Arkansas Regional Haze Planning Period II

State Implementation Plan

CHAPTER I: BACKGROUND

CHAPTER I: BACKGROUND

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I. Background

A. Impact of Pollution on Visitor Experiences at Federal Class I Areas

National parks, national forests, and national wildlife refuges are valuable assets managed by the federal government for the people of the United States. Visitors to these areas experience unique opportunities to see remarkable views of natural landscapes and wildlife and to engage in recreational activities. Tourism to these areas bolsters the local economies as visitors support outfitters, lodging, gift shops, and restaurants. Due to their size and scenic nature, 156 of these areas have been designated as protected visual environments referred to as federal Class I areas.

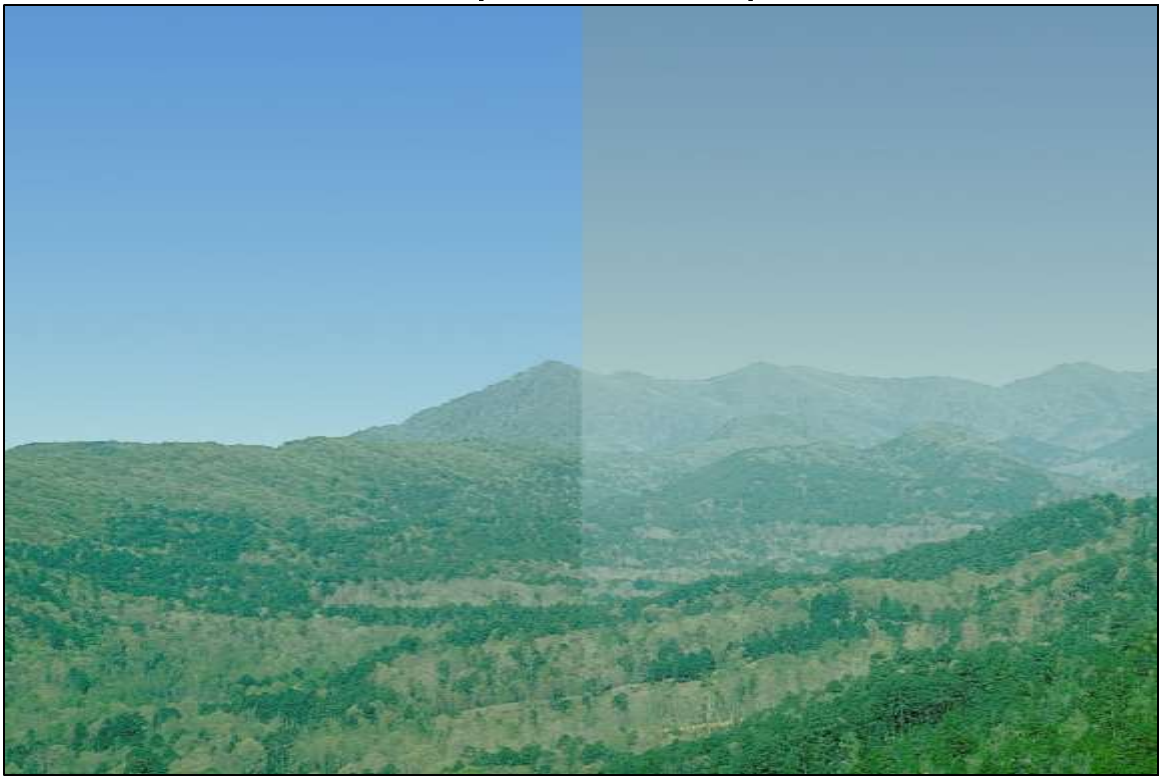
Congress has established requirements to protect and enhance the visibility of vistas in these federal Class I areas for the benefit of current and future generations.

Certain air pollutants can impair visibility by forming haze. Pollutants in haze impair visibility by absorbing and/or scattering light, which can reduce the clarity, color, and range[1] of what an observer can see. When conditions are hazy, the visibility impairment can detract from visitors' enjoyment of a federal Class I area.

Figure I-1 illustrates the impact of haze on visibility at Caney Creek, which is one of Arkansas's federal Class I areas. In the right half of the image, the hills in the distance are noticeably blurred, with attributes of the bluffs darkened by haze. The left side shows sharper ridgelines and color, a result of fewer light-scattering and light-absorbing particles between the viewer and the distant landscape.

[1] "The greatest distance at which an observer can just see a black object viewed against the horizon sky." William C. Malm. Introduction to Visibility. Page 10. https://www.epa.gov/sites/production/files/2016-07/documents/introvis.pdf.

Figure I-1: WinHAZE Modeled Visibility Conditions at Caney Creek[2]



A number of aerosol species, including solid particles and liquid droplets, contribute to haze formation. These particle types (or "species") include ammonium sulfate, ammonium nitrate, organic mass, elemental carbon, soil, coarse mass, and sea salt. Each species of particulate matter (PM) results from emissions of various pollutants from a number of natural and anthropogenic sources. The following paragraphs discuss sources of each PM species that contributes to visibility impairment at federal Class I areas.

Natural sources of sulfate include sea spray and the oxidation of sulfur gases emitted from volcanoes, wetlands, oceans, and wildfires. The primary anthropogenic source of sulfate PM is fossil fuel combustion. The oxidized sulfur gases combine with ammonia in the atmosphere to form ammonium sulfate.

Natural nitrate PM results from the oxidation of nitrogen oxides (NOx) emitted from soils, wildfires, and lightning. Anthropogenic sources of NOx include motor vehicle exhaust, prescribed burning, and other fossil fuel combustion. NOx combines with ammonia in the atmosphere to form ammonium nitrate.

Organic mass comes from both natural and anthropogenic sources. Natural sources include

[2] Retrieved modeled images via http://vista.cira.colostate.edu/Improve/winhaze/ on June 6, 2019, using Regional Haze Metrics for Caney Creek Wilderness Area, "light extinction." Average 20% Best Visibility Days, 2015 (Left) and Average 20% Worst Visibility Days, 2015 (Right)

wildfires and the oxidation of hydrocarbons emitted by vegetation. Anthropogenic sources include open burning, wood burning, prescribed fires, cooking, motor vehicle exhaust, incineration, tire wear, and the oxidation of hydrocarbons emitted from various types of burning, fuel storage and transport, and solvent usage.

Elemental carbon is emitted naturally from wildfires. Manmade sources include motor vehicle exhaust, wood burning, prescribed fires, and cooking.

Soil particles including aluminum, silicon, calcium, titanium, and iron, as well as their oxides that are emitted from mining and quarrying activities, construction, agriculture, and fugitive road dust. Soil particles contribute to both fine and coarse particulate fractions.

Coarse mass may be emitted naturally by wind erosion and re-entrainment of deposited particles. Anthropogenic sources of coarse mass include fugitive dust from paved and unpaved roads, agricultural operations, construction and demolition activities, forestry, mining and quarrying activities, and some industrial processes.[3]

In addition to inhibiting visibility, the pollutants that contribute to haze may also increase illnesses in susceptible populations.[4] Individuals may inhale or ingest small particles and then experience adverse reactions. Physical symptoms from pollutants on hazy days can also detract from visitors' enjoyment of a federal Class I area.

B. Regional Haze Program Overview

In 1977, Congress amended the Clean Air Act to include requirements to address existing visibility impairment resulting from anthropogenic air pollution and prevent future visibility impairment in federal Class I areas.[5] Part of these amendments included the addition of requirements to ensure that new major sources of air pollution do not cause significant deterioration of air quality, including air quality impacts on visibility in federal Class I areas. Other amendments added requirements for monitoring and reporting on visibility conditions as well as developing programs to remedy existing visibility impairment in federal Class I areas.

The Regional Haze Program, established in response to Clean Air Act 169A, is a joint air quality management effort among federal and state partners that seeks to preserve and improve visibility at federal Class I areas. The United States (U.S.) Environmental Protection Agency (EPA) promulgates rules and guidance that advise states on how to develop and implement air quality protection plans to reduce the pollution that causes visibility impairment. The requirements for state plans codified by EPA's Regional Haze Regulations (RHR), as amended, can be found in

[3] Visibility in Mandatory Federal Class I Areas, 1994–1998, A Report to Congress. https://www.epa.gov/visibility/visibility-report-congress-november-2001

[4] States implement programs pursuant to Clean Air Act § 110 to ensure attainment and maintenance of EPA-set health-based standards referred to as national ambient air quality standard or NAAQS.

[5] Clean Air Act 160–169B

40 CFR § 51.308. Federal land managers (FLMs) from the National Park Service (NPS), U.S. Fish and Wildlife Service (FWS), and the U.S. Forest Service (FS) monitor visibility in federal Class I areas through the Interagency Monitoring of Protected Visual Environments (IMPROVE) network and provide advice on state regional haze plan development. States are responsible for developing and implementing regional haze plans, called state implementation plans (SIPs), for each ten-year planning period and evaluating how these plans impact progress towards natural visibility conditions. States also consult with each other at a regional level when emissions from one state impact visibility in a federal Class I area in another state. These federal and state partners work together to achieve the Regional Haze Program's goal of eliminating visibility impairment from man-made air pollution at federal Class I areas.

1. Planning Period I Implementation Overview

First planning period SIPs established the metrics for gauging progress toward natural visibility conditions, a commitment to monitoring and documenting emissions reductions in the state, a control strategy, and goals for visibility improvement by 2018. Control strategies for the first planning period primarily focused on certain sources required by statute to install best available retrofit technology (BART). States also performed a reasonable progress analysis to determine whether any additional controls beyond installation of BART were necessary to ensure reasonable progress during the first planning period.

DEQ worked closely with states and tribes in the Central Regional Air Planning Association (CENRAP), as well as EPA Region 6 and the FLMs of federal Class I areas in the Central States region[6] in developing a SIP for the first implementation period (2008–2018). CENRAP, with input and guidance from its state, tribal, and federal members, prepared technical support documents, for member states to use in SIP development. DEQ relied upon these CENRAP technical support documents as well as EPA guidance in its decision-making for the SIP. DEQ also engaged in formal consultation on proposed SIPs with Missouri Department of Natural Resources (Missouri DNR) and the FLMs.

On September 9, 2008, DEQ submitted a SIP covering 2008–2018 to comply with RHR requirements for the first planning period. In the 2008 SIP submission, DEQ:

- Determined that sources in Arkansas affect the following federal Class I areas: Caney Creek Wilderness Area, Upper Buffalo Wilderness Area, Hercules Glades Wilderness Area, and Mingo National Wildlife Refuge;
- Established baseline and natural visibility conditions and determined a uniform rate of progress (URP) necessary to achieve natural visibility conditions by 2064 in each of the Arkansas federal Class I areas (Caney Creek and Upper Buffalo);
- Evaluated and determined which sources were subject to RHR BART requirements;

[6] State and tribal areas in Arkansas, Kansas, Minnesota, Nebraska, Texas, Iowa, Louisiana, Missouri, Oklahoma

- Performed source-specific analyses to determine NOx, sulfur dioxide (SO_2), and PM BART emission limits for each subject-to-BART source. The Arkansas Pollution Control and Ecology Commission (APC&EC) adopted these emission limits, compliance schedules, and recordkeeping and reporting requirements into APC&EC Regulation No. 19;
- Determined that no additional controls beyond BART were necessary to achieve reasonable progress and established 2018 reasonable progress goals (RPGs) based on this determination; and
- Described the state's consultation with the FLMs and other states, its plan for coordination of regional haze and reasonable attributable visibility impairment (RAVI), its monitoring strategy, and its commitment to submit periodic SIP revisions and progress reports.

In 2012, EPA partially approved and partially disapproved the 2008 SIP submission.[7] While EPA approved many of the SIP elements described above, EPA specifically disapproved the compliance dates, the list of BART-eligible and subject-to-BART sources, select BART control determinations, the RPGs, and the long-term strategy of the 2008 SIP submission. This partial approval/partial disapproval of the 2008 SIP submission triggered a requirement for EPA to either approve a SIP revision submitted on behalf of Arkansas or promulgate a federal implementation plan (FIP) within twenty-four months of the 2012 partial approval/partial disapproval of the 2008 SIP submission.

On June 2, 2015, DEQ submitted a progress report assessing progress towards RPGs established for Caney Creek and Upper Buffalo and examined the adequacy of existing implementation measures in achieving reasonable progress. EPA approved the progress report on October 1, 2019 after taking action on the Phase I and Phase II SIP revisions described below.[8]

On September 27, 2016, EPA finalized a FIP for Arkansas for the first planning period (2016 FIP).[9] The 2016 FIP established new BART requirements for sources with BART determinations in the 2008 SIP submittal that EPA disapproved. EPA also required installation of additional controls at a power plant that was not subject to BART for the purposes of achieving reasonable progress.

On October 31, 2017, DEQ submitted a SIP revision to address NOx requirements for the first planning period from electric generating units (EGUs) that are subject to the Cross-State Air

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[7] 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)

[8] Air Plan Approval; Arkansas; Regional Haze Five-Year Progress Report State Implementation Plan, (84 FR 51986, October 1, 2019)

[9] 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)

Pollution Rule (CSAPR). DEQ refers to the 2017 SIP revision as the Phase I SIP revision. EPA approved the Phase I SIP revision on February 12, 2018 and simultaneously rescinded NOx BART requirements for EGUs included in the 2016 FIP.[10]

On August 8, 2018, DEQ submitted a SIP revision to replace SO_2 and PM BART requirements for EGUs included in the 2016 FIP. DEQ refers to the 2018 SIP revision as the Phase II SIP revision. This SIP also included NOx, SO_2, and PM BART requirements for an auxiliary boiler, a revised reasonable progress analysis, and revised 2018 reasonable progress goals for Caney Creek and Upper Buffalo Wilderness Areas. EPA approved the Phase II SIP revision on September 27, 2019 and simultaneously rescinded SO_2 and PM requirements for EGUs included in the 2016 FIP.[11]

On August 14, 2019, DEQ submitted a SIP revision to replace BART requirements for Domtar Ashdown Mill that were included in the 2016 FIP. DEQ refers to the 2019 SIP submission as the Phase III SIP revision. With EPA's approval of the Phase III SIP revision and withdrawal of the remaining elements of the 2016 FIP, Arkansas's Regional Haze SIP for the first planning period has been fully approved.[12] DEQ refers to the approved elements of the 2008 SIP submittal, the Phase I SIP revision, the Phase II SIP revision, and the Phase III SIP revision, collectively, as the Planning Period I SIP.[13]

2. Requirements for Planning Period II

The RHR at 51.308(f) details requirements for second planning period SIPs (Planning Period II SIPs). The RHR establishes a due date of July 31, 2021. However, states may submit completed SIPs at any time prior to July 31, 2021. Appendix A provides a checklist of required elements for Planning Period II SIP, RHR citations, and where the requirement is addressed in this SIP narrative. The following paragraph provides an overview of Planning Period II SIP requirements.

In Planning Period II SIPs, each state must demonstrate how they have and will continue to make progress toward natural visibility conditions at federal Class I areas. Due to revisions in the RHR

[10] 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)
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)
[11] Air Quality State Implementation Plans; Approvals and Promulgations: Arkansas; Approval of Regional Haze State Implementation Plan Revision for Electric Generating Units in Arkansas (84 FR 51033, September 27, 2019)
Air Quality State Implementation Plans; Approvals and Promulgations: Arkansas; Regional Haze Federal Implementation Plan Revisions; Withdrawal of Portions of the Federal Implementation Plan, (84 FR 51056, September 27, 2019)
[12] 86 FR 15104, March 22, 2021

[13] All Regional Haze SIP documentation for Planning Period I, including Phases I - III submissions, may be accessed through DEQ's website: https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx

and associated guidance, states must update their calculations of baseline visibility conditions, natural visibility conditions, current visibility conditions and the URP toward natural visibility conditions for each federal Class I area.[14] States must perform four-factor analyses[15] to determine what control measures should be included in the state's long-term strategy for Planning Period II. After establishing the long-term strategy, states must set 2028 goals for visibility improvement on the twenty percent most impaired days and ensure no degradation from baseline conditions for the twenty percent clearest days. States must also include a monitoring strategy for characterizing and reporting visibility impairment at federal Class I areas. In addition, states must report progress on implementation of control strategies from first planning period SIPs, emissions trends, and visibility trends. States must also evaluate whether any significant changes in anthropogenic emissions of visibility-impairing pollutants are limiting or impeding progress. In developing Planning Period II SIPs, each state must consult with the FLMs and any other state air quality agency with federal Class I areas impacted by sources in the state.

[14] EPA (2018). Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program. Pgs. 5–14. https://www.epa.gov/sites/production/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf

[15] The four factors that must be evaluated are cost of compliance, time necessary for compliance, energy and Non-air quality environmental impacts of compliance, remaining useful life of any existing source subject to compliance.

Arkansas Regional Haze Planning Period II

State Implementation Plan

CHAPTER II: ARKANSAS FEDERAL CLASS I AREAS

Chapter II: Arkansas Federal Class I Areas

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II. Arkansas Federal Class I Areas

The RHR at 40 CFR § 51.308(f)(1) requires states to calculate baseline, current, and natural visibility conditions for federal Class I areas located in the state, evaluate progress to date toward natural visibility conditions, and determine the URP necessary to achieve natural visibility conditions by 2064. Sections A and B of this chapter provide updates to previous SIP submittals consistent with amendments to the RHR and revised EPA guidance.

In determining baseline and current conditions, the RHR requires states to examine the twenty percent most impaired days and the twenty percent clearest days each year. The most impaired days are those days during which decreased visibility results primarily from anthropogenic emissions, as determined by application of EPA's recommended method for selecting the twenty percent most impaired days.[1] The clearest days are days during which the least visibility impairment occurs. Whether the visibility impairment results from anthropogenic or natural sources of impairment is not a factor in selecting the clearest days.

Natural conditions cannot be measured directly and must be estimated. Generally, visibility impairment resulting from episodic and routine natural contributions to visibility impairment are used to estimate natural conditions. Episodic natural contributions are those that occur infrequently and variably from year to year, such as wildfires and large dust storms. Routine natural contributions are those that occur on all or most days of the year and are more consistent from year to year, such as secondary biogenic aerosols.[2]

Progress toward natural visibility conditions is tracked on both an annual basis and on a rolling five-year average. The five-year average metric was included in the RHR in order to minimize the impacts of year to year variability resulting from extreme natural events such as wildfires.

The URP is the amount of visibility improvement in deciviews that would be needed to stay on a linear path from the baseline period to natural conditions.[3] EPA guidance instructs states to calculate the URP by subtracting natural visibility conditions for the twenty percent most impaired days from baseline (2000–2004) visibility conditions for the twenty percent most impaired days and dividing the difference by sixty.[4] The formula is as follows:

$$\text{URP} = [(\text{baseline visibility})_{20\%\ \text{most impaired}} - (\text{natural visibility})_{20\%\ \text{most impaired}}]/60$$

[1] See EPA (2018). Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program. Pgs. 5–14. https://www.epa.gov/sites/production/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf

[2] Id.

[3] Id.

[4] Id.

The Regional Haze Rule at 40 CFR 51.308(f)(1)(vi)(B) allows states to adjust the URP formula to account for international anthropogenic sources. International anthropogenic emissions contribute to visibility impairment in federal Class I areas, but these emissions are beyond the control of the state. DEQ has adjusted the URP for each Arkansas federal Class I area to account for international anthropogenic emissions in accordance with EPA guidance. The international anthropogenic contributions for Caney Creek and Upper Buffalo Wilderness are 4.88 Mm^{-1} and 7.02 Mm^{-1}, respectively.[5] The international anthropogenic contribution in the unit of inverse megameters (Mm^{-1}) can be converted to deciviews using the following formula:

$$\text{deciviews} = 10 * \ln (\text{bext}_{\text{natural conditions}} + \text{bext}_{\text{international anthropogenic}}) / \text{bext}_{\text{natural conditions}};$$

where bext is the atmospheric light extinction coefficient in Mm^{-1}

The adjusted URP glidepath endpoint of 2064 is calculated by adding the contribution of international anthropogenic emissions to the natural visibility condition. The adjusted URP endpoint for CACR and UPBU are 11.26 deciviews and 11.83 deciviews, respectively. The adjusted URP is calculated in accordance with the following formula:

$$\text{URP} = [(\text{baseline visibility})_{20\%\text{ most impaired}} - (\text{natural visibility})_{20\%\text{ most impaired}} + (\text{International anthropogenic impacts})_{20\%\text{ most impaired}}]/60$$

Sections A and B of this chapter establish adjusted URPs, examine trends in visibility-impairing particulate species impacts, projected sources of visibility impairment in 2028, and areas of influence for each Arkansas federal Class I area.

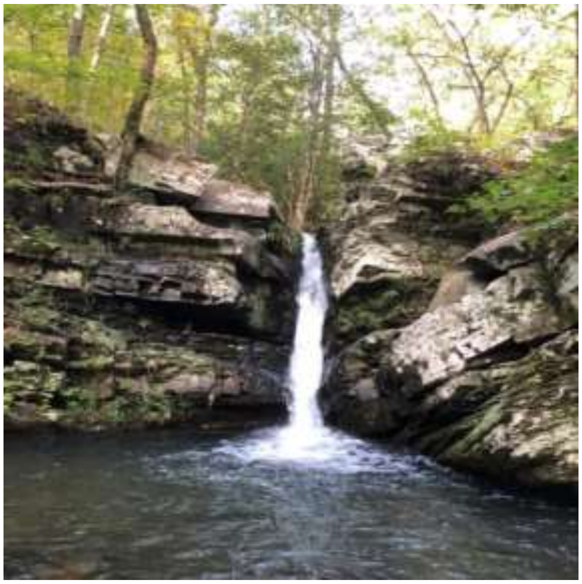
A. Caney Creek

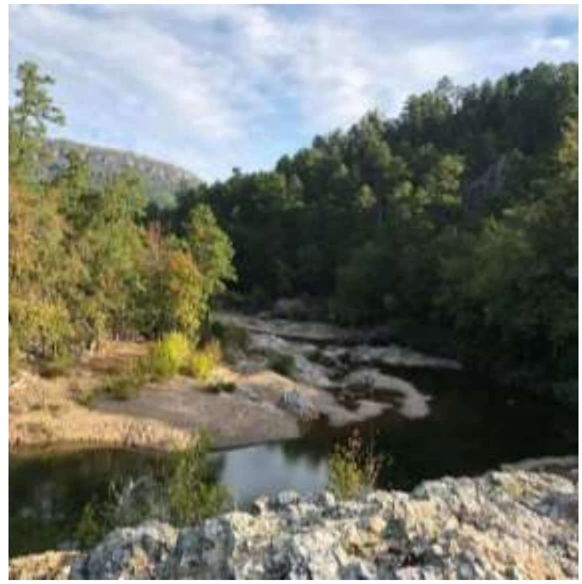
The Caney Creek Wilderness includes 14,460 acres of forested area, streams, and hiking trails.[6] It is located in the Ouachita National Forest in southwest Arkansas. Caney Creek supports multiple recreational activities including hiking, horse riding, and camping. Figure II-1 illustrates the scenic quality of the Caney Creek Wilderness.

[5] https://www3.epa.gov/ttn/scram/reports/Updated_2028_Regional_Haze_Modeling-TSD-2019.pdf

[6] U.S. National Forest Service, https://www.fs.usda.gov/recarea/ouachita/recarea/?recid=10792

Figure II-1: Katy Creek Falls (Left) and Little Missouri River (Right), Caney Creek Wilderness[7]





1. Ambient Data Analysis

The Caney Creek monitor is located at latitude 34.4544, longitude -94.1429 in Polk County, Arkansas at an elevation of 683 meters (m) above mean sea level (MSL). DEQ uses data from this monitor to determine visibility conditions for Caney Creek consistent with the requirements of 40 CFR § 51.308(f).

a. Baseline, Current, and Natural Visibility Conditions

DEQ is revising its previous determinations for baseline visibility conditions pursuant to 40 CFR § 51.308(f). In its Planning Period I SIP, DEQ determined baseline and current visibility conditions for Caney Creek for the twenty percent haziest days and the twenty percent clearest days. The 2017 amendments[8] to the RHR require states to examine the most impaired twenty percent days in place of the twenty percent haziest days. Table II-1 lists DEQ's revised determinations for baseline, natural, and current visibility conditions for the most impaired days and clearest days based on IMPROVE data and EPA's guidance[9] on determining the twenty percent most impaired days at Caney Creek.

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[7] Image Credit: Tricia Treece

[8] EPA (2017). "Protection of Visibility: Amendments to Requirements for State Plans." 82 FR 3078

[9] EPA (2018). "Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program." https://www.epa.gov/sites/production/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf

Table II-1: Baseline (2000–2004), Current (2014–2018), and Natural Visibility Conditions for the Twenty Percent Most Impaired Days and Twenty Percent Clearest Days at Caney Creek[10]

Metric	**Baseline Visibility Conditions[11] (deciviews)**	**Current Visibility Conditions[12] (deciviews)**	**Natural Visibility Conditions (deciviews)**
Most Impaired Days	23.99	17.65	9.54
Clearest Days	11.24	7.79	4.23

Consistent with 40 CFR § 51.308(f)(1)(iv) and (v), DEQ has determined the actual progress toward natural visibility conditions made to date for the clearest and most impaired days since the baseline period and actual progress made during the previous planning period. Table II-2 lists these metrics and the difference between current visibility conditions and natural visibility conditions.

Table II-2**:** Progress Toward Natural Visibility Conditions at Caney Creek

Metric	**Progress to Date[13] (deciviews)**	**Progress During Planning Period I[14] (deciviews)**	**Difference between Current and Natural Visibility Conditions[15] (deciviews)**
Most Impaired Days	6.34	5.7	8.11
Clearest Days	3.46	3.22	3.56

b. Uniform Rate of Progress

DEQ is revising its previous URP calculation for Caney Creek included in the Planning Period I SIP submittals. This revision is necessary to comply with the 2017 amendments[16] to the RHR, which require states to examine the twenty percent most anthropogenically impaired days in place of the twenty percent haziest days. In addition to revising the metric used for evaluating visibility progress, DEQ is also adjusting the URP to account for international anthropogenic contributions in accordance with EPA guidance. The revised URP is -0.212 deciviews per year

[10] Baseline and Natural Conditions from EPA (2020). "Technical addendum including updated visibility data through 2018 for the memo titled 'Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program."
Data used to calculate current visibility conditions obtained from IMPROVE data files sia_impairment_group_means_12_20 (Most Impaired Days) and SIA_group_means_12_20 (Clearest Days)

[11] 2000–2004 average

[12] 2015–2019 average

[13] Difference between baseline (2000–2004) average conditions and 2015–2019 average conditions

[14] Difference between baseline (2000–2004) average conditions and 2014–2018 average conditions

[15] Difference between 2015–2019 average conditions and natural conditions

[16] EPA (2017). "Protection of Visibility: Amendments to Requirements for State Plans." 82 FR 3078

based on an adjusted endpoint of 11.26 deciviews.

Figure II-2 demonstrates progress on the twenty percent most impaired days as compared to the glidepath set by the revised URP. The glidepath represents the URP that needs to be maintained throughout each implementation period in order to reach the 2064 goal. Figure II-2 includes both annual observations and the rolling five-year average of annual observations for visibility impairment on the most impaired days. Figure II-2 marks the point on th glidepath in 2028, the last year in the Planning Period II, for comparison with observed trends in visibility impairment.

Figure II-2: Progress on the Twenty Percent Most Impaired Days at Caney Creek Compared to the Glidepath[17]

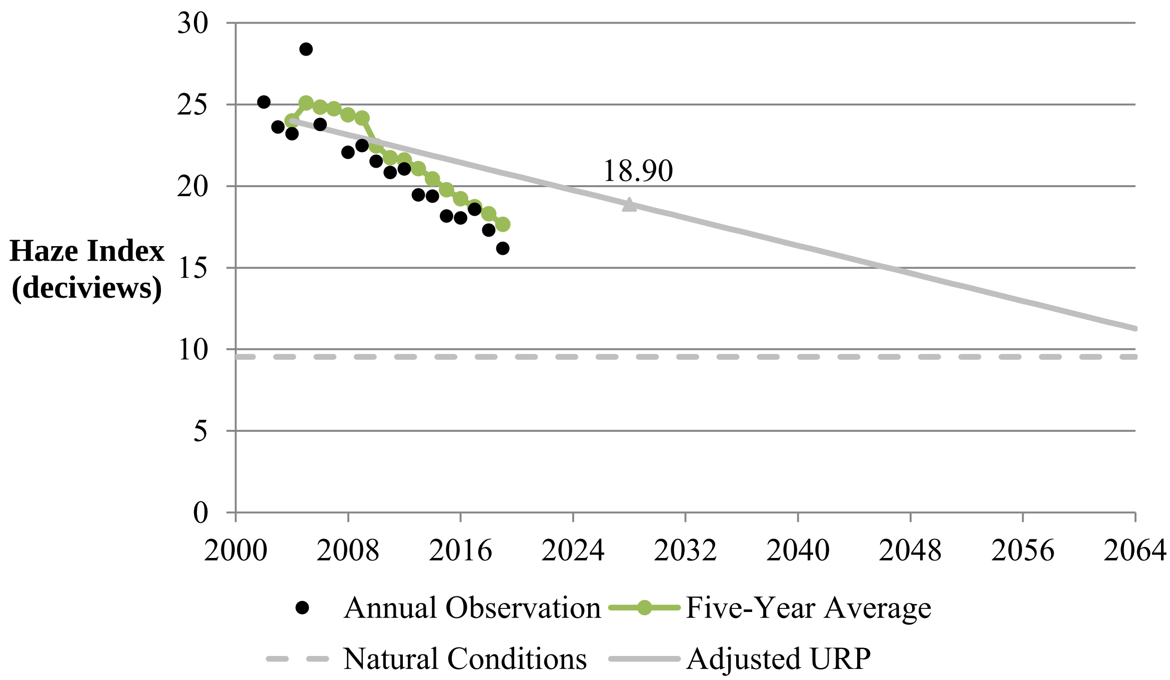
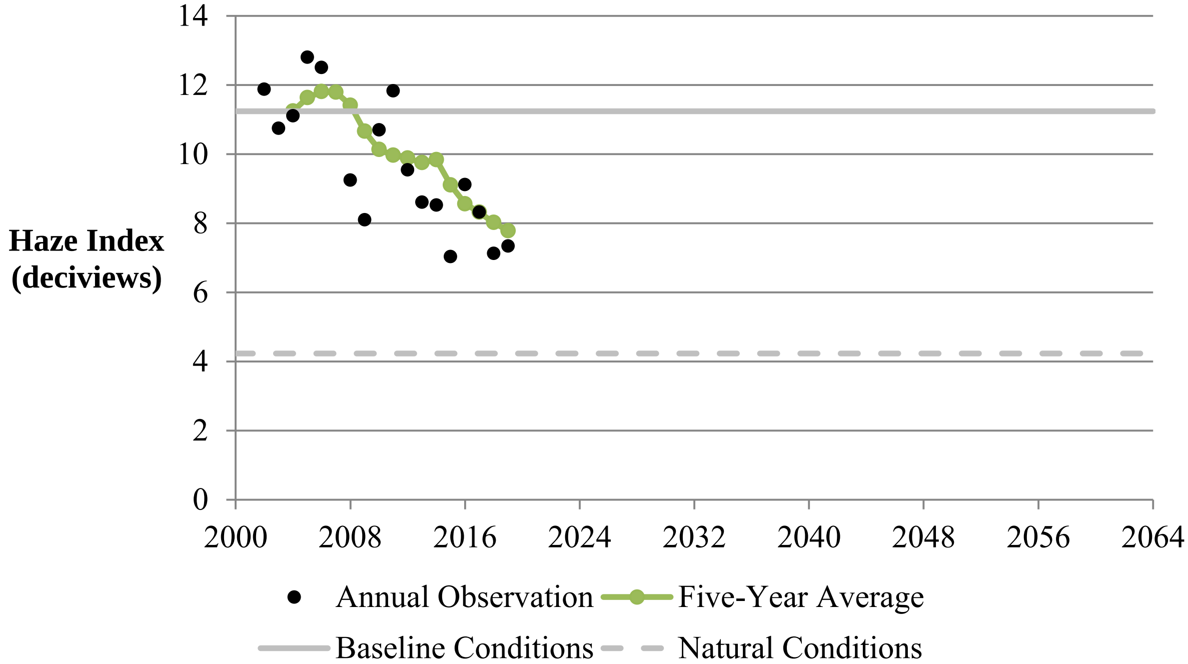


Figure II-2 shows continued improvement in visibility conditions at Caney Creek, particularly since 2009. The rolling five-year average of the twenty percent most impaired days has remained below the revised glidepath since 2010. The most recent five-year average (2015–2019) is below the URP value for 2028.

The RHR requires states to prevent degradation of visibility on the twenty percent clearest days from baseline conditions (2000–2004). Figure II-3 demonstrates progress on the twenty percent clearest days relative to baseline conditions and natural conditions.

[17] Annual observations obtained from IMPROVE data file sia_impairment_group_means_12_20

Figure II-3: Progress on the Twenty Percent Clearest Days Compared to Natural and Baseline Conditions at Caney Creek[18]



The five-year rolling average of the twenty percent clearest days illustrates continued improvement since 2007 with five-year averages remaining below baseline conditions since 2009.

c. Key Pollutants Impacting Visibility

Figure II-4 shows annual visibility tracking metrics for the twenty percent most impaired days at Caney Creek. The bars show the relative contribution of each particulate species to visibility impairment in each year in terms of Mm^{-1} (left y-axis). The line shows annual visibility impairment in terms of deciviews (right y-axis).

[18] Annual observations obtained from IMPROVE data file SIA_group_means_12_20

Figure II-4: Annual Extinction Composition, Most Impaired Days at Caney Creek, 2002–2019[19]

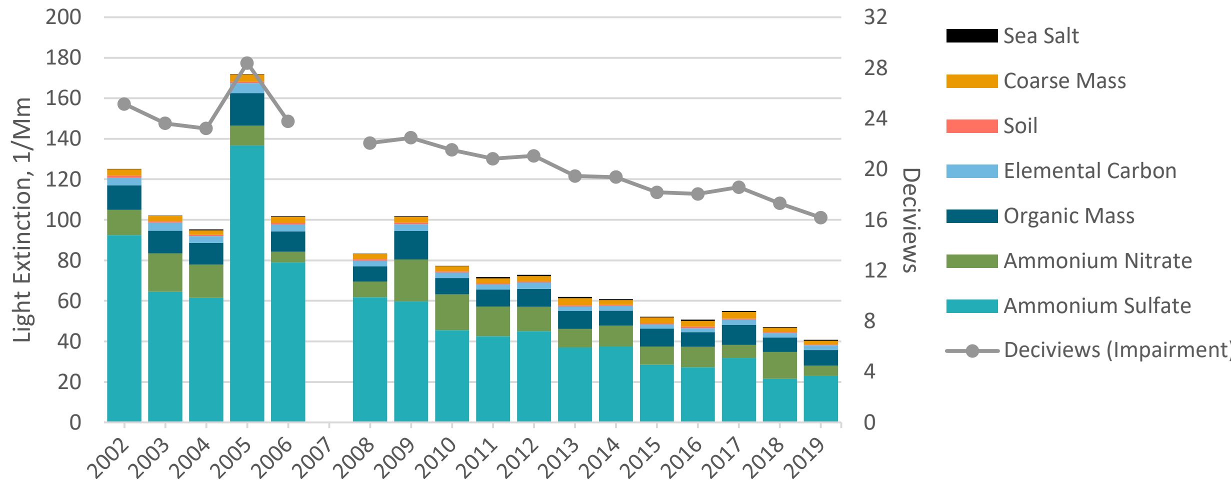


Figure II-4 shows that visibility impairment on the most impaired days has decreased over time at Caney Creek as light extinction due to ammonium sulfate, organic mass, and elemental carbon has decreased. Light extinction due to ammonium nitrate, coarse mass, and soil has fluctuated over time, but no apparent trend is evident. Light extinction due to sea salt has increased over time.

Figure II-4 indicates that, in 2019, ammonium sulfate was the largest contributor to light extinction at Caney Creek on the most impaired days followed by organic mass. Ammonium nitrate is the third largest contributor to light extinction. Elemental carbon and coarse mass each make up approximately four percent and three percent, respectively, of the annual light extinction composition in 2019 on the most impaired days. Sea salt and soil make up a very small fraction of the light extinction composition on the most impaired days.

Figure II-5 shows daily haze composition due to anthropogenic sources and Figure II-6 shows daily haze composition due to natural sources on the most impaired days at Caney Creek in 2018. In combination, these figures provide information about potential pollutants to include in DEQ's analysis of potential strategies for reasonable progress during Planning Period II.

[19] Data obtained from IMPROVE data file sia_impairment_group_means_12_20.

Figure II-5: Daily Haze Composition Due to Anthropogenic Sources, Most Impaired Days at Caney Creek, 2019[20]

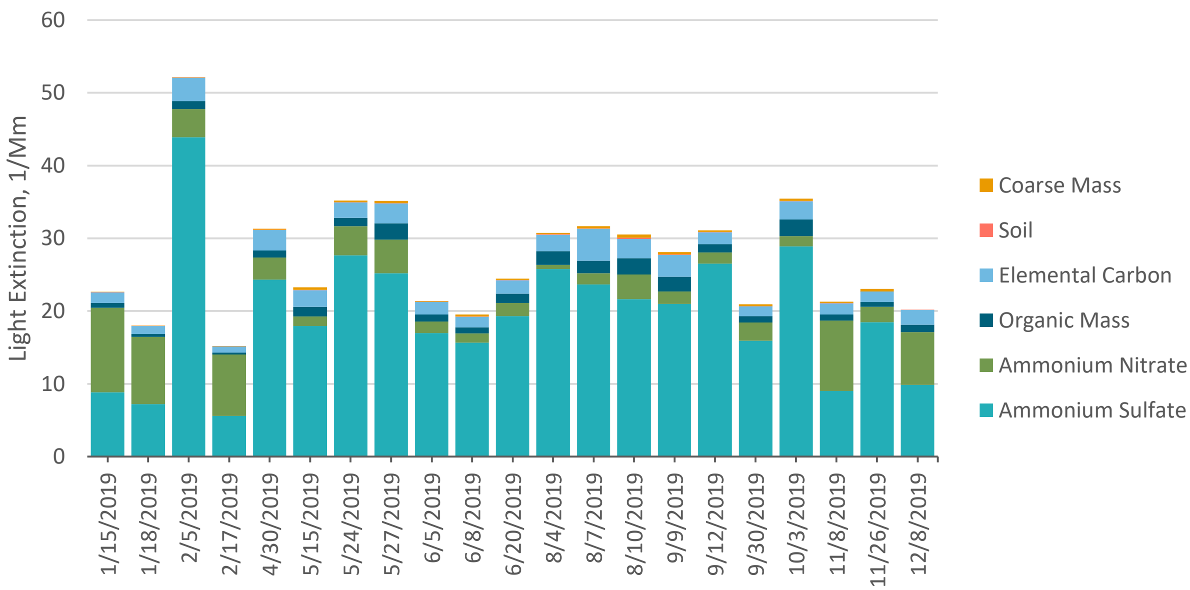
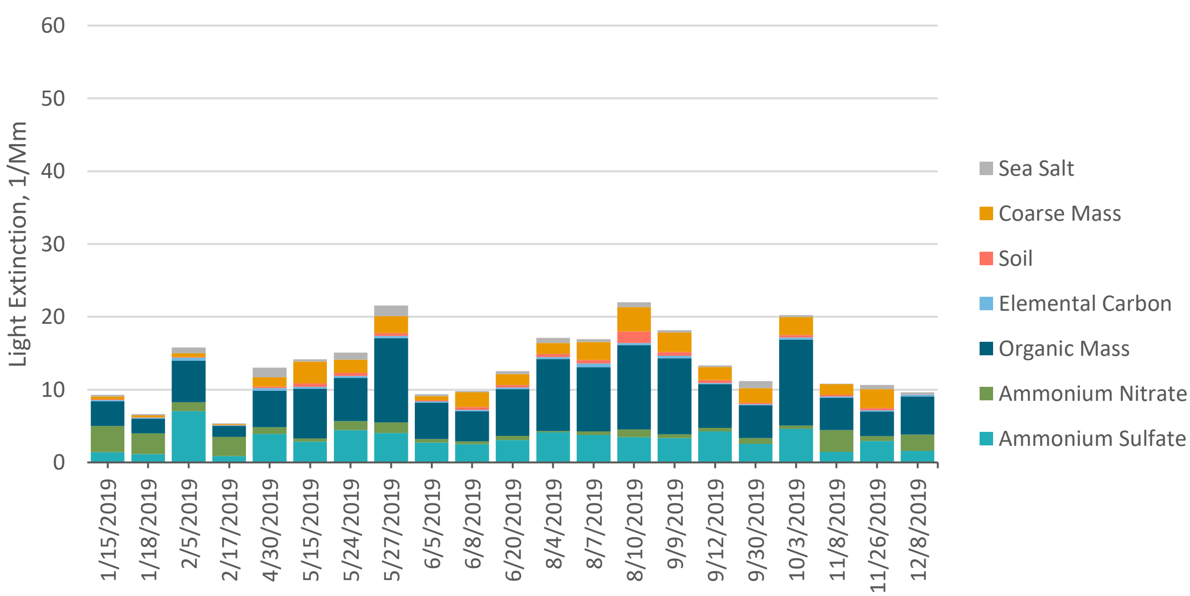


Figure II-6: Daily Haze Composition Due to Natural Sources, Most Impaired Days at Caney Creek, 2019[21]



Figures II-5 and II-6 show that light-extinction from ammonium nitrate, ammonium sulfate, and elemental carbon on the most impaired days at Caney Creek is primarily anthropogenic in nature. Light extinction on the most impaired days at Caney Creek due to coarse mass, organic mass,

[20] Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.

[21] Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.

and soil are primarily due to natural sources.

Figure II-7 shows annual visibility tracking metrics for the twenty percent clearest days at Caney Creek. The bars show the relative contribution of each particulate species to visibility impairment in each year in terms of Mm^{-1} (left y-axis). The line shows annual visibility impairment in terms of deciviews (right y-axis).

Figure II-7: Annual Extinction Composition, Clearest Days at Caney Creek, 2002–2019[22]

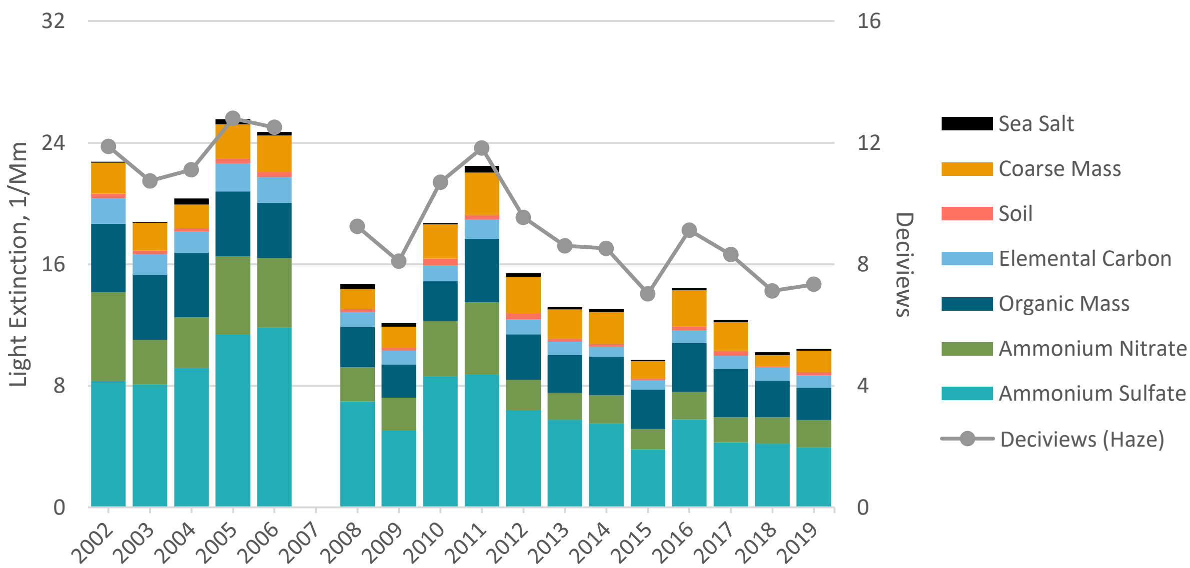


Figure II-7 shows a reduction of visibility impairment on the clearest days at Caney Creek. This reduction appears to correspond to decreased light extinction from ammonium sulfate and ammonium nitrate. The impacts from ammonium sulfate and ammonium nitrate continue to outweigh the impacts from elemental carbon at Caney Creek.

Based on these observations, strategies to reduce visibility impairment at Caney Creek from manmade air pollution during Planning Period II should focus on the following key pollutants: ammonium nitrate and ammonium sulfate.

2. Modeling Data Analysis

Multiple modeling studies have been performed to project 2028 visibility conditions at federal Class I areas. EPA performed air quality modeling using a 2016-based platform for all federal Class I areas in the United States. The results of EPA's modeling study are reported in EPA's 2019 "Technical Support Document for EPA's Updated 2028 Regional Haze Modeling Platform." [23] Alpine Geophysics, LLC and Eastern Research Group, Inc., conducted an air

[22] Data obtained from IMPROVE data file SIA_group_means_12_20.

[23] EPA (2019). "Technical Support Document for EPA's Updated 2028 Regional Haze Modeling."

quality modeling study using a 2011-based platform on behalf of the VISTAS RPO to project 2028 visibility conditions at federal Class I areas in the Southeastern United States and at federal Class I areas that may be impacted by sources of air pollution located in the Southeastern United States.[24] Each modeling exercise provides useful information regarding the projected relative contribution of particulate matter species and sources of air pollution to visibility impairment at the end of Planning Period II.

EPA's modeling provides projected 2028 visibility conditions and source sector contribution information. In particular, the modeling results differentiate between visibility impairment contribution from United States anthropogenic sources of emissions and international anthropogenic sources of emissions. DEQ used this data to adjust the URP glidepath for Arkansas federal Class I areas. In addition, the modeling results provide insight into the relative impact of emission source categories on projected visibility impairment in 2028. The EPA modeling does not provide information about the relative contribution to projected visibility impairment in 2028 from particular stationary sources, states, or regions.

The VISTAS modeling also provides projected 2028 visibility conditions information. In addition, particulate source apportionment was performed for many stationary sources in the Southeast and surrounding states and for certain states and regions. Because of the source-specific and region-specific tagging performed as part of the VISTAS modeling effort, the VISTAS modeling results are useful in assessing the potential visibility benefits of control strategies under evaluation by states, including Arkansas, on federal Class I areas within the model domain.

The EPA and VISTAS modeling differ in 2028 emission inventory projections and meteorology. For non-EGUs, 2016 emissions and meteorology were used for the EPA modeling and 2011 emissions and meteorology were used for VISTAS modeling. For EGUs, the Integrated Planning Model (IPM) was used to project future EGU emissions for the EPA modeling and the Eastern Regional Technical Advisory Committee (ERTAC) EGU projection tool was used to project future EGU emissions for the VISTAS modeling. The IPM model is primarily an economic model that may make unrealistic choices, such as shutting down must-run units or changing fuels at plants not designed for and with no plans for fuel switching. The ERTAC EGU tool does not make assumptions about new units, retirements, and fuel changes. Instead, the tool incorporates state-provided information about new units, retirements, controls, etc. to project future year hourly activity and emissions estimates. In addition, the VISTAS RPO reached out to states for input on any additional changes in controls since the ERTAC EGU v16 results were posted prior to conducting modeling. DEQ provided adjusted emission rates (lb/MMBtu) for two sources in

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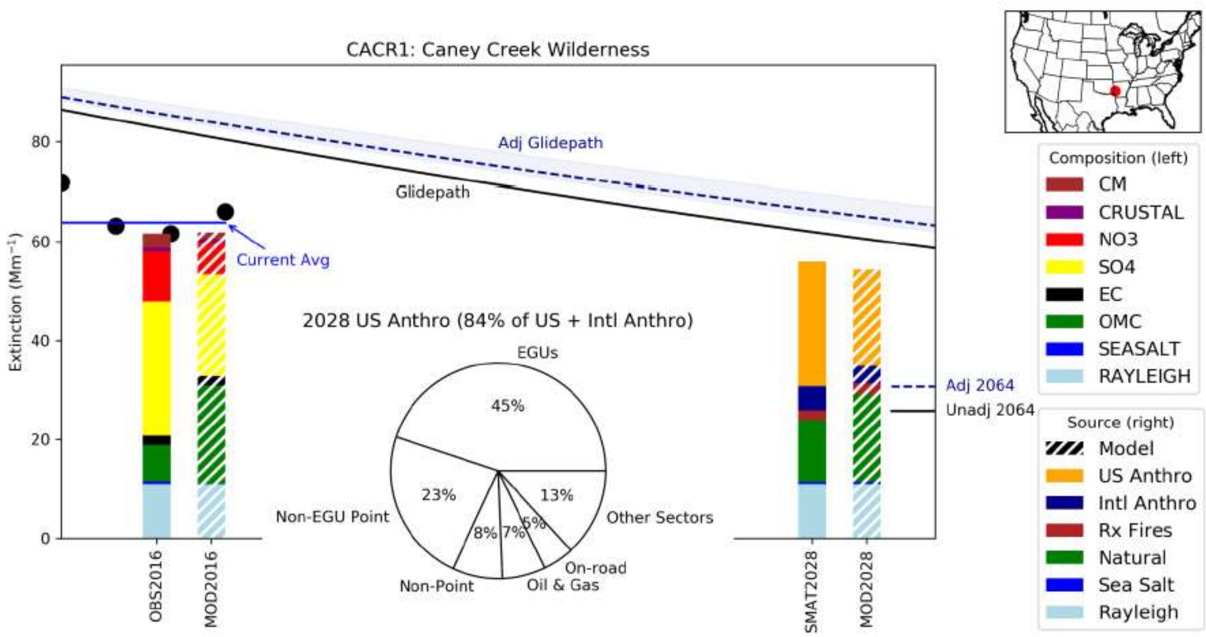
https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling

[24] See Task 2 (Emissions Inventories), Task 6 (Air Quality Modeling), and Task 7 (Source Apportionment Modeling/Tagging) on the VISTAS Regional Haze Program webpage: https://www.metro4-sesarm.org/content/vistas-regional-haze-program

Arkansas that recently switched to lower sulfur coal and installed low NOx burners. The difference in EPA and VISTAS modeling inventory inputs results in different 2028 visibility conditions projections, with the VISTAS modeling results projecting greater visibility impairment on the twenty percent most impaired days in 2028 at Arkansas federal Class I areas than the EPA modeling results.

Figure II-8 illustrates for Caney Creek the results of EPA's modeling effort. The figure presents observed data for 2014–2017, 2028 base case projections, and possible glidepaths under different assumptions. The dashed line represents EPA's default adjusted glidepath, which was adjusted based on relative international anthropogenic model contributions and ambient natural conditions.[25] The figure also includes a pie chart representing the specific anthropogenic emissions sector contributions identified as contributing to visibility impairment at Caney Creek.

Figure II-8: EPA Regional Haze Modeling Summary Plot for Caney Creek Wilderness[26]



The blue dashed line, the black line, and the blue shaded area in Figure II-8 indicate that, without additional emission reductions beyond those already required by regulations on the books, the rate of progress towards natural visibility would be faster than the range of URP options calculated by EPA, including the URP determined by Arkansas. The model predicts a visibility impairment value of 16.97 deciviews in 2028 for the most impaired days at Caney Creek. This

[25] The different glidepaths EPA included in their summary plots are based on different 2064 endpoint adjustment assumptions. DEQ's adjusted endpoint (11.26 deciviews) is higher than EPA's default adjusted endpoint (11.21 deciviews), but lower than EPA's maximum endpoint (12.49 deciviews).

[26] EPA (2019). "Technical Support Document for EPA's Updated 2028 Regional Haze Modeling." https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling

projected impairment value is lower than the 18.90 deciviews glidepath value in 2028 created by DEQ's URP. The visibility impairment value in 2019 for the most impaired days (16.18 deciviews) and the most recent (2015–2019) five-year average of most impaired days (17.65 deciviews) at Caney Creek are also below the glidepath value in 2028.

The pie chart in Figure II-8 represents specific source categories contributing to visibility impairment at Caney Creek in 2028 and indicates that the most prominent source categories are EGUs and Non-EGU point sources with smaller contributions from other U.S. anthropogenic sources. Other U.S. anthropogenic sources include oil and gas, area sources, mobile sources, and prescribed fires. The source apportionment presented in the pie chart suggests that strategies to reduce visibility impairment in 2028 should focus on reducing emissions from the following source categories: EGU and non-EGU point.

Figures II-9 and II-10 illustrate the 2028 base case results for Caney Creek of the VISTAS modeling effort. The VISTAS modeling base case results project visibility impairment in 2028 at Caney Creek on the most impaired days (18.32 deciviews) to be above the unadjusted glidepath (18.18 deciviews) and below the DEQ glidepath (18.90 deciviews). The projected most impaired days impairment value in 2028 at Caney Creek is higher than the 2019 monitor observation and 2015–2019 five-year average of monitor observations.[27] The projected base case results for the clearest days (8.79 deciviews) show no degradation from the 2000–2004 baseline (11.24 deciviews).

[27] Actual emissions data demonstrates a downward trend in pollutants affecting visibility at federal Class I sites; the VISTAS projections for most impaired days' impairment values are higher than actuals, due to shut-downs and on the books controls that may not be reflected in VISTAS modeling.

Figure II-9: VISTAS Base Case Results for Caney Creek Wilderness (Most Impaired Days)[28]

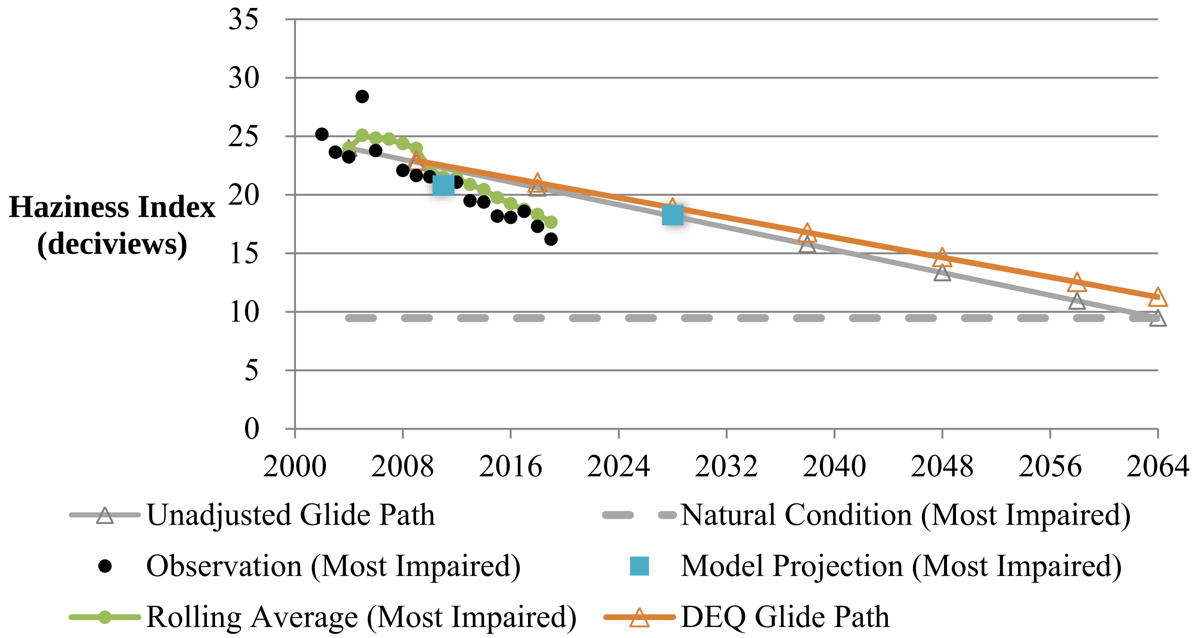
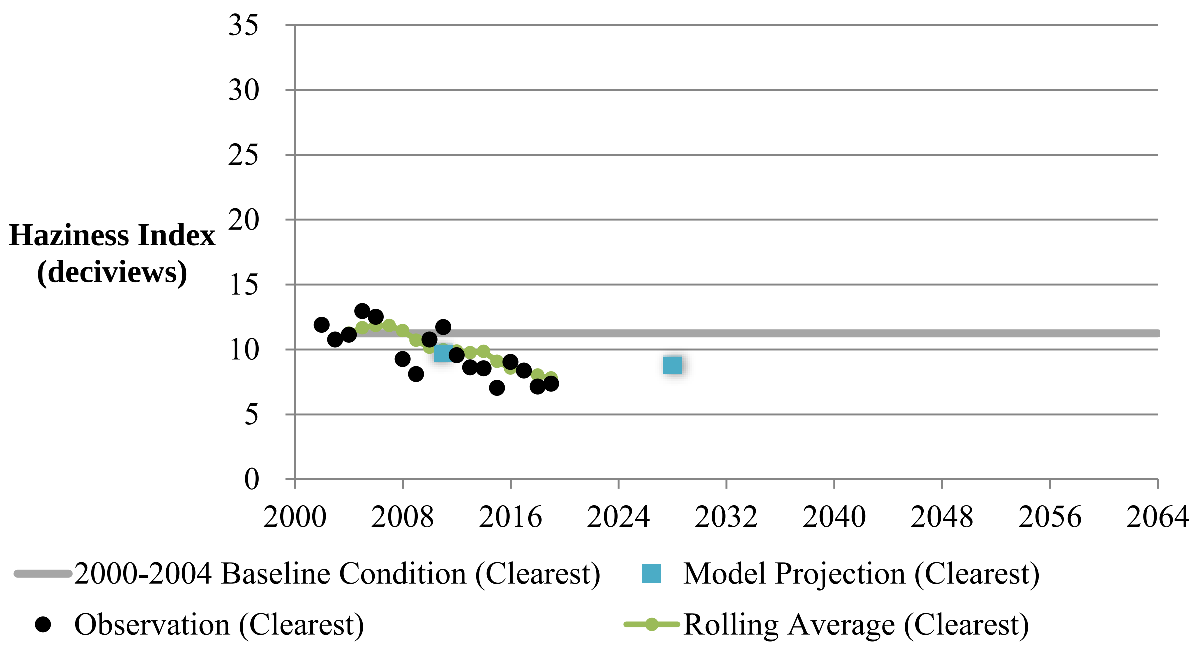


Figure II-10: VISTAS Base Case Results for Caney Creek Wilderness (Clearest Days)[29]



In addition to photochemical models, the WinHaze visual modeling tool enables the user to visualize various levels of visibility impairment in each federal Class I area. Figure II-11 shows

[28]Model results obtained from Metro 4/SESARM: Copy of V5_GlidePath_MI20_unit_Deciview_07-17-2020_jb
[29] Model results obtained from Metro 4/SESARM: Copy of V5_GlidePath_20C_unit_Deciview_07-17-2020

how a vista at Caney Creek Wilderness would look during the most impaired days in 2002 (left), 2019 (center), and under natural conditions (right). The improvement between the center image and the left image shows how the visibility has improved over time on the most impaired days.

Figure II-11: Caney Creek Wilderness WinHAZE Visualization Twenty Percent Most Impaired: 2002, 2019, and Natural Conditions

3. Area of Influence (AOI) Analysis

The Central States Air Resources Association (CENSARA) contracted with Ramboll US Corporation (Ramboll) to perform an area of influence (AOI) analysis for federal Class I areas in the CenSARA states and for federal Class I areas that might potentially be impacted by emissions from the CenSARA states. The CenSARA region includes Arkansas, Iowa, Kansas, Louisiana, Missouri, Nebraska, Oklahoma, and Texas. The analysis used a back-trajectory model, 2016 actual emissions and projected 2028 emissions from stationary sources, and extinction composition data for each federal Class I area to identify the geographic areas and anthropogenic emission sources with a high probability of impacting visibility at federal Class I areas within the CenSARA region and in nearby states. The AOI analysis used the following trajectory ending altitudes to model back-trajectories: 100m, 200m, 500m, and 1000m. Results were produced for each trajectory height and for all trajectory heights combined. The analysis focused on NOx and SO_2 because monitoring data indicate that these are the primary anthropogenic particulate species precursors that impair visibility at federal Class I areas in the CenSARA region. Other particulate species (such as salt, soil, and organic material) are often biogenic in nature. Elemental carbon is often influenced by prescribed and wildfire.

The AOI analysis generated several metrics that states could use. One metric is the distance-weighted residence time, which states can use to generally assess the probability of air parcels originating outside a given federal Class I area reaching the area. A second metric is the "extinction-weighted residence time" (EWRT) for NOx and for SO_2, which states can use to identify areas of influence for each pollutant at each federal Class I area. Another metric states can use is extinction-weighted residence time multiplied by emissions from a stationary source divided by the distance from the source to the federal Class I area (EWRT*Q/d). When the EWRT*Q/d values for SO_2 and NOx are summed for a source, this provides a surrogate for visibility impact for the source. Ramboll produced a report that summarizes the approach of the analysis and a spreadsheet that the CenSARA states could use to evaluate the results.[30]

DEQ applied a 0.05% threshold to the 2016 EWRT NOx results and 2016 EWRT SO_2 results for all trajectory heights combined to identify pollutant-specific areas of influence for each federal Class I area included in the AOI analysis.[31] For sources with an EWRT value greater than or equal to 0.05% for either pollutant, DEQ included the source in the AOI for each federal Class I area. Sources that did not meet this threshold—sources that have less than a 0.05% chance of impacting the relevant federal Class I area—were not included in the AOI.

DEQ summed the EWRT*Q/d values for NOx and SO_2 to produce a total visibility impact surrogate value for each source in each AOI. Throughout this submittal, DEQ refers to this combined EWRT*Q/d value for NOx and SO_2 as "the visibility impact surrogate." An overview of DEQ's methods and the results, with the visibility impact surrogate values ranked from largest to smallest for each federal Class I area, are included in Appendix C. This approach allows DEQ to identify the sources that are having the largest impact on each federal Class I area by holistically looking at the combination of impacts from the key pollutants from stationary sources.

Based on DEQ's evaluation of the 2016 AOI results, sources in the following states may impact visibility on the most impaired days at Caney Creek: Texas, Arkansas, Louisiana, Oklahoma, Missouri, Illinois, Indiana, Kansas, Iowa, Nebraska, Kentucky, Minnesota, Tennessee, North Dakota, Wisconsin, and Mississippi. Figure II-12 shows the relative percentage from each state of the visibility impact surrogate for all sources in the AOI.

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[30] The report and the all-trajectories spreadsheet used by DEQ in the development of this SIP are included in Appendix B.

[31] DEQ's methods for examining AOI results are detailed in the spreadsheet AR Screening Method included with Appendix C.

Figure II-12: Relative Visibility Impact Surrogate of Source in AOI analysis on Most Impaired Days at Caney Creek in 2016[32]

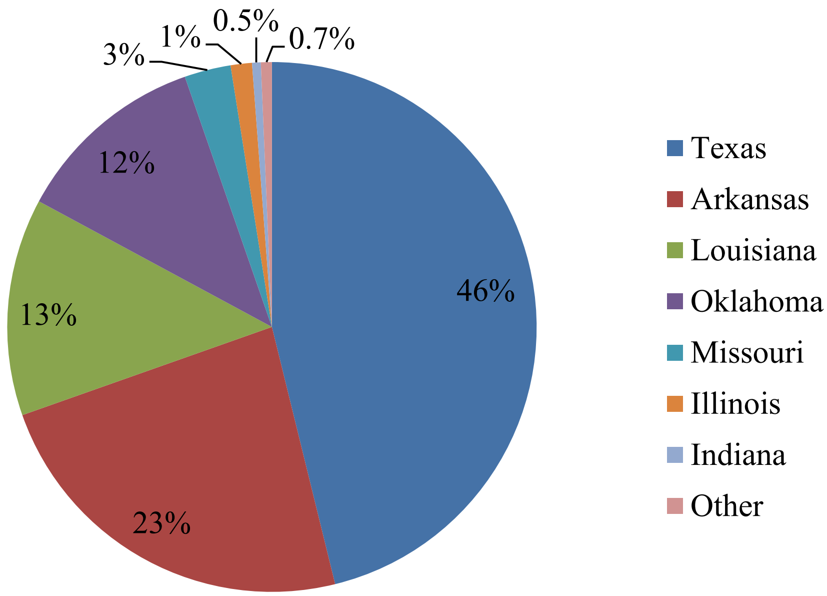

Figure II-12 indicates that stationary sources in Texas contributed the most to visibility impairment on the most impaired days at Caney Creek out of the stationary sources in the 2016 AOI. Sources in Arkansas were the second largest contributor.

B. Upper Buffalo

The Upper Buffalo Wilderness is located in the Ozark-Saint Francis National Forest in northern Arkansas. The area includes approximately 12,000 acres of mostly second and third growth oak-hickory forest with scattered areas of Shortleaf Pine.[33] The Buffalo River, which has been designated as a national wild and scenic river, flows through the Upper Buffalo Wilderness. The Upper Buffalo Wilderness supports multiple recreational activities including camping, kayaking and canoeing, fishing, hiking, horseback riding, and hunting. Figure II-13 shows two photographs taken within the Upper Buffalo Wilderness that illustrate the scenic quality of the area.

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[32] The "Other" category includes Kansas, Iowa, Offshore, Nebraska, Kentucky, Minnesota, Tennessee, North Dakota, Wisconsin, and Mississippi. Combined visibility impact surrogate from sources in each of these states are less than one percent of the total visibility impact surrogate from all sources in the 2016 AOI results.

[33] U.S. National Forest Service. https://www.fs.usda.gov/recarea/osfnf/recarea/?recid=43499

Figure II-13: Buffalo River (Left) and Whitaker Point (Right), Upper Buffalo Wilderness[34]

1. Ambient Data Analysis

The Upper Buffalo Wilderness monitor is located one mile north of the U.S. Forest Service workstation near Deer, AR at an elevation of 722 meters above MSL. DEQ uses data from this monitor to determine visibility conditions for Upper Buffalo consistent with the requirements of 40 CFR § 51.308(f).

a. Baseline, Current, and Natural Visibility Conditions

DEQ is revising its previous determinations for visibility conditions pursuant to 40 CFR § 51.308(f) to be consistent with the requirements of the 2017 RHR amendments and EPA's guidance.[35] Table II-3 lists DEQ's revised determinations for baseline, natural, and current visibility conditions for the most impaired days and clearest days at Upper Buffalo Wilderness.

[34] Image Credit: National Park Service https://www.nps.gov/buff/planyourvisit/floating.htm (Left Image) and Tricia Treece (Right Image)

[35] Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program.
https://www.epa.gov/sites/production/files/2018-12/documents/technical_guidance_tracking_visibility_progress.pdf

Table II-3: Baseline (2000–2004), Current (2014–2018), and Natural Visibility Conditions for the Twenty Percent Most Impaired Days and Twenty Percent Clearest Days at Upper Buffalo Wilderness[36]

Metric	Baseline Visibility Conditions (deciviews)[37]	Current Visibility Conditions[38] (deciviews)	Natural Visibility Conditions (deciviews)
Most Impaired Days	24.21	17.52	9.41
Clearest Days	11.71	8.17	4.18

Consistent with 40 CFR § 51.308(f)(1)(iv) and (v), DEQ has determined the actual progress toward natural visibility conditions made to date for the clearest and most impaired days since the baseline period and actual progress made during the previous planning period. For both the twenty percent most impaired days and the twenty percent clearest days, Table II-4 lists actual progress to date since the baseline period, progress during Planning Period I, and the difference between current visibility conditions and natural visibility conditions.

Table II-4: Progress Toward Natural Visibility Conditions at Upper Buffalo

Metric	Progress to Date[39] (deciviews)	Progress During Planning Period I [40] (deciviews)	Difference between Current and Natural Visibility Conditions[41] (deciviews)
Most Impaired Days	6.70	6.26	8.11
Clearest Days	3.54	3.51	3.993

b. Uniform Rate of Progress

DEQ is revising its previous URP calculation for Upper Buffalo included in the Planning Period I SIP submittals for consistency with the 2017 amendments[42] to the RHR, including adjustments to the 2064 endpoint based on international anthropogenic contributions in accordance with EPA guidance. The revised URP is -0.206 deciviews per year. Figure II-14 demonstrates progress on

[36] Baseline and Natural Conditions from EPA (2020). "Technical addendum including updated visibility data through 2018 for the memo titled 'Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program." Data used to calculate current visibility conditions obtained from IMPROVE data files sia_impairment_group_means_12_20 (Most Impaired Days) and SIA_group_means_12_20 (Clearest Days)

[37] 2000–2004

[38] 2015–2019

[39] Difference between baseline (2000–2004) average conditions and 2015–2019 average conditions

[40] Difference between baseline (2000–2004) average conditions and 2014–2018 average conditions

[41] Difference between 2015–2019 average conditions and natural conditions

[42] EPA (2017). "Protection of Visibility: Amendments to Requirements for State Plans." 82 FR 3078

the twenty percent most impaired days as compared to the glidepath set by the revised URP.

Figure II-14: Progress on the Twenty Percent Most Impaired Days at Upper Buffalo Compared to the Glidepath[43]

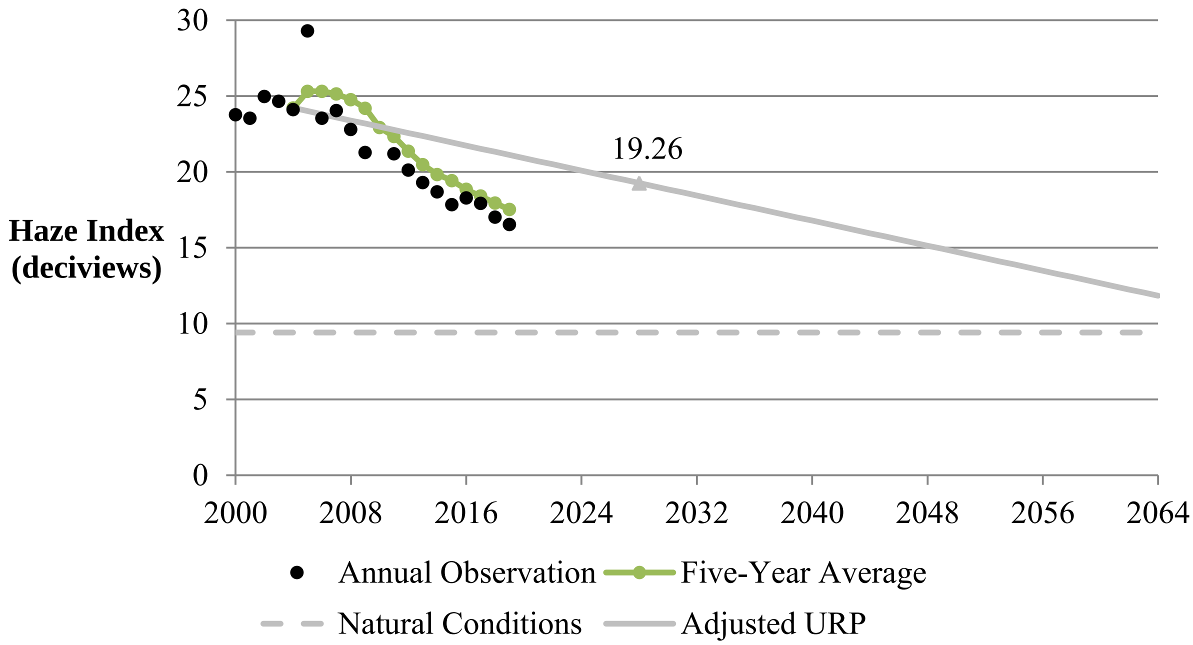
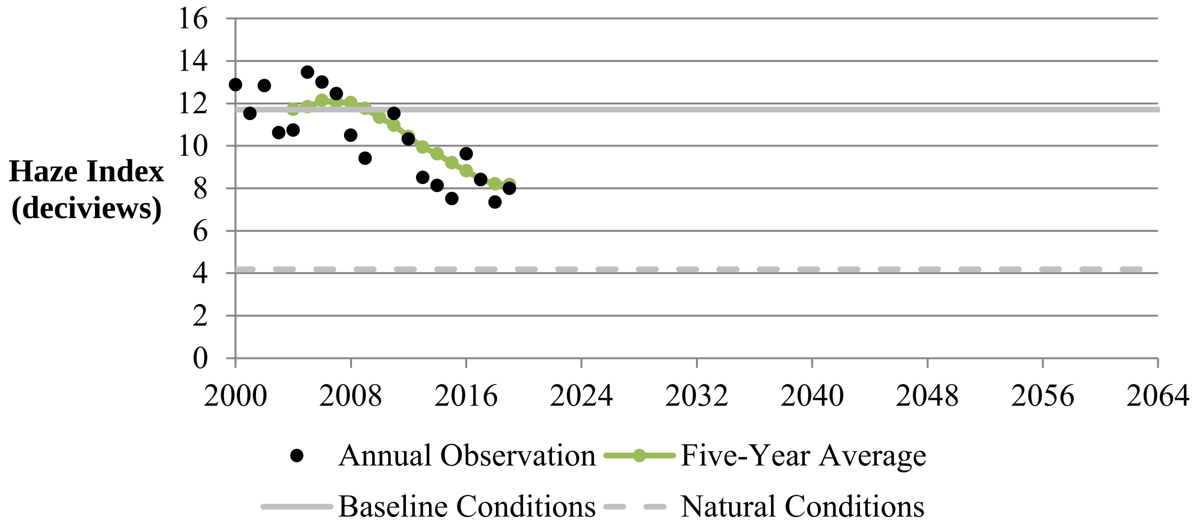


Figure II-14 shows continued improvement in visibility conditions at Upper Buffalo, particularly since 2006. The rolling five-year average of the twenty percent most impaired days has remained below the glidepath since 2010. The most recent five-year average (2015–2019) is below the URP value for 2028, the last year in Planning Period II.

Figure II-15 demonstrates progress on the twenty percent clearest days relative to baseline conditions and natural conditions.

[43] Annual observations obtained from IMPROVE data file sia_impairment_group_means_12_20

Figure II-15: Progress on the Twenty Percent Clearest Days Compared to Natural and Baseline Conditions[44]



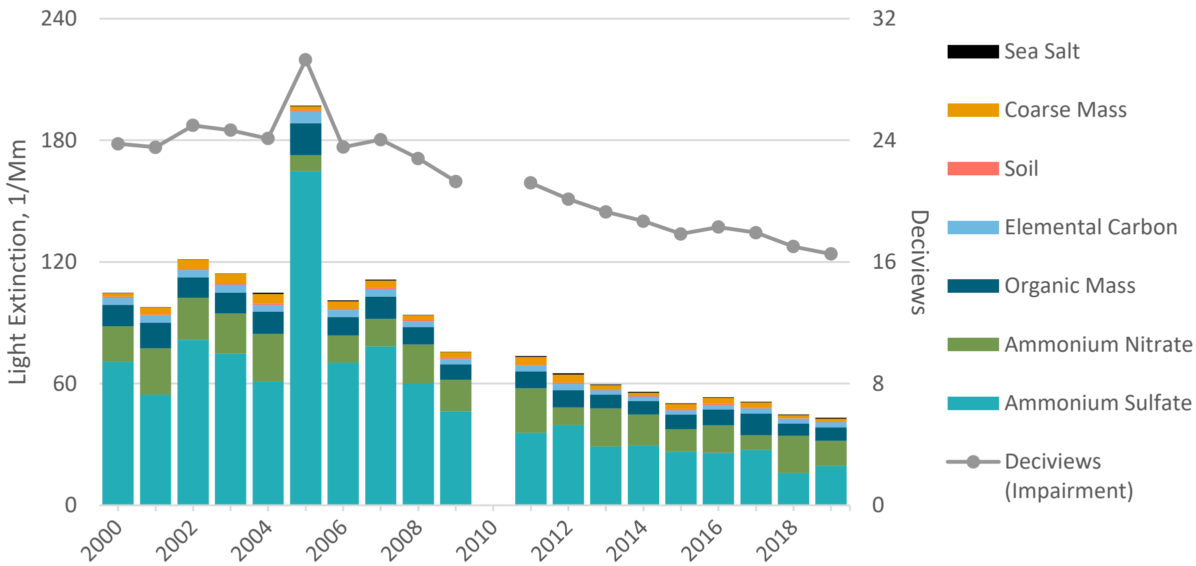
The five-year rolling average of the twenty percent clearest days in Figure II-15 illustrates continued improvement since 2007, indicating no degradation of the clearest days during Planning Period I.

c. Key Pollutants Impacting Visibility

Figure II-16 shows that visibility impairment on the most impaired days has decreased over time at Upper Buffalo as light extinction due to ammonium sulfate—and to a lesser extent coarse mass, elemental carbon, organic mass and soil—has decreased. Light extinction due to ammonium nitrate has fluctuated over time, but no trend is apparent.

[44] Annual observations obtained from IMPROVE data file sia _group_means_12_20

Figure II-16: Annual Extinction Composition, Most Impaired Days at Upper Buffalo, 2000–2019[45]



In 2019, ammonium sulfate was the largest contributor to light extinction at Upper Buffalo on the most impaired days, followed by ammonium nitrate. Organic mass was the third largest contributor to light extinction in 2019. Elemental carbon contributed six percent of light extinction and coarse mass contributed four percent. Sea salt and soil make up a small fraction of the light extinction on the most impaired days.

Figure II-17 shows daily haze composition due to anthropogenic sources and Figure II-18 shows daily haze composition due to natural sources on the most impaired days at Upper Buffalo in 2019. In combination, these figures provide information about potential pollutants to include in DEQ's analysis of potential strategies for reasonable progress during Planning Period II.

[45] Data obtained from IMPROVE data file sia_impairment_group_means_12_20.

Figure II-17: Daily Haze Composition Due to Anthropogenic Sources, Most Impaired Days at Upper Buffalo, 2019[46]

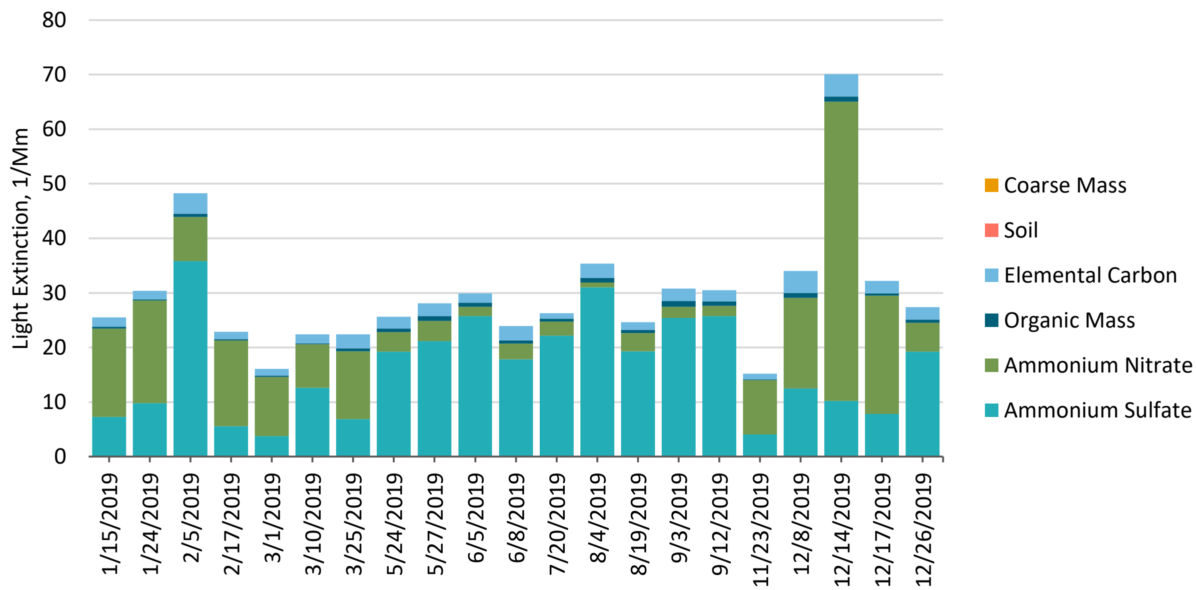
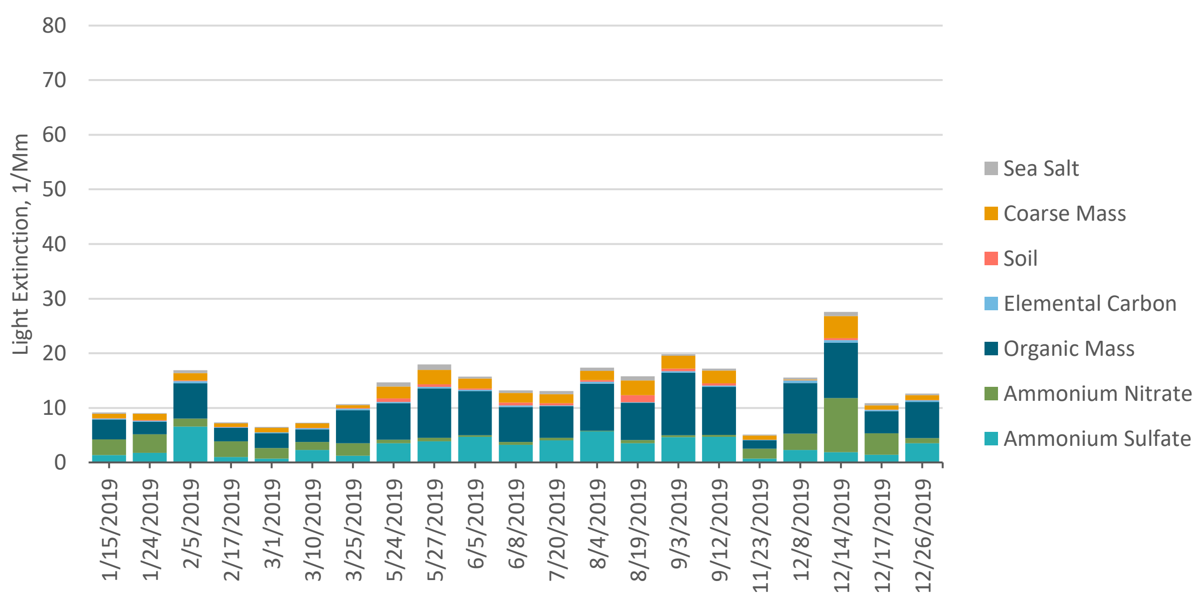


Figure II-18: Daily Haze Composition due to Natural Sources, Most Impaired Days at Upper Buffalo, 2019[47]



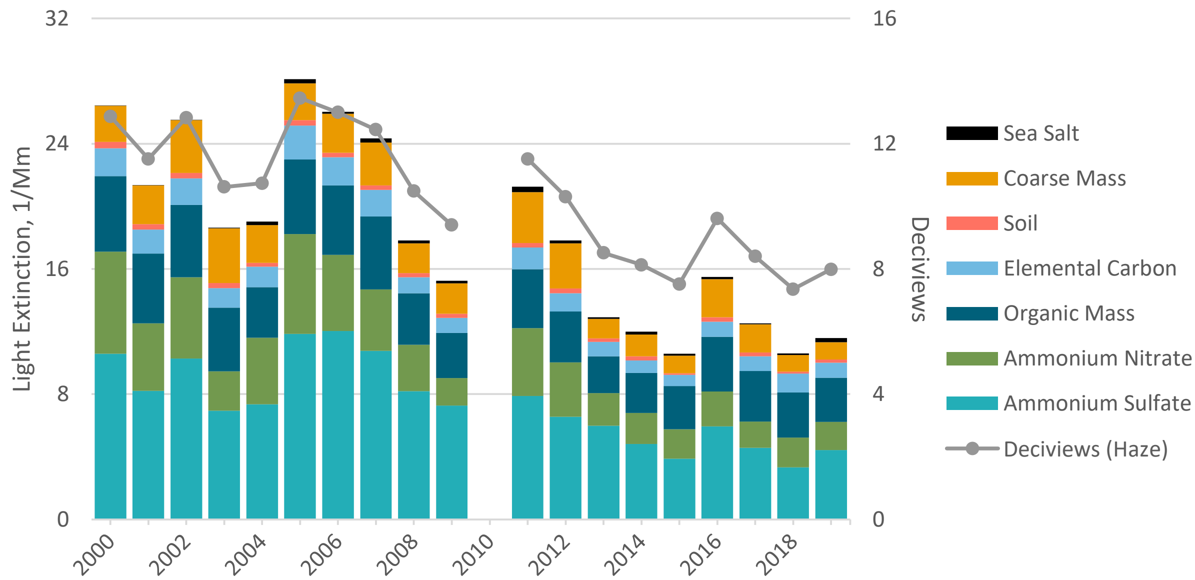
Figures II-17 and II-18 show that light extinction from ammonium nitrate, ammonium sulfate, and elemental carbon on the most impaired days at Upper Buffalo is primarily anthropogenic in nature. Natural sources are the primary contributor of light extinction due to organic mass, coarse

[46] Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.
[47] Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.

mass, sea salt, and soil.

Figure II-19 shows annual visibility tracking metrics for the twenty percent clearest days at Upper Buffalo. The bars show the relative contribution of each particulate species to visibility impairment for each year in Mm^{-1} (left y-axis). The line shows annual visibility impairment on the clearest days in deciviews (right y-axis).

Figure II-19: Annual Extinction Composition, Clearest Days at Upper Buffalo, 2000–2019[48]



The data show a reduction of visibility impairment on the clearest days at Upper Buffalo. This reduction appears to correspond to decreased light extinction from ammonium sulfate and ammonium nitrate.

Based on these monitoring data observations, strategies to reduce visibility impairment at Upper Buffalo from manmade air pollution during Planning Period II should focus on the following key pollutants: ammonium nitrate and ammonium sulfate.

2. Modeling Data Analysis

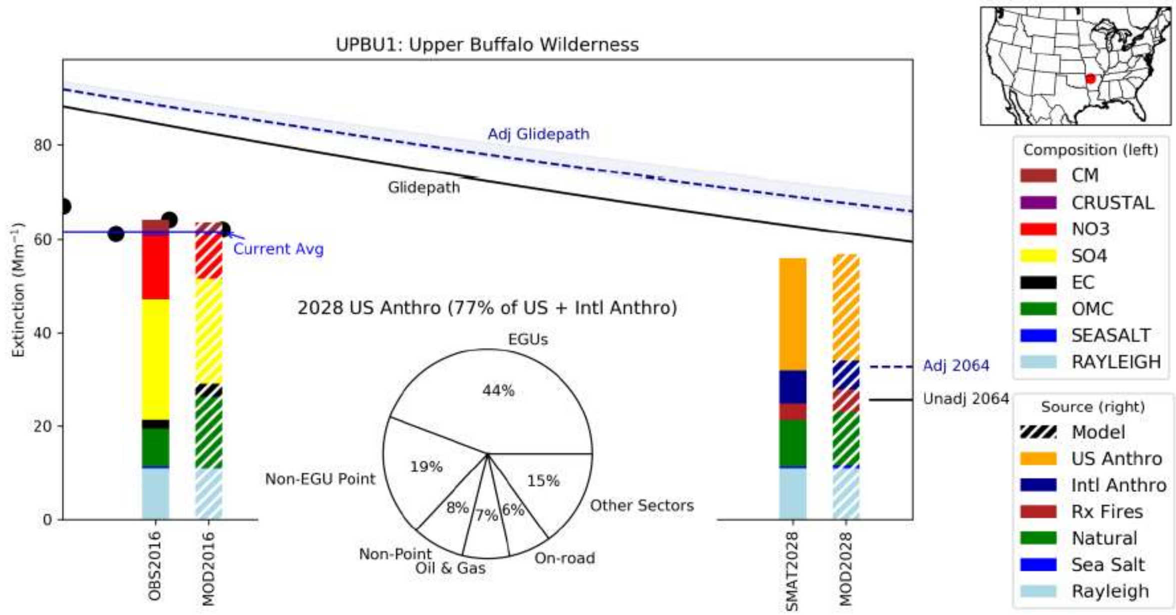
Figure II-20 illustrates for Upper Buffalo the results of EPA's modeling effort. The figure presents observed data for 2014–2017, 2028 base case projections, and possible glidepaths under different assumptions for the most impaired days. The dashed line represents EPA's default adjusted glidepath, which was adjusted based on relative international anthropogenic model contributions and ambient natural conditions.[49] The figure also includes a pie chart representing

[48] Data obtained from IMPROVE data file SIA_group_means_12_20.

[49] The different glidepaths EPA included in their summary plots are based on different 2064 endpoint adjustment assumptions. DEQ's adjusted endpoint (11.26 deciviews) is higher than EPA's default adjusted endpoint (11.21 deciviews), but lower than EPA's maximum endpoint (12.49 deciviews).

the specific anthropogenic emissions sector contributions identified as contributing to visibility impairment at Upper Buffalo.

Figure II-20: EPA Regional Haze Modeling Summary Plot for Upper Buffalo Wilderness[50]



The blue dashed line, the black line, and the blue shaded area in Figure II-20 indicate that, without additional emission reductions beyond those already required by regulations on the books, the rate of progress towards natural visibility at Upper Buffalo would be faster than the range of URP options calculated by EPA, including the URP determined by Arkansas. The model predicts a visibility impairment value of 16.92 deciviews in 2028 for the most impaired days at Upper Buffalo. This projected impairment value is lower than the 19.26 deciviews glidepath value in 2028 created by DEQ's URP. Recent monitoring data are also below the glidepath value in 2028.

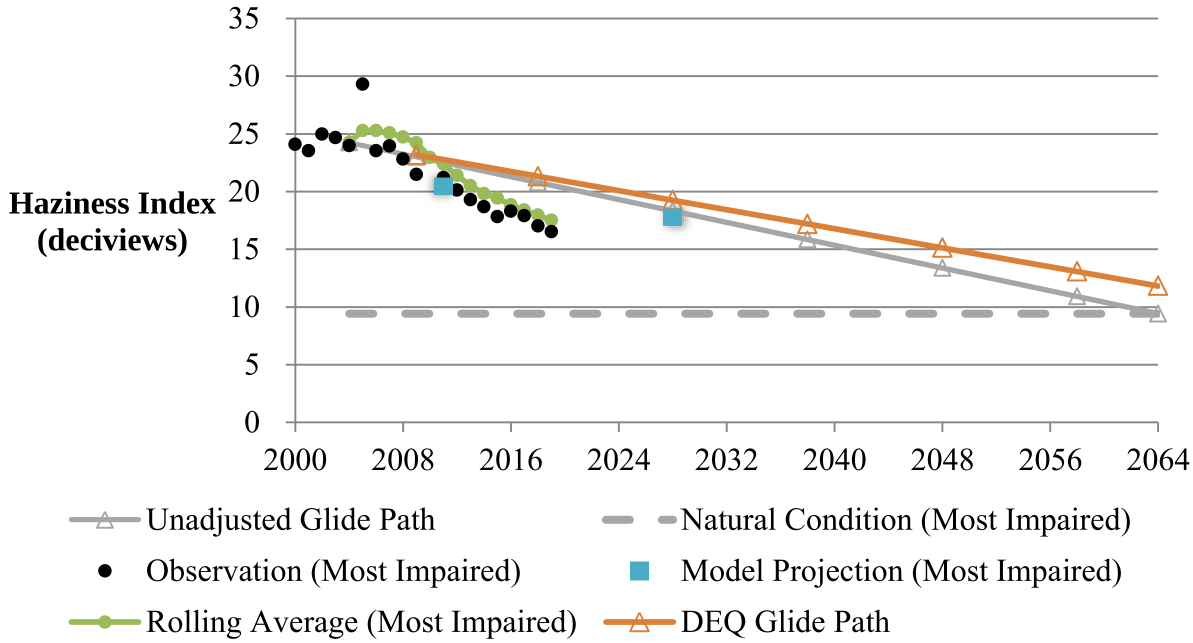
The pie chart in Figure II-20 indicates the most prominent source categories are EGUs and Non-EGU point sources, with smaller contributions from other U.S. anthropogenic sources, non-point sources, and the oil and gas sector. The source apportionment presented in the pie chart suggests that strategies to reduce visibility impairment in 2028 should focus on reducing emissions from the following source categories: EGU and non-EGU point.

Figures II-21 and II-22 illustrate the 2028 base case results for Upper Buffalo of the VISTAS modeling effort. The VISTAS modeling base case results project visibility impairment in 2028 at Upper Buffalo on the most impaired days (17.82 deciviews) to be below both the unadjusted

[50] EPA (2019). "Technical Support Document for EPA's Updated 2028 Regional Haze Modeling." https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf

glidepath (18.32 deciviews) and the DEQ glidepath (19.26 deciviews). The projected most impaired days impairment value in 2028 at Upper Buffalo is higher than current monitor observations.[51] The projected base case results for the clearest days (8.93 deciviews) show no degradation from the 2000–2004 baseline (11.71 deciviews).

Figure II-21: VISTAS Base Case Results for Upper Buffalo Wilderness (Most Impaired Days)[52]



[51] Actual emissions data demonstrates a downward trend in pollutants affecting visibility at federal Class I sites; the VISTAS projections for most impaired days' impairment values are higher than actuals, due to shut-downs and on the books controls not reflected in VISTAS modeling.

[52] Model results obtained from Metro4/SESARM: Copy of V5_GlidePath_MI20_unitDeciview_07-17-2020_jb

Figure II-22: VISTAS Base Case Results for Upper Buffalo Wilderness (Clearest Days)[53]

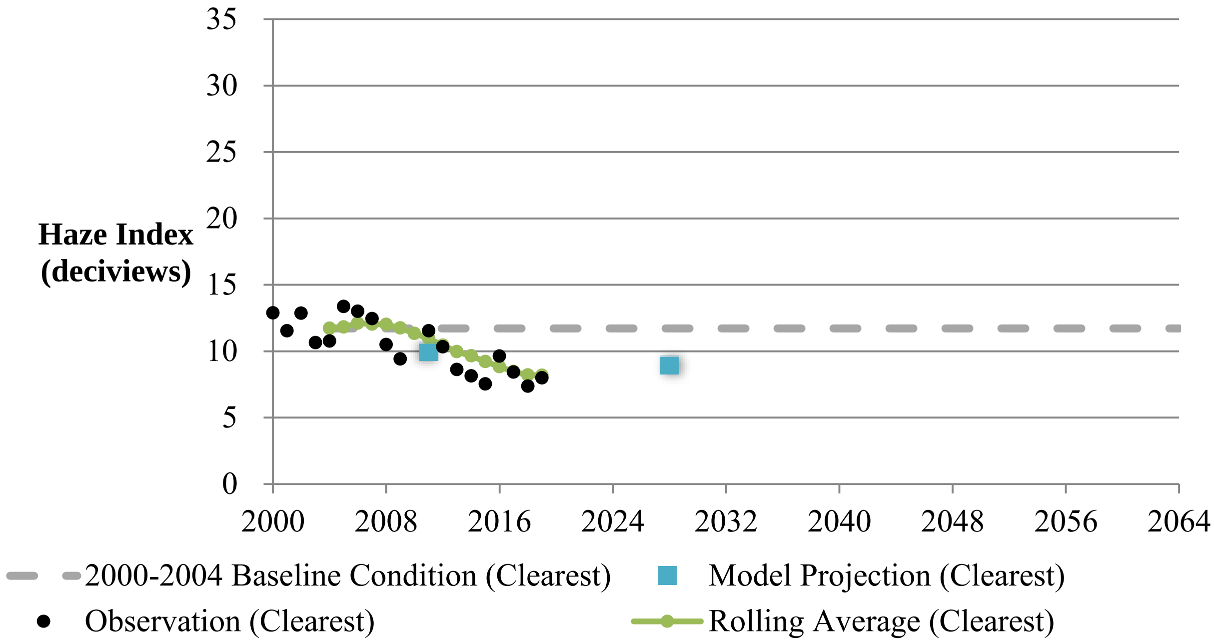
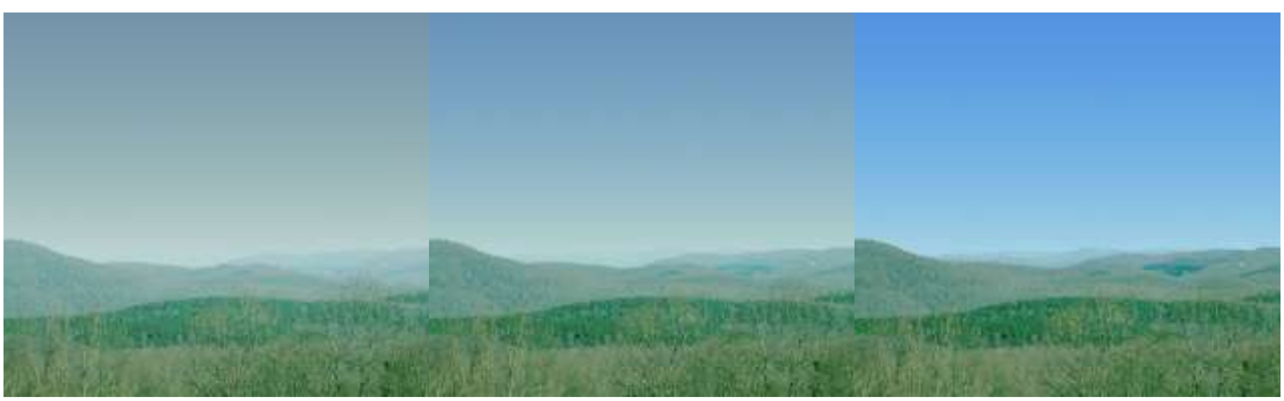


Figure II-23 created using the WinHaze visual modeling tool shows how a vista at Upper Buffalo Wilderness would look during the most impaired days in 2002 (left), 2019 (center), and under natural conditions (right). The improvement between the center image and the left image shows how the visibility has improved over time on the most impaired days.

Figure II-23: Upper Buffalo Wilderness WinHAZE Visualization Twenty Percent Most Impaired: 2002, 2019, and Natural Conditions[54]



[53] Model results obtained from Metro 4/SESARM: Copy of V5_GlidePath_20C_unitDeciview_07-17-2020

[54] Interagency Monitoring of Protected Visual Environments. http://vista.cira.colostate.edu/Improve/winhaze/

3. AOI Analysis

Based on DEQ's evaluation of the 2016 AOI results, as described in section A of this chapter, sources in the following states may impact visibility on the most impaired days at Upper Buffalo: Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nebraska, Oklahoma, South Dakota, Tennessee, Texas, and Wisconsin. Figure II-24 shows the relative percentage from each state of the visibility impact surrogate for all sources in the AOI.

Figure II-24: Relative Visibility Impact Surrogate of Sources in AOI Analysis on Most Impaired Days at Upper Buffalo in 2016[55]

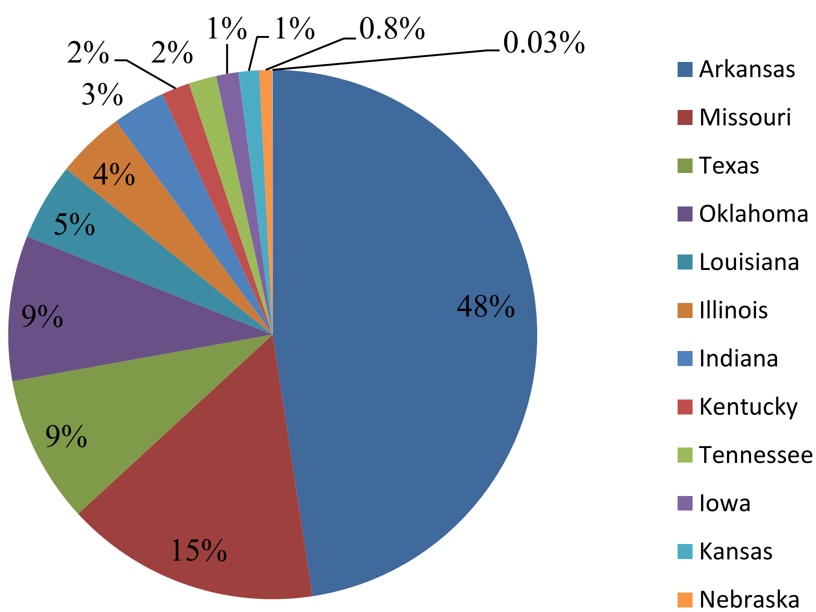


Figure II-24 indicates that point sources in Arkansas contributed the most out of the sources in the AOI to visibility impairment at Upper Buffalo on the most impaired days. Sources in Missouri were the second largest contributor.

[55] The "Other" category includes Offshore, Minnesota, Wisconsin, Mississippi, South Dakota, and Tribal. Combined visibility impact surrogates from sources in each of these states are less than once percent of the total visibility impact surrogate from all sources in the 2016 AOI.

Arkansas Regional Haze Planning Period II

State Implementation Plan

CHAPTER III: FEDERAL CLASS I AREAS IN OTHER STATES

IMPACTED BY ARKANSAS SOURCES

CHAPTER III: FEDERAL CLASS I AREAS IN OTHER STATES IMPACTED BY ARKANSAS SOURCES

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III. Federal Class I Areas in Other States Impacted by Arkansas Sources

40 CFR § 51.308(f) requires that states address emissions within the state that impair visibility in each mandatory federal Class I area within the state, as well as emissions within the state that may impair visibility in federal Class I areas in other states.

DEQ used the AOI analysis by Ramboll to determine areas of influence for federal Class I areas in and near the CenSARA region. Specifically, DEQ examined distance-weighted residence time plots to identify federal Class I areas that may be influenced by air masses from Arkansas. The RHR does not provide specific guidance for thresholds values for residence time. Therefore, DEQ selected 0.05% as a cut-off to identify areas of influence from the distance-weighted residence time plots.[1]

Based on the AOI analysis, DEQ identified the following Class I areas for which emissions from Arkansas sources may be reasonably anticipated to contribute to visibility impairment:

- Hercules Glades Wilderness (Hercules Glades), MO;
- Mammoth Cave National Park (Mammoth Cave), KY;
- Sipsey Wilderness (Sipsey), AL; and
- Wichita Mountains Wilderness (Wichita Mountains), OK

In addition to the federal Class I areas DEQ identified using distance-weighted residence times, DEQ also identified two additional Class I areas for which the 2016 visibility surrogate or photochemical modeling indicated that a particular source within the state of Arkansas may contribute to visibility impairment: Mingo Wilderness (Mingo), MO and Shining Rock Wilderness (Shining Rock), North Carolina. During source selection for the reasonable progress analysis described in Chapter V, DEQ identified the Independence Power Plant in Arkansas as meeting its threshold for a reasonable progress analysis for Mingo in Missouri. Other state air organizations (WRAP, VISTAS, and LADCO) performed photochemical modeling; only VISTAS made a request of DEQ to perform a reasonable progress analysis for Independence Power Plant in Arkansas, as their modeling shows impacts at Shining Rock in North Carolina. Therefore, DEQ has also included a discussion of Mingo and Shining Rock in this chapter.

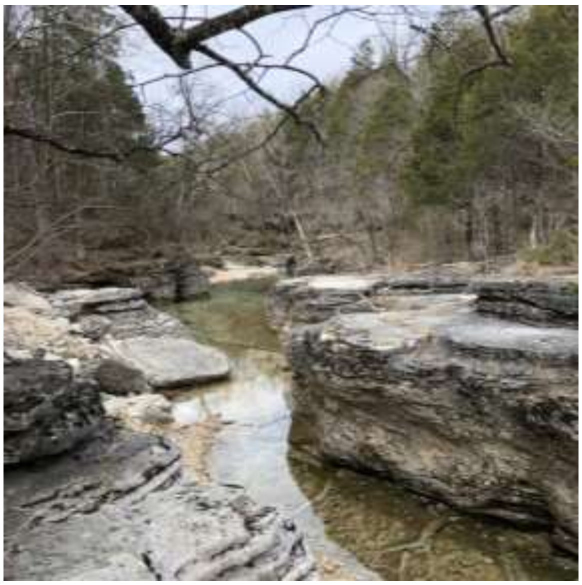
DEQ has examined the sources of visibility impairment for each of identified federal Class I areas and progress toward the goal of natural visibility conditions in 2064.

[1] See Appendix B for distance-weighted residence time plots.

A. Hercules Glades Wilderness Area

The Hercules Glades Wilderness Area consists of 12,413 acres of open grasslands, forested knobs, steep rocky hillsides, and narrow drainages. The area is characterized by shallow, droughty soils and limestone outcrops.[2] Figure III-1 illustrates the scenic quality of Hercules Glades.

Figure III-1: Hercules Glades Wilderness[3]



1. Ambient Data Analysis

The Hercules Glades Wilderness Area monitor is located twelve miles east of Forsythe, Missouri at latitude 36.6138, longitude -92.9221, at an elevation of 404 meters above MSL.

Figure III-2 shows that visibility impairment has decreased over time at Hercules Glades on the twenty percent most impaired days. In particular, light extinction on the most impaired days due to ammonium sulfate has decreased dramatically since 2002. Light extinction on the most impaired days due to ammonium nitrate has fluctuated over the period between 2002 and 2019. In 2019, the relative impact on light extinction on the most impaired days was forty percent for ammonium sulfate and thirty-seven percent for ammonium nitrate. Coarse mass, elemental carbon, organic mass, sea salt, and soil have varied over time, but make up smaller fractions of the overall particulate species impairing visibility on the most impaired days.

[2] U.S. Forest Service. https://www.fs.usda.gov/recarea/mtnf/recarea/?recid=21754

[3] Image Credit: Tricia Treece (Left) and National Forest Service https://www.fs.usda.gov/recarea/mtnf/recarea/?recid=21754 (Right)

Figure III-2: Annual Extinction Composition, Most Impaired Days at Hercules Glades, 2002–2019[4]

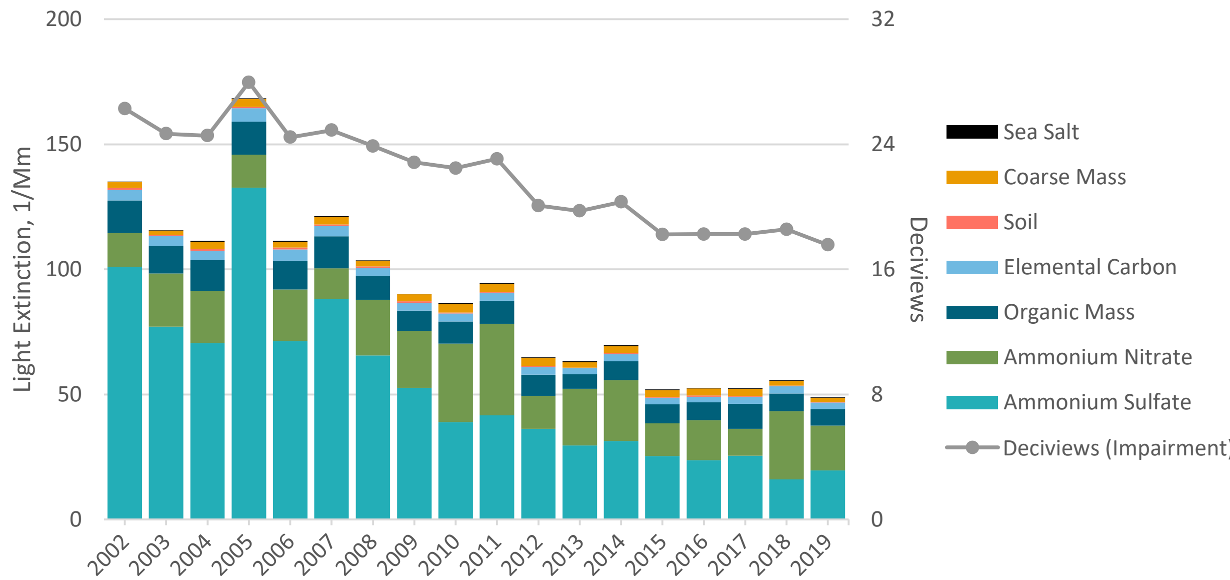


Figure III-3 shows no degradation on the twenty percent clearest days at Hercules Glades.

Figure III-3: Annual Extinction Composition, Clearest Days at Hercules Glades, 2002–2019[5]

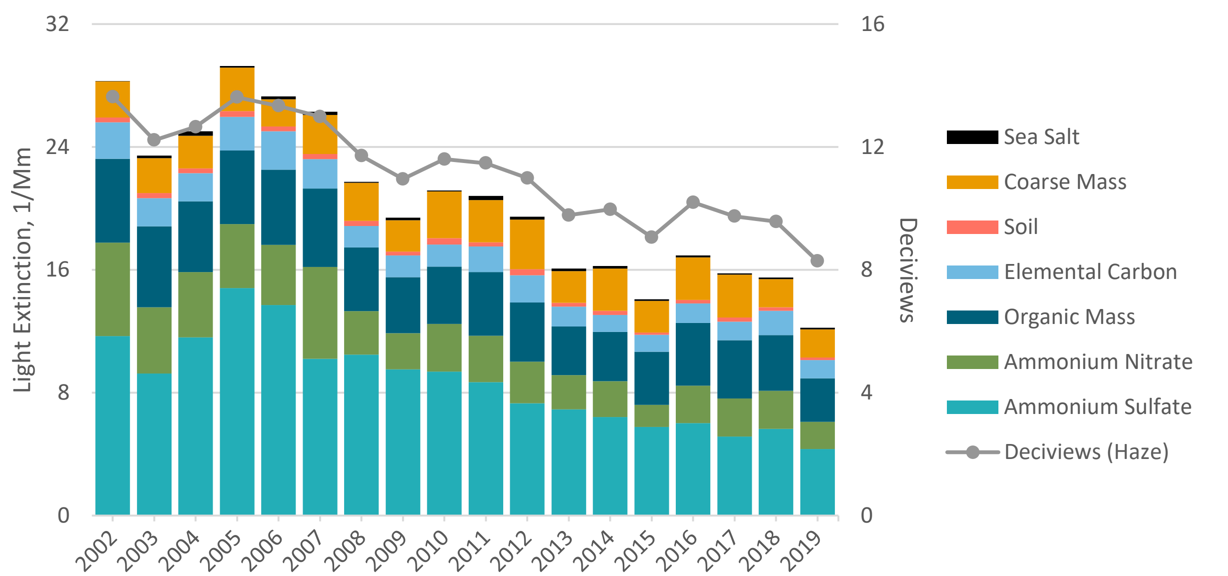


Figure III-4 shows daily haze composition due to anthropogenic sources and Figure III-5 shows

[4] Data obtained from IMPROVE data file sia_impairment_group_means_12_20

[5] Data obtained from IMPROVE data file SIA_group_means_12_20.

daily haze composition due to natural sources on the most impaired days at Hercules Glades in 2018.

Figure III-4: Daily Haze Composition Due to Anthropogenic Sources, Most Impaired Days at Hercules Glades, 2018[6]

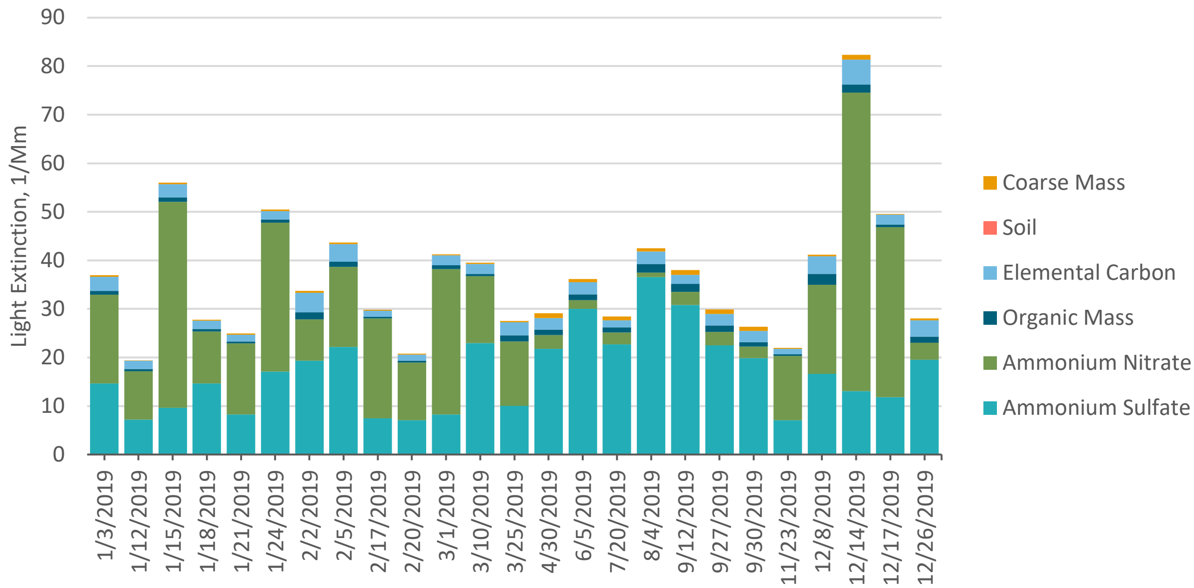
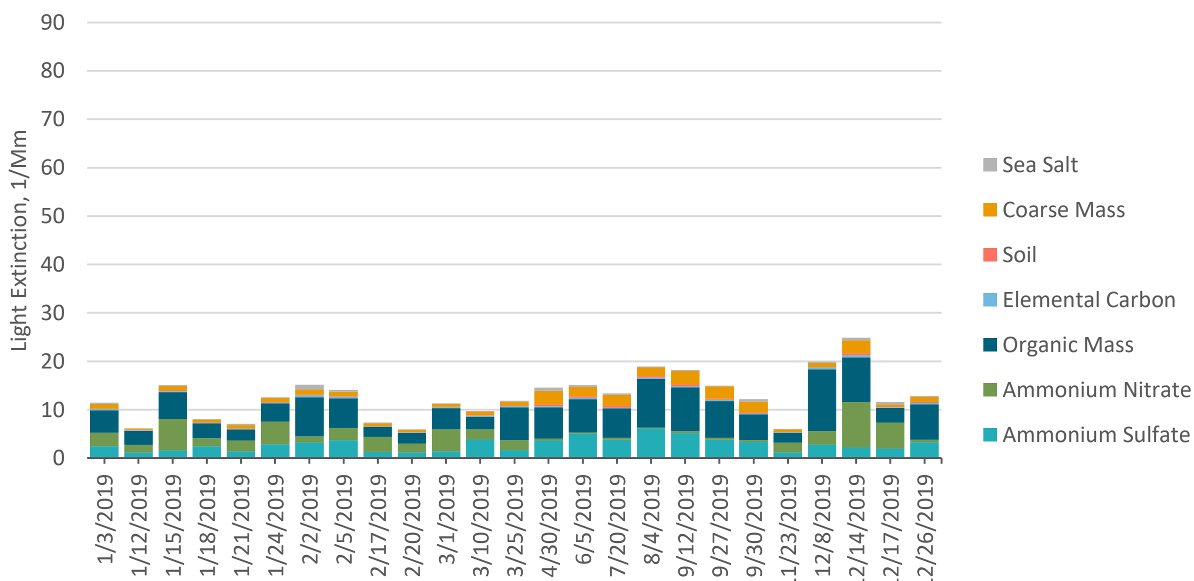


Figure III-5: Daily Haze Composition Due to Natural Sources, Most Impaired Days at Hercules Glades, 2019[7]



[6] Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.
[7] Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.

Figures III-4 and III-5 show that light extinction on the most impaired days at Hercules Glades in 2018 from ammonium nitrate, ammonium sulfate, and elemental carbon are primarily anthropogenic in nature. Light extinction on the most impaired days at Hercules Glades in 2019 from coarse mass, organic mass, sea salt, and soil are primarily due to natural sources.

Based on these monitor data observations, strategies to reduce visibility impairment at Hercules Glades from manmade air pollution during Planning Period II should focus on the following key pollutants: ammonium nitrate and ammonium sulfate.

2. Modeling Data Analysis

Figure III-6 illustrates for Hercules Glades the results of EPA's modeling effort. The figure presents observed data for 2014–2017, 2028 base case projections, and possible glidepaths under different assumptions. The dashed line represents EPA's default adjusted glidepath, which was adjusted based on relative international anthropogenic model contributions and ambient natural conditions.[8] The figure also includes a pie chart representing the specific anthropogenic emissions sector contributions identified as contributing to visibility impairment at Hercules Glades in 2028.

Figure III-6: IMPROVE Site Summary Plot for Hercules Glades

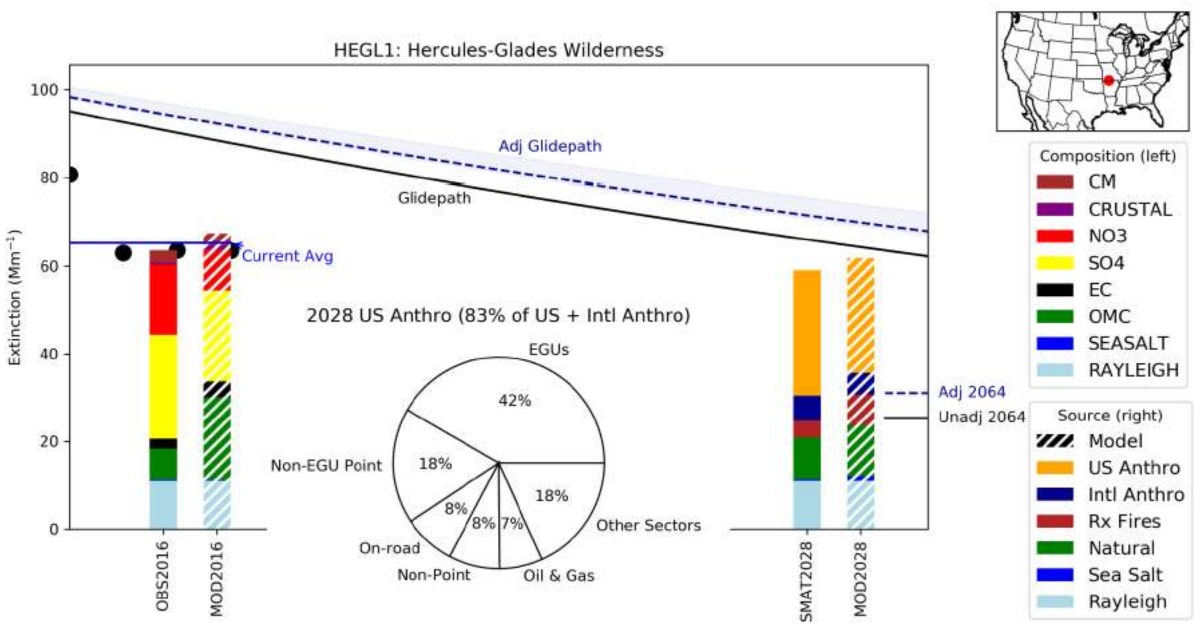


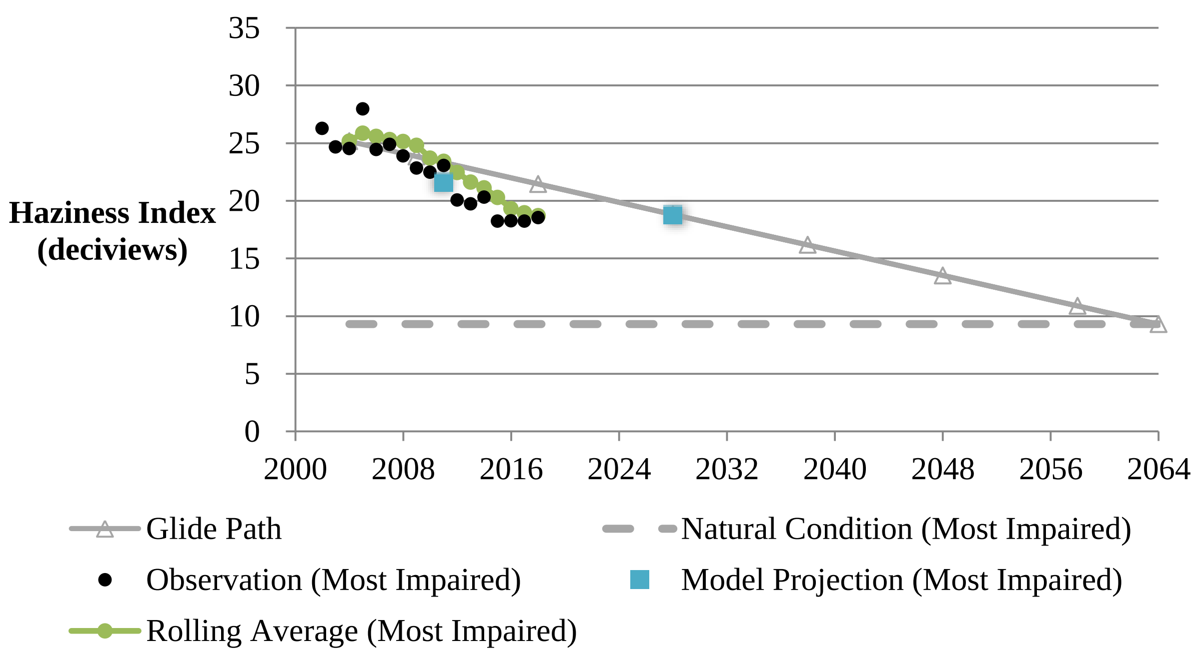
Figure III-6 shows that visibility impairment on the most impaired days in 2028 is projected to remain below any glidepath that the State of Missouri may establish in their Planning Period II SIP even before consideration of additional control measures to ensure reasonable progress.

[8] The different glidepaths EPA included in their summary plots are based on different 2064 endpoint adjustment assumptions.

The pie chart in Figure III-6 represents specific source categories contributing to visibility impairment at Hercules Glades on the most impaired days in 2028 and indicates the most prominent source categories are EGUs and Non-EGU point sources, with smaller contributions from on-road sources, non-point sources, oil and gas, and other sectors. The source apportionment presented in the pie chart suggests that strategies to reduce visibility impairment in 2028 should focus on reducing emissions from the following source categories: EGU and non-EGU point.

Figures III-7 and III-8 illustrate the 2028 base case results for Hercules Glades of the VISTAS modeling effort. The VISTAS modeling base case results project visibility impairment in 2028 at Hercules Glades on the most impaired days (18.80 deciviews) to be just below the unadjusted glidepath (18.82 deciviews).[9] The projected base case results for the clearest days (9.75 deciviews) show no degradation from the 2000–2004 baseline (12.84 deciviews).

Figure III-7: VISTAS Base Case Results for Hercules Glades Wilderness (Most Impaired Days)[10]



[9] Missouri DNR confirmed plans to use the unadjusted URP for this planning period's projections.
[10] Model results obtained from Metro 4/SESARM: Copy of V5_GlidePath_MI20_unitDeciview_07-17-2020

Figure III-8: VISTAS Base Case Results for Hercules Glades Wilderness (Clearest Days)[11]

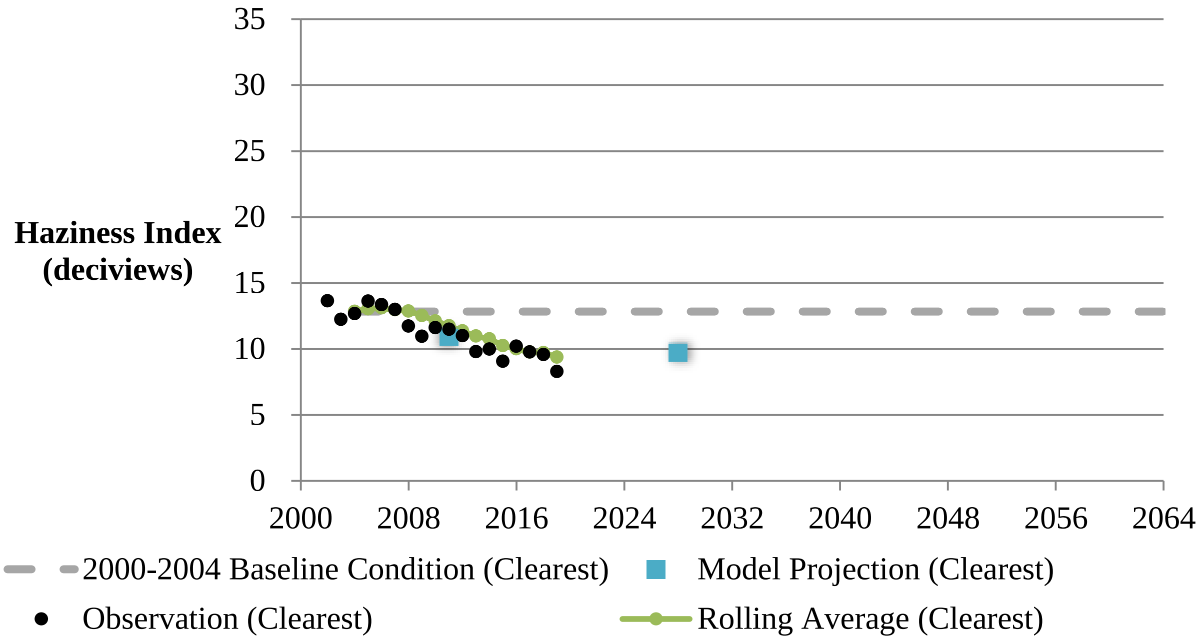


Figure III-9 shows how a vista at Hercules Glades Wilderness would look during the most impaired days in 2002 (left), 2019 (center), and under natural conditions (right). The improvement between the center image and the left image shows how the visibility has improved over time on the most impaired days.

Figure III-9: Hercules Glades Wilderness WinHAZE Visualization Twenty Percent Most Impaired: 2002, 2019, and Natural Conditions[12]

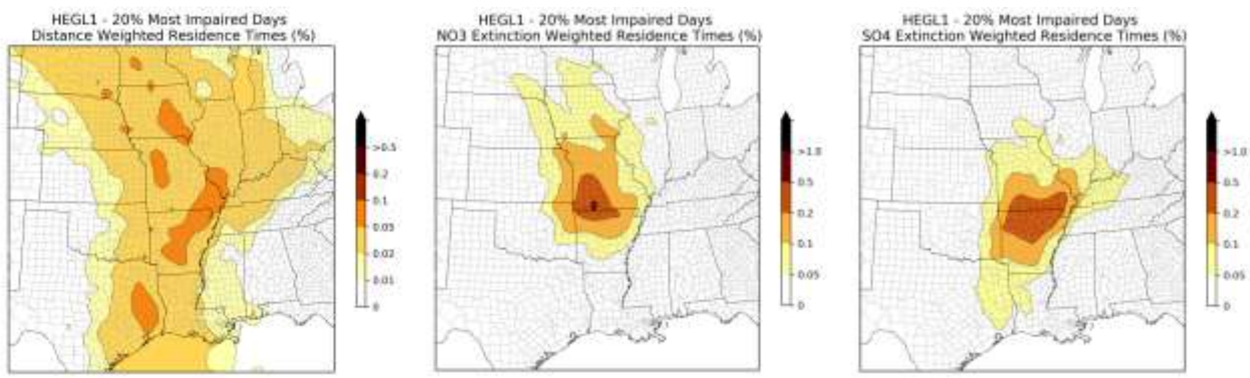
[11] Model results obtained from Metro 4/SESARM: Copy of V5_GlidePath_20C_unitDeciview_07-17-2020

[12] Interagency Monitoring of Protected Visual Environments. http://vista.cira.colostate.edu/Improve/winhaze/

3. AOI Analysis

As described in Chapter II, DEQ used the AOI analysis results produced by Ramboll for the CenSARA states to evaluate which geographic regions and sources have a high probability of contributing to anthropogenic visibility impairment at federal Class I areas within the CenSARA region and in neighboring states. Figure III-10 shows the distance-weighted residence time and pollutant-specific extinction-weighted residence times (EWRT NO_3 and EWRT SO_4) for Hercules Glades for the most impaired days. Based on the distance-weighted residence time plot, air masses from the following states are within the 0.05% distance-weighted residence time contour for Hercules Glades on the most impaired days: Arkansas, Illinois, Iowa, Kentucky, Minnesota, Missouri, Nebraska, Oklahoma, South Dakota, and Texas. The EWRT NO_3 plot indicates that air masses coming from the following states may be impacting ammonium nitrate concentrations at Hercules Glades on the most impaired days: Arkansas, Illinois, Iowa, Kansas, Minnesota, Missouri, Nebraska, Oklahoma, South Dakota, and Wisconsin. The EWRT SO_4 plot indicates that air masses coming from the following states may be impacting ammonium sulfate concentrations at Hercules Glades on the most impaired days: Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Mississippi, Missouri, Oklahoma, Tennessee, and Texas. Darker areas on these plots indicate a larger influence on Hercules Glades on the most impaired days for the examined metric.

Figure III-10: All Trajectories Distance-Weighted Residence Times, EWRT NO_3, and EWRT SO_4 for the Twenty-Percent Most Impaired Days—Hercules Glades (Normalized Percentages)



The EWRT NO_3 and EWRT SO_4 plots indicate that air masses from northern Arkansas and southern Missouri have the greatest influence on ammonium nitrate and ammonium sulfate on Hercules Glades on the most impaired days. The individual sources with the highest visibility impact surrogate values for Hercules Glades in 2016 were sources in Arkansas, Illinois, Indiana, Kentucky, Louisiana, Missouri, Nebraska, Oklahoma, Tennessee, and Texas. Thirty-two percent of the inventory's visibility surrogate total for Hercules Glades in 2016 is attributable to Arkansas sources.

Based on the pollutant-specific EWRT plots for the dominant pollutants and the relatively large percentage of the AOI inventory's visibility surrogate table attributable to Arkansas sources, DEQ concludes that emissions from Arkansas sources are reasonably anticipated to contribute to visibility impairment at Hercules Glades.

B. Mammoth Cave

The Mammoth Cave National Park federal Class I area consists of 51,303 acres in the Green River valley and contains the world's longest known cave system.[13] Mammoth Cave supports many recreational activities including camping, hiking, cave tours, horseback riding, fishing, and boating.[14] Figure III-11 illustrates the scenic nature of Mammoth Cave.

Figure III-11: Mammoth Cave Wilderness[15]

1. Ambient Data Analysis

The Mammoth Cave monitor is located at latitude 37.1318, longitude -86.1479, at an elevation of 235 meters above MSL.

Figure III-12 shows that visibility impairment has decreased at Mammoth Cave on the twenty percent most impaired days. In particular, light extinction due to ammonium sulfate on the most impaired days has decreased markedly on the most impaired days since 2000. Light extinction due to organic mass, elemental carbon, and soil has also decreased. Light extinction due to

13 https://www.nps.gov/maca/index.htm
14 https://www.nps.gov/maca/planyourvisit/things2do.htm
15 https://npgallery.nps.gov/AssetDetail/c9335a50fca140338a4216fd1e8fb14a# (left)
https://npgallery.nps.gov/AssetDetail/31AE4F7F-1DD8-B71B-0BF11F0110B23707 (right)

ammonium nitrate and sea salt has increased. In 2019, the relative impact on light extinction on the most impaired days was forty-five percent for ammonium sulfate and thirty-three percent for ammonium nitrate. Coarse mass, elemental carbon, organic mass, sea salt, and soil make up smaller fractions of the overall particulate species impairing visibility on the most impaired days.

Figure III-12: Annual Extinction Composition, Most Impaired Days at Mammoth Cave, 2000–2019[16]

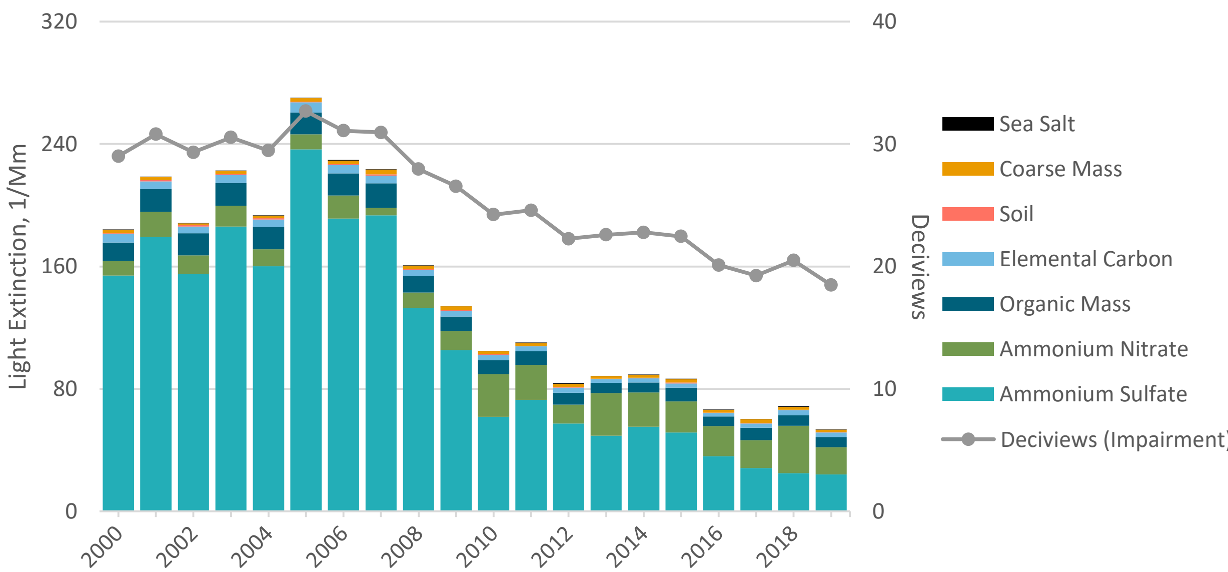


Figure III-13 shows no degradation on the clearest days at Mammoth Cave. Light extinction due to ammonium sulfate on the clearest days has dramatically decreased since 2000.

[16] Data obtained from IMPROVE data file sia_impairment_group_means_12_20.

Figure III-13: Annual Extinction Composition, Clearest Days at Mammoth Cave, 2000–2019[17]

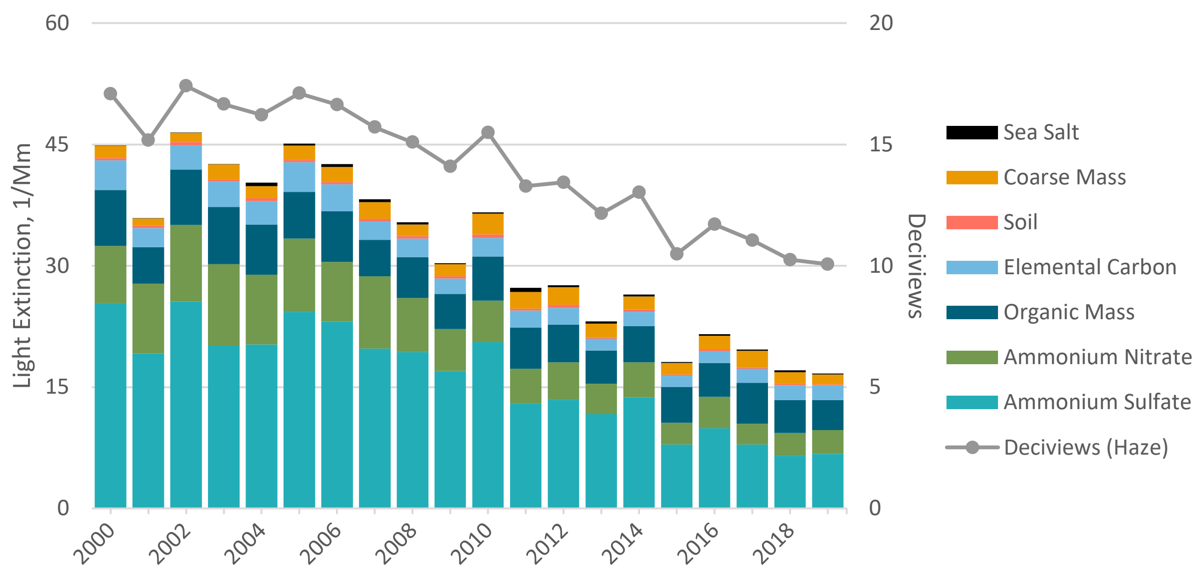
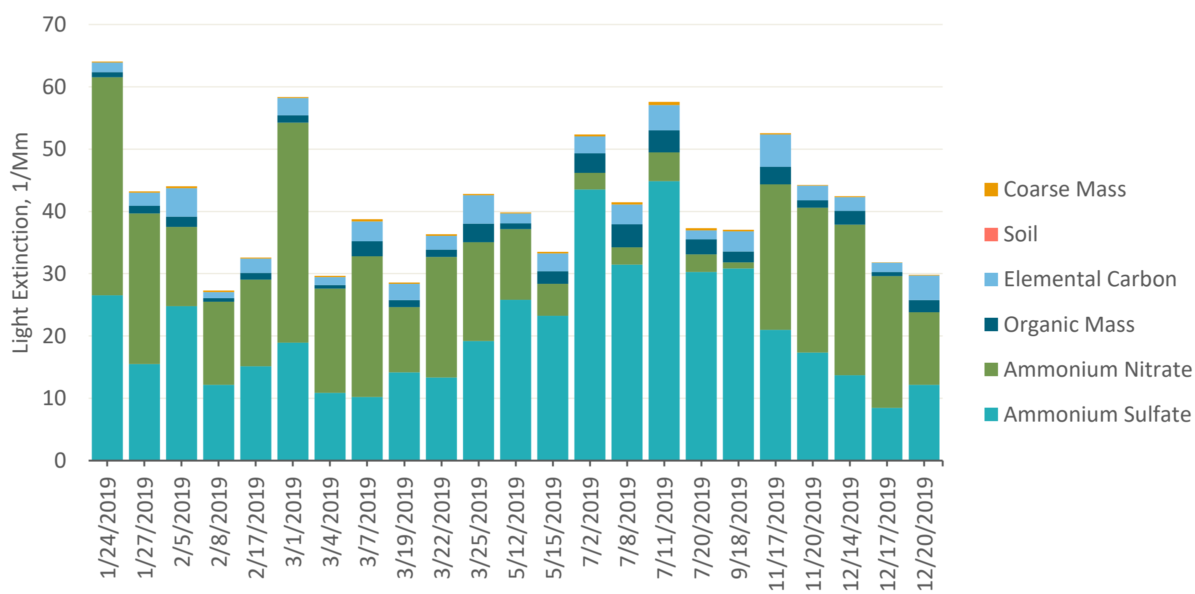


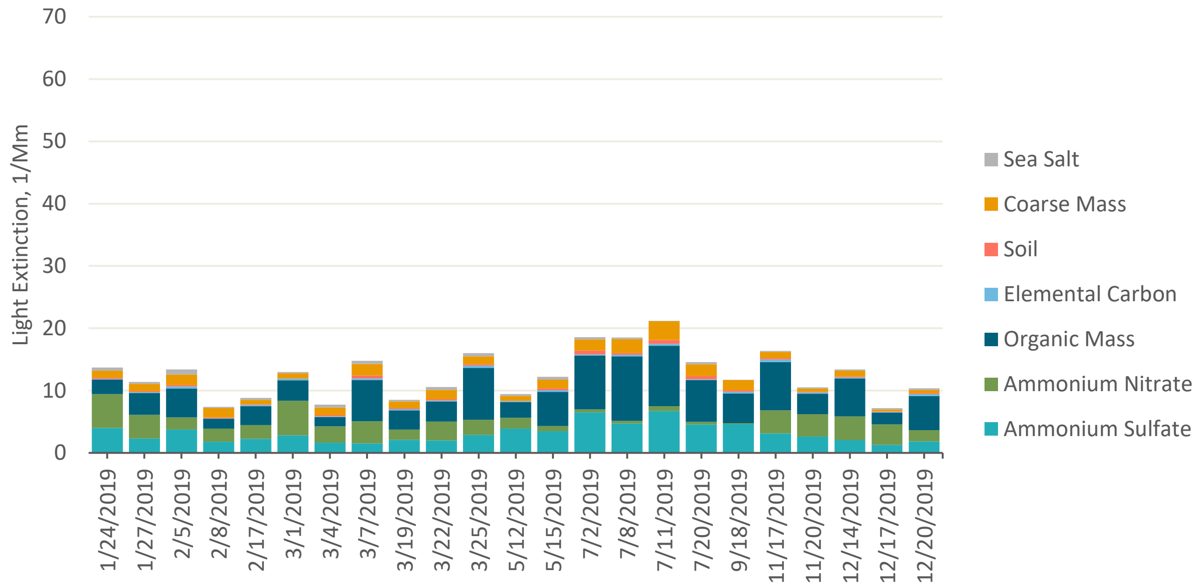
Figure III-14 shows daily haze composition due to anthropogenic sources and Figure III-15 shows daily haze composition due to natural sources on the most impaired days at Mammoth Cave in 2019.

Figure III-14: Daily Haze Composition Due to Anthropogenic Sources, Most Impaired Days at Mammoth Cave, 2019[18]



[17] Data obtained from IMPROVE data file SIA _group_means_12_20.
[18] Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.

Figure III-15: Daily Haze Composition Due to Natural Sources, Most Impaired Days at Mammoth Cave, 2019[19]



Figures III-14 and III-15 show that light extinction on the most impaired days at Mammoth Cave during 2018 from ammonium nitrate, ammonium sulfate, and elemental carbon are primarily anthropogenic in nature. Light extinction due to organic mass and coarse mass are primarily from natural sources. On the most impaired days, ammonium nitrate is the predominant species during the cooler months and ammonium sulfate is the predominant species in the summer.

Based on these monitor data observations, strategies to reduce visibility impairment at Mammoth Cave from manmade air pollution during Planning Period II should focus on the following key pollutants: ammonium nitrate and ammonium sulfate.

2. Modeling Data Analysis

Figure III-16 illustrates the results of EPA's modeling effort for Mammoth Cave. The figure presents observed data for 2014–2017, 2028 base case projections, and possible glidepaths under different assumptions. The dashed line represents EPA's default adjusted glidepath, which was adjusted based on relative international anthropogenic model contributions and ambient natural conditions.[20] The figure also includes a pie chart representing the specific anthropogenic emissions sector contributions identified as contributing to visibility impairment at Mammoth Cave in 2028.

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[19] Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.

[20] The different glidepaths EPA included in their summary plots are based on different 2064 endpoint adjustment assumptions.

Figure III-16: IMPROVE Site Summary Plot for Mammoth Cave

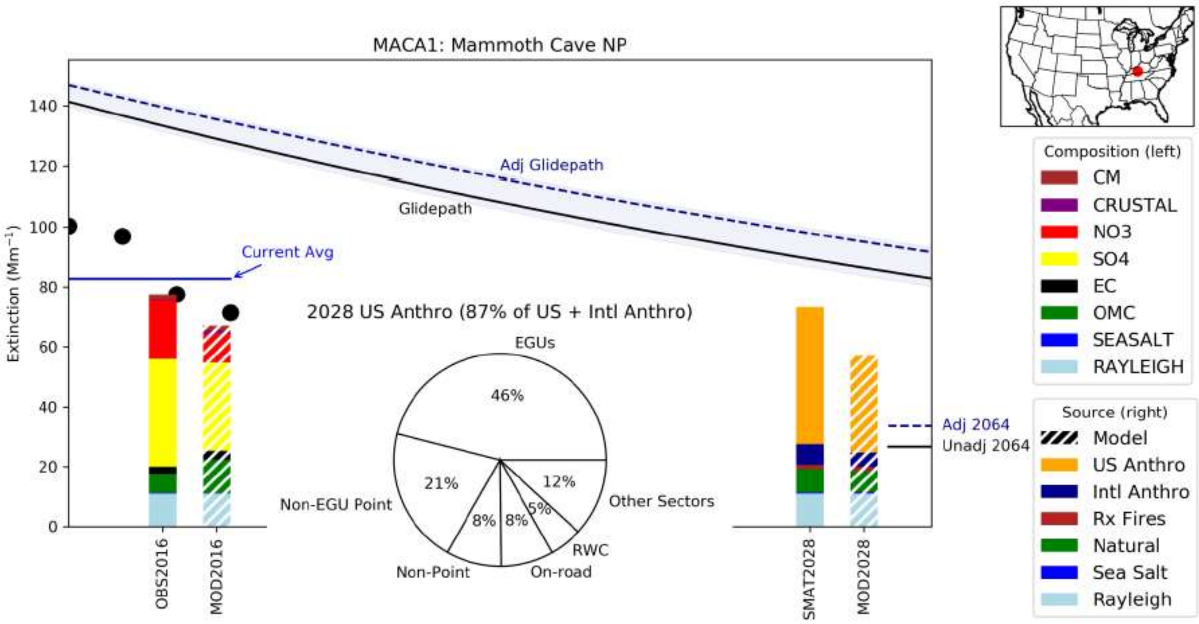


Figure III-16 shows that visibility impairment on the most impaired days in 2028 is projected to remain below any glidepath that the State of Kentucky may establish in their Planning Period II SIP even before consideration of additional control measures to ensure reasonable progress.

The pie chart in Figure III-16 represents specific source categories projected to contribute to visibility impairment at Mammoth Cave on the most impaired days in 2028 and indicates that the most prominent source categories are EGUs and non-EGU point sources, with smaller contributions from non-point sources, on-road sources, other sectors, and residential wood combustion. The source apportionment presented in the pie chart suggests that strategies to reduce visibility impairment in 2028 should focus on reducing emissions from the following source categories: EGU and non-EGU point.

Figures III-17 and III-18 illustrate the 2028 base case results for Mammoth Cave of the VISTAS modeling effort. The VISTAS modeling base case results project visibility impairment in 2028 at Mammoth Cave on the most impaired days (19.27 deciviews) to be above the unadjusted glidepath (21.81 deciviews).[21] The projected base case results for the clearest days (11.66 deciviews) show no degradation from the 2000–2004 baseline (16.51 deciviews).

[21] Kentucky Energy and Environment confirmed plans to use 21.82 deciviews for the 2028 URP for Mammoth Cave based on the updated natural conditions value for most impaired days that is in the 2020 EPA memo (Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program). In that data update, the natural conditions/endpoint for Mammoth Cave changed to 21.82 deciviews from the prior value of 21.81 deciviews, which shifted the glidepath accordingly.

Figure III-17: VISTAS Base Case Results for Mammoth Cave (Most Impaired Days)[22]

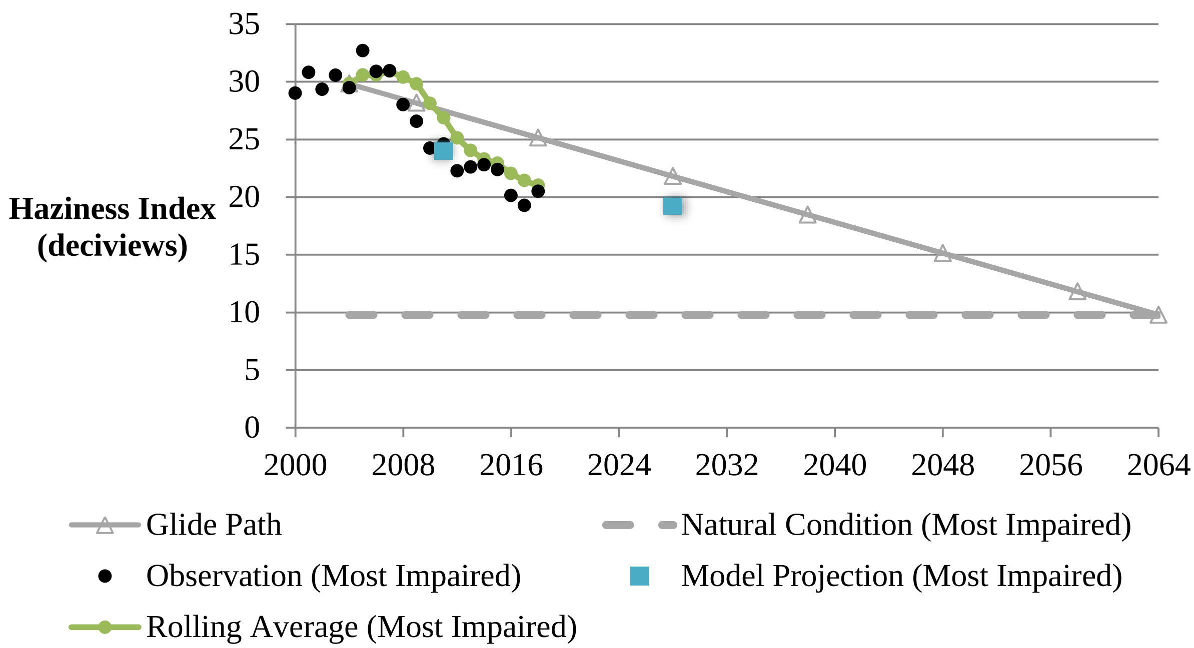
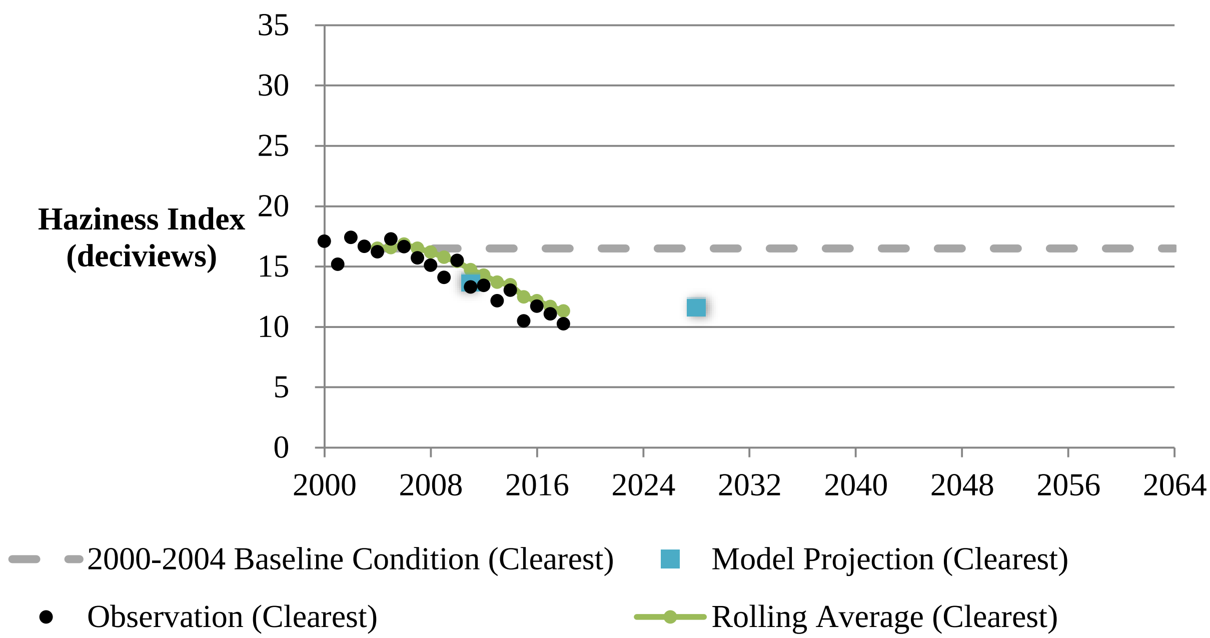


Figure III-18: VISTAS Base Case Modeling Results for Mammoth Cave – 20% Clearest Days[23]



[22] Model results obtained from Metro 4/SESARM: Copy of V5_GlidePath_MI20_unitDeciview_07-17-2020_jb
[23] Model results obtained from Metro 4/SESARM: Copy of V5_GlidePath_20C_unitDeciview_07-17-2020

Figure III-19 shows how a vista at Mammoth Cave would look during the most impaired days in 2002 (left), 2019 (center), and under natural conditions (right). The improvement between the center image and the left image shows how the visibility has improved over time on the most impaired days. The image on the right visualizes natural conditions for the area.

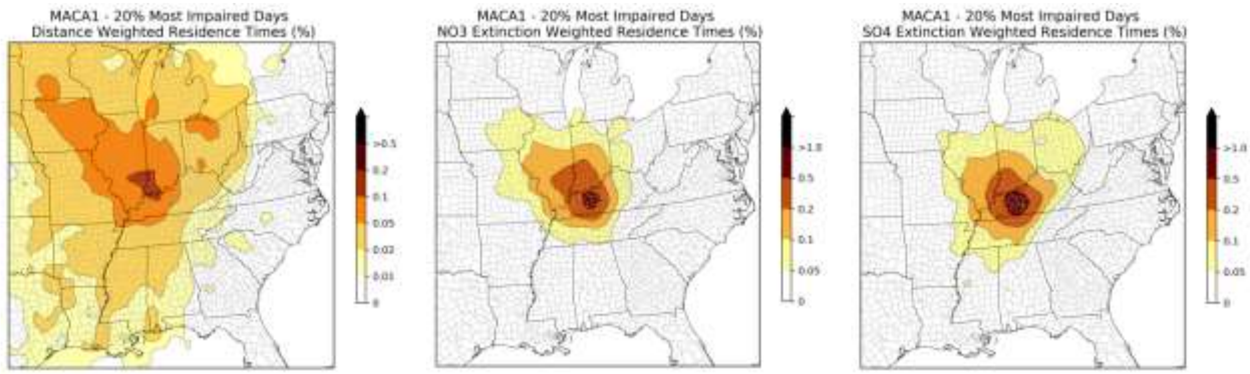
Figure III-19: Mammoth Cave WinHAZE Visualization Twenty Percent Most Impaired: 2002, 2019, and Natural Conditions[24]

3. AOI Analysis

As described in Chapter II, DEQ used the AOI analysis results produced by Ramboll for the CenSARA states to evaluate which geographic regions and sources have a high probability of contributing to anthropogenic visibility impairment at federal Class I areas within the CenSARA region and in neighboring states. Figure III-20 shows the distance-weighted residence time and pollutant-specific extinction-weighted residence times (EWRT NO_3 and EWRT SO_4) for Mammoth Cave for the most impaired days. Based on the distance-weighted residence time plot, air masses from the following states are within the 0.05% distance-weighted residence time contour for Mammoth Cave on the most impaired days: Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Ohio, Tennessee and Wisconsin. The EWRT NO_3 plot indicates that air masses coming from the following states may be impacting ammonium nitrate concentrations at Mammoth Cave on the most impaired days: Alabama, Arkansas, Illinois, Indiana, Iowa, Kentucky, Michigan, Missouri, Tennessee, and Ohio. The EWRT SO_4 plot indicates that air masses coming from the following states may be impacting ammonium sulfate concentrations at Mammoth Cave on the most impaired days: Alabama, Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Ohio, Tennessee and West Virginia. Darker areas on these plots indicate a larger influence on Mammoth Cave on the most impaired days for the examined metric.

[24] Interagency Monitoring of Protected Visual Environments. http://vista.cira.colostate.edu/Improve/winhaze/

Figure III-20: All Trajectories Distance-Weighted Residence Times, EWRT NO_3, and EWRT SO_4 for the Twenty-Percent Most Impaired Days—Mammoth Cave (Normalized Percentages)



Based on the EWRT NO_3 and EWRT SO_4 plots, air masses from Kentucky have the greatest influence on ammonium nitrate and air masses from Indiana, Kentucky, and Tennessee the plot, air masses from Indiana, Kentucky, and Tennessee have the greatest influence on ammonium sulfate at Mammoth Cave on the most impaired days. The individual sources with the highest visibility impact surrogate values for Mammoth Cave in 2016 were sources in Indiana, Kentucky, and Tennessee. Less than one percent of the inventory's visibility surrogate total for Mammoth Cave in 2016 is attributable to Arkansas sources.

Although only a small percentage of the AOI inventory's visibility surrogate table attributable to Arkansas sources, the pollutant-specific EWRT plots do extend into Arkansas. Therefore, DEQ concludes that emissions from Arkansas sources are reasonably anticipated to contribute to visibility impairment at Mammoth Cave.

C. Mingo Wilderness

The Mingo National Wildlife Refuge Wilderness Area consists of 7,730 acres of swamp, riparian areas, and Ozark Plateau uplands.[25] Mingo Wilderness supports multiple recreational activities including hiking and fishing. Figure III-21 shows two photographs that illustrate the scenic quality of the Mingo Wilderness.

[25] National Wildlife Refuge System. https://www.fws.gov/refuge/mingo/

Figure III-21: Mingo Wilderness Area[26]

1. Ambient Data Analysis

The Mingo Wilderness Area monitor is located in southeastern Missouri at latitude 36.9717 and longitude -90.1432 at an elevation of 111 meters above MSL.

Figure III-22 shows that visibility impairment has decreased over time at Mingo on the twenty percent most impaired days. In particular, light extinction on the most impaired days due to ammonium sulfate has decreased markedly since 2000. Light extinction on the most impaired days due to ammonium nitrate has fluctuated over the period between 2000 and 2018 and has surpassed ammonium sulfate in relative contribution to light extinction on the most impaired days at Mingo. In 2001, the relative impact on light extinction for the most impaired days was fifty-eight percent for ammonium sulfate and twenty-five percent for ammonium nitrate. In 2018, the relative impact on light extinction on the most impaired days was thirty percent for ammonium sulfate and forty-nine percent for ammonium nitrate. Coarse mass, elemental carbon, organic mass, sea salt, and soil have varied over time, but make up smaller fractions of the overall particulate species impairing visibility.

[26] Image Credit: https://www.fws.gov/Refuge/Mingo/wildlife_and_habitat/wilderness.html (Left) and https://www.fws.gov/refuge/Mingo/about.html (Right)

Figure III-22: Annual Extinction Composition, Most Impaired Days at Mingo, 2001–2019[27]

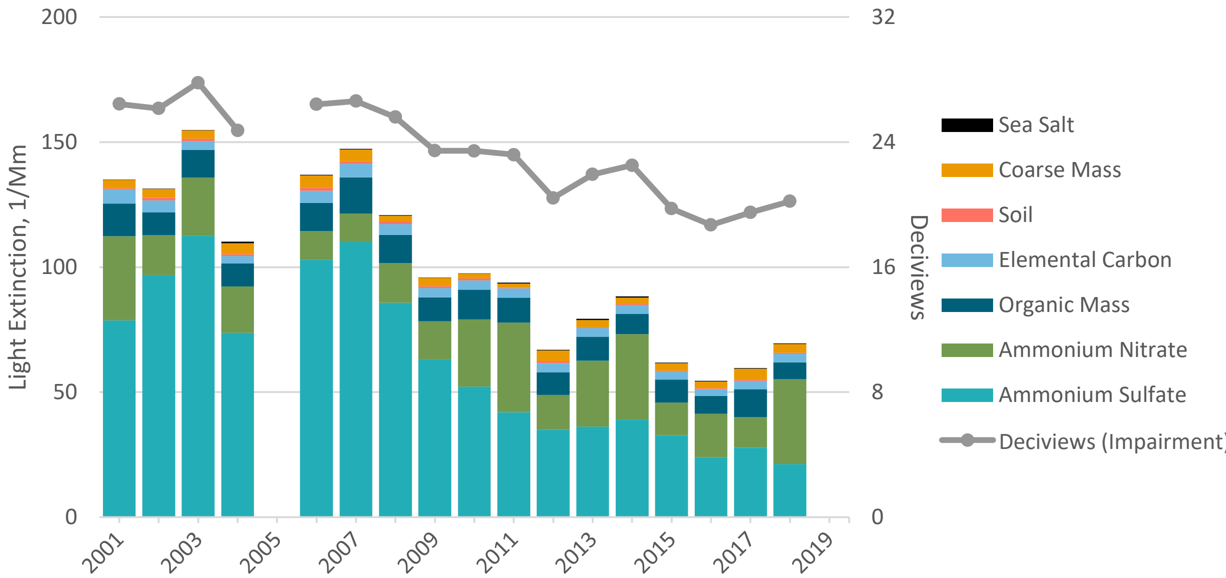
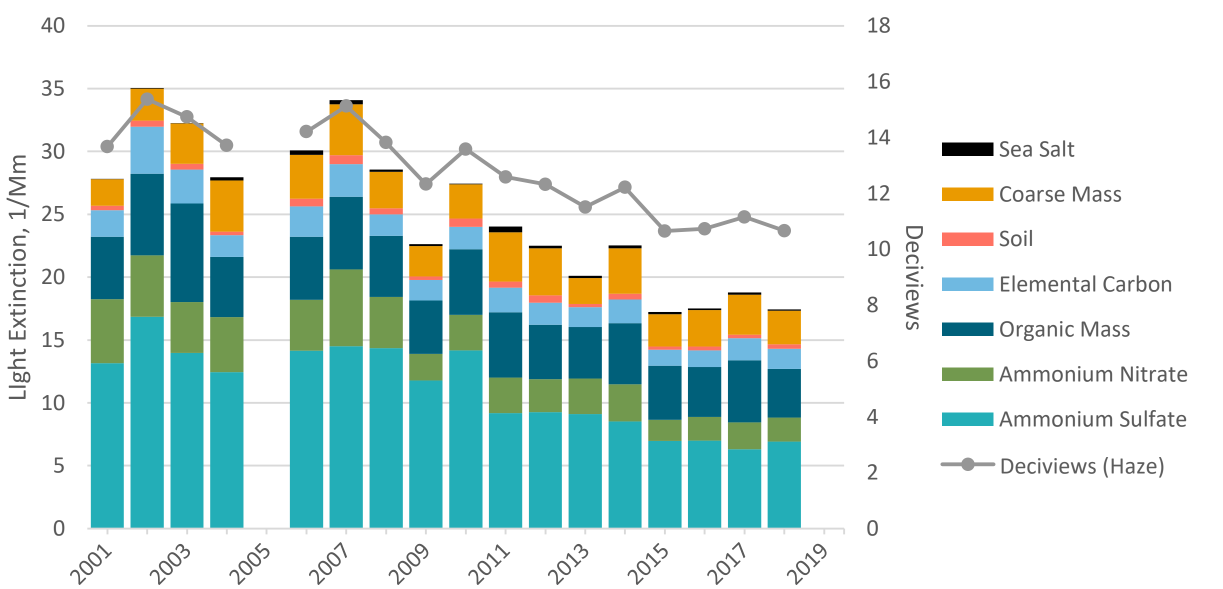


Figure III-23 shows no degradation on the twenty percent clearest days at Mingo.

Figure III-23: Annual Extinction Composition, Clearest Days at Mingo, 2001–2019[28]



[27] Data obtained from IMPROVE data file sia_impairment_group_means_12_20. There are no impairment means for 2019 for Mingo because the monitor did not meet completeness criteria.

[28] Data obtained from IMPROVE data file SIA_group_means_12_20. There are no impairment means for 2019 for Mingo because the monitor did not meet completeness criteria.

Figure III-24 shows daily haze composition due to anthropogenic sources and Figure III-25 shows daily haze composition due to natural sources on the most impaired days at Mingo in 2018.

Figure III-24: Daily Haze Composition Due to Anthropogenic Sources, Most Impaired Days at Mingo, 2018[29]

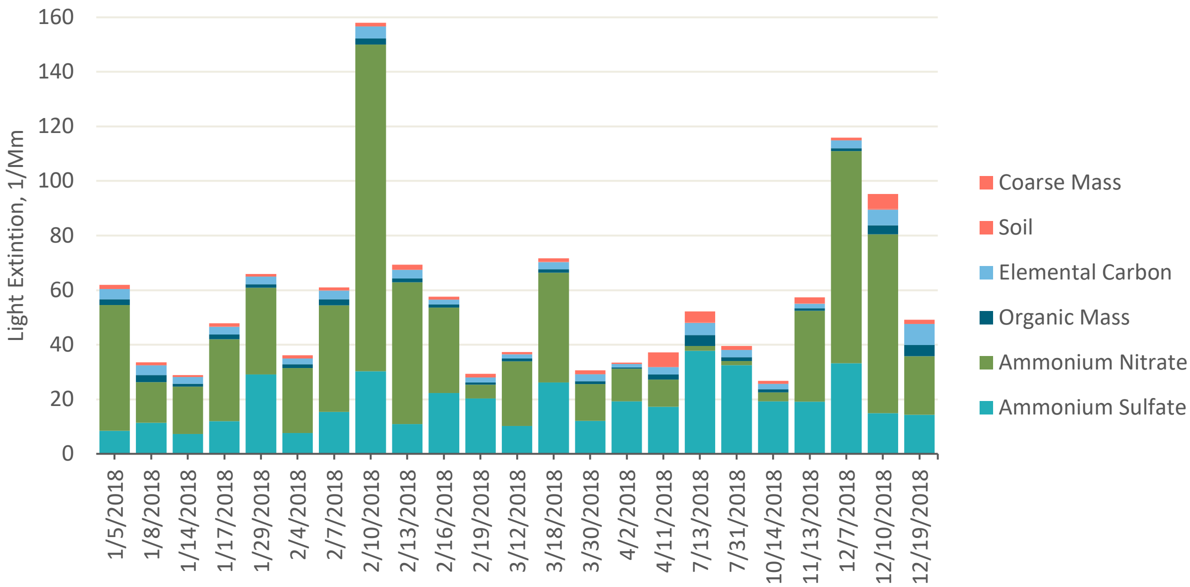
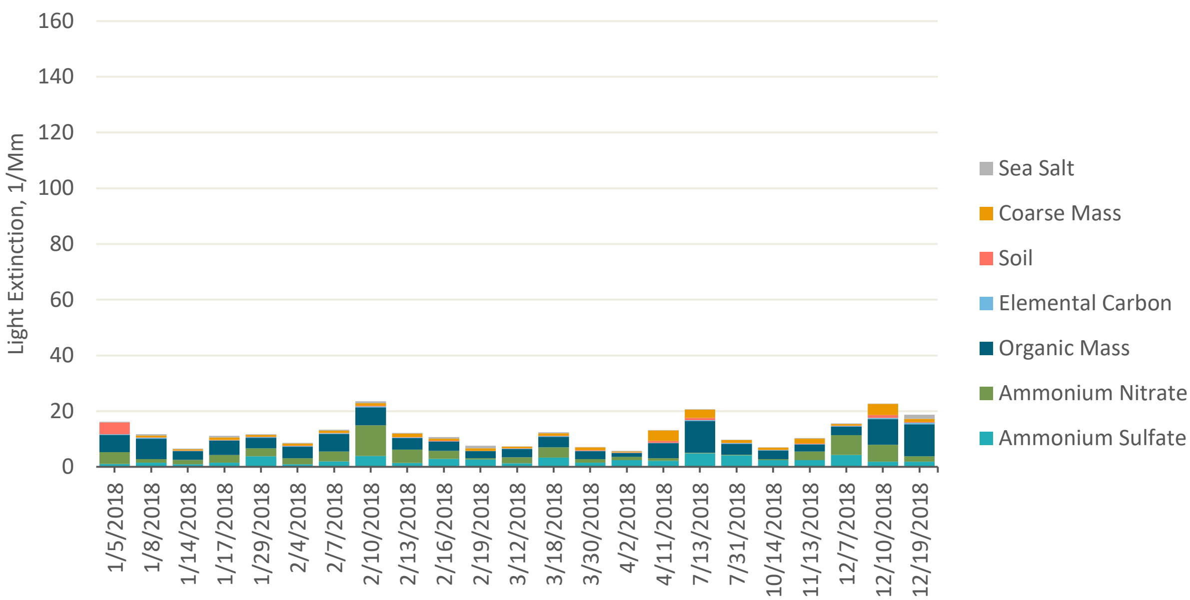


Figure III-25: Daily Haze Composition Due to Natural Sources, Most Impaired Days at Mingo, 2018[30]



[29] Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.
[30] Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.

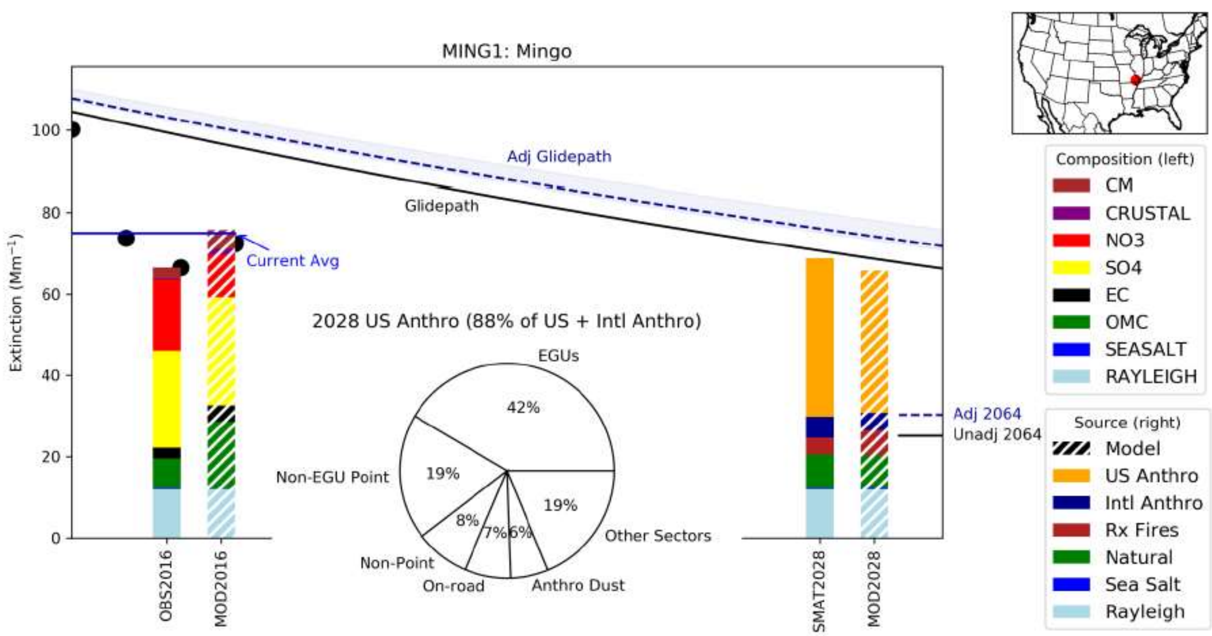
Figures III-24 and III-25 show that light extinction on the most impaired days at Mingo in 2018 from ammonium nitrate, ammonium sulfate, and elemental carbon are primarily anthropogenic in nature. Light extinction on the most impaired days at Mingo from coarse mass, organic mass, sea salt, and soil is primarily due to natural sources.

Based on these monitor data observations, strategies to reduce visibility impairment at Mingo from manmade air pollution during Planning Period II should focus on the following key pollutants: ammonium nitrate and ammonium sulfate.

2. Modeling Data Analysis

Figure III-26 illustrates for Mingo the results of EPA's modeling effort. The figure presents observed data for 2014–2017, 2028 base case projections, and possible glidepaths under different assumptions. The dashed line represents EPA's default adjusted glidepath, which was adjusted based on relative international anthropogenic model contributions and ambient natural conditions.[31] The figure also includes a pie chart representing the specific anthropogenic emissions sector contributions identified as contributing to visibility impairment at Mingo Wilderness in 2028.

Figure III-26: EPA Regional Haze Summary Plot for Mingo Wilderness[32]



[31] The different glidepaths EPA included in their summary plots are based on different 2064 endpoint adjustment assumptions.

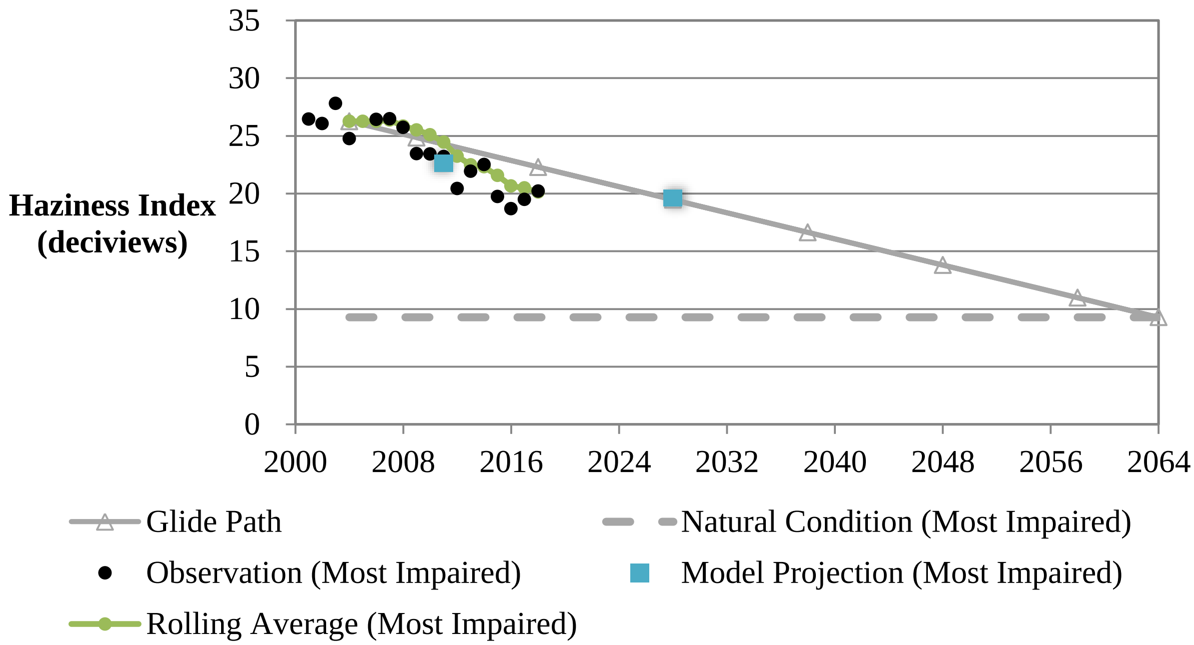
[32] EPA (2019). Updated 2028 Regional Haze Modeling Technical Support Document. https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling

Figure III-26 shows that visibility impairment on the most impaired days in 2028 is projected to remain below any glidepath that the State of Missouri may establish in their Planning Period II SIP even before consideration of additional control measures to ensure reasonable progress.

The pie chart in Figure III-26 represents specific source categories contributing to visibility impairment at Mingo in 2028 and indicates the most prominent source categories are EGUs and Non-EGU point sources, and with smaller contributions from on-road sources, non-point sources, dust, and other sectors. The source apportionment presented in the pie chart suggests that strategies to reduce visibility impairment in 2028 should focus on reducing emissions from the following source categories: EGU and non-EGU point.

Figures III-27 and III-28 illustrate the 2028 base case results for Mingo of the VISTAS modeling effort. The VISTAS modeling base case results project visibility impairment in 2028 at Mingo on the most impaired days (19.69 deciviews) to be above the unadjusted glidepath (19.48 deciviews).[33] The projected base case results for the clearest days (11.14 deciviews) show no degradation from the 2000–2004 baseline (14.29 deciviews).

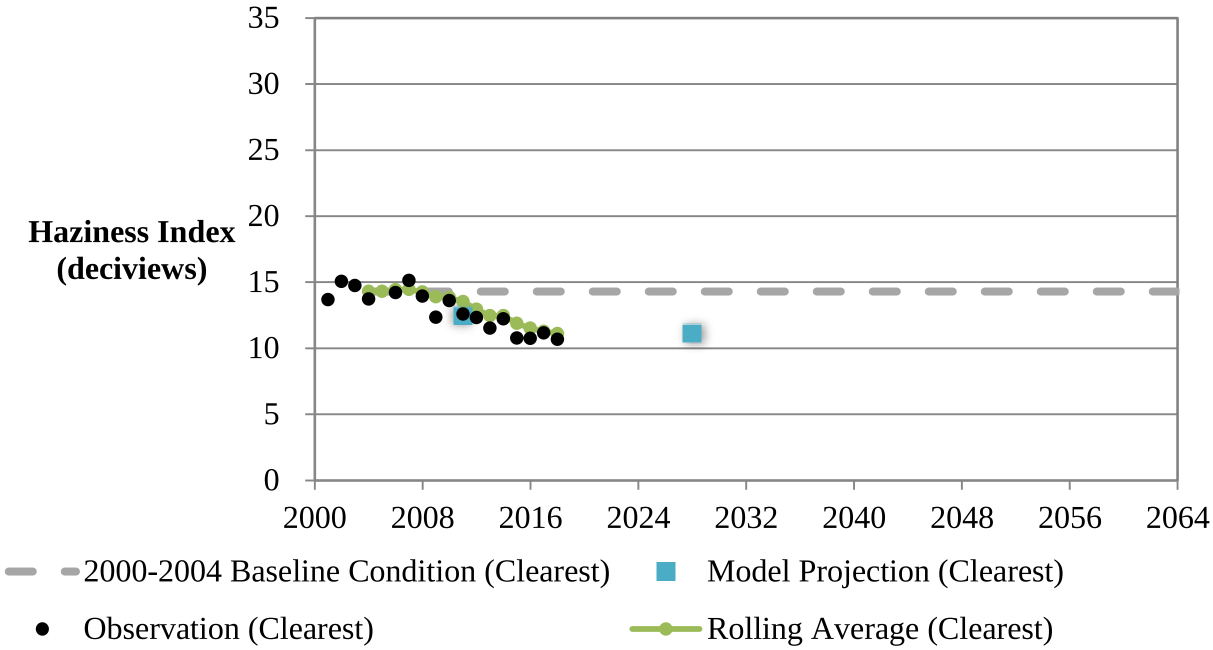
Figure III-27: VISTAS Base Case Results for Mingo Wilderness (Most Impaired Days)[34]



[33] Missouri DNR confirmed plans to use the unadjusted URP for this planning period.

[34] Model results obtained from Metro 4/SESARM: Copy of V5_GlidePath_MI20_unitDeciview_07-17-2020_jb

Figure III-28: VISTAS Base Case Results for Mingo Wilderness (Clearest Days)[35]



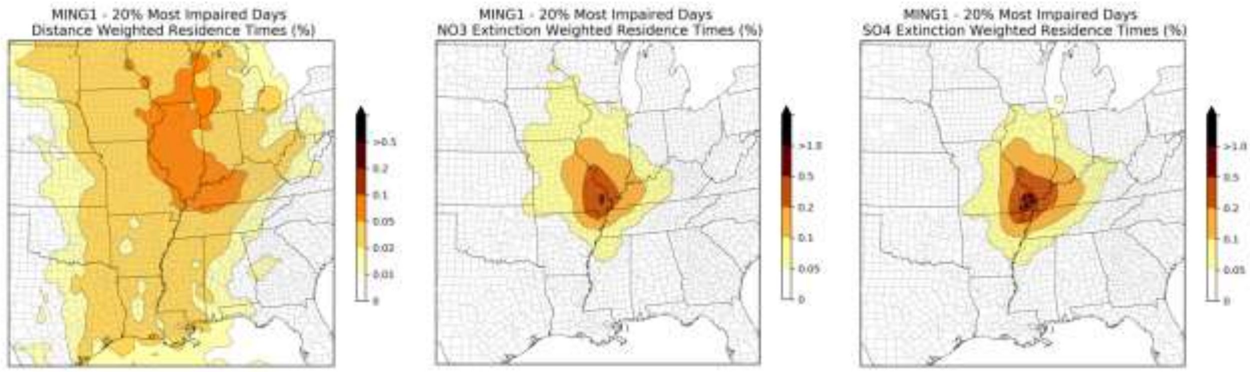
The WinHaze Tool does not include Mingo as a federal Class I area for which visibility impairment can be visualized using the tool.

3. AOI Data Analysis

As described in Chapter II, DEQ used the AOI analysis results produced by Ramboll for the CenSARA states to evaluate which geographic regions and sources have a high probability of contributing to anthropogenic visibility impairment at federal Class I areas within the CenSARA region and in neighboring states. Figure III-29 shows the distance-weighted residence time and pollutant-specific extinction-weighted residence times (EWRT NO_3 and EWRT SO_4) for Mingo for the most impaired days. Based on the distance-weighted residence time plot, air masses from the following states are within the 0.05% distance-weighted residence time contour for Mingo on the most impaired days: Illinois, Indiana, Iowa, Kentucky, Michigan, Minnesota, Missouri, Tennessee, and Wisconsin. The EWRT NO_3 plot indicates that air masses coming from the following states may be impacting ammonium nitrate concentrations at Mingo on the most impaired days: Arkansas, Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Mississippi, Missouri, Oklahoma, Tennessee, and Wisconsin. The EWRT SO_4 plot indicates that air masses coming from the following states may be impacting ammonium sulfate concentrations at Mingo on the most impaired days: Arkansas, Illinois, Indiana, Iowa, Kentucky, Mississippi, Missouri, Ohio, and Tennessee. Darker areas on these plots indicate a larger influence on Mingo on the most impaired days for the examined metric.

[35] Model results obtained from Metro 4/SESARM: Copy of V5_GlidePath_20C_unitDeciview_07-17-2020

Figure III-29: All Trajectories Distance-Weighted Residence Times, EWRT NO_3, and EWRT SO_4 for the Twenty-Percent Most Impaired Days—Mingo (Normalized Percentages)



Based on the EWRT NO_3 and EWRT SO_4 plots, air masses from Missouri have the greatest influence on ammonium nitrate and air masses from Illinois and Missouri have the greatest influence on ammonium sulfate at Mingo on the most impaired days. The individual sources with the highest visibility impact surrogate values for Mingo in 2016 were sources in Arkansas, Illinois, Indiana, Missouri, and Tennessee. Four percent of the inventory's visibility surrogate total for Mingo in 2016 is attributable to Arkansas sources.

Based on the pollutant-specific EWRT plots for the dominant pollutants and the percentage of the AOI inventory's visibility surrogate table attributable to Arkansas sources, DEQ concludes that emissions from Arkansas sources are reasonably anticipated to contribute to visibility impairment at Mingo.

D. Shining Rock

The Shining Rock federal Class I area consists of over 18,000 acres[36] on the north side of the Pisgah Ledge in the Blue Ridge Mountains in North Carolina. This wilderness supports hiking, horseback riding, and dispersed camping.[37] Figure III-30 illustrates the scenic nature of Shining Rock.

[36] 13,350 acres when originally designated

[37] https://www.fs.usda.gov/recarea/nfsnc/recarea/?recid=48260

Figure III-30: Shining Rock[38]

1. Ambient Data Analysis

The Shining Rock monitor is located at latitude 35.3937, longitude -82.774 at an elevation of 1617 meters above MSL.

Figure III-31 shows that visibility impairment decreased between 2001 and 2019 at Shining Rock on the most impaired days. Light extinction due to ammonium sulfate decreased over the same time period, while ammonium nitrate increased. In 2019, the relative impact on light extinction on the most impaired days was fifty-one percent for ammonium sulfate, nineteen percent for organic carbon, and sixteen percent for ammonium nitrate. Elemental carbon and coarse mass constituted six percent each of the light extinction budget on the most impaired days in 2019.

[38] Image Credit: National Scenic Byways Program http://www.fhwa.dot.gov/byways/photos/76067 (left) and Ken Thomas (Public Domain) obtained from https://commons.wikimedia.org/wiki/File:Cold_Mountain-27527.jpg (right)

Figure III-31: Annual Extinction Composition, Most Impaired Days at Shining Rock, 2001–2019[39]

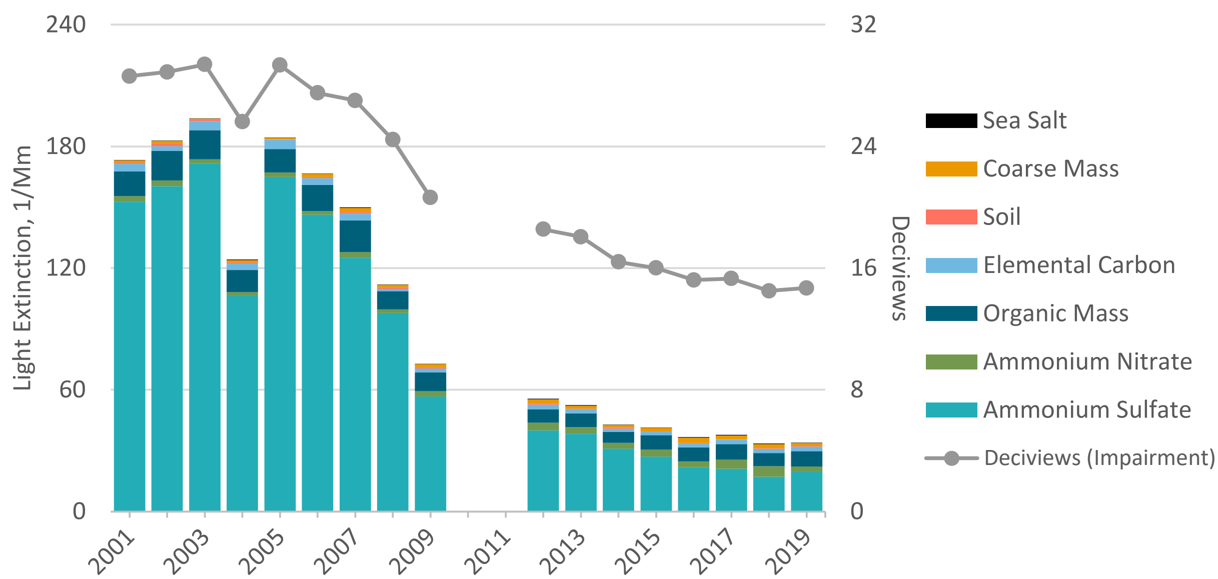
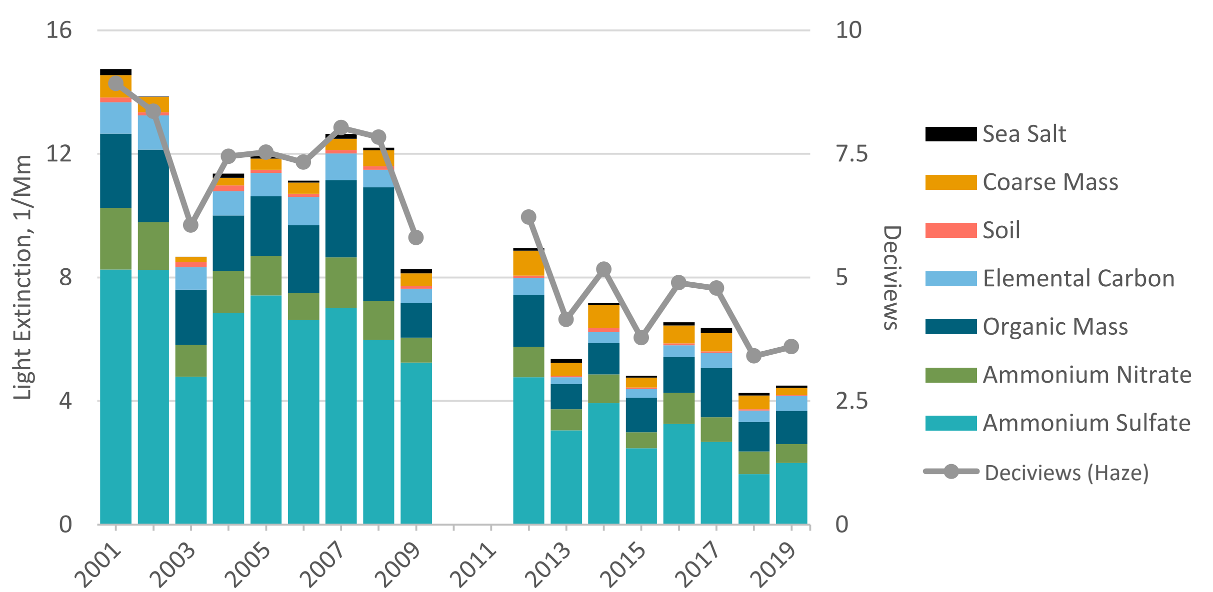


Figure III-32 shows no degradation on the clearest days at Shining Rock during the 2001 to 2019 period.

Figure III-32: Annual Extinction Composition, Clearest Days at Shining Rock, 2001–2019[40]



[39] Data obtained from IMPROVE data file sia_impairment_group_means_12_20.

[40] Data obtained from IMPROVE data file SIA_group_means_12_20.

Figure III-33 shows daily haze composition due to anthropogenic sources, and Figure III-34 shows daily haze composition due to natural sources on the most impaired days at Shining Rock in 2018.

Figure III-33: Daily Haze Composition Due to Anthropogenic Sources, Most Impaired Days at Shining Rock, 2019[41]

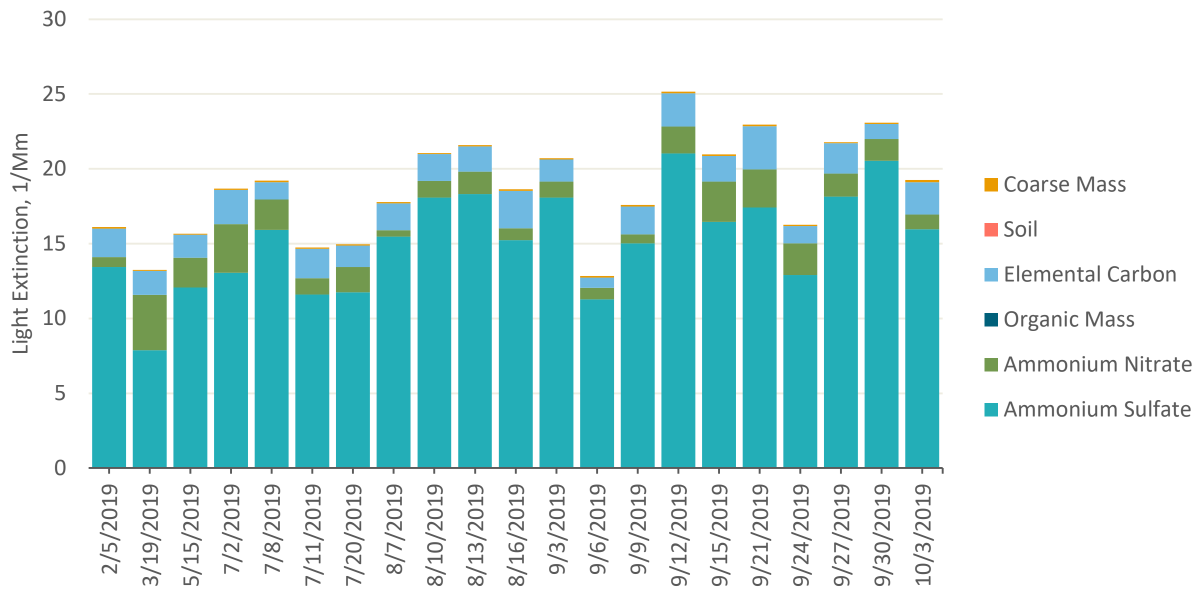
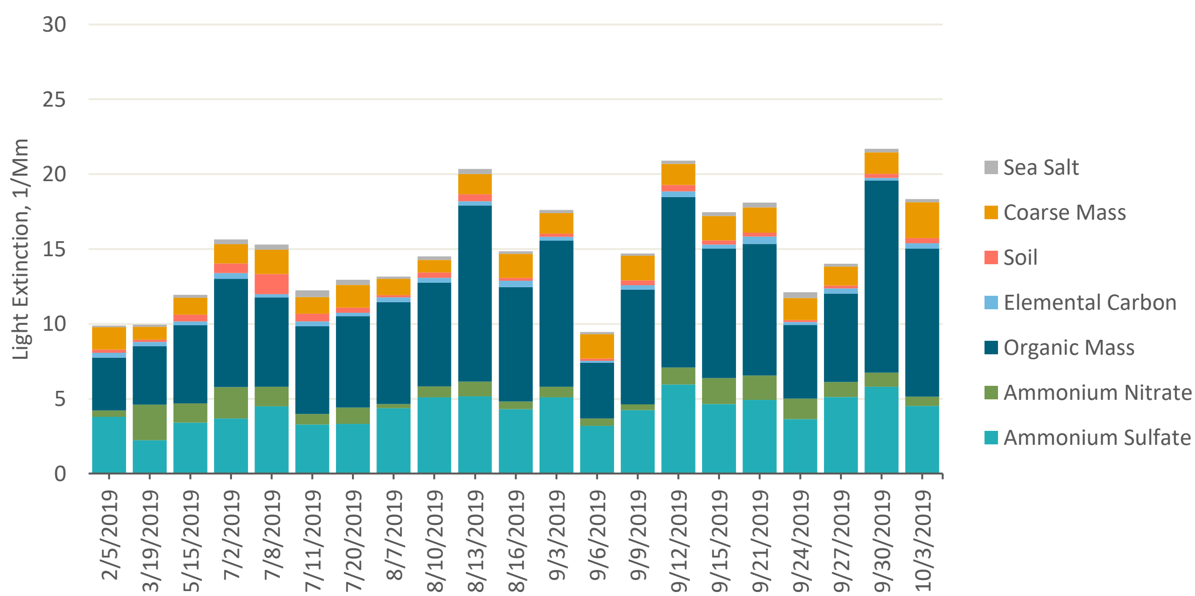


Figure III-34: Daily Haze Composition Due to Natural Sources, Most Impaired Days at Shining Rock, 2019[42]



[41] Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.

[42] Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.

Figures III-33 and III-34 show that light extinction on the most impaired days at Shining Rock from ammonium sulfate, ammonium nitrate and elemental carbon are primarily anthropogenic in nature. Impairment due to coarse mass and organic mass at Shining Rock come primarily from natural sources.

Based on these monitor data observations, strategies to reduce visibility impairment at Shining Rock from manmade air pollution during Planning Period II should focus on the following key pollutant: ammonium sulfate.

2. Modeling Data Analysis

Figure III-35 illustrates for Shining Rock the results of EPA's 2016-based CAMx modeling effort. The figure presents observed data for 2014–2017, 2028 base case projections, and possible glidepaths under different assumptions. The dashed line represents EPA's default adjusted glidepath, which was adjusted based on relative international anthropogenic model contributions and ambient natural conditions.[43] The figure also includes a pie chart representing the specific anthropogenic emissions sector contributions identified as contributing to visibility impairment Shining Rock in 2028.

Figure III-35: IMPROVE Site Summary Plot for Shining Rock

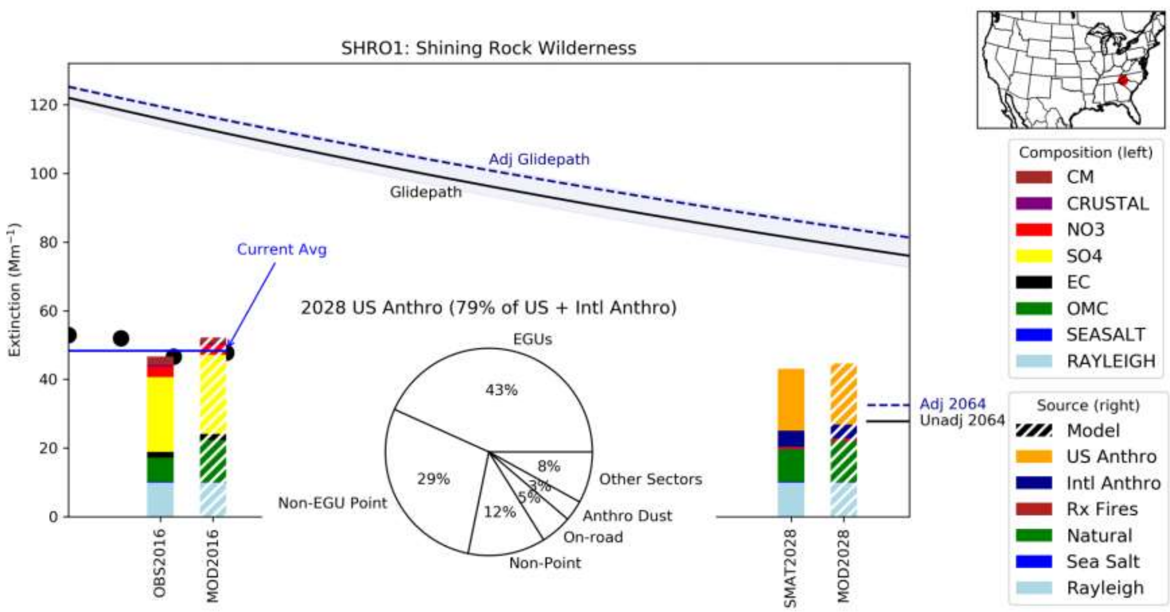


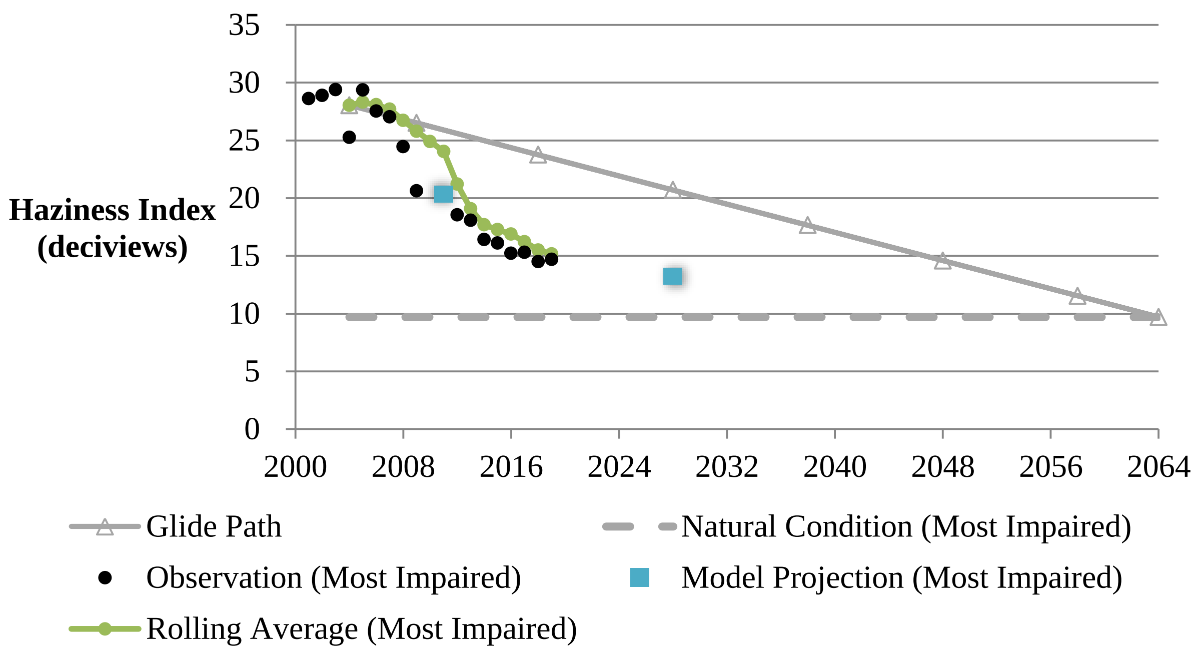
Figure III-35 shows that visibility impairment on the most impaired days in 2028 is projected to remain below any glidepath North Carolina may set for Shining Rock.

[43] The different glidepaths EPA included in their summary plots are based on different 2064 endpoint adjustment assumptions.

The pie chart shows that the largest contributors to visibility impairment in 2028 are projected to be EGUs followed by non-EGU point sources. Nonpoint, on-road, anthropogenic dust, and other sectors are projected to make up a smaller contribution to light extinction on the most impaired days at Shining Rock in 2028. The source apportionment presented in the pie chart suggests that strategies to reduce visibility impairment in 2028 should focus on reducing emissions from the following source categories: EGU and non-EGU point.

Figures III-36 and III-37 illustrate the 2028 base case results for Shining Rock of the VISTAS modeling effort. The VISTAS modeling base case results project visibility impairment in 2028 at Shining Rock on the most impaired days (13.31 deciviews) to be below the unadjusted glidepath (20.70 deciviews).[44] The projected base case results for the clearest days (4.54 deciviews) show no degradation form the 2000–2004 baseline (7.70 deciviews).

Figure III-36: VISTAS Base Case Results for Shining Rock (Most Impaired Days)[45]



[44] North Carolina Department of Environmental Quality confirmed plans to use 20.98 deciviews for the 2028 URP for Shining Rock based on the updated natural conditions value for most impaired days that is in the 2020 EPA memo (Recommendation for the Use of Patched and Substituted Data and Clarification of Data Completeness for Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program). In that data update, the natural conditions/endpoint for Shining Rock changed to 20.98 deciviews from the prior value of 20.70 deciviews, which shifted the glidepath accordingly.

[45] Model results obtained from Metro 4/SESARM: Copy of V5_GlidePath_MI20_unitDeciview_07-17-2020_jb

Figure III-37: VISTAS Base Case Modeling Results for Shining Rock (Clearest Days)[46]

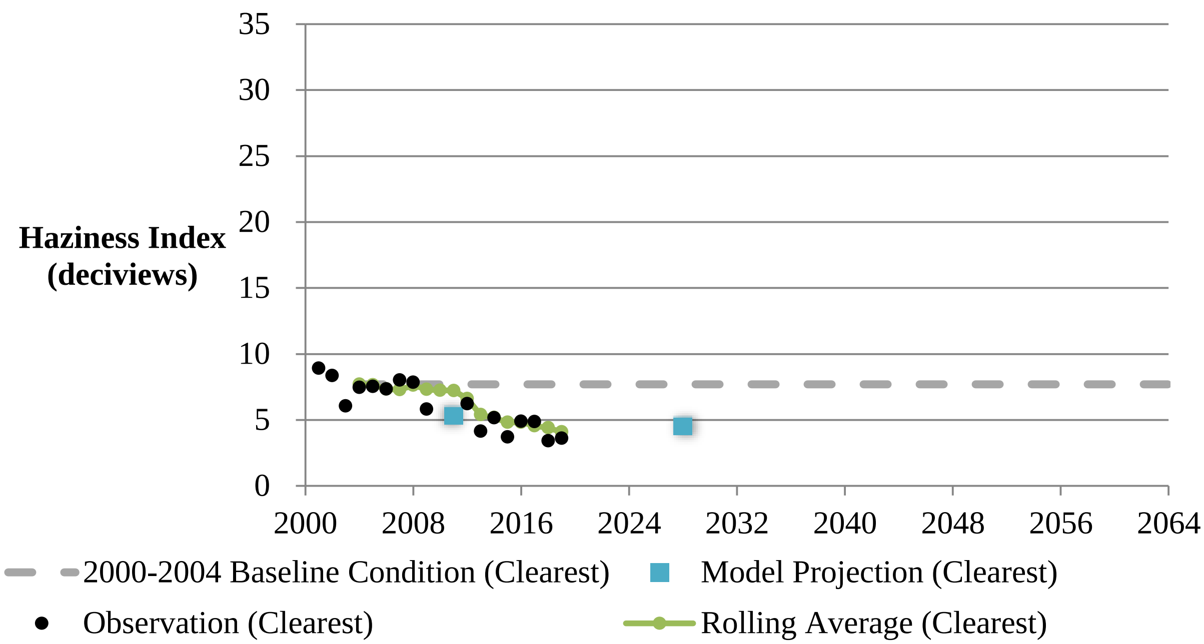


Figure III-38 shows how a vista at Shining Rock would look during the most impaired days in 2002 (left), 2017 (center), and under natural conditions.

Figure III-38: Shining Rock WinHAZE Visualization Twenty Percent Most Impaired: 2002, 2017, and Natural Conditions[47]

3. AOI Analysis

Shining Rock was not included in the CenSARA AOI analysis.

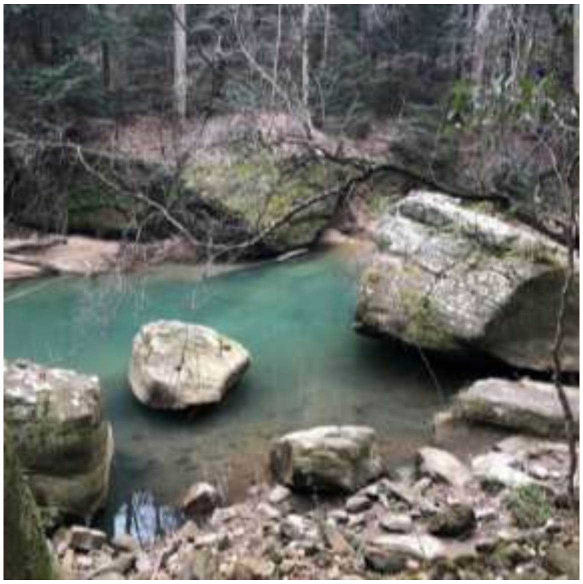
[46] Model results obtained from Metro 4/SESARM: Copy of V5_GlidePath_20C_unitDeciview_07-17-2020

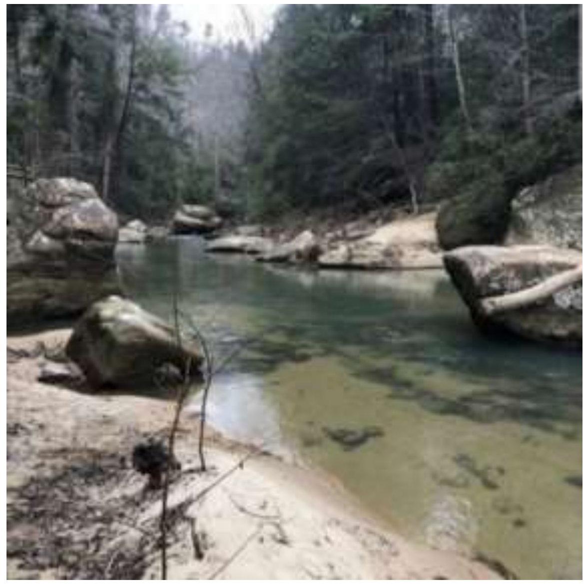
[47] Interagency Monitoring of Protected Visual Environments. http://vista.cira.colostate.edu/Improve/winhaze/

E. Sipsey

The Sipsey Wilderness federal Class I area consists of 12,646 acres in the Bankhead National Forest. Sipsey Wilderness Area offers a number of recreational activities including hiking, camping, hunting, horseback riding, and fishing.[48] Figure III-3 illustrates the scenic nature of the Sipsey Wilderness Area.

Figure III-39: Sipsey Wilderness Area [49]





1. Ambient Data Analysis

The Sipsey Wilderness Area monitor is located four miles north of Grayson Alabama at latitude 34.3433, longitude -87.3388, at an elevation of 286 meters above MSL.

Figure III-40 shows that visibility impairment on the most impaired days has decreased at Sipsey. During this period, light extinction due to ammonium sulfate decreased dramatically. Organic mass and elemental carbon, which make up a relatively small portion of the haze budget during the 2000–2019 period also decreased. Light extinction due to ammonium nitrate increased over this period. In 2019, the relative impact on light extinction on the most impaired days was fifty percent for ammonium sulfate, fourteen percent for ammonium nitrate, twenty-three percent for organic carbon, and eight percent for elemental carbon.

[48] https://www.fs.usda.gov/detail/alabama/about-forest/districts/?cid=fsbdev3_002553

[49] Image Credit: Tricia Treece (both left and right)

Figure III-40: Annual Extinction Composition, Most Impaired Days at Sipsey, 2001–2019[50]

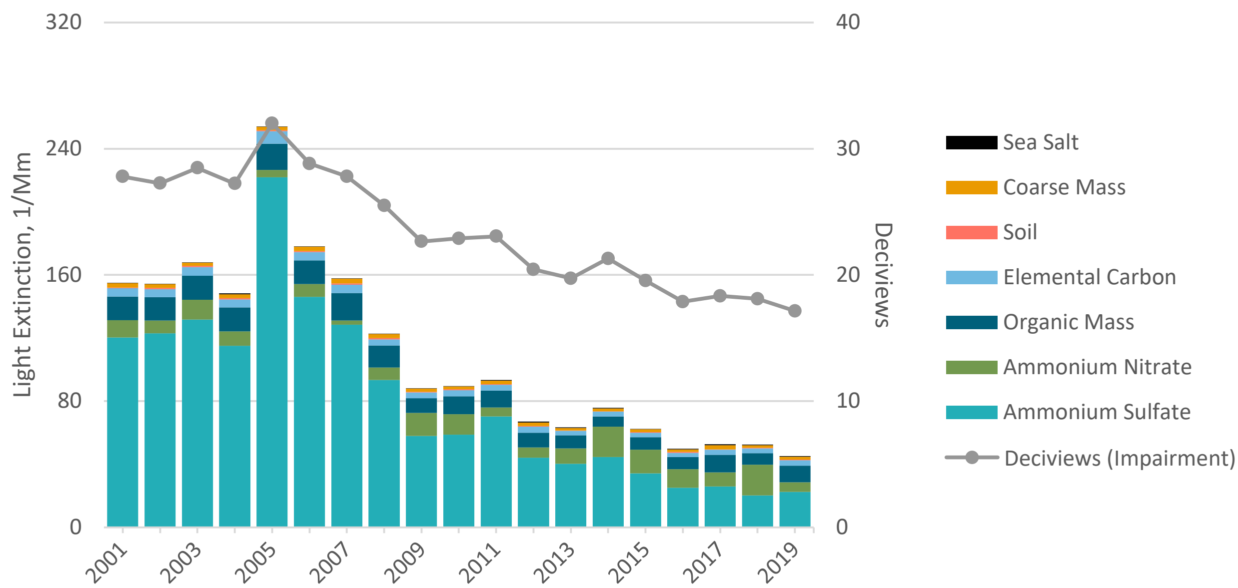


Figure III-41 shows no degradation in visibility on the clearest days at Sipsey. Ammonium nitrate and ammonium sulfate light extinction decreased on the clearest days.

Figure III-41: Annual Extinction Composition, Clearest Days at Sipsey, 2001–2019[51]

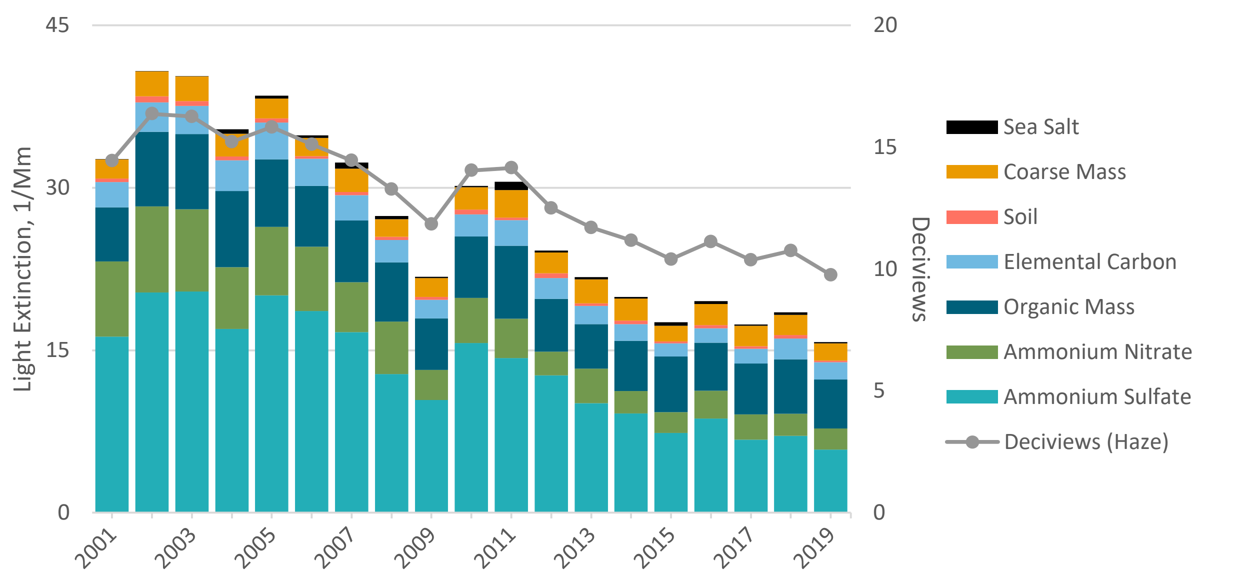


Figure III-42 shows daily haze composition due to anthropogenic sources and Figure III-43

[50] Data obtained from IMPROVE data file sia_impairment_group_means_12_20.
[51] Data obtained from IMPROVE data file SIA_group_means_12_20.

shows daily haze composition due to natural sources on the most impaired days at Sipsey in 2019.

Figure III-42: Daily Haze Composition Due to Anthropogenic Sources, Most Impaired Days at Sipsey, 2019[52]

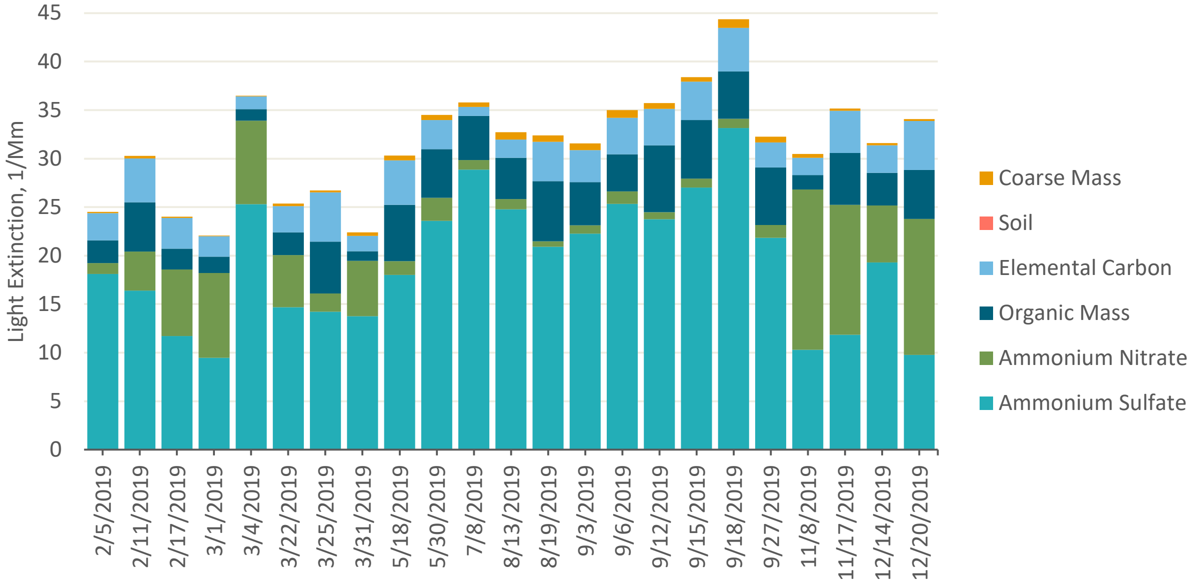
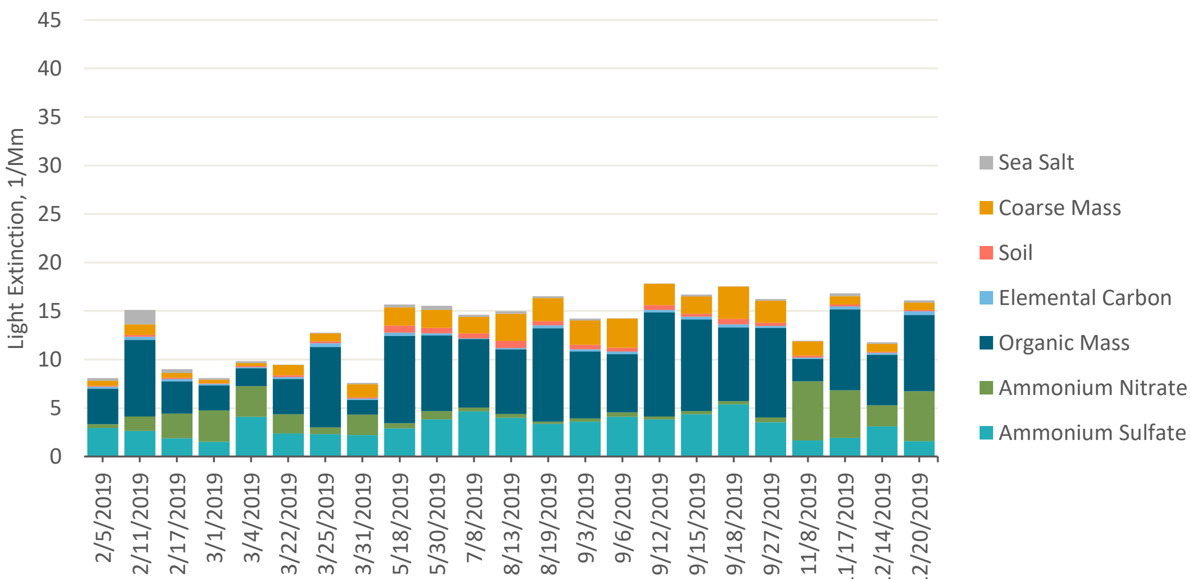


Figure III-43: Daily Haze Composition Due to Natural Sources, Most Impaired Days at Sipsey, 2019[53]



52 Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.

53 Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.

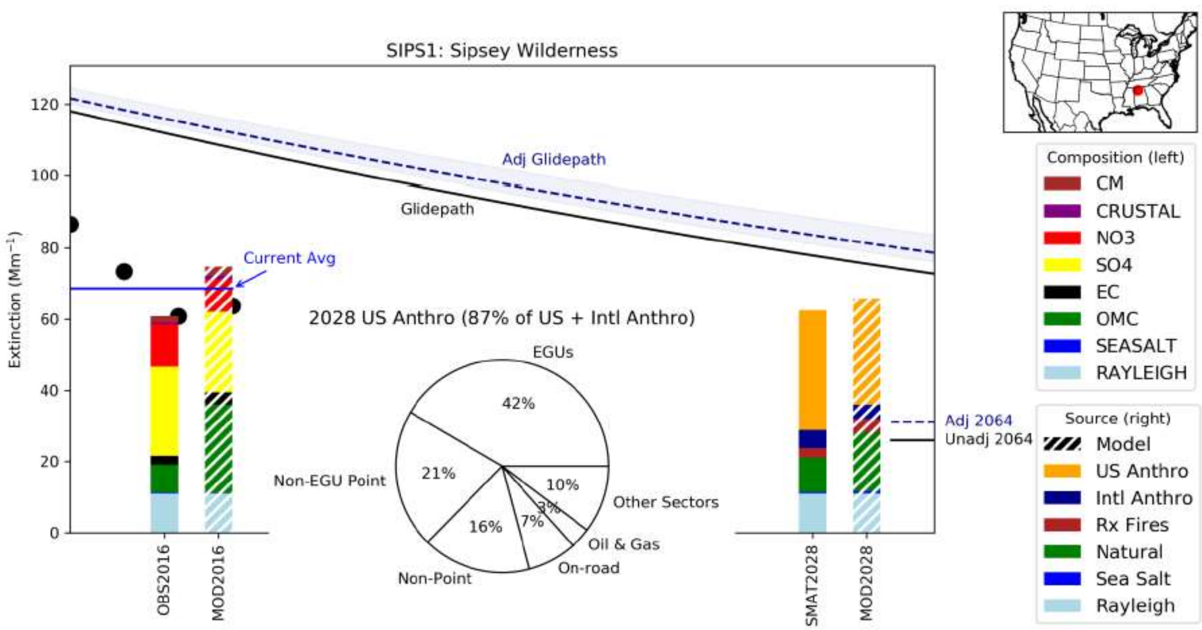
Figures III-43 and III-44 show that light extinction at Sipsey on the most impaired days from ammonium sulfate, ammonium nitrate, and elemental carbon are primarily anthropogenic in nature. Extinction due to natural and anthropogenic organic mass are similar with natural sources contributing more to light extinction than anthropogenic sources. Sea salt, soil, and coarse mass are primarily due to natural sources. On the most impaired days, ammonium sulfate is the predominant species in the summer.

Based on these monitoring data observations, strategies to reduce visibility impairment at Sipsey from manmade air pollution during Planning Period II should focus on the following key pollutant: ammonium sulfate.

2. Modeling Data Analysis

Figure III-44 illustrates for Sipsey the results of EPA's modeling effort. The figure presents observed data for 2014–2017, 2028 base case projections, and possible glidepaths under different assumptions. The dashed line represents EPA's default adjusted glidepath, which was adjusted based on relative international anthropogenic model contributions and ambient natural conditions.[54] The figure also includes a pie chart representing the specific anthropogenic emissions sector contributions identified as contributing to visibility impairment at Sipsey in 2028.

Figure III-44: IMPROVE Site Summary Plot for Sipsey



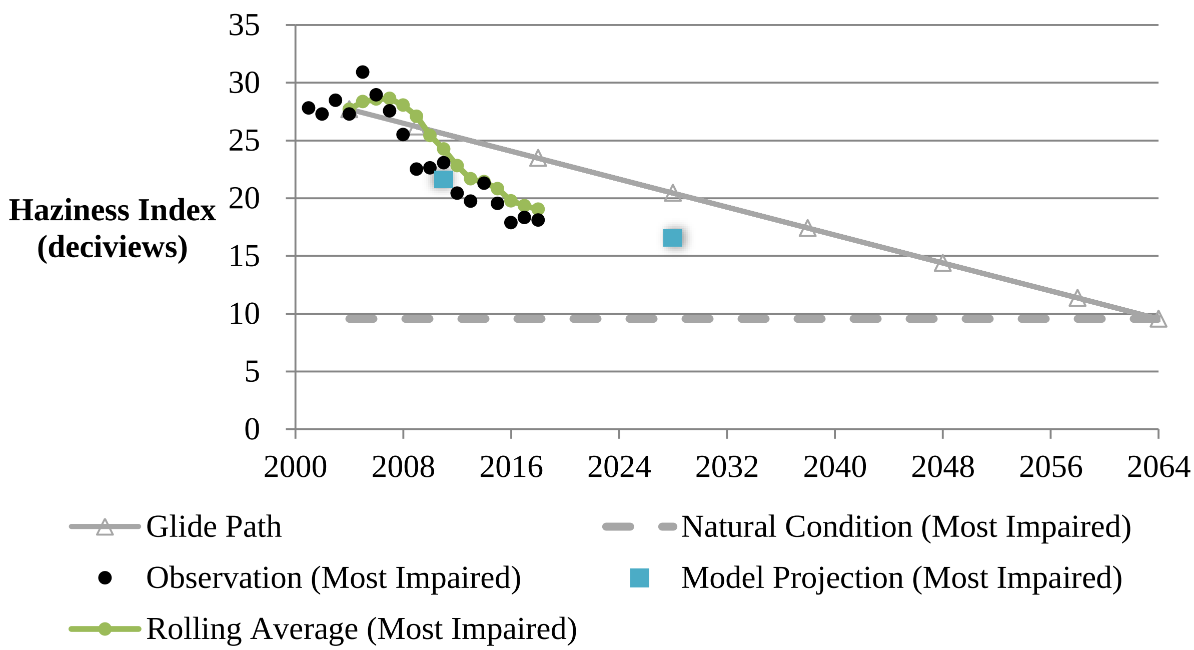
[54] The different glidepaths EPA included in their summary plots are based on different 2064 endpoint adjustment assumptions.

Figure III-44 shows that visibility impairment on the most impaired days in 2028 is projected to remain below any glidepath that the State Alabama may establish in their Planning Period II SIP even before consideration of additional control measures to ensure reasonable progress.

The pie chart represents specific source categories projected to contribute to visibility impairment at Sipsey on the most impaired days in 2028 and indicates that the most prominent source categories are EGUs and non-EGU point sources, with smaller contributions from non-point sources, on-road sources, other sectors, and oil and gas. The source apportionment presented in the pie chart suggests that strategies to reduce visibility impairment in 2028 should focus on reducing emissions from the following source categories: EGU and non-EGU point.

Figures III-45 and III-46 illustrate the 2028 base case results for Sipsey of the VISTAS modeling effort. The VISTAS modeling base case results project visibility impairment in 2028 at Sipsey on the most impaired days (16.62 deciviews) to be below the unadjusted glidepath (20.44 deciviews).[55] The projected base case results for the clearest days (11.11 deciviews) show no degradation from the 2000–2004 baseline (15.57 deciviews).

Figure III-45: VISTAS Base Case Results for Sipsey Wilderness (Most Impaired Days)[56]



[55] Alabama Department of Environmental Management confirmed plans to use the unadjusted URP for this planning period.

[56] Model results obtained from Metro 4/SESARM: Copy of V5_GlidePath_MI20_unitDeciview_07-17-2020_jb

Figure III-46: VISTAS Base Case Results for Sipsey Wilderness (20% Clearest Days)[57]

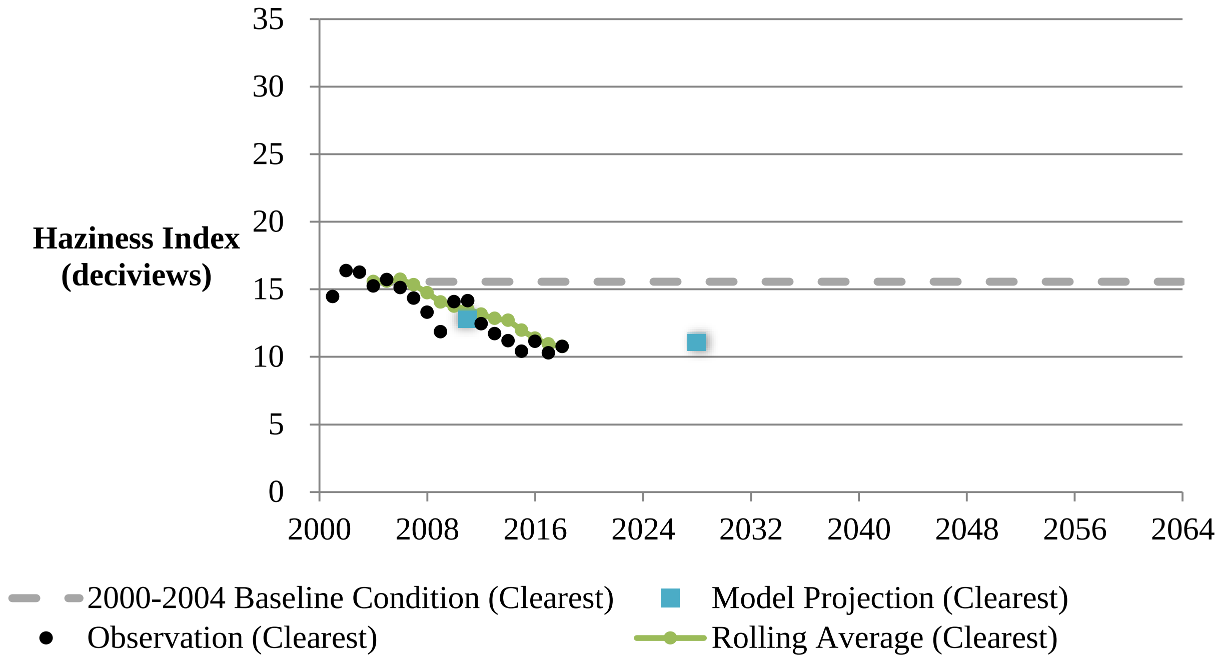


Figure III-47 shows how a vista at Sipsey would look during the most impaired days in 2001 (left), 2019 (center), and under natural conditions (right). The improvement between the center image and the left image shows how the visibility has improved over time on the most impaired days. The image on the right visualizes natural conditions for the area.

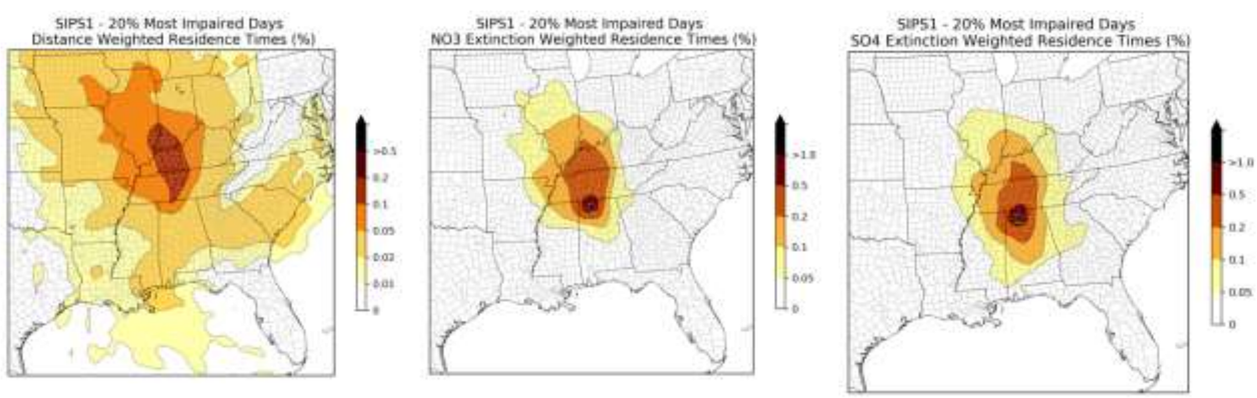
Figure III-47: Sipsey WinHAZE Visualization Twenty Percent Most Impaired: 2001, 2019, and Natural Conditions[58]

[57] Model results obtained from Metro 4/SESARM: Copy of V5_GlidePath_20C_unitDeciview_07-17-2020
[58] Interagency Monitoring of Protected Visual Environments. http://vista.cira.colostate.edu/Improve/winhaze/

3. AOI Analysis

As described in Chapter II, DEQ used the AOI analysis results produced by Ramboll for the CenSARA states to evaluate which geographic regions and sources have a high probability of contributing to anthropogenic visibility impairment at federal Class I areas within the CenSARA region and in neighboring states. Figure III-48 shows the distance-weighted residence time and pollutant-specific extinction-weighted residence times (EWRT NO_3 and EWRT SO_4) for Sipsey for the most impaired days. Based on the distance-weighted residence time plot, air masses from the following states are within the 0.05% distance-weighted residence time contour for Sipsey on the most impaired days: Alabama, Arkansas, Illinois, Indiana, Iowa, Kentucky, Mississippi, Missouri, Ohio, Tennessee, and Wisconsin. The EWRT NO_3 plot indicates that air masses coming from the following states may be impacting ammonium nitrate concentrations at Sipsey on the most impaired days: Alabama, Arkansas, Georgia, Indiana, Illinois, Iowa, Kentucky, Mississippi, Missouri, and Tennessee. The EWRT SO_4 plot indicates that air masses coming from the following states may be impacting ammonium sulfate concentrations at Sipsey on the most impaired days: Alabama, Arkansas, Georgia, Illinois, Indiana, Kentucky, Mississippi, Missouri, North Carolina, Ohio, and Tennessee. Darker areas on these plots indicate a larger influence on Sipsey on the most impaired days for the examined metric.

Figure III-48: All Trajectories Distance-Weighted Residence Times, EWRT NO_3, and EWRT SO_4 for the Twenty-Percent Most Impaired Days—Sipsey (Normalized Percentages)



Based on the EWRT NO_3 and EWRT SO_4 plots, air masses from northern Alabama and southern Tennessee have the greatest influence on ammonium nitrate and ammonium sulfate at Sipsey on the most impaired days. The individual sources with the highest visibility impact surrogate values for Sipsey in 2016 were sources in Alabama, Illinois, Indiana, Kentucky, Missouri, and Tennessee. Two percent of the inventory's visibility surrogate total for Sipsey in 2016 is attributable to Arkansas sources.

Although only a small percentage of the AOI inventory's visibility surrogate table attributable to Arkansas sources, the pollutant-specific EWRT plots do extend into Arkansas. Therefore, DEQ concludes that emissions from Arkansas sources are reasonably anticipated to contribute to visibility impairment at Sipsey.

F. Wichita Mountains

The Wichita Mountains federal Class I area consists of 8,900 acres of canyons and grasslands. Wichita Mountains serves as a wildlife refuge to preserve bison. The southern portion of the wilderness is open to the public and provides recreational opportunities including hiking, rock climbing, hunting, and camping.[59] Figure III-49 illustrates the scenic nature of the Wichita Mountains.

Figure III-49: Wichita Mountains[60]

1. Ambient Data Analysis

The Wichita Mountains monitor is located at latitude 34.7323, longitude -98.713, at an elevation of 509 meters above MSL.

Figure III-50 shows that visibility impairment decreased between 2002 and 2019 at Wichita Mountains on the twenty percent most impaired days. Light extinction due to ammonium sulfate decreased over this period. In 2019, the relative impact on light extinction on the most impaired days was thirty-seven percent for ammonium sulfate and thirty-six percent for ammonium nitrate. Coarse mass, elemental carbon, organic mass, sea salt, and soil make up smaller fractions of the overall particulate species impairing visibility on the most impaired days.

[59] https://wilderness.net/visit-wilderness/?ID=650#trip-planning

[60] https://wilderness.net/visit-wilderness/image-search-results.php?w:650#4206-Modal (left) http://www.wilderness.net/images/NWPS/lib/small/03RobWood041315.jpg (right)

Figure III-50: Annual Extinction Composition, Most Impaired Days at Wichita Mountains, 2002–2019[61]

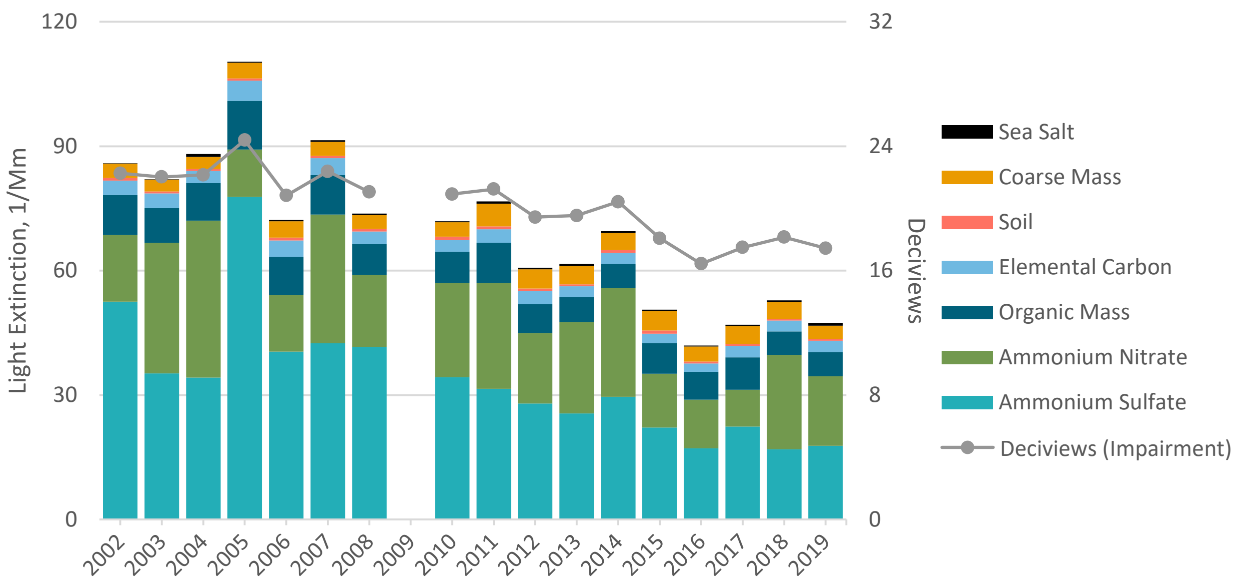
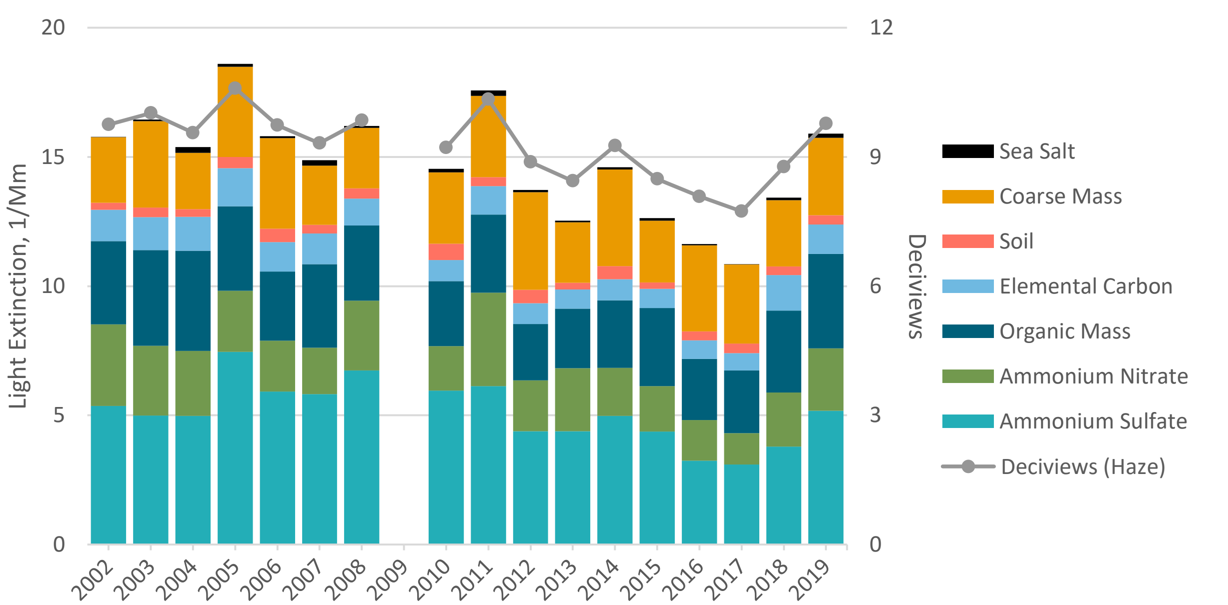


Figure III-51 shows no degradation on the clearest days at Wichita Mountains during the 2002 to 2019 period.

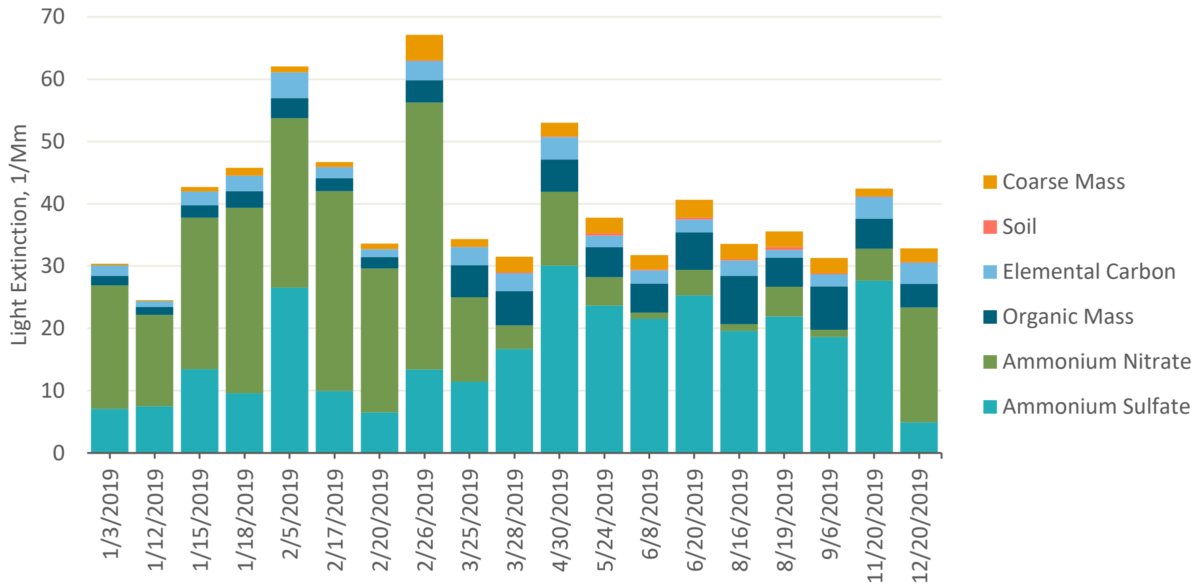
Figure III-51: Annual Extinction Composition, Clearest Days at Wichita Mountains, 2002–2019[62]



[61] Data obtained from IMPROVE data file sia_impairment_group_means_12_20.
[62] Data obtained from IMPROVE data file SIA_group_means_12_20.

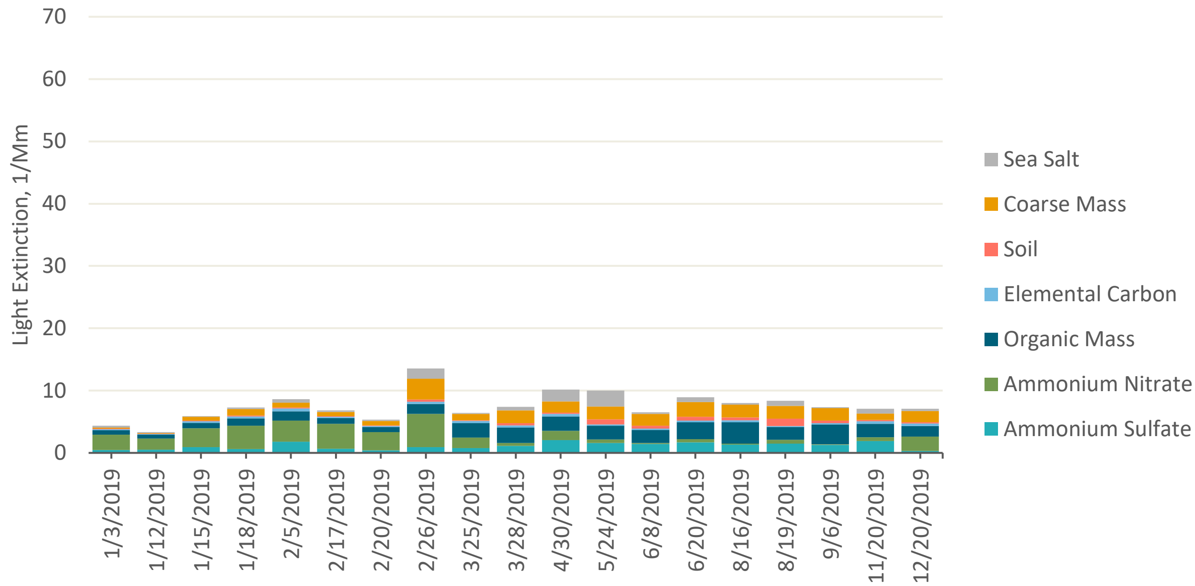
Figure III-52 shows daily haze composition due to anthropogenic sources and Figure III-53 shows daily haze composition due to natural sources on the most impaired days at Wichita Mountains in 2018.

Figure III-52: Daily Haze Composition Due to Anthropogenic Sources, Most Impaired Days at Wichita Mountains, 2019[63]



[63] Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.

Figure III-53: Daily Haze Composition Due to Natural Sources, Most Impaired Days at Wichita Mountains, 2019[64]



Figures III-52 and III-53 show that light extinction on the most impaired days at Wichita Mountains from ammonium sulfate, ammonium nitrate, elemental carbon, and organic mass are primarily anthropogenic in nature. Light extinction due anthropogenic sources and natural sources of coarse mass is similar. Light extinction due to ammonium nitrates is more pronounced in the cooler months.

Based on these monitor data observations, strategies to reduce visibility impairment at Wichita Mountains from manmade air pollution during Planning Period II should focus on the following key pollutants: ammonium nitrate and ammonium sulfate.

2. Modeling Data Analysis

Figure III-54 illustrates for Wichita Mountains the results of EPA's modeling effort. The figure presents observed data for 2014–2017, 2028 base case projections, and possible glidepaths under different assumptions. The dashed line represents EPA's default adjusted glidepath, which was adjusted based on relative international anthropogenic model contributions and ambient natural conditions.[65] The figure also includes a pie chart representing the specific anthropogenic emissions sector contributions identified as contributing to visibility impairment at Wichita Mountains in 2028.

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[64] Data obtained from IMPROVE data file sia_impairment_daily_budgets_12_20.

[65] The different glidepaths EPA included in their summary plots are based on different 2064 endpoint adjustment assumptions.

Figure III-54: IMPROVE Site Summary Plot for Wichita Mountains

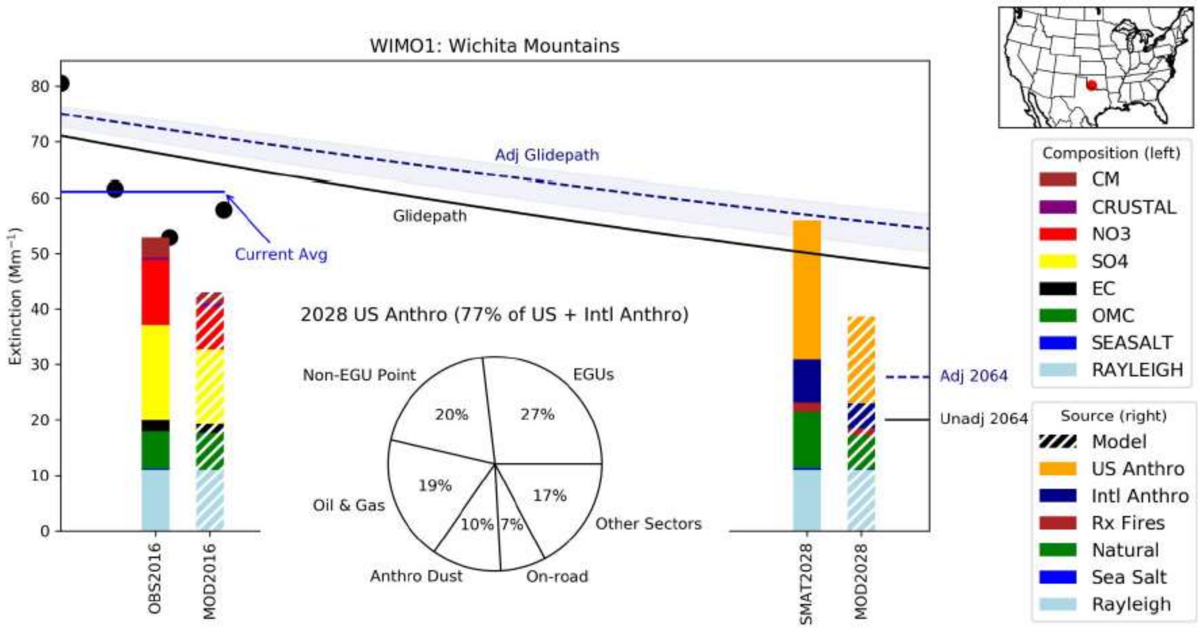


Figure III-54 shows that visibility impairment on the most impaired days in 2028 is projected to remain below some glidepaths that the State of Oklahoma may establish in their Planning Period II SIP even before consideration of additional control measures to ensure reasonable progress. The projected 2028 visibility impairment calculated using the SMAT software is above the unadjusted glidepath and some of the adjusted glidepath options. The absolute 2028 modeled impairment (MOD2028) is below all of glidepaths.

The pie chart shows that the largest contributors to visibility impairment in 2028 are projected to be EGUs, non-EGU point sources, oil and gas, and other sectors. Anthropogenic dust and on-road sources make up smaller fractions of the projected contribution to light extinction in 2028 at Wichita Mountains. The source apportionment presented in the pie chart suggests that strategies to reduce visibility impairment in 2028 should focus on reducing emissions from the following source categories: EGU, non-EGU point, and oil and gas.

Figures III-55 and III-56 illustrate the 2028 base case results for Wichita Mountains of the VISTAS modeling effort. The VISTAS modeling base case results project visibility impairment in 2028 at Wichita Mountains on the most impaired days (18.10 deciviews) to be above the unadjusted glidepath (16.06 deciviews). Based on consultation between DEQ and Oklahoma DEQ, DEQ understands that Oklahoma DEQ intends to adjust the URP glidepath consistent with EPA guidance. In 2028, the adjusted URP value for Wichita Mountains is 17.36 deciviews. The projected base case 2028 results for the clearest days (8.56 deciviews) show no degradation from the 2000–2004 baseline (9.78 deciviews).

Figure III-55: VISTAS Base Case Results for Wichita Mountains (Most Impaired Days)[66]

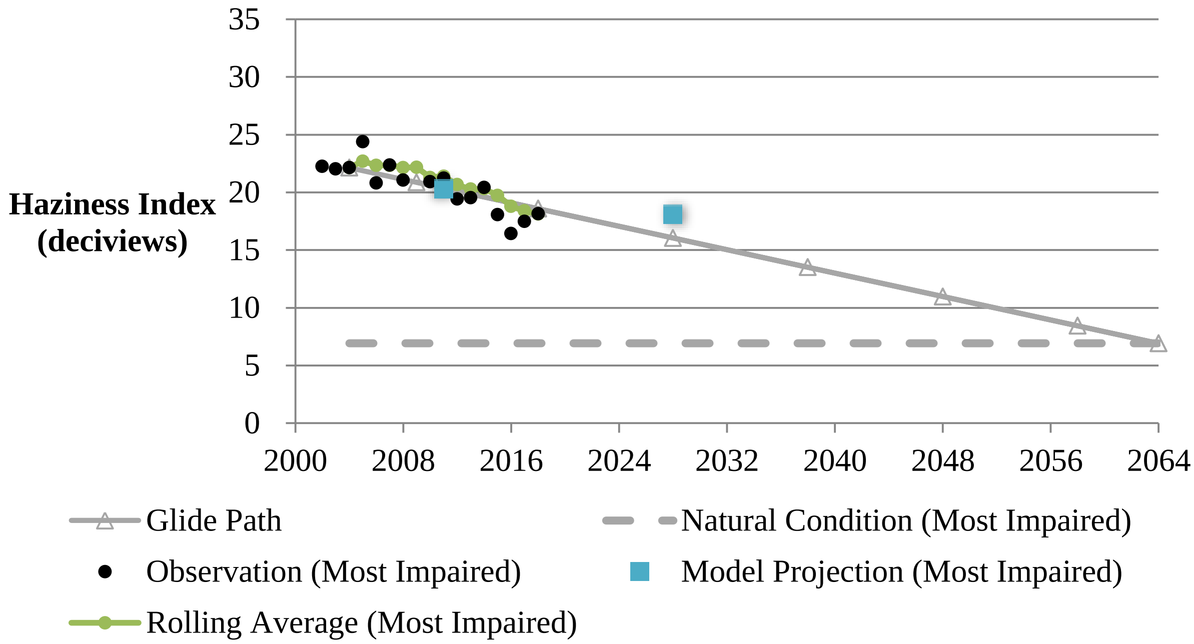


Figure III-56: VISTAS Base Case Results for Wichita Mountains (Clearest Days)[67]

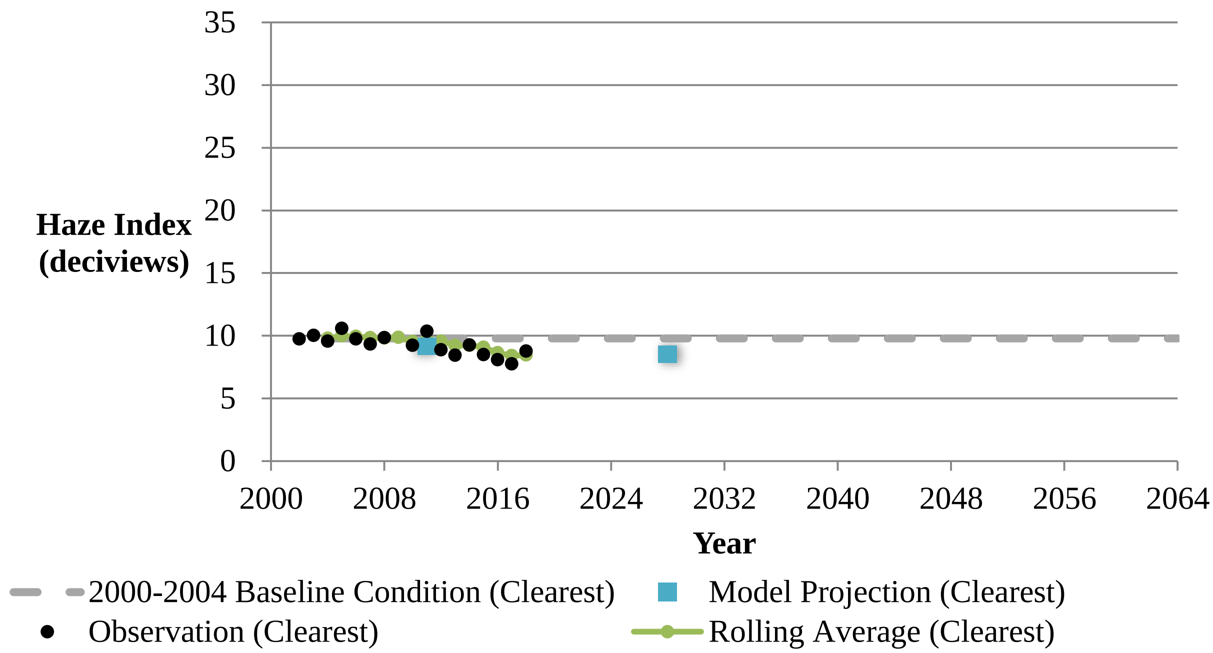


Figure III-57 shows how a vista at Wichita Mountains would look during the most impaired days in 2002 (left), 2019 (center), and under natural conditions (right). The improvement between the

[66] Model results obtained from Metro 4/SESARM: Copy of V5_GlidePath_MI20_unitDeciview_07-17-2020_jb
[67] Model results obtained from Metro 4/SESARM: Copy of V5_GlidePath_20C_unitDeciview_07-17-2020

center image and the left image shows how the visibility has improved over time on the most impaired days. The image on the right visualizes natural conditions for the area.

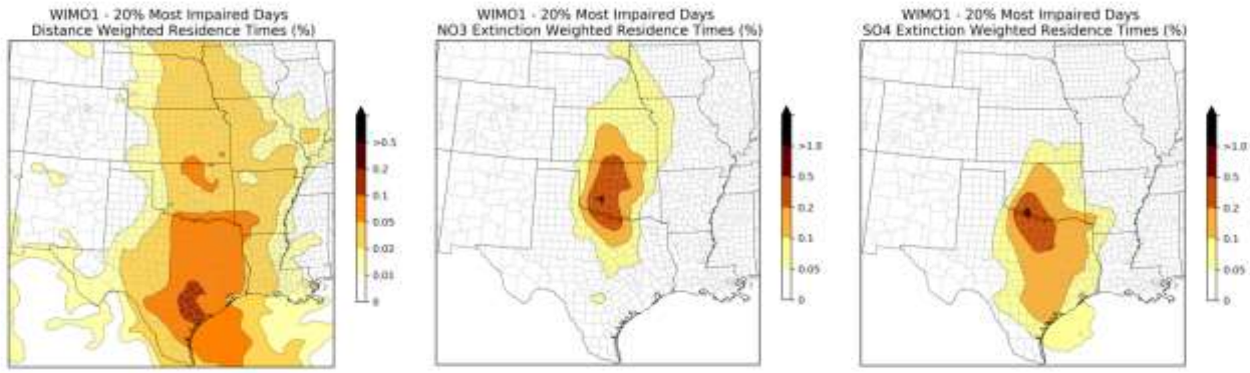
Figure III-57: Wichita Mountains WinHAZE Visualization Twenty Percent Most Impaired: 2002, 2019, and Natural Conditions[68]

3. AOI Analysis

As described in Chapter II, DEQ used the AOI analysis results produced by Ramboll for the CenSARA states to evaluate which geographic regions and sources have a high probability of contributing to anthropogenic visibility impairment at federal Class I areas within the CenSARA region and in neighboring states. Figure III-58 shows the distance-weighted residence time and pollutant-specific extinction-weighted residence times (EWRT NO_3 and EWRT SO_4) for Wichita Mountains for the most impaired days. Based on the distance-weighted residence time plot, air masses from the following states are within the 0.05% distance-weighted residence time contour for Wichita Mountains on the most impaired days: Arkansas, Kansas, Louisiana, Oklahoma, and Texas. The EWRT NO_3 plot indicates that air masses coming from the following states may be impacting ammonium nitrate concentrations at Wichita Mountains on the most impaired days: Iowa, Kansas, Missouri, Nebraska, Oklahoma, South Dakota, and Texas. The EWRT SO_4 plot indicates that air masses coming from the following states may be impacting ammonium sulfate concentrations at Wichita Mountains on the most impaired days: Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas. Darker areas on these plots indicate a larger influence on Wichita Mountains on the most impaired days for the examined metric.

[68] Interagency Monitoring of Protected Visual Environments. http://vista.cira.colostate.edu/Improve/winhaze/

Figure III-58: All Trajectories Distance-Weighted Residence Times, EWRT NO_3, and EWRT SO_4 for the Twenty-Percent Most Impaired Days—Wichita Mountains (Normalized Percentages)



Based on the EWRT NO_3 and EWRT SO_4 plots, air masses from Oklahoma have the greatest influence on ammonium nitrate and air masses from Oklahoma and Texas have the greatest influence on ammonium sulfate at Wichita Mountains on the most impaired days. The individual sources with the highest visibility impact surrogate values for Wichita Mountains in 2016 were sources in Arkansas, Iowa, Kansas, Missouri, Nebraska, Oklahoma, and Texas. Less than one percent of the inventory's visibility surrogate total for Wichita Mountains in 2016 is attributable to Arkansas sources.

Based on the pollutant-specific EWRT plots for the dominant pollutants and the small percentage of the AOI inventory's visibility surrogate table attributable to Arkansas sources, DEQ concludes that emissions from Arkansas sources are reasonably anticipated to contribute to visibility impairment at Wichita Mountains.

Arkansas Regional Haze Planning Period II

State Implementation Plan

CHAPTER IV: PROGRESS REPORT

Chapter IV: Progress Report

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IV. Progress Report

The RHR at 40 CFR § 51.308(f)(5) requires states to address the requirements for progress reports in 40 CFR § 51.308(g)(1)–(5) in their plan revisions. Pursuant to § 51.308(g)(1)–(5), this chapter provides the status of control strategies since the most recent progress report, emission reductions achieved through implementation of control strategies, visibility progress since the most recent progress report, and an assessment of significant changes in anthropogenic emissions of visibility-impairing pollutants.

EPA recommends that SIP revisions due in 2021 cover the period from the first full year that was not incorporated in the previous progress report through a year that is as close as possible to the submission date of the SIP.[1] Arkansas submitted its progress report for Planning Period I in June 2015 and included information up through the year 2011. As of the time that this section was written, 2019 was the most recent year for visibility impairment data, 2020 was the most recent year that emissions for EGUs were reported (NOx, SO_2, and CO_2), 2019 was the most recent year that emissions from Type A[2] facilities were reported to DEQ, and 2017 was the most recent year for the national emissions inventory.

A. Planning Period I Measures

This section describes the status of implementation of all measures included in the Planning Period I SIP, as revised, and a summary of the emission reductions achieved through the Planning Period I SIP, as revised. This section is intended to comply with 40 § CFR 51.308(g)(1) and (2).

1. Implementation Status

In the Planning Period I SIP, as revised, the long-term strategy included source-specific control measures, participation in the CSAPR Ozone Season NOx Trading Program, ongoing state and federal air pollution control programs (e.g., vehicle emission standards), and voluntary programs (e.g., DEQ's Go RED! funding assistance program and the voluntary Arkansas Smoke Management Plan).

a. Source-Specific Control Measures

Table IV-1 provides the implementation status for each source-specific control measure

[1] EPA (2019). "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" at page 55.
https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

[2] Stationary sources that must report emissions are categorized based on the annual potential to emit (PTE) of one or more pollutants. Type A sources must report emissions annually. Type B sources must report emissions every three years

established in the Planning Period I SIP, as revised in 2017, 2018, and 2019.

Table IV-1: Implementation Status for the Arkansas Planning Period I SIP Source-Specific Control Measures

Source	Unit	Pollutant	Control Measure	Implementation Status
Carl E. Bailey Generating Station (AFIN 74-00024)	SN-01 Boiler	NOx	Participation in CSAPR Ozone Season NOx Trading Program	Implementation of CSAPR began in 2015. The emissions budget stringency for Arkansas increased for 2017 and again for 2018 and beyond.
		SO_2 and PM	Fuel switching to fuel with a sulfur content of 0.5% or less by weight	Compliance was required beginning October 27, 2021, Prohibited from purchasing fuel with a sulfur content greater than 0.5% after August 8, 2018. However, the Carl E. Bailey Generating Station was permanently retired on July 10, 2020.
McClellan Generating Station (AFIN 52-00055)[3]	SN-01 Boiler	NOx	Participation in CSAPR Ozone Season NOx Trading Program	Implementation of CSAPR began in 2015. The emission budget stringency for Arkansas increased for 2017 and again for 2018 and beyond.
		SO_2 and PM	Fuel switching to fuel oil with a sulfur content of 0.5% or less by weight	Compliance required beginning October 27, 2021. Prohibited from purchasing fuel with a sulfur content greater than 0.5% after August 8, 2018.
White Bluff Power Plant (AFIN 35-	SN-01 Unit 1 Boiler	NOx	Participation in CSAPR Ozone Season NOx Trading	Implementation of CSAPR began in 2015. The emission budget stringency for

[3] Permit #1887-AOP-R5 https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/1887-AOP-R5.pdf

00110)[4]			Program	Arkansas increased for 2017 and again for 2018 and beyond.
		SO_2	0.60 lb/MMBtu based on fuel switching to low sulfur coal	Compliance required by August 8, 2021. The cessation of coal combustion by December 31, 2028 is enforceable by a 2018 administrative order.[5]
		PM	714 lb/hr based on permitted emission limit as of October 15, 2007	Entergy has been required to comply with this emission limit as a permit condition since April 28, 2005.
	SN-02 Unit 2 Boiler	NOx	Participation in CSAPR Ozone Season NOx Trading Program	Implementation of CSAPR began in 2015. The emission budget stringency for Arkansas increased for 2017 and again for 2018 and beyond.
		SO_2	0.60 lb/MMBtu based on fuel switching to low sulfur coal	Compliance required by August 8, 2021. The cessation of coal combustion by December 31, 2028 is enforceable by a 2018 administrative order.[6]
		PM	714 lb/hr based on permitted emission limit as of October 15, 2007	Entergy has been required to comply with this emission limit as a permit condition since April 28, 2005
	SN-05 Auxiliary Boiler	NOx	32.2 lb/hour NOx	Per the Planning Period I SIP, compliance was required as of August 8, 2018; however, Entergy has been required to

[4] Permit #0263-AOP-R16 https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/0263-AOP-R16.pdf

[5] Administrative Order LIS No. 18-073 requiring White Bluff Unit 1 (SN-01) and White Bluff Unit 2 (SN-02) to permanently cease coal-fired operations by no later than December 31, 2028. https://www.adeq.state.ar.us/air/planning/sip/pdfs/regional-haze/entergy-ao-executed-8-7-2018.pdf

[6] *Ibid.*

				comply with this emission limit based on permit conditions since August 9, 2012.
		SO_2	105.2 lb/hour SO2	Per the Planning Period I SIP, compliance was required as of August 8, 2018; however, Entergy has been required to comply with this emission limit based on permit conditions since August 9, 2012.
		PM	4.5 lb/hour PM	Per the Planning Period I SIP, compliance was required as of August 8, 2018; however, Entergy has been required to comply with this emission limit based on permit conditions since April 28, 2005.
Flint Creek Power Plant (AFIN 04-00107)[7]	SN-01 Boiler	NOx	Participation in CSAPR Ozone Season NOx Trading Program	Implementation of CSAPR began in 2015. The emission budget stringency for Arkansas increased for 2017 and again for 2018 and beyond.
		SO_2	0.06 lb/hr based on installation of novel integrated deacidification system	Compliance required by August 8, 2018.
		PM	632.4 lb/hour based on the permitted emission limit as of October 15, 2007	SWEPCO has been required to comply with this emission limit as a permit condition since September 17, 2001.
Domtar Ashdown Mill	SN-03 Power	NOx	191 lb/hr	Domtar has been operating under these emission limits
		SO_2	0.5 lb/hr	

[7] Permit #0276-AOP-R9 https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/0276-AOP-R9.pdf

(AFIN 41-00002)[8]	Boiler #1	PM	5.2 lb/hr	since at least December 2016. These limits became state enforceable immediately upon issuance of a minor modification letter sent to Domtar on February 28, 2019.[9]
	SN-05 Power Boiler #2	NOx	293 lb/hr	
		SO_2	435 lb/hr	
		PM	81.6 lb/hr	
Lake Catherine (AFIN 30-00011)[10]	SN-03 Unit 4	NOx	Participation in CSAPR Ozone Season NOx Trading Program	Implementation of CSAPR began in 2015. The emission budget for Arkansas was tightened for 2017 and for 2018 and beyond.
		PM	45 lb/hour based on the permitted emission limit as of October 15, 2007	Entergy has been required to comply with this emission limit as a permit condition since January 5, 2005.
		SO2 and PM	Prohibition on burning fuel oil at Unit 4 until SO2 and PM BART determinations for fuel oil are approved into the SIP by EPA.	This is a federally and state enforceable provision executed through a source-specific Administrative Order that was submitted as part of a Regional Haze SIP revision for planning period I.
Independence Power Plant (AFIN 32-00042)[11]	SN-01 Unit 1 Boiler	NOx	Participation in CSAPR Ozone Season NOx Trading Program	Implementation of CSAPR began in 2015. The emission budget for Arkansas was tightened for 2017 and for 2018 and beyond.
		SO_2	0.60 lb/MMBtu based on fuel switching to low sulfur coal	Compliance required by August 8, 2021.

[8] Permit #0287-AOP-R23 https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/0287-AOP-R23.pdf

[9] Domtar Ashdown Mill No. 2 Power Boiler is described in the proposed SIP (Chapter V-36) as burning coal among other fuels. An air permit modification application was submitted to the DEQ on April 12, 2022 (0287-AOP-R25) that includes a fuel switch from coal to natural gas for the No. 2 Power Boiler.

[10] Permit #1717-AOP-R8 https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/1717-AOP-R8.pdf

[11] Permit # 0449-AOP-R17 https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/0449-AOP-R2.pdf

	SN-02 Unit 2 Boiler	NOx	Participation in CSAPR Ozone Season NOx Trading Program	Implementation of CSAPR began in 2015. The emission budget for Arkansas was tightened for 2017 and for 2018 and beyond.
		SO_2	0.60 lb/MMBtu based on fuel switching to low sulfur coal	Compliance required by August 8, 2021.

b. CSAPR Ozone Season NOx Trading Program

In the Planning Period I SIP, as revised, DEQ determined that no additional NOx controls beyond those required for subject-to-BART sources and participation on the CSAPR ozone season NOx trading rule were necessary for reasonable progress. The statewide ozone-season NOx budget for Arkansas in 2017 was 12,048 tons with a variability limit of 2,530 tons and an assurance level of 14,578 tons. The statewide ozone-season NOx budget for Arkansas from 2018 forward is 9,210 tons with a variability limit of 1,934 tons and an assurance level of 11,144 tons. This translates to a 24% decrease in the statewide ozone-season NOx budget in 2018 and beyond. Table IV-2 lists the units required to participate in the CSAPR Ozone Season NOx Trading Rule and their allocations.

Table IV-2: CSAPR Ozone Season NOx Trading Rule Allocations

Plant Name	**State**	**ORIS ID**	**Boiler ID**	**NOx OS Allocation 2017 (tons)**	**NOx OS Allocation 2018 and Beyond (tons)**
Carl Bailey	Arkansas	202	01	36	26
Cecil Lynch	Arkansas	167	2		
Cecil Lynch	Arkansas	167	3	118	86
City Water & Light - City of Jonesboro	Arkansas	56505	SN04	20	14
City Water & Light - City of Jonesboro	Arkansas	56505	SN06	24	17
City Water & Light - City of	Arkansas	56505	SN07	19	15

Jonesboro					
Dell Power Plant	Arkansas	55340	1	17	17
Dell Power Plant	Arkansas	55340	2	18	18
Flint Creek Power Plant	Arkansas	6138	1	1,332	965
Fulton	Arkansas	7825	CT1	14	14
Hamilton Moses	Arkansas	168	1		
Hamilton Moses	Arkansas	168	2		
Harry D. Mattison Power Plant	Arkansas	56328	1	21	21
Harry D. Mattison Power Plant	Arkansas	56328	2	19	18
Harry D. Mattison Power Plant	Arkansas	56328	3	12	12
Harry D. Mattison Power Plant	Arkansas	56328	4	9	9
Harvey Couch	Arkansas	169	1		
Harvey Couch	Arkansas	169	2	17	12
Hot Spring Energy Facility	Arkansas	55418	CT-1	28	28
Hot Spring Energy Facility	Arkansas	55418	CT-2	21	21
Hot Spring Power Co., LLC	Arkansas	55714	SN-01	37	37
Hot Spring Power Co., LLC	Arkansas	55714	SN-02	38	38
Independence	Arkansas	6641	1	1,840	1,333
Independence	Arkansas	6641	2	2,017	1,461
John W. Turk Jr. Power Plant	Arkansas	56564	SN-01	322	322
Lake Catherine	Arkansas	170	1	0	0
Lake Catherine	Arkansas	170	2	0	0
Lake Catherine	Arkansas	170	3	1	1
Lake Catherine	Arkansas	170	4	256	186

McClellan	Arkansas	203	01	108	78
Oswald Generating Station	Arkansas	55221	G1	26	22
Oswald Generating Station	Arkansas	55221	G2	19	19
Oswald Generating Station	Arkansas	55221	G3	24	21
Oswald Generating Station	Arkansas	55221	G4	14	14
Oswald Generating Station	Arkansas	55221	G5	19	17
Oswald Generating Station	Arkansas	55221	G6	18	16
Oswald Generating Station	Arkansas	55221	G7	18	18
Pine Bluff Energy Center	Arkansas	55075	CT-1	108	108
Plum Point Energy Station	Arkansas	56456	1	690	690
Robert E Ritchie	Arkansas	173	2		
Thomas Fitzhugh	Arkansas	201	2	53	45
Union Power Station	Arkansas	55380	CTG-1	27	27
Union Power Station	Arkansas	55380	CTG-2	26	26
Union Power Station	Arkansas	55380	CTG-3	32	32
Union Power Station	Arkansas	55380	CTG-4	30	30
Union Power Station	Arkansas	55380	CTG-5	27	27
Union Power Station	Arkansas	55380	CTG-6	26	26
Union Power Station	Arkansas	55380	CTG-7	32	32
Union Power Station	Arkansas	55380	CTG-8	29	29
White Bluff	Arkansas	6009	1	2,116	1,533
White Bluff	Arkansas	6009	2	2,130	1,544

c. Ongoing state and federal air pollution control programs

In the Planning Period I SIP, DEQ discussed multiple federal rules that impact emissions of visibility-impairing pollutants.

The rules mentioned in the 2008 SIP submittal were incorporated into the modeling to establish the Planning Period I RPGs. Each of these programs was implemented during the first planning period; however, the Clean Air Interstate Rule implemented through Chapter 14 of Regulation No. 19 was replaced with CSAPR, which is implemented as a FIP.

In the 2018 Phase II SIP, DEQ updated the list of ongoing state and federal air pollution control programs to reflect other federal rules that had been implemented since the 2008 SIP submittal. These rules remain in effect at the time of this progress report. The emission reductions from these ongoing state and federal programs are reflected in the emissions inventory information for Arkansas and the surrounding states presented in this chapter.

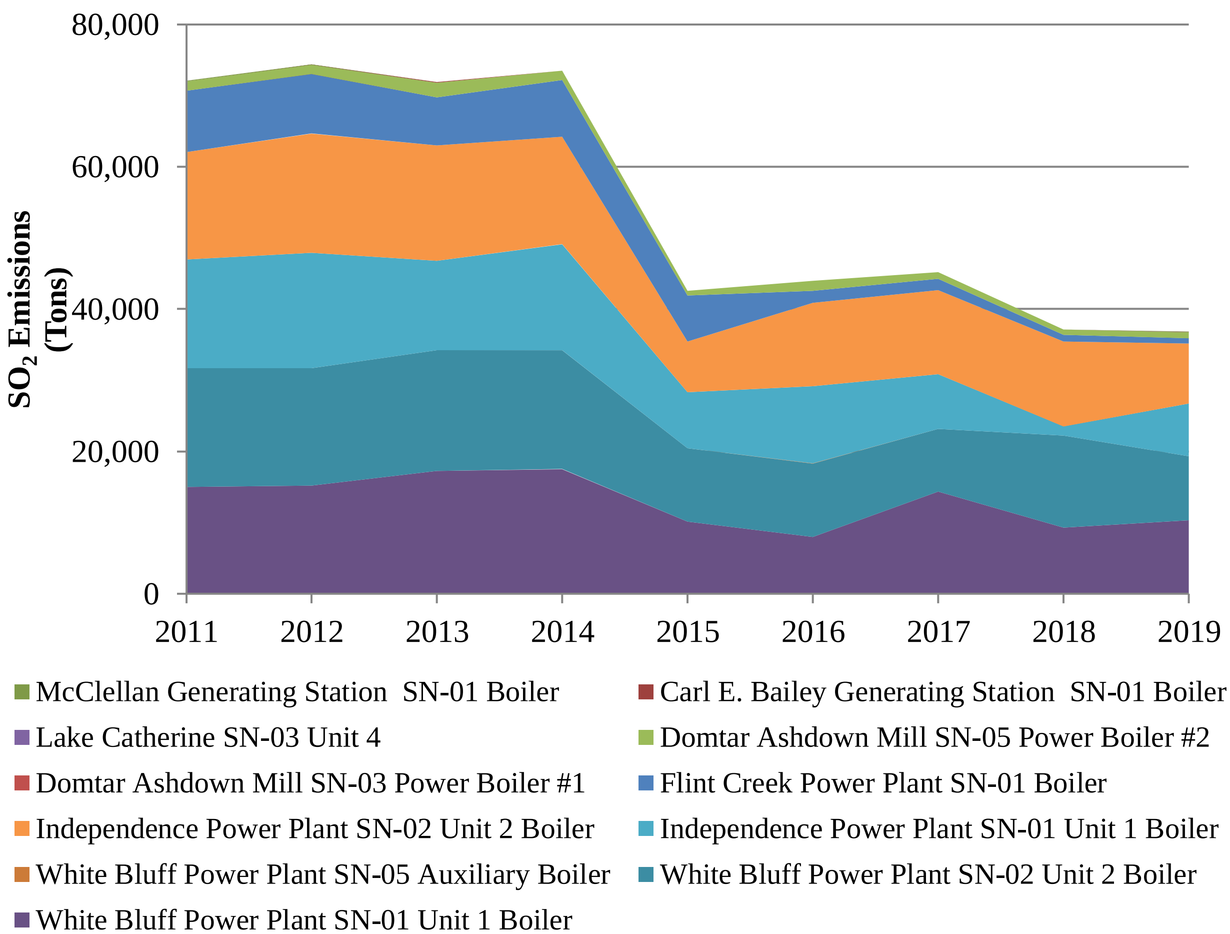
d. Smoke Management Plan

Arkansas foresters have been implementing a voluntary smoke management plan for prescribed fires since 2007. More recently, the Arkansas Department of Agriculture adopted a voluntary smoke management plan for row crop farmers based on input from a smoke management task force and members of the Agricultural Council of Arkansas, Arkansas Department of Agriculture, DEQ, Farm Bureau of Arkansas, Arkansas Rice, Arkansas Soybean Association, and the University of Arkansas Division of Agriculture Research and Extension Service. The Arkansas Department of Agriculture coordinates prescribed fire activities, reports fire weather, and assists with voluntary smoke management. Copies of the most recent publications of the Arkansas voluntary smoke management plans for prescribed fires and row crops are available at https://www.agriculture.arkansas.gov/arkansas-voluntary-smoke-management-guidelines.

2. Emission Reductions Achieved from Planning Period I Measures

Figures IV-1, IV-2, and IV-3 show the changes in SO_2, NOx, and Primary $PM_{2.5}$ emissions, respectively, since 2011 for each emission unit subject to source-specific emission limitations in the Arkansas Planning Period 1 SIP.[12] Taken together, SO_2 annual emissions from these units in 2019 were forty-nine percent lower than in 2011, NOx annual emissions in 2019 were sixty-one percent lower than in 2011, and primary $PM_{2.5}$ emissions decreased by ten percent. These trends are consistent with emission limitations included in the Planning Period I SIP, which primarily required emission reductions of SO_2 and NOx and maintenance of existing particulate matter limitations. The decreases in SO_2 from the larger coal units are also influenced by changes in dispatch patterns for electricity generation that began in 2014.

Figure IV-1: SO_2 Emission Reductions from Arkansas Stationary Sources Controlled under Planning Period I SIP



[12] Data obtained from Arkansas emissions inventory reported to EPA. Primary $PM_{2.5}$ includes both filterable and condensable emissions from sources, but does not include $PM_{2.5}$ formed from photochemical reactions in the atmosphere.

Figure IV-2: NOx Emission Reductions from Sources Controlled under Planning Period I SIP

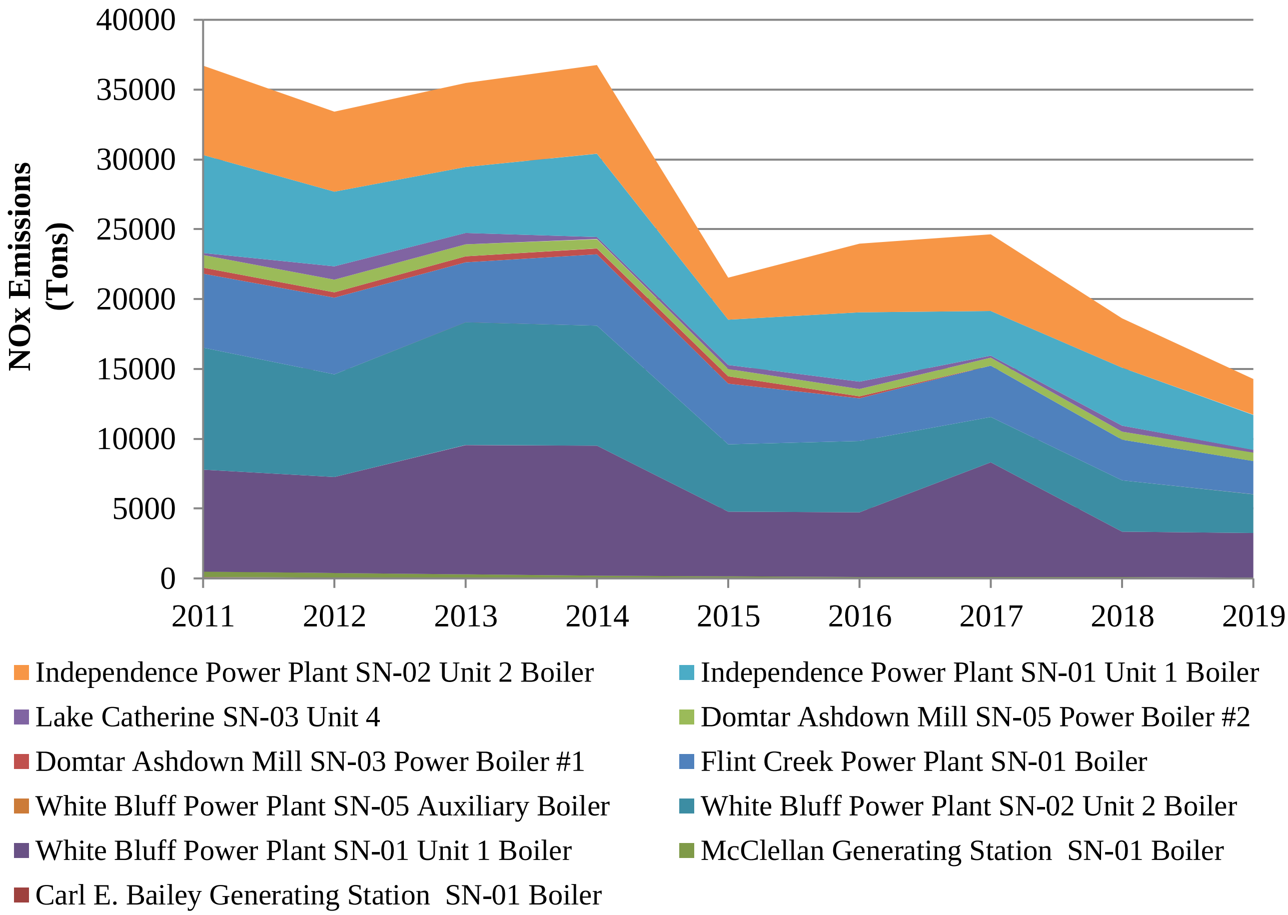


Figure IV-3: Primary $PM_{2.5}$ Emissions from Sources Controlled under Planning Period I SIP

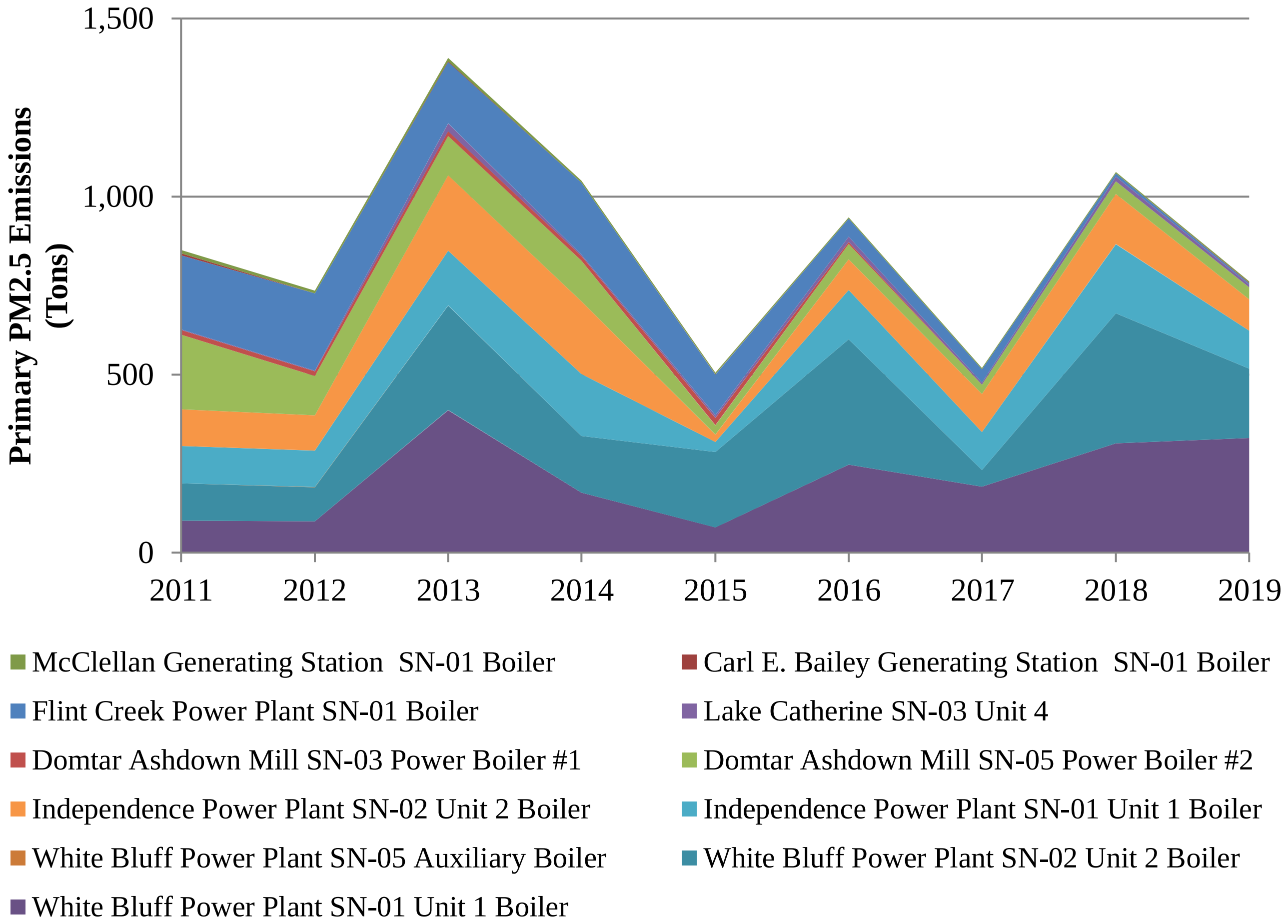


Figure IV-4 illustrates the change in annual NOx emissions since 2011 of all EGUs subject to the CSAPR trading program for ozone season NOx in each of the states that participates in CSAPR ozone season group 2. Annual NOx emissions for EGUs in these states decreased by 895,264 tons (63.7%) between 2011 and 2020.[13]

Figure IV-4: Changes in Annual NOx Emissions from EGUs in States Subject to the CSAPR Ozone Season Trading Program for NOx (2011–2020)

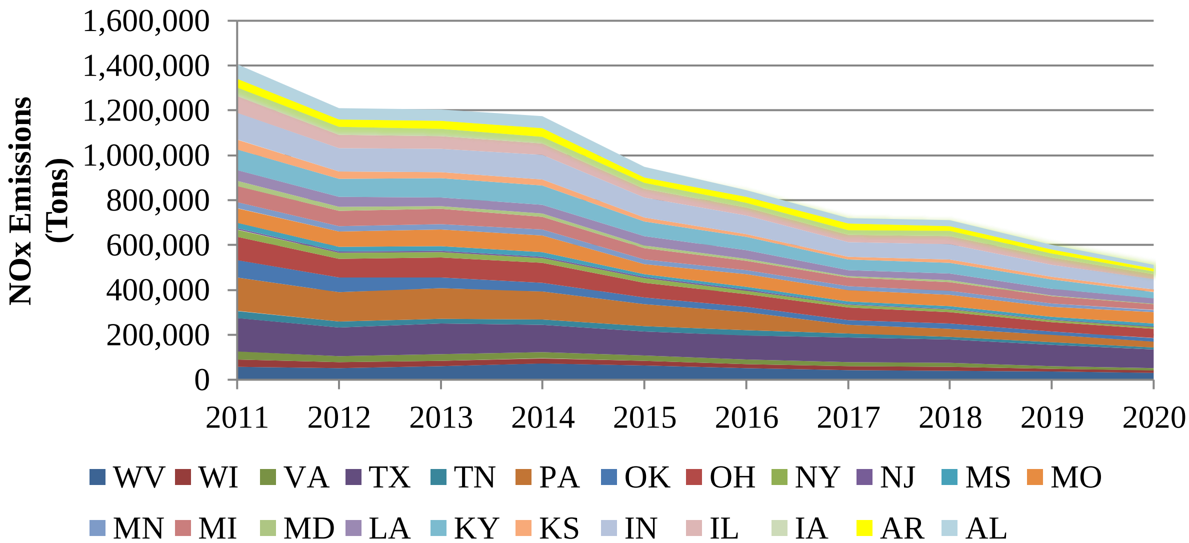
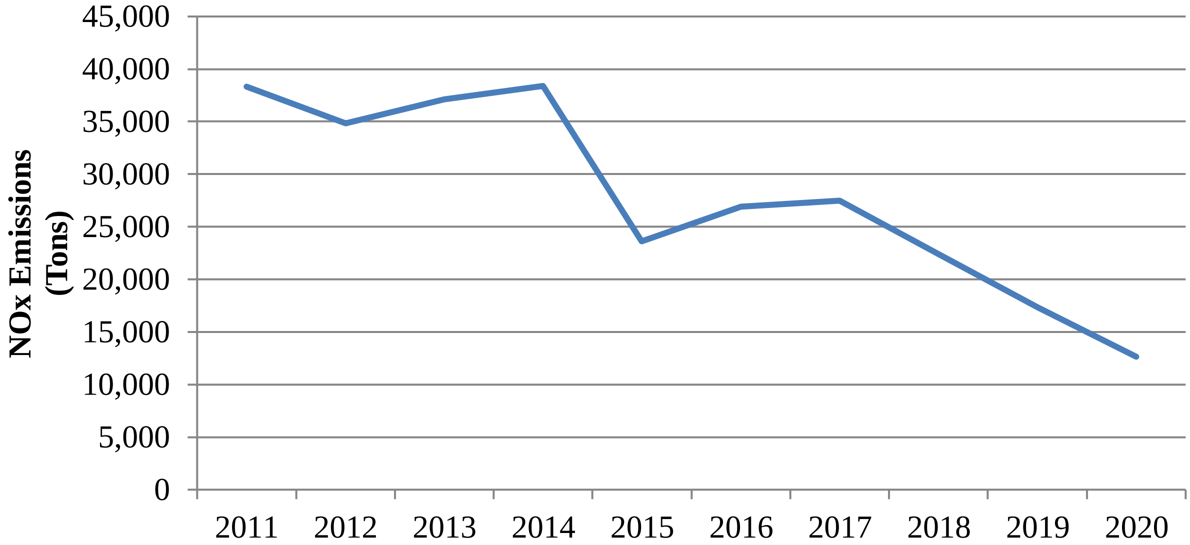


Figure IV-5 illustrates the same trend, but for Arkansas EGUs only. The dip in emissions between 2014 to 2015 reflects the transition from CAIR to CSAPR. The further decrease observed in 2018 reflects the more stringent of the two emissions budgets for Arkansas EGUs included in the CSAPR update. Furthermore, low NOx burners were installed on five large EGUs in the 2017–2018 time period. Annual NOx emissions from Arkansas EGUs decreased by 25,692 tons (67%) between 2011 and 2020.

[13]Data obtained from Air Markets Program Database

Figure IV-5: Changes in Annual NOx Emissions from EGUs in Arkansas (2011–2020)



Arkansas forest managers and farmers utilize voluntary smoke management plans to reduce smoke impacts from burning. Figures IV-6, IV-7, and IV-8 illustrate changes in NOx, SO_2, and Primary $PM_{2.5}$ emissions associated with agricultural fires, prescribed burns, and wildfires. Each of these figures shows a similar trend in emissions. Emissions from agricultural fires decreased in 2014 and again in 2017 for all three pollutants. Emissions of the three pollutants from prescribed fires decreased between 2011 and 2014, but those emissions increased between 2014 and 2017. The same trend in emissions is observed for wildfire. The increase between 2014 and 2017 inventories in NOx, SO_2, and $PM_{2.5}$ emissions are a result of a 153,612 increase in acres burned using prescribed fire and a 12,195 increase in acres burned by wildfire.

Figure IV-6: Changes in Annual NOx Emissions from Fire in Arkansas

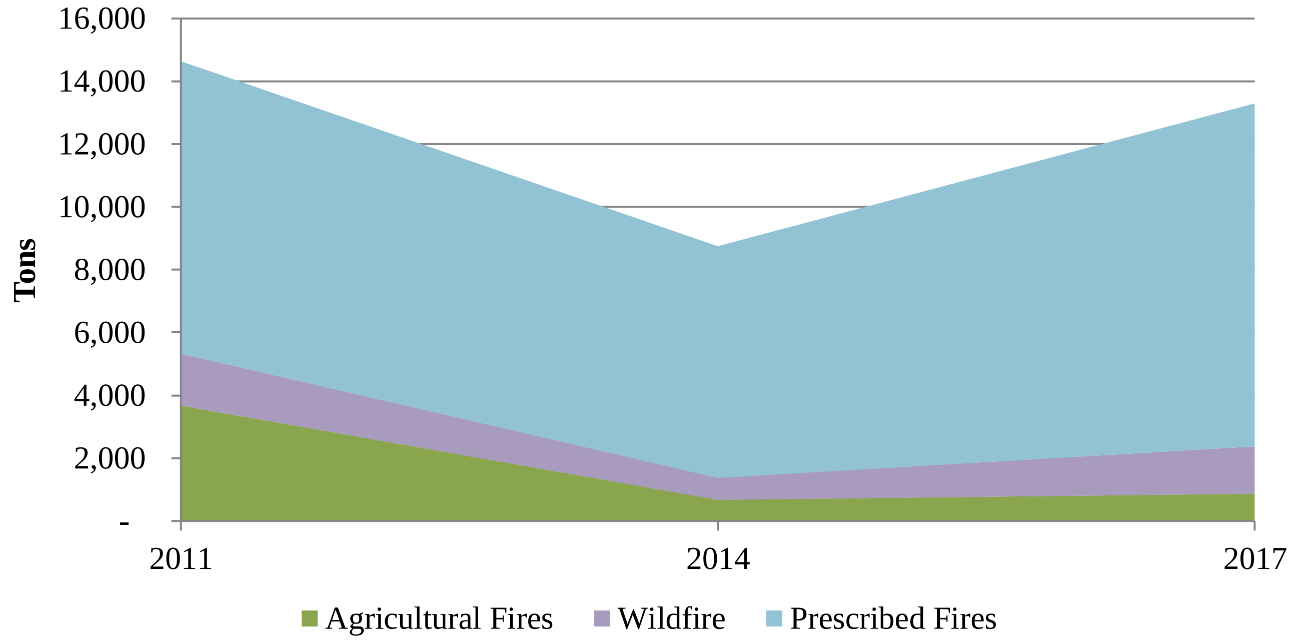


Figure IV-7: Changes in Annual SO_2 Emissions from Fire in Arkansas

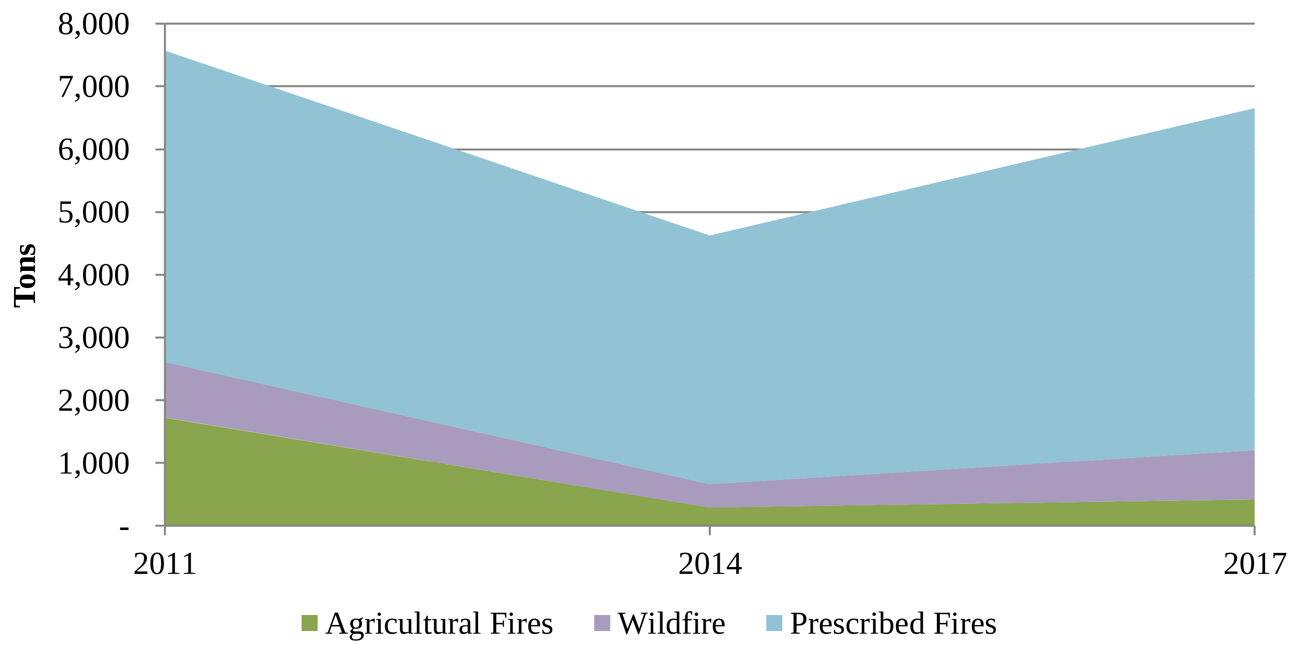
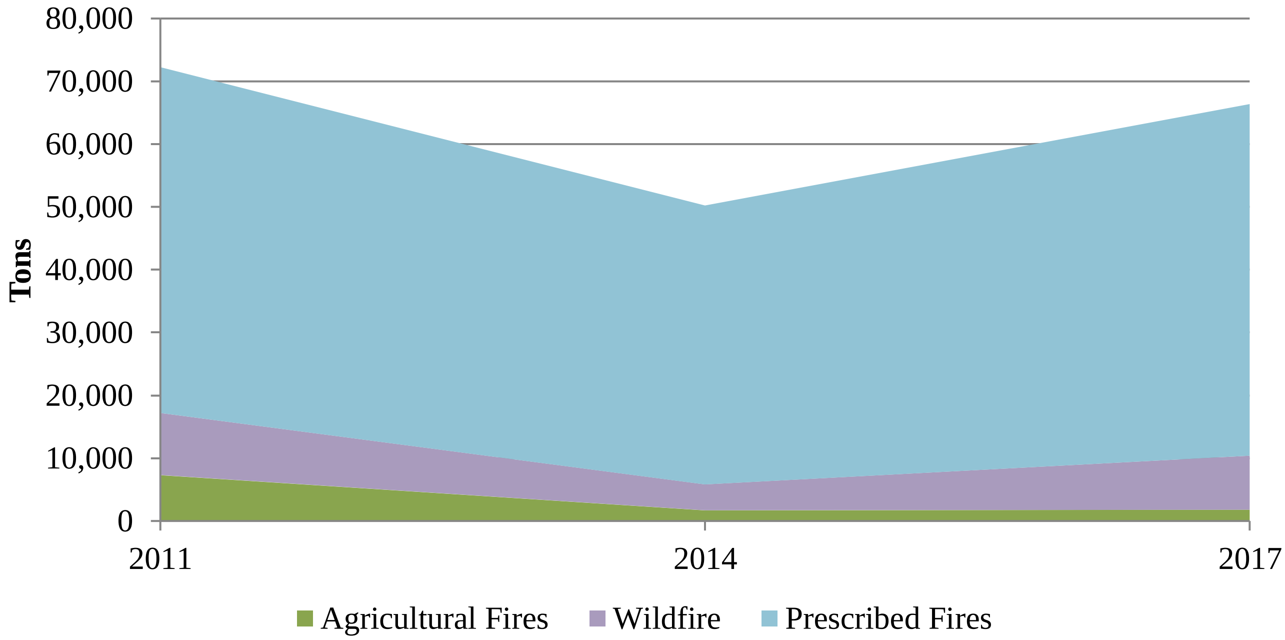


Figure IV-8: Changes in Annual Primary $PM_{2.5}$ Emissions from Fire in Arkansas



Arkansas's voluntary smoke management plans are intended to minimize smoke impacts associated with fire rather than reduce use of fire as a management tool. The changes in emissions do not necessarily reflect the efficacy of these plans in reducing visibility impacts.

B. Assessment of Visibility Conditions and Emissions Changes

1. Assessment of Changes in Visibility Conditions

The RHR requires states to assess changes in visibility conditions expressed in five-year averages for the most impaired days and least impaired days for progress reports due before January 31, 2025 and in terms of five-year averages for most impaired and clearest days for progress reports due after January 31, 2025. Table IV-3 compares visibility for all three metrics at Arkansas federal Class I areas for the baseline period (2000–2004), the period included in the last progress report (2007–2011), and the current (most recent) visibility conditions (2015–2019). Visibility conditions at Arkansas federal Class I areas have improved for all three metrics since the period included in the last progress report.

Table IV-3: Visibility Conditions at Arkansas Federal Class I Areas: Baseline (2000–2004), Last Progress Report (2007–2011), Current (2015–2019)

Federal Class I Area	Metric	Baseline Visibility Conditions (deciviews)	Last Progress Report Period Visibility Conditions (deciviews)	Current Visibility Conditions (2015–2019) (deciviews)
Caney Creek	Most Impaired Days	23.99	21.72	17.65
	Clearest Days	11.24	9.96	7.79
	Least Impaired Days[14]	13.47	11.18	9.61
Upper Buffalo	Most Impaired Days	24.21	22.33	17.52
	Clearest Days	11.71	10.96	8.17
	Least Impaired Days[15]	14.09	13.38	10.12

2. Assessment of Emissions of Visibility-Impairing Pollutants

The RHR requires states to report changes in visibility-impairing pollutants since the last progress report. In the 2015 Arkansas Regional Haze Progress Report, DEQ presented statewide emissions information through 2011 for the following pollutants: NOx, SO_2, Primary $PM_{2.5}$, ammonia, and VOCs. The figures below illustrate the trends by sector of each of these pollutants between 2011 and the most recent NEI year 2017.

Figure IV-9 demonstrates the overall downward trajectory of statewide NOx emissions in Arkansas between 2011 and 2017. Table IV-4 lists the emissions by category and compares 2017 emissions to the year included in the last progress report (2011).

[14] In the last progress report, DEQ reported 2007–2011 conditions for haziest days as current conditions. These metrics have been replaced for that time period with visibility conditions on the most impaired days in this SIP revision. Data obtained from IMPROVE SIA_group_means_12_20 and sia_impairment_group_means_12_20 datasets.

[15] Id.

Figure IV-9: 2011–2017 Statewide NOx Emissions by Sector

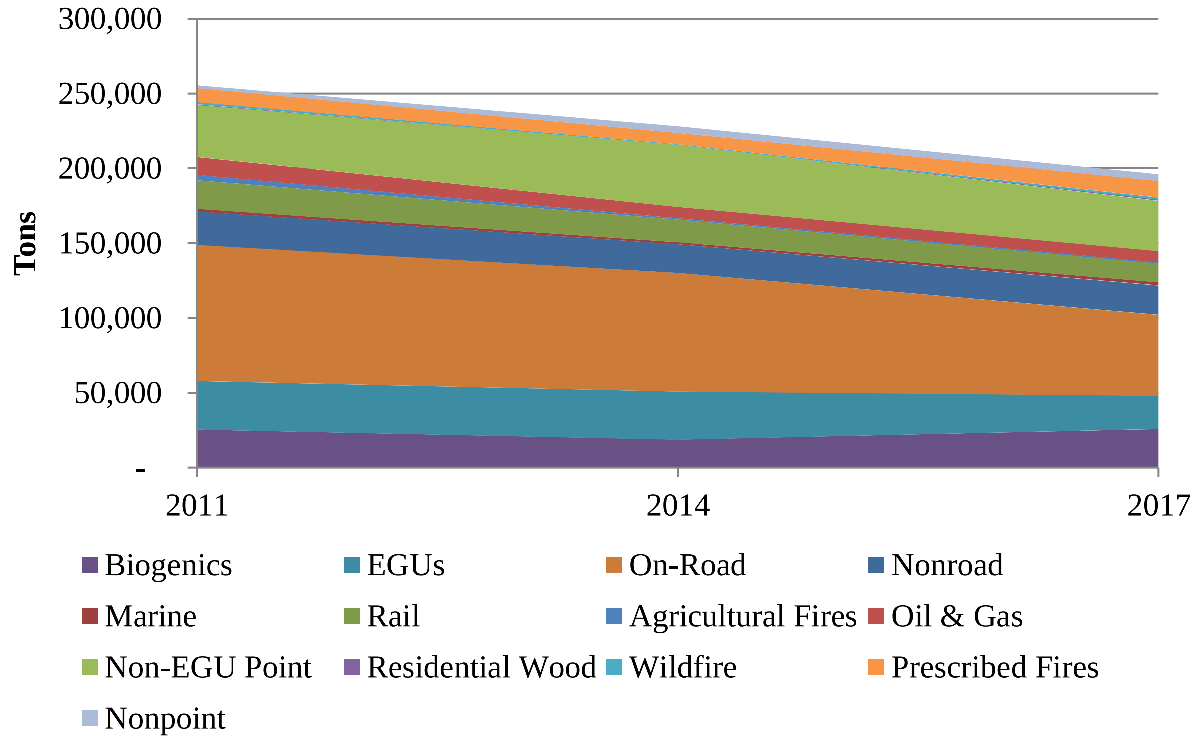


Table IV-4: Statewide NOx Emissions (Tons) by Sector (2011–2017 for non-EGUs, 2011–2020 for EGUs[16])

Category	2011	2014	2017	2020	Δ Since last Progress Report (2011)
Biogenics	25,331	18,588	25,748	--	417
EGUs	32,489	32,238	22,165	12,646	(19,843)
On-Road	91,215	79,428	54,278	--	(36,938)
Nonroad	22,185	18,837	19,682	--	(2,503)
Marine	1,797	1,727	1,930	--	133
Rail	19,001	15,074	12,476	--	(6,525)
Agricultural Fires	3,673	671	866	--	(2,807)
Oil & Gas	11,834	7,482	7,463	--	(4,371)
Non-EGU Point	35,089	41,446	33,810	--	(1,279)
Residential Wood	130	143	652	--	522
Wildfire	1,656	700	1,503	--	(153)

[16] Sources with CEMS that report to EPA have more recent data available than other sectors. EPA considers the appropriate "current year" for CEMS data sources (mostly EGUs) to be 2020.

Prescribed Fires	9,311	7,372	10,933	--	1,622
Nonpoint	1,793	4,632	4,515	--	2,722
Total	255,505	228,338	196,022		(69,003)

With the exception of the following categories, anthropogenic NOx emissions in Arkansas decreased between 2011 and 2017: marine, residential wood, prescribed fire, and nonpoint sources. The categories that increased make up 9% of the overall Arkansas NOx inventory. Overall, NOx emissions in Arkansas have decreased by 69,003 annual tons since 2011. The largest emission decrease came from the on-road mobile sector.

Figure IV-10 demonstrates the overall downward trajectory of statewide SO_2 emissions in Arkansas between 2011 and 2017. Table IV-5 lists the emissions by category and compares 2017 emissions to the year included in the last progress report (2011).

Figure IV-10: 2011–2017 Statewide SO_2 Emissions by Sector

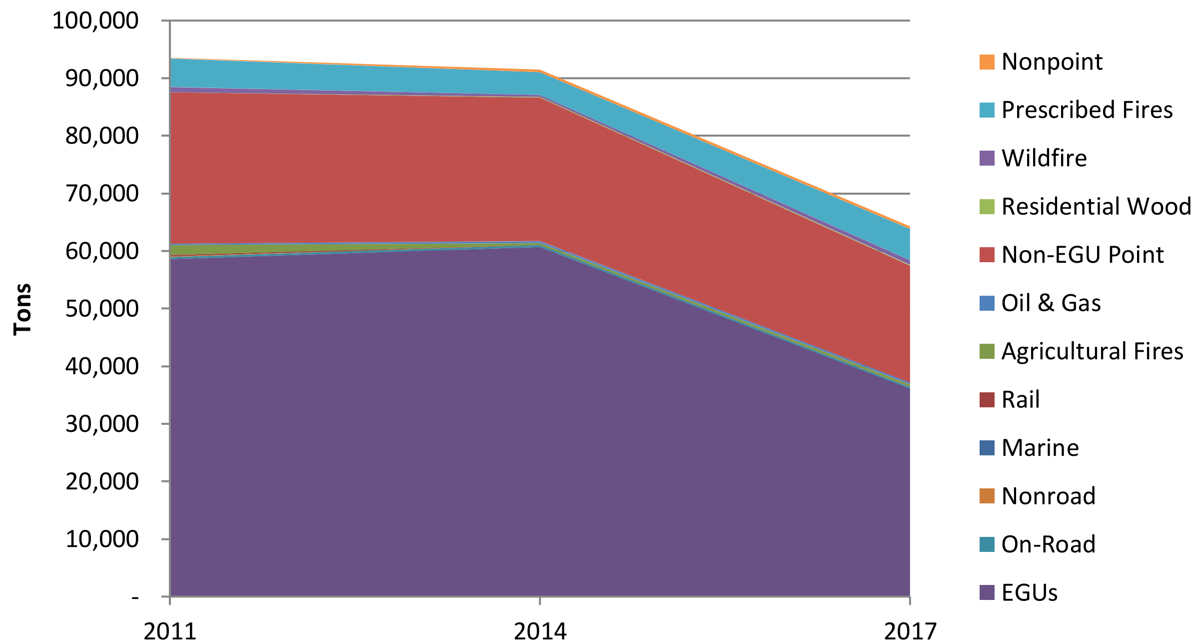


Table IV-5: Statewide SO_2 Emissions (Tons) by Sector (2011–2017 for non-EGUs, 2011–2020 for EGUs[17])

Category	2011	2014	2017	2020	Δ Since last Progress report (2011)
EGUs	58,629	60,687	36,079	22,230	(36,399)
On-Road	360	333	312		(48)
Nonroad	59	42	35		(24)
Marine	22	1	7		(15)
Rail	188	9	8		(180)
Agricultural Fires	1,721	289	417		(1,304)
Oil & Gas	316	332	305		(10)
Non-EGU Point	26,253	24,976	20,293		(5,961)
Residential Wood	19	26	141		122
Wildfire	888	372	791		(96)
Prescribed Fires	4,962	3,963	5,442		480
Nonpoint	131	460	454		323
Total	93,547	91,490	64,284		(43,112)

With the exception of the following categories, anthropogenic SO_2 emissions in Arkansas decreased between 2011 and 2017: residential wood, prescribed fire, and nonpoint sources. The categories that increased make up 9% of the overall Arkansas SO_2 inventory. Overall SO_2 emissions in Arkansas have decreased by over 43,000 annual tons since 2011. The largest annual SO_2 emission decrease came from the EGU sector.

[17] Sources with CEMS that report to EPA have more recent data available than other sectors. EPA considers the appropriate "current year" for CEMS data sources (mostly EGUs) to be 2020.

Figure IV-11 illustrates changes in emissions of Primary $PM_{2.5}$ between 2011 and 2017. Table IV-6 lists the emissions by category and compares 2017 emissions to the year included in the last progress report (2011).

Figure IV-11: 2011–2017 Statewide Primary $PM_{2.5}$ Emissions by Sector

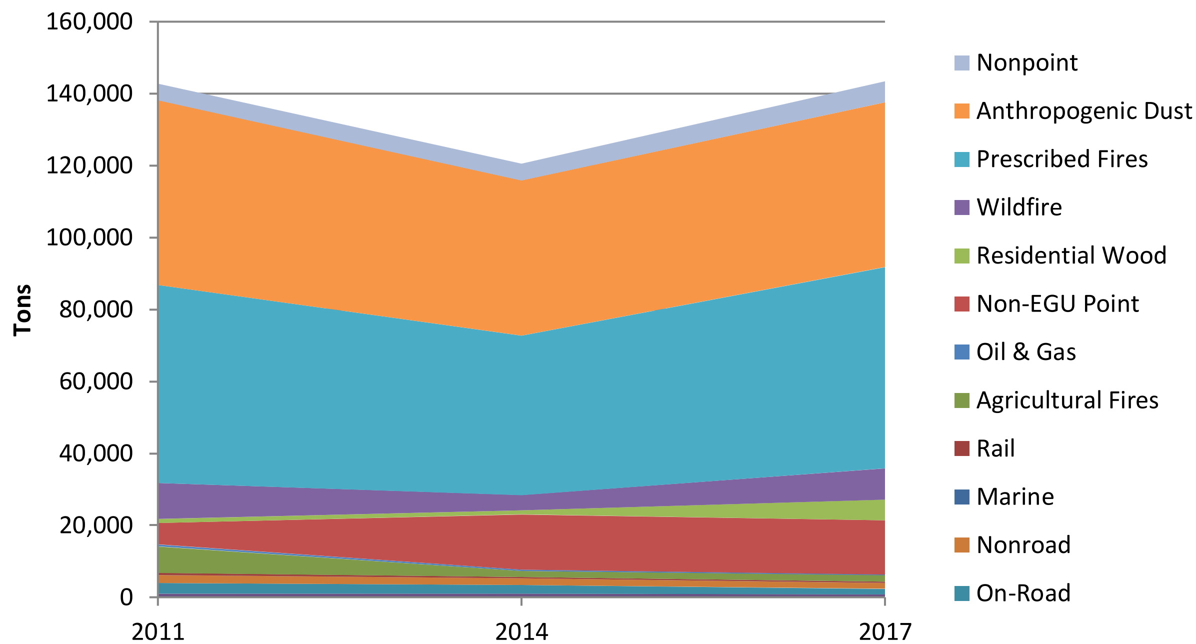


Table IV-6: 2011–2017 Statewide Primary $PM_{2.5}$ Primary Emissions (Tons) by Sector

Category	2011	2014	2017	Δ Since last Progress report (2011)
EGUs	979	933	785	(194)
On-Road	2,981	2,436	1,600	(1,382)
Nonroad	2,213	1,836	1,559	(654)
Marine	58	43	53	(4)
Rail	566	440	353	(213)
Agricultural Fires	7,292	1,705	1,761	(5,530)
Oil & Gas	570	253	200	(371)
Non-EGU Point	5,976	15,335	15,162	9,187
Residential Wood	1,146	1,266	5,680	4,533

Wildfire	9,907	4,112	8,662	(1,244)
Prescribed Fires	55,057	44,380	55,931	874
Anthropogenic Dust	51,475	43,097	45,792	(5,683)
Nonpoint	4,598	4,742	5,892	1,293
Total	142,818	120,580	143,431	613

Overall, annual emissions of Primary $PM_{2.5}$ increased between 2011 and 2017 by 613 tons. Although annual emissions decreased in most categories, annual emissions in non-EGU Point, residential wood, prescribed fire, and nonpoint categories increased. In particular, non-EGU point source annual emissions increased by over 9,000 tons and residential wood annual emissions increased by approximately 4,500 tons.

Figure IV-12 illustrates changes in annual ammonia emissions between 2011 and 2017. Table IV-7 lists the emissions by category and compares 2017 emissions to the year included in the last progress report (2011).

Figure IV-12**:** 2011–2017 Statewide Ammonia Emissions by Sector

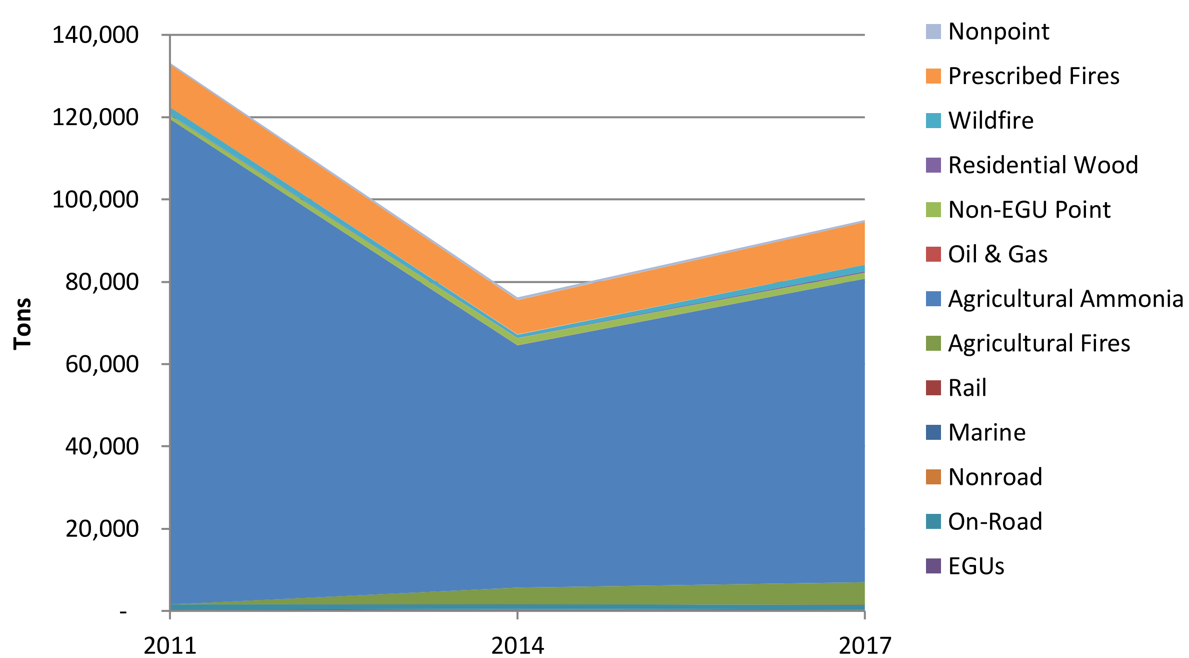


Table IV-7: 2011–2017 Statewide Ammonia Emissions (Tons) by Sector

Category	2011	2014	2017	Δ Since last Progress report (2011)
EGUs	230	406	298	68
On-Road	1,307	1,235	1,183	(124)
Nonroad	27	28	26	(1)
Marine	1	1	1	(0)
Rail	8	8	7	(1)
Agricultural Fires[18]	-	3,919	5,432	5,432
Agricultural Ammonia	117,957	58,981	73,710	(44,247)
Oil & Gas	1	1	30	29
Non-EGU Point	984	1,769	1,518	534
Residential Wood	63	64	340	278
Wildfire	1,874	776	1,630	(243)
Prescribed Fires	10,397	8,400	10,353	(44)
Nonpoint	390	535	401	10
Total	133,239	76,123	94,932	(38,307)

Overall statewide annual emissions of ammonia decreased since 2011, largely due to a 44,247 ton decrease in annual emissions from the agricultural ammonia category. EGU, agricultural fire, oil and gas, non-EGU point, residential wood, and nonpoint annual ammonia emissions increased. However, the categories that increased in emissions make up just 8% of the Arkansas ammonia inventory.

[18] No annual emissions of ammonia from agricultural fires were reported in the 2011 NEI.

Figure IV-13 (all categories) illustrates the changes in annual VOC emissions between 2011 and 2017. For VOCs, biogenics make up the vast majority of annual emissions in Arkansas. Therefore, changes in annual emissions of each other category between 2011 and 2017 are presented in Figure IV-14. Table IV-8 lists the emissions by category and compares 2017 emissions to the year included in the last progress report (2011).

Figure IV-13**:** 2011–2017 Statewide VOC Emissions by Sector

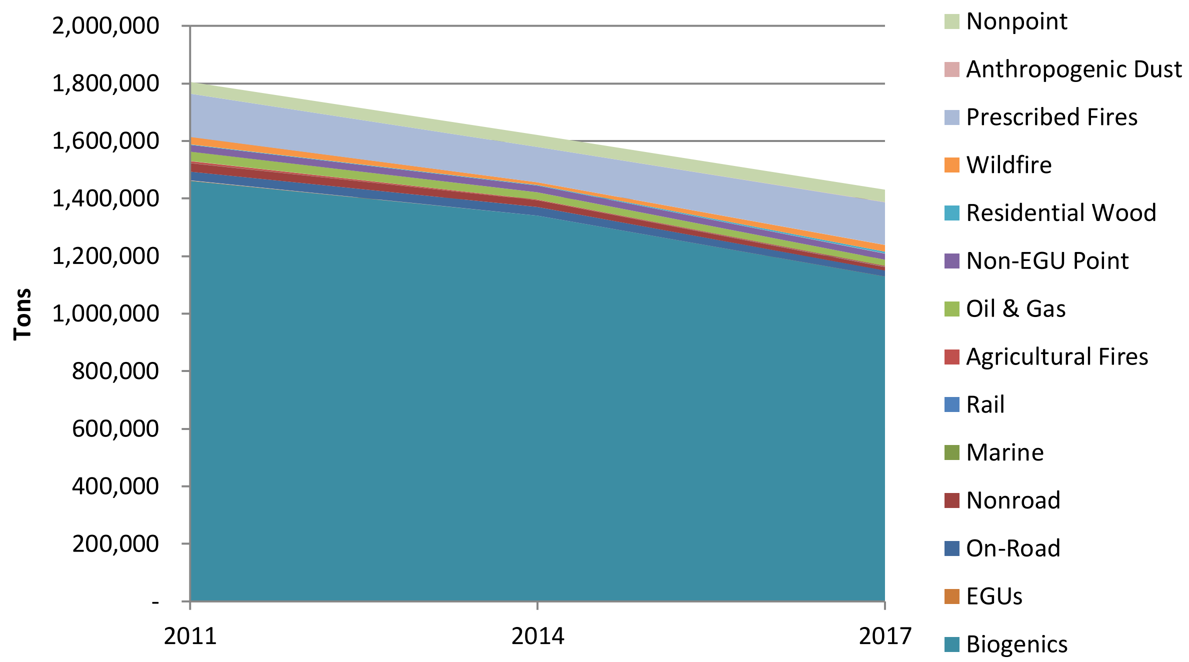


Figure IV-14**:** 2011–2017 Statewide VOC Emissions Without Biogenics by Sector

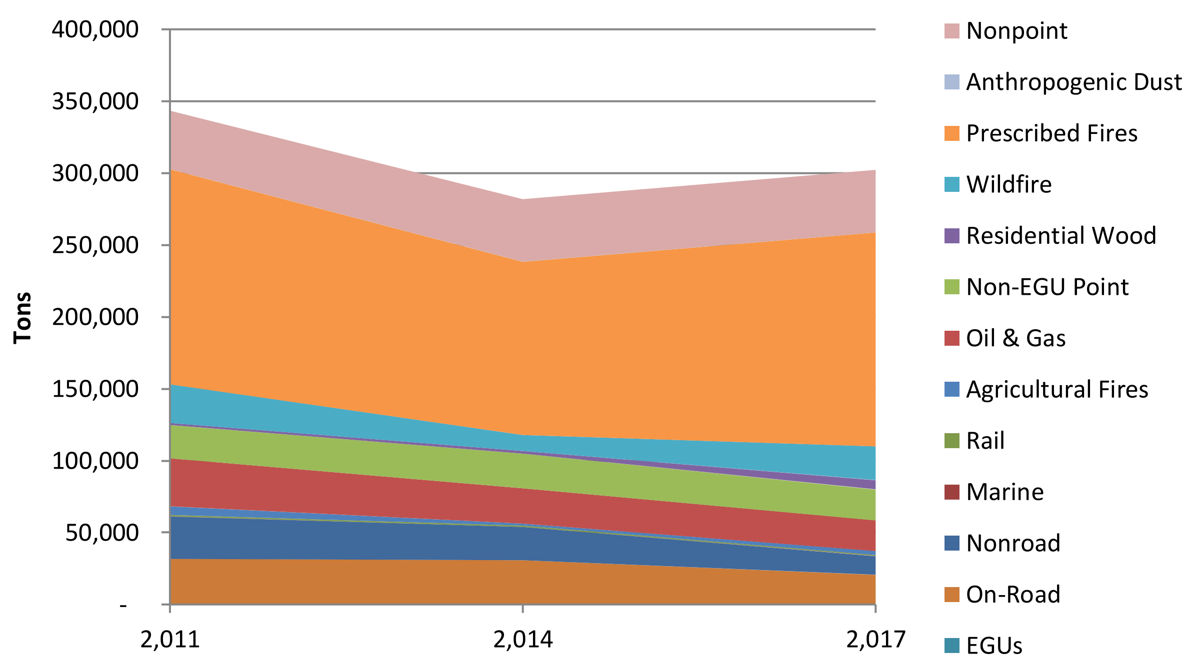


Table IV-8: 2011–2017 Statewide VOC Emissions (Tons) by Sector

Category	2011	2014	2017	Δ Since last Progress report (2011)
Biogenics	1,461,600	1,339,614	1,128,900	(332,701)
EGUs	442	427	356	(85)
On-Road	31,389	30,298	20,322	(11,067)
Nonroad	29,374	23,209	13,051	(16,323)
Marine	41	20	91	49
Rail	980	764	594	(386)
Agricultural Fires	5,987	1,297	2,707	(3,281)
Oil & Gas	33,449	24,836	21,285	(12,164)
Non-EGU Point	23,117	24,257	21,665	(1,452)
Residential Wood	1,485	1,406	6,427	4,942
Wildfire	26,933	11,154	23,437	(3,495)
Prescribed Fires	149,459	120,746	148,830	(629)
Anthropogenic Dust	-	0	0	0
Nonpoint	40,750	43,383	43,276	2,526
Total (excluding biogenics)	343,406	281,796	302,041	(41,365)
Total	1,805,006	1,621,410	1,430,940	(374,066)

With the exception of the marine, anthropogenic dust, and nonpoint categories, annual emissions of VOCs decreased in Arkansas between 2011 and 2017. The categories that increased in emissions make up 4% of the Arkansas VOC inventory. Total annual emissions decreased by 374,066 tons. However, once the biogenics category is excluded, emissions across all other categories decreased by 41,365 tons.

3. Assessment of Significant Changes in Anthropogenic Emissions

With the exception of Primary $PM_{2.5}$, emissions of visibility-impairing pollutants in Arkansas decreased significantly since the last progress report. Annual Primary $PM_{2.5}$ emissions increased by 613 tons between 2011 and 2017, largely due to emission increases in non-EGU point and residential wood source categories. This emission increase in Primary $PM_{2.5}$ is dwarfed by the annual emission reductions in NOx and SO_2 (69,003 tons and 43,112 tons, respectively), which contribute the most to visibility impairment at Arkansas federal Class I areas.

Although overall emissions of anthropogenic NOx, SO_2, ammonia, and VOCs have decreased between 2011 and 2017, there were some increases in emissions estimates for certain source sectors:[19]

- NOx and VOC emissions estimates increased for marine vessels;
- NOx, SO_2, and ammonia emissions estimates increased for residential wood combustion;
- NOx and SO_2 emissions estimates increased for prescribed fire;
- NOx, SO_2, ammonia, and VOC emissions estimates increased for nonpoint sources;
- Ammonia emissions estimates increased for agricultural fire;
- Ammonia emissions estimates increased for oil and gas; and
- VOC emissions estimates increased for anthropogenic dust.

These emissions represented a fairly small portion of the Arkansas inventory for each of the pollutants identified above. Furthermore, EPA revised methodology in the 2017 NEI for estimating emissions used in previous NEIs for certain source categories.

- For commercial marine vessels, EPA created new source classification codes (SCC), revised emission factors, changed the way it uses shape files for estimating marine emissions, and eliminated maneuvering, hoteling, cruise, and reduced speed zone emission types.
- For residential wood combustion, EPA revised its estimates based a national survey of wood-burning activity in 2018.
- For nonpoint sources:
    - EPA revised its fertilizer estimates for crops without state or USDA fertilizer data by approximately 20% from 2014 NEI estimates resulting in a large increase in ammonia emissions estimates;
    - Ammonia emission factors for livestock were updated between 2014 and 2017;
    - EPA revised VOC emission factors and added ammonia estimates for agricultural fires;
    - EPA revised emission factors for oil and gas production; and
    - EPA revised how county-level estimates for publically-owned treatment works

[19] DEQ has no authority to regulate the source sectors listed in this section.

were calculated by summing facility-level data instead of allocating a national flow rate to counties based on population;

Therefore, it is likely that some of the emission increases identified for certain source categories may not represent an actual change in emissions.

Based on DEQ’s evaluation of emissions trends for Arkansas sources and visibility trends on the most impaired, least impaired, and clearest days at Caney Creek and Upper Buffalo since the last progress report, DEQ concludes that the changes in anthropogenic emissions are facilitating, rather than impeding, progress towards natural visibility conditions at Arkansas federal Class I areas.

Arkansas Regional Haze Planning Period II

State Implementation Plan

CHAPTER V: REASONABLE PROGRESS ANALYSIS

CHAPTER V: REASONABLE PROGRESS ANALYSIS

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V. Reasonable Progress Evaluation

The RHR at 40 C.F.R. 51.308(f)(2)(i) requires each state to "evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the cost of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment." The RHR specifies that states should "consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area [(nonpoint)] sources."

This chapter documents the technical basis that DEQ is relying upon to determine the emission reduction measures that are necessary to make reasonable progress at each federal Class I area affected by emissions from Arkansas, consistent with the RHR at 40 C.F.R.51.308(f)(2)(iii). The additional factors the State must consider in developing its long-term strategy consistent with RHR at 40 C.F.R.51.308(f)(2)(iii) are described in Chapter VI.

A. Identification of Key Pollutants and Source Categories that Contribute to Visibility Impairment at Federal Class I Areas in Arkansas and in Other States that may be Affected by Emissions from Arkansas

EPA guidance highlights that the RHR does not require a state to evaluate all sources of emissions in each implementation period.[1] The guidance further notes that the RHR does not explicitly list the factors a state must consider when selecting sources for a reasonable progress analysis. Therefore, each state "must reasonably choose factors and apply them in a reasonable way given the statutory requirement to make reasonable progress toward natural visibility.[2] The guidance also provides that a state may "focus on the [particulate species] that dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors."[3] Consistent with EPA's guidance, DEQ's selection of key pollutants and source categories to evaluate for its reasonable progress analysis is based on the following factors:

- Particulate species from anthropogenic sources of emissions that dominate visibility impairment at federal Class I areas in Arkansas and those affected by emissions from Arkansas;
- Relative contributions of various sectors to the Arkansas emission inventory; and
- Projected 2028 sector-based source apportionment results from EPA's modeling.[4]

1. Key Anthropogenic Particulate Species

[1] EPA (2019). "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period. at page 9.
[2] *Id.* at page 10
[3] *Id.* at page 11
[4] EPA (2019). "Technical Support Document for EPA's Updated 2028 Regional Haze Modeling." https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling

As described in Chapters II and III, 2019 data show that visibility impairment on the most impaired days at Class I areas that are reasonably anticipated to be impacted by emissions from Arkansas sources are consistently dominated by ammonium sulfate, ammonium nitrate, or both. Both species are primarily attributable to anthropogenic sources. At Caney Creek, organic mass contributes more than ammonium nitrate. However, most of the impairment from organic mass at Caney Creek is attributable to natural sources. Elemental carbon is primarily anthropogenic in nature, but it makes up a smaller contribution to visibility impairment at the federal Class I areas described in Chapters II and III.

Table V-1 lists the key anthropogenic particulate species impairing visibility on the most impaired days for federal Class I areas described in Chapters II and III. Visibility impairment on the clearest days has remained below baseline conditions. Therefore, DEQ did not put weight on relative contributions to visibility impairment on the clearest days in its consideration of source selection for the Planning Period II reasonable progress analysis.

Table V-1: Summary of Key Anthropogenic Particulate Species

Class I area	Key Anthropogenic Particulate Species	Precursor Pollutants
Caney Creek	Ammonium Sulfate Ammonium Nitrate	Ammonia, SO_2, NOx
Upper Buffalo	Ammonium Sulfate Ammonium Nitrate	Ammonia, SO_2, NOx
Mingo	Ammonium Nitrate Ammonium Sulfate	Ammonia, SO_2, NOx
Hercules Glades	Ammonium Sulfate Ammonium Nitrate	Ammonia, SO_2, NOx
Mammoth Cave	Ammonium Sulfate Ammonium Nitrate	Ammonia, SO_2, NOx
Sipsey	Ammonium Sulfate	Ammonia, SO_2
Wichita Mountains	Ammonium Nitrate Ammonium Sulfate	Ammonia, SO_2, NOx
Shining Rock	Ammonium Sulfate	Ammonia, SO_2

Chapter IV provides detailed information about trends in emissions of the precursor pollutants listed in Table V-1 in Arkansas and directly emitted $PM_{2.5}$ (Primary $PM_{2.5}$). DEQ notes that its emission inventory of Primary $PM_{2.5}$ is not speciated and therefore includes all particulate species directly emitted rather than just ammonium sulfate and ammonium nitrate.

2. Key Anthropogenic Particulate Species and their Precursors in the Arkansas Emission Inventory

Table IV-6 in Chapter IV details trends in statewide Primary $PM_{2.5}$ emissions data between 2011 and 2017 broken out by emission sector. Figure V-1 uses the data presented in Table IV-6 to show the relative contribution of each sector to the total Primary $PM_{2.5}$ emission inventory based on the most recent NEI (2017). In 2017, 85% of Primary $PM_{2.5}$ emissions in Arkansas came from sectors that DEQ does not have the authority to regulate under Arkansas law or from which DEQ is pre-empted from regulating by EPA.

Figure V-1: Sector Contributions to the Arkansas 2017 Primary $PM_{2.5}$ Emissions Inventory

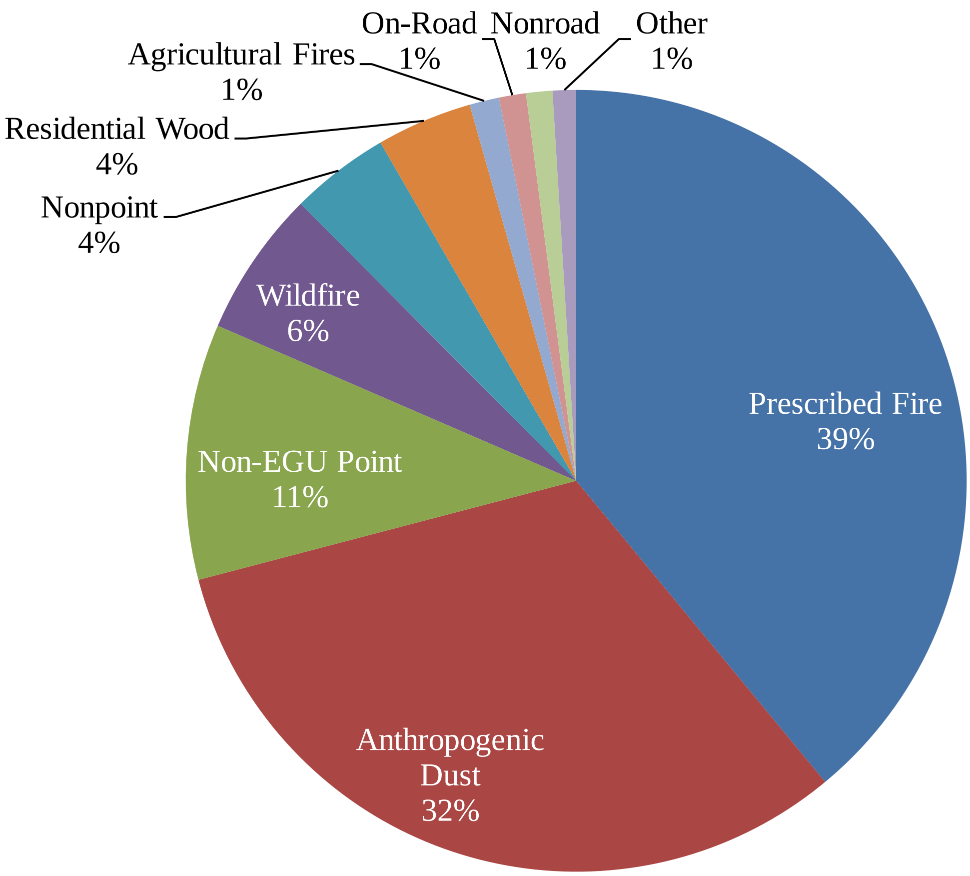


Table IV-7 in Chapter IV details trends in ammonia emissions from anthropogenic sources in Arkansas between 2011 and 2017. Figure V-2 uses the data presented in Table IV-7 to show the relative contribution of each sector to the total ammonia emission inventory based on the 2017 NEI. In 2017, 98% of ammonia emissions in Arkansas came from sectors that DEQ does not have authority to regulate under Arkansas law or from which DEQ is pre-empted from regulating by EPA. DEQ's long-term strategy does include voluntary measures to mitigate impacts from prescribed and agricultural fires.

Figure V-2: Sector Contributions to the Arkansas 2017 Ammonia Emissions Inventory

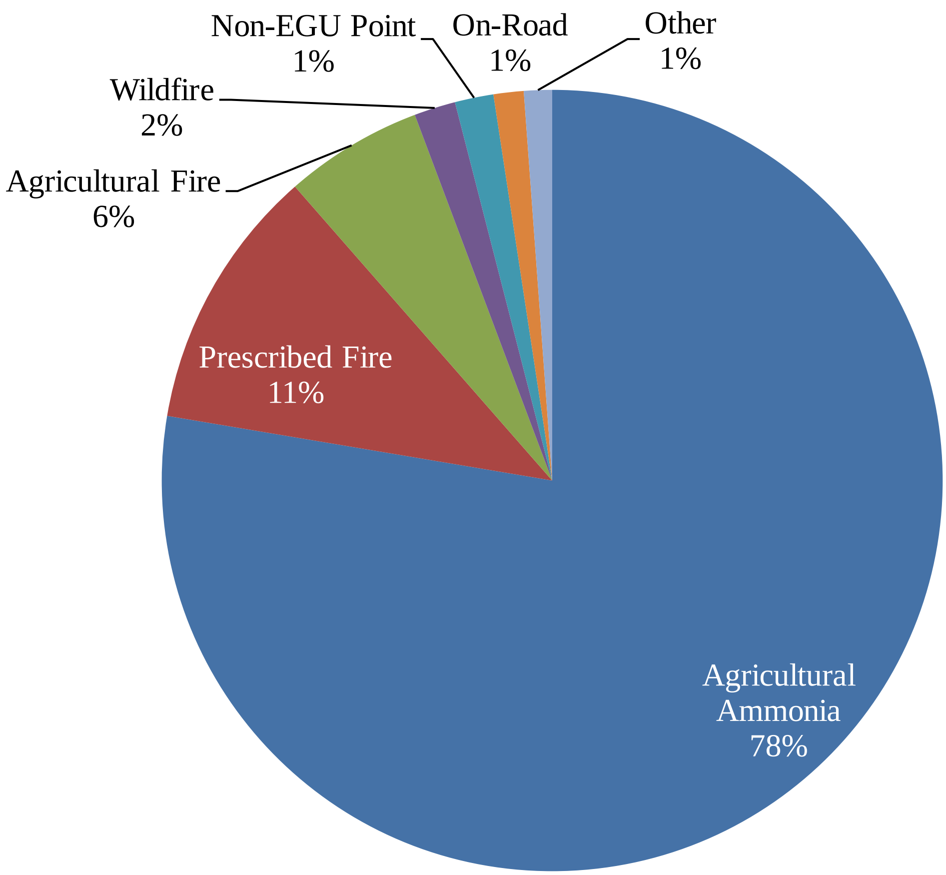


Table IV-4 in Chapter IV details trends in NOx emissions from anthropogenic sources in Arkansas between 2011 and 2017. Figure V-3 uses the data presented in Table IV-4 to show the relative contribution of each sector to the total NOx emission inventory based on the 2017 NEI. In 2017, 35% of NOx emissions in Arkansas came from sectors that DEQ has authority to regulate under Arkansas law, including larger concentrated sources, such as EGUs and Non-EGU point sources.

Figure V-3: Sector Contributions to the Arkansas 2017 NOx Emissions Inventory

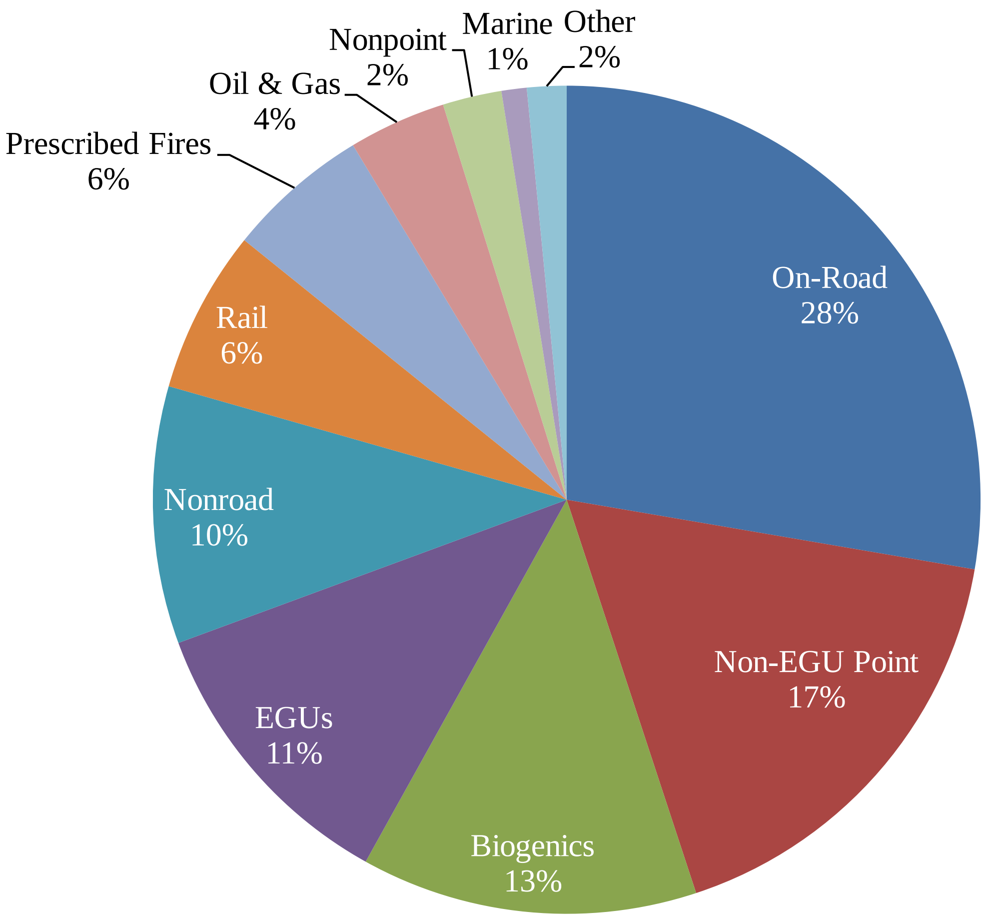
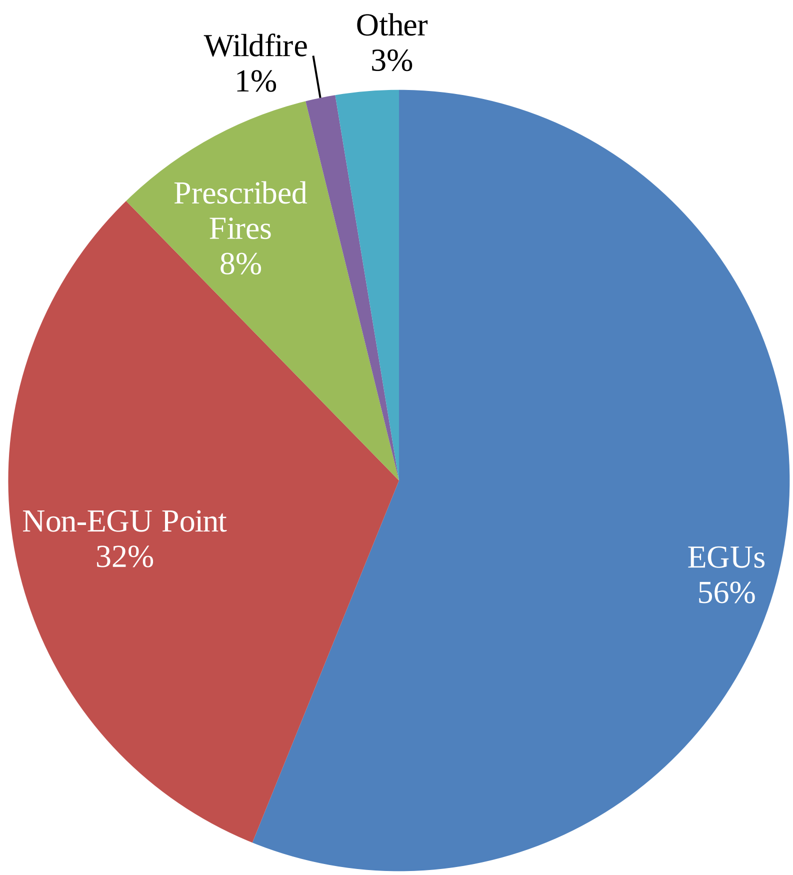


Table IV-5 in Chapter IV details trends in SO_2 emissions from anthropogenic sources in Arkansas between 2011 and 2017. Figure V-4 uses the data presented in Table IV-5 to show the relative contribution of each sector to the total SO_2 emission inventory based on the 2017 NEI. In 2017, 89% of SO_2 emissions in Arkansas came from sectors that DEQ has authority to regulate under Arkansas law, including larger concentrated sources such as EGUs and Non-EGU point sources.

Figure V-4: Sector Contributions to the Arkansas 2017 SO_2 Emissions Inventory



3. Key Emissions Sectors

Chapters II and III describe the projected relative contribution of different emission source sectors to visibility impairment on the most impaired days in 2028 at the federal Class I areas in Arkansas (Chapter II) and in federal Class I areas that may be affected by emissions from Arkansas (Chapter III). Table V-2 summarizes the sectors with the largest impact on each of the identified federal Class I areas according to EPA modeling.

Table V-2: Summary of Key Sectors Affecting Visibility Impairment in 2028

Class I area	Key Sectors Affecting Visibility Conditions in 2028
Caney Creek	EGUs (45%), Non-EGU Point (23%)
Upper Buffalo	EGUs (45%), Non-EGU Point (19%)
Mingo	EGUs (42%), Non-EGU Point (19%)
Hercules Glades	EGUs (42%), Non-EGU Point (18%)
Mammoth Cave	EGUs (46%), Non-EGU Point (21%)
Sipsey	EGUs (42%), Non-EGU Point (21%)
Wichita Mountains	EGUs (27%), Non-EGU-Point (20%), Oil & Gas (19%)
Shining Rock	EGUs (43%), Non-EGU Point (29%)

The projected 2028 source apportionment data suggests that the key sectors impacting visibility in the federal Class I areas in Arkansas and in those areas that may be affected by emissions in Arkansas are EGUs, Non-EGU Point, and Oil & Gas. EGUs and Non-EGU point sources are permitted by DEQ as stationary sources. The larger sources within the Oil & Gas sector (major pipeline and compressor stations) in Arkansas are also permitted as stationary sources.

4. Key Pollutants and Source Categories Summary

DEQ finds that it is reasonable to focus its reasonable progress evaluation for Planning Period II on stationary sources of NOx and SO_2. Recent monitor data show that the dominant anthropogenic pollutant(s) impacting visibility conditions on the most impaired days at the federal Class I areas in Arkansas and those in other states that may be affected by emissions from Arkansas is ammonium nitrate, ammonium sulfate, or both. The precursors of ammonium nitrate and ammonium sulfate include ammonia, NOx, and SO_2. In Arkansas, 98% of ammonia emissions come from sources outside the scope of DEQ's regulatory. Thirty-five percent of NOx emissions and eighty-nine percent of SO_2 emissions come from stationary sources that are regulated by DEQ. The source apportionment data show that point sources (stationary sources) are projected to continue to contribute the most to visibility impairment at these federal Class I areas. Based on this data, DEQ sees no reasonable basis for seeking additional regulatory authority to address other source categories at this time.

B. Selection of Stationary Sources of NOx and SO_2 for Analysis

DEQ used the 2016 results from the Ramboll AOI study performed for the CenSARA states to select stationary sources for consideration.[5] DEQ used a threshold of seventy percent of cumulative percentage of 2016 AOI Impacts for NOx and SO_2 combined to determine which sources to bring forward for a source-specific analysis. This screening method brings forward for further analysis five facilities in Arkansas. Table V-3 lists each facility, the federal Class I areas that each facility impacts, major emission units, and existing controls at the facility.

Consistent with EPA Guidance, this analysis was designed to ensure that source selection resulted in a set of pollutants and sources the evaluation of which has the potential to meaningfully reduce their contributions to visibility impairment.[6] DEQ also considered a threshold of 80% during the early stages of methodology development. This brought forward another eighteen sources, but all with minimal visibility impact relative to other sources on Class I Areas. The seventy percent threshold occurred at a natural break in data distribution, included the highest contributors to visibility impairment at Class I Areas, and did not unnecessarily bring forward minimal-impact sources for four-factor analysis. Consistent with EPA's July 8, 2021 Memo, *Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period* (page 4), the additional sources that would have been brought forward for analysis would not have had the "potential to meaningfully reduce contributions to visibility impairment."

Table V-3: Arkansas Sources Selected for Further Analysis

Facilities	Areas Impacted	Major Emissions Unit(s)	Existing SO_2 Controls	Existing NOx Controls
White Bluff Power Plant	Caney Creek Upper Buffalo Hercules Glades	2 Coal-fired electric generating units	Low Sulfur Coal	Low NOx Burners with Separated Overfire Air
Independence Power Plant	Upper Buffalo Hercules Glades Mingo Caney Creek	2 Coal-fired electric generating units	Low Sulfur Coal	Low NOx Burners with Separated Overfire Air

[5] AR Screening Method – V3.2_2016 Inventory Data Sheet included in Appendix C.

[6] EPA's July 8, 2021 Memo, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period (page 4)

FutureFuel Chemical Co.	Upper Buffalo Hercules Glades	3 Coal-fired boilers	None	None
Domtar A.W. LLC – Ashdown Mill	Caney Creek Wichita Mountains	Power Boiler 2	Venturi scrubbers	Overfire air
		Power Boiler 3	None	Overfire air
		Recovery Boiler 2	None	None
		Recovery Boiler 3	None	None
Flint Creek Power Plant	Upper Buffalo Hercules Glades	1 Coal-fired electric generating unit	Novel Integrated Desulfurization (Dry Lime FGD)	Low NOx Burners with Overfire Air

This method also brings forward 18 sources in other states. These sources are listed in Table V-4. DEQ sent a letter to each of these states asking the states to consider performing a four-factor analysis on the selected sources. These "Ask" letters are included in Appendix D of this SIP submittal.

Table V-4: Sources in other states selected for inclusion in "Ask" letters

State	Facility	Areas Impacted
Texas	Martin Lake Electrical Station	Caney Creek, Upper Buffalo
	AEP Pirkey	Caney Creek, Upper Buffalo
	Welsh Power Plant	Caney Creek, Upper Buffalo
	WA Parish Electric Generating Station	Caney Creek
Louisiana	CLECO Power LLC Dolet Hills	Caney Creek, Upper Buffalo
	Entergy Louisiana LLC- Roy S Nelson Plant	Caney Creek
Oklahoma	Muskogee Generating Station	Caney Creek, Upper Buffalo
	Hugo Generating Station	Caney Creek, Upper Buffalo
	Grand River Energy Center	Upper Buffalo
Missouri	Ameren Missouri Labadie Plant	Upper Buffalo
	Ameren Missouri Rush Island Plant	Upper Buffalo
	New Madrid Power Plant Marston	Upper Buffalo
	City Utilities of Springfield Missouri John Twitty Energy Center	Upper Buffalo
	Thomas Hill Energy Center Power Division	Upper Buffalo
Illinois	Prairie Generating Station	Upper Buffalo

Indiana	Indiana Michigan Power DBA AEP Rockport	Upper Buffalo
	Duke Energy Indiana LLC - Gibson Genera	Upper Buffalo
Kentucky	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	Upper Buffalo

DEQ shared these lists of sources with EPA and the FLMs. In response, EPA asked DEQ to consider whether the retirement or installation of controls at certain sources in Texas and Oklahoma that occurred after 2016, the emissions year in the AOI analysis inventory, might impact source-selection.[7] Specifically, EPA suggested revising the emissions for the following sources while maintaining the 2016 emissions for the remainder of the inventory:

- Remove or zero-out the emissions of Sandow, Big Brown, and Monticello in Texas, which shut down in 2018; and
- Use 2019 emissions for Sooner and Muskogee in Oklahoma, which implemented control strategies that reduced their SO_2 emissions in 2018.

DEQ disagrees with selectively updating emissions for some sources, but not others. Either the analysis should be based on the emissions of all sources in the year analyzed or emissions from all sources should be updated. At the time the AOI study was prepared for CenSARA, 2016 was the most recent year of emissions data for all sources. Updating the emissions for all sources for would be an unreasonable diversion of DEQ and/or CenSARA resources as well infeasible to complete as a practical matter given the deadline for submittal of the second planning period SIP. The 2016 AOI results provide an adequate representation of the relative contribution of stationary sources to visibility impairment at the federal Class I areas at the start of the second planning period for the purposes of screening sources for further analysis. DEQ chose not to use the projected 2028 AOI data because it reflects some of changes based on unrealistic assumptions from the Integrated Planning Model for 2028 emissions from EGUs.

Nevertheless, DEQ has performed a sensitivity analysis to see if EPA's requested change would alter the Arkansas sources brought forward for further analysis for Planning Period II. DEQ performed this sensitivity analysis for each of the federal Class I areas that includes at least one Arkansas source in the 2016 AOI and at least one of the five sources identified by EPA.[8] The spreadsheet used for this analysis is included in Appendix E. At a seventy percent selection

[7] See email from Michael Feldman (EPA R6) dated April 13, 2020 included in Appendix D.

[8] Caney Creek, AR; Upper Buffalo, AR; Hercules Glades, MO; and Wichita Mountains, OK are the only federal Class I areas for which the data that include at least one of the five sources mentioned by EPA in the 0.05% EWRT threshold AOIs. Therefore, there would be no changes for Isle Royale, Badlands, Sipsey, Mammoth Cave, or Mingo.

threshold, this sensitivity analysis would bring in two additional sources in Arkansas for further consideration. These two sources are included in Table V-5.

Table V-5: Additional Potential Sources based on Sensitivity Analysis

Facilities	2016 NOx Emissions (tons)	2016 SO_2 emissions (tons)	Major Emissions Unit(s)
Weyerhaeuser NR Company – Dierks Mill	201.441	23.236	SN 45 Wood-fired Boilers
Albemarle Corporation – South Plant	113.42	1650.361	SR-01 Tail Gas Incinerator

Weyerhaeuser NR Company – Dierks Mill (Dierks Mill) is a sawmill that processes lumber and wood residuals. This plant has relatively low emissions of NOx and SO_2 compared to the sources selected with the seventy percent threshold based on the 2016 AOI (with no emissions substitutions). The mill is located 40 km from Caney Creek. Dierks Mill has one major emission unit for NOx (100 tpy or greater) and none for SO_2. This emission unit is a 249.0 MMBtu/hr wood-fired boiler that combusts wood, small amounts of waste paper generated on site, and small quantities of sawdust.[9] This boiler was last operated in 2017 and removed from the Dierks Mill permit in May 2020.[10] Based on the Dierks Mill's wood-fired boiler's maximum fuel consumption rating and low annual emissions as compared to larger sources of NOx emissions, DEQ does not anticipate that retrofit post-combustion controls would have been reasonable even if this unit had continued to operate. Based on this assessment, addition of Dierk's Mill to the set of sources for evaluation using the four factors would not produce more potential for meaningfully reducing contributions from Arkansas sources to visibility impairment at Class I areas.

Albemarle Corporation – South Plant (Albemarle South) is a chemical manufacturer that extracts bromine-containing brine from geologic formations. The facility has one major emission unit for SO_2 (100 tpy or greater) and none for NOx. This emission unit is itself part of a control system that burns off tail gas from the sulfur recovery plant. The sulfur recovery plant removes ninety-three percent of the sulfur from sour gas created during bromine separation from the extracted brine. Based on a review of the RACT/BACT/LAER database, DEQ did not identify any additional technically feasible SO_2 controls for this type of emission unit that could be implemented in addition to the existing control (tail gas incinerator). Based on this assessment, addition of Albermarle South to the set of sources for evaluation using the four factors would not

[9] EPA's Control Cost Manual provides retrofit cost estimation information based on studies of boilers with 250 MMBtu/hr or greater.
[10] Permit No. 0023-AOP-R14

produce more potential for meaningfully reducing contributions from Arkansas sources to visibility impairment at Class I areas.

EPA's suggested source selection adjustments would make no difference in the sources that DEQ would analyze using the four reasonable progress factors. Furthermore, the changes at Dierks Mill highlight the rationale for not selectively updating only the handful of sources that EPA R6 requested. Any changes to facilities occurring after the historical year used for screening (2016) will be reflected in the 2028 reasonable progress goals.

Consistent with EPA guidance, DEQ selected sources to perform additional analyses to determine what control measures are necessary to achieve reasonable progress. The four sources that DEQ selected for further analysis were Independence Power Plant, Future Fuel Chemical Company, Domtar Ashdown Mill, and Flint Creek Power Plant. DEQ then determined which potential emission control measures to consider for each facility and, based on information from the four-factor analysis for each facility, determined what emission control measures will be necessary to make reasonable progress for the second implementation period.

C. Analyses for Selected Sources

DEQ gathered data for each selected source to evaluate for potential emission control measures through a combination of permit review, information collection requests (ICRs)[11], and emission inventory data. For each selected source, DEQ identified the emission units that emit the majority of SO_2, NOx, or both; identified existing controls in place at each of the identified emission units, and identified potential control strategies that may be technically feasible for each emission unit. These data, together with historic and projected visibility data at Class I areas in Arkansas and in other states that may be affected by emissions from Arkansas, were evaluated to assess what emission control measures, if any, at the selected sources are necessary to achieve reasonable progress during Planning Period II.

1. Characterization of Factors for Emission Control Measures

Clean Air Act 169A(g) and the RHR at 40 C.F.R. 51.308(f)(2)(i) requires states consider four factors in its evaluation to determine whether emission reduction measures for selected sources are necessary to make reasonable progress: cost of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment. However, a state is not limited to solely considering these factors. In addition to the mandatory factors, DEQ also considered in its evaluation the progress that has been achieved at these federal Class I areas, the anticipated visibility impairment in 2028 at these federal Class I areas. This approach is consistent with the flexibility provided to states under the RHR, the recommendations included in EPA's guidance, and the iterative nature of the regional haze program.

[11] Information collection requests and responses are included in Appendices F–I.

a. Cost of Compliance

For the purposes of DEQ's evaluation, the cost of compliance is expressed in terms of cost per ton of emissions reduced by a potential control strategy. To determine the numerator in the cost/ton metric, DEQ's ICR instructed the permittees to quantify the annual cost of implementing each technically feasible potential control strategy using the EPA Pollution Control Cost Manual[12] overnight methodology. DEQ reviewed the cost information provided to ensure that the estimated costs were reasonable and consistent with the EPA Pollution Control Cost Manual. To determine the denominator in the cost/ton metric, DEQ's ICR instructed the permittees to quantify their baseline actual emission rate,[13] the control rate, and the resulting annual emission reductions that would be anticipated from each potential control technology.

This cost/ton metric for expressing cost of compliance is consistent with EPA guidance[14] and allows DEQ to perform an "apples-to-apples" comparison of the cost of different control options at the same source and across different sources. This metric also allows for comparison against the cost of measures that have been previously implemented as part of Regional Haze Planning Period I plans or in response to other Clean Air Act requirements.

EPA guidance also states that "when the cost/ton of a possible measure is within the range of the cost/ton values that have been incurred multiple times by sources of similar type to meet regional haze requirements or any other [Clean Air Act] requirement, this weighs in favor of concluding that the cost of compliance is not an obstacle to the measure being considered necessary to make reasonable progress."[15] Based on this guidance, DEQ performed a survey of cost/ton values that were incurred as a result of BART and reasonable progress determinations during Planning Period I. DEQ escalated the cost/ton values of each determination to 2019 dollars using the Chemical Engineering Plant Cost Index. DEQ did not include any BART-alternatives in this analysis because many BART alternatives were either trading programs or selected on the basis that an operations change suggested by a facility had greater visibility benefit than what would be achieved by BART rather than on a technology-specific cost-basis. The spreadsheet of compiled Planning Period I costs/ton is included in Appendix J. Table V-6 provides summary statistics for Planning Period I cost/ton by emission unit type. These summary statistics provide options for selection of a threshold for DEQ to use to determine potential control measures for which cost is not an obstacle to the measure being considered necessary to make reasonable progress.

Table V-6: Descriptive Statistics for Cost/Ton Values of Planning Period I Source-Specific Control Technology Determinations by Emission Unit Type

[12] https://www.epa.gov/economic-andcost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[13] Generally, the baseline period for this analysis was January 1, 2017 – December 31, 2019. However, DEQ requested shorter baseline periods for certain emission units based on controls implemented after January 1, 2017.
[14] EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period
[15] EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period

Emission Unit Type	MIN	MAX	MEAN	MEDIAN	STDEV	98th Percentile
EGU Boiler	(57)	5,193	2,023	1,419	131	**5086**
Industrial Boiler	428	3,732	1,406	833	428	**3328**
Kiln	514	4,774	1,567	1,143	514	**4194**
Smelter	912	1,044	978	93	912	**1041**
All	*(57)*	*5,193*	*1,905*	*1,353*	*(57)*	*4989*

DEQ has selected a 98th percentile for each emission unit type listed in Table V-6 as a threshold to evaluate the cost of compliance for each potential control strategy evaluated for the selected sources for Planning Period II. This metric ensures that costs incurred multiple times by sources of a similar type are captured while potential outliers that may have only occurred once or twice are eliminated.

DEQ's decision to select different thresholds for different emission unit types is reasonable because certain aspects of the four factors have different implications for different facilities. One such distinction is how the costs of compliance are financed and on whom those costs are imposed. For example, the cost of compliance for investor-owned EGUs in Arkansas, such as Flint Creek, is passed on to ratepayers by statute that allows the recovery of investments to comply with administrative rules or that related to the protection of the public health, safety, or the environment. By contrast, the costs of Industrial Boilers are borne by the company that owns that facility. Whether these costs can be absorbed by the facility owners or passed on to customers is a matter of the market for the goods or services the facility provides.

Although DEQ has created a cost-effectiveness threshold, there may be circumstances for which multiple control strategies are cost-effective. Cost-effectiveness is just one of the four factors states must consider and there may be other factors beyond the four statutory factors that inform a state's decision-making. For example, in Planning Period I, DEQ identified three cost-effective control strategies for the Entergy Independence coal-fired boilers: fuel switching to LSC, Dry FGD, and Wet FGD.[16] Wet FGD was eliminated based on an EPA analysis that found that the high incremental cost between Dry FGD and Wet FGD was not justified given the minimal incremental increase in visibility benefit that would be achieved over Dry FGD. Although Dry FGD is a more stringent control, DEQ selected LSC as the control for the Independence units necessary to make reasonable progress during Planning Period I because the cost-effectiveness value was better, overall costs were lower than Dry FGD resulting in less of a burden to electricity ratepayers, and Arkansas Class I areas were already making substantial progress toward natural visibility conditions. This decision was approved by EPA in its 2019 action on the Phase II SIP revision for Planning Period I.[17]

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[16] 2018 Planning Period I, Phase II Arkansas SIP, https://www.adeq.state.ar.us/air/planning/sip/pdfs/regional-haze/rh-phase-ii-sip-narrative-final.pdf

[17] Approval and Promulgation of Implementation Plans; Arkansas; Approval of Regional Haze State Implementation Plan Revision for Electric Generating Units in Arkansas, 84 FR 51033-01

b. Time Necessary for Compliance

The time necessary for compliance factor requires estimation of the time needed for the source to come into compliance with a potential control measure in an "efficient manner without unusual amounts of overtime, above-market wages and prices, or premium charges for expedited delivery of control equipment."[18] Although a required factor for consideration, time necessary for compliance is more relevant to establishing compliance schedules for control measures determined to be necessary to ensure reasonable progress rather than for determining whether a potential control measure is reasonable and necessary. The time necessary for compliance can play a role in determining the cost of compliance if the remaining useful life for an emission unit is less than the life of the equipment involved in the potential control measure(s) under consideration. Specifically, the time necessary for compliance may influence how capital costs of control measures are annualized under such circumstances.

c. Energy and Non-Air Environmental Quality Impacts of Compliance

Unless the non-air environmental quality impact of compliance for a potential control measure renders that control measure technically infeasible, DEQ's ICR instructed the permittees of selected sources to specify any energy and non-air environmental impacts and factor the associated costs into the cost of implementing a potential control measure. Therefore, this factor is subsumed into the cost of compliance factor for the purposes of DEQ's evaluation.

d. Remaining Useful Life

For the purposes of DEQ's evaluation, the remaining useful life factors into the cost of compliance. If an emission unit has an enforceable requirement to cease operation, this may shorten the number of years over which capital costs are annualized and thus increase the cost/ton amount. If there is no such enforceable requirement, annualization of capital costs is based on the expected life of the equipment involved in the potential control measures under evaluation. EPA guidance also explicitly provides that states may choose not to conduct a four-

[18] EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period". Page 45
https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period

factor analysis for a particular source if that source is "expected to close by December 31, 2028, under an enforceable requirement."[19]

e. Visibility Considerations

Consideration of historical and projected visibility progress provides valuable context for the consideration of potential control measures that may be necessary for ensuring reasonable progress. As described in Chapters II and III, federal Class I areas in Arkansas and federal Class I areas in other states that may be affected by emissions from Arkansas made considerable progress towards natural visibility conditions on the most impaired days during Planning Period I. Projected 2028 conditions for each Class I area, with the exception of Wichita Mountains, are on track with any glidepath the relevant state may choose to establish in their Planning Period II SIP before consideration of additional control measures to ensure reasonable progress. Any additional controls required by DEQ and/or other states will further accelerate progress toward natural visibility conditions during Planning Period II.

2. Evaluation of Potential Control Measures for White Bluff Power Plant

White Bluff Power Plant (White Bluff) is a coal-fired electric generating station located in Jefferson County, Arkansas. White Bluff has two major emissions units: Unit 1 and Unit 2. Unit 1 and Unit 2 are identical tangentially-fired 850 megawatt boilers with a maximum heat input capacity of 8,950 MMBtu/hr each. Units 1 and 2 burn sub-bituminous coal as a primary fuel. Units 1 and 2 are equipped with low NOx burners with separated overfire air to control NOx emissions and electrostatic precipitators to control particulate matter emissions.

Entergy is required to comply with an emission limit of 0.60 lb SO_2/MMBtu for Units 1 and 2 on a thirty-boiler-operating-day rolling average based on fuel switching to lower sulfur coal by August 7, 2021 pursuant to an agreed order between DEQ and Entergy as part of the 2018 Phase II Regional Haze SIP revision.[20] This state- and federally-enforceable administrative order also requires Units 1 and Units 2 to cease coal-fired operations by no later than December 31, 2028.

DEQ considers the enforceable requirement to cease coal-fired operations at White Bluff by December 31, 2028 to be sufficient reason to not perform a four-factor analysis for this source for Planning Period II. This determination is consistent with EPA guidance on source selection for four-factor analyses.[21] It is clear that no additional control measures will be cost-effective for this source. As demonstrated in DEQ's Phase II SIP revision for Planning Period I, additional control measures beyond the low NOx burners and low sulfur coal, which have already been

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[19] Ibid., Page 20.

[20] Administrative Order LIS No. 18-073, dated August 7, 2018; accessible here: https://www.adeq.state.ar.us/air/planning/sip/pdfs/regional-haze/entergy-ao-executed-8-7-2018.pdf

[21] Page 20 of EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" instructs states that "If a source is expected to close by December 31, 2028, under an enforceable requirement, a state may consider that to be sufficient reason to not select the source at the source selection step."

implemented at White Bluff, were not cost-effective due to the plant's remaining useful life.[22] The annual cost for control measures evaluated during Planning Period I would only be expected to increase in an updated reasonable progress analysis because White Bluff is nearer to its cessation of coal-fired operations date than it was in the previous analysis. The technologies available to reduce NOx and SO_2 at power plants, such as White Bluff, have not changed since 2018.[23] This determination is also consistent with EPA guidance that allows for the exclusion of sources from additional analyses when it is clear that no additional control measures will be adopted.[24]

DEQ has determined that existing control measures at White Bluff are sufficient for reasonable progress. The requirement to burn low sulfur coal is already part of the SIP. The low NOx burners installed at White Bluff are an inherent part of equipment design (i.e., cannot be shut down temporarily, as is the case with a post-combustion control). Therefore, no separate emission limit is necessary for inclusion in the SIP to ensure operation of the low NOx burners.

If Entergy chooses to continue operations of the White Bluff units after December 31, 2028, they must apply for a permit revision to burn a different fuel. Such a permit revision would be subject to new source review requirements. If the change would result in a significant increase in emissions, prevention of significant deterioration and best available control technology requirements would be triggered. The most likely fuel switch would be to natural gas, which inherently emits much less SO_2 and NOx relative to coal.[25, 26]

3. Independence Power Plant

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[22] See EPA's Final Rule, 84 FR 51033, at page 51040: "Under a BART analysis, the remaining useful life of a scrubber is assumed to be 30 years unless a facility has an enforceable agreement in place to shut down or cease coal combustion earlier [ ] Entergy entered into an Administrative Order with ADEQ [ ] to cease coal combustion at Units 1 and 2 at White Bluff by December 31, 2028. It was therefore appropriate for ADEQ to rely on this cease to combust coal date for White Bluff Units 1 and 2 in the calculation of the units' remaining useful life, which is used to determine the cost effectiveness of controls in the BART analysis."

[23] See EPA's Menu of Control Measures. https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

[24] EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" at Page 20 states: "EPA expects that, typically, states are more likely to select sources based on visibility impacts and not consider the four reasonable progress factors (i.e., cost of compliance, remaining useful life, time necessary for compliance, and energy and non-air quality environmental impacts) until after a source is selected. However, in some cases, a state may already have information on one or more of the four reasonable progress factors at the time of source selection. If so, the state may consider that information at the source-selection stage. In particular circumstances, that information may indicate that it is reasonable to exclude the source for evaluation of emission control measures because it is clear at this step that no additional control measures would be adopted for the source."

[25] EPA's Menu of Control Measures estimates that fuel switching from subbituminous coal to natural gas has a typical control efficiency of 99.9%. https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

[26] EPA (2014). Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units—GHG Abatement Measures. Office of Air and Radiation.

The Entergy Independence Power Plant (Independence) is a coal-fired electric generating station located in Independence County, Arkansas. Independence has two identical 900-megawatt boilers: Unit 1 and Unit 2. 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. Independence was identified by DEQ, Oklahoma Department of Environmental Quality, Missouri Department of Natural Resources, and the VISTAS as a source whose NOx and/or SO_2 emissions may affect visibility conditions in federal Class I areas.

The two Independence units are equipped with low-NOx burners with separated overfire air to control NOx emissions and electrostatic precipitators to control particulate matter emissions. Entergy is required to comply with an emission limit of 0.60 lb SO_2/MMBTU for these two units on a thirty-boiler-operating-day rolling average based on fuel switching to lower sulfur coal by August 7, 2021, pursuant to an agreed order between DEQ and Entergy as part of the 2018 Phase II Regional Haze SIP revision. Entergy Independence's Title V permit contains a 6090 lb NOx/hr and a 0.7 lb NOx/MMBTU limit for each unit.

On January 8, 2020, DEQ sent an ICR to Entergy asking for information about potential emission reduction strategies for SO_2 and NOx emissions from Independence Units 1 and 2. Specifically, DEQ requested updated information regarding the following control technologies:

- SO_2 (ranked from highest control efficiency to lowest)[27]
    - Fuel Switching from coal to natural gas
    - Wet Gas Scrubber (Wet FGD)
    - Spray Dryer Absorber (Dry FGD)
    - In-Duct Dry Sorbent Injection (DSI)
- NOx (ranked from highest control efficiency to lowest) for all units[28]
    - Selective Catalytic Reduction (SCR)
    - Selective Non-Catalytic Reduction (SNCR)

On April 7, 2020, Entergy provided information responsive to DEQ's ICR. This response is included in Appendix F. DEQ's evaluation of potential control strategies for Independence is based on the information contained in Entergy's response.

a. Technical Feasibility of Identified Control Strategies

Wet FGD, Dry FGD, DSI, SCR, and SNCR are technically feasible control technologies for Independence Units 1 and 2, and fuel switching to natural gas is not a feasible control technology for the purpose of DEQ's reasonable progress analysis. In their response to the ICR, Entergy explains that fuel-switching from coal to natural gas would not be a feasible control strategy for

[27] EPA Menu of Control Measures
https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation
[28] EPA Menu of Control Measures
https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

Independence. In particular, Entergy points out that fuel-switching the two 880 MW units would be a “significant and fundamental change,” and that the modifications necessary to make such a switch have not been demonstrated in similarly sized units. EPA’s 2019 “Guidance on Regional Haze State Implementation Plans for the Second Implementation Period” states that “[s]tates may also determine that it is unreasonable to consider some fuel-use changes because they would be too fundamental to the operation and design of a source.[29] In addition, Entergy stated that the installation of a natural gas pipeline to connect to the nearest existing pipeline five miles away could result in negative impacts to streams and wetlands along the pipeline route. Furthermore, a switch to natural gas at Independence would render the plant less efficient relative to units originally designed to burn natural gas. Based on the information provided by Entergy and EPA guidance, DEQ finds that it is unnecessary to perform an analysis of the fuel-switching from coal to natural gas as an emission reduction strategy for the Independence units.

b. Baseline Emission Rate

Entergy provided baseline SO_2 and NOx emissions for each Independence unit annualized on both a maximum monthly emission rate basis and an average monthly emission rate basis for the period of November 1, 2018, to December 31, 2019, for Unit 1 and January 1, 2018, to December 31, 2019, for Unit 2.[30] DEQ used the maximum monthly emission rate to ensure that control technology evaluated is adequately sized for the purposes of control cost calculations. DEQ used the average monthly baseline emission rate to estimate typical emission reductions that can be anticipated from the application of a control strategy. Table V-7 summarizes baseline emissions on an average monthly basis for Independence.

Table V-7: Entergy Independence Baseline Emissions (Average Month Basis)

Emission Unit	SO_2 Baseline Emissions (tpy)	NOx Baseline Emissions (tpy)
Unit 1	9,945	3,423
Unit 2	10,672	3,180

c. Control Effectiveness

Table V-8 summarizes the control effectiveness of each technically feasible emission reduction strategy evaluated for the Independence units in Entergy’s response to DEQ’s ICR.

Table V-8: Control Effectiveness and Emission Reductions Estimated for Control Strategies Evaluated for Entergy Independence

Emission Unit	Control Strategy	Pollutant	Controlled Emission Rate (lb/MMBtu)	Estimated Emission Reductions (tpy)
Unit 1	WFGD	SO_2	0.04	9,104

[29] EPA (2019). “Guidance on Regional haze State Implementation Plans for the Second Planning Period,” p.30.

[30] DEQ requested this baseline period for Independence based on the timing of installation of low-NOx burners for Independence Units 1 and 2.

	DFGD	SO_2	0.06	8,864
	Enhanced DSI	SO_2	0.15	6,792
	DSI	SO_2	0.35	2,587
	SCR	NOx	0.055	2,267
	SNCR	NOx	0.13	690
Unit 2	WFGD	SO_2	0.04	9,786
	DFGD	SO_2	0.06	9,342
	Enhanced DSI	SO_2	0.15	7,347
	DSI	SO_2	0.35	2,914
	SCR	NOx	0.055	1,961
	SNCR	NOx	0.13	298

d. Cost of Compliance

In their response to DEQ's ICR, Entergy calculated the cost of the compliance based on the assumption that the Independence units will cease coal-fired operations by December 31, 2030. In addition, Entergy used a 7% interest rate for annualizing capital costs. This interest rate is consistent with past cost analyses for regional haze planning and the interest rate for calculating the social cost of rulemaking referenced in the EPA Control Cost Manual. The EPA Control Cost Manual recommends that assessments of private cost "should be prepared using firm-specific nominal interest rates if possible, or the bank prime rate if firm-specific interest rates cannot be estimated or verified."[31] While DEQ originally proposed to use a bank prime rate of 3.25%, after considering comments received during the public comment period, and recent upward trend of the federal interest rate, DEQ is revising analyses to employ 7% as a "default" interest rare as is outlined in EPA's Control Cost Manual. For comparison, DEQ has also calculated annual costs based on the expected life of the control equipment evaluated.[32] DEQ's cost calculations are included in Appendix F.

Table V-9 presents the estimated costs for the control strategies evaluated for the Independence units using a 7% interest rate for both Entergy's remaining useful life (RUL) assumptions and equipment life assumptions in 2019 dollars.[33] Table V-10 provides the cost-effectiveness of each of these strategies on an average month basis for each unit. Table V-10 also presents the cost-effectiveness averaged across both units. Because both units are identical in design and perform the same function at the same plant, implementing a control on only one unit could result in reducing the use of that unit and increasing the use of the other. As a result, the emission reductions estimated from controlling the one unit would likely not be fully achieved.

Table V-9: Estimated Total Annual Cost of Evaluated Control Strategies for Independence in

[31] *Id.* at pages 2-15

[32] Equipment life assumptions: Thirty years for WFGD, FGD, Enhanced DSI, DSI, and SCR and 20 years for SNCR.

[33] Chemical Engineering Plant Cost Index used to escalate costs provided by Entergy to 2019.

2019 Dollars

Emission Unit	Control Strategy	Total Annual Cost ($2019 MM/year)	
		Entergy RUL Assumptions	Equipment Life Assumptions
Unit 1	WFGD	163.78	58.14
	DFGD	128.76	29.47
	Enhanced DSI	98.40	47.18
	DSI	52.72	26.01
	SCR	62.31	13.33
	SNCR	9.34	7.18
Unit 2	WFGD	163.78	58.14
	DFGD	128.76	29.47
	Enhanced DSI	98.40	47.18
	DSI	52.72	26.01
	SCR	62.31	13.33
	SNCR	9.34	7.18

Table V-10: Estimated Cost-Effectiveness of Evaluated Control Strategies for Independence in 2019 Dollars

Emission Unit	Control Strategy	Pollutant	Cost-effectiveness ($2019/ton)	
			Entergy RUL Assumptions	Equipment Life Assumptions
Unit 1	Wet FGD	SO_2	19,109	7,627
	Dry FGD	SO_2	15,931	4,616
	Enhanced DSI	SO_2	15,673	8,335
	DSI	SO_2	22,001	11,955
	SCR	NOx	29,573	8,191
	SNCR	NOx	13,861	10,739
Unit 2	Wet FGD	SO_2	17,778	7,095
	Dry FGD	SO_2	14,809	4,291
	Enhanced DSI	SO_2	14,489	7,706
	DSI	SO_2	19,532	10,613
	SCR	NOx	34,188	9,469
	SNCR	NOx	32,095	24,864
Average of Units 1 and 2	Wet FGD	SO_2	18,444	7,361
	Dry FGD	SO_2	15,370	4,454
	Enhanced DSI	SO_2	15,081	8,020
	DSI	SO_2	20,766	11,284
	SCR	NOx	31,881	8,830
	SNCR	NOx	22,978	17,802

Table V-10 illustrates that cost-effectiveness based on the assumption of a 2030 cessation of coal-fired operation of Unit 1 and Unit 2 greatly increases the annual cost of compliance above the annual costs that would be incurred over the life of the control equipment. The cost of all potential control strategies examined exceeds DEQ's cost threshold for EGU boilers under the assumption that coal-fired operations of Independence Units 1 and 2 ceases by December 31, 2030. Based on equipment life, only Dry FGD would fall below the threshold.

e. Time Necessary for Compliance

Table V-11 provides a summary of the time that Entergy indicated would be necessary to comply with each of the assessed control technologies.

Table V-11: Time Necessary to Comply for Evaluated Control Strategies for Independence

Control Strategy	Time Necessary to Comply	Basis
Wet FGD	5 years	Time determined necessary for compliance in EPA 2016 FIP
Dry FGD	5 years	Time determined necessary for compliance in EPA 2016 FIP
Enhanced DSI	3 years	None provided by Entergy in 2020 Response
DSI	3 years	None provided by Entergy in 2020 Response
SCR	5 years	Precedent in Utah and North Dakota FIPs[34]
SNCR	5 years	Precedent in Utah and North Dakota FIPs

DEQ finds it is reasonable to rely on the estimates provided in Table V-11 for this specific source. Entergy did not provide a basis for the time necessary to implement enhanced DSI and DSI in their April 7, 2020 response to DEQ's ICR. However, similar estimates of time necessary to comply have been provided for these technologies in other analyses.[35] As a result, it is appropriate to rely on the time necessary for compliance information provided for these two control technologies as well.

f. Energy and Non-Air Quality Impacts

Entergy reported that each SO_2 control technology evaluated (Wet FGD, Dry FGD, and DSI) would result in generation of additional wastes. Wet FGD and Dry FGD would increase water consumption. In addition, Entergy would no longer be able to sell fly ash if DSI were implemented due to sodium byproducts in the ash produced during reaction of the sorbent (Trona) and SO_2.

Entergy reported that both NOx control technology evaluated (SCR and SNCR) would increase electricity needs to operate the system. In addition, the storage of aqueous ammonia that would be used by either system presents a risk to health of persons in the vicinity in the event of an accidental release. Operation of SCR and SNCR may also release unreacted ammonia into the atmosphere if temperatures during ammonia injection are too low or if there is an over-injection of ammonia. In addition, disposal of spent SCR, if it cannot be recycled, must be disposed of as a waste.

The energy and non-air quality impacts associated with the reviewed technology have been factored into the cost of compliance.

g. Remaining Useful Life of the Source

[34] 77 FR 20944 (April 6, 2012) and 81 FR 43907 (July 5, 2016), respectively.
[35] See FutureFuel Chemical Company's response to DEQ's ICR in Appendix G.

Entergy used an assumption of 5.42 years remaining useful life for both Enhanced DSI and DSI to annualize capital and indirect costs. Entergy used 3.42 years for all other assessed technologies. These remaining useful life assumptions are based on the time necessary for compliance and Entergy's plans to cease coal-fired operations at both Independence units by December 31, 2030.

> On March 11, 2021, Entergy entered into a consent decree with Sierra Club that renders Entergy's planned cessation of coal-fired operations at Independence by December 31, 2030 binding.[36] DEQ has entered into an administrative order with Entergy that renders the requirement to cease coal-fired operations by no later than December 31, 2030 at Independence enforceable by the state immediately and, upon approval of the SIP, federally enforceable by EPA.[37] Visibility Considerations

The 2016 results from the Ramboll AOI study indicate that emissions from Independence had a greater impact on Upper Buffalo and Hercules Glades than any other stationary source.[38] The results indicate that Independence contributed to a lesser extent to visibility impairment at Caney Creek, Mingo, and Sipsey.[39] These five Class I areas are on track to make greater progress than the URP glidepath in 2028 before consideration of potential controls for Independence. Independence is not within the nitrate or sulfate-specific area of influence for Mammoth Cave or Wichita Mountains based on the 0.05% threshold. Source apportionment from VISTAS modeling indicated that Independence was projected to contribute 1.04% of the total sulfate and 0.01% of total nitrate point source visibility impact on the most impaired days in 2028 at Shining Rock. Shining Rock is also on track to make greater progress than the URP glidepath in 2028 before consideration of potential controls for Independence.

h. Proposed Decision on Control Measures Necessary to Make Reasonable Progress

In determining whether additional control measures are necessary for Independence during Planning Period II, DEQ weighs the four statutory factors and visibility considerations. The time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life have been factored into the cost of compliance for the potential controls considered for Independence. The cost of compliance for each potential control strategy for Independence, given the planned cessation of coal-fired operations by December 31, 2030, exceeds DEQ's cost threshold for EGU Boilers. Similar to White Bluff, if Independence were to continue to operate past December 31, 2030, a permit revision with new source review would be required for the new fuel. Furthermore, each federal Class I area for which Independence is within the nitrate- or

[36] https://237995-729345-1-raikfcquaxqncofqfm.stackpathdns.com/wp-content/uploads/2021/03/settle.pdf

[37] See Appendix F.

[38] The Independence visibility surrogate value was 26% of the total sum of surrogate values for all point sources in the 2016 inventory for Upper Buffalo and 20% for Hercules Glades.

[39] The Independence visibility surrogate value was 5% of the total sum of surrogate values for all point sources in the 2016 inventory for 5% for Caney Creek, 3% for Mingo, and1% for Sipsey.

sulfate-specific area of influence are on track to make greater progress than the URP glidepath in 2028 before consideration of additional controls at Independence. Although the URP is not determinative in making a decision with respect to whether a control is reasonable after consideration of the four factors, being below the URP glidepath means that the additional demonstrations under 40 C.F.R. 51.308(f)(3)(ii) are not required. After consideration of the statutory factors and visibility considerations, DEQ has determined that no additional controls are necessary at Independence Units 1 and 2 to make reasonable progress during Planning Period II.

4. FutureFuel Chemical Company

FutureFuel Chemical Company manufactures specialty organic chemical intermediates used in the manufacture of color film and photographic paper, paints and coatings, plastics and bottle polymers, medical supplies, prescription medicines, food supplements, household detergents, agricultural products, and biofuel. Ninety-nine percent of the facility's SO_2 emissions and seventy-two percent of the facility's NOx emissions come from three coal-fired boilers used to produce steam and destroy chemical wastes.[40] Other emission units that emit SO_2, NOx, or both include two natural gas-fired boilers, a regenerative thermal oxidizer, thermal oxidizers and caustic scrubbers, a chemical waste destructor, a flare, two hot oil systems, a diesel glycol pump, two diesel waste disposal pumps, a diesel generator, and a diesel fire water pump.

The three coal-fired boilers are balanced draft steam generation boilers designed to operate at 70 MMBtu/hr per unit. The units share a common primary fuel conveying system, a common ash handling system, and a common 200-foot-tall stack. Each unit is equipped with its own ESP to control particulate emissions. The units do not have existing controls for NOx or SO_2. Emission limits for the three-boiler system are 1,391 lbs/hr SO_2 (5982.9 tpy) and 106 lbs/hr NOx (488.2 tpy), contained in the facility's federally-enforceable Title V permit.[41] FutureFuel is also subject to a permit condition that prohibits combusion of coal with sulfur content greater than 3.8% by weight.

On January 8, 2020, DEQ sent an ICR to FutureFuel asking for information about potential emission reduction strategies for SO_2 and NOx emissions from the three coal-fired boilers.

[40] 2016 ADEQ Emission Inventory
[41] https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/1085-AOP-R15.pdf

Specifically, DEQ requested information for the following potential emission reduction strategies:

- SO_2 (ranked from highest control efficiency to lowest)[42]
    - Fuel Switching from coal to natural gas
    - Wet Gas Scrubber
    - Spray Dryer Absorber (SDA)
    - DSI
    - Fuel Switching to a lower sulfur coal
- NOx (ranked from highest control efficiency to lowest) for all units[43]
    - SCR
    - SNCR
    - Low-NOx Burner

On April 7, 2020, FutureFuel provided information responsive to DEQ's ICR. This response is included in Appendix G. Additional follow-up communication to provide further technical justification and calculations are also included in Appendix G. DEQ's evaluation of potential control strategies for FutureFuel are based on the information contained in FutureFuel's response.

a. Technical Feasibility of Identified Control Strategies

SDA, Wet Scrubbing with lime slurry, fuel switching to natural gas, fuel switching to lower sulfur coal, SCR, and SNCR are technically feasible control technologies for FutureFuel's three coal-fired boilers. FutureFuel identified two options for fuel switching to natural gas: retrofitting the existing boilers and replacing the existing boilers with new boilers designed to operate using natural gas. FutureFuel identified three options for fuel switching to lower sulfur coal: 2.5% sulfur content, 2% sulfur content, and 1.5% sulfur content.

FutureFuel was unable to identify a supply of coal lower than 1.5% sulfur content that was also able to meet the heating value and fusion temperature necessary for use in the three coal-fired boilers, which are designed for coal with a heating value of at least 11,100 Btu/lb and a minimum fluid fusion temperature of 2,550 degrees Fahrenheit. Burning coal that does not meet the design requirements for FutureFuel's boilers is expected to result in caking, clinker formation, and damage to equipment. FutureFuel examined the feasibility of switching to coal from a nearby power plant (0.05% sulfur content), switching to coals from the Powder River Basin (0.8 lb SO_2/MMBTU, 8,800 Btu/lb), and switching to coals from the Uinta Basin (0.8 lb SO_2/MMBTU, 11,700 Btu/lb). Both the coal from the local power plant and Powder River Basin have a heating value below the minimum heating value required for the stoker boilers and a

[42] EPA Menu of Control Measures https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

[43] EPA Menu of Control Measures https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

fusion temperature value below the minimum fluid fusion temperature required for the stoker boilers. Uinta Basin coals have a sufficient heating value; however, the mean and median fusion temperatures from Uinta Basin coal are below the minimum recommended fusion temperatures for FutureFuel's stoker boilers. The distance to Uinta Basin would also require large upgrades to FutureFuel's coal trucking fleet, making the cost of fuel switching to Uinta Basin coal infeasible. Therefore, these coal types were considered technically infeasible for FutureFuel's coal-fired stoker boilers.

FutureFuel also identified wet scrubbing using sodium hydroxide as a technically infeasible emission reduction strategy because the salts that would be formed from use of this strategy could exceed National Pollution Discharge Elimination System (NPDES) sulfate permit limits. FutureFuel is subject to a sulfate limit of 70,000 lb/day based on Technology-Based Effluent Limitations (TBEL) established by DEQ. FutureFuel discharges between 15,500 and 30,000 lb sulfate/day and installation of a wet sodium hydroxide scrubber would increase discharge by 43,000 lb sulfate/day. TBEL represent the minimum level of treatment of pollutants for point sources based on available treatment technologies. Clean Water Act standards are subject to anti-backsliding requirements that prohibit the renewal, reissuance, or modification of an existing NPDES permit that contains effluent limitations, permit conditions, or standards less stringent than those established in a previous permit.[44] There are certain exceptions to the anti-backsliding requirements for TBELs:

- Material and substantial alterations or additions that justify the relaxation;
- New information that was not available at the time of permit issuance that would have justified a less stringent limitation;
- Technical mistakes or mistaken interpretation of the law;
- Events beyond the permittee's control with no reasonably available remedy;
- Modifications under Clean Water Act § 301(c), 301(g), 301(h), 310(i), 301(k), 301(n), or 316(a);
- Inability to meet effluent limits when technology upon which the TBEL was established is installed, properly operated, and maintained.[45]

Installation of a wet scrubber using sodium hydroxide to reduce sulfur dioxide emissions would likely qualify for an exception from anti-backsliding requirements for a TBEL as a "material and substantial alteration" that justifies relaxation of the effluent limitation.[46] The state water quality-based effluent limitations are 1,520,429 lb sulfate/day. Therefore, DEQ anticipates that FutureFuel could request an NPDES permit amendment from DEQ's Office of Water Quality to accommodate the additional 3,000 lb sulfate per day beyond the TEBL from operation of wet scrubbers using sodium hydroxide if there were no adverse environmental impact. However, FutureFuel did provide an alternative reagent for analysis of a wet scrubber. DEQ anticipates that

[44] 40 CFR §122.44(l)
[45] 40 CFR §122.44(l)
[46] Personal communication with Shane Bynum, Permit Engineer in DEQ's Office of Water Quality

the wet scrubbing scenario with lime slurry as the reagent would be similar in cost and control efficiency to sodium hydroxide wet scrubbing.[47] Therefore, DEQ considers FutureFuel's evaluation of wet scrubbing using lime slurry as sufficient for DEQ's assessment of both scrubbing reagent types.

FutureFuel also explained that low-NOx burners are not a technically feasible control technology for the three coal-fired boilers because there is no available or applicable low-NOx burner systems designed for stoker style boilers. [48]

b. Baseline Emission Rate

FutureFuel provided baseline SO_2 and NOx emissions for the three coal-fired boilers annualized on a maximum monthly emission rate for the period between 2017 and 2019. DEQ used the maximum monthly emissions rate to ensure that cost estimates for control technologies were based on appropriately sized equipment. In addition, DEQ calculated the average annual emissions during the 2017–2019 period to estimate the typical emission reductions that may be achievable from application of controls.[49] The average SO_2 baseline emissions for the three coal-fired boilers are 2,171 tons per year and the average NOx baseline emissions are 247 tons per year.

c. Control Effectiveness

Table V-12 summarizes the control effectiveness of each technically feasible emission reduction strategy evaluated in FutureFuel's response to DEQ's ICR and the estimated emission reductions that would be achieved if the strategy were implemented.

[47] See EPA's Air Pollution Control Cost Manual, Section 5. https://www.epa.gov/sites/production/files/2021-05/documents/wet_and_dry_scrubbers_section_5_chapter_1_control_cost_manual_7th_edition.pdf

[48] DEQ performed a review of the EPA RACT/BACT/LAER database to verify that low NOx boilers have not been implemented for similar equipment as part of new source review. There were three entries for spreader-stoker boilers in the RBLC database: IA-0013, IA-0015, and MI-0005. None of these entries identified low NOx Burners as a RACT, BACT, or LAER control strategy. In addition, low NOx burners are not listed as an available control strategy for industrial coal-fired stoker boilers in EPA's Menu of Control Measures. See EPA's Air Pollution Control Cost Manual, Chapter 1, Table 1.2, which identifies no available urea-based SNCR for stoker-fired boilers: https://www.epa.gov/sites/production/files/2017-12/documents/sncrcostmanualchapter7thedition20162017revisions.pdf See also Chapter 2 for information about SCR: https://cfpub.epa.gov/si/si_public_file_download.cfm?p_download_id=532813&Lab=OAQPS

[49] Average of annual emissions reported to the DEQ Emission Inventory team for years 2017 – 2019 for SN:6M01-01.

Table V-12: Control Effectiveness and Anticipated Annual Emission Reductions for Control Strategies Evaluated for FutureFuel Coal-Fired Boilers

Control Strategy		Control Effectiveness		Annual Emission Reductions (tpy)		
		SO_2	NOx	SO_2	NOx	Both
Fuel Switching from Coal to Natural Gas Strategies[50]	Retrofit 1 Boiler	32%	30%	690	74	764
	Replace 1 Boiler	32%	30%	690	74	764
	Retrofit all 3 Boilers	99%	90%	2,149	222	2,371
	Replace all 3 Boilers	99%	90%	2,149	222	2,371
SO_2 Scrubbing Strategies	Wet Scrubbers – Lime Slurry	94%	0%	2,041	0	2,041
	SDA	92%	0%	1,997	0	1,997
	DSI[51]	40%	0%	868	0	868
Fuel Switching to Lower Sulfur Coal Strategies	1.5% Sulfur Content Coal	44%	0%	966	0	966
	2% Sulfur Content Coal	27%	0%	591	0	591
	2.5% Sulfur Content Coal	10%	0%	215	0	215
NOx Post-Combustion Control Strategies	SCR	0%	80%	0	197	197
	SNCR	0%	40%	0	99	99

d. Cost of Compliance

DEQ made the following revisions to the cost of compliance estimates provided by FutureFuel to ensure compliance with the EPA Control Cost Manual:[52]

- Contingency costs were revised to twenty percent of total capital investment. The EPA Control Cost Manual suggests use of 20% of total capital investment for contingency for study level cost estimates and 5–15% for "mature control technologies." FutureFuel used 30% of capital costs (excluding energy and non-environmental capital costs that are part of total capital investment) in their cost calculations without providing an explanation of

[50] "Replace" means complete removal and replacement of older coal-fired equipment with new equipment that combusts natural gas; for details, see responses to DEQ's ICR provided by FutureFuel, located in Appendix G of this proposal. To "retrofit," FutureFuel would have to redesign and modify each boiler's coal fuel system to a natural gas fuel system. Each boiler would be designed to produce 50 KPPH steam using natural gas. According to FutureFuel's response, this design would change the dynamics so significantly that it would require a significant physical modification to the entire boiler system for the plant. FutureFuel estimated that it would take approximately one year for each Boiler retrofit to demolish the old feed system, install a new natural gas system, optimize the combustion criteria, check out the equipment, train operators, and then start up the modified unit.

[51] EPA's Menu of Control Measures estimates the control efficiency of DSI for industrial boilers burning high sulfur coal to be approximately 40%. https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

[52] See revised cost-calculations provided in Appendix G and email from Philip Antici on July 23, 2020 in Appendix G.

why this change was appropriate due to site-specific considerations.

- AFUDC and Owner's costs, which are not valid costs under the EPA Control Cost Manual overnight estimation methodology were removed. EPA has noted that these costs were not consistent with the EPA Control Cost Manual in several actions on Planning Period I SIPs and FIPs.[53]
- All line-item costs estimated using total capital investment were revised to reflect changes in contingency and removal of the disallowed costs using formulas provided by the EPA Control Cost Manual.
    - Administrative costs = 2% of capital investment
    - Property tax = 1 % of capital investment
    - Insurance = 1% of capital investment
- Equipment life for control technologies was revised to be consistent with EPA control cost manual and similar technology assessments made during Regional Haze Planning Period I.
    - Wet FGD: 30 years
    - Dry FGD (SDA): 30 years
    - DSI: 30 years
    - SCR: 30 years
    - SNCR: 20 years
- The cost of fuel for natural gas scenarios was revised to reflect the incremental change in cost of using natural gas compared to coals currently in use for boilers based on EIA data. In addition, the cost associated with electrical, maintenance, operating and support labor, permitting and compliance were removed because these do not represent cost increases above the current cost of using coal.[54]
- The tax associated with the 1.5% coal control scenario was adjusted to remove cost of transportation from the taxable amount and costs were adjusted to reflect the incremental increase in cost above current stocks for each of the lower sulfur coal strategies (2.5%, 2%, and 1.5%).

Table V-13 summarizes the estimated costs for the control strategies evaluated for the three coal-fired boilers at FutureFuel under a 7% interest rate assumption. While DEQ originally proposed to use a bank prime rate of 3.25%, after considering comments received during the public comment period, and recent upward trend of the federal interest rate, DEQ is revising analyses to employ 7% as a "default" interest rate as is outlined in EPA’s Control Cost Manual.[55] See DEQ‘s response to comments for the rationale for this change.

[53] EPA (2011). “Response to Technical Comments for Sections E through H of the Federal Register Notice for the Oklahoma Regional Haze and Visibility Transport Federal Implementation Plan,” Docket No. EPA-R06-OAR-2010-0190.
[54] See email from Philip Antici on July 23, 2020 in Appendix G.
[55] EPA’s Control Cost Manual. page 16

DEQ has calculated the annualized capital costs using the total capital investment estimates provided by FutureFuel and a 7% interest rate.[57] Table V-14 provides the cost-effectiveness of each of these strategies an annual average basis.

Table V-13: Estimated Cost of Control Strategies Evaluated for FutureFuel Coal-Fired Boilers

Control Strategy		Total Annual Cost ($/year)
Fuel Switching from Coal to Natural Gas	Retrofit 1 Boiler	9,080,283
	Replace 1 Boiler	9,300,725
	Retrofit all 3 Boilers	26,377,284
	Replace all 3 Boilers	26,456,177
SO_2 Scrubbing	Wet Scrubbers – Lime Slurry	13,025,851
	SDA	10,260,367
	DSI	8,302,597
Fuel Switching to Lower Sulfur Coal	1.5% Sulfur Content Coal	2,679,500
	2% Sulfur Content Coal	1,282,500
	2.5% Sulfur Content Coal	738,720
NOx Post-Combustion Control	SCR	6,259,396
	SNCR	2,489,783

Table V-14: Estimated Cost-Effectiveness of Control Strategies Evaluated for FutureFuel Coal-Fired Boilers

Control Strategy		Cost-Effectiveness ($/ton reduced)
Fuel Switching from Coal to Natural Gas[58]	Retrofit 1 Boiler	13,155
	Replace 1 Boiler	13,474
	Retrofit all 3 Boilers	12,273
	Replace all 3 Boilers	12,309
SO_2 Scrubbing	Wet Scrubbers – Lime Slurry	6,383
	SDA	5,137
	DSI	9,561
Fuel Switching to Lower Sulfur Coal	1.5% Sulfur Content Coal	2,774
	2% Sulfur Content Coal	2,171
	2.5% Sulfur Content Coal	3,430
NOx Post-Combustion Control	SCR	31,720

[57] Revised from 3.25% to 7%, based on public comments received on the draft SIP, and in accordance with EPA's Control Cost Manual (*Ibid*. page 16).

[58] Cost-effectiveness represents cost per ton of SO_2 and NOx combined

	SNCR	25,234

Two control strategies were cost-effective for FutureFuel based on DEQ's threshold for industrial boilers: fuel switching to two percent sulfur content coal and fuel switching to 1.5% sulfur content coal. The most cost-effective strategy is switching to two percent sulfur content coal. The costs of the other potential control strategies considered were above DEQ's threshold for industrial boilers.

e. Time Necessary for Compliance

Table V-15 provides a summary of the time that FutureFuel indicated would be necessary to comply with each of the assessed control technologies.

Table V-15: Time Necessary to Comply for Evaluated Control Strategies for FutureFuel

Control Strategy		Time Necessary to Comply	Basis
Fuel Switching from Coal to Natural Gas Strategies	Retrofit 1 Boiler	2 years	Time necessary for engineering design, DEQ approval, demolition of old feed system, installation of natural gas system, optimization, and logistics for shipping waste off-site
	Replace 1 Boiler	2 years	Time necessary for engineering design, DEQ approval, equipment build, delivery, construction, and logistics for shipping waste off-site
	Retrofit all 3 Boilers	4 years	Time necessary for engineering design, DEQ approval, demolition of old feed system, installation of natural gas system, optimization, and logistics for shipping waste off-site
	Replace all 3 Boilers	2.5 years	Time necessary for engineering design, DEQ approval, equipment build, delivery, construction, and logistics for shipping waste off-site
SO_2 Scrubbing Strategies	Wet Scrubbers – Lime Slurry	6 years	Time necessary for engineering design, DEQ review and approval, vendor and equipment selection, demolition of an existing building, purchase and installation of equipment, training, and start-up
	SDA	4 years	Time necessary for engineering design, DEQ review and approval, vendor and equipment selection, demolition or movement of an existing building, purchase and installation of equipment, training, and start-up
	DSI	3 years	Time necessary to for engineering design, DEQ

			review and approval, vendor and equipment selection, demolition or relocation of existing structures, delivery, construction, training, and startup.
Fuel Switching to Lower Sulfur Coal Strategies	1.5% Sulfur Content Coal	3 years	Time necessary to complete contracts and exhaust existing coal stockpile
	2% Sulfur Content Coal	3 years	Time necessary to complete contracts and exhaust existing coal stockpile
	2.5% Sulfur Content Coal	3 years	Time necessary to complete contracts and exhaust existing coal stockpile
NOx Post-Combustion Control Strategies	SCR	4 years	Time necessary for engineering design, DEQ review and approval, vendor and equipment selection, demolition or movement of an existing building, purchase and installation of equipment, training, and start-up
	SNCR	4 years	Time necessary for engineering design, DEQ review and approval, vendor and equipment selection, demolition or movement of an existing building, purchase and installation of equipment, training, and start-up

f. Energy and Non-Air Quality Impacts

FutureFuel reported energy and non-environmental impacts for each of the assessed technologies. Impacts of each technology are summarized below.

With the exception of the fuel-switching to lower sulfur coal options, all strategies assessed would have both energy and waste impacts for FutureFuel. FutureFuel recovers and burns solvent waste that cannot be reused in the coal-fired boilers. These wastes residues assist in steam production and reduce the amount of coal combustion necessary. Retrofitting or replacing the coal-fired boilers with natural gas would render FutureFuel unable to use the solvent wastes to produce steam and would require FutureFuel to ship the waste, including hazardous waste, offsite. Retrofitting or replacing just one of the three boilers would reduce FutureFuel's capacity to recover solvent wastes and result in some off-site waste disposal. SCR, SNCR, DSI, wet scrubbers, and spray dry absorbers would require the boilers to be temporarily taken offline and require disposal of solvent wastes during the offline period. The costs associated with the impacts of each assessed technology on waste energy recovery is factored into the cost of compliance reported by FutureFuel.

Implementation of a wet scrubbing, spray dry absorption, or DSI would result in waste disposal costs, which have been factored into the cost of compliance.

Fuel-switching to any of the lower sulfur coal options identified would not be expected to yield any energy or non-air quality impacts so long as the coal used meets the coal heating value and fusion temperature requirements of the boilers.

FutureFuel did not identify any energy and non-air quality impacts for the implementation of SCR or SNCR other than the impacts to waste energy recovery noted above during installation of the technologies.

g. Remaining Useful Life of the Source

There is no enforceable limitation on the useful life of the three coal-fired boilers. Therefore, FutureFuel used the equipment life of the control technologies evaluated found in the EPA Pollution Control Cost Manual to annualize total capital investment for each control strategy assessed.

h. Visibility Considerations

The 2016 results from the Ramboll AOI study indicate that emissions from FutureFuel are anticipated to contribute to visibility impairment at Upper Buffalo and Hercules Glades.[59] FutureFuel's 2016 impact on federal Class I areas was less than six other point sources for Upper Buffalo and less than eleven other point sources for Hercules Glades according to the 2016 AOI analysis. FutureFuel's impact at Caney Creek, Mingo, and Sipsey is less than one percent of the total sum of surrogate values for all point sources. These five Class I areas are on track to make greater progress than the URP glidepath in 2028 before consideration of potential controls for FutureFuel. FutureFuel is not within the nitrate or sulfate-specific area of influence for Mammoth Cave or Wichita Mountains based on the 0.05% threshold. FutureFuel was not identified as a source reasonably anticipated to contribute to visibility impairment at other federal Class I areas by modeling from other RPOs.

i. Proposed Decision on Control Measures Necessary to Make Reasonable Progress

[59] The FutureFuel visibility surrogate value was 3% of the total sum of surrogate values for all point sources in the 2016 inventory for Upper Buffalo and 2% for Hercules Glades.

In determining whether potential control measures are necessary for FutureFuel during Planning Period II, DEQ weighed the four statutory factors. The time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life have been factored into the cost of compliance for the potential control strategies considered for FutureFuel.

After consideration of the statutory factors, DEQ determined that an emission limit for FutureFuel's coal-fired boilers based on fuel switching to 2% sulfur content coal would be reasonable to ensure continued progress toward natural visibility conditions at federal Class I areas during Planning Period II. However, after discussions with FutureFuel representatives and consideration of comments received on the publicly noticed proposed SIP, DEQ reached the conclusion that a commitment by FutureFuel to switch to 1.5% sulfur content coal offers a cost-effective control with even greater visibility benefits for Upper Buffalo and Hercules Glades federal Class I areas, allowing for greater progress than Arkansas's reasonable progress goals.

As such, DEQ has entered into an administrative order with FutureFuel that would render the 1.5% sulfur coal content and resulting emission limit enforceable by DEQ and, upon approval, by EPA as part of the SIP.[60] Due to recent supply chain and shipping issues resulting from the pandemic and market shifts, and a realistic concern that there may be future shortages or delays in shipment of fuel resources, included in the AO is a contingency that allows for a time-limited temporary variance to utilize 2% sulfur content coal. To qualify for the temporary variance, FutureFuel must fully demonstrate that the inability to utilize 1.5% sulfur coal is wholly beyond the company's control, and that FutureFuel has made every effort to procure 1.5% sulfur content coal such that the temporary variance request could be avoided. The contingency is also protective of federal Class I areas, in that the 2% sulfur content coal restriction limiting the temporary variance period is congruent with DEQ's original analyses, and keeps the state on track for reasonable progress, even during short periods when 1.5% coal is not available.

A final administrative order signed by DEQ and FutureFuel renders the requirements enforceable as a matter of state law.

5. Domtar Ashdown Mill

The Ashdown Mill is a pulp and paper mill owned by Domtar A.W. LLC located in Little River County, Arkansas. Ashdown Mill has four emission units that emit over 100 tpy of NOx: No. 2 Power Boiler (SN-05), No. 3 Power Boiler (SN-01), No. 2 Recovery Boiler (SN-06), and No. 3 Recovery Boiler (SN-14). Two of those units also emit over 100 tpy of SO_2: No. 2 Power Boiler (SN-05) and No. 3 Power Boiler (SN-01). Combined, these four emission units emit the majority of SO_2 and NOx from Ashdown Mill.

Both the No. 2 and No. 3 Power Boilers primarily burn clean cellulosic biomass (bark) and

[60] See Appendix G.

natural gas. The No. 2 Power Boiler additionally burns coal.[61] Both boilers are identified as hybrid suspension/grate burners under 40 CFR 63 Subpart DDDDD. The No. 3 Power Boiler has a moving grate, combustion air system including over fire air, and a two-chamber dry electrostatic precipitator (ESP). The No. 2 Power Boiler is equipped with a traveling grate, combustion air system including over fire air, multiclones, and two venturi scrubbers in parallel.

Both No. 2 and No. 3 Power Boilers function as swing load boilers, responding to changes in demand for steam from the various process area users. The Ashdown Mill operates three separate pulping lines (of which two are batch processes), three separate bleach plants, two separate evaporator units, and currently two finished product lines. Any changes in steam demand from the process areas is accommodated through an associated swing in load on either or both of the power boilers to avoid further upsets in the steam header control systems. The recovery boilers are typically base-loaded to protect the chemical recovery process and avoid upsets in the liquor cycle and inventory. The mill consistently experiences variable process steam requirements due to the number of different process areas in operation. It is common to experience steam demand swings on both power boilers in the range of 100,000 – 300,000 lb/hr on any given operating day. There are also seasonal variations that impact steam demand, as well as varying fuel moisture content (primarily due to wet bark or coal).

The No. 3 Power Boiler flue gas exhaust temperatures are low, similar to No. 2 Power Boiler. No. 2 Power Boiler is slightly lower due to the venturi scrubber. No. 3 Power Boiler is a little higher due to the associated dry (ESP). Both boilers typically operate with high excess percent of O_2, in the range of 10%.

No. 3 Power Boiler is located just to the North of No. 2 Power Boiler.[62] There is a bark distribution and feed system located between the two boilers, as well as building structure that houses various motor control centers for both boiler's operating equipment, auxiliary equipment, and a control room. The No. 3 Power Boiler is adjacent to the No. 2 Recovery Boiler unit just to the North. These factors provide very similar space constraints as have been identified with the No. 2 Power Boiler in Domtar's ICR response.

No. 2 Power Boiler has a design heat input rate of 820 MMBtu/hr and is capable of burning a variety of fuels including clean cellulosic biomass, coal, tire derived fuel, natural gas, wood chips used to absorb oil, and petroleum coke. The unit is equipped with two Venturi scrubbers for removal of particulates and SO_2. No. 2 Power Boiler was subject to BART for Regional Haze Planning Period I. Based on the BART analyses for this unit, EPA established a BART limit of 91.5 lb SO_2/hr 345 lb NOx/hr for this unit. The SO_2 BART limit was based on utilization of

[61] The Ashdown Mill's No. 2 Power Boiler is described in the proposed SIP (at V36) as burning coal among other fuels. An air permit modification application was submitted to the DEQ on April 12, 2022 (0287-AOP-R25) that includes a fuel switch from coal to natural gas for the No. 2 Power Boiler. Once the permit is finalized and the cessation of coal burning in the No.2 Power Boiler is completed, significant reductions in emissions in several pollutants such as nitrogen oxides (NO_x) are expected.

[62] See Domtar's ICR response, facility layout map, in Appendix H.

additional reagent in the existing Venturi scrubbers installed for No. 2 Power Boiler. The NOx BART limit was based on no new controls for NOx. In 2019, DEQ finalized an alternative to BART for this unit and No. 1 Power Boiler based on changes in operations at Ashdown Mill. This alternative to BART achieved greater visibility progress than the 2016 FIP BART limits.

The BART alternative limits for Domtar Ashdown Mill No. 1 Power Boiler are 0.5 lbs/hr for SO_2 and 191.1 lbs/hr for NOx. The BART alternative limits for Domtar Ashdown Mill No. 2 Power Boiler are 425 lbs/hr for SO_2 and 293 lbs/hr for NOx. These limits are specified in both the Title V permit for the facility and in the Arkansas Regional Haze SIP revision approved by EPA and effective on April 12, 2021, and therefore, federally-enforceable.[63]

No. 3 Power Boiler was a recovery boiler converted to a power boiler in 1990-91. It has a design heat input rate of 790 MMBtu/hr and is capable of burning a variety of fuels including clean cellulosic biomass, bark and wood chips used to absorb oil spills, wood waste, tire derived fuel, and natural gas. No. 3 Power Boiler has no existing combustion or post-combustion controls for NOx or SO_2. No. 3 Power Boiler is subject to a NOx emission limit of 0.30 lb/MMBTU and a SO_2 emission limit of 0.10 lb/MMBTU in the Ashdown Mill Title V permit.

No. 2 Recovery Boiler has a heat input capacity of 1,160 MMBtu/hr and combusts black liquor solids to recover inorganic chemicals and natural gas. No. 2 Recovery Boiler has no combustion or post-combustion controls for NOx or SO_2 listed in the permit for Ashdown Mill. No. 2 Recovery Boiler is subject to a NOx emission limit of 309.2 lb/hr and a SO_2 emission limit of 286 lb/hr in the Ashdown Mill Title V permit.

No. 3 Recovery Boiler has a heat input capacity of 1,088 MMBtu/hr and combusts black liquor solids to recover inorganic chemicals and natural gas. No. 3 Recovery Boiler has no combustion or post-combustion controls for NOx or SO_2 listed in the permit for Ashdown Mill. No. 2 Recovery Boiler is subject to a NOx emission limit of 270 lb/hr and a SO_2 emission limit of 425 lb/hr in the Ashdown Mill Title V permit.

Domtar employs good operating practices for both No. 2 and No. 3 Recovery Boilers. These practices include optimization of liquor properties and combustion air fire patterns to reduce SO_2 and NOx emissions.

On January 8, 2020, DEQ sent an information collection request to Domtar, asking for information about potential emission reduction strategies for these emission units at Ashdown Mill. Specifically, DEQ requested information about the technical feasibility and cost of the following SO_2 and NOx emission reduction strategies:

- SO_2 (ranked from highest control efficiency to lowest)[64]
    - For SN-05

[63] Permit No.0287-AOP-R23 https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/0287-AOP-R23.pdf
[64] EPA Menu of Control Measures https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

        - Installation of new add-on scrubbers operating downstream of the existing scrubbers (typical control efficiency for industrial coal-fired boilers ≈ ninety to ninety-five percent control efficiency for industrial coal-fired boilers)
        - Increasing the SO_2 control efficiency of the existing scrubbers from current levels to ninety percent through the use of additional scrubbing reagent
        - Upgrades to the existing scrubbers
    - For SN-01
        - Installation of a wet gas scrubber (typical control efficiency for industrial coal-fired boilers ≈ ninety to ninety-nine percent)
        - Installation of a SDA (typical control efficiency for industrial coal-fired boilers ≈ ninety to ninety-five percent);
- NOx (ranked from highest control efficiency to lowest) for all units[65]
    - Selective Catalytic Reduction (typical control efficiency ≈ eighty percent for industrial boilers coal and ninety percent for industrial boilers wood/bark/waste)
    - Regenerative Selective Catalytic Reduction (typical control efficiency ≈ seventy-five percent for industrial boilers wood/bark/waste)
    - Selective Non-Catalytic Reduction (typical control efficiency ≈ forty percent for industrial boilers coal).

A copy of the information request letter is included in Appendix H.

On April 6, 2020, Domtar submitted the requested information to DEQ. This response is included in Appendix H. After reviewing Domtar's April 6, 2020 response, DEQ requested updates to certain emission reduction assumptions included in the response based on actual hours operated during the baseline. DEQ also requested that Domtar provide emission reduction and cost-effectiveness estimates based on an average emission rate for the baseline period in addition to estimates based on the maximum month emission rate. On May 7, 2020, Domtar submitted the updated information that DEQ requested. The revised response is also included in Appendix H. After review of the information provided by Domtar, DEQ made the following revisions to control efficiency and cost assumptions for consistency with the EPA control cost manual and to reflect existing controls on No. 2 Power Boiler.[66]

a. Technical Feasibility of Identified Control Strategies

For No. 2 Power Boiler, the following controls measures were considered technically feasible: the addition of a new downstream scrubber, increased reagent usage for the existing venturi scrubbers, and SNCR. SCR was determined to be technically infeasible for No. 2 Power Boiler

[65] EPA Menu of Control Measures https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

[66] See Domtar revised cost calculations and email from Kelly Crouch on July 24, 2020 in Appendix H.

in a previous analysis submitted for Planning Period I. Regenerative SCR has not been successfully implemented on an emission unit comparable to No. 2 Power Boiler. In addition, the space and temperature constraints for No. 2 Power Boiler make regenerative SCR technically infeasible.

While SNCR is technically feasible for No. 2 Power Boiler, Domtar explained that the emission reduction capability of this technology as applied to No. 2 Power Boiler is limited due to the wide variability in temperature at No. 2 Power Boiler.

No. 3 Power Boiler is similar in design and operation profile to No. 2 Power Boiler. Therefore, the technologies considered technically infeasible for No. 2 Power Boiler (SCR and regenerative SCR) are also technically infeasible for No. 3 Power Boiler. No. 3 Power Boiler also has similar limitations with the control efficiency of SNCR. No. 3 Power Boiler does not have existing scrubbers. Therefore, the technically feasible control technologies for No. 3 Power Boiler include Wet FGD, SDA, and SNCR. Domtar's report also describes the inherent scrubbing properties of ash created from combusting bark in the boiler. This inherent scrubbing is an existing control that captures some of the sulfur dioxide when co-firing of sulfur-containing fossil fuels and is represented in the baseline emission rate.

None of the identified control technologies were technically feasible for No. 2 and No. 3 Recovery Boilers. Based on information available in the EPA RACT/BACT/LAER Clearinghouse, the National Council for Air and Stream Improvement information, and Trinity Consultants' library of air pollution control assessments, Domtar concluded that flue gas desulfurization, SCR, and SNCR are not technically feasible.[67] FGD was determined not to be technically feasible because it is capital-intensive, and energy-intensive, and its efficacy is unproven, considering the generally low but rapidly fluctuating levels of SO_2 in kraft recovery furnace flue gases.[68]

An RBLC query indicates that SCR and SNCR are infeasible on recovery boilers as no determinations for these technologies on recovery boilers were found. Recovery boilers produce complex chemical reactions, and disruptions to the reaction chemistry could potentially damage the furnace, impact the quality of the product, or otherwise unacceptably affect the system. Additionally, kraft recovery boilers operate at varying loads that make it difficult to inject SNCR reagent within the desired temperature window.[69] Because SCR and SNCR have not been

[67] NCASI Handbook of Environmental Regulations and Control, Volume 1: Pulp and Paper Manufacturing, April 2013, Section 6.8.3.3; RBLC searches were completed on February 3, 2020 for Process Types 30.211, 30.219, 30.290, 11.190, 11.290, and 11.900 and for process names that include the word "recovery."

[68] Appendix H, Trinity Consultants Report: Response to January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request, p 6-1

[69] NCASI Handbook of Environmental Regulations and Control, Volume 1: Pulp and Paper Manufacturing, April 2013, Section 6.8.3.4

applied to recovery boilers, these technologies are not considered feasible for Recovery Boilers 2 and 3.[70]

Because no technically feasible control technologies were identified for No. 2 Recovery Boiler and No. 3 Recovery Boiler, DEQ finds it unnecessary to perform an analysis for these emission units.

b. Baseline Emission Rate

Domtar provided baseline emission rates for No. 2 Power Boiler and No. 3 Power Boiler annualized on both a maximum monthly emission rate basis and an average monthly emission rate basis from the baseline period of 2017–2019. DEQ used the annualized baseline emission rate based on maximum monthly emissions to ensure that cost estimates for control technologies were based on appropriately sized equipment. DEQ used the annualized baseline emissions rate based on average monthly emissions to estimate the typical emission reductions that may be achievable from application of controls. The average baseline emissions for No. 2 Power Boiler and No. 3 Power Boiler are presented in Table V-16.

Table V-16: Annualized Baseline Emissions for Ashdown Mill No. 2 Power Boiler and No. 3 Power Boiler (Average Month Basis)

Emission Unit	SO_2 Baseline Emissions (tpy)	NOx Baseline Emissions (tpy)
No. 2 Power Boiler	858.9	559.9
No. 3 Power Boiler	46.9	290.1

c. Control Effectiveness

Table V-17 summarizes the control effectiveness of each technically feasible emission reduction strategy evaluated for No. 2 Power Boiler and No. 3 Power Boiler in Domtar's response to DEQ's ICR. Domtar's response to DEQ's ICR indicated that no emissions reductions are possible from upgrades to the existing scrubbers. Therefore, no further evaluation of the existing scrubber upgrades strategy is included in this analysis.

Table V-17: Control Effectiveness and Anticipated Annual Emission Reductions for Control Strategies Evaluated for Ashdown Mill No. 2 Power Boiler and No. 3 Power Boiler

Emission Unit	Control Strategy	Pollutant	Control Efficiency	Controlled Emission Rate (tpy)	Emission Reductions (tpy)
No. 2 Power	New downstream scrubber	SO_2	90%	279.8	579.1

[70] Appendix H, Trinity Consultants Report: Response to January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request, p 7-2

Boiler	Increased reagent usage at existing scrubbers	SO_2	90%[71]	279.8	579.1
	SNCR (Scenario 1)	NOx	3%	543.1	16.8
	SNCR (Scenario 2)	NOx	27.5%	406	154
No. 3 Power Boiler	Wet FGD	SO_2	90%	4.7	42.2
	Dry FGD	SO_2	90%	4.7	42.2
	SNCR (Scenario 1)	NOx	3%	281.4	8.7
	SNCR (Scenario 2)	NOx	27.5%	210.3	79.8

Domtar's estimate of three percent control effectiveness of SNCR for NOx emissions (Scenario 1) is lower than the typical control efficiency of this technology due to unit-specific constraints for No. 2 Power Boiler and No. 3 Power Boiler. Domtar explains that this low control effectiveness is because of the temperature variability inherent in their operation of these power boilers. Domtar performed a study to analyze temperature variability of No. 2 Power Boiler. Based on this study, Domtar estimates that the SNCR would achieve forty percent emission reductions during the seven percent of operations during which the SNCR system could be operated under optimal conditions. DEQ also performed a sensitivity case using the 27.5% control efficiency assumption used in the EPA 2016 FIP (Scenario 2). Domtar has asserted that this control efficiency is unrealistic given the operating characteristics of No. 2 Power Boiler and could result in stack emissions of 1,700 tons or more per year of unreacted urea.[72] These assumptions are also applicable to No. 3 Power Boiler which has similar variability in exit gas temperature that limits when an SNCR system can function.

d. Cost of Compliance

DEQ has revised the cost estimates for No. 2 Power Boiler and No. 3 Power Boiler provided by Domtar in their responses to DEQ's ICR as follows:[73]

- DEQ has revised cost-effectiveness of increasing scrubbing reagent for the existing scrubber based on the anticipated emission reductions calculated using the formulas EPA used in AR020.0188 Domtar PB2_Cost 2011-2013;
- DEQ revised cost calculations for SNCR to reflect the system operation scenario presented by Domtar (Scenario 1);
- DEQ has also calculated the cost of SNCR under the control efficiency and operational assumptions that EPA used in the 2016 FIP (Scenario 2) for comparison with Scenario 1; and

[71] Total control efficiency of existing scrubbers after increasing reagent usage is estimated to be 90%. The baseline emissions for No. 2 Power Boiler represent approximately 69% control efficiency from the existing scrubbers. Adding additional reagent to achieve the maximum control efficiency of the existing scrubber is estimated to reduce baseline emissions by 67%. See Domtar revised cost calculations spreadsheet in Appendix H.
[72] Email from Kelley Crouch on July 24, 2020 in Appendix H.
[73] See spreadsheet Domtar Revised Cost Calculations in Appendix H.

- Costs have been escalated to 2019 dollars using the Chemical Engineering Plant Cost Index.

Table V-18 provides estimated cost of each control strategy and cost-effectiveness in $/ton.

Table V-18: Estimated Cost and Cost-Effectiveness of Control Strategies Evaluated for Ashdown Mill No. 2 Power Boiler and No. 3 Power Boiler in 2019 Dollars

Emission Unit	Control Strategy	Total Annual Cost ($/year)	Cost-effectiveness ($/ton)
No. 2 Power Boiler	New downstream scrubber	10,369,341	17,914
	Increased reagent usage at existing scrubbers	2,083,824	3,600
	SNCR (Scenario 1)	393,950	25,129
	SNCR (Scenario 2)	1,056,587	6,862
No. 3 Power Boiler	Wet FGD low estimate	3,425,883	81,182
	Wet FGD high estimate	16,903,828	400,565
	Dry FGD low estimate	4,159,746	98,572
	Dry FGD high estimate	51,227,655	1,213,925
	SNCR (Scenario 1)	393,950	48,499
	SNCR (Scenario 2)	1,056,587	13,244

The $/ton values for each control strategy evaluated for No. 2 and No. 3 Power Boiler exceed DEQ's threshold for industrial boilers.

e. Time Necessary for Compliance

Table V-19 summarizes the time Domtar estimates would be necessary to comply with an emission limit based on the assessed technologies for No. 2 Power Boiler and No. 3 Power Boiler.

Table V-19: Time Necessary to Comply for Evaluated Control Strategies for Ashdown Mill No. 2 Power Boiler and No. 3 Power Boiler

Emission Unit	Control Strategy	Time Necessary to Comply	Basis
No. 2 Power Boiler	New downstream scrubber	3 years	34 week shipment and construction period; 18 month outage frequency for No. 2 Power Boiler
	Increased reagent usage at existing scrubbers	2 years	Time needed to procure and install two new pumps and 18 month outage frequency for No. 2 Power Boiler

	SNCR	5 years	Precedent in Utah and North Dakota FIPs
No. 3 Power Boiler	Wet FGD	5 years	Determinations for utilities in other SIPs for Planning Period I
	SDA	5 years	Determinations for utilities in other SIPs for Planning Period I
	SNCR	5 years	Precedent in Utah and North Dakota FIPs

f. Energy and Non-Air Quality Impacts

Domtar reported that installation of a new scrubber downstream of the existing scrubber would result in increased water usage and wastewater generation and impact energy needs for Ashdown Mill. These considerations are factored into the reported cost of compliance with this technology.

Domtar reported that energy and non-air quality environmental impacts of increased reagent usage at the existing scrubbers are expected to be minimal.

Domtar does not expect that energy impacts or non-air quality environmental impacts for SNCR would be greater for No. 2 Power Boiler and No. 3 Power Boiler than at any other industrial facility under the operational scenario presented. Under the 2016 FIP operational scenario, Domtar estimates that 1,700 tons or more of unreacted urea would be emitted through the stack for No. 2 Power Boiler if an SNCR was operated during the ninety-three percent that the boiler is operated outside the optimal temperatures required for SNCR.[74]

g. Remaining Useful Life of the Source

Domtar has no plans to cease operations of No. 2 Power Boiler or No. 3 Power Boiler. The useful life values for control equipment assessed in EPA's Control Costs Manual were assumed in amortizing capital costs for the purposes of annualizing capital costs.

h. Visibility Considerations

The 2016 results from the Ramboll AOI study indicate that emissions from Ashdown Mill are anticipated to contribute to visibility impairment at Caney Creek.[75] Ashdown Mill's 2016 visibility surrogate for Caney Creek was less than five other point sources according to the 2016 AOI analysis. Caney Creek is on track with the URP glidepath in 2028 before consideration of potential controls for Ashdown Mill. Ashdown Mill's visibility surrogate is less than one percent of the total sum of surrogate values for all point sources for Hercules Glades, Upper Buffalo, and Wichita Mountains. Ashdown Mill is not within the nitrate- or sulfate-specific area of influence for Mammoth Cave, Mingo, or Sipsey based on the 0.05% threshold. Ashdown Mill was not

[74] Email from Kelley Crouch on July 24, 2020 in Appendix H.

[75] Domtar Ashdown Mill's visibility surrogate value was 5% of the total sum of surrogate values for all point sources in the 2016 inventory for Caney Creek.

identified as a source reasonably anticipated to contribute to visibility impairment at other federal Class I areas by modeling from other RPOs.

i. Proposed Decision on Control Measures Necessary to Make Reasonable Progress

In determining whether potential control measures are necessary for Ashdown Mill during Planning Period II, DEQ weighs the four statutory factors and visibility considerations. The time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life have been factored into the cost of compliance for the potential control strategies considered for Ashdown Mill. All of the control strategies evaluated for Ashdown Mill exceed DEQ's cost threshold for industrial boilers. Furthermore, Ashdown Mill has a smaller impact on federal Class I areas relative to other point sources and the primary federal Class I area impacted by Ashdown Mill is on track with the URP glidepath in 2028 before consideration of potential controls for Ashdown Mill. Although the URP is not determinative in making a decision with respect to whether a control is reasonable after consideration of the four factors, being below the URP glidepath means that the additional demonstrations under 40 C.F.R. 51.308(f)(3)(ii) are not required. After consideration of the statutory factors and visibility considerations, DEQ has determined that no additional controls are necessary for Ashdown Mill to make reasonable progress during Planning Period II.

6. Flint Creek Power Plant

The Flint Creek Power Plant (Flint Creek) is a coal-fired electric generating station located in Benton County, Arkansas. Flint Creek has one 558-megawatt dry bottom wall-fired boiler. The boiler burns low sulfur western coal as a primary fuel, but it can also combust fuel oil and tire-derived fuels.

The Flint Creek boiler is equipped with low-NOx burners with separated overfire air to control NOx emissions, dry flue gas desulfurization with pulse jet fabric filter and activated carbon injection to control SO_2 emissions, and electrostatic precipitators to control particulate matter emissions. The Flint Creek boiler is subject to an emission limit of 0.06 lb SO_2/MMBtu on a thirty-day rolling average. This limit is contained in the Arkansas SIP. Flint Creek is subject to a NOx emission limit of 4,426.8 lb/hr in its Title V permit. However, the low-NOx burners with over-fire air are guaranteed to achieve an emission rate of 0.23 lb/MMBtu or less. The low NOx burners are an inherent part of equipment design (i.e., cannot be shut down temporarily, as is the case with a post-combustion control). Based on the existing controls and emission limits contained in the Title V permit, DEQ determined that no further analysis of potential controls for SO_2 was necessary for this planning period.[76]

[76] EPA guidance instructs states that it is unlikely that an analysis of control measures would conclude that an even more stringent control is necessary is necessary to make reasonable progress for a coal-fired power plant that is already equipped with a scrubber and meeting an emission limit less than 0.2 lb SO_2/MMBtu. See EPA (2019) "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" at page 23. https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-

On January 8, 2020, DEQ sent an ICR to Southwestern Power Company (SWEPCO), a subsidiary of American Electric Power Service Company, asking for information about potential emission reduction strategies for Flint Creek Boiler 1. Specifically, DEQ requested information about the technical feasibility and cost of two potential post-combustion NOx reduction strategies: SCR and SNCR. A copy of the information request letter is included in Appendix I.

On March 25, 2020, SWEPCO submitted the requested information to DEQ. This letter is included in Appendix I. DEQ's evaluation of potential control strategies for Flint Creek are based on the information contained in SWEPCO's response.

a. Technical Feasibility of Identified Control Strategies

Both SCR and SNCR were considered technically feasible.

b. Baseline Emission Rate

SWEPCO reported baseline emissions for NOx on both a maximum month basis and average month basis for the period between June 1, 2018 and December 31, 2019. The period included in the baseline represents operations after the low-NOx burners were installed at Flint Creek in 2018.[77] DEQ used the maximum monthly emission rate to ensure that control technology evaluated is adequately sized for the purposes of control cost calculations. DEQ used the average monthly baseline emission rate to estimate typical emission reductions that can be anticipated from the application of a control strategy. The average baseline NOx emissions were 2,868 tons per year.

c. Control Effectiveness

Both SCR and SNCR were recently evaluated as potential BART technologies for EPA's 2016 FIP. In the analysis supporting the 2016 FIP, a controlled emission rate of 0.055 lb NOx/MMBtu was estimated for SCR and a controlled emission rate of 0.20 lb NOx/MMBtu was estimated for SNCR. These controlled emission rate estimates represent a 72.5% emission reduction for SCR and no reduction for SNCR from the baseline maximum rate. However, the controlled emission rate used for SNCR with LNB/SOFA in the 2016 FIP was a middle value in a range of vendor estimated controlled emission rates (0.18–0.23). Furthermore, some degree of emission reduction would be anticipated from installation of SNCR. However, the control efficiency percent for SNCR decreases with decreasing inlet NOx concentrations. Therefore, DEQ expects that the control effectiveness of adding a SNCR system for Flint Creek would be well below the typical control efficiency for SNCR.[78]

_regional_haze_guidance_final_guidance.pdf

[77] Construction of low-NOx burners with separated overfire air was completed on May 8, 2018.

[78] EPA's Menu of Control Measures lists a typical control efficiency of 90% for SCR and 35–50% for SNCR. These control efficiencies presume that no other NOx control systems are in place and are intended to provide a "ball park" starting point for control efficiency and cost. Flint Creek recently installed low-NOx burners, which resulted in 35%

For LNB/OFA alone, the controlled emission rate was estimated at 0.23 lb/MMBtu in the 2016 FIP. This value was in the upper end of the range (0.18–0.23) of expected controlled emission rates provided by the vendor for LNB/OFA. In practice, Flint Creek has achieved an even lower emission rate after installation of LNB/OFA (0.20 lb/MMBTU on a maximum month basis and 0.186 lb/MMBTU on an average month basis).

The difference in control efficiency between the two estimated controlled emission rates (LNB/OFA and LNB/OFA/SNCR) is ten percent. Additionally, the difference between the maximum monthly NOx emission rate during the baseline (0.20 lb/MMBTU) and the lower range of controlled emission rates provided by the vendor for LNB/OFA/SNCR (0.18 lb/MMBTU) would result in a 10% emission reduction. Therefore, an inlet emission rate of 0.20 lb/MMBTU and a control efficiency of 10% is appropriate to use for determining costs to ensure that the system is adequately sized to accommodate maximum inlet concentrations.

The difference between the average monthly emission rate during the baseline (0.186 lb/MMBTU) and a controlled emission rate of 0.18 lb/MMBTU is 3.22%. Therefore, DEQ estimates that Flint Creek could achieve up to a 3.22% emission reduction from baseline emissions if SNCR were installed.

d. Cost of Compliance

DEQ has revised the cost estimates for Flint Creek provided by SWEPCO in their responses to DEQ's ICR as follows:[79]

- DEQ revised cost calculations for SNCR to reflect the maximum NOx inlet rate and a ten percent maximum control efficiency; and
- DEQ escalated costs to 2019 dollars using the Chemical Engineering Plant Cost Index.

Table V-20 summarizes the estimated costs and cost-effectiveness for the control strategies evaluated for Flint Creek

Table V-20: Estimated Cost of Control Strategies Evaluated for Flint Creek in 2019 Dollars

Control Strategy	Total Annual Cost ($/year)	Cost-Effectiveness ($/ton)
SCR	15,836,308	8,641
SNCR	1,478,938	17,620

Both control strategies evaluated for Flint Creek exceed DEQ's threshold for EGU Boilers.

reduction in emissions.

[79] See spreadsheet Flint Creek Revised Cost Calculations in Appendix I.

e. Time Necessary for Compliance

DEQ expects that the time necessary for compliance with either SCR or SNCR would be three years after EPA approval of such a control technology into the Arkansas SIP. This time estimate is based on the time SWEPCO reported would be necessary to complete engineering design, procurement, construction, and shakedown.

f. Energy and Non-Air Quality Impacts

SWEPCO reported that installation and operation of SCR for Flint Creek would create additional parasitic load due to the electricity requirements of SCR system equipment. To produce an equivalent amount of net generation, additional fuel would be required thus increasing the cost of generation and emission of other pollutants not controlled by the SCR system.

Both SCR and SNCR systems utilize ammonia, which is dangerous at high concentrations, as part of the chemical reaction used to reduce NOx emissions. The risk of accidental release during transport and storage; therefore, must be managed. In addition, unreacted ammonia may be emitted to the atmosphere from SCR and SNCR systems under certain conditions and react with sulfates and nitrates to form visibility-impairing particles, i.e., ammonium sulfate and ammonium nitrate.

The anticipated costs on energy and non-air quality impacts for each system are factored into the cost of compliance.

g. Remaining Useful Life of the Source

Flint Creek is not under any state- or federally-enforceable requirement that would limit the life of Boiler 1. Therefore, EPA's default life values for SCR (30 years) and SNCR (20 years) were used by SWEPCO in quantifying the cost of compliance with these technologies.

h. Visibility Considerations

The 2016 results from the Ramboll AOI study indicate that emissions from Flint Creek are anticipated to contribute to visibility impairment at Hercules Glades and Upper Buffalo.[80] Flint Creek's 2016 visibility surrogate was less than fourteen other point sources for Hercules Glades and was less than 11 other point sources for Upper Buffalo according to the 2016 AOI analysis. Both Class I areas on track with the URP glidepath in 2028 before consideration of potential controls for Flint Creek. Flint Creek's visibility surrogate is less than one percent of the total sum of surrogate values for all point sources for Caney Creek. Flint Creek is not within the nitrate- or sulfate-specific area of influence for Mammoth Cave, Mingo, Sipsey, or Wichita Mountains based on the 0.05% threshold. Flint Creek was not identified as a source reasonably anticipated

[80] Flint Creek's visibility surrogate value was 1% of the total sum of surrogate values for all point sources in the 2016 inventory for Hercules Glades and Upper Buffalo.

to contribute to visibility impairment at other federal Class I areas by modeling from other RPOs.

i. Proposed Decision on Control Measures Necessary to Make Reasonable Progress

In determining whether additional control measures are necessary for Flint Creek during Planning Period II, DEQ weighs the four statutory factors and visibility considerations. The time necessary for compliance, energy and non-air quality environmental impacts, and remaining useful life have been factored into the cost of compliance for potential controls considered for Flint Creek. Flint Creek is already well controlled for NOx and SO_2, having recently installed controls for both pollutants. The cost of the additional potential controls considered for Flint Creek exceed DEQ's cost threshold for EGU boilers. Furthermore, federal Class I areas for which Flint Creek is within the nitrate- or sulfate-specific area of influence are on track to make greater progress than the URP glidepath in 2028 before consideration of additional controls at Flint Creek. Although the URP is not determinative in making a decision with respect to whether a control is reasonable after consideration of the four factors, being below the URP glidepath means that the additional demonstrations under 40 C.F.R. 51.308(f)(3)(ii) are not required. After consideration of the statutory factors and visibility considerations, DEQ has determined that no additional controls are necessary for Flint Creek during Planning Period II.

D. Share of Emission Reduction Obligations from Other States Impacting Arkansas Federal Class I Areas

Using the 2016 AOI analysis, DEQ has quantified the relative contribution of Arkansas sources to federal Class I areas in other states.[81] The AOI analysis indicates that Arkansas sources have a relatively small impact on federal Class I areas in other states with the exception of Hercules Glades in Missouri. Arkansas's relative impact compared to other states, based on the 2016 AOI analysis is two percent for Sipsey in Alabama, four percent for Mingo in Missouri, and less than one percent for Mammoth Cave and Wichita Mountains.

In addition, DEQ brought forth for further analysis each Arkansas source included when using a threshold of seventy percent of cumulative percentage of 2016 AOI Impacts for NOx and SO_2 combined for all federal Class I areas included in the AOI analysis.

DEQ also received a request from the VISTAS on behalf of North Carolina to perform a four-factor analysis on Entergy Independence. VISTAS conducted photochemical modeling with particulate source apportionment technology using projected 2028 emissions to identify sources that should undergo a reasonable progress analysis. The VISTAS "ask" letter and other correspondence between DEQ, VISTAS, and North Carolina on this matter are included in Appendix D.

No specific controls were requested from any other state, including those that requested that DEQ perform four-factor analyses, or agreed to as part of consultation. Independence, White

[81] See Chapter III.

Bluff, FutureFuel, and Flint Creek were among the highest point source contributors to the total point source visibility surrogate value at Hercules Glades. White Bluff is under an enforceable commitment to cease coal-fired operations by the end of 2028, which should help to address Arkansas's share of emission reductions for Hercules Glades during Planning Period II. Independence is under an enforceable commitment to cease coal-fired operations, which will occur during Planning Period III and should help to address Arkansas's share of emission reductions for Hercules Glades. DEQ has included a control strategy for FutureFuel for Planning Period II that is anticipated to reduce its contribution to visibility impairment at Hercules Glades. Additional control measures included in Arkansas's long-term strategy, beyond the source-specific controls determined as a result of the reasonable progress evaluation described in this chapter, are described in Chapter VI and are also anticipated to reduce Arkansas's contribution to visibility impairment at federal Class I areas in other states.

Arkansas Regional Haze Planning Period II

State Implementation Plan

CHAPTER VI: LONG-TERM STRATEGY FOR PLANNING PERIOD II

CHAPTER VI: LONG-TERM STRATEGY FOR PLANNING PERIOD II

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VI. Long-Term Strategy for Planning Period II

A. Emission Reductions Due to Ongoing Air Pollution Control Programs

40 CFR § 51.308(f)(2)(iv)(A) requires states to consider emission reductions due to ongoing air pollution control programs in their long-term strategies. These programs include new source performance standards, national emissions standards for hazardous air pollutants, national on-road and nonroad emissions standards, the cross-state air pollution rule, and other national rules that limit the emissions of pollutants that may contribute to visibility impairment. These emission reductions achieved by these programs are factored into 2028 emissions projections used to develop the RPGs for Arkansas federal Class I areas.[1]

B. Measures to Mitigate the Impacts of Construction Activities

In developing the long-term strategy, 40 CFR § 51.308(f)(2)(iv)(B) requires states to consider measures to mitigate the impact of construction-related activities. Appendix A of EPA's 2017 Construction General Permit guidelines defines construction activities. [2]

DEQ is responsible for all air pollution control programs in Arkansas; however, Arkansas Water and Pollution Control Act §8-4-305 limits DEQ's authority with respect to certain construction activities, such as land clearing operations, land grading, and road construction. As noted in Arkansas's 2008 Regional Haze SIP, current and future federal programs result in some mitigation through incentive offerings for voluntary emission reduction measures and through tier standards for nonroad equipment.[3] In addition, DEQ also provides funding opportunities for voluntary emission reduction projects for nonroad equipment used for construction through its Go RED! program.

C. Emission Reductions Anticipated from the Arkansas Energy Efficiency Resource Program

DEQ and the Arkansas Public Service Commission (APSC) performed an analysis of energy efficiency (EE) programs implemented by electric utilities with operations in Arkansas to determine the projected emissions reductions resulting from the EE programs. The analysis was

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[1]See EPA (2019). "Technical Support Document (TSD) Preparation of Emissions Inventories for the Version 7.2 2016 North American Emissions Modeling Platform." pgs 14 – 17. https://www.epa.gov/sites/production/files/2019-09/documents/2016v7.2_regionalhaze_emismod_tsd_508.pdf

[2]Construction activities means "earth-disturbing activities, such as the clearing, grading, and excavation of land, and other construction-related activities (e.g., stockpiling of fill material; placement of raw materials at the site) that could lead to the generation of pollutants. Some of the types of pollutants that are typically found at construction sites are: sediment; nutrients; heavy metals; pesticides and herbicides; oil and grease;•bacteria and viruses; trash, debris, and solids; treatment polymers; and any other toxic chemicals." https://www.epa.gov/sites/production/files/2019-05/documents/final_2017_cgp_appendix_a_-_definitions.pdf. Find the full guideline at https://www.epa.gov/npdes/epas-2017-construction-general-permit-cgp-and-related-documents.

[3] State of Arkansas Regional Haze Rule State Implementation Plan, 2008. http://www.adeq.state.ar.us/air/planning/sip/pdfs/regional-haze/arkansas-regional-haze-sip.pdf page 73

performed in order to assess emissions reductions of haze-forming pollutants that will help states with federal Class I areas meet the visibility goals set forth in the RHR. Anticipated emissions reductions were calculated using EPA's AVoided Emissions and geneRation Tool (AVERT) tool. The AVERT outputs were based on anticipated avoided generation resulting from the Arkansas investor-owned utility energy efficiency programs during Planning Period II. Annual emission reductions were quantified for the AVERT Southeast Region and the AVERT Lower Midwest Region. The detailed analysis is included in Appendix K. The remainder of this Chapter summarizes the emission reductions projected for each AVERT region as a result of Arkansas's EE resource standard.

Tables VI-1 and VI-2 list the projected annual emission reductions resulting from EE programs administered by Arkansas's investor-owned utilities during Regional Haze Planning Period II estimated by DEQ using AVERT. Figures VI-1–VI-3 show where AVERT predicts the 2028 emission reductions listed in Table VI-1 will occur in the Southeast Region and Figures VI-4–VI-6 show where AVERT predicts the 2028 emission reductions listed in Table VI-2 will occur in the Lower Midwest Region.

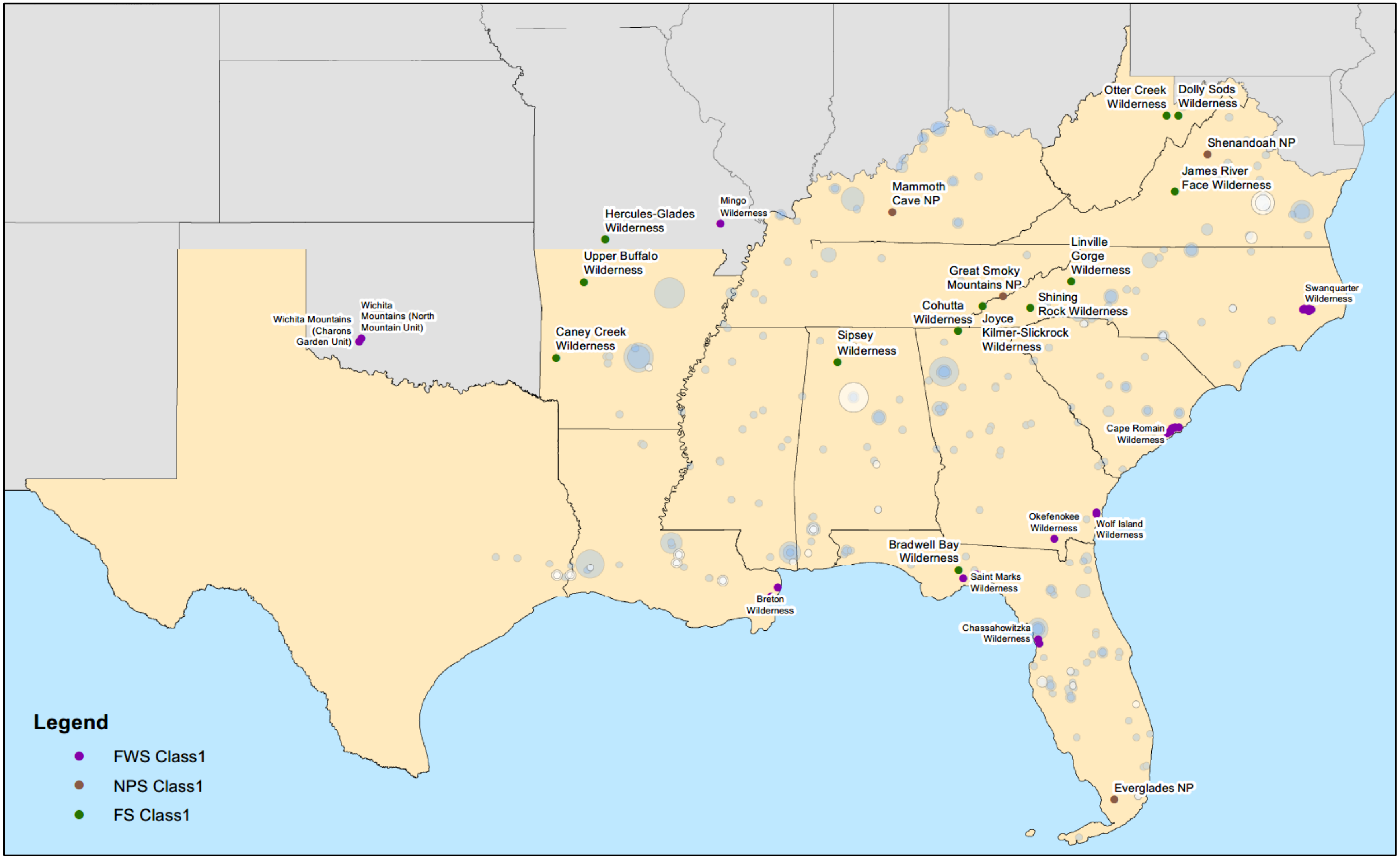
Table VI-1: Estimated Annual Emission Reductions for the AVERT Southeast Region Resulting From Arkansas EE Measures During the Second Implementation Period of the Regional Haze Program

Year	**SO_2 (tons)**	**NOx (tons)**	**$PM_{2.5}$ (tons)**
2018	538.42	584.60	64.99
2019	585.09	630.61	70.82
2020	663.92	713.88	79.92
2021	724.62	779.28	87.25
2022	780.78	839.69	94.28
2023	820.05	890.76	99.85
2024	863.71	937.91	105.14
2025	875.16	959.21	107.70
2026	906.99	994.12	111.63
2027	915.69	1019.06	115.20
2028	952.03	1042.43	117.85

Table VI-2: Estimated Annual Emission Reductions for the AVERT Lower Midwest Region Resulting From Arkansas EE Measures During the Second Implementation Period of the Regional Haze Program

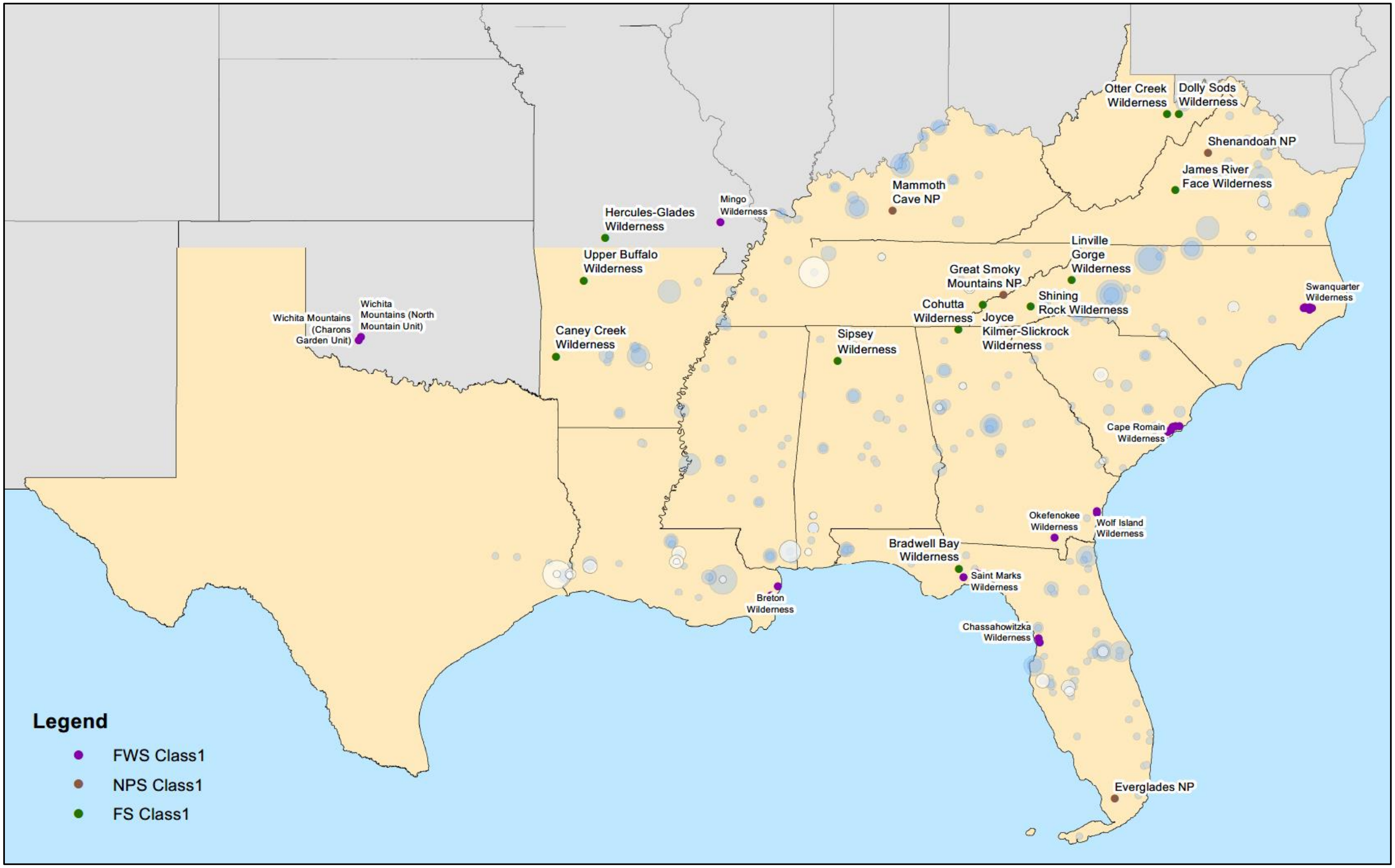
Year	SO_2 (tons)	NOx (tons)	$PM_{2.5}$ (tons)
2018	237.20	201.43	15.52
2019	263.09	227.08	17.11
2020	300.48	259.25	19.54
2021	331.48	286.81	21.24
2022	362.69	313.93	23.24
2023	391.21	338.70	25.08
2024	417.07	361.14	26.74
2025	440.23	381.23	28.22
2026	460.71	398.95	29.54
2027	483.42	422.50	30.89
2028	498.57	435.75	31.86

Figure VI-1: Projected 2028 SO_2 Reductions from Arkansas EE Programs for the AVERT Southeast Region*



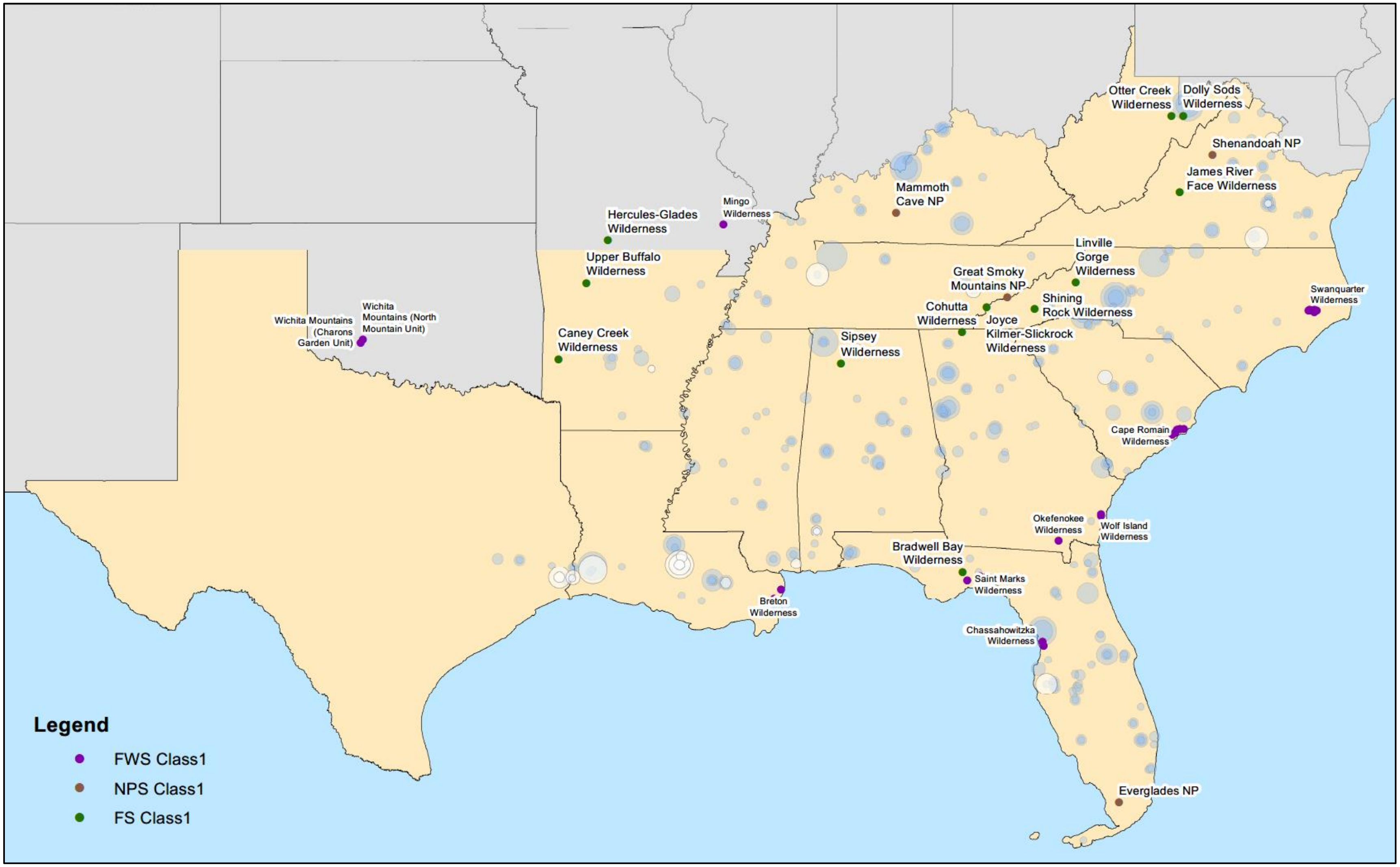
* The diameter of each circle indicates the magnitude of a unit's change in generation/emissions. Circles are semi-transparent: darker areas occur in regions with overlapping units. Negative changes (emissions decreases) are indicated with blue circles; positive changes (emissions increases) are indicated with black-bordered white circles.

Figure VI-2: Projected 2028 NOx Reductions from Arkansas EE Programs for the AVERT Southeast Region*



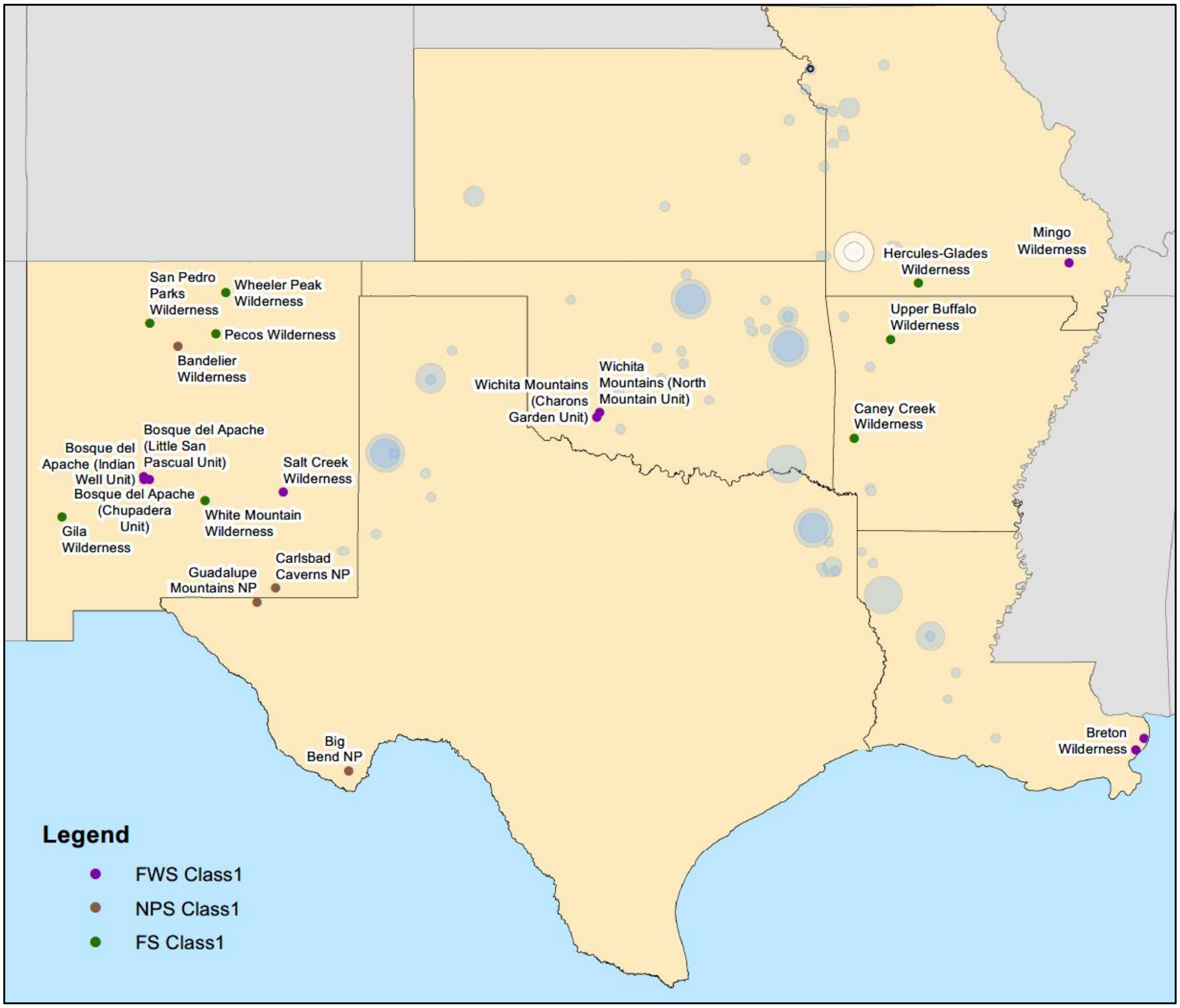
* The diameter of each circle indicates the magnitude of a unit's change in generation/emissions. Circles are semi-transparent: darker areas occur in regions with overlapping units. Negative changes (emissions decreases) are indicated with blue circles; positive changes (emissions increases) are indicated with black-bordered white circles.

Figure VI-3: 2028 $PM_{2.5}$ Reductions from Arkansas EE Programs for the AVERT Southeast Region*



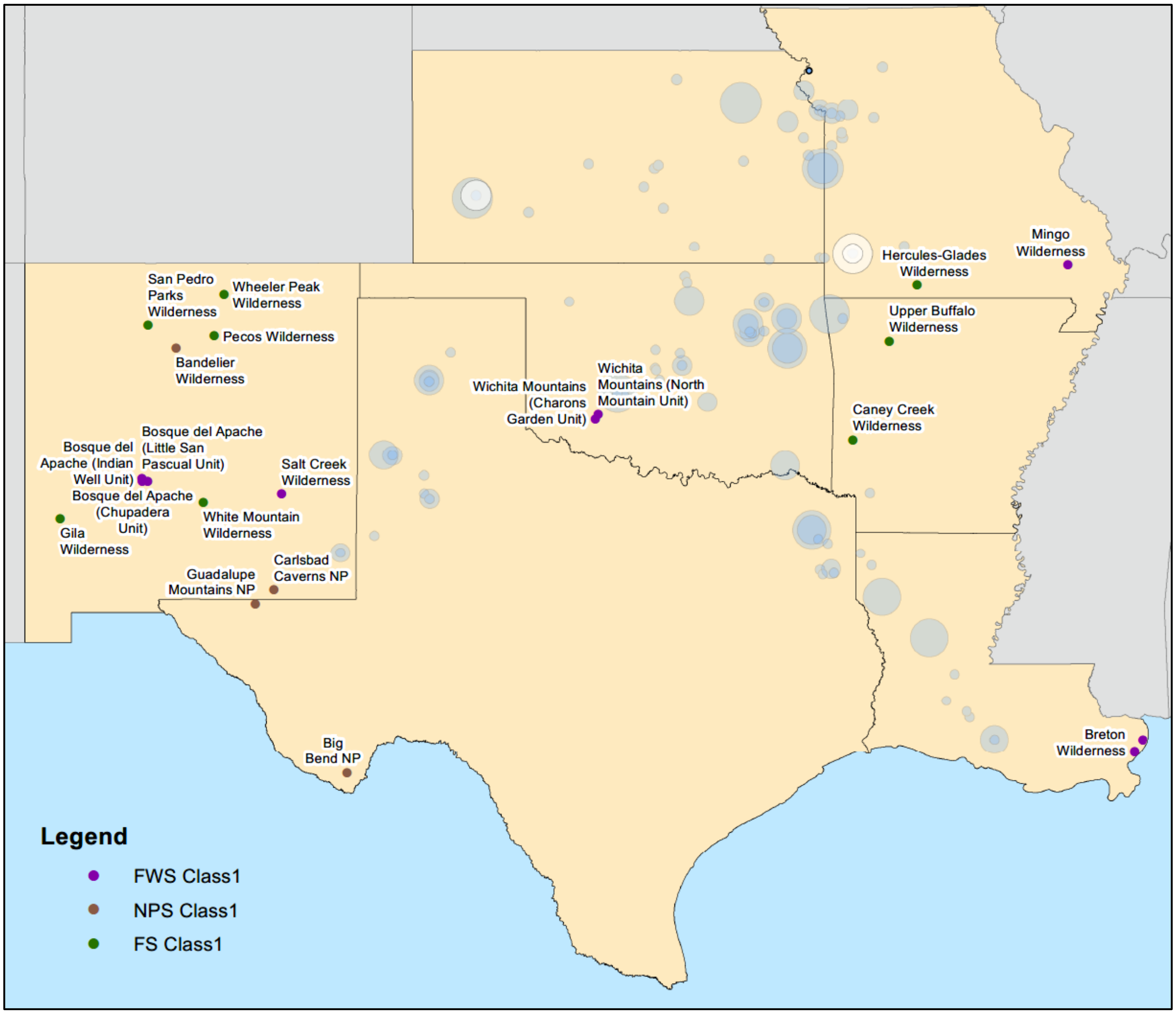
* The diameter of each circle indicates the magnitude of a unit's change in generation/emissions. Circles are semi-transparent: darker areas occur in regions with overlapping units. Negative changes (emissions decreases) are indicated with blue circles; positive changes (emissions increases) are indicated with black-bordered white circles.

Figure VI-4: Projected 2028 SO_2 Reductions from Arkansas EE Programs for the AVERT Lower Midwest Region*



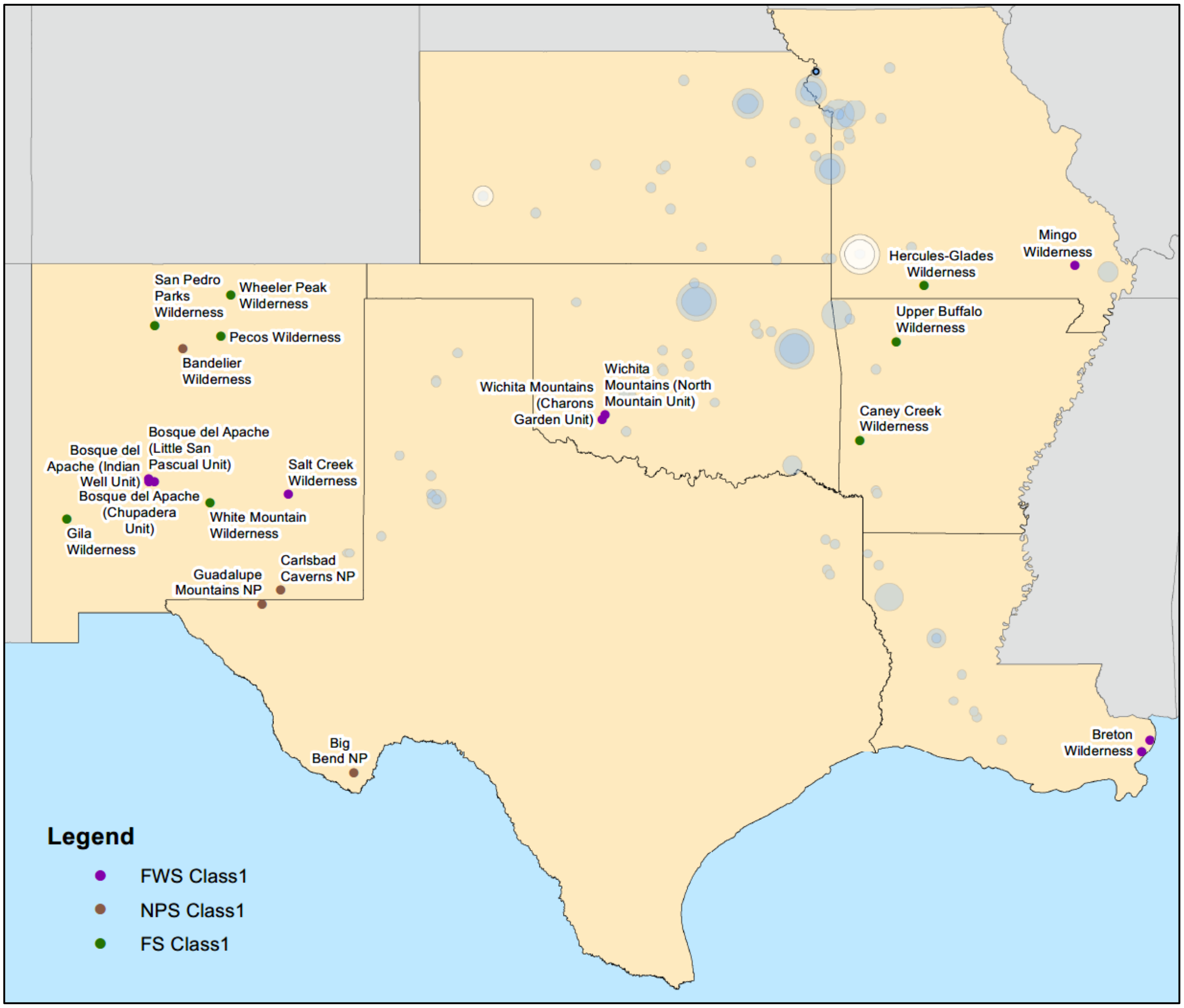
* The diameter of each circle indicates the magnitude of a unit's change in generation/emissions. Circles are semi-transparent: darker areas occur in regions with overlapping units. Negative changes (emissions decreases) are indicated with blue circles; positive changes (emissions increases) are indicated with black-bordered white circles.

Figure VI-5: Projected 2028 NO_X Reductions from Arkansas EE Programs for the AVERT Lower Midwest Region*



*** The diameter of each circle indicates the magnitude of a unit's change in generation/emissions. Circles are semi-transparent: darker areas occur in regions with overlapping units. Negative changes (emissions decreases) are indicated with blue circles; positive changes (emissions increases) are indicated with black-bordered white circles.**

Figure VI-6: Projected 2028 $PM_{2.5}$ Reductions from Arkansas EE Programs for the AVERT Lower Midwest Region*



*** The diameter of each circle indicates the magnitude of a unit's change in generation/emissions. Circles are semi-transparent: darker areas occur in regions with overlapping units. Negative changes (emissions decreases) are indicated with blue circles; positive changes (emissions increases) are indicated with black-bordered white circles.**

Implementation of Arkansas's EE Resource Standard is expected to reduce emissions of visibility-impairing pollutants over a wide geographic area, and thus contribute to visibility progress at federal Class I areas throughout the Southeast and Lower Midwest. Because the energy savings from APSC-approved EE Portfolios are not required under federal air pollution control rules, federal EE rules, or Arkansas air pollution control rules the emission reductions resulting from these programs are wholly surplus benefits.

Inclusion of Arkansas's EE Resource Standard as part of Arkansas's long-term strategy has other benefits including grid resiliency, reduced need for additional generation assets, and reduced costs when compared to traditional environmental control strategies. EE program investments are recoverable through rate adjustments, but ratepayers themselves receive real-world energy bill savings from the EE programs that their utility payments subsidize.

DEQ has confidence in the emission reductions predicted using AVERT because of the robust framework established by APSC to incentivize and verify energy savings from Arkansas investor-owned utilities' EE portfolios. DEQ plans to compare the results of this analysis to actual energy savings reported by utilities and the emission reductions modeled based on those actual savings in Arkansas's 2025 Regional Haze Progress Report.

D. Source Retirement and Replacement Schedules

DEQ's 2015 Regional Haze Progress report provided information about potential emissions and actual emissions from new sources subject to PSD new source review between 2002 and 2012 and retirement of "PSD sources." This SIP narrative reports total Title V initial permits and Title V permits voided without issuance of a revised Title V permit. DEQ is presenting the tracking of source retirement and replacement differently in this SIP revision because DEQ no longer tags facilities in its permit database system as Title V. Instead, air permits for stationary sources are categorized as Reg. 18.315, minor source, or Title V.

Between 2002 and 2019, DEQ issued 108 initial Title V permits and 110 Title V permits were voided without being replaced by a revised permit. Figure VI-7 illustrates the number of initial Title V permits issued each year. Figure VI-8 illustrates the number of Title V permits voided for which there was no subsequent permit revision or renewal. These figures demonstrate the retirement and replacement of large stationary sources since the beginning of the Regional Haze Program.[4]

[4] Stationary sources for which an initial Title V permit is issued may have had a minor source permit prior to triggering requirements to be permitted under Regulation No. 26. Stationary sources for which a Title V permit was voided and no subsequent revision issued may have been reclassified as a minor source and permitted solely under Regulation No. 18 and/or Rule 19.

Figure VI-7: Initial Title V Permit Issuance per Year

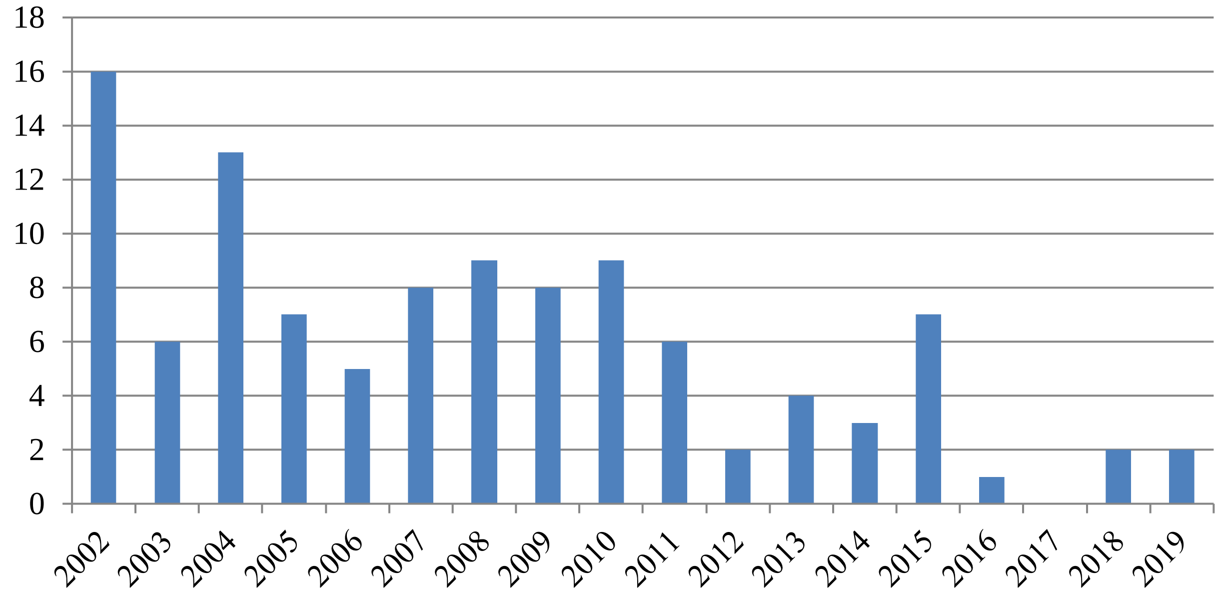
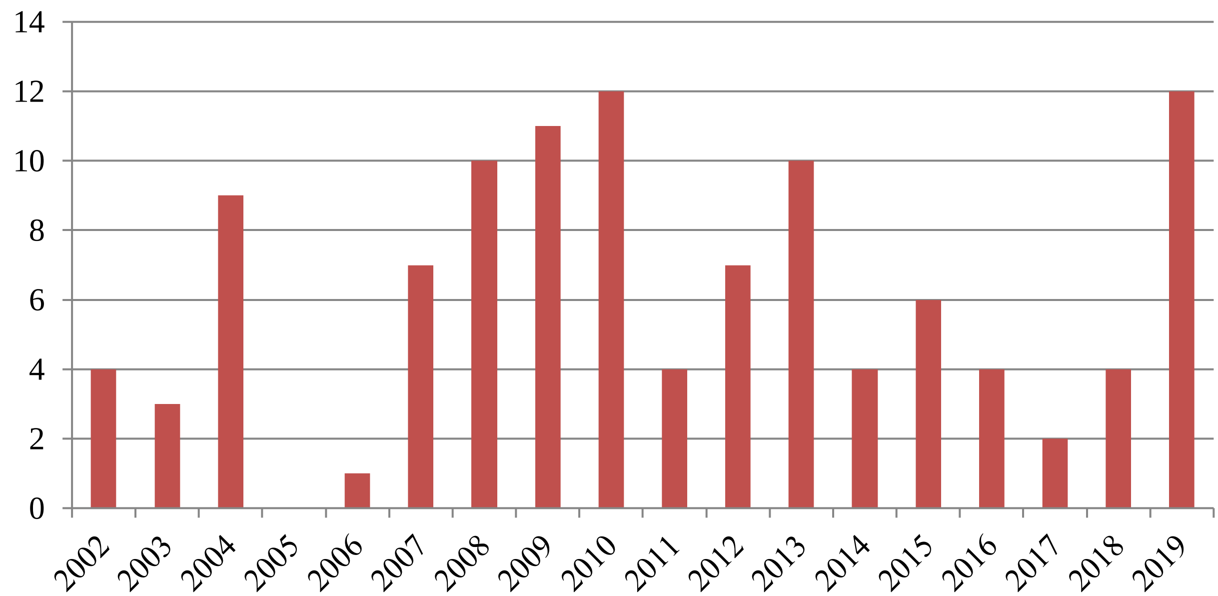


Figure VI-8: Title V Permits Voided without Replacement with Revised Title V Permit



The following stationary sources in Arkansas are anticipated to retire during Planning Period II:

- Entergy Lake Catherine (2025)[5] and
- Entergy White Bluff (2028).[6]

[5]Planned retirement year https://www.epa.gov/sites/production/files/2020-03/egrid2018_data_v2.xlsx

DEQ will manage new and modified sources in conformance with existing SIP requirements pertaining to PSD and minor new source review. DEQ will track source retirement and replacement through ongoing point source inventories and permitting actions.

In addition, the following stationary sources identified in DEQ's AOI screening analysis are also anticipated to retire during Planning Period II: Dolet Hills and Indiana Michigan Rockport.[7][8]

E. Smoke Management

As described in Chapter IV.A.1.d., Arkansas has adopted voluntary smoke management plans for both prescribed fire and agricultural burning. These plans are implemented by Arkansas foresters and farmers on a voluntary basis with the assistance of the Arkansas Department of Agriculture. The plans are available at https://www.agriculture.arkansas.gov/arkansas-voluntary-smoke-management-guidelines.

F. Additional Measures to Ensure Reasonable Progress and Address Interstate Transport of Visibility-Impairing Emissions

Based on DEQ's reasonable progress analysis in Chapter V. of this narrative, DEQ determined that the following measures are necessary to ensure reasonable progress for Arkansas federal Class I areas and to address interstate transport of visibility-impairing emissions:

1. FutureFuel

DEQ has determined that an emission limit for FutureFuel's coal-fired boilers based on fuel switching to two percent sulfur content coal is necessary for reasonable progress during Planning Period II. To establish such an emission rate, DEQ requested baseline emission data from FutureFuel for SO_2 emissions and heat input from burning coal and SO_2 emissions and heat input when burning other wastes in the three coal-fired boilers.

FutureFuel provided data based on fuel use records for coal and wastes burned in the boilers between 2017 and 2019. The SO_2 emissions are estimated from these fuel use records based on feed stream analysis that assumes all sulfur entering the boilers through fuel, is emitted as SO_2. This data is available in Appendix G. The average emission rate for coal burned was 5.1 lb SO_2/MMBtu (2092 tons) and the average emission rate for all fuels burned during the baseline was 4.6 lb SO_2/MMBtu (2171 tons). FutureFuel also provided 30-day rolling average emission rates for the same period and estimated what these emissions would be if FutureFuel were to use two percent sulfur coal and 1.5% sulfur content coal in place of the coal that was used over the

[6] Under an enforceable order (LIS-18-073) with DEQ to cease coal-fired operations of all units by December 31, 2028: http://www.adeq.state.ar.us/air/planning/sip/pdfs/regional-haze/entergy-ao-executed-8-7-2018.pdf

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

[8] SWEPCO has also announced the closure of Welsh and Pirkey in Texas, which have a large impact on visibility at Caney Creek, but as these planned retirements are not enforceable by Texas or EPA as part of the Texas SIP, DEQ has assumed in its modeling that these units continue to operate.

baseline period. Based on these data, FutureFuel estimates that it could achieve continuous compliance with an emission limit of 3.69 lb SO_2/MMBtu on a 30-day rolling average based on fuel switching to two percent sulfur content coal and 2.93 lb SO_2/MMBtu based on fuel switching to 1.5% percent sulfur content coal.

After public comment, DEQ and FutureFuel determined that 1.5% sulfur content coal was also cost-effective, would provide a greater visibility benefit at federal Class I areas, and would further ensure Arkansas meets reasonable progress goals. Therefore, DEQ and FutureFuel have agreed to an emission limit based on 1.5% sulfur content coal with a temporary variance mechanism that would provide a temporary alternative emission limit based on 2% sulfur content coal for a period not to exceed 365 days in a five-year period. This variance is intended to address long-term supply chain concerns for 1.5% sulfur content coal that meets FutureFuel's stoker boiler specifications by providing time for FutureFuel to develop an alternative compliance strategy to meet the 2.93 lb SO2/MMBtu limit. DEQ's modeling used an assumption of a 2% sulfur content coal limit for FutureFuel. Therefore, DEQ anticipates greater reductions of visibility impairment than projected by DEQ's RPGs.

DEQ entered into an administrative order with FutureFuel to adopt the emission limit and the associated compliance schedule, monitoring, recordkeeping, and reporting requirements. The final version of the executed administrative order has been included as part of the SIP submission to EPA. As of the date of signature by DEQ and FutureFuel, the requirements are enforceable as a matter of state law.

2. Independence

Although DEQ has determined that no additional control measures are reasonable for Independence for Planning Period II, DEQ has entered into an administrative order with Entergy that would render their planned cessation of coal-fired operations at Unit 1 and Unit 2 by December 31, 2030 enforceable as part of the SIP. Their planned cessation of coal-fired operations is already enforceable in court under a consent decree entered as part of a settlement between Sierra Club and Entergy. However, inclusion in the SIP renders the planned cessation enforceable by both DEQ and EPA. The executed administrative order has been included in this submittal. As of the data of signature by DEQ and Entergy, the requirements are enforceable as a matter of state law.

G. Enforceability of Emissions Limitations and Control Measures included in this SIP

DEQ has rendered the control strategy for FutureFuel and the cessation of coal combustion at Independence enforceable through administrative orders. The orders have been submitted to EPA for incorporation by reference into the SIP. The executed administrative orders are included with this SIP revision in Appendices F and G.

Inclusion of permanently enforceable emissions limitations and compliance schedules in the included AOs is consistent with and allowable under federal programs.

Sampling, monitoring, and reporting requirements that are generally applicable to stationary sources, including sources for which emissions limitations are established in this SIP, are contained in SIP-approved Arkansas Pollution Control and Ecology Commission (APC&EC) Rule No. 19 Chapter 7. No revisions to existing requirements in Rule No. 19 Chapter 7 were necessary for this SIP revision.

H. Anticipated Visibility Conditions in 2028 that will Result from Implementation of the Long-Term Strategy

DEQ performed CAMx modeling using a 2016 platform to project visibility conditions in 2028 based on DEQ's long-term strategy. Details on model assumptions, performance, results, and methodology are described in Appendix L. Table VI-3 compares current visibility conditions to projected visibility conditions in 2028 as a result of DEQ's long-term strategy.

Table VI-3: Visibility Progress due to SIP Control Strategy Anticipated Impact 2028 Projected Visibility Impairment[9]

	Modeled Visibility Conditions on the Most Impaired Days (deciviews)		Modeled Visibility Conditions on the Clearest Days (deciviews)	
Class I Area	2016	2028 SIP Control Strategy	2016	2028 SIP Control Strategy
Caney Creek	18.29	16.31	8.02	7.50
Upper Buffalo	17.95	16.49	8.20	7.72
Hercules Glades	18.72	17.30	9.71	9.07
Mingo	20.13	18.83	11.08	10.47
Mammoth Cave	21.02	19.37	11.31	10.47
Sipsey	19.03	17.41	10.76	10.04
Wichita Mountains	18.12	16.81	8.47	8.17
Shining Rock	15.49	13.83	4.40	4.00

DEQ notes that its modeling does not take into account emission reductions that other states have

[9] 2019 data was not available for Mingo, therefore, the current visibility conditions for this Class I area in the table are based on 2014–2018 data.

determined necessary as a result of their reasonable progress analysis. Any emission reduction measures that other states may determine necessary to ensure reasonable progress would be anticipated to further improve visibility conditions in 2028. The modeling also does not take into account the change in long-term strategy for FutureFuel to a more stringent limit based on the use of 1.5% sulfur content coal.

I. Adoption of Reasonable Progress Goals

Table VI-4 lists DEQ's RPG determinations for Planning Period II. DEQ did not request any particular control strategy be applied to sources in other states that impact Arkansas's Class I areas. Therefore, DEQ's RPG values do not include any emission reductions that may occur as a result of adoption of Regional Haze Planning Period II control strategies by other states, except in those instances where there is an enforceable retirement.

Table VI-4: 2028 Reasonable Progress Goals for Arkansas Federal Class I Areas on the Most Impaired Days

Federal Class I Areas	2028 Reasonable Progress Goal (deciviews)
Caney Creek	16.31
Upper Buffalo	16.49

DEQ's goal for the clearest days in 2028 is no degradation from the 2000–2004 baseline.

J. Progress, Degradation, and URP Glidepath Checks

After consideration of the four reasonable progress factors and visibility impacts, DEQ made control determinations that would result in greater visibility progress than the URP DEQ established for each federal Class I area in Arkansas. DEQ's modeling results summarized in Table VI-3 demonstrate that the long term strategy will result in improvement on the most impaired days. Table VI-5 compares the 2028 model results for Arkansas federal Class I areas based on DEQ's long-term strategy to the 2028 point on the URP for the most impaired days and to 2000–2004 conditions for the clearest days. As noted in Chapter II, DEQ adjusted its URP in accordance with EPA guidance. The data summarized in Table VI-5 demonstrates that there will be no degradation on the twenty percent clearest days in 2028 and that implementation of the long-term strategy will result in faster progress than under DEQ's adjusted URP glidepath for each Arkansas federal Class I area.

Table VI-5: 2028 Visibility Conditions Progress Check for Arkansas Federal Class I Areas

	Most Impaired Days (deciviews)		Clearest Days (deciviews)	
Class I Area	2028 URP	Modeled 2028 SIP Control Strategy	2000–2004 baseline	Modeled 2028 SIP Control Strategy
Caney Creek	18.90	16.31	11.24	7.50

Upper Buffalo	19.26	16.49	11.71	7.72

Table VI-6 compares the 2028 model results based on DEQ's long-term strategy to the 2028 point on the URP for the most impaired days at federal Class I areas that may be affected by emissions from Arkansas. DEQ consulted with neighbor states to confirm whether or not each state expects to adjust the glidepath for the federal Class I areas listed in Table VI-6, which is allowed by EPA guidance, but is not required.[10] Table VI-6 does not account for visibility improvement that would be achieved from adoption of control measures in Planning Period II by other states.

Table VI-6: 2028 Visibility Conditions Progress Check for Federal Class I Areas that may be Affected by Emissions from Arkansas

Class I Area	Most Impaired Days (deciviews)		Clearest Days (deciviews)	
	2028 URP	Modeled 2028 SIP Control Strategy	2000–2004 baseline	Modeled 2028 SIP Control Strategy
Hercules Glades	18.82	17.3	12.84	9.07
Mingo	19.48	18.83	14.29	10.47
Mammoth Cave*	21.82	19.37	16.51	10.47
Sipsey	20.44	17.41	15.57	10.04
Wichita Mountains*	17.36	16.81	9.78	8.17
Shining Rock*	20.98	13.83	7.7	4.0

*Adjusted value: State indicated in consultation that the 2028 URP, based on the updated natural conditions value for most impaired days from the 2020 EPA memo[11] would be used in Planning Period II projections

As discussed in Chapter V, no specific controls were requested from any other state, including the states that requested that DEQ perform a four-factor analysis, or agreed to as part of consultation. The 2028 SIP-controlled model results for the most impaired days demonstrate that all federal Class I areas for which sources in Arkansas may reasonably be anticipated to impact visibility conditions are below the respective state's URP glidepath before consideration of control measures determined necessary to ensure reasonable progress in SIPs from other states.

[10] See email correspondence between states, dated September 29, 2021 through September 30, 2021, included in Appendix D.

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

K. Consideration of Factors in Exercise of Powers

Pursuant to Ark. Code Ann. § 8-4-312, the APC&EC and DEQ must consider the factors listed in Ark. Code Ann. § 8-4-312, when exercising their powers and responsibilities. Table VI-9 provides DEQ's assessment of the statutory factors as applied to this SIP.

Table VI-7: Consideration of Ark. Code Ann. § 8-4-312 factors

Ark. Code Ann. § 8-4-312 Factors	Consideration of the Factors
(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	DEQ's consideration of this factor is addressed in Chapter II
(2) Existing physical conditions and topography	Modeling in support of this SIP utilizes these factors as inputs.
(3) Prevailing wind directions and velocities	The AOI analysis developed by Ramboll for the CenSARA states incorporates prevailing wind directions and velocities into its assessment of the probability of sources in a geographic area impacting visibility for each federal Class I area. DEQ relied on this analysis to determine which sources to examine for potential control measures. Modeling in support of this SIP also utilizes these factors as inputs.
(4) Temperatures and temperature-inversion periods, humidity, and other atmospheric conditions	Atmospheric conditions are a factor in estimating the amount of visibility impairment created by particulate species captured by monitoring equipment.[12]
(5) Possible chemical reactions between air contaminants or between such air contaminants and air gases, moisture, or sunlight	Two of the primary anthropogenic species contributing to visibility at many federal Class I areas, including those in Arkansas and those that are impacted by sources in Arkansas are ammonium sulfate and ammonium nitrate.

[12] The IMPROVE website provides the formula for calculating light extinction for the purposes of the Regional Haze Program: http://vista.cira.colostate.edu/Improve/the-improve-algorithm/

	Both of these species are formed by chemical reactions in the air. Ammonium sulfate is formed in a photochemical reaction between sulfur dioxide and ammonia. Ammonium nitrate is formed in a photochemical reaction between nitrogen oxides and ammonia.
(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 federal Class I areas is wilderness. The federal Class I areas support recreational activities and wildlife management. Sources affected by the control strategy in this SIP include sources near federal Class I areas and sources with large emissions of nitrogen oxides and sulfur dioxide. These emissions react with ammonia to form fine particulate matter that is capable of traveling long distances.
(7) Availability of air-cleaning devices	DEQ's consideration of this factor is described in Chapter V.
(8) Economic feasibility of air-cleaning devices	DEQ's consideration of this factor is described in Chapter V.
(9) Effect on normal human health of particular air contaminants	Although the Regional Haze Program does not focus on the human health effects, the particulate species that impact visibility in federal Class I areas also impact human health. Numerous scientific studies have linked particle pollution to a number of adverse health effects.[13] These effects include: premature death in people with heart or lung disease, nonfatal heart attacks, irregular heartbeat,

[13] EPA prepares an integrated science assessment each time the agency reviews the national ambient air quality standards for particulate matter. The integrated science assessment provides EPA's assessment of the extent scientific literature on the potential human health and welfare effects associated with ambient exposure to particulate matter. EPA's integrated science assessment reports can be accessed here: https://www.epa.gov/naaqs/particulate-matter-pm-air-quality-standards.

	aggravated asthma, decreased lung function, and increased respiratory symptoms such as irritation of airways, coughing, and difficulty breathing.
(10) Effect on efficiency of industrial operation resulting from use of air-cleaning devices	DEQ's consideration of this factor is described in Chapter V.
(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 focuses on improving visibility at federal Class I areas.
(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	DEQ's consideration of this factor is described in Chapter I.
(13) The volume of air contaminants emitted from a particular class of air contamination sources	DEQ's consideration of this factor is described in Chapters II, III, and V.
(14) The economic and industrial development of the state and the social and economic value of the air contamination sources	DEQ's consideration of the potential economic impacts of this SIP on sources of air contaminant emissions is discussed in Chapter V.
(15) The maintenance of public enjoyment of the state's natural resources	Visibility improvements are expected to occur at Arkansas federal 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 measures included this SIP.
(16) Other factors that the Division or the commission may find applicable	DEQ has not identified any other factors that are applicable that are not already discussed in this SIP.

Arkansas Regional Haze Planning Period II

State Implementation Plan

CHAPTER VII: MONITORING STRATEGY AND OTHER IMPLEMENTATION PLAN REQUIREMENTS

CHAPTER VII: MONITORING STRATEGY AND OTHER IMPLEMENTATION PLAN REQUIREMENTS

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VII. Monitoring Strategy and Other Implementation Plan Requirements

A. Monitoring Strategy

DEQ's monitoring strategy for Caney Creek and Upper Buffalo relies upon the continued availability of the IMPROVE monitoring network. IMPROVE is a collaborative association of state, tribal, and federal agencies, and international partners. The U.S. Environmental Protection Agency is the primary funding source, with contracting and research support from NPS. The Air Quality Group at the University of California, Davis is the central analytical laboratory, with ion analysis provided by Research Triangle Institute, and carbon analysis provided by Desert Research Institute.

IMPROVE monitors consist of four sampling modules that collect $PM_{2.5}$ and PM_{10} data for twenty-four hours every three days.[1] Data collected at IMPROVE sites includes specific information on the composition of haze-forming particles. This data is used to calculate visibility impairment and indicate the extent to which the visibility impairment is a result of anthropogenic or natural emissions of air pollutants.[2] A description of each monitor for Arkansas federal Class I areas is provided in Chapter II.

DEQ is committed to continued participation with IMPROVE, including consultation regarding monitoring sites and equipment, if needed.

B. Statewide Inventory of Emissions of Pollutants Reasonably Anticipated to Cause or Contribute to Visibility Impairment in any Federal Class I Area

DEQ will continue to submit annual inventories of pollutants, including those reasonably anticipated to cause or contribute to visibility impairment, in accordance with EPA Air Emissions Reporting Requirements.[3]

C. Other Elements Necessary to Access and Report on Visibility

Data from the IMPROVE monitors is posted to the IMPROVE website http://vista.cira.colostate.edu/Improve/improve-data/. This data is accessible to EPA and the public. This fulfills DEQ's annual reporting requirements of visibility monitoring data under 40 CFR § 51.308(f)(6)(iv).

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[1] Colorado State IMPROVE Program, http://vista.cira.colostate.edu/Improve/improve-program/
IMPROVE is a collaborative association of state, tribal, and federal agencies, and international partners. US Environmental Protection Agency is the primary funding source, with contracting and research support from the National Park Service. The Air Quality Group at the University of California, Davis is the central analytical laboratory, with ion analysis provided by Research Triangle Institute, and carbon analysis provided by Desert Research Institute.

[2] The algorithm used to estimate light extinction for the purposes of the Regional Haze Program and other relevant information can be accessed at the IMPROVE website: http://vista.cira.colostate.edu/Improve/the-improve-algorithm/

[3] 40 CFR Part 51 Subpart A

D. Review, Consultation, & Comments

DEQ developed a framework document for communication and consultation among DEQ, EPA, states with federal Class I areas impacted by visibility-impairing emissions from Arkansas sources, and tribes. The framework document also contains a log tracking communications with EPA, the FLMs, states, and other stakeholders. This framework document can be found in Appendix D.

1. EPA Review and Action

In addition to informal conversations during development of the draft SIP, DEQ sent an email to EPA R6 partners on March 1, 2021, to notify them of the availability of the pre-proposal draft SIP and to provide them with the opportunity for early input. Correspondence between DEQ and R6 is included in Appendix D of this SIP.

DEQ plans to submit the final SIP proposal to EPA for review and approval following the public comment period and finalization of any resulting revisions to the draft SIP.

2. Federal Land Manager Review and Consultation

In accordance with 40 CFR § 51.308(i)(2), DEQ formally consulted with designated FLM staff personnel on this SIP. In addition to informal conversations during development of the SIP, DEQ submitted letters to the FLMs on March 1, 2021, to notify them of the availability of the pre-proposal draft SIP and provide them with the opportunity to discuss the following:

- The FLM’s assessment of impairment of visibility in any mandatory federal Class I area; and
- The FLM’s recommendations on the development and implementation of strategies to address visibility impairment.

The FLM contact list, notification letters, comments received, and DEQ’s written consideration of the comments are included in Appendix D of this SIP.

Additionally, to address continuous consultation with FLMs, under 40 CFR 51.308(i)(4), DEQ continues to include FLMs in regional haze consultation through monthly regional haze calls with CenSARA states. DEQ has consulted with FLMs throughout this planning period, and will continue to coordinate with FLMs in the implementation of Arkansas’s RH SIP for planning period II. In addition, DEQ’s five-year progress report is due by January 31, 2025, and DEQ anticipates communications regularly occurring prior to the submittal, starting as early as mid-2023 to ensure that proper consultation is achieved during that time. In conclusion, DEQ is committed to effectively consulting FLMs as required under the RHR.

3. States Consultation

40 CFR § 51.308(f)(2)(ii) specifies consultation requirements for states that are reasonably anticipated to contribute to visibility impairment of another state’s federal Class I areas:

- The State must demonstrate that it has included in its implementation plan all measures agreed to during state-to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement;

- The State must consider the emission reduction measures identified by other States for their sources as being necessary to make reasonable progress in the mandatory federal Class I area; and
- In any situation in which a State cannot agree with another State on the emission reduction measures necessary to make reasonable progress in a mandatory federal Class I area, the State must describe the actions taken to resolve the disagreement.

Arkansas confers regularly with neighboring states through CenSARA regional haze conference calls. DEQ shares and receives feedback regarding reasonable progress, monitoring efforts, and other strategies relevant to regional haze planning and program implementation. DEQ also consulted with individual states via conference and video calls; these consultations are documented in Appendix D, in the communication log. On March 1, 2021, DEQ submitted a letter to the Illinois EPA, Indiana DEM, Kentucky DEQ, Louisiana DEQ, Missouri DNR, North Carolina DEQ, Oklahoma DEQ, and Texas CEQ, to notify them of the availability of the pre-proposal draft SIP and provide them with the opportunity to discuss and provide feedback. Availability of the pre-proposal draft SIP was also announced on CenSARA planning calls that occurred March 2, 2021, and April 12, 2021, which included state agency partners from Alabama, Georgia, Iowa, Kansas, and Nebraska. Only Texas CEQ submitted comments on the pre-proposal draft SIP. The affected states and federal partners contact list, notification letters, comments received, and DEQ's written consideration of the comments are included in Appendix D of this SIP proposal.

4. Public Review and Comments

DEQ provided notice of the final SIP proposal on February 27, 2022, and hosted a public hearing on March 29, 2022 to receive comments on the proposed SIP revision. The notice of the proposal and public hearing was published in the Arkansas Democrat-Gazette, on February 27, 2022; the Democrat-Gazette is a newspaper in circulation statewide, and thirty-day notice was provided prior to the date of the public hearing. The public comment period concluded on April 28, 2022. This notice was also posted to DEQ's website concurrent with newspaper publication of the public notice. The notice provided logistical information regarding the public hearing and the length of the public comment period, including virtual and in-person options for attending the public hearing. The public hearing was recorded and is available for streaming online.[4] A copy of the Proposed SIP was made available to the public online beginning February 27, 2022, at **https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx**. Comments received by DEQ during the public comment period were posted on the DEQ Regional Haze webpage.

Copies of written comments, a summary of DEQ's response to comments, and records from the

[4] https://www.youtube.com/watch?v=BJkqNZFV2Sg Regional Haze Requirements of the Clean Air Act Hearing

public hearing are included in the final SIP proposal package being submitted to EPA for approval. Evidence of these elements is included in the submission package.

DEQ's public review process provides the opportunity for meaningful involvement of all people regardless of race, color, national origin, or income. Documentation associated with this SIP revision are freely available on DEQ's webpage. DEQ public notices are published in a newspaper of statewide circulation and the online version of the notice is freely available at https://classifieds.arkansasonline.com/marketplace-littlerock/category/Legal%20Notices/Legal%20Notices.

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