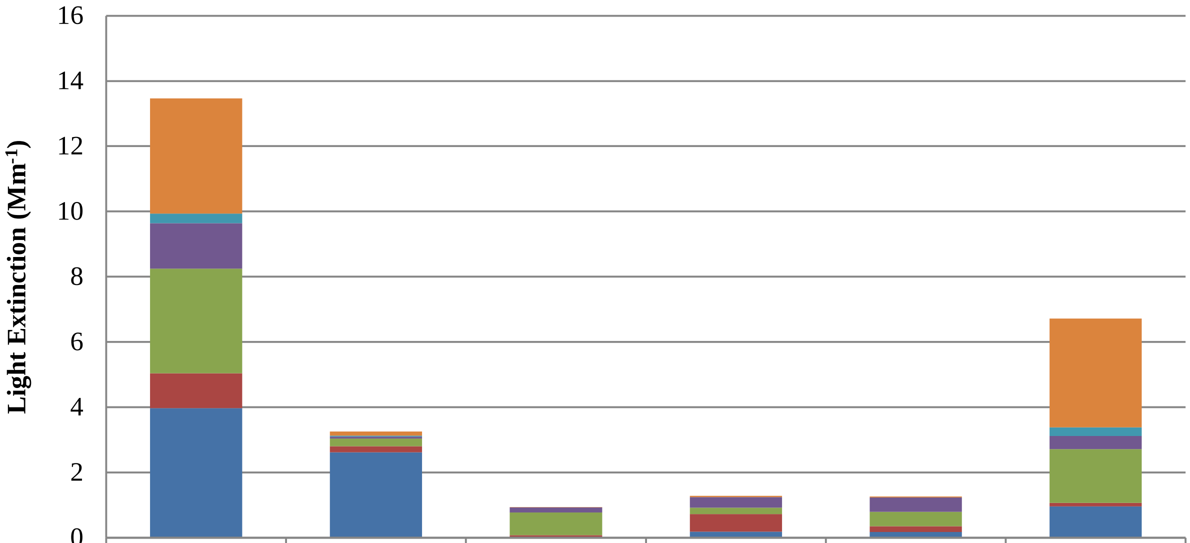
Figure 6 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Caney Creek in 2002[33]



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	1.89	0.1	0.02	0.03	0.01	1.73
SOIL	0.27	0.03	0	0	0	0.23
EC	1.61	0.08	0.18	0.38	0.53	0.44
POA	3.54	0.33	0.74	0.21	0.64	1.62
NO3	2.11	0.36	0.12	1.09	0.35	0.18
SO4	4.14	2.94	0.03	0.17	0.17	0.83

[33] All values have been rounded to the second decimal place. Values less than 0.005 have been rounded down to 0.

Figure 7 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Upper Buffalo in 2002[34]



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	3.53	0.13	0.01	0.03	0.02	3.34
SOIL	0.3	0.03	0	0	0	0.26
EC	1.39	0.06	0.16	0.33	0.45	0.4
POA	3.21	0.24	0.69	0.19	0.44	1.65
NO3	1.07	0.18	0.06	0.54	0.17	0.11
SO4	3.97	2.62	0.02	0.19	0.18	0.96

Table 10 shows the relative contributions of sources within Arkansas to light extinction for each source category at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2018. Area sources are projected to continue to have a larger impact on light extinction than do point sources when only sources located in Arkansas are considered. Area sources are projected to contribute approximately forty-three percent of light extinction attributed to Arkansas sources (six percent of total light extinction) at Caney Creek and fifty-four percent of light extinction attributed to Arkansas sources (eight percent of total light extinction) at Upper Buffalo. Point sources are projected to contribute approximately thirty-six percent of light extinction attributed to Arkansas sources (five percent of total light extinction) at Caney Creek and thirty percent of light extinction attributed to Arkansas sources (four percent of total light extinction) at Upper Buffalo. The other sources in Arkansas are projected to contribute between two percent and nine percent each to light extinction from Arkansas sources (0.3–1.2% of total light extinction) at Arkansas Class I areas on the twenty percent worst days in 2018.

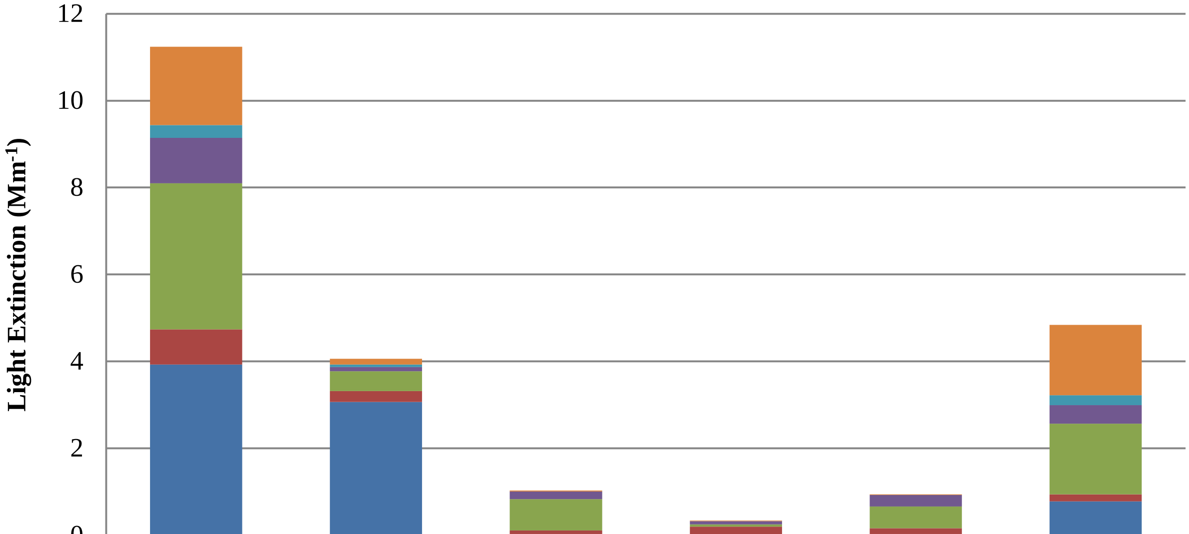
[34] All values have been rounded to the second decimal place. Values less than 0.005 have been rounded down to 0.

Table 10 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Caney Creek and Upper Buffalo in 2018 (Mm^{-1})

	Point	Natural	On-Road	Non-Road	Area
Caney Creek	4.05	1.04	0.35	0.95	4.85
Upper Buffalo	3.63	0.91	0.3	0.66	6.52

Figure 8 and Figure 9 show the relative contributions of sources within Arkansas to light extinction for each species and source category at Caney Creek and Upper Buffalo, respectively, on the twenty percent worst days in 2018. According to the PSAT data for Arkansas sources, light extinction attributed to Arkansas NO_3 sources is projected to decrease by sixty-two percent at Caney Creek and by forty-one percent at Upper Buffalo. This projected decrease is largely due to a decrease in light extinction attributed to NO_3 from Arkansas on-road sources. Overall light extinction attributed to Arkansas sources of SO_4 are projected to decrease at Arkansas Class I areas; however, light extinction attributed to point sources of SO_4 located in Arkansas is projected to increase by four percent at Caney Creek and five percent at Upper Buffalo on the twenty percent worst days. Nevertheless, the contribution to total light extinction of SO_4 from Arkansas point sources remains relatively small—three percent of total light extinction at each Arkansas Class I area. Light extinction due to Arkansas sources of POA, EC, and CM are also projected to decrease. Light extinction due to Arkansas sources of soil is projected to increase; but, soil will remain the smallest Arkansas contributor to light extinction at both Arkansas Class I areas.

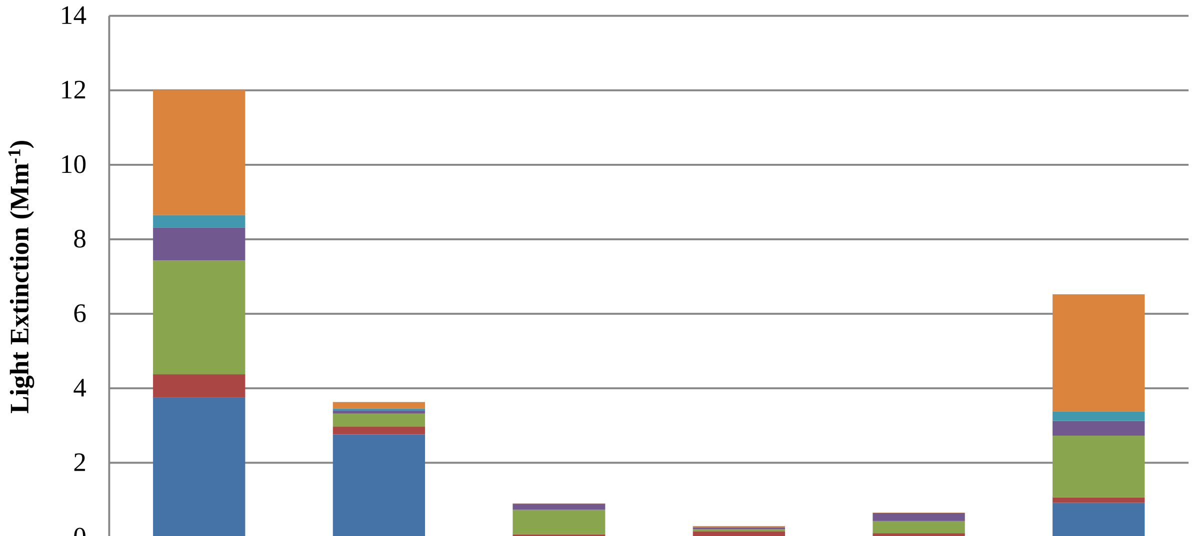
Figure 8 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Caney Creek in 2018[35]



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	1.8	0.13	0.02	0.02	0.01	1.62
SOIL	0.3	0.06	0	0	0	0.23
EC	1.04	0.1	0.18	0.07	0.27	0.42
POA	3.36	0.45	0.72	0.05	0.5	1.63
NO3	0.81	0.25	0.08	0.18	0.13	0.16
SO4	3.93	3.07	0.03	0.02	0.03	0.78

[35] All values have been rounded to the second decimal place. Values less than 0.005 have been rounded down to 0.

Figure 9 Modeled Light Extinction due to Arkansas Sources for the 20% Worst Days at Upper Buffalo in 2018[36]



	All Source Categories	Point	Natural	On-Road	Non-Road	Area
CM	3.36	0.17	0.01	0.03	0.01	3.14
SOIL	0.33	0.06	0	0	0	0.26
EC	0.89	0.08	0.16	0.06	0.21	0.39
POA	3.05	0.35	0.66	0.05	0.33	1.66
NO3	0.63	0.21	0.06	0.14	0.09	0.14
SO4	3.75	2.76	0.02	0.02	0.02	0.93

3. Summary of Key Pollutant and Source Category Findings

The region-wide PSAT data indicate that the relative contribution of SO_4 to light extinction at Arkansas Class I areas is much higher than for other pollutants on the twenty percent worst days. The majority of light extinction due to SO_4 can be attributed to point sources. The PSAT results for Arkansas sources illustrate that the relative contribution to light extinction of the various species from Arkansas sources is not as weighted toward SO_4 as the regional data set showed. Approximately a quarter of light extinction at Arkansas Class I areas resulting from sources located in Arkansas can be attributed to point sources of SO_4. Light extinction from all species associated with the point source category is smaller than for area sources when only sources located in Arkansas are considered. POA and CM are the primary species associated with area source contributions to light extinction.

After examining both region-wide PSAT data and data for Arkansas sources, ADEQ has identified SO_4 as the key species contributing to light extinction at Caney Creek and Upper Buffalo. Area sources do contribute a larger proportion of total light extinction when only sources located in Arkansas are considered; however, the cost-effectiveness for control of POA

[36] All values have been rounded to the second decimal place. Values less than 0.005 have been rounded down to 0.

and CM species from many individual small sources is difficult to quantify. Only a small proportion of total light extinction is due to NO_3 from Arkansas sources and this proportion has historically been driven by onroad sources. NO_3 from Arkansas point sources contributed less than half a percent of total light extinction on the twenty percent worst days at Caney Creek and Upper Buffalo based on 2002 PSAT data and is projected to contribute even less in 2018. Attribution of light extinction to soil and EC for Caney Creek and Upper Buffalo remain in both regional and Arkansas data sets.

The primary driver of SO_4 formation is emissions of SO_2 from point sources both region-wide and in Arkansas. As such, in this SIP ADEQ evaluates sources emitting at least 250 tons per year (tpy) of SO_2. These sources will be evaluated to determine whether their emissions and proximity to Arkansas Class I areas warrant further analysis using the four statutory factors.

B. Reasonable Progress Factors Broadly Applicable to Arkansas Sources

1. Visibility

ADEQ has determined that visibility is a relevant factor for statewide consideration in this reasonable progress analysis. Restoring natural visibility conditions in Class I areas is the central goal of the Regional Haze Program. As stated in 42 U.S.C.A. § 7491, Congress declared "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." As such, ADEQ finds that visibility is the necessary context within which to view whether additional controls are reasonable in the first planning period.

Visibility has improved substantially in Arkansas Class I areas, and the Natural State is approaching natural background conditions more rapidly than the glidepath would indicate is necessary to achieve the goal of natural visibility conditions in Arkansas Class I areas by 2064.[37] Specifically, as reflected in both ADEQ's Five Year Progress Report and the Regional Haze Modeling Assessment Report, Entergy Arkansas, Inc. – Independence Plant, Trinity Consultants (August 4, 2015) visibility conditions in Caney Creek and the Upper Buffalo for the 20% worst days are improving more rapidly than necessary to achieve the URP, ADEQ's disapproved Reasonable Progress goals, and EPA's Reasonable Progress Goals imposed in the Regional Haze FIP.[38] Moreover, according to 2016 IMPROVE monitoring data, visibility improvements at Arkansas Class I areas are already greater than the Reasonable Progress Goals in the AR RH FIP.[39] Figures 10 and 11 demonstrate visibility progress for the twenty percent worst days at Arkansas Class I areas.

[37] See discussion *infra* Part V.A.1.
[38] ADEQ's Five Year Progress Report; Regional Haze Modeling Assessment Report, Entergy Arkansas, Inc. – Independence Plant, Trinity Consultants (August 4, 2015).
[39] Visibility Status and Trends Following the Regional Haze Rule Metrics: IMPROVE Aerosol, Regional Haze Rule II (New Equation), with substituted data. Caney Creek, Upper Buffalo, http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx.

Figure 10 Visibility Progress at Caney Creek – 20% Worst Days

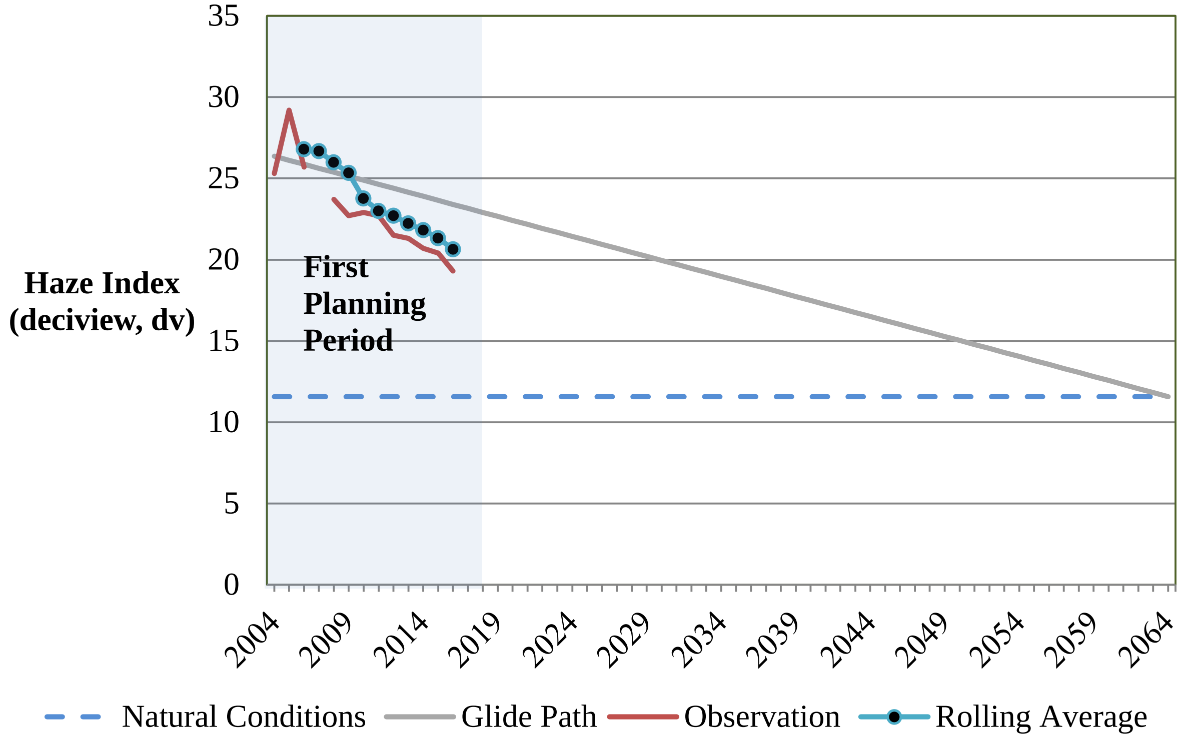
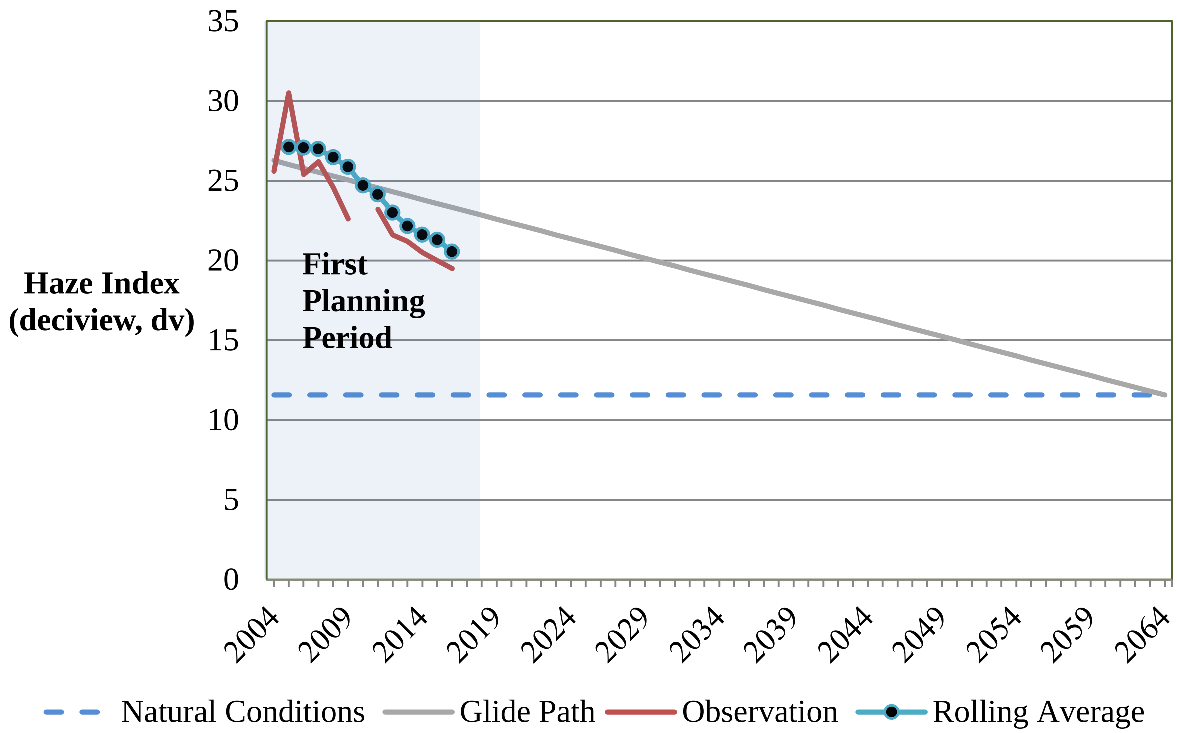


Figure 11 Visibility Progress at Upper Buffalo – 20% Worst Days



As shown by Figures 10 and 11, Arkansas Class I areas are making greater progress toward natural visibility than would result from a URP toward the 2064 goal, even before consideration of the controls included in this SIP. The visibility improvements observed in these Class I areas are a result of reductions from State and federal programs; including new source performance standards for a variety of source types, vehicle emissions standards, changes in NAAQS; innovations in emissions control technologies; retirement or reconstruction of older facilities; and market-driven changes in electricity generation. The BART controls required by this SIP will further keep Arkansas Class I areas on track for achieving natural visibility conditions on or before 2064.

The visibility trajectory in Arkansas's Class I areas is an additional relevant factor for consideration of whether any additional controls are necessary to ensure reasonable progress during this first ten year planning period. If Arkansas Class I areas were making less progress than necessary to achieve the URP during this 2008–2018 planning period, more costly controls could be warranted if found reasonable after consideration of the four statutory factors and other relevant factors. However, Arkansas Class I areas are already below the 2018 point on the URP; therefore, it is reasonable to consider this visibility progress, in addition to the mandatory reasonable progress factors, when evaluating whether additional controls for key pollutants at source categories contributing to visibility impairment are necessary for achieving reasonable progress during the first planning period.

2. Costs of Compliance

The 2007 Reasonable Progress Guidance states that the cost of compliance "can be interpreted to encompass . . . the implication of compliance costs to the health and vitality of industries within a state."[40] In the AR RH FIP, EPA imposed over $2 billion in SO_2 control costs over the next thirty years for the purposes of reasonable progress based solely on cost-effectiveness. By contrast, ADEQ has determined that a broader interpretation, as stated in the guidance, is appropriate for analysis in this context for reasons including the visibility trends identified above.

Additional costs of compliance would create negative impacts on the health and vitality of industries within the State. These additional costs would have even greater negative impacts if additional SO_2 controls were imposed on the electricity sector. ADEQ notes that energy companies are permitted to recover costs related to the installation of emissions control technologies at EGUs required by the final SIP from electricity ratepayers subject to approval by the Arkansas Public Service Commission.[41] Any additional costs to EGUs in the form of required emissions control technologies would be allowed to be passed on to Arkansas ratepayers, including a variety of industries. Energy-intensive industries would be disproportionately impacted by additional costs of controls on the EGUs.

Further discussion of these and other costs related specifically to Independence, the sole facility mandated to control for reasonable progress in the AR RH FIP, is set forth more fully below in Part V.D.4.

[40] EPA (2007) Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program at p. 5-1.
[41] Ark. Code Ann. § 23-4-501

3. Time Necessary for Compliance

The time necessary for compliance varies depending on control technologies considered. The time necessary for compliance for SO_2 control technologies considered for BART in this SIP was typically three to five years, unless progress had already been made toward implementing those control technologies.

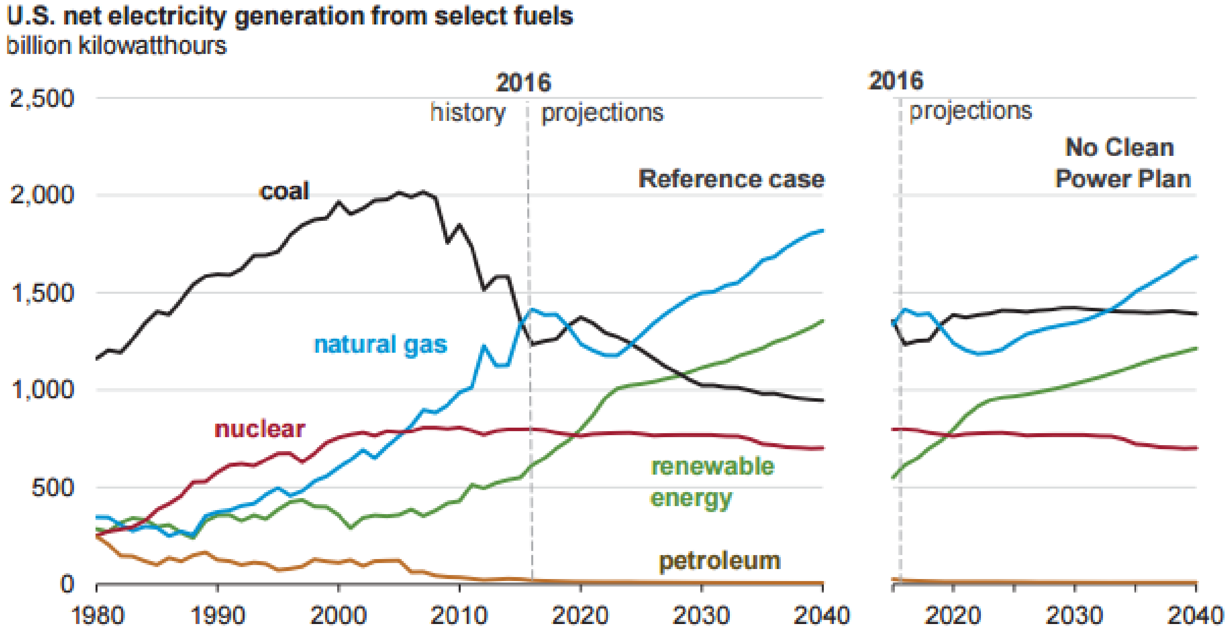
4. Energy & Non-Air Quality Impacts of Compliance

SO_2 control technologies have negative energy and non-air quality impacts including temporary outages required for the installation of such controls, parasitic load, and new waste products. The installation of additional control technologies on Arkansas EGUs including dry and wet scrubbers may have negative impacts including temporary outages required for the installation of such controls, which would temporarily disrupt the supply of electricity to the grid. Similarly, certain control technologies will reduce the generating capacity of particular EGU, which is referred to as a parasitic load.

Energy markets are already producing energy sector trends that are conducive for visibility improvement in Arkansas Class I areas. Market trends for coal and natural gas have resulted in decreased dispatch of coal-fired facilities broadly. This, in turn, decreases the overall amounts of key pollutants that impact visibility: SO_2, NOx, and $PM_{2.5}$. According to data from the Energy Information Administration, the economic pressure on coal units due to low natural gas prices is expected to continue throughout the rest of the first planning period and beyond.[42] Figure 12 shows energy consumption trends from the electricity sector by fuel from 1980–2016 and projects trends out to 2040.

[42] U.S. Energy Information (2017). "Annual Energy Outlook 2017" <https://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf>

Figure 12 United States Electricity Sector Energy Consumption by Fuel[43]



5. Remaining Useful Life of Potentially Affected Sources

The 2007 Reasonable Progress Guidance states that "this factor is generally best treated as one element of the overall costs analysis." If the remaining useful life for a given facility is less than the typical amortization period for new control equipment, the annualized cost and the controls become less cost-effective. In addition, the cost of controls may result in an economic decision to discontinue operations, thus truncating the remaining useful life of a source.

C. Evaluation of SO_2 Point Sources

In addition to the statewide reasonable progress analysis above, ADEQ has also examined, sources that emitted at least 250 tpy of sulfur dioxide as reported to the EPA Emission Inventory System (EIS) in any given year between 2002 and 2015 in order to determine which sources to evaluate as a rebuttal of the analysis employed by EPA in the AR RH FIP.[44] For those sources that participate in the Acid Rain Program, ADEQ obtained 2015 sulfur dioxide emissions from the Air Markets Program Data tool.[45] ADEQ then narrowed the list of sources to eleven sources that emitted at least 250 tons per year averaged over most recent three-year period for which data is available. These sources are listed in Table 11 below.

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[43] U.S. Energy Information (2017). "Annual Energy Outlook 2017" At 70 <https://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf>

[44] Emissions Inventory datasets: 2002 National Emissions Inventory, 2005 National Emissions Inventory, 2008 National Emissions Inventory V3, 2009 Arkansas Department of Environmental Quality, 2010 Arkansas Department of Environmental Quality, 2011 National Emissions Inventory V2, 2012 Arkansas Department of Environmental Quality, 2013 Arkansas Department of Environmental Quality, 2014 National Emissions Inventory V1, and 2015 Arkansas Department of Environmental Quality.

[45] https://ampd.epa.gov/ampd/

Table 11 Sulfur Dioxide Emissions from Sources Emitting Greater Than 250 Tons per Year

Facility	Most Recent Three-Year Period	Average Sulfur Dioxide Emissions (Tons Per Year)
Entergy White Bluff*	2014–2016	24,346
Entergy Independence	2014–2016	22,531
Flint Creek Power Plant (SWEPCO)*	2014–2016	5,350
Plum Point Energy Station Unit 1	2014–2016	2,759
FutureFuel Chemical Company	2013–2015	2,837
Domtar A.W. LLC, Ashdown Mill*	2013–2015	1,553
Evergreen Packaging-Pine Bluff	2013–2015	986
Albemarle Corporation-South Plant	2013–2015	1,382
SWEPCO- John W. Turk Jr. Power Plant	2014–2016	908
Ash Grove Cement Company/Foreman Cement Plant	2013–2015	369
Nucor-Yamato Steel Company	2013–2015	301

*Facilities are subject to BART requirements which satisfy the four factor analysis requirement for reasonable progress for these sources.

Entergy White Bluff, Flint Creek, and Domtar are all subject to BART. Since the BART analyses conducted to establish BART control requirements are based on an assessment of many of the same factors that must be addressed in establishing the reasonable progress goals, these control requirements satisfy the reasonable progress goal-related requirements for review of these sources during this planning period. No additional emissions controls are necessary for these sources. For the other sources listed in Table 11, ADEQ calculated the total average actual emissions rate (Q) in tons of SO_2 per year over the most recent three-year period and determined the distance (D) in kilometers of each source to its closest Class I area. A Q divided by D value of ten was used as a threshold for further evaluation of reasonable progress controls. This value was selected based on guidance contained in the BART guidelines and is consistent with the approach used in other EPA rulemakings.[46] Table 12 lists the Q/D values for these sources.

Table 12 Q/D Values for Large SO_2 Point Sources[47]

Facility	Upper Buffalo	Caney Creek
Entergy Independence	126	81
Plum Point Energy Station Unit 1	9	7
FutureFuel Chemical Company	17	10
Evergreen Packaging-Pine Bluff	4	5
Albemarle Corporation-South Plant	5	9
SWEPCO- John W. Turk Jr. Power Plant	4	11

[46] 40 CFR part 51, app. Y, § III; Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Proposed Rule (February 18, 2014)

[47] Class I Areas_Q Over D Calculations.xls in Appendix F.

Ash Grove Cement Company/Foreman Cement Plant	1	5
Nucor-Yamato Steel Company	1	1

Three sources identified in Table 12 had a maximum Q/D value greater than or equal to ten: Entergy Independence, FutureFuel Chemical Company, and John W. Turk Jr. Power Plant. Entergy Independence is the second largest point source of SO_2 in Arkansas with average 2014–2016 emissions of 22,531 tpy. By contrast, FutureFuel Chemical Company averaged 2,837 tpy (2013–2015) and John W. Turk Jr. Power Plant averaged 908 tpy (2014–2016). SO_2 emissions from FutureFuel Chemical Company and John W. Turk Jr. Power Plant are approximately an order of magnitude lower than emissions from Entergy Independence. FutureFuel Chemical Company was a BART-eligible source. In the 2008 AR RH SIP, ADEQ determined that FutureFuel Chemical was not subject-to-BART based on modeling conducted for the development of that SIP. Therefore, ADEQ does not find it necessary to further evaluate controls for this facility for this planning period. John W. Turk Jr. Power Plant began operation in 2012 and has implemented best available control technology, which is more stringent than BART; therefore, ADEQ does not anticipate that more stringent controls would be available and/or reasonable for this planning period.

Entergy Independence is not a BART-eligible facility and was required by the AR RH FIP to install controls for the purpose of ensuring reasonable progress. Due to these unique circumstances, ADEQ finds that Independence specifically warrants further consideration under the reasonable progress factors.

D. Consideration of Reasonable Progress Factors for Entergy Independence.

In determining reasonable progress, Clean Air Act section 169(A)(g)(1) requires states to examine the cost of compliance, the time necessary for compliance, energy and nonair impacts, and remaining useful life. In development of the AR RH FIP, EPA performed a reasonable progress analysis that considered two control technologies for Entergy Independence: Wet FGD and Dry FGD.

Entergy provided additional information regarding EPA's analysis in comments on the AR RH FIP, including a proposal to switch to LSC at Independence. Entergy also provided additional information with respect to costs associated with the use of LSC for Entergy White Bluff in an August 18, 2017 submittal. ADEQ's proposed analysis was based on the data provided by EPA in support of the AR RH FIP as supplemented by Entergy. In comments on ADEQ's proposed analysis, Entergy provided additional Independence-specific cost-estimates and modeled benefits anticipated for LSC. ADEQ's final analysis replaces White Bluff data used as a surrogate for Independence with Independence-specific information.

The Entergy Independence Power Plant is a coal-fired electric generating station with two identical 900 megawatt boilers. These boilers burn Wyoming Powder River Basin sub-bituminous coal as their primary fuel and No. 2 fuel oil or bio-diesel as start-up fuel. The layout and boiler units used at this facility are similar to those used at Entergy White Bluff; however, construction at the units at Independence began in 1978 and operation in 1983; therefore, the units are not subject to BART.

The available SO_2 retrofit control technology options for Entergy Independence Units 1 and 2 considered in the AR RH FIP and in this SIP revision are fuel switching to LSC, Dry FGD and Wet FGD. All three options are technically feasible. Fuel switching to coal with a sulfur content of 0.6 lb/MMBtu would result in a four to six percent reduction in SO_2 emissions from 2009–2013 levels.[48] Dry FGD systems have control efficiencies ranging from sixty to ninety-five percent. These systems utilize a fine mist of lime slurry sprayed into an absorption tower to absorb SO_2. The resulting calcium sulfite and calcium sulfate are then collected with a fabric filter. Wet FGD, scrubbing the exhaust stream with a lime or limestone slurry, is capable of achieving eighty-to ninety-five percent control of SO_2 emissions.

1. Existing controls

Each of the Entergy Independence units are subject to a prevention of significant deterioration (PSD) emissions limitation of 0.93 lb/MMBtu is in effect for these units. Entergy Independence Units 1 and 2 are currently permitted to emit 35,438.6 tons per year (tpy) of SO_2 (8,091.0 lb SO_2/hr) each or 70,877.2 tpy of SO_2 (16,182 lb SO_2/hr) combined.[49] Annual emissions for Entergy Independence Units 1 and 2 combined from 2008–2014 ranged from 26,448–32,974 tpy SO_2—less than half of total allowable emissions in their permit.[50] Annual emissions from Entergy Independence dropped to 14,994 tpy SO_2 in 2015—less than a quarter of total allowable emissions in their permit.[51] Annual emissions from Entergy Independence increased to 22,569 SO_2 in 2016, but are lower than any annual emissions rate from 2008–2014.[52]

As previously discussed in Section V.B.4. of this SIP, market trends for coal and natural gas have resulted in decreased dispatch of coal-fired EGUs, which includes Entergy Independence.

2. Degree of Improvement in Visibility Anticipated from Evaluated Controls

Although the degree of visibility improvement is not one of the four statutory factors for a reasonable progress analysis, the ultimate goal of any reasonable progress controls should be achieving visibility improvements.

[48] Calculated based on a comparison of the maximum 30 boiler operating day SO_2 emission rate during 2009–2013 to a 0.6 lb/MMBtu limit for low sulfur coal. This baseline was selected to match the EPA baseline used to calculate control efficiency and cost-effectiveness values for Dry FGD and Wet FGD.

[49] Entergy Arkansas, Inc. – Independence, Permit No. 0449-AOP-R10 AFIN: 32-00042

[50] 2009 Arkansas Department of Environmental Quality Emissions Inventory, 2010 Arkansas Department of Environmental Quality Emissions Inventory, 2011 National Emissions Inventory Version 2, 2012 Arkansas Department of Environmental Quality Emissions Inventory, 2013 Arkansas Department of Environmental Quality Emissions Inventory, 2014 National Emissions Inventory Version 1 <https://eis.epa.gov/eis-system-web>

[51] Air Markets Program Data: Air Markets Program Data: Annual SO_2 Data for Entergy Independence for 2015 <https://ampd.epa.gov/ampd/>

[52] Air Markets Program Data: Air Markets Program Data: Quarterly SO_2 Data for Entergy Independence for 2015 and 2016 <https://ampd.epa.gov/ampd/>

In the AR RH FIP, EPA estimated, using the CALPUFF model, that installation of Dry FGD at Entergy Independence Unit 1 and Unit 2 would achieve a 1.096 deciview improvement at Caney Creek and a 1.178 deciview improvement at Upper Buffalo.[53] In comments on the AR RH FIP, Entergy disagreed with EPA's estimates of visibility improvements that would be achieved from installation of Dry FGD at Entergy Independence. Using scaled results from CAMx, a photochemical model, instead of the CALPUFF model, Entergy estimated that installation of Dry FGD at Independence would only result in a 0.08 deciview improvement at Caney Creek and a 0.07 deciview improvement at Upper Buffalo on the twenty percent worst days.[54] A value of one deciview is considered perceptible.

In comments on the proposed SIP, Entergy included CALPUFF modeling results for LSC at Entergy Independence Unit 1 and Unit 2 estimating a 0.112 deciview improvement at Caney Creek and a 0.236 deciview improvement at Upper Buffalo based on ninety-eighth percentile values.[55]

3. Remaining Useful Life

There are no State or federally enforceable limitations on continued operations at Entergy Independence; therefore, cost of compliance calculations are based upon a thirty-year amortization period for Dry and Wet FGD. However, Entergy has expressed its intention of ceasing coal-fired operations at Independence by the end of 2030. In addition, market pressures may also impact continued operations at Independence, including changes in dispatch and economic decisions concerning the continued viability of the units. Although the cost of compliance for control technologies evaluated in this SIP are based on a thirty-year amortization period, ADEQ recognizes that Entergy's choices may result in a remaining useful life of less than thirty years and thus higher annual costs associated with controls evaluated.

4. Cost of Compliance

In the AR RH FIP, EPA estimated cost-effectiveness for the Dry FGD and Wet FGD for Entergy Independence based on five-factor BART analysis for White Bluff. Entergy provided different cost-effectiveness values for Dry FGD estimates in their comments on the AR RH FIP and also submitted Independence Dry FGD cost estimates in Exhibit I to their comments on the proposed SIP. ADEQ calculated cost information using information provided by Entergy regarding LSC

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[53] In EPA's supplemental modeling of impacts of Dry FGD and Wet FGD at Independence for the AR RH FIP, EPA evaluated two scenarios lines. The BASE case emission rates for NOx and SO_2 were from the maximum actual 24-hour emissions during the 2001–2003 period. The BASE 2 case emission rates for SO_2 were based on the maximum actual 24-hour emissions during the 2001-2003 period and the NOx emissions were based on the maximum 24-hour emissons during the 2011–2013 period. EPA also modeled the expected visibility impact of controls for each of the BASE case emissions assumptions. The values presented above represent the values included in the Final AR RH FIP.

[54] Entergy Arkansas Inc. (2015). Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas. Docket ID No. EPA-R06-OAR-2015-0189

[55] Entergy's modeling submitted in comments on the Proposed SIP is based on a 2011–2013 baseline period for modeled emission rates. While Entergy's baseline differs from the two baselines modeled by EPA, we do not expect that the difference would substantially impact the comparison of the visibility benefits among controls evaluated.

cost premiums, U.S. Energy Information Administration fuel consumption data, and EPA Air Markets Program Data.

Fuel switching to LSC has no associated capital costs; however, there is a cost premium associated with guaranteeing that the sulfur content is below 0.6 lb/MMBtu.[56] ADEQ estimated annualized operation and maintenance costs of switching to LSC at $1.6 million and $1.7 million for Entergy Independence Unit 1 and Unit 2, respectively.[57] Controlled annual emission rates for the LSC scenario were calculated based on these annualized costs and the anticipated emission reductions from switching to LSC.[58] ADEQ estimated that the average cost-effectiveness for fuel switching to LSC is approximately $2,437/ton of SO_2 reduced at Entergy Independence Unit 1 and $2,345/ton of SO_2 reduced at Entergy Independence Unit 2.

Installation of Wet FGD requires a large capital investment. Entergy did not provide Independence-specific cost-estimates for Wet FGD; however, EPA estimated total annualized costs of Wet FGD at $49,526,167 for each Entergy Independence unit based on a thirty-year amortization period. EPA estimated that the average cost-effectiveness for Wet FGD was $3,706 per ton of SO_2 reduced at Entergy Independence Unit 1 and $3,416 per ton of SO_2 reduced at Entergy Independence Unit 2. In the AR RH FIP, EPA eliminated Wet FGD due to the high incremental cost and the minimal incremental increase in estimated visibility improvement achieved over Dry FGD.[59] Therefore, ADEQ also finds that Wet FGD does not warrant further consideration.

Installation of Dry FGD also requires a large capital investment. In the proposed SIP, ADEQ based its evaluation of costs on the EPA estimated total annualized costs of Dry FGD for each Entergy Independence unit based on a thirty-year amortization period and information available for White Bluff. In comments on the proposed SIP, Entergy submitted control cost estimates specific to Independence. Entergy estimated total capital costs of Dry FGD at Independence to be $491,893,500 per unit based on claimed actual costs and $355,391,500 based on EPA-allowed costs.[60] Entergy annualized the capital cost for both values based on a nine-year amortization period based on their plans for ceasing coal-fired operations at Independence by the end of year in 2030. Entergy's estimates for anticipated emission reductions as a result of Dry FGD also differed from the EPA estimates. Entergy based emissions reduction calculations on a 2009–

[56]The Entergy August 18, 2017 revised BART analysis for White Bluff estimated this cost premium at $0.50/ton.
[57] Annualized capital costs were calculated using average annual fuel consumption in tons multiplied by the $0.50/ton cost premium Entergy quoted for low sulfur coal in their August 18, 2017 revised BART analysis for White Bluff. Annual fuel consumption date was obtained from U.S. Energy Information Administration Form EIA-923 detailed data for 2009–2013.
[58] The control efficiency for low sulfur coal for each unit was calculated based on the difference between the maximum 30-boiler operating day rolling average emission rate during the 2009–2013 baseline period and the controlled emission rate. The controlled annual emissions rate was calculated based on the percent decrease in 30-boiler operating day emission rate from the maximum emission rate achieved by low sulfur coal.
[59] EPA concluded that the minimal amount of incremental visibility improvement projected to result from wet FGD does not justify the higher cost compared to Dry FGD. Based on EPA's supplemental modeling, the incremental visibility improvement of Wet FGD versus Dry FGD would be 0.019 deciviews or less at each of the four Class I areas.
[60] Table 3-1 of Entergy Arkansas Inc. Comments on the Proposed Arkansas Phase II Regional Haze SIP Revision Exhibit I

2013 baseline; whereas, EPA based emission reduction calculations on a baseline over the same period dropping the minimum and maximum year values. ADEQ estimates that, for a thirty-year amortization period, the cost-effectiveness of Dry FGD at Independence would be $2,970/ton for unit 1 and $2,742/ton for unit 2 based on Entergy's Independence-specific capital cost estimates, annual O&M costs, and anticipated emission reductions for Dry FGD.[61]

In addition to the typical cost-effectiveness calculations used to evaluate various control technologies in the context of BART, ADEQ finds other cost-related factors to be of relevance to reasonable progress with regard to specific analysis of Independence including total capital costs, costs to Arkansas communities, and the average dollar-per-deciview reduction in visibility impairment anticipated from assessed control technologies. The total capital costs for Wet FGD and Dry FGD are high even though cost-effectiveness in dollars per ton for these technologies, given a thirty-year remaining useful life assumption, are within the range that other states and EPA have found cost-effective. Cost-effectiveness estimates no longer fall into this range for a nine-year remaining useful life based on Entergy's anticipated cessation of coal-fired operations date at Independence. Therefore, capital costs are a particularly relevant consideration given Entergy's intentions to cease coal-fired operations at Independence in fewer than thirty years. In addition, any costs for control at Independence would be passed on to Arkansas electricity ratepayers. In the proposed SIP, ADEQ presented average cost per deciview reduction values for Dry FGD at Independence, but not for LSC because no modeling of LSC at Independence had been conducted. In comments on the SIP, Entergy provided updated Independence-specific cost-estimates and modeled visibility benefits associated with LSC. Table 13 lists ADEQ's estimates of cost-per-deciview improvement for LSC and Dry FGD at Independence.

Table 13 Average Dollar-Per-Deciview for Control Options at Independence Units 1 and 2[62]

	Caney Creek	Upper Buffalo	Hercules Glades	Mingo
LSC	$29,469,780	$10,929,190	$13,985,658	$12,179,393
Dry FGD	$68,337,085	$63,580,175	$70,925,611	$71,672,197

The cost-per-decivew improvement for Dry FGD is a little over two times higher than for LSC at Caney Creek and between five and six times higher at Upper Buffalo and the two Missouri Class I areas. Evaluation of cost per deciview demonstrates a greater difference in cost to achieve visibility benefits than a cost per ton of pollutant removed metric. Either control evaluated would result in millions of dollars being spent to achieve little visibility benefit.

[61] ADEQ revised the EPA-allowed annualized capital cost for Dry FGD at Independence included in Exhibit I to Entergy's comments based on a thirty-year remaining useful life for the Dry FGD equipment because no enforceable commitment to cease operations by 2030 is in place for Independence. The revised annualized capital cost is based on a capital recovery factor calculated for a thirty-year amortization period in accordance with Chapter 2 of the EPA Control Cost Manual. ADEQ's calculations are included in Appendix F. <https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf>

5. Time Necessary for Compliance

The typical time necessary for compliance for either add-on technology—Dry FGD or Wet FGD—is five years. Entergy estimates that the time necessary to comply with a limit based on LSC is three years due to time left on existing coal supply contracts, the time required to burn through current fuel stocks, and the time needed to build up a stockpile of LSC to assure against possible fuel supply disruptions.

6. Energy and Nonair Quality Environmental Impacts of Compliance

Dry FGD utilizes lime slurry to remove SO_2 from flue gas. In the process, particulate matter is generated that must be controlled through use of a baghouse or electrostatic precipitator. Once collected, the waste material is disposed of through landfilling. Costs associated with control of particulate matter and additional power requirements were factored into the cost estimates calculated by Entergy and EPA. Entergy has not indicated unusual circumstances that would create greater problems than experienced elsewhere that Dry FGD was utilized as BART. Use of LSC is not anticipated to result in any energy or nonair quality environmental impacts.

7. Reasonable Progress Control Determination for Independence

Based on ADEQ's evaluation of the reasonable progress factors for Entergy Independence, ADEQ finds that no additional controls at this source are necessary for reasonable progress during the first planning period. The controls evaluated would result in millions of dollars of costs annually that would be passed on to Arkansas ratepayers for little visibility benefit for visitors to Arkansas's Class I areas. Such costs are not necessary under reasonable progress when Arkansas Class I areas are already making more progress than the URP.

Although ADEQ does not find any of the controls evaluated for Entergy Independence to be necessary for achieving reasonable progress during the first planning period, ADEQ acknowledges Entergy's proposal to switch to LSC at Independence within the next three years. This voluntarily proposed SIP-strengthening measure would result in some visibility benefit at Arkansas Class I areas that, while less than would be anticipated from Dry FGD, would require no capital cost.[63] The lack of substantial capital costs associated with LSC provides flexibility regarding Entergy's planned cessation of coal-fired operations at Independence by the end of 2030 and avoids potential stranded costs associated with controls that require a large capital investment. ADEQ has included Entergy's proposed use of LSC at Independence in the long-term strategy for this SIP and expects that modeled visibility benefits will be realized from use of LSC.

E. Additional Controls Necessary for Reasonable Progress at Arkansas Class I Areas

After consideration of the four statutorily required factors and other relevant factors to reasonable progress, ADEQ has determined that no additional controls beyond BART and other

[63] There is an assumed $0.50/ton cost premium associated with guaranteeing that the sulfur coal content delivered by contract would ensure compliance with an emission rate of 0.60 lb/MMBtu.

Clean Air Act programs are necessary to ensure reasonable progress during the 2008–2018 regional haze planning period. ADEQ evaluated the monitored trajectory of visibility impairment during this planning period, particulate source apportionment data, and SO_2 emissions relative to proximity to Arkansas Class I areas, and the statutory reasonable progress factors.

ADEQ has determined, based on an analysis of the reasonable progress factors both statewide and for Independence, that the cost of additional controls evaluated for the purposes of reasonable progress is unnecessary to ensure reasonable progress during this planning period. Any of the controls evaluated would result in millions of dollars of costs annually for little visibility improvement. If the controls included in the AR RH FIP were imposed, the costs would be passed on to the citizens and businesses of Arkansas through electricity rate increases. Such costs are not warranted under reasonable progress when Arkansas Class I areas are well below their respective URPs during this planning period.

ADEQ's determination that no controls beyond BART and other Clean Air Act programs are necessary to ensure reasonable progress during this planning period is consistent with EPA's rationale for the sixty-year lifespan of the regional haze program. The regional haze program was established as a sixty-year program broken into ten-year planning periods. The program period established in the 1999 Regional Haze Regulations was set in part based on EPA's expectation that continued visibility progress will be possible as "industrial facilities built in the latter half of the 20th century will reach the end of their 'useful lives' and are retired and/or replaced by cleaner, more fuel-efficient facilities."[64] In addition, EPA noted the agency's anticipation that further innovations in control technologies will enable new facilities to achieve lower emissions rates.[65] Entergy's anticipated cessation of coal-fired operations at Independence by the end of 2030 is an example of this principle. The Regional Haze Regulations provide for a fresh look at the changing landscape of visibility impacting sources and potential controls every ten years.

The 2007 reasonable progress guidance states that "[g]iven the significant emissions reductions that we anticipate to result from BART, the CAIR, and the implementation of other CAA, including the ozone and $PM_{2.5}$ NAAQS, for many States this will be an important step in determining your RPG, and may be all that is necessary to achieve reasonable progress in the first planning period."[66]As discussed in greater detail in the long term strategy, more programs with beneficial impacts to visibility in Class I areas have come into effect since this guidance was finalized in 2007.[67] Consistent with these principles, ADEQ is deferring consideration of further measures for the purposes of reasonable progress at Arkansas Class I areas to future planning periods.

F. Reasonable Progress Goals for Arkansas Class I Areas

ADEQ is revising the RPGs established in the 2008 AR RH SIP for the twenty percent worst days at Caney Creek and Upper Buffalo to reflect control measures included in this SIP revision and the NOx Regional Haze SIP that are required to be in effect by the end of the first planning

[64] EPA (1999). "Regional Haze Regulations; Final Rule" (64 FR 35714)
[65] Id. at 35732
[66] EPA (2007) Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program
[67] See discussion *Infra* Part VI.

period. In order to provide RPGs that account for emissions reductions from SIP controls, we have used a method similar to that used by EPA for the AR RH FIP. This method is based on a scaling of light extinction components in proportion to emissions changes anticipated from SIP controls for which compliance is required on or before December 31, 2018. ADEQ is not revising its goal of no degradation on the twenty percent best days included in the 2008 AR RH SIP.

Using the same formulas EPA used to develop its RPGs for the AR RH FIP, ADEQ scaled CENRAP's CAMx 2018 projection of light extinction components for SO_4 and NO_3 in proportion to the SIP revision's emissions reductions for SO_2 and NOx, respectively. ADEQ made updates to reflect the most recent three years of data for emissions and heat input for Arkansas EGUs. The most recent three years of data (2014–2016) were used as opposed to EPA's method of using the five most recent years of data minus the minimum and maximum values (2009–2013) to ensure that recent changes in dispatch of Arkansas EGUs were captured.[68] The results of our analysis for the twenty percent worst days for 2018 for Caney Creek and Upper Buffalo are included in Table 14.[69]

Table 14 Reasonable Progress Goals for 2018 for Caney Creek and Upper Buffalo

Class I Area	2018 RPG 20% Worst Days (deciviews)
Caney Creek	22.47
Upper Buffalo	22.51

Figure 13 and Figure 14 demonstrate that Arkansas is already achieving greater visibility improvements than the RPGs listed in Table 14.[70]

[68] EIA projections show decreased consumption of coal by electric generating units that is expected to continue through 2040. Therefore, ADEQ anticipates that the coal EGU dispatch trends seen in the most recent three years is likely to continue through the first regional haze planning period and the next two planning periods. See Figure 10

[69] See RPG Calculation Data Sheet provided at https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx.

[70] Figures 13 and 14 are updates to Figures 11 and 12 in the Proposed SIP. These figures have been updated so that the rolling average is inclusive of the current year and four previous years rather than reflecting the five previous years and to include 2016 data. 2000–2016 visibility data included in Figures 1 and 2 were obtained from: Visibility Status and Trends Following the Regional Haze Rule Metrics: IMPROVE Aerosol, Regional Haze Rule II (New Equation), with substituted data. Caney Creek, Upper Buffalo http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx.

Figure 13 Caney Creek Reasonable Progress Assessment – 20% Worst Days

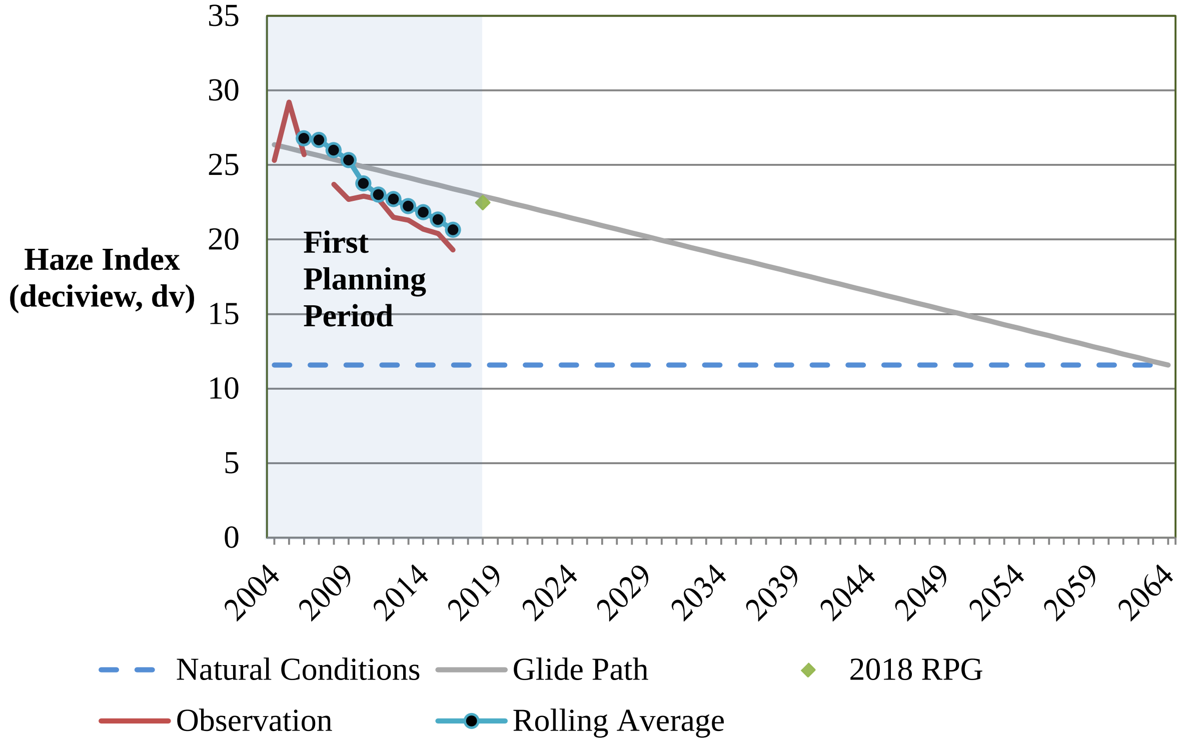
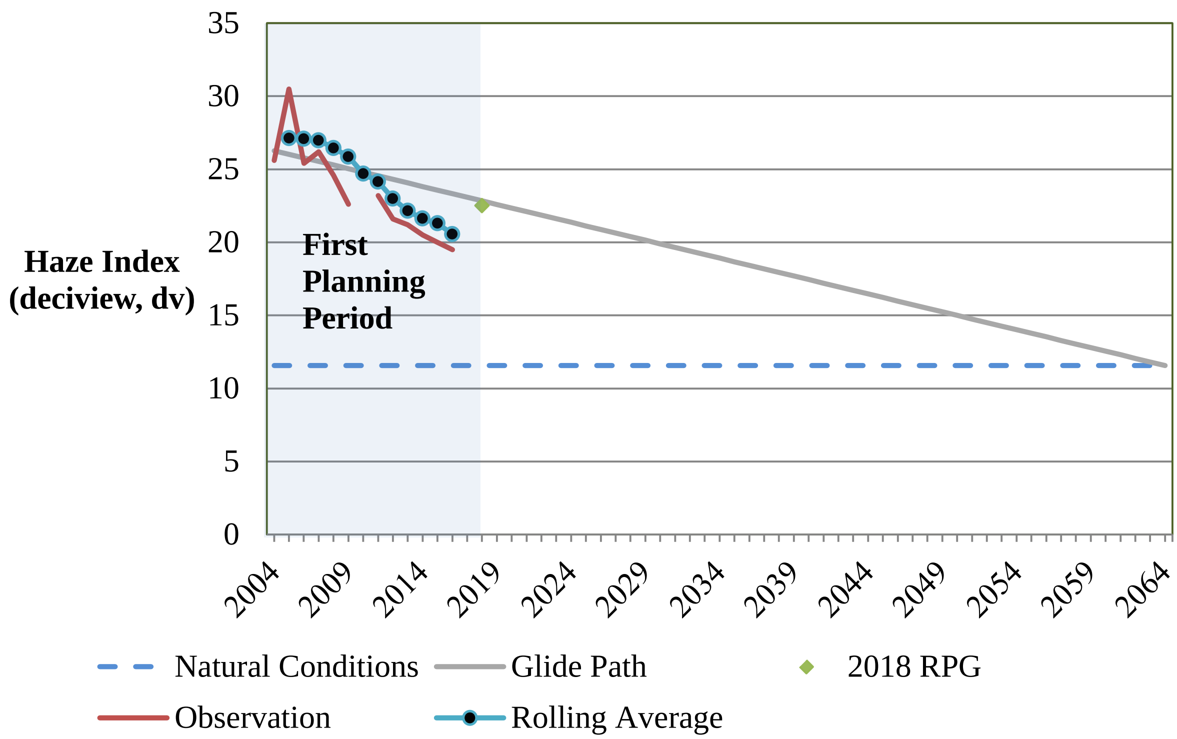


Figure 14 Upper Buffalo Reasonable Progress Assessment – 20% Worst Days



G. Interstate Visibility Transport

Sources in Arkansas impact two Class I areas in Missouri: Hercules Glade and Mingo. CENRAP PSAT data indicates that Arkansas sources contributed approximately seven percent of light extinction at Hercules Glades and four percent of light extinction at Mingo. The relative impact of Arkansas sources compared to sources in other states are projected to increase between 2002 and 2018 to approximately nine percent of total light extinction at Hercules Glades and five percent at Mingo based on the CENRAP PSAT data; however, actual contributions to light extinction attributed to Arkansas sources are projected to decrease by fourteen percent for Hercules Glades and eighteen percent for Mingo See Figures 15 and 16.

Figure 15 Comparison of Projected Light Extinction at Hercules Glades on the Haziest Twenty Percent Days Due to Particulate Species Attributed to Arkansas Sources

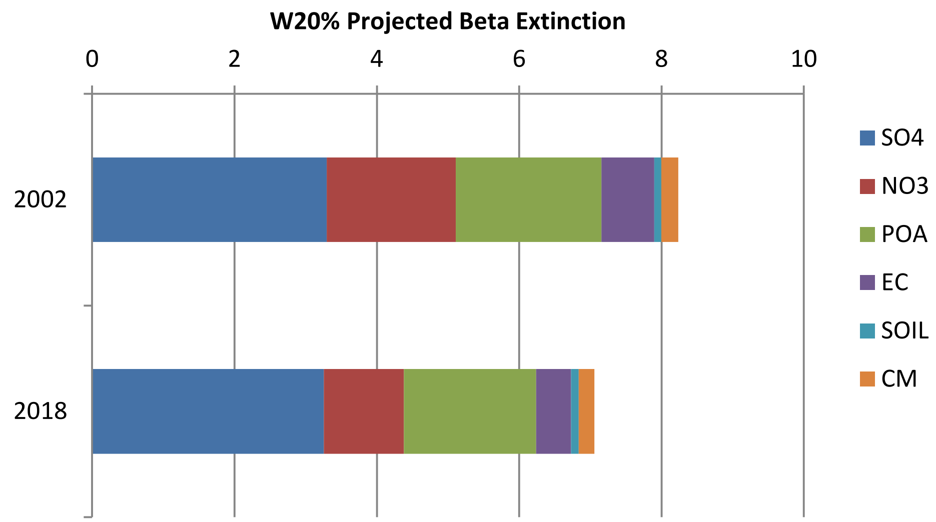


Figure 16 Comparison of Projected Light Extinction at Mingo on the Haziest Twenty Percent Days Due to Particulate Species Attributed to Arkansas Sources

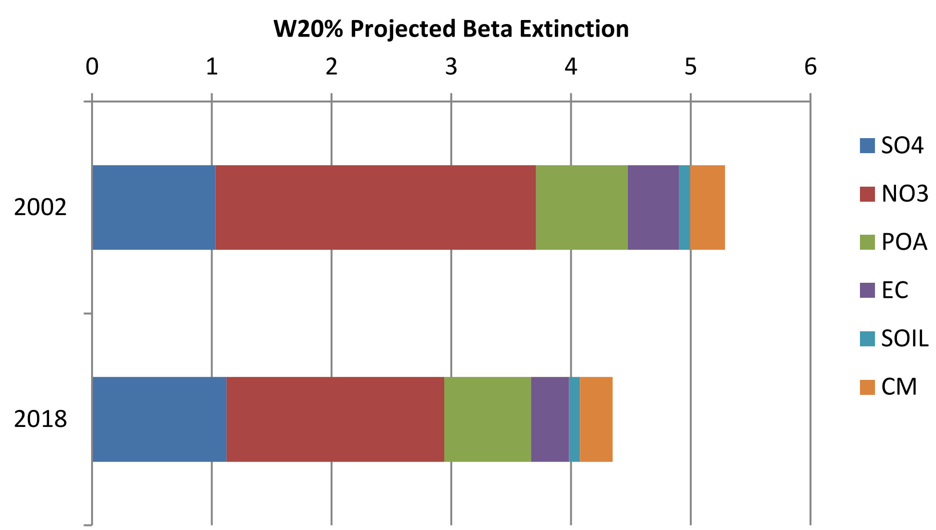
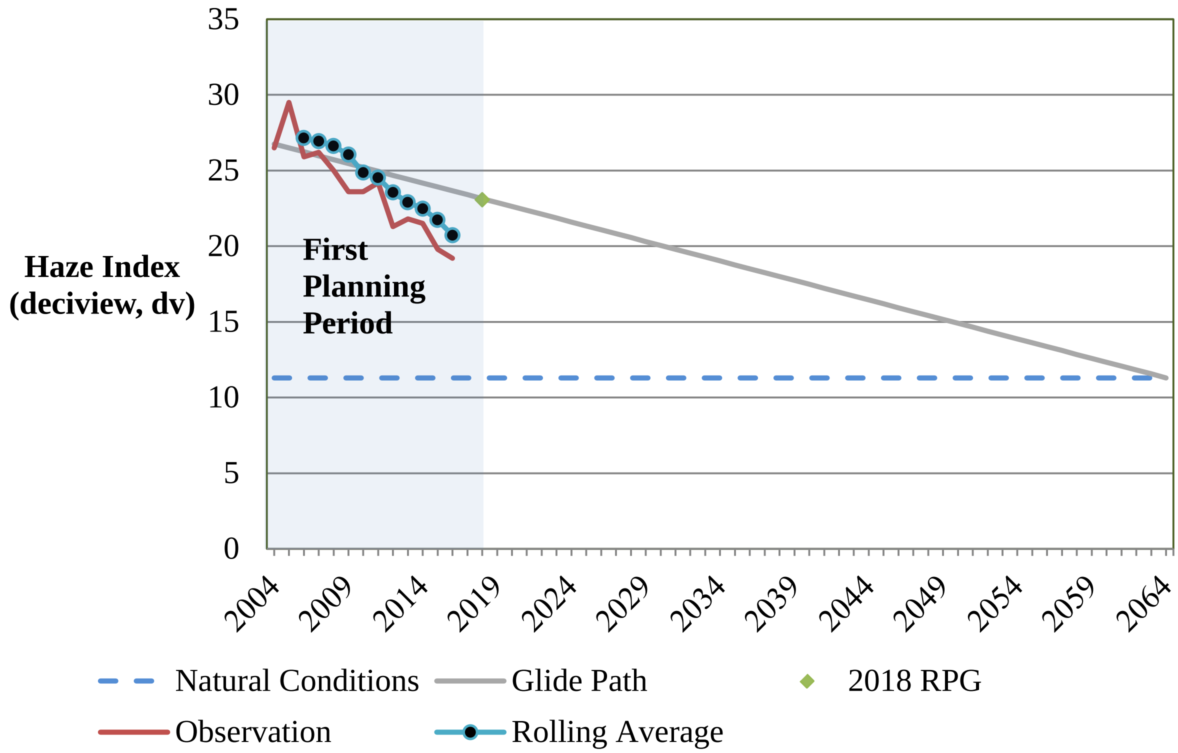


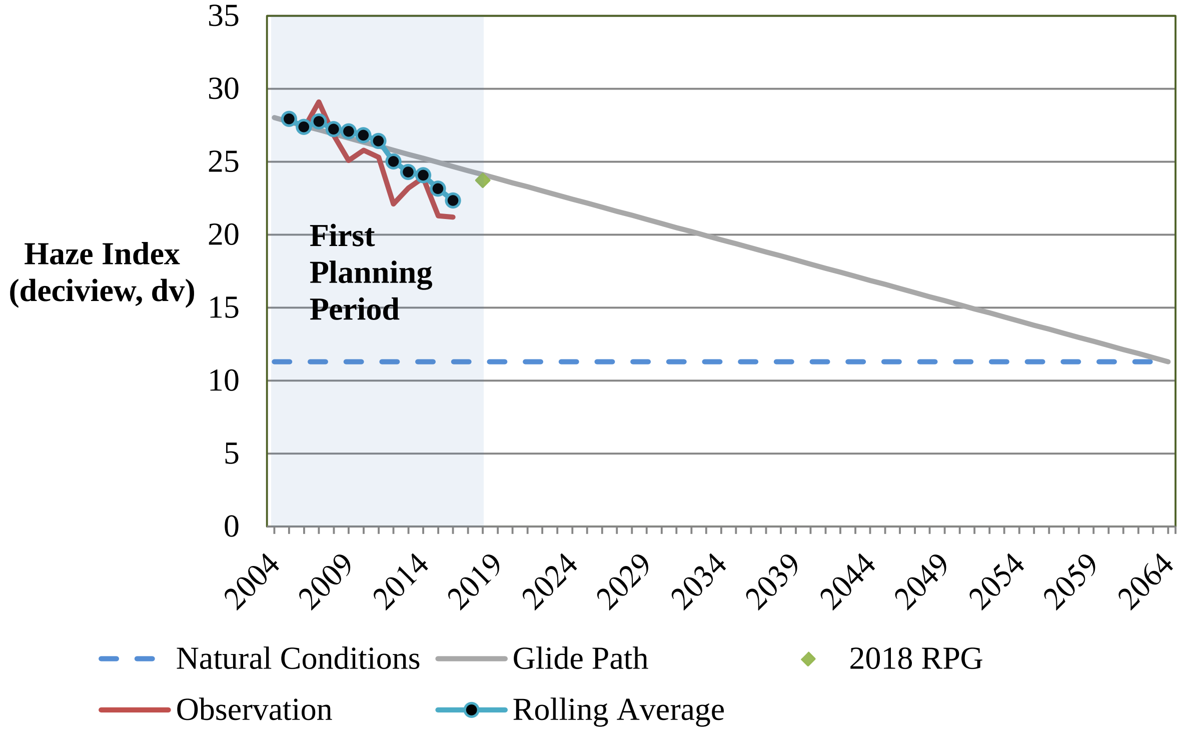
Figure 17 and Figure 18 demonstrate that Missouri is on track to achieve its visibility goals. In Missouri's 2009 Regional Haze SIP, Missouri established 2018 reasonable progress goals of 23.71 deciview for Mingo and 23.06 deciview for Hercules Glades. The most recent calculations for the twenty percent worst days and twenty percent best days for Class I areas were performed for 2015.[71] For both Mingo and Hercules Glades, visibility impairment on the twenty percent worst days in 2015 beat Missouri's 2018 RPGs for both Class I areas. The most recent five-year rolling average of observed visibility impairment on the twenty percent worst days at Hercules Glades beat Missouri's 2018 RPG for that Class I area and the most recent five year-rolling average of observed visibility impairment on the twenty percent worst days at Mingo is on track to beat Missouri's RPG for that Class I area. The visibility progress observed indicates that sources in Arkansas are not interfering with the achievement of Missouri's RPGs for Hercules Glades and Mingo.

Figure 17 Hercules Glades Reasonable Progress Assessment – 20% Worst Days



[71] Figures 17 and 18 are updates to Figures 13 and 14 in the Proposed SIP. These figures have been updated so that the rolling average is inclusive of the current year and four previous years rather than reflecting the five previous years and to include 2016 data. 2000–2016 visibility data were obtained from: Visibility Status and Trends Following the Regional Haze Rule Metrics: IMPROVE Aerosol, Regional Haze Rule II (New Equation), with substituted data. Hercules Glades, Mingo http://views.cira.colostate.edu/fed/SiteBrowser/Default.aspx.
Note: Missouri DNR revised its natural baseline conditions for Mingo on the twenty percent haziest days from 12.4 deciviews to 11.3 deciviews in their 2012 technical supplement to their 2009 Regional Haze SIP. https://dnr.mo.gov/env/apcp/reghaze/regional-haze-jan-30-2012.pdf

Figure 18 Mingo Reasonable Progress Assessment – 20% Worst Days



In the 2008 AR RH SIP, ADEQ relied upon the technical analyses developed by CENRAP and approved by all State participants. CENRAP visibility projections indicated that the emission reductions planned for CENRAP states were sufficient to achieve the reasonable progress goals for Class I areas located in Missouri Class I areas.[72] In addition, CENRAP contracted with Alpine Geophysics to evaluate control strategies for reasonable progress. Alpine Geophysics recommended reasonable progress control strategies for six Class I areas within the CENRAP region: Big Bend National Park, Breton Island, Boundary Waters, Guadalupe Mountains, Wichita Mountain, and Voyageurs.[73] Neither Hercules Glades nor Mingo were included in the list of regions for which additional control strategies were recommended for reasonable progress. In addition, no specific measures were requested by Missouri for achieving reasonable progress in each mandatory Class I Federal area affected by Arkansas.

ADEQ has determined that no additional controls on sources within Arkansas are necessary to ensure that other states' visibility goals for their Class I areas are met.

[72] Technical Support Documentation for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation included in Appendix F

[73] Alpine Geophysics, LLC (2006) "CENRAP Regional Haze Control Strategy Analysis Plan" included in Appendix F

VI. Long-Term Strategy

In 2012, EPA partially approved and partially disapproved Arkansas's long-term strategy included in the 2008 AR RH SIP. 40 CFR 51.308(d)(3)(v) requires the consideration of the following factors in developing a long-term strategy: (1) Emissions reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment; (2) measures to mitigate the impacts of construction activities; (3) emissions limitations and schedules for compliance to achieve the reasonable progress goal; (4) source retirement and replacement schedules; (5) smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for these purposes (6) enforceability of emissions limitations and control measures; and (7) the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy. Because EPA disapproved some of ADEQ's BART determinations and RPGs, EPA disapproved the emissions limitations and schedules of compliance element of the long-term strategy included in the 2008 AR RH SIP. EPA approved the other six elements of the long-term strategy.

Because the ongoing air pollution programs element of the Arkansas long-term strategy was previously approved, ADEQ is not proposing changes to that element in this SIP revision. Nevertheless, ADEQ notes that the landscape of ongoing air pollution programs has changed since EPA approved that element of the long-term strategy in the 2008 AR RH SIP. These changes include more stringent vehicle emission standards, renewable fuel standards, fuel efficiency standards, marine and aircraft standards, mercury and air toxics standards, various national emission standards for hazardous air pollution, and a replacement for the clean air interstate rule in the form of CSAPR. These additional air pollution programs are anticipated to achieve even greater emissions reductions that may result in further visibility improvement than the programs described in the 2008 AR RH SIP. A partial list of ongoing air pollution programs that have been implemented since the 2008 AR RH SIP is provided below:

- Tier 3 Vehicle Emissions and Fuel Standards Program (light duty, medium duty, and some heavy duty) (79 FR 23414, 2014)
- 2017 and Later Model Year CAFÉ Standards (77 FR 62624, 2012)
- Renewable Fuel Standard Program: Standards for 2014, 2015, and 2016 and Biomass-Based Diesel Volume for 2017 (80 FR 77420, 2015)
- Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy Duty Engines and Vehicles (76 FR 57106)
- Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles—Phase 2 (81 FR 73478, 2016)
- Ocean-going vessels category 3 marine rule (2010), NOx standards for Aircraft (2012)
- Small Nonroad Engine and Marine Spark-Ignition Engines and Vessels Emission Standards Phase 3 (2008)
- New NAAQS standards: 2006 $PM_{2.5}$, 2008 Ozone, 2010 NO_2, 2010 SO_2, 2012 $PM_{2.5}$
- Mercury and Air Toxics Standards
- CSAPR and CSAPR update
- NESHAP for Primary Aluminum Reduction Plants (80 FR 62390, 2015)
- NESHAP for Secondary Aluminum Production (80 FR 56700, 2015)

- NESHAP for Phosphoric acid manufacturing and phosphate fertilizer production (80 FR 50386, 2015)
- NESHAP for Mineral Wool Production and Wool Fiberglass manufacturing (80 FR 45280, 2015)
- NESHAP for Ferroalloys Production (80 FR 37366, 2015)
- NESHAP for Off-site waste and recovery operations (80 FR 14248, 2015)
- NSPS update for New Residential Wood Heaters, New Residential Hydronic Heaters, and Forced-Air Furnaces (80 FR 13672, 2015)
- NSPS update for Kraft Pulp Mills (79 FR 18952, 2014)
- NESHAP for Group IV Polymers and Resins; Pesticide Active Ingredient Production; and Polyether Polyols production (79 FR 17340, 2014)
- NESHAP and NSPS for Portland cement Manufacturing Industry (78 FR 10006, 2013)
- NESHAP for Hard and Decorative Chromium Electroplating and Chroming Anodizing Tanks and NESHAP for Pickling-HCl Process Facilities and Hydrochloric Acid Regeneration Plants (77 FR 58220, 2012)
- NSPS and NESHAP for Oil and Natural Gas Sector (77 FR 4940, 2012)
- NSPS for Nitric Acid Plants (77 FR 48433, 2012)
- Greenhouse Gas Tailoring Rule Step 3 and Plantwide Applicability Limits (77 FR 41051, 2012)
- NESHAP for Coal- and Oil-Fired Electric Utility Steam Generating Units and NSPS for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small-Industrial-Commercial-Institutional Steam Generating Units (77 FR 9304, 2012)
- NESHAP for Secondary Lead Smelting (77 FR 556, 2012)
- NESHAP for Wood Furniture Manufacturing Operations revision (76 FR 72050, 2011)
- NESHAP for Primary Lead Processing (76 FR 70834, 2011)
- NESHAP for Marine Tank Vessel Loading Operations and NESHAP for Group I Polymers and Resins (76 FR 22566, 2011)
- NESHAP for Major Sources Industrial, Commercial, and Institutional Boiler and Process Heaters (76 FR 15608, 2011)
- Source Determination for Certain Emissions Units in the Oil and Natural Gas Sector (81 FR 35622, 2016)

In addition to the changing regulatory landscape, ADEQ also acknowledges planned changes in operations at Arkansas EGUs. Specifically, ADEQ acknowledges the low NOx burners that are being installed at Entergy Independence and Entergy White Bluff. ADEQ acknowledges receipt of the submittal of documentation by Entergy indicating the planned retirement of Entergy Lake Catherine, the planned cessation of coal-fired operations at Entergy White Bluff by the end of 2028, and the planned cessation of coal-fired operations at Entergy Independence by the end of 2030. In addition, ADEQ appreciates Entergy's commitment, as indicated in their comments on the proposed SIP, to transition to LSC at Independence within the next three years for the rest of that facility's remaining coal-fired life. Per Entergy's request to make this fuel switch an enforceable element of ADEQ's long term strategy, ADEQ has included an emission limit of 0.60 lb SO2/MMBtu on a thirty-boiler operating day rolling average for each of the Entergy Independence units in AO LIS No. 18-073. ADEQ anticipates that these changes will result in emission reductions that provide further progress toward natural visibility at Arkansas and Missouri Class I areas during the second and third planning period.

ADEQ also acknowledges planned changes in operations at large stationary sources outside of Arkansas that have historically impacted Arkansas Class I areas. Specifically, ADEQ anticipates further reductions in visibility impairment due to recent announced closures of power plants in Texas and Tennessee. In October 2017, Luminant announced retirement in 2018 of three large power plants in Texas: Big Brown Plant, Sandow Plant, and Monticello Plant.[74] The Deely plant owned by CPS Energy is also scheduled to close in 2018.[75] Big Brown Plant, Monticello Plant, and Deely impact visibility at Caney Creek.[76] The baseline maximum visibility impact from Big Brown at Caney Creek is 3.775 deciviews, the baseline maximum visibility impact from Monticello at Caney Creek is 10.498 deciviews, and the baseline maximum visibility impact from Deely at Caney Creek is 1.513 deciviews. [77] In addition, the coal-fired units at Tennessee Valley Authority Allen plant in Memphis, Tennessee are scheduled to retire by June 2018 and will be replaced with natural gas generators.[78]

In this SIP revision, ADEQ has addressed the disapproved BART determinations for all subject-to-BART sources in Arkansas, with the exception of Domtar Ashdown Mill, and reasonable progress determinations. BART determinations are summarized in Section IV of this SIP and additional technical supporting data are found in Appendices B–E. Emissions limitations and schedules of compliance are rendered enforceable by AOs. BART requirements and compliance schedules for Domtar Ashdown Mill are included in the AR RH FIP. The long-term strategy and RPGs are reflective of those federally enforceable AR RH FIP controls for Domtar. Therefore, ADEQ requests that EPA fully approve Arkansas's revised long-term strategy.

VII. Review, Consultations, and Comments

A. Federal Land Manager Consultation

In accordance with the provisions of 40 C.F.R. § 51.308(i)(2), ADEQ consulted with designated FLM staff personnel on this SIP. This consultation gave FLMs the opportunity to discuss their assessment of the impact of the proposed SIP revisions on Arkansas Class I areas——Upper Buffalo and Caney Creek—and other Class I areas.

On October 27, 2017, ADEQ submitted letters to notify the federal land manager staff of this proposed SIP revision and to provide them with electronic access to the revision and related documents. ADEQ engaged in telephone communications with the FLMs. In addition, comments

[74] https://www.luminant.com/luminant-announces-decision-retire-monticello-power-plant/; https://www.luminant.com/luminant-close-two-texas-power-plants/
[75]https://www.power-eng.com/articles/2017/10/cps-deely-coal-to-still-close-even-with-clean-power-plan-reversal.html
[76] Promulgation of Air Quality Implementation Plans; State of Texas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan: Proposed Rule (82 FR 912, January 4, 2017)
[77] Id. Table 15 at 931
[78] https://www.tva.gov/Energy/Our-Power-System/Coal/Allen-Fossil-Plant

received from the FLMs were considered and posted to ADEQ's Regional Haze webpage: https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx. The FLM contact list, notification letters, and comments received are included in Tab E of this SIP package.

B. Consultation with States

For the 2008 AR RH SIP, ADEQ engaged in extensive interstate consultation with states participating in the CENRAP RPO. Because Missouri has two Class I areas impacted by Arkansas sources, ADEQ submitted a letter on October 27, 2017 to Missouri Department of Natural Resources (DNR) air pollution control program staff to notify them of this proposed SIP revision and to provide them with electronic access to the revision and related documents. Missouri DNR did not have any comments on this SIP revision. The notification letter is included in Tab E of this SIP package.

C. Public Review

ADEQ provided notice of a public hearing to receive public comments on the proposed SIP revision. The notice of the proposal and public hearing was published in the Arkansas Democrat Gazette, which is a newspaper in circulation statewide, on October 31, 2017. The notice contained information on the availability of the proposed SIP revision for public inspection at ADEQ information depositories, ADEQ headquarters, and ADEQ's Regional Haze webpage. On November 3, 2017, a second notice was published to correct typographical errors with respect to dates for the close of the public comment period and the public hearing. On December 18, 2017, a third notice was published extending the public comment period, postponing the public hearing in response requests received, and providing a notice of data availability regarding Entergy's unredacted updated five factor analysis for White Bluff and a reasonable progress analysis performed by Entergy. On January 12, 2018, ADEQ issued a press release providing a second extension of the public comment period. In addition, ADEQ posted this comment period extension to ADEQ's website and notified persons who had already submitted comments via email of the extension.

The public comment period for this SIP revision began on October 31, 2017 and concluded on February 2, 2018 at 11:59 p.m. CST. The public hearing was held on January 19, 2018.

Both oral and written comments received by ADEQ during the public comment period were posted on the ADEQ Regional Haze web page. Copies of written comments, ADEQ's response to comments, and records from the public hearing are included in Tab E.

VIII. Conclusion

With the NOx Regional Haze SIP submission and this SIP submission together, ADEQ has addressed all disapproved elements of the 2008 AR RH SIP, with the exception of requirements for Domtar Ashdown Mill. The compliance obligations for Domtar under the AR RH FIP are currently the subject of litigation and ADEQ supports Domtar's efforts to demonstrate that, due to their changes in operation, alternative emission limits are appropriate as a result of emission reductions achieved from their conversion of the Ashdown Mill to fluff pulp production. ADEQ commits to continuing to work with Domtar to ensure that credit is given for their success in reducing emissions and thereby their impacts on visibility. Arkansas requests that EPA withdraw the elements of the AR RH FIP addressed in this SIP revision and review and approve this SIP revision and Arkansas's "State Implementation Plan Review for the Five-Year Regional Haze Progress Report" submitted in 2015 as expeditiously as possible.

APPENDIX A
Additional Information Regarding BART Screening for Georgia-Pacific Crossett Mill

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GP Crossett Mill_Title V Permit_# 0597-AOP-R14	A.1
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April 1 2013_Email from GP re letter and attachments	A.6
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APPENDIX B

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APPENDIX D
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August18, 2017 Updated BART Five-Factor Analysis White Bluff-Unredacted	D.5
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APPENDIX E
BART Five-Factor Analysis for Southwestern Power Company Flint Creek

APPENDIX F

Reasonable Progress Analysis Technical Supporting Information and Data Sheets

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