To: OGC ARLO[OGC_ARLO@epa.gov]
From: Graham, Cheryl
Sent: Mon 4/3/2017 10:47:44 AM
Subject: Reminder: 04/03/17 Reg Review Agenda Updates
17-04-03 agenda.docx

Attached is the strikeout version of the reg agenda, if you have any additions/deletions please let me know by 11:00 today. Reg Review is scheduled for today (4/3) at 2:30pm in room 4045.

Thank you

Cheryl R. Graham
OGC/ARLO
(202) 564-5473

To: Zenick, Elliott[Zenick.Elliott@epa.gov]
Cc: Anderson, Lea[anderson.lea@epa.gov]; Marks, Matthew[Marks.Matthew@epa.gov]; Hogan, Stephanie[Hogan.Stephanie@epa.gov]
From: Smith, Kristi
Sent: Fri 3/31/2017 9:14:50 PM
Subject: FW: Tex Reg Haze, What we need for Texas SIP AND Ark_TX sticking points
Tx Reg Haze SIP_ WHAT EPA NEEDS Mar 31 2017 .docx
Tex Reg Haze SIP Ideas Moving Forward Mar 31 2017.docx
Texas_ Arkansas Reg Haz two Pager March 31 2017a.docx

Elliott –

Given that the focus appears to be haze [Ex. 5 - Attorney Client] I'll let you, Matt, & Lea take the lead. But please let Stephanie & I know if there are transport-related elements we should review.

- Kristi

Kristi M. Smith * Assistant General Counsel for the NAAQS Implementation Group * Air & Radiation Law Office * US EPA, Office of General Counsel * smith.kristi@epa.gov * (202) 564-3068 *

CONFIDENTIAL communication for internal deliberations only; may contain deliberative, attorney-client, attorney work product, or otherwise privileged material; do not distribute outside EPA or DOJ.

From: Koerber, Mike
Sent: Friday, March 31, 2017 4:45 PM
To: Beaver, Melinda <Beaver.Melinda@epa.gov>; Smith, Kristi <Smith.Kristi@epa.gov>; Lorang, Phil <Lorang.Phil@epa.gov>; Werner, Christopher <Werner.Christopher@epa.gov>; Anderson, Lea <anderson.lea@epa.gov>; Marks, Matthew <Marks.Matthew@epa.gov>; Hogan, Stephanie <Hogan.Stephanie@epa.gov>; Jones, Rhea <Jones.Rhea@epa.gov>
Cc: Wood, Anna <Wood.Anna@epa.gov>
Subject: FW: Tex Reg Haze, What we need for Texas SIP AND Ark_TX sticking points

See note from Region 6….

From: Stenger, Wren
Sent: Friday, March 31, 2017 4:39 PM
To: Coleman, Sam <Coleman.Sam@epa.gov>; Gray, David <gray.david@epa.gov>; Donaldson, Guy <Donaldson.Guy@epa.gov>; Smith, Suzanne <Smith.Suzanne@epa.gov>; Payne, James <payne.james@epa.gov>; Tomasovic, Brian <Tomasovic.Brian@epa.gov>; Thomas, Carrie <Thomas.Carrie@epa.gov>; Medina, Dayana <Medina.Dayana@epa.gov>; Kordzi, Joe <Kordzi.Joe@epa.gov>; Feldman, Michael <Feldman.Michael@epa.gov>; Snyder, Erik <snyder.erik@epa.gov>; Olszewski, Joshua <olszewski.joshua@epa.gov>
Cc: Stenger, Wren <stenger.wren@epa.gov>; Koerber, Mike <Koerber.Mike@epa.gov>; Wood, Anna <Wood.Anna@epa.gov>
Subject: Tex Reg Haze, What we need for Texas SIP AND Ark_TX sticking points

All,

Three things to catch all up on activities this week and needed moving forward on Texas Reg Haze:

1. TO DO: What we need from Texas for a Reg Haze SIP (2nd attached file). We created a one-page document for Sam in advance of the March 28 meeting in Austin. Sam promised to get something similar to Texas. Ex. 5 - Deliberative Process

Ex. 5 - Deliberative Process

2. FYI: We prepared a "sticking" points document for Texas and Arkansas Reg Haze at the request of HQs for Sarah and the Administrator. It is the 1st file attached.

3. TO DO: The Air Branch developed notes on "ideas" discussed with TCEQ at the Austin, March 28 meeting. It is the 3rd file attached. We need to continue to develop ideas for a path forward with TCEQ to ultimately capture what works and eliminate things that won't work.

4. NEXT STEPS: Our commitment from the Austin meeting was to proceed with 1-2 calls weekly to work towards what Texas can provide for an approvable SIP. The Air Branch will take the lead for scheduling and inviting folks to these calls.

Anna, Mike,

You can share with your folks or not. The Air Branch will be sharing out our drafts more broadly as they schedule the meetings.

As we edit and share documents, please make sure they are dated.

Thanks to all for the efforts this week. More to come.

From: Algoe-Eakin, Amy
Location: R7-RO2.4-F28-8/R7-RO
Importance: Normal
Subject: NE RH Status of Review- Conference Line- Ex. 6 - Personal Privacy
Agenda Added
Start Date/Time: Thur 12/1/2016 5:00:00 PM
End Date/Time: Thur 12/1/2016 6:00:00 PM
April 2016 Email from Matt Marks.pdf
NE_Regional Haze_Proposed Rulemaking for Remand PLorang after Lea v2.docx

Proposed Agenda

1) Discuss why we took remand- Ex. 5 - Deliberative Process
Ex. 5 - Deliberative Process

2) Previous discussion regarding rationale for notice (see attached email from Matt Marks)

3) Focus on the background- Ex. 5 - Deliberative Process
Ex. 5 - Deliberative Process

Ex. 5 - Deliberative Process

4) Who revises the notice? Revised schedule for signature.

To: OGC ARLO[OGC_ARLO@epa.gov]
From: Graham, Cheryl
Sent: Mon 3/27/2017 12:32:07 PM
Subject: 03/27/17 Reg Review Agenda Updates
17-03-27 agenda.docx

Attached is the latest strikeout version of the reg agenda, if you have any additions/deletions please let me know by 11:00 today. Reg Review is scheduled for today (3/27) at 2:30pm in room 4045.

Thank you

Cheryl R. Graham
OGC/ARLO
(202) 564-5473

To: Anderson, Lea[anderson.lea@epa.gov]
From: Nann, Barbara
Sent: Fri 2/17/2017 8:58:31 PM
Subject: FW: AR RH SIP Appendix 10.1
AR RH SIP_Appendix 10.1 through 11.2.pdf

See appendix 10.1 for Arkansas analysis.

"The following discussion

demonstrates how, in the case where it can be demonstrated that the anticipated rate of progress toward a return to natural background conditions results in achieving that goal prior to the statutorily-mandated timeframe, the four factor analysis becomes an unnecessary exercise."

From: Medina, Dayana
Sent: Friday, February 17, 2017 2:44 PM
To: Nann, Barbara <nann.barbara@epa.gov>
Subject: AR RH SIP Appendix 10.1

Hi Barbara,

The appendix you're looking for is found under "Appendix Volume 6" of the SIP, which is a pdf file that is 633 pages long and was too large for our server to allow me to email. So I had to extract Appendix 10.1 from the file. Here it is. Let me know if there are any other appendices you need.

Thanks,

Dayana Medina

U.S. Environmental Protection Agency, Region 6

Multimedia Division

State Implementation Section A (6MM-AA)

214-665-7241

To: Anderson, Lea[anderson.lea@epa.gov]
From: Nann, Barbara
Sent: Fri 2/17/2017 8:19:01 PM
Subject: RE: briefing on Entergy Independence
Arkansas Regional Haze SIP submittal.pdf

From: Anderson, Lea
Sent: Friday, February 17, 2017 12:38 PM
To: Nann, Barbara <nann.barbara@epa.gov>
Subject: briefing on Entergy Independence

Barbara,

Is the Arkansas SIP in regulations.gov for the prior disapproval in 2012?

Do you have time today to look through the SIP to see what type of analysis (if any) was done to address reasonable progress? **Ex. 5 - Attorney Client**

Ex. 5 - Attorney Client

Also, while digging through the SIP, can you see if they describe how the RPGs were set? **Ex. 5 - Attorney Client**

Ex. 5 - Attorney Client

thanks,

Lea

To: Anderson, Lea[anderson.lea@epa.gov]; Nann, Barbara[nann.barbara@epa.gov]
From: Spence, Samara (ENRD)
Sent: Thur 12/22/2016 5:43:52 PM
Subject: ARRH - Mots to Intervene
ARRH - Mot to Interven by Entergy et al.pdf
ENV_DEFENSE-#790351-v1-DN_4478835_MOTION_interested_party__National_Park....pdf

Lea and Barbara,

The motion to intervene from Entergy, AECC, and EEAA has been filed. I'm also sending the previous one from NPCA and Sierra Club because I can't remember if I sent it before. Ex. 5 - Attorney Client

Ex. 5 - Attorney Client

Please let me know what you've decided about Ark Affordable Energy Coalitions similar pending motion.

Samara

IN THE UNITED STATES COURT OF APPEALS
FOR THE EIGHTH CIRCUIT

ARKANSAS AFFORDABLE ENERGY COALITION,	}	
Petitioner,	}	**Case No. 16-4296**
v.	}	
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,	}	
Respondent.	}	

OPENING BRIEF OF THE ARKANSAS AFFORDABLE ENERGY COALITION

Mark Walters
Mike Nasi
JACKSON WALKER L.L.P.
100 Congress Ave., Suite 1100
Austin, Texas 78701
[Tel.] (512) 236-2360
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COUNSEL FOR THE ARKANSAS AFFORDABLE ENERGY COALITION

SUMMARY OF THE CASE AND STATEMENT REGARDING ORAL ARGUMENT

Petitioner the Arkansas Affordable Energy Coalition (AAEC) seeks an order vacating the final rule promulgated by the United States Environmental Protection Agency entitled, "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan," 81 Fed. Reg. 66332 (Sept. 27, 2016). The rule conflicts with federal law and is in excess of EPA's authority. It requires expenditures of well over $1 billion with little or no benefit. These costs will ultimately be borne by customers and rate payers, including members of AAEC.

A number of other petitions have been filed challenging the rule. All the petitions have been consolidated under the lead case, *State of Arkansas, et al v. United States Environmental Protection Agency, et al.*, No. 16-4270. AAEC believes that, considering all the petitions together as a single "case," this is an exceptional case warranting argument in excess of 30 minutes per side.

RULE 26.1 DISCLOSURE STATEMENT OF ARKANSAS AFFORDABLE ENERGY COALITION

Pursuant to Rule 26.1 of the Federal Rules of Appellate Procedure and Circuit Rule 26.1, the Arkansas Affordable Energy Coalition declares as follows: the Arkansas Affordable Energy Coalition is an association of Arkansas electric power consumers, suppliers of goods and services to the electric power industry, and/or associations that support them. The Arkansas Affordable Energy Coalition does not have a parent corporation, and no publicly held corporation owns 10% or more of its stock.

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STATEMENT OF JURISDICTION

On September 27, 2016, EPA published "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan," 81 Fed. Reg. 66332 (September 27, 2016). On November 23, 2016, AAEC timely filed a petition for review of this rule in this Court. The Court has jurisdiction over AAEC's petition pursuant to section 307(b) of the Clean Air Act, 42 U.S.C. 7607(b).

ISSUES PRESENTED

1. Did EPA err in imposing pollution controls under the "reasonable progress" prong of the Regional Haze Program, 42 U.S.C. § 7491, when Arkansas was already making "reasonable progress" without such controls? Apposite Authority: 42 U.S.C. § 7491(b)(2).

2. Did EPA err in analyzing individual sources of air pollution and imposing source-specific requirements under the "reasonable progress" prong of the Regional Haze Program? Apposite Authority: *Texas v. EPA*, 829 F.3d 405, 427-28 (5th Cir. 2016); 42 U.S.C. § 7491(a)(3), (b)(1); 40 C.F.R. §§ 51.301, 308(d).

3. Must EPA's Federal Implementation Plan for Arkansas for regional haze be set aside because EPA failed to properly consider all the costs of the pollution controls that are required to be installed? Apposite Authority: *Michigan v. EPA*, 135 S. Ct. 2669 (2015).

4. Did EPA fail to properly consider and adequately explain its rationale as to cost as it relates to the anticipated improvement in visibility from the pollution controls required by EPA's Federal Implementation Plan for Arkansas? Apposite Authority: *Michigan v. EPA*, 135 S. Ct. 2669 (2015); *Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134 (9th Cir. 2014).

5. Did EPA err in making its Best Available Retrofit Technology determinations by failing to consider the use of low-sulfur coal as a control technology? Apposite Authority: *North Dakota v. EPA*, 730 F.3d 750, 764 (8th Cir. 2013); 42 U.S.C. § 7491(g)(2).

6. Must EPA's determination that scrubbers must be installed at certain power plants be set aside because EPA failed to consider other required factors? Apposite Authority: *GenOn REMA , LLC v. EPA*, 722 F.3d 513, 516 (3rd Cir. 2013); *U.S. Magnesium, LLC v. EPA*, 690 F.3d 1157, 1159 (10th Cir. 2012); Ark. Code Ann. § 8-4-312.

7. Were EPA's decisions on baseline visibility impacts and visibility improvements unreasonable? Apposite Authority: 40 CFR Part 51, App. Y, § IV.D.4.c.

STATEMENT OF FACTS/STATEMENT OF THE CASE

This case involves a challenge—filed initially in this Court pursuant to § 307(b) of the Clean Air Act ("CAA" or "Act"), 42 U.S.C. § 7607(b)—to a final rule of the United States Environmental Protection Agency ("EPA"), promulgated under Section 169A of the CAA, 42 U.S.C. § 7491. This section establishes what is sometimes called the "Regional Haze Program." It addresses visibility in federal Class I areas, which include many national parks and wilderness areas. 42 U.S.C. §§ 7472(a), 7491(g)(5). Under the Regional Haze Program, states are to develop State Implementation Plans (SIPs) containing "emission limits, schedules of compliance and other measures" in a series of ten-year state programs "as may be necessary to make reasonable progress toward meeting the national" visibility goal. *See* 42 U.S.C. § 7491(b)(2). The "national visibility goal" is "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution." 42 U.S.C. § 7491(a)(1).

The State of Arkansas submitted a SIP. EPA approved part of Arkansas's SIP, but disapproved other parts. *Approval and Promulgation of Implementation Plans; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze; Final Rule*, 77 Fed. Reg. 14604 (Mar. 12, 2012). Over four years later, EPA

promulgated a Federal Implementation Plan ("FIP") to replace the disapproved portions of Arkansas's SIP. This final EPA rule was published in the *Federal Register* at 81 Fed. Reg. 66332 (Sept. 27, 2016) and is entitled: *Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan* (the "Rule" or "Final Rule" or the "FIP" or the "Final FIP").[1] It is this FIP that AAEC and the other petitioners now challenge.

There are two Class I areas in Arkansas: the Caney Creek Wilderness Area and the Upper Buffalo Wilderness Area. 81 Fed. Reg. at 66332, JA____. In addition, EPA claims that emissions from two sources in Arkansas contribute to regional haze in two Class I areas in Missouri: the Hercules-Glades Wilderness Area and the Mingo National Wildlife Refuge. 81 Fed. Reg. at 66332, JA____.[2]

---

[1] EPA first proposed the FIP in April 2015: *Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan*, 80 Fed. Reg. 18944 (April 8, 2015) (the "Proposed FIP"). The Final FIP finalizes the substantive requirements of the Proposed FIP, except where it is indicated in the Final FIP that changes have been made. *See, e.g.*, 81 Fed. Reg. at 66333, 66338, JA_____,_____.

[2] In the Proposed FIP, EPA stated that the interstate visibility provision of CAA § 110(a)(2)(D)(i)(II) required Arkansas to comply with EPA's FIP in order to "ensure that emissions reductions other states relied on in their RPG demonstrations take place." 80 Fed. Reg. at 18998. In the Final FIP, however, EPA stated that "an approved Regional Haze SIP is not the only possible means to satisfy" the CAA interstate visibility transport provision (81 Fed. Reg. at 66413) and appears to have abandoned this argument. However, to the extent that EPA maintains the position stated in its Proposed FIP, EPA's action is not based on its regulations, is in excess of its authority and is contrary to the CAA. *See* EPA-R06-

Among other things, EPA's FIP requires the installation of pollution controls for sulfur dioxide (SO_2) in the form of flue gas desulfurization units (commonly referred to as "scrubbers," *see* 81 Fed. Reg. at 66335, JA_____) at three coal-fired power plants: the White Bluff Electric Power Plant near Redfield, Arkansas ("White Bluff") (two units); the Independence Steam Electric Station near Newark, Arkansas ("Independence") (two units); and the Flint Creek Power Plant in Gentry, Arkansas ("Flint Creek"). 81 Fed. Reg. at 66335-36, 66341, 66343, JA_____,_____,_____.[3] Flint Creek is owned by Southwestern Electric Power Company and co-petitioners Arkansas Electric Cooperative Corporation ("AECC"). White Bluff and Independence are owned by AECC and co-petitioners Entergy Arkansas Inc., Entergy Mississippi Inc. and Entergy Power LLC (collectively "Entergy"), as well as several Arkansas municipal utilities.

The total estimated cost of the controls required by the FIP is in excess of $2 billion—with a "b". *See* 81 Fed. Reg. at 66356, 66406. The visibility benefits, according to EPA's own figures, will be virtually nil.[4]

OAR-2015-0189-0163, Comments of Nucor Steel – Arkansas and Nucor-Yamato Steel Company ("Nucor comments") at 50-53, JA_____.

[3] For Flint Creek, EPA's emission limits for SO_2 were calculated based on a particular type of scrubber referred to as "Novel Integrated Technology" or "NID." *See* 81 Fed. Reg. at 66335, 66341, JA_____,_____.

[4] Throughout the FIP, EPA describes anticipated visibility improvements using unquantified subjective terms like "significant" and "considerable." As explained below, however, as calculated by EPA, most of these alleged benefits would be so small they would not be observable with the human eye.

AAEC is a coalition that includes electric consumers, and associations of consumers, that receive power from the affected power plants. For example, the Arkansas steel mills of AAEC member Nucor Corporation are significant customers of and members in the Mississippi County Electric Cooperative, Inc. (MCECI). MCECI is a member of Arkansas Electric Cooperatives, Inc. (AECI), which is a co-owner of the Independence, White Bluff, and Flint Creek plants. Much of the electricity purchased by Nucor's Arkansas mills comes from these three power plants. AAEC's membership also includes Arkansas Electric Energy Consumers, whose members are large, industrial customers of Entergy Arkansas, Inc.

Plant owners and operators will be responsible initially for the cost of installing the pollution controls mandated by the FIP. However, Arkansas law permits the direct pass through and recovery of the costs and expenses of installing, operating, and maintaining such pollution controls from electric utility customers and ratepayers, such as Nucor and other AAEC members, through electricity rates and tariffs filed with the Arkansas Public Service Commission. *See* Ark. Code Ann. §§ 23-4-501, -504 (authorizing an immediate utility rate surcharge to recover costs incurred by a utility to comply with environmental regulations).

In addition, AAEC's members include providers of goods and services to power plants, in particular coal-fired power plants, including those affected by the FIP. These providers of goods and services would be harmed financially if, instead of installing the scrubbers, any of these plants were to curtail operations or close in response to the FIP, and this has been suggested as a possibility.

A total of seven petitions for review have been filed in this Court challenging the FIP, including the one filed by the Sierra Club and the National Parks Conservation Association, one filed by the State of Arkansas, and one filed by AAEC. These petitions have all been consolidated under Case No. 16-4270, *The State of Arkansas v. United States Environmental Protection Agency, et al.* Also consolidated as part of this case are petitions for review filed by the State of Arkansas and Entergy challenging EPA's failure to grant Motions for Reconsideration of the FIP filed with the agency.

SUMMARY OF ARGUMENT

The FIP must be set aside as arbitrary and capricious, an abuse of discretion, and/or otherwise unlawful for numerous reasons, seven of which are discussed here.

First, it is undisputed that Arkansas is already, without the installation of scrubbers at Independence, making the reasonable progress towards the national visibility goal that the Regional Haze Rule requires. It was unlawful for EPA to

require the installation of scrubbers at Independence as "necessary" to make reasonable progress.

Second, in analyzing reasonable progress, it is impermissible for EPA to individually analyze specific sources, *i.e.*, Independence. Instead, it may only consider *categories* of sources, like "electric generating units."

Third, EPA's determination that scrubbers must be installed at Independence, White Bluff, and Flint Creek must be set aside because EPA failed to properly consider all relevant costs.

Fourth, EPA's determination that scrubbers must be installed White Bluff, Independence, and Flint Creek must be set aside because EPA failed to properly consider and failed to adequately explain its rationale as to cost as it relates to the anticipated improvement in visibility.

Fifth, EPA's determination that scrubbers must be installed at White Bluff and Flint Creek as the "best available retrofit technology" must be set aside because EPA failed to consider the use of low-sulfur coal as a control technology.

Sixth, EPA's determination that scrubbers must be installed at Independence, White Bluff, and Flint Creek must be set aside because EPA failed to consider other required factors.

Seventh, EPA's decisions on baseline visibility impacts and visibility improvements are unreasonable and do not support its determinations that scrubbers must be installed at Independence, White Bluff, and Flint Creek.

STANDARD OF REVIEW

The Court must set aside any final EPA action that is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law; contrary to constitutional right, power, privilege or immunity; in excess of statutory jurisdiction, authority, or limitations, or short of statutory right; or without observance of procedure required by law." CAA § 307(d)(9), 42 U.S.C. § 7607(d)(9).

ARGUMENT

The Clean Air Act has been described as "an experiment" in "cooperative federalism"—the idea that the national, state, and local governments will work together cooperatively and collectively to solve a common problem. *Michigan v. EPA*, 268 F.3d 1075, 1083 (D.C. Cir. 2001). The Act "establishes a comprehensive program for controlling and improving the nation's air quality through state and federal regulation." *BCCA Appeal Grp. v. EPA*, 355 F.3d 817, 821-22 (5th Cir. 2003). The Act establishes a preference, however, that states, not EPA, are the primary engines driving the process.

For example, CAA § 110, 42 U.S.C. § 7410, creates a framework for managing air quality through National Ambient Air Quality Standards or "NAAQS." Under this framework, EPA's primary role is to set appropriate standards. It is up to the states, in the first instance, to decide how to best meet those standards through SIPs, and the CAA grants each state "wide discretion in formulating its plan . . . ." *Union Elec. Co. v. EPA*, 427 U.S. 246, 250 (1976). "[S]o long as the ultimate effect of a State's choice of emission limitations is compliance with the national standards for ambient air, the State is at liberty to adopt whatever mix of emission limitations it deems best suited to its particular situation." *Train v. Nat. Res. Def. Council, Inc.*, 421 U.S. 60, 79 (1975).

This same structural framework applies to the CAA's Regional Haze Program, codified in CAA § 169A, 42 U.S.C. § 7491. The Regional Haze Program addresses visibility in federal Class I areas, which are certain international parks, national wilderness areas, national memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres. 42 U.S.C. §§ 7472(a), 7491(g)(5).[5] Under CAA § 169A, the national government—represented by EPA—is to work together with the states to establish and attempt to meet the "national goal" of "preventi[ng] [] any future, and . . . remedying [] any existing, impairment of

[5] Additionally, the areas must have been in existence on August 7, 1977, to be Class I areas. *See* 42 U.S.C. § 7472(a).

visibility in mandatory class I Federal areas which impairment results from man-made air pollution." 42 U.S.C. § 7491(a)(1).

Consistent with the structure described above, under the Regional Haze Program, EPA's primary responsibility is to identify those federal Class I areas where "visibility is an important value," 42 U.S.C. § 7491(a)(2), and to promulgate regulations to guide the states in developing SIPs to improve visibility in the identified areas.

A state SIP must contain "emission limits, schedules of compliance and other measures" in a series of 10-year state plans "as may be *necessary* to make *reasonable progress* toward meeting the national" visibility goal. *See* 42 U.S.C. § 7491(b)(2) (emphasis added). As noted above, the national visibility goal is to prevent any future, and remedy any existing, visibility impairment in Class I areas caused by anthropogenic pollution. *See id.* § 7491(a)(1). Congress, however, did not specify a timetable for meeting this goal. EPA, through its Regional Haze Rule, 40 C.F.R. § 51.300 *et seq.*, has established a goal "to restore natural visibility conditions at Class I areas by 2064." 81 Fed. Reg. 66332, JA_____. The CAA, however, does not require that this goal be met by 2064, but "only that reasonable progress be made towards the goal during each planning period." 81 Fed. Reg. 66355, JA_____; *see also* 42 U.S.C. § 7491(a)(4) (requiring EPA to promulgate regulations to assure reasonable progress towards meeting the national goal).

There are three primary components of a state's SIP. First, it must contain "reasonable progress goals," or "RPGs," "that provide for reasonable progress towards achieving natural visibility conditions" 40 C.F.R. § 51.308(d)(1). To calculate RPGs, a state must first "[a]nalyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064." *Id.* § 51.308(d)(1)(B). This rate of progress is often referred to as the "uniform rate of progress" or "URP," and the slope from the present visibility conditions (expressed in numerical deciviews (dv)) to natural visibility conditions in 2064 via URP is sometimes referred to as "the glide path." *See, e.g.*, 81 Fed. Reg. at 66367, J.A._____.

For convenience, the portion of the Regional Haze Program dealing with reasonable progress is referred to as the "reasonable progress prong." CAA § 169A(g)(1), 42 U.S.C. § 7491(g)(1), sets out four factors to be considered in determining reasonable progress:

- the costs of compliance;
- the time necessary for compliance;
- the energy and nonair quality environmental impacts of compliance; and
- the remaining useful life of any existing source subject to such requirements.

The second component of a state's SIP is a long-term (10-15 year) strategy for making reasonable progress towards meeting the national visibility goal. 42 U.S.C. § 7491(b)(2)(B).

Finally, a SIP must also identify the "best available retrofit technology" (BART) for 26 listed source categories. Sources that meet these criteria are often referred to as "BART eligible sources." One such category, applicable to White Bluff and Flint Creek, is "fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input—that (a) have the potential to emit 250 tons or more of "any pollutant;" (b) were constructed between 1962 and 1977; and (c) emit "any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any" Class I area. 42 U.S.C. § 7491(b)(2)(A) & (g)(7).

CAA § 169A(g)(2), 42 U.S.C. § 7491(g)(2), lists five factors to be considered in determining BART for a BART eligible source:

- the costs of compliance;
- the energy and nonair quality environmental impacts of compliance;
- any existing pollution control technology in use at the source;
- the remaining useful life of the source; and
- the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

As discussed above, EPA's role in this process is to review the state's SIP for compliance with the CAA. Only if a state fails to comply with the CAA may EPA itself draft a state-specific plan, like the FIP at issue here. CAA § 110(c), 42 U.S.C. § 7410(c). Importantly for this case, however, where EPA promulgates a FIP, the same requirements for state SIPs apply to the FIP.

In this case, the State of Arkansas submitted a SIP. *See* 81 Fed. Reg. 66333. Moreover, it is undisputed that Arkansas is already exceeding its "reasonable progress" goals for the first reporting period ending in 2018, and that regional haze has declined and visibility has improved in federal Class I areas in Arkansas since 2002. *See* EPA-R06-OAR-2015-0189-1063, Arkansas Department of Environmental Quality Five-Year Regional Haze Progress Report—Revised (ADEQ RHPRR) 46-53, 55-56 (May 2015), JA_____; Nucor comments, Ex. 3, JA_____. Indeed, within the FIP itself, EPA effectively concedes, repeatedly, that—even without the installation of any of these controls—Arkansas is already below the URP rate and, therefore, already in compliance with the "glide path" to meet the national visibility goal by 2064. *See, e.g.,* 81 Fed. Reg. at 66351, 66360-61, 66363, 66370, JA_____,_____,_____,_____.

Notwithstanding these concessions, EPA approved only part of Arkansas's SIP. *See* 81 Fed. Reg. at 66333.[6] It disapproved other parts, *see id.*, and, over four years later, promulgated its FIP to replace the disapproved portions of Arkansas's SIP. Among other things, the FIP will require installation of scrubbers at Flint Creek and White Bluff as BART, that is, under the provision of the Regional Haze Program that requires the installation of the Best Available Retrofit Technology. *See* 81 Fed. Reg. 66335, JA_____. Independence is not BART eligible, and, therefore, not subject to BART, *see* 81 Fed. Reg. at 66339, JA____, but the FIP requires the installation of scrubbers at Independence under the reasonable progress prong of the Regional Haze Rule. 81 Fed. Reg. at 66336, 66352, JA_____,_____.

The FIP is unlawful and must be set aside for multiple reasons, seven of which are discussed here: (1) EPA failed to demonstrate that its "reasonable progress" determinations, in particular that scrubbers must be installed at Independence, are "necessary" for Arkansas to maintain reasonable progress as required by the Regional Haze Program; (2) in any event, EPA may not impose source-specific pollution controls as part of the reasonable progress prong of the Regional Haze Rule; (3) EPA failed to properly consider the costs of installation,

[6] The partial disapproval was published on March 12, 2012 at 77 Fed. Red. 14604. *See* 81 Fed. Reg. 66333. AAEC members commented on EPA's action on the Arkansas SIP, objecting to some of the SIP's BART determinations that suffer from some of the same defects as EPA's FIP in this case.

operation, and maintenance of scrubbers at Independence, White Bluff, and Flint Creek; (4) in making its BART determinations, EPA failed to properly consider the anticipated effect on visibility; (5) EPA failed to consider the use of low-sulfur coal in its BART determinations as an alternative to scrubbers; (6) EPA's determination that scrubbers must be installed at Independence, White Bluff, and Flint Creek must be set aside because EPA failed to consider other required factors, specifically Ark. Code Ann. § 8-4-312; and (7) EPA's decisions on baseline visibility impacts and visibility improvements are unreasonable and do not support its BART and reasonable progress determinations.

A. Where, as here, a state has already achieved "reasonable progress," EPA cannot impose additional requirements under the "reasonable progress" prong of the Regional Haze Rule.

As noted above, SIPs—and FIPs—must contain "emission limits, schedules of compliance and other measures as may be *necessary* to make *reasonable progress* toward meeting the national" visibility goal. 42 U.S.C. § 7491(b)(2) (emphasis added). A state's plan is developed ten years at a time, and the FIP in this case only addresses reasonable progress that is required for the period ending in 2018. The next ten-year planning period will end in 2028, and Arkansas will have to submit another SIP to achieve the RPGs and URP on the glide path at the endpoint for 2028.

As multiple commenters to the proposed FIP pointed out, "necessary" means "indispensable," "absolutely needed." *See, e.g.*, Nucor comments at 18, JA____. Thus, if Arkansas has already achieved reasonable progress without the installation of scrubbers at Independence, then scrubbers are *not indispensable* for Arkansas to achieve reasonable progress for the period ending in 2018. Thus, scrubbers are not "necessary" within the meaning of CAA § 169A, and pollution controls like scrubbers cannot be required under the reasonable progress prong just because EPA thinks they are cost effective or would otherwise be a good idea.

In the FIP, EPA has failed to demonstrate that the installation of scrubbers at Independence is "necessary" for Arkansas to make reasonable progress towards the national visibility goal or that controls on any other sources are necessary to achieve reasonable progress for the planning period ending in 2018. Arkansas is already below the URP and on or under the glide path to reasonable progress because of (1) emissions reductions already made through national and regional programs like the Mercury and Air Toxics Standards, the Clean Air Interstate Rule, and the Cross State Air Pollution Rule; (2) emissions reductions anticipated in the future from other national and regional programs, like the implementation of the 1-hour SO_2 NAAQS; and (3) reductions proposed for White Bluff and Independence (through controls other than scrubbers). *See* EPA-R06-OAR-2015-0189-0175, Comments of Arkansas Electric Energy Consumers, Inc. and Arkansas Gas

Consumers ("AEEC comments") at 8, JA_____; Nucor comments at 16-17 & Exs. 3, 5, & 6; JA_____,____,_____,_____; *see also* ADEQ RHPRR at 46-53, 55-56, JA_____,_____.

EPA does not dispute that Arkansas is under the URP. Indeed, it effectively admits it, repeatedly, in the FIP. *See, e.g.*, 81 Fed. Reg. at 66360-61 (asserting that an analysis of the four factors in 42 U.S.C. § 7491(g)(1) is required even where the state is under the URP), 66363 (noting that in the Proposed Rule, EPA stated that it was appropriate to evaluate Independence "even though Arkansas Class I areas and those outside of Arkansas most significantly impacted by Arkansas sources are projected to the meet the URP for the first planning period."), JA_____,_____,_____.

This should end the matter. If Arkansas has already achieved reasonable progress for the current planning period, then additional controls are not "necessary" under the commonly understood meaning of that word.

To try to get around this problem, EPA misreads and misapplies § 7491(b)(2). According to EPA, it does not matter that Arkansas has already achieved reasonable progress without the installation of scrubbers at Independence. EPA can require additional controls if it determines they are "reasonable" based upon the four factors in § 7491(b)(2), *even if they are not necessary*.

EPA is clear and unequivocal about this, stating that its "longstanding interpretation of the regional haze rule is that the URP does not establish a 'safe harbor' for the state in setting its progress goals. If it is reasonable to make more progress than the URP, a state must do so." 81 Fed. Reg. at 66370, JA_____ (internal quotation and footnote omitted); *see also* 81 Fed. Reg. at 66351, (stating that the obligation to apply the four-factor analysis "applies even when a Class I area is below the URP and even when monitoring data show that a Class I area is meeting or is projected to meet the RPG previously established by the state"), 66361 ("We see nothing in the Reasonable Progress Guidance indicating that additional controls can only be required if further action beyond BART is needed to remain on or below the URP glide path."). JA_____,_____.

Section 7491(b)(2), however, simply cannot support EPA's interpretation. It effectively reads the word "necessary" out of the statute. The test becomes, not what is "necessary"—which is what Congress provided—but what EPA determines to be reasonable. *But that is not what the statute says*. The plain language of § 7491(b)(2) admits of only one reading—that a control may be imposed if it is necessary—*e.g.*, required—for the state to make reasonable progress. A control is either necessary for the state to make reasonable progress or it is not. If it is not, then there is no possible application and consideration of the four factors in § 7491(b)(2) that can magically change "is not" to "is." Thus,

§ 7491(b)(2) cannot be read to allow EPA to impose unnecessary controls just because EPA deems them to be cost-effective or otherwise reasonable.[7]

EPA's misreading of § 7491(b)(2) leads it to make an error similar to the one it made with the Cross State Air Pollution Rule (CSAPR). That rule implements the "good-neighbor" provisions of the CAA, which require states to take steps to reduce certain air pollution that travels outside the state's borders and contributes to another state's being unable to meet certain NAAQS. 42 U.S.C. § 7410(a)(2)(D). In the CSAPR case, EPA imposed SO_2 controls for several states—on the grounds that they were cost effective and would be beneficial—without there being any evidence that these controls were necessary to maintain the NAAQS in any other state. Following remand from the Supreme Court, the D.C. Circuit held that these controls were unlawful because the statute did not allow controls to be imposed in one state without a showing that the controls were "necessary"—in the sense of "required"—for another state to attain or maintain the NAAQS. *See EME Homer City Generation, L.P. v. EPA*, 795 F.3d 118, 128-32

[7] Additionally, EPA's reading of § 7491(b)(2) inverts what is supposed to be the cooperative-federalism approach of the regional haze program. Under EPA's reading, the question is no longer, "Has the state adopted measures to ensure it is making reasonable progress?" Instead, it becomes, "Has the state required every control that EPA deems to be reasonable under the four factors listed in § 7491(b)(2), regardless of whether the state agrees and regardless of whether a control is necessary for the state to achieve reasonable progress?" This simply cannot be squared with either the text of § 7491(b)(2) or the structure of the Regional Haze Program as a whole.

(D.C. Cir. 2015). It was not enough that EPA believed the controls were cost-effective, reasonable, fair, or otherwise a good idea.

Similarly, § 7491(b)(2) only allows the imposition of reasonable progress measures that are necessary for the state to make reasonable progress. In this case, the undisputed record evidence demonstrates that Arkansas is well on its way to meeting the national visibility goals and has already achieved reasonable progress for the planning period ending in 2018 without the installation of scrubbers at Independence. Therefore, it was erroneous and unlawful (and arbitrary and capricious and beyond EPA's authority) for EPA to attempt to impose controls under the guise of "reasonable progress" (1) costing hundreds of millions of dollars (if not more) and (2) having few if any visibility benefits, especially in the 2008-2018 planning period covered by the FIP.

B. EPA impermissibly analyzed individual sources and imposed source-specific requirements under the reasonable progress prong of the Regional Haze Rule.

Additionally, the requirement that scrubbers be installed at Independence is unlawful for a separate reason: in setting reasonable progress goals, EPA may not analyze specific individual sources and require the installation of controls on source-by-source basis.

Reasonable progress provisions are intended to address contributions from numerous sources collectively over a wide area, not individual sources. Therefore,

these provisions may not be applied on a specific source-by-source basis. They can be applied only to categories of sources. By contrast, other provisions like BART and Reasonably Attributable Visibility Impairment (RAVI) (*see* 40 C.F.R. §§ 51.301-.302) apply to specific, individual sources.

With respect to reasonable progress, CAA § 169A discusses "classes or categories of sources" that "may reasonably be anticipated to cause or contribute significantly to impairment of visibility . . . ." 42 U.S.C. § 7491(a)(3), (b)(1). Similarly, under EPA's rules, reasonable progress goals are to address "regional haze," which EPA defines as "visibility impairment that is caused by the emission of air pollutants from numerous sources of a wide geographic area." 40 C.F.R. §§ 51.301, .308(d). By contrast, EPA defines BART as an "emission limitation [that] must be applied on a case-by-case basis . . . ." *Id.* § 51.301. EPA also defines RAVI as "visibility impairment that is caused by the emissions of air pollutants from one, or a small group of sources." 40 C.F.R.§ 51.301.

Consistent with this, EPA has not, until recently, attempted to require a source-specific analysis for reasonable progress, and the courts agreed with the approach. For example, in *WildEarth Guardians v. EPA*, 770 F.3d 919 (10th Cir. 2014), the court rejected the argument that § 169A requires source-specific reasonable progress analysis, holding that "[n]either the Clean Air Act nor the

Regional Haze Rule requires source-specific analysis in the determination of reasonable progress." *Id.* at 944.

In proposing a FIP for the State of Texas in 2016, however, EPA partially rejected Texas's SIP on the ground (among others) that Texas should have conducted source-specific reasonable progress analyses at certain facilities. *See Approval and Promulgation of Implementation Plans; Texas and Oklahoma; Regional Haze State Implementation Plans; Interstate Visibility Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze; Federal Implementation Plan for Regional Haze*, 81 Fed. Reg. 296, 302 (Jan. 5, 2016); *see also Texas v. EPA*, 829 F.3d 405, 427-28 (5th Cir. 2016). Texas and several other petitioners challenged the Texas FIP, and the Fifth Circuit granted a preliminary injunction prohibiting its enforcement. The court specifically found that the petitioners had a strong likelihood of success on the merits because "EPA's requirement that Texas conduct a source-specific analysis is not supported by the Clear Air Act or the Regional Haze Rule." *Texas v. EPA*, 829 F.3d at 428. For the same reason, EPA's attempt to require the installation of scrubbers at Independence as part of "reasonable progress" must likewise be rejected.

Additionally, besides requiring the installation of scrubbers at Independence for "reasonable progress," the FIP also requires that scrubbers be installed as BART at White Bluff and Flint Creek. These determinations must be set aside for

several reasons, including: (1) EPA's failure to properly consider the costs of installation of scrubbers (this also applies to the decision to require scrubbers at Independence) and (2) EPA's failure to properly consider the anticipated effect on visibility and the use of low-sulfur coal in making its BART determinations.

C. EPA's determination that scrubbers must be installed at Independence, White Bluff, and Flint Creek must be set aside because EPA failed to properly consider all costs.

In determining both reasonable progress and BART, EPA was required to consider, among other things, the costs of compliance. 42 U.S.C. § 7491(g)(1)-(2). In this case EPA failed to consider all of the costs associated with the installation of scrubbers at Independence, White Bluff, and Flint Creek. Therefore, these requirements of the FIP must be vacated and remanded to EPA so that those costs may be considered.

In the FIP, EPA determined the cost of scrubbers to be \$2,853/ton SO_2 and \$2,634/ton SO_2 for Independence units 1 and 2, \$2,565/ton SO_2 and \$2,421/ton SO_2 for White Bluff units 1 and 2, and \$3,845/ton SO_2 for Flint Creek.[8] *See* EPA-R06-OAR-2015-0189-0002, *Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan* (TSD) at 62 (Flint Creek), JA_____; 81 Fed. Reg. at 66343 (White Bluff), 66341 (Flint Creek)

[8] As discussed below, EPA failed to consider all relevant costs. In addition, however, EPA has promulgated a presumptive range of cost-effectiveness for SO_2 controls for BART of between \$00-\$2,000/ton SO_2. EPA's own numbers exceed this range.

& 66352 (Independence), JA_____, _____, _____. These estimates, however, failed to include all the costs of installation, maintenance, and operation. Under Arkansas law, the costs of installation, including the costs EPA declined to consider, will ultimately be borne by Independence's, White Bluff's, and Flint Creek's customers and ratepayers, including members of AAEC, through electricity rates and tariffs filed with the Arkansas Public Service Commission. *See* Ark. Code Ann. §§ 23-4-501, -504 (authorizing an immediate utility rate surcharge to recover costs incurred by a utility to comply with environmental regulations). Accordingly, EPA was required to consider these costs as part of its BART analysis. *See Michigan v. EPA*, 135 S. Ct. 2699, 2706 (2015) (holding that "agency action is lawful only if it rests on a consideration of the relevant factors.") (internal quotation omitted).

The costs EPA failed to consider include the "Allowance for Funds Used During Construction" or "AFUDC." AFUDC is part of the Federal Energy Regulatory Commission's Uniform System of Accounts, and it is utilized by both the FERC and state regulatory commissions, including the Arkansas Public Service Commission, to account for construction financing costs that are added to the cost of the plant for purposes of determining the rates that will allow the utilities to recover the costs of installation. AFUDC can easily amount to tens of millions of dollars. *See* Nucor comments at 33-34, JA____.

EPA also failed to consider the rate of return that will be allowed to the owners of Independence, White Bluff, and Flint Creek on the total allowable costs of any control technology required by EPA, including scrubbers. *See* AEEC comments at 13-14, JA_____, Nucor comments at 34-35, JA____.

EPA's response is that these costs are not allowed under its "Cost Control Manual," 81 Fed. Reg. 66383, JA_____, but this is no answer at all. EPA's manual is not the standard.

Section 7491(g)(1)-(2) requires EPA to consider the costs of compliance. This means the actual costs of compliance. EPA's Cost Control Manual may be useful as a starting point to compare rough baseline costs of various control technologies, but it is not sufficient by itself to satisfy this statutory mandate because it does not include *all* costs. Here, irrespective of what may be in EPA's manual, the Arkansas Public Service Commission is required by law to allow the owners of Independence, White Bluff, and Flint Creek to recover their actual costs incurred in installing the scrubbers, including AFUDC, plus a reasonable rate of return, which, recently, has been between four and six percent of total cost (including AFUDC). AEEC comments at 14, JA_____, Nucor comments at 35, JA_____. Consideration of *all* costs is critical because § 7491(g)(1)-(2) requires EPA in promulgating a FIP (and a state in promulgating a SIP) to weigh all the factors listed therein in determining reasonable progress (§ 7491(g)(1)) and BART

(§ 7491(g)(2)). Thus, EPA must consider not just whether a control technology is cost effective compared to other technologies, it must also evaluate the cost of those technologies in relation to the visibility benefits, if any. Since the costs described above like AFUDC and a reasonable rate of return are legally allowed under Arkansas law and will be passed on to customers and rate payers, EPA was required to consider them in determining reasonable progress for Independence[9] and BART for White Bluff and Flint Creek. EPA's failure to consider these costs requires vacatur and remand.

D. EPA's determination that scrubbers must be installed at White Bluff, Independence, and Flint Creek must be set aside because EPA failed to properly consider and failed to adequately explain its rationale as to cost as it relates to the anticipated improvement in visibility.

The only purpose of the Regional Haze Program is the improvement of visibility in Class I areas, and that is the only reason that controls may be mandated under CAA § 169A. Other factors, like health benefits may not be considered. *See Texas v. EPA*, 829 F.3d at 434 n.42.

Furthermore, in addition to cost, to determine BART for a particular, BART eligible source, EPA must also consider the "degree of improvement in visibility which may reasonably be anticipated to result" from the use of EPA's preferred technology. 42 U.S.C. § 7491(g)(2). Similarly, for the reasonable progress prong

[9] Assuming EPA is allowed to analyze individual sources under the reasonable progress prong, a point AAEC contests.

of the Regional Haze Rule, EPA believes it is appropriate to consider the "visibility improvement of controls[,]" in addition to the four factors in 42 U.S.C. § 7421(g)(1). *See* 81 Fed. Reg. at 66351.

Visibility is measured in "deciviews." Most people cannot detect a change in visibility of less than one deciview.[10] In the FIP, EPA based its determination that scrubbers must be installed at Independence, White Bluff, and Flint Creek on its conclusion that the cost was reasonable on a dollar/per ton of SO_2 basis. However, a determination that a particular technology is cost-effective cannot be the end of the inquiry. The degree of visibility improvement must also be considered and compared to the cost. Otherwise, BART simply becomes a technology forcing program, instead of a visibility improvement program.

Point sources in Arkansas—*i.e.*, individual sources like Independence, Flint Creek, and White Bluff, have very little impact on visibility impairment at Class I areas on the days of worst visibility—a point EPA acknowledges. *See* 81 Fed. Reg. 66350. Thus, the cost of install scrubbers relative to the visibility benefit obtained is high—very high indeed. Using EPA's own costs estimates, the cost of installing the scrubbers *on a dollar per year per deciview basis* are as follows:

White Bluff 1: $39,337,306/yr./dv

[10] *See Approval and Promulgation of Implementation Plans; State of Idaho; Regional Haze State Implementation Plan*, 77 Fed. Reg. 30248, 30250 (proposed May 22, 2012) (to be codified at 40 C.F.R. pt. 52).

White Bluff 2:	$42,415,424/yr./dv
Flint Creek:	$65,769,250/yr./dv
Independence 1:	$64, 219,337/yr./dv
Independence 2:	$52,171,633/yr./dv[11]

Notwithstanding these costs, EPA determined that scrubbers should be installed as BART at White Bluff and Flint Creek and in the name of "reasonable progress" at Independence. By contrast, in determining BART for the J.E. Corette power plant in Billings, Montana, EPA found that costs/dv of $30,477,272 for dry sorbent injection ("DSI") scrubbers and $50,308,300 for a semi-dry scrubbers were excessive, even though EPA determined that both of those controls were "cost-effective" on a $/ton of SO_2 basis and even though EPA concluded that the use of either would result in visibility improvements. *See* Nucor Comments at 37 & Ex. 18, JA_____, _____; *Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan*, 77 Fed. Reg. 23988, 24043 (April 20, 2012). For Corette, EPA concluded that "the cost of controls is not justified by the visibility improvement." 77 Fed. Reg. at 24043. Accordingly, EPA determined that the best alternative for Corette was the low-sulfur coal it was already using. *See Approval and Promulgation of Implementation Plans; State of Montana; State*

[11] *See* Nucor comments at 36-37 & Exhibit 18, JA_____.

Implementation Plan and Regional Haze Federal Implementation Plan, 77 Fed. Reg. 57864, 57893 (Sept. 18, 2012).[12]

EPA's response is that it may, but is not required to, measure costs on a $/yr./dv basis. 81 Fed. Reg. 66388-89. But again, that is no answer at all. Even assuming it is correct, it misses the point. All EPA has done is (1) found that its preferred technology is cost-effective compared to other technologies and (2) described the anticipated visibility improvement with a subjective label like "considerable" or "significant," even though it is so small it cannot be detected by the human eye. This is not enough. EPA is required to articulate a rationale, grounded in the four factors of § 7491(g)(1) for reasonable progress or the five factors of § 7491(g)(2) for BART, that explains why the cost of its preferred pollution controls is justified by the anticipated visibility improvements. It has failed to do so here, and this means that its FIP cannot even be reviewed. *See Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1142-44 (9th Cir. 2014).

Administrative agencies must engage in "reasoned decision making." *Michigan*, 135 S. Ct. at 2706. To be lawful and valid, an agency rule, like the FIP at issue here, must be reached through a process that is "logical and rational." *Id.* (internal quotation omitted). Furthermore, the agency must explain its reasoning,

[12] For Montana, the state did not submit a SIP. EPA proposed a FIP on April 20, 2012. In the final rule, published on September 18, 2012, EPA adopted the findings and conclusions of the proposed FIP except as expressly set forth in the final rule. 77 Fed. Reg. at 57866.

that reasoning must make sense, and it must be supported by the evidence in the administrative record. The agency's *ipse dixit* is not enough. Accordingly, courts have tended to affirm EPA's BART determinations and other judgments where EPA has offered a rational explanation for its decision. But, where, as here, none is offered, courts have remanded rules to the agency to provide the required explanation.

For example, in *National Parks Conservation Association*, the court reviewed the Montana regional-haze FIP discussed above. In the FIP, EPA, among other things, concluded that controls for nitrogen oxides (NO_x) costing $1,487/ton were not justified at Corette, but it also concluded that NO_x costing $1,500/ton were justified as BART for another power plant. The court found this latter determination to be arbitrary and capricious because EPA failed to explain the basis for this inconsistency. 788 F.3d at 1145.

In this case, EPA required scrubbers as BART for White Bluff and Flint Creek and as "reasonable progress" for Independence. In determining BART, EPA was statutorily required to consider, among other things, the costs of compliance and the degree of improvement in visibility which may reasonably be anticipated to result from the use of the technology. 42 U.S.C. § 7491(g)(2). EPA's own guidelines approve calculating visibility improvement using a $/yr./dv calculation. *See* 70 Fed. Reg. 39104, 39107 (July 6, 2005). Here, the costs per deciview for

White Bluff, Flint Creek, and Independence are higher than those found to be too high for Corette. Thus, given its determination for Corette, EPA was required to provide some explanation and justification for concluding that the high $/yr./dv costs are justified as BART for White Bluff and Flint Creek. This is especially true given that, like Corette, White Bluff and Flint Creek are already burning low-sulfur coal.

EPA has failed to offer an adequate explanation for the different standards applied in Montana and Arkansas, and it has failed offer an adequate justification for the high cost of scrubbers at Independence, White Bluff, and Flint Creek relative to the low anticipated visibility benefits. It did not, for example, attempt to explain that other factors applicable to the BART determination (*see* 42 U.S.C. § 7491(g)(2)) justified requiring scrubbers notwithstanding their high cost per dv. Accordingly, EPA did not engage in reasoned decision making, and it has not adequately explained the reasons for its actions.[13]

E. EPA's determination that scrubbers must be installed at White Bluff and Flint Creek must be set aside because EPA failed to consider the use of low-sulfur coal as an alternative.

[13] As noted above, EPA's justification for requiring scrubbers at Independence, White Bluff, and Flint Creek is that doing so will remove most of their contribution to regional haze in Class I areas on the worst visibility days. *See* 81 Fed. Reg. at 66350. But as EPA's own calculations recognize, the total contributions these sources make on the worst days is very small—two percent or less. "Most" or "a lot" of "not very much" is still not very much.

In making its BART determinations for White Bluff and Flint Creek, EPA was also statutorily required to consider existing pollution control technologies already in use. 42 U.S.C. § 7491(g)(2); *North Dakota v. EPA*, 730 F.3d 750, 764 (8th Cir. 2013).

Low-sulfur coal can be effective in controlling SO_2 emissions, and both White Bluff and Flint Creek have used low-sulfur coal for many years. In fact, the Arkansas Public Service Commission required White Bluff to use low-sulfur coal as a condition of its construction permit. *See* Nucor comments at 29 & n. 19 & Ex. 11, JA_____, _____ (citing Ark. Pub. Serv. Comm'n Order No. 14, Docket 73-048 U (U-2488), October 11, 1974, which is attached as Ex. 11 to Nucor's comments). The U.S. Energy Administration states that the use of low-sulfur coal reduces SO_2 emissions by as much as 85%, and EPA's own documentation indicates that low-sulfur coal reduces SO_2 emissions by more than 70%. *See* Nucor comments at 29 & nn.21-22 & Exs. 13-14, JA_____, _____-_____.

As noted above, EPA previously approved the use of low-sulfur coal as an alternative for the Corette power plant in Montana. Additionally, it has approved low-sulfur coal as meeting the "best available control technology" (a/k/a BACT) requirements for the Prevention of Significant Deterioration (PSD) program, which is designed to ensure that areas that are "in attainment" for a NAAQS stay in attainment. *See* Nucor comments at 29-30, JA_____-_____.

In this case by contrast, EPA failed to analyze and consider the use of low-sulfur coal at White Bluff and Flint Creek. Thus, EPA failed to consider a factor it was statutorily required to consider, and this, in turn, requires vacatur of EPA's BART determinations for White Bluff and Flint Creek.

F. EPA's determination that scrubbers must be installed at Independence, White Bluff, and Flint Creek must be set aside because EPA failed to consider other required factors.

Additionally, EPA's determination that scrubbers must be installed at Independence, White Bluff, and Flint Creek must be set aside because EPA failed to consider other required factors. EPA has approved what is known as Arkansas's "infrastructure SIP" pursuant to CAA § 110, 42 U.S.C. § 7410. *See* 40 C.F.R. § 52.170(e). When EPA approves a SIP, its requirements become federal law and are fully enforceable in federal court. *See, e.g.*, *GenOn REMA , LLC v. EPA*, 722 F.3d 513, 516 (3rd Cir. 2013) ("If the EPA approves the SIPs, they become enforceable as federal law."); *U.S. Magnesium, LLC v. EPA*, 690 F.3d 1157, 1159 (10th Cir. 2012) ("Approved SIPs are enforceable as federal law . . . ."). This is true even if the underlying state law is later repealed—that is, the now-repealed state law is still federally-enforceable in the Clean Air Act context as part of the federally-enforceable SIP. *See General Motors Corp. v. United States*, 496 U.S. 530 (1990) (holding that where Massachusetts amended its SIP to extend a particular deadline but EPA did not act to approve (or disapprove) the revision, the

United States could still maintain a civil enforcement action against an automobile manufacturer for failing to meet the original deadline); *Ky. Res. Council v. EPA*, 304 F.Supp.2d 920 (W.D. Ky. 2004) (holding that because Louisville's vehicle emission testing program was part of Kentucky's Clean Air Act SIP, it could not be discontinued without EPA's approval, notwithstanding a state law directing that the program be terminated).

As part of the approval of Arkansas's infrastructure SIP, EPA approved what is now codified as Ark. Code Ann. § 8-4-312, and it is therefore now enforceable as federal law and binding on EPA as well as Arkansas's state agencies. *See* 40 C.F.R. § 52.170(e) (approving former Ark. State. Ann. § 82-1936, now codified as Ark. Code Ann. § 8-4-312). Section 8-4-312 delineates multiple factors that must be considered in deciding to regulate air quality in Arkansas, one which is "the economic and industrial development of the state and the social and economic value of air contamination sources . . . ." Ark. Code Ann. § 8-4-312(14).

Unlike other commercial and industrial sources, the costs of compliance on electric utilities that are regulated in a monopoly market like Arkansas have wide-ranging impacts on the state (and also implicate aspects of the state's sovereignty). The installation of scrubbers at Independence, White Bluff and Flint Creek will cost more than $2 billion and will necessarily result in significant increases in

electric rates over most of Arkansas for the customers and ratepayers of these facilities (including members of AAEC). Moreover, these facilities constitute a large part of the baseload electric generation for Arkansas, and an even larger proportion of the baseload generation for co-petitioner AECC and its member cooperatives (and AAEC members are members and customers of some of these cooperatives). AAEC comments at 15-16, JA_____; Nucor comments at 21-22, JA____. Nowhere in the FIP, however, did EPA adequately consider any of this.

This failure not only violates Ark. Code Ann. § 8-4-312, it also contravenes both the spirit an purpose of EPA's own Environmental Justice ("EJ") guidelines, which require EPA to "consider the impacts of our regulatory actions on populations documented as frequently bearing the greatest burdens imposed by environmental pollution." EPA, Guidance on Considering Environmental Justice During the Development of Regulatory Actions," May 2015 at 2.[14]

Federal data demonstrates that the poorer a household is, the greater the harm of higher energy rates is on those households. Arkansas is the second poorest state, having a median household income of $40,768, and it has the fourth highest percentage of residents living in poverty. Almost 20% of the people living in the areas served by Independence, White Bluff, and Flint Creek live below the federal poverty level—in some counties as many as 30%. Nucor Comments at 24-25,

[14] Available at http://www.epa.gov/environmentaljustice/resources/policy/considering-ej-in-rulemaking-guide-final.pdf.

JA_____. EPA failed to consider this in requiring scrubbers to be installed at Independence, White Bluff, and Flint Creek, and this failure requires vacatur of these decisions.

G. EPA's decisions on baseline visibility impacts and visibility improvements are unreasonable and do not support its BART or reasonable progress determinations.

EPA's own guidelines for determining BART provide that "[t]he baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." 40 C.F.R. Part 51, App. Y, § IV.D.4.c; Nucor Comments at 38, JA_____. EPA failed to comply with this guidance in this case.

For example, EPA failed to use the most recent—2009-2011—emissions data for White Bluff, Flint Creek, and Independence, and instead, used the maximum 24-hour recorded emissions of SO_2 from each unit, extrapolated over a three year period from 2001-2003, to determine the visibility impacts. 80 Fed. Reg. at 18969.[15] EPA should have used the emissions data for the three-year period from 2009-2011, which Entergy specifically proposed as part of its White Bluff analysis. The data submitted by Entergy showed a significant decrease is SO_2 emissions between 2001-2003 and 2009-2011 at White Bluff. *See* Nucor comments 39-40 & n.37 & Exs. 15A & 15B, JA_____-_____, _____-_____.

[15] This information is contained in the Proposed Rule. In the Final Rule, EPA finalized the BART determinations from the Proposed Rule based on this data from 2001-2003. *See generally supra* n. 2.

Additionally, using the maximum 24-hour recorded emissions, greatly overestimates the visibility impacts, as EPA recognizes. For example, from 2001-2003, the maximum 24-hour SO_2 emissions rates for Independence were 5,463 lb/hr for unit 1 and 6,337 lb/hr for unit 2. However, the average daily emission rates over the same period (without including downtime) were 2,927 lb/hr for unit 1 and 3,088 lb/hr for unit 2. In other words, the actual emissions were about half of what EPA used for its modeling analysis. *See* Nucor comments at 38, JA_____.

EPA recognized this problem, and in an effort to correct it, used the 98th percentile of modeled visibility values, which eliminated about seven days per year from the analysis. *See* Nucor comments at 39, JA_____. But this is just something EPA made up. It has no support in the scientific literature as a method to accurately "normalize" emissions data that is overestimated. Nor is there any scientifically demonstrated correlation between the highest modelled visibility impacts and the highest visibility impacts actually observed.

And EPA's methodology does not work. For example, removing the seven days with the highest visibility impact for 2001-2003 for Independence gives maximum 24-hour emissions rates of 4,768 lb/hr at unit 1 and 5,357 lb/hr at unit 2—still far above the actual emission rates. *See id.*

Additionally, it was arbitrary and capricious for EPA to rely on the modeling system known as CALPUFF in making its BART determinations for White Bluff

and Flint Creek, given that CALPUFF significantly overestimates visibility impacts—in this case by at least a factor of two and probably more.

CALPUFF simulates the distribution of atmospheric pollution. EPA uses it to assess the long-range transport of pollutants. However, it is well-known that CALPUFF likely overestimates visibility impacts by 2-10 times for distances greater that 100 km. One cause of this is the impact of what is known as overnight plume transport. During that time (the overnight period), the plume is distorted by wind shear. If the "puff splitting" feature of CALPUFF is not used, this wind shear is ignored, which, in turn, causes visibility impacts of the traveling plume to be overstated. Accordingly, the CALPUFF User's Manual specifically advises that "puff splitting" should be used when overnight transport is involved. Here, the distance from White Bluff and Flint Creek to the Class I areas involved is greater than 100 km in each case. Given the time it takes to travel that distance, overnight transport is almost always involved. EPA, however, did not use the "puff splitting" feature of the CALPUFF model, notwithstanding the recommendation of CALPUFF's developer. Therefore, the EPA's modelling overestimated the visibility impacts of White Bluff and Flint Creek on these Class I areas by at least a factor of 2 and probably more. *See* Nucor comments at 42-44 & nn. 39-41 & Exs. 19-20, JA_____-_____,_____,_____.

This overestimation is significant. There is no explanation or justification by EPA in the FIP that demonstrates that the visibility impacts EPA derived from its CALPUFF model are precise enough to demonstrate that the BART controls at White Bluff and Flint Creek "will lead to reasonably anticipated visibility improvement" at Class I areas. *See* Nucor comments at 45 & Ex. 15 at 23, JA_____,_____; *see also Nat'l Parks Conservation Ass'n*, 788 F.3d at 1146. Indeed, EPA has found that the CALPUFF is a reasonable application for deciview impacts exceeding 2-3 deciviews, *id.*, but not for fractions of a deciview. In the FIP, however, *as calculated by EPA using CALPUFF*, the maximum visibility impact modeled for any Class I area for White Bluff or Flint Creek is 0.813 dv for White Bluff Unit 1 at Caney Creek—less than the 1 dv limit detectable by the human eye. Reduced by 1/2, this maximum impact becomes 0.465, which is below the level EPA considers as contributing to visibility impairment.[16] Reduced by 1/5, it becomes 0.163—virtually nil and far below the ability of CALPUFF to meaningful measure.

EPA fails to address any of this in the FIP. Indeed, it does not address numerical differences at all. Instead, it uses subjective, and in this context meaningless, adjectives like "considerable," "significant," and "meaningful." The FIP, however, is devoid of any explanation as to what EPA means by these terms

[16] According to EPA, a source with an impact greater than or equal to .5 dv are considered to "contribute" to visibility impairment. *See* 81 Fed. Reg. at 66391.

or how any of its modeled visibility impacts can be considered "considerable," "significant," or "meaningful" in the ordinary understanding of those words, given that they are beyond the precision of CALPUFF to measure. EPA's visibility analysis systematically overstates both the baseline visibility impacts of White Bluff and Flint Creek and the visibility benefits that would result from installation of scrubbers.

Furthermore, because the projected visibility impacts are beyond the precision of the CALPUFF model, EPA has failed to adequately explain how its preferred control technology will lead to "reasonable anticipation of visibility improvement" as required by 42 U.S.C. § 7491(g)(2). *See Nat'l Parks Conservation Ass'n*, 788 F.3d at 1147; *Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1, 7 (D.C. Cir. 2002) (holding that it is arbitrary and capricious to require the installation of expensive controls where there would be no appreciable effect on haze in any Class I area).

PRAYER

For the foregoing reasons, Petitioner the Arkansas Affordable Energy Coalition respectfully requests that the Arkansas Regional Haze Federal Implementation Plan be vacated.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that February 17, 2017, I electronically filed the foregoing Opening Brief of the Arkansas Affordable Energy Counsel with the Clerk of the Court for the United States Court of Appeals for the Eighth Circuit by using the CM/ECF system. I certify that all participants in the case are registered CM/ECF users and that service will be accomplished by the CM/ECF system.

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CERTIFICATE OF COMPLIANCE

The undersigned counsel states that this Opening Brief complies with Fed. R. App. P. 32(7)(B) because excluding the parts of the document exempted by Fed. R. App. P. 32(f), this document contains 9,534 words as counted by a word processing system and is within the 13,000 word limit. This brief also complies with typeface and type-style requirements of Fed. R. App. P. 32(a)(5) because it has been prepared in a proportionally spaced typeface in 14-point Times New Roman font.

Dated: February 17, 2017

/s/ Mark Walters
Mark Walters

UNITED STATES COURT OF APPEALS
FOR THE EIGHTH CIRCUIT

No. 16-4270 & 17-1276 (Consolidated)

STATE OF ARKANSAS, et al.,
Petitioners,
v.
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al.,
Respondents

On Petition for Review of an Agency Action of the
United States Environmental Protection Agency

BRIEF OF PETITIONER THE STATE OF ARKANSAS

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SUMMARY OF THE CASE AND STATEMENT REGARDING ORAL ARGUMENT

The State of Arkansas seeks an order vacating the final rule promulgated by the United States Environmental Protection Agency entitled, "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan," 81 Fed. Reg. 66332 (Sept. 27, 2016) ("Final Rule"). The Final Rule conflicts with federal law, threatens the reliability of Arkansas's electricity supply, and inexplicably and irrationally orders the people of Arkansas to spend well in excess of a billion dollars to achieve visibility conditions inferior to those that already exist.

Given the number of petitioners that have sought review of the Final Rule, Arkansas believes argument in excess of 30 minutes per side is warranted.

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STATEMENT OF JURISDICTION

On September 27, 2016, EPA published "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan," 81 Fed. Reg. 66332 (Sept. 27, 2016). The Final Rule only applies to facilities operating in Arkansas. On November 22, 2016, Arkansas timely filed its petition for review of the Final Rule in this Court.

On November 22, 2016, the Arkansas Department of Environmental Quality (ADEQ) asked EPA to reconsider the Final Rule. EPA constructively denied that request on January 31, 2017, and Arkansas timely filed a petition for review of that constructive denial on February 6, 2017.

This Court has jurisdiction over those petitions pursuant to 42 U.S.C. 7607(b).

STATEMENT OF THE ISSUES PRESENTED

The questions presented are:

1. The Clean Air Act and EPA's regulations require an implementation plan achieve reasonable progress toward natural visibility at certain federal parks and wildlife areas during the period covered by the implementation plan. The Final Rule adopted by EPA imposes an implementation plan that carries more than a billion dollar price tag but will not achieve progress toward natural visibility during the planning period. Did EPA act arbitrarily, capriciously, or otherwise contrary to law in adopting the Final Rule?

> Apposite Authority: 42 U.S.C. 7491; 42 U.S.C. 7607; 40 C.F.R. 51.308; *Michigan v. EPA*, 135 S. Ct. 2699 (2015); *North Dakota v. EPA*, 730 F.3d 750 (8th Cir. 2013); *Texas v. EPA*, 829 F.3d 405 (5th Cir. 2016).

2. Under the Clean Air Act, in adopting an implementation plan, EPA is required to consider the energy impacts of compliance and to explain how it considered those impacts. Here, the Final Rule requires five electric generating units at three facilities—which account for a substantial portion of Arkansas's electricity output—to be taken offline to install sophisticated new controls. EPA originally proposed allowing those installations to take place over a three year period, and commenters explained that such a narrow compliance period would be insufficient to coordinate and schedule unit

outages without threatening the reliability of Arkansas's electricity supply. Nevertheless, EPA narrowed the compliance period to just 18 months because there was evidence that *one* unit at a *single* facility could typically be installed within six to eight months. Did EPA act arbitrarily, capriciously, or otherwise contrary to law in failing to: 1) consider comments concerning the ability to safely coordinate multiple outages without endangering reliability; and 2) explain how it concluded that multiple outages could be safely coordinated and controls installed on five units at three facilities within 18 months because there was evidence that similar controls can typically be installed on a single unit in six to eight months?

> Apposite Authority: 42 U.S.C. 7491; *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983); *Nat'l Parks Conservation Ass'n v. EPA*, 803 F.3d 151 (3d Cir. 2015); *Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134 (9th Cir. 2015).

3. Under the Clean Air Act and EPA's regulations, an implementation plan must contain reasonable progress goals for reducing visibility impairment over the period of the implementation plan and impose controls necessary to achieve those goals. Here, EPA imposed source specific controls that it determined were reasonable and only thereafter established reasonable progress goals for the planning period. Was EPA's approach arbitrary, capricious, or otherwise contrary to law?

Apposite Authority: 42 U.S.C. 7491; 40 C.F.R. 51.308; *North Dakota v. EPA*, 730 F.3d 750 (8th Cir. 2013); EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program* (June 1, 2007).

4. Before imposing controls under the best available retrofit technology (or BART) framework, the Clean Air Act and EPA's regulations require EPA to establish the degree of improvement in visibility which may be reasonably anticipated to result from the use of the selected technology. In imposing such controls here, EPA employed modeling that projected a change in visibility so small that it was beyond the model's capacity. Did EPA act arbitrarily, capriciously, or otherwise contrary to law in imposing controls based on projections of change beyond EPA's ability to project?

Apposite Authority: 42 U.S.C. 7491; 40 C.F.R. 51.308; *Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134 (9th Cir. 2015); *Eagle–Picher Indus., Inc. v. EPA*, 759 F.2d 905 (D.C. Cir. 1985).

4. The Clean Air Act requires EPA to convene a reconsideration proceeding when a party seeks reconsideration based on an objection that could not have been raised during the public comment period and where the objection is of central relevance to the outcome of the rule. Here, Arkansas sought reconsideration based on, among other things, data that became available after the comment period demonstrating that Arkansas had already achieved greater progress toward natural visibility than the Final Rule

determined would constitute reasonable progress for the first planning period. Did EPA act arbitrarily, capriciously, or otherwise contrary to law in refusing to convene a reconsideration proceeding based on that data?

Apposite Authority: 42 U.S.C. 7607.

STATEMENT OF THE CASE

A. Regulatory Framework

The Clean Air Act establishes a national goal of preventing any future, and remedying existing, manmade air visibility impairment in designated national parks and wildlife areas (Class I areas). 42 U.S.C. 7491(a)(1). Visibility impairment means the "reduction in visual range and atmospheric discoloration," *id.* at 7491(g)(6), and it is "caused by geographically dispersed sources emitting fine particles and their precursors into the air." *Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1, 3 (D.C. Cir. 2002) (per curiam). Two Class I areas—Caney Creek and Upper Buffalo—are primarily at issue here. *See* 81 Fed. Reg. at 66332/3.[1]

The Clean Air Act requires EPA to issue regulations designed to ensure "reasonable progress toward meeting [Congress' natural visibility] goal." 42 U.S.C. 7491(a)(4). But Congress did not assign EPA responsibility for determining how best to make reasonable progress toward the natural visibility goal. Instead, "the [Clean Air Act] grants states the primary role of determining the appropriate pollution controls within their borders." *North Dakota v. EPA*, 730 F.3d 750, 760-61 (8th Cir. 2013); *accord Texas v. EPA*, 829 F.3d 405, 423 (5th Cir. 2016) ("The

[1] At points, the Final Rule also discusses other Class I areas, including Hercules-Glades Wilderness Area and the Mingo National Wildlife Refuge in Missouri. *E.g.*, 81 Fed. Reg. at 66332/3.

structure of the Clean Air Act indicates a congressional preference that states, not EPA, drive the regulatory process.").

As part of that process, states draft and "submit [State Implementation Plans] SIPs containing . . . measures necessary to make reasonable progress toward meeting the national visibility goal." *North Dakota*, 730 F.3d at 755 (internal quotation marks omitted); *accord* 42 U.S.C. 7491(b). SIPs are submitted every ten years, and they must achieve reasonable progress "for the period covered by the implementation plan." 40 C.F.R. 51.308(d)(1)(i)(B); *id.* at 51.308(f) (2012).[2] The first SIPs—covering progress by 2018—were due in 2007. 40 C.F.R. 51.308(b).

Among other things, a SIP must "establish goals (expressed in deciviews) that provide for reasonable progress towards achieving natural visibility conditions," provide "an improvement in visibility for the most impaired days over the period of the implementation plan," and "ensure no degradation in visibility for the least impaired days over the same period" in each Class I area located in the state. 40 C.F.R. 51.308(d)(1). A deciview "is a haze index derived from calculated

[2] After adopting the Final Rule, EPA amended its regulations. *See Protection of Visibility: Amendments to Requirements for State Plans*, 82 Fed. Reg. 3078 (Jan. 10, 2017). Because the Final Rule was adopted under the pre-amendment regulations, the pre-amendment regulations and guidance interpreting those regulations apply here. *See Texas*, 829 F.3d at 430 ("Agency actions must be assessed according to the statutes and regulations in effect at the time of the relevant activity."). Further, although the period for petitioning for judicial review of those amendments has not yet run, at least one state has already sought judicial review of those amendments. *See State of Texas v. EPA*, No. 17-1021 (D.C. Cir.).

light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired." 40 C.F.R. 51.301 (2012). Only "a change in visibility of 1.0 deciview is . . . perceptible." 81 Fed. Reg. 66390/3 n.239.

EPA's regulations refer to the goals in a SIP as "reasonable progress goals," and in setting those goals, states must consider four statutory factors. 40 C.F.R. 51.308(d)(1)(A)(i). Those factors include "the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources." *Id.*; *see also* 42 U.S.C. 7491(g)(1). Additionally, every SIP must include a calculation of the rate of progress required to move from baseline to natural visibility conditions by 2064; EPA's regulations refer to that rate as the uniform rate of progress. 40 C.F.R. 51.308(d)(1)(i)(B). If a state's reasonable progress goals provide for less planning period progress than the uniform rate of progress would indicate is required to achieve natural visibility by 2064, the state must demonstrate that its goals are reasonable based on the four statutory factors noted above. *Id.* at 51.308(d)(1)(ii).

A SIP must also contain a strategy for achieving those goals during the planning period. *See* 40 C.F.R. 51.308(d)(3). In particular, EPA's regulations require that a SIP include "enforceable emissions limitations, compliance

schedules, and other measures as necessary to achieve the reasonable progress goals." *Id.*; *cf. id.* at 51.308(d)(1)(v) (while the reasonable progress goals "are not directly enforceable," they are critical to evaluating a SIP). In establishing those limitations and imposing other measures, EPA must also consider the degree to which visibility may likewise improve due to other existing federal and state air quality programs and regulations. EPA, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program* (June 1, 2007) ("2007 Guidance"), 4-1.[3]

And—under that standard—where existing regulatory requirements and programs will yield the same rate of progress that EPA determined will constitute reasonable progress for a planning period, no further controls will be required. *See id.* at 4-1 ("Given the significant emissions reductions that we anticipate to result from" [controls enacted under the framework outlined below] and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period for some States."); *see also* 40 C.F.R. 51.308(d)(3) (control measures must be "necessary to achieve the reasonable progress goals").

Among the various controls that EPA must consider before imposing additional controls to achieve reasonable progress are any controls already required

[3] *Available at* https://www3.epa.gov/ttn/naaqs/aqmguide/collection/cp2/20070601_wehrum_reasonable_progress_goals_reghaze.pdf.

by the best available retrofit technology (BART) framework. *See* 2007 Guidance, 4-1; *see also* 40 C.F.R. 51.308(d)(3). BART requires states to determine the best technology for controlling emissions—at certain major sources built between 1962 and 1977—"which may reasonably be anticipated to cause or contribute to" visibility impairment in any Class I area. 42 U.S.C. 7491(b)(2)(A). A stationary source "causes" visibility impairment when its impact at a single Class I area is greater than 1 deciview, and it "contributes" to visibility impairment where it has at least a 0.50 deciview impact at a Class I area. *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations*, 70 Fed. Reg. 39104, 39161 (July 6, 2005). In making BART determinations, states must conduct an analysis that considers "the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology." 40 C.F.R. 51.308(e)(1)(i)-(ii); *accord* 42 U.S.C. 7491(g)(2). And any technology identified through that process must be installed "as expeditiously as practicable," but not later than five years after a SIP's approval. 40 C.F.R. 51.308(e)(1)(iv); *see* 42 U.S.C. 7491(g)(4).

Alternatively, "[a] State may opt to implement or require participation in an emissions trading program or other alternative measure rather than to require

sources subject to BART to install, operate, and maintain BART." 40 C.F.R. 51.308(e)(2). As relevant here, one such program is the "Transport Rule, also known as the Cross-State Air Pollution Rule," which EPA has determined will "achieve greater reasonable progress towards the national goal of achieving natural visibility conditions in Class I areas than source-specific [BART]." *Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans*, 77 Fed. Reg. 33642, 33643 (June 7, 2012). That program requires certain states, including Arkansas, to significantly reduce nitrogen oxide (NOx) and sulfur dioxide (SO_2) emissions that cross state lines, and to achieve that goal, the rule caps emissions and allows covered "sources to trade emissions allowances with other sources within the same program." *Id.* at 33645. On October 26, 2016, EPA published the relevant state emissions caps—or budgets—for NOx required to make the program workable. *See Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, 81 Fed. Reg. 74504 (Oct. 26, 2016).

If a state complies with the requirements for adopting a SIP, EPA must approve the SIP. 42 U.S.C. 7410(k)(3). If EPA disapproves a SIP, it must, within two years, promulgate a federal implementation plan (or FIP) that complies with the above framework. *Id.* at 7410(c).

B. Facts

1. Arkansas's State Implementation Plan

Arkansas submitted its first planning period SIP in September 2008. 81 Fed. Reg. at 66333/1-2. That document and subsequent revisions represented years of work by ADEQ, other state agencies, and stakeholders. *See id.* In drafting the SIP, ADEQ likewise coordinated with the Central Regional Air Planning Association, Arkansas's regional planning organization, federal land managers, EPA, neighboring states, and the public. Substantial portions of Arkansas's SIP were developed based on emissions inventories, models, and protocols developed through the Central Regional Air Planning Association. *See id.* at 66412/2-3; 77 Fed. Reg. 14604, 14626 (March 12, 2012).

Using that accepted modeling, Arkansas calculated the uniform rate of progress necessary to achieve natural visibility conditions by 2064. *See* 77 Fed. Reg. at 14626. Arkansas established reasonable progress goals—22.48 deciviews at Caney Creek and 22.52 deciviews at Upper Buffalo—better than the rate of improvement required to achieve natural visibility conditions by that deadline. *See* 76 Fed. Reg. 64186, 64195/1 (Oct. 17, 2011). Arkansas also employed monitoring data to calculate baseline visibility conditions for the 20% worst and 20% best days during the 2000-2004 period and used Central Regional Air Planning Association modeling to estimate likely improvements from all federal and state emissions

programs, including existing BART limitations. *See id.* at 64194. Because that modeling demonstrated that, as a result of existing regulatory and BART controls, Arkansas's progress had exceeded the uniform rate of progress and that Arkansas would achieve natural visibility *before* 2064, Arkansas determined that additional controls were not required to make reasonable progress in the first planning period. *See id.* at 64194-96.

2. EPA's disapproval of Arkansas's State Implementation Plan

In March 2012, EPA concluded that Arkansas had correctly calculated the uniform rate of progress. 81 Fed. Reg. at 66408/2. It also acknowledged that Arkansas had established reasonable progress goals better than that rate, and it agreed with Arkansas's SIP's conclusion that Arkansas was on track to achieve natural visibility before EPA's 2064 deadline. *See* 77 Fed. Reg. at 14626.

Nevertheless, EPA partially disapproved Arkansas's SIP because, in EPA's view, Arkansas had not sufficiently discussed the four statutory factors in establishing reasonable progress goals for Upper Buffalo and Caney Creek. 81 Fed. Red. at 66408/2-3. EPA reasoned that if Arkansas had conducted what EPA deemed a thorough analysis of those factors, Arkansas might have determined that additional progress—*beyond* that which would achieve natural visibility conditions *before* 2064—could be achieved in the first planning period. *Id.* at 66361/1-2.

3. EPA's failure to promulgate a Federal Implementation Plan within the period required by the Clean Air Act

As the Final Rule acknowledges, it had two years from the time it disapproved Arkansas's SIP to promulgate a FIP. 81 Fed. Reg. at 66333. Yet it was not until April 8, 2015—more than a year after that deadline—that EPA even proposed a FIP "to address the disapproved portions of [Arkansas's SIP]." *Id.*

Because EPA failed to promulgate a FIP within two years of disapproving Arkansas's SIP, on August 6, 2014, Sierra Club filed a federal district court complaint seeking an order requiring EPA to promulgate a FIP by a date certain. *See Sierra Club v. EPA*, No. 4:14-cv-00643 (E.D. Ark.), Doc. #1. In response to that lawsuit, EPA agreed to promulgate a FIP by August 31, 2016. *Id.* at Doc. #75 (Sept. 22, 2015), p. 9. And the district court subsequently ordered EPA to file a response by that date. *Id.* at Doc. #93 (Nov. 3, 2015), p. 7.

4. The Final Rule imposing a Federal Implementation Plan

On September 27, 2016, EPA published the Final Rule imposing a FIP. 81 Fed. Reg. at 66332.[4] In sum, the Final Rule requires multiple facilities throughout Arkansas to install and implement substantially more than a billion dollars in controls that were not contained in Arkansas's disapproved SIP. For instance, it requires expansive new BART controls at the Arkansas Electric Cooperative

[4] On August 31, 2016, then-EPA Administrator Gina McCarthy signed a prepublication version of the Final Rule imposing a FIP. Final publication in the Federal Register did not occur until the next month. *See* 81 Fed. Reg. at 66415.

Corporation's Carl E. Bailey (Bailey) and John L. McClellan (McClellan) electricity generating stations, American Electric Power's Flint Creek Power Plant, Entergy's White Bluff and Lake Catherine power plants, and Domtar's Ashdown Mill Power Boilers. *E.g., id.* at 66338-66350. It likewise requires the installation and adoption of costly and complex controls at Entergy's Independence power generating station. *E.g., id.* at 66338-39.

Yet the Final Rule estimates that, in total, all of those complex and costly controls will, at most, eke out just 0.01 deciviews more visibility improvement than Arkansas's disapproved SIP was projected to achieve. *See id.* at 66332/3, 66354/3 (projecting Final Rule's controls to result in change in visibility conditions at Caney Creek to 22.47 deciviews and 22.51 deciviews at Upper Buffalo); 76 Fed. Reg. at 64195 (establishing reasonable progress goals 0.01 deciviews lower at each site). Indeed, even assuming EPA's future visibility impairment projections had been correct (which as discussed below, they were not), the Final Rule would have imposed more than a billion dollars in costs to achieve a change *100 times smaller* than anyone can see. *See* 81 Fed. Reg. 66390/3 n.239 (only changes greater than 1 deciview are perceptible).

a. BART Controls

The Final Rule imposes extensive and costly controls at six BART-eligible facilities across Arkansas. *E.g.,* 81 Fed. Reg. at 66338-66350. Those controls

focus on particulate matter, NOx, and SO_2 emissions. The Final Rule's controls will not perceptibly impact visibility, and most do not even address emissions that—under BART—"contribute" to visibility impairment. Indeed, given the minimal visibility impact of those controls, EPA attempted to justify many of those controls through the use of a cumulative visibility impact metric that aggregates fractions of imperceptibility at different Class I areas. *Id.* at 66389.

i. Bailey and McClellan

The Final Rule imposes a requirement that Bailey and McClellan no longer purchase fuel with more than 0.5% sulfur content by weight. 81 Fed. Reg. at 66339/1-2, 66340/1-2. It also requires those facilities to discontinue use of fuels with higher sulfur content with the purported purpose of reducing particulate matter and SO_2 emissions. *Id.* at 66339/2, 66340/1-2. At Bailey, those controls will have less than a 0.25 deciview impact at Arkansas's—and for that matter other—Class I areas. *See id.* at 66340. EPA similarly projects that the McClellan controls will have a *de minimis* visibility impact. *See id.* at 66341. Only by adding fractions of imperceptibility at four different locations—inside and outside of Arkansas—was EPA able to demonstrate an impact greater than even 0.50 deciviews. *See id.* at 66340-41.

ii. Lake Catherine

The Final Rule imposes a 30-day rolling average emissions limitation at Lake Catherine. 81 Fed. Reg. at 66345/2. That limitation is to be achieved through the installation and operation of what is commonly referred to as "burners out of service" or BOOS controls. *Id.*; *see also id.* at 66335/2. At its most basic, that control involves terminating the fuel flow to selected burners while leaving the air registers open and thereby lowering peak flame temperatures and reducing the NOx formation. *See* 80 Fed. Reg. 18944, 18976 (April 8, 2015). According to EPA's own projections, those controls will have no perceptible impact at any Class I area, and once again, the Final Rule relied on a cumulative visibility metric to create a misleading impression of greater impact. 81 Fed. Reg. at 66345.

iii. Ashdown Mill

EPA also imposed both SO_2 and NOx emissions limits at Ashdown Mill. 81 Fed. Reg. at 66345-49. The Final Rule also requires Ashdown Mill to upgrade existing SO_2 scrubbers and use an additional scrubbing reagent to further reduce SO_2 emissions. *Id.* at 66347/3. Those controls will all have well under a 0.25 deciview impact. *See id.* at 66347-48.

iv. Flint Creek

The Final Rule requires Flint Creek to install costly and extensive new SO_2 and NOx controls within a short timeframe.

To reduce NOx emissions, the Final Rule requires Flint Creek to install low NOx burners with separated overfire air on one unit at the end of April 2018. *Id.* at 66416/2. In determining BART required that installation, EPA relied on the California Puff Model (CALPUFF) to estimate that low NOx burners would have a 0.081 deciview impact at Caney Creek, a 0.026 deciview impact at Upper Buffalo, and even less at other sites. *See id.* at 66342. CALPUFF has an acknowledged margin of error greater than any of those amounts, and as a result, it is unclear—as comments observed—whether the use of low NOx burners at Flint Creek will have even the infinitesimal impact that EPA projected. *See id.* at 66342 (projected impact of low NOx burners at Flint Creek); *id.* at 66398-400 (CALPUFF margin of error analysis); Comments from Industry Associations, IV.15, p. 9 (Aug. 7, 2015), [App.__].[5] Despite that, EPA declined to explain why it believed the CALPUFF model's estimates were sufficiently reliable to justify the imposition of NOx controls. *See* 81 Fed. Reg. at 66399/2. Instead, EPA simply asserted that the projected impacts were sufficient to justify controls because CALPUFF *can* also under-predict impacts. *Id.*

Further, despite the lack of demonstrable visibility impact, the Final Rule requires that low NOx burners be installed at Flint Creek—and as discussed below on four other units at Independence and White Bluff—within a brief 18-month

[5] ["App" cites are to designated record material.]

window. *See id.* at 66342/3, 66378/2-3. Because Flint Creek, White Bluff, and Independence represent a substantial portion of Arkansas's electricity output, any outage and installation work will need to be carefully planned, scheduled, and coordinated, and given that, EPA originally proposed giving operators three years to install low NOx burners at those facilities. *See* 81 Fed. Reg. at 66342, 66378/2-3; *see also* 81 Fed. Reg. at 74552/3 (Cross State Air Pollution Rule noting that, White Bluff and Independence alone "account[] for 40 percent of the state's 2015 heath input."). In response, commenters explained that it would actually require five years to safely "coordinat[e] and schedul[e] unit outages" and successfully install the burners. 81 Fed. Reg. at 66342/1. Indeed, commenters emphasized that requiring five separate units be taken offline and modified within a three year period could threaten the reliability of Arkansas's electricity supply. *See id.*

But instead of giving operators five—or even the proposed three—years to make those modifications, the Final Rule inexplicably narrowed the installation period for all three facilities to just 18 months. *See, e.g.*, 81 Fed. Reg. at 66342, 66378/2-3. As support for that conclusion, the Final Rule alluded to evidence submitted by Sierra Club that suggested, "the typical deployment of [low NOx burners] . . . takes between 24-32 weeks (6-8 months) on a typical industrial boiler covering the bid evaluation through startup." Institute of Clean Air Companies, *Typical Installation Timelines for NOx Emissions Control Technologies on*

Industrial Sources (Dec. 4, 2006), p. 3 (cited as authority for estimate in report discussed in Comments from Sierra Club, Earthjustice, and National Parks Conservation Association, Index to Administrative Record, IV.8, pp. 10, 14-19, 22, 25 (Aug. 7, 2015)), [App.__]; *see also* 81 Fed. Reg. at 66378/2-3. Yet the Final Rule did not offer any explanation for how that evidence led it to conclude that five separate low NOx burners at three different facilities could be safely installed within 18 months without threatening reliability. *Id.* (arguing only that, "[t]his compliance date provides the affected utilities sufficient time beyond typical . . . installation timeframes to install these controls . . . while safeguarding the continuity of Arkansas' electricity supply."). Indeed, no one had even suggested an 18-month installation period.

With respect to SO_2 controls, the Final Rule requires Flint Creek to meet a stringent new emissions limit, and to meet that limit, it requires Flint Creek to install and upgrade scrubbers. 81 Fed. Reg. at 66342/1-2. The change will have no perceptible impact visibility. *See id.* at 66342/3. The Final Rule requires that installation and upgrade be completed and that Flint Creek comply with the new emissions limit within 18 months, but it declined to explain how it determined that 18 months was an appropriate compliance period. *See* 81 Fed. Reg. at 66342/2-3. Rather, the Final Rule simply asserts that, "[w]e believe that this will provide

sufficient time for the facility to be able to" meet the new emissions limit. *Id.*

v. White Bluff

The Final Rule imposes essentially the same controls at White Bluff that it requires at Flint Creek, except that low NOx burners must be installed on two White Bluff units and the SO_2 scrubber installation must begin from scratch. *See* 81 Fed. Reg. at 66343/3-66345/2. As above, those controls will not have any perceptible impact on visibility at Caney Creek, Upper Buffalo, or anywhere else. *Id.* at 66343-45. Indeed, the low NOx burners at each unit will have less than a 0.25 deciview impact at any Class I area. *Id.* at 66344-45. And, as above, despite that infinitesimal impact, the Final Rule requires those burners to be installed within 18 months. *Id.* at 66344/3.

b. Reasonable Progress Analysis

After imposing BART controls, EPA did not begin its reasonable progress analysis by determining the rate of progress required to achieve natural visibility conditions or by setting reasonable progress goals. *See* 81 Fed. Reg. at 66350-51. Nor did EPA focus on controls that would help achieve reasonable progress in the first planning period. *See id.*

Instead, EPA began its reasonable progress analysis by noting that SO_2 and NOx are the two largest contributors to visibility impairment at Caney Creek and Upper Buffalo. *See, e.g.*, 81 Fed. Reg. at 66350/3. Ignoring all out-of-state,

natural, and other sources of those elements, EPA then identified White Bluff, Flint Creek, and Independence as the "three largest" Arkansas-based sources of SO_2 and NOx. 81 Fed. Reg. at 66350/3, 66336/2. Indeed, it excluded any consideration of other sources even though, in combination, *all* Arkansas-based sources account for only about 3% of modeled visibility impairment from SO_2 and a miniscule 0.25% of visibility impairment from NOx at Arkansas's Class I areas. *Id.* at 66350.

As noted above, both White Bluff and Flint Creek are subject to BART and the Final Rule purported to apply the BART framework in requiring those facilities to install additional controls. Because Independence is not subject to BART, the Final Rule purported to take "into consideration the four reasonable progress factors" in requiring Independence—like White Bluff and Flint Creek—to install SO_2 scrubbers in 2021 and low NOx burners on two units just before the first planning period concludes. *Id.* at 66351-53. But far from considering the four statutory factors, the Final Rule's analysis amounted to little more than an assertion that it would be unreasonable not to impose the same controls on all three of the state's largest emitters of SO_2 and NOx. *See id.* at 66363/2. And, as above, without explaining how it selected that compliance period or addressing comments that requiring three separate facilities to install low NOx burners in the same brief period could threaten the reliability of Arkansas's electricity supply, the Final Rule requires Independence to install those burners within 18 months. *Id.* at 66354/1.

In imposing those controls, EPA did not determine whether they were actually necessary to achieve—at that point, unestablished—reasonable progress goals or first planning period progress. Nor could EPA have determined that those controls were necessary to make first planning period progress since the SO_2 scrubbers—which would purportedly address "the principal contributor to visibility extinction," will not be installed until *years after* the first planning period concludes. *Id.* at 66351/1, 66420. Likewise, even though the low NOx burners will be installed during the first planning period, EPA could not have concluded they were necessary to make reasonable progress since they will not be installed until just before the first planning period's conclusion and will have effectively no impact whatsoever during that period. *See id.*; 40 C.F.R. 51.308(f) (second planning period SIPs due in July 2018 for achieving progress in the second planning period).

Indeed, even after the planning period ends, the Final Rule concedes that its various controls will have no discernable impact. *See*, *e.g.* 81 Fed. Reg. at 66353/2-3 (*ultimately*, low NOx burners will result in just a 0.50 deciview change at one site and less than a 0.25 deciview change at another site). And as a consequence, rather than address the actual impact of those individual controls, the Final Rule simply claimed that the various controls were justified because over time and "in the aggregate" they "will contribute to visibility progress." *Id.* at

66391/2; *see also, e.g.*, 66403/2-3 (claiming NOx controls are warranted because of the impact from the combination of NOx and SO_2 controls).

c. Reasonable Progress Goals

After imposing those controls, the Final Rule calculated reasonable progress goals "reflect[ing] the visibility improvement anticipated by 2018 from [its] combination of control measures." 81 Fed. Reg. at 66332/3. Specifically, the Final Rule concluded that its various controls would reduce visibility impairment at Caney Creek to 22.47 deciviews and to 22.51 deciviews at Upper Buffalo. *See id.* at 66410/3, 66354/3. As noted, those goals represented just 0.01 deciviews more improvement at each Class I area than the disapproved SIP showed could be achieved without additional controls and less progress than Arkansas has actually already achieved.

5. Arkansas's request for reconsideration

On November 22, 2016, ADEQ sought reconsideration of the Final Rule on three separate grounds. First, ADEQ argued that the controls at Independence are unnecessary because 2015 Interagency Monitoring of Protected Visual Environments (or IMPROVE) network monitoring data demonstrates that Arkansas has already achieved and exceeded the Final Rule's reasonable progress goals. *See State of Arkansas v. EPA*, No. 17-1276 (8th Cir.), Doc. # 1 (Feb. 6, 2017) (Arkansas's Petition for Review, Petition for Reconsideration and Request

for Administrative Stay), p. 6 ("Petition for Reconsideration"), [App.__]. That data, which only became available after the comment period, demonstrates that as a result of existing controls—and without any of the Final Rule's controls—visibility impairment had declined to 20.41 deciviews at Caney Creek and 19.96 deciviews at Upper Buffalo. *Id.* at 9, [App.__]. Thus, in other words, that data demonstrates that Arkansas has already achieved visibility conditions approximately 2 deciviews better than the Final Rule would purportedly achieve through the imposition of more than a billion dollars in additional controls.

Second, ADEQ requested that EPA reconsider the Final Rule's NOx limitations at BART-eligible facilities and determine that compliance with the Transport Rule is an acceptable way of meeting the NOx limitations imposed under BART. *Id.* at 14, [App.__]. ADEQ's request explained that states may include reliance on the Transport Rule in their implementation plans as an alternative method of complying with BART, and consequently, EPA may do the same in promulgating a FIP. *Id.*, [App.__]. Moreover, ADEQ explained that it would not have been practical to raise this possibility during the comment period because the relevant revised NOx budgets—that serve as the basis for the Transport Rule program—were not published until October 26, 2016. *Id.* at 10-11, [App.__]; *see also* 81 Fed. Reg. 74504.

Third, ADEQ requested that EPA reconsider its decision not to analyze available alternative SO_2 control technologies for White Bluff. Petition for Reconsideration, p. 13, [App.__]. In particular, ADEQ requested that EPA analyze and consider the use of low sulfur coal as an alternative control technology for White Bluff under BART. *Id.* at 15, [App.__].

In addition to seeking reconsideration, ADEQ also requested that EPA administratively stay the Final Rule and toll its compliance deadlines. *See id.* at 15-19, [App.__]. Given the Final Rule's short compliance deadlines, ADEQ notified EPA that if ADEQ did not receive a response within 70 days, Arkansas would treat that failure as a constructive denial. *Id.* at 7, [App.__].

EPA failed to act on the request for an administrative stay or the petition for reconsideration and thereby constructively denied those requests.

6. Proceedings before this Court

On November 22, 2016, Arkansas filed its initial petition for review. After EPA constructively denied ADEQ's petition for agency reconsideration, Arkansas filed a petition for review of that constructive denial on February 6, 2017. On February 7, 2017, Arkansas filed a motion for a judicial stay. That motion for a stay is still pending.

STANDARD OF REVIEW

Agency actions that are "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law" will be set aside. 5 U.S.C. 706(2)(A); 42 U.S.C. 7607(d)(9)(A). EPA acts arbitrarily and capriciously where it "relie[s] on factors which Congress has not intended it to consider, entirely fail[s] to consider an important aspect of the problem, offer[s] an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise." *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). Thus, EPA must "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" *Id.* (quoting *Burlington Truck Lines v. United States*, 371 U.S. 156, 168 (1962)); *see also* 42 U.S.C. 7607(d)(6)(B) (EPA must respond to "comments, criticisms, and new data"). And "EPA's actions must . . . be [internally] consistent." *Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1141 (9th Cir. 2015); *accord Gen. Chem. Corp. v. United States*, 817 F.2d 844, 857 (D.C. Cir. 1987) (per curiam).

SUMMARY OF ARGUMENT

The Final Rule should be vacated in its entirety for, at least, four reasons. First, the Final Rule should be vacated because it irrationally requires the people of Arkansas to spend substantially more than a billion dollars to achieve visibility conditions *inferior* to present visibility conditions. In fact, despite being presented with evidence that Arkansas has already achieved perceptively better progress than the Final Rule concluded would be reasonably achievable through more than a billion dollars in controls, EPA refused to reconsider the Final Rule. Moreover, even if EPA were not required to reconsider the Final Rule based on that evidence, the Final Rule should be vacated because in promulgating the Final Rule, EPA arbitrarily and capriciously ignored evidence that Arkansas would achieve at least the same rate of progress that the Final Rule would purportedly achieve without a single dollar in additional controls.

Second, the Final Rule should be vacated because EPA failed to consider whether the Final Rule would endanger the reliability of Arkansas's electricity supply. For instance, the Final Rule requires that five electrical generation units—which represent a substantial portion of Arkansas's electricity output—all be taken offline within a brief 18-month period so that sophisticated new controls can be installed. Yet EPA offers no explanation for how it concluded that all of those

units could be safely modified in that brief period without endangering the reliability of Arkansas's electricity supply.

Third, in adopting the Final Rule, EPA unlawfully reversed the process for establishing controls. Under the Clean Air Act, EPA is required to establish reasonable progress goals, consider anticipated visibility improvement from existing programs and BART, and then, if additional controls are necessary to meet the reasonable progress goals, implement additional measures. Yet EPA did not do that here. Instead, EPA reversed that process by arbitrarily focusing on the three largest Arkansas-based emissions sources, determining that their status as large emitters should make them subject to additional controls, deciding that Independence (as the only non-BART source) should be subject to the same controls as the other two emitters by virtue of that status, and only thereafter setting reasonable progress goals.

Fourth, the Final Rule fails to address numerous comments suggesting that EPA consider alternative methods of calculating costs, explain why individual controls are justified, and validate its use of specific models.

Alternatively, EPA should be required to convene a reconsideration proceeding to reconsider: a) whether the Final Rule's more than a billion dollars in additional controls are actually necessary given that Arkansas has already achieved more progress than the Final Rule would purportedly achieve; b) the Final Rule's

NOx limitations at BART-eligible facilities and determine whether compliance with the Transport Rule is an acceptable way of meeting those limitations; and c) whether low sulfur coal is a viable alternative to the Final Rule's BART controls.

ARGUMENT

I. The Final Rule imposes massive costs with no visibility benefit.

The Final Rule concludes that more than a billion dollars in controls are "cost-effective" and will "result in meaningful visibility benefit." 81 Fed. Reg. at 66361/3. That conclusion is arbitrary, capricious, and otherwise contrary to law.

A. The Final Rule unlawfully imposes costly controls that will not achieve any visibility benefit during the first planning period.

An implementation plan must achieve reasonable progress "for the period covered by the implementation plan." 40 C.F.R. 51.308(d)(1)(i)(B). Indeed, EPA's regulations make clear that plans must provide for "an improvement in visibility for the most impaired days *over the period of the implementation plan*" and "ensure no degradation in visibility for the least impaired days *over the same period*." 40 C.F.R. 51.308(d)(1). The period covered by the Final Rule concludes in 2018. *See id.* at 51.308(f) (2012) (second planning period SIPs due July 31,

2018).[6] Consequently, under the plain text of EPA's regulations, the Final Rule's controls must achieve reasonable progress during the first planning period.

But the Final Rule imposes controls at Independence that are not designed to—and will not—achieve *any* progress during the first planning period. For example, the Final Rule requires Independence to install SO_2 scrubbers in 2021. 81 Fed. Reg. at 66351-53, 66420/1. Because those scrubbers will not be installed until *three years* after the first planning period ends, by definition, they will not result in any first planning period progress. Similarly, while low NOx burners will be installed at Independence just before the first planning period ends, it is undisputed that installing those controls at the planning period's conclusion will not result in any real—let alone reasonable, perceptible, or meaningful—planning period progress. *See* 81 Fed. Reg. at 66403/2 (effectively all improvement from Independence controls will occur because of SO_2 controls installed after the covered period); *see also id.* at 66351/1 (conceding that NOx is "not the principal contributor to visibility extinction"). And to the extent there is any doubt that the Final Rule will not accomplish any progress in exchange for substantially more than a billion dollars in additional controls, EPA itself estimates that the total, combined impact from its various controls—at Independence, White Bluff, Flint

[6] The due date for second planning period SIPs was amended after the Final Rule's adoption. *See* 82 Fed. Reg. at 3080 ("EPA is finalizing a one-time adjustment to the due date for the next SIPs (from 2018 to 2021)"); *see also id.* at 3080 ("The first state plans were due in 2007 and covered the 2008-2018 planning period.").

Creek, Bailey, McClellan, Lake Catherine, and Ashdown Mill—will be just 0.00742 deciviews at Caney Creek and 0.007 deciviews at Upper Buffalo. Motion of the State of Arkansas for Stay of Final Rule, Exhibits to Motion, p. 143, ¶ 23 (Feb. 7, 2017) ("Motion for Stay Exhibits").

Tellingly, EPA does not even attempt to justify the imposition of more than a billion dollars in costs to achieve that microscopic change. Nor could EPA do so since it is hardly reasonable, cost-effective, or rational to impose more than a billion dollars in costs to achieve something infinitesimally smaller than an eagle—let alone a human—could perceive.[7] *See Michigan v. EPA*, 135 S. Ct. 2699, 2707 (2015) ("One would not say that it is even rational, never mind 'appropriate,' to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits."); *see also Nat'l Parks,* 788 F.3d at 1144 (EPA must "explain what makes a cost reasonable in light of potential visibility benefits"). In fact, it is worth noting that even if the Final Rule had imposed *only* a billion dollars in costs, each dollar spent would have yielded just 0.00000000000781 deciviews of planning period improvement. Motion for Stay Exhibits, p. 143, ¶ 23.

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[7] According to Intervenor Sierra Club, an eagle's "eyesight is six to eight times better than a human, enabling them to see prey up to one mile away." Shelley Bance, *Teatown's Eagle Fest*, Fresh Air: The Quarterly Newsletter of the Atlantic Chapter Mid-Hudson Group (Spring 2016), p. 2, *available at* http://www.sierraclub.org/sites/www.sierraclub.org/files/sce/Mid-Hudson-group/Spring2016.pdf

The Final Rule attempts to entirely sidestep any discussion of planning period progress by arguing that, *over time* and in combination, the Final Rule's various post-planning period controls will result in meaningful visibility improvement. *See, e.g.*, 81 Fed. Reg. at 66403/3. But that approach conflicts with the clear requirement discussed above that planning period controls must "achieve [reasonable progress] *for the period covered* by the implementation plan." 40 C.F.R. 51.308(d)(1)-(3) (emphasis added). Indeed, the Fifth Circuit recently rejected the exact same argument that EPA made here and held that EPA had exceeded its legal authority by imposing post-planning period controls in a Texas FIP since, by definition, those controls will not achieve planning period progress. *Texas*, 829 F.3d at 429. And that conclusion makes particularly acute sense in a case like the present where a contrary approach would undermine the Clean Air Act's system of cooperative federalism since allowing EPA to impose post-planning period controls would divest "the individual States" of their authority to "determine, in the first instance," how best to achieve reasonable progress for each planning period. *North Dakota*, 730 F.3d at 757 (quoting *EME Homer City Generation, L.P. v. EPA*, 696 F.3d 7, 12 (D.C. Cir. 2012)).

Further, the Final Rule's suggestion that EPA should be permitted to impose post-planning period controls here because less than two years of the first planning period remain conflicts with the Clean Air Act's text and ignores EPA's decision

to wait more than four-and-a-half years, after rejecting the SIP, to promulgate a FIP. *See Texas*, 829 F.3d at 430. Therefore, because the Final Rule rests on post-planning period controls that will not achieve planning period progress, it should be vacated.

B. Arkansas has already exceeded the rate of progress that the Final Rule would purportedly achieve.

Assuming that the Final Rule was designed to achieve some first planning period progress and that it was rational to spend more than a billion dollars to achieve it, the Final Rule would still be unnecessary because, by 2015, Arkansas had already achieved perceptibly better progress. As noted, the Final Rule concluded that reducing visibility impairment at Caney Creek to 22.47 deciviews and to 22.51 deciviews at Upper Buffalo represents the reasonable rate of progress that will be achieved by 2018 from the Final Rule's various controls. *See* 81 Fed. Reg. at 66414/1, 66410/3. But IMPROVE network monitoring data that became available after the Final Rule's public comment period establishes that in 2015, visibility impairment at Caney Creek fell to 20.41 deciviews and impairment at Upper Buffalo similarly declined to 19.96 deciviews. *See* Petition for Reconsideration, p. 9, [App.__].

In light of that newly available data, Arkansas requested that EPA convene an administrative proceeding to reconsider the Final Rule's conclusion that more than a billion dollars in additional controls were necessary to achieve reasonable

progress.[8] As relevant here, EPA is required to convene such a proceeding where a party seeks reconsideration based on an objection that could not have been raised during the public comment period and where the "objection is of central relevance to the outcome of the rule." 42 U.S.C. 7607(d)(7)(B). Arkansas's request met both requirements. First, while the public comment period closed on April 8, 2015, the monitoring data establishing Arkansas's progress did not become available until after that date. *See* Petition for Reconsideration, p. 8 (data covers January through September 2015), [App.__]. Thus, during the comment period, Arkansas could not have argued that the Final Rule was unnecessary and irrational because Arkansas had already achieved greater progress than the Final Rule would purportedly achieve.

Second, no one can dispute the relevance of that data. Indeed, had EPA considered that evidence, it could not have concluded that more than a billion dollars in additional controls were required to achieve what the Final Rule concluded constituted reasonable first planning period progress. To the contrary, if EPA had concluded that it was reasonable or cost-effective to require those

[8] By failing to timely act on ADEQ's petition for reconsideration and a stay of the Final Rule, EPA constructively denied that petition. That constructive denial constitutes final agency action and is judicially reviewable. *See, e.g., IDS Life Ins. Co. v. SunAmerica, Inc.*, 103 F.3d 524, 526 (7th Cir. 1996) ("A showing of unjustifiable delay coupled with irreparable injury if an immediate appeal is not allowed is enough to make a constructive denial appealable, if a formal denial would be."); *see also* 42 U.S.C. 7607(d)(7)(b) (authorizing judicial review of denial of administrative petition for reconsideration).

controls to achieve existing conditions, that conclusion would have been utterly irrational. *See Michigan*, 135 S. Ct. at 2707. That data also undermines the Final Rule's entire analysis because it demonstrates that EPA's methodology for estimating and predicting visibility improvement due to existing controls is extraordinarily unreliable. Additionally, even if EPA were permitted to rely entirely on post-planning period progress to justify planning period controls (which, as noted, it cannot), that data would be relevant to determining whether the Final Rule's controls are actually necessary to achieve the same rate of post-planning progress. Therefore, EPA was required to consider that data and its failure to do so was arbitrary, capricious, and contrary to law.

C. The Final Rule ignored evidence that Arkansas was already on track to achieve reasonable progress and natural visibility before EPA's 2064 goal.

Even if EPA was not required to consider newly available data demonstrating that Arkansas has already better visibility conditions than the Final Rule would purportedly achieve, the Final Rule should be vacated because EPA ignored evidence that Arkansas would achieve reasonable progress—and natural visibility before 2064—without any additional controls.

In particular, commenters explained that as a result of existing controls and other regulatory requirements, Arkansas would achieve, at least, the same rate of progress as the Final Rule. *See* 81 Fed. Reg. at 66351-52 (noting comments),

66366/1-2 (similar), 66408/1-2 (similar); 76 Fed. Reg. at 64194-95 (SIP concluded that without additional controls, Arkansas would achieve visibility conditions just 0.01 deciviews short of the Final Rule's reasonable progress goals); *see also* Motion for Stay Exhibits p. 141, ¶ 18 (similar). And to underscore that analysis, commenters submitted data to EPA demonstrating that by May 2011, without any additional controls, Arkansas had already "achieved 73% of the 2018 [goals] [Arkansas] established for Caney Creek . . . and 66% of the 2018 [goals] [Arkansas] established for Upper Buffalo." 81 Fed. Reg. at 66360/2.

EPA arbitrarily, capriciously, and unlawfully ignored that evidence. With respect to the May 2011 data, for instance, EPA concluded that it was "not obligated to consider" that data because it concerned unapproved SIP goals that in EPA's view had been established without a sufficient four factor analysis and had been compiled in connection with a SIP revision. 81 Fed. Reg. at 66361/3-62. That decision runs counter to the statutory requirement that EPA respond to "new data submitted . . . during the comment period," 42 U.S.C. 7607(d)(6)(B), and EPA guidance requiring it to consider reductions anticipated to occur from other regulatory programs. 2007 Guidance, 4-1. It also disregards the fact that the SIP and Final Rule set essentially the same goals and, therefore, evidence that Arkansas would meet the SIP's goals likewise demonstrated that it would meet the Final Rule's goals. *See* Motion for Stay Exhibits, p. 141, ¶ 16-18.

The Final Rule also failed to consider whether the cost of additional controls were warranted given that Arkansas was projected to achieve more progress than the uniform rate of progress demonstrated would be required to achieve natural visibility by 2064. *See* 81 Fed. Reg. at 66408/2 (conceding progress). EPA justified its failure to consider that evidence on the grounds that more progress might be achieved. *See id.* at 66361/1. But EPA does not explain how it concluded that it was rational to impose more than a billion dollars in additional costs to achieve infinitesimal movement toward an ultimate goal that Arkansas was already on track to accomplish. *See Michigan*, 135 S. Ct. at 2707 ("One would not say that it is even rational, never mind 'appropriate,' to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits."). And EPA's failure to explain its analysis requires that the Final Rule be vacated. *See Nat'l Parks,* 788 F.3d at 1144.

Further, as we now know (thanks to subsequently available data demonstrating what Arkansas had already told EPA), had EPA considered *any of that evidence*, it could have avoided irrationally imposing costly controls designed to achieve less progress than currently exists.

D. <u>The Final Rule failed to consider whether individual controls were justifiable in light of their massive costs.</u>

The Final Rule did not determine whether the fractions of imperceptible improvement from particular individual controls justified the costs of those

controls. For example, EPA claims that the low NOx burners at Independence will—over time—result in less than 0.50 deciviews of improvement at Caney Creek and 0.25 deciviews of improvement at Upper Buffalo. 81 Fed. Reg. at 66353. But rather than determine whether such fractions of imperceptibility justify the burners' costs, the Final Rule simply lumped those burners with other controls and concluded "that, in the aggregate" and over time, various controls "will contribute to visibility progress." *Id.* at 66391/2. Indeed, the Final Rule requires the installation of those burners despite the fact that NOx is "not the principal contributor to visibility extinction," *id.* at 66351/1, because the impact from the *combination* of NOx and SO_2 controls will eventually "exceed 1 [deciview]." *Id.* at 66403/1. And it ignored the fact that effectively all of that improvement will occur because of SO_2 controls installed after the covered period. *See* 81 Fed. Reg. at 66403/2.

The Final Rule likewise eschewed any consideration of the rationality of imposing costly BART controls that would in EPA's estimation achieve, at best, fractions of imperceptible change. For instance, the Final Rule failed to consider whether the costs of low NOx burners at Flint Creek are justified by a rate of progress so infinitesimally minute that it is beyond the modeling's ability to reliably predict. *See id.* at 66342; *see also infra* at p. 18 (discussing CALPUFF modeling). Similarly, the Final Rule imposes controls at Bailey, McClellan,

Ashdown Mill, and White Bluff that will purportedly eliminate emissions that have an impact smaller than BART deems relevant. *See* 81 Fed. Reg. at 66340 (Bailey controls will achieve less than 0.25 deciview change), 66341 (McClellan controls will yield 0.12 deciviews of change at Upper Buffalo and just 0.3 deciviews at Caney Creek), 66347-48 (Ashdown Mill controls projected to have well under 0.25 deciview impact), 66344-45 (substantially less than 0.25 deciview change from White Bluff controls); 70 Fed. Reg. at 39161 (under BART, emissions do not even contribute to visibility impairment unless impact at Class I area is at least 0.50 deciviews). Thus, the Final Rule should be vacated because EPA failed to consider or determine whether it was rational to impose additional costs to achieve infinitesimal fractions of a change in visibility.

E. EPA's cumulative visibility metric caused it to overstate the Final Rule's benefits.

EPA declined to consider comments explaining why EPA's use of a cumulative visibility impact metric—which aggregates fractions of imperceptibility at different sites—caused EPA to overstate control benefits. *See* 81 Fed. Reg. at 66389. Commenters observed, for instance, that by aggregating tiny, fractions of imperceptible impacts at different sites, EPA created a false impression of progress. *See id.*; *see also id.* at 66340-48. Indeed, given the minimal visibility impact from the Final Rule's controls, EPA attempted to justify many of those controls through the use of a cumulative visibility impact metric that

aggregates fractions of imperceptibility at different Class I areas. *See id.* at 66340 (adding fractions of imperceptibility at multiple sites to create erroneous impression of progress from Bailey controls), 66341 (same analysis for McClellan controls), 66345 (same approach for Lake Catherine), 66347-48 (similar approach for Ashdown Mill), 66342 (same for Flint Creek).

Instead of responding to those comments, EPA created a strawman, arguing that, contrary to the comments, "[n]othing in the Regional Haze Rule suggests that" EPA "should ignore the full extent of the visibility impacts and improvements from controls at multiple Class I areas." *Id.* at 66390/2. But no one disputes that EPA can consider impacts at multiple locations. Rather, the comments suggested that EPA's method of considering those impacts was misleading and caused EPA to overestimate the benefits of additional controls. Because EPA failed to address those comments, the Final Rule should be vacated.

F. <u>The Final Rule ignored comments demonstrating that on a dollar-per-deciview basis its controls were inconsistent with other federal implementation plans.</u>

The Final Rule did not respond to comments suggesting that in determining cost-effectiveness, EPA should consider visibility improvement on a dollar-per-deciview basis because that calculation showed the Final Rule was inconsistent with other FIPs. *See* 81 Fed. Reg. at 66388/2; Comments from Nucor Steel-

Arkansas and Nucor-Yamato Steel Company, IV.20, pp. 36-37 (July 15, 2015), [App.__].

EPA has taken inconsistent—and confusing—positions on that metric's applicability. *See Nat'l Parks Conservation Ass'n v. EPA*, 803 F.3d 151, 164 (3d Cir. 2015). Yet here, EPA simply declined to consider it, claiming that, "while the $/deciview metric can be useful" it "suggest[s] a level of precision in the calculation of visibility impacts that is not justified in many cases" and that the dollar-per-ton of pollution removed metric is *generally* preferred. 81 Fed. Reg. at 66388/3. Thus, in other words, despite comments explaining why the dollar-per-deciview metric would be useful in assessing *this particular FIP*, EPA simply declined to address those comments.

EPA's failure to address those comments—or conduct a relevant comparison that would have revealed inconsistencies between this FIP and others—means EPA failed to consider an important issue raised by the comments. And therefore, the Final Rule should be vacated.

II. The Final Rule threatens the reliability of Arkansas's electricity supply.

"In determining reasonable progress," EPA must consider "the energy . . . impacts of compliance." 42 U.S.C. 7491(g)(1)-(2). The Final Rule ignores those impacts, including the threat to Arkansas's electricity supply posed by requiring

Independence, White Bluff, and Flint Creek to all install sophisticated new controls within a narrow 18-month window.

For instance, the Final Rule requires five units at Independence, White Bluff, and Flint Creek to install low NOx burners. *See* 81 Fed. Reg. at 66342, 66378/2. Those units represent a substantial portion of Arkansas's electricity output, and given that, EPA originally proposed giving operators three years to install those controls. *See* 81 Fed. Reg. at 66342/1, 66378/2; *see also* 81 Fed. Reg. at 74552/3 (Cross State Air Pollution Rule noting that, White Bluff and Independence alone "account[] for 40 percent of the state's 2015 heath input."). In response, stakeholders and others explained that the three year compliance period would not be sufficient. *Id.* at 66342/1. Instead, they explained that a five year installation period would be required to safely "coordinat[e] and schedul[e] unit outages" and successfully install the new controls without diminishing the reliability of Arkansas's electricity supply. *Id.* By contrast, Sierra Club submitted evidence that "the typical deployment of [low NOx burners] . . . takes between 24-32 weeks (6-8 months) on a typical industrial boiler covering the bid evaluation through startup," no one suggested an 18-month compliance period. Institute of Clean Air Companies, p. 3 (cited in report relied on by Comments from Sierra Club, Earthjustice, and National Parks Conservation Association, IV.8, to estimate

timeframe), [App.__]; *see* 81 Fed. Reg. at 66378/2-3 (citing comments relying on Institute of Clean Air Companies).[9]

Nevertheless, citing that estimate, EPA *somehow* concluded that outages and installations at the five units involved here could all be scheduled, coordinated, and completed within 18 months without endangering the reliability of Arkansas's electricity supply. 81 Fed. Reg. at 66378/2-3. In fact, EPA's only explanation for that finding consists of a conclusory assertion that, "[t]his compliance date provides the affected utilities sufficient time beyond typical . . . installation timeframes to install these controls . . . while safeguarding the continuity of Arkansas' electricity supply." *Id.* No explanation was offered for how EPA determined that 18 months—as opposed to 24, 36, or 42 months—provided sufficient time beyond the typical installation time to ensure safe installation and safeguard the reliability of Arkansas's electricity supply. Indeed, even basic math—multiplying the number of units by eight months—would have suggested a

[9] Sierra Club suggested that all five installations could take place within six to eight months, but unlike the stakeholder comments supporting a longer compliance period, Sierra Club did not explain how five installations at three separate facilities could be safely scheduled, coordinated, and completed within such a narrow window. Comments from Sierra Club, Earthjustice, and National Parks Conservation Association, IV.8, pp. 10, 14-19, 22, 25, [App.__].

longer period.[10] Nor does EPA appear to have considered whether Sierra Club's generalized estimate would even apply here.[11]

The Final Rule also requires Flint Creek to install and then upgrade new scrubbers and meet a new emissions limit within 18 months. 81 Fed. Reg. at 66342/2. EPA had originally proposed giving Flint Creek five years to comply with that requirement. *Id.* at 66335/2. EPA did not offer an explanation for how it arrived at an 18-month compliance period other than a bald conclusion that, "[w]e believe that this will provide sufficient time for the facility to be able to" meet the new emissions limit. *Id.* at 66342/2 (noting that because new scrubbers were being installed, a five year compliance period was not necessary, but offering no explanation for upgrade or emissions limit conclusion or how it determined 18 months was appropriate).

Thus, from EPA's "explanation[s], the Rule's reader is left to wonder what rationale EPA used to determine" that 18 months would safeguard Arkansas's electricity supply. *Nat'l Parks*, 788 F.3d at 1144 (similar approach was arbitrary

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[10] EPA might *now* speculate that the Final Rule derived the 18-month figure by multiplying the number of facilities involved by six months, but the Final Rule contains no evidence that is how EPA actually derived that period. Nor for that matter would that speculation explain why EPA decided that six—instead of eight—months were required for installation at each facility.

[11] As explained in Arkansas's motion for a stay, contrary to Sierra Club's generalized estimate, here, it will actually take six to eight months just to modify the relevant permits. *See* Motion of the State of Arkansas for Stay of Final Rule, p. 17 n.5 (Feb. 7, 2017).

and capricious); *see also* *Nat'l Parks Conservation Ass'n*, 803 F.3d at 160-61 (impossible to meaningfully review conclusory assertions that alternatives were considered). And the Final Rule's failure to explain its conclusion is particularly troubling given EPA's recent acknowledgment in revising the Cross-State Air Pollution Rule that, "it may be difficult to schedule outage time to upgrade all four" electric generating units at White Bluff and Independence "to state-of-the-art combustion controls for the 2017 ozone season and supply adequate electricity to meet demand in the state." 81 Fed. Reg. at 74552/3. Thus, the Final Rule should be vacated because EPA did not explain its conclusions or demonstrate that it otherwise took electricity impacts into account.

III. The Final Rule unlawfully reverses the process for instituting controls.

A. The Final Rule unlawfully imposes source specific controls before establishing reasonable progress goals.

Under the Clean Air Act and EPA's implementing regulations, a state or federal implementation plan must contain reasonable progress goals for reducing visibility impairment over the period of the implementation plan. 40 C.F.R. 51.308(d)(1)-(3); *see* 42 U.S.C. 7491(g)(1). The plan must then establish "enforceable emissions limitations, compliance schedules, and other measures as necessary *to achieve the reasonable progress goals*." 40 C.F.R. 51.308(d)(3) (emphasis added); *see also* 42 U.S.C. 7491(b)(2) (implementation plans must

"contain such emission limits . . . as may be necessary to make reasonable progress"); *North Dakota*, 730 F.3d at 755 (states must "submit SIPs containing . . . measures necessary to make reasonable progress" (internal quotation marks omitted)). And in determining what, if any, additional controls are "necessary to achieve the reasonable progress goals," EPA must consider any anticipated visibility improvement from other existing regulatory programs and BART controls. *See* 2007 Guidance, 4-1. Thus, in other words, the Clean Air Act and EPA's regulations anticipate a logical sequence whereby EPA establishes reasonable progress goals, considers anticipated visibility improvement from existing programs and BART, and then, if additional controls are necessary to meet the reasonable progress goals, EPA may impose additional controls. *See* 42 U.S.C. 7491(b)(2); 40 C.F.R. 51.308(d)(3); 2007 Guidance, 4-1.

EPA did not follow that approach here.[12] Instead, EPA began—not by setting progress goals but—by arbitrarily deciding that White Bluff, Flint Creek, and Independence should be singled out for additional controls because they are the three largest Arkansas-based emitters of SO_2 and NOx. *See*, *e.g.*, 81 Fed. Reg. at 66350/3 (emphasizing status as "three largest emitters"). White Bluff and Flint Creek are subject to BART, and EPA purported to impose controls on those

[12] EPA's amended regulations (which are currently being challenged in the D.C. Circuit) reflect EPA's novel approach to setting reasonable progress goals, but those amendments do not apply here. *See supra* at p. 7, n. 2 (explaining that pre-amendment regulations apply to Final Rule).

facilities pursuant to that framework. Then, because EPA determined that it would be unreasonable not to impose the same controls on all three of the state's largest SO_2 and NOx emitters, EPA imposed the same controls on Independence. *See id.* at 66363/2. And only after imposing controls did EPA establish any reasonable progress goals. *See id.* at 66337/3, 66360-61.

That approach is contrary to law because far from establishing "enforceable emissions limitations, compliance schedules, and other measures as necessary *to achieve the reasonable progress goals*," 40 C.F.R. 51.308(d)(3) (emphasis added), EPA's approach institutes controls and then formulates goals to reflect those controls. Moreover, in contrast to the plain regulatory text's logical requirement that controls be necessary to achieve a goal, EPA's new approach empowers the agency to arbitrarily and capriciously determine a facility should be subject to additional controls, impose massive costs, and only thereafter determine how much progress was reasonable. And the Final Rule keenly illustrates the danger of EPA's new approach since it empowered EPA to impose massive costs to achieve the same goals that data showed could be (and have been) achieved without any additional controls.

B. EPA offers inconsistent explanations for its decision to single out Independence for additional controls.

Even assuming EPA's approach to establishing controls was lawful (which it is not), the Final Rule should be vacated because it offers inconsistent and conflicting explanations for its decision to focus exclusively on Independence.

For instance, at various points, the Final Rule argues that Independence should be subject to the same controls as the BART-eligible facilities at White Bluff and Flint Creek because it would be illogical not to require the same controls at the state's "three largest emitters" of SO_2 and NOx. *Id.* at 66350/3; *accord id.* at 66336/2-3, 66362/3-66364. Yet in response to comments arguing that it was inappropriate to impose the same controls on Independence simply because of its emissions status, the Final Rule claimed that status had nothing to do with the decision to impose controls. *Id.* at 66363/2. Instead, the Final Rule claims that the same controls were imposed on Independence because those controls were reasonable. *See id.*, 66336/2-3, 66350/3, 66351/3-66352/1. But the Final Rule does not explain what made those controls reasonable, beyond Independence's status as one of the three largest emitters. *See id.* Thus, the Final Rule's reader is left to wonder why Independence was singled out for additional controls or what—other than size or EPA's mere desire to impose additional controls—made the additional controls at Independence reasonable.

IV. The Final Rule misapplies the California Puff Model.

The Final Rule erroneously relies on CALPUFF modeling to justify the installation of low NOx burners at Flint Creek. Flint Creek is subject to BART, and to impose controls under that framework, EPA must establish "the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology." 40 C.F.R. 51.308(e)(1)(i)-(ii); *accord* 42 U.S.C. 7491(g)(2). Here, the Final Rule argues that the low NOx burners are "reasonably . . . anticipated to result" in 0.081 deciviews of improvement at Caney Creek and small improvements at other sites. 81 Fed. Reg. at 66342. On that basis, it required the installation of low NOx burners. *See id.*

Comments challenged the basis for that conclusion, arguing that CALPUFF cannot reliably project such infinitesimal improvements. Comments from Industry Associations, IV.15, pp. 9-10, [App.__]. And consistent with those comments, the Ninth Circuit recently concluded that EPA could not rely on CALPUFF modeling to demonstrate that controls would result in a 0.085 deciview improvement because that rate of improvement is less than CALPUFF can reliably predict. *See id.*, [App.__]; *see also* *Nat'l Parks*, 788 F.3d at 1146-47. Given that, commenters asked EPA to conduct a site specific analysis that would validate its conclusion that the controls at Flint Creek could reasonably be anticipated to result in improvement. Comments from Industry Associations, IV.15, p. 9, [App.__].

When an agency's model is challenged, it "must provide a full analytical defense." *Eagle–Picher Indus., Inc. v. EPA*, 759 F.2d 905, 921 (D.C. Cir. 1985); *accord Nat'l Parks*, 788 F.3d at 1146-47. But rather than do that, EPA simply dismissed the concern about CALPUFF raised in the comments on the grounds that while that model has been known to overestimate impacts, it *can* also under-predict impacts. 81 Fed. Reg. at 66399/2. Thus, in other words, instead of responding to comments asking EPA to do a site specific analysis to validate its conclusions or explain why it determined the use of CALPUFF was acceptable here, EPA simply ignored those concerns. Indeed, far from offering a full defense of that model, EPA simply pointed to the model's unreliability to justify dismissing concerns over its unreliability. And because EPA failed to justify the use of that model—or otherwise validate the conclusions that model supposedly supported—the Final Rule should be vacated.

V. EPA acted arbitrarily, capriciously, and contrary to law in failing to reconsider the Final Rule.

As noted above, EPA must convene a reconsideration proceeding where a party seeks reconsideration based on an objection that could not have been raised during the public comment period and where the "objection is of central relevance to the outcome of the rule." 42 U.S.C. 7607(d)(7)(B). ADEQ raised three objections that could not have been raised during the public comment period and

that are of central relevance to the Final Rule's outcome. EPA declined to act on those requests and, as explained above, it thereby constructively denied ADEQ's reconsideration petition and companion request for an administrative stay. *See supra* at p. 35 n. 8 (discussing constructive denial jurisprudence).

First, as discussed above, ADEQ sought reconsideration of the Final Rule based on subsequently available data demonstrating that Arkansas has already achieved greater progress than the Final Rule would purportedly achieve. S*ee supra* at pp. 34-38. And as explained, in so doing, EPA acted arbitrarily, capriciously, and contrary to law in declining to convene a reconsideration proceeding based on that information. *See id.*

Second, EPA acted arbitrarily, capriciously and contrary to law by failing to convene a proceeding to reconsider the Final Rule's NOx limitations at BART-eligible facilities and determine that compliance with the Transport Rule is an acceptable way of meeting the Final Rule's NOx emissions limitations. Petition for Reconsideration, p. 10, [App.__]. ADEQ's objection is central to the Final Rule's outcome because it presents an alternative means for meeting the limitations imposed by the Final Rule without installing BART technology. And under EPA's regulations, states—or EPA when it promulgates a FIP—may include reliance on the Transport Rule in their implementation plans as an alternative method of achieving progress that would otherwise be achieved through the imposition of

BART controls. *See* 40 C.F.R. 51.308(e)(2) ("A State may opt to implement or require participation in an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART."); 77 Fed. Reg. at 33643 ("EPA is finalizing our finding that the trading programs in the Transport Rule, also known as the Cross-State Air Pollution Rule (CSAPR), achieve greater reasonable progress towards the national goal of achieving natural visibility conditions in Class I areas than source-specific [BART] in those states covered by the Transport Rule."). Moreover, ADEQ could not have made this argument prior to the April 2015 close of the public comment period because the relevant revised state NOx budgets—that serve as the basis for the Transport Rule trading program—were not published until October 26, 2016. *See* 81 Fed. Reg. 74504. Thus, EPA was required to convene a reconsideration proceeding.

Third, EPA was required to reconsider the use of low sulfur coal as a BART control technology at White Bluff. In requesting reconsideration, ADEQ attached an October 13, 2016 letter from EPA expressing EPA's "preliminary views on supplemental comments" from Entergy regarding the use of dry sorbent injection as "a proposed alternative strategy for their White Bluff facility." *See* Petition for Reconsideration, p. 9, 44, [App.__]. That letter suggests that EPA might have considered Entergy's proposal if it had not been under a court ordered deadline for

promulgating a FIP and that to adequately evaluate that proposal it would be "necessary to consider whether there are any additional SO_2 control measures [for White Bluff] . . . that constitute BART" that, like Entergy's proposal, might be more cost-effective and have planning period effect. *Id.* at 46, [App.__]; *see id.* at 44, [App.__]. EPA additionally asked Arkansas to consider a SIP that would incorporate those possibilities. *Id.*, [App.__].

Because EPA's letter suggests that EPA failed to consider viable alternatives to compliance that are both more cost-effective than those required under the Final Rule and would have planning period effect (unlike the Final Rule's controls), ADEQ requested that EPA reconsider the use of low sulfur coal and other technologies that might meet that standard. *See* Petition for Reconsideration, pp. 9-10, [App.__]. EPA's acknowledgment that it failed to consider such technologies and that it would have considered them if it had not been under a court ordered deadline required EPA to grant reconsideration to consider those alternatives. Thus, EPA acted arbitrarily, capriciously and contrary to law in failing to convene a reconsideration proceeding.

CONCLUSION

For the foregoing reasons, this Court should vacate the Final Rule in its entirety.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I, Nicholas J. Bronni, Deputy Solicitor General, do hereby certify that on February 17, 2017, I electronically submitted for filing the foregoing brief with the Clerk of the Court for the United States Court of Appeals for the Eighth Circuit via the CM/ECF system. Participants in the case who are registered CM/ECF users will be served by the CM/ECF system.

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NO. 16-4302

IN THE UNITED STATES COURT OF APPEALS FOR THE EIGHTH CIRCUIT

DOMTAR A.W. LLC,

Petitioner,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY AND CATHERINE MCCABE,

Respondents.

On Petition for Review from Final Action of United States Environmental Protection Agency and Catherine McCabe, Acting Administrator of United States Environmental Protection Agency

BRIEF AND ADDENDUM OF PETITIONER DOMTAR A.W. LLC

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SUMMARY OF THE CASE AND REQUEST FOR ORAL ARGUMENT

Petitioner Domtar A.W. LLC challenges the Environmental Protection Agency's (EPA) final action in its Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule, 81 Fed. Reg. 66,331 (Sept. 27, 2016). Under the Clean Air Act and applicable rules, EPA was required to address, among other things, the Regional Haze Rule's requirements for Best Available Retrofit Technology (BART) and reasonable progress for the State of Arkansas.

EPA's application of these requirements to Domtar A.W. LLC's Ashdown mill was arbitrary and capricious.

Petition Domtar A.W. LLC requests oral argument of 15 minutes in this case, apart from any argument made by any other petitioner or respondents, because of the complexity of the issues and the importance of the regional haze requirements.

RULE 26.1 DISCLOSURE STATEMENT

Domtar A.W. LLC's sole member is Domtar Corporation, a publicly held corporation. No publicly held corporation owns 10% or more of Domtar Corporation's stock.

s/ Eric L. Maassen
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JURISDICTIONAL STATEMENT

Jurisdiction in this Court is proper under section 307(b)(1) of the Clean Air Act, 42 U.S.C. § 7607(b)(1), which requires that a petition for review of an EPA action promulgating an implementation plan which is locally or regionally applicable be filed only in the Court of Appeals for the applicable circuit. Here, that is the United States Court of Appeals for the Eighth Circuit.

The Clean Air Act requires that a petition for review of EPA action in an implementation plan be filed "within 60 days from the date that notice of such promulgation, approval, or action appears in the Federal Register." *Id.* EPA's final decision was published at 81 Fed. Reg. 66,331 on September 27, 2016. The 60th day was extended to November 28, 2016 by virtue of Fed. R. App. P. 26(a)(1)(C); *see also* 81 Fed. Reg. at 66,415 ("Under section 307(b)(1) of the Clean Air Act, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by November 28, 2016."). Domtar A.W. LLC, having commented on the proposed rule below, timely commenced this action by

filing a petition for review with the Clerk of this Court on November 28, 2016.

STATEMENT OF THE ISSUE

Whether that portion of the Rule that set sulfur dioxide (SO_2) limits for Domtar's Ashdown Mill Power Boiler No. 2 must be vacated because it was arbitrary, capricious and in excess of EPA's statutory authority, where EPA's calculation of the purported visibility improvement due to SO_2 reductions fell within the margin of error for the modeling methodology used by EPA, and thus EPA failed to demonstrate that, or provide a reasonable explanation of how, any improvement can be "reasonably anticipated"?

Most apposite law: *Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134 (9th Cir. 2015); Clean Air Act § 169A, 42 U.S.C. § 7491; 40 C.F.R. § 51.308; 81 Fed. Reg. 66,331 (Sept. 27, 2016).

STANDARD OF REVIEW

On direct review under Federal Rule of Appellate Procedure 15, a court "will set aside EPA's Final Rule if it is 'arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law,' or 'in excess of statutory jurisdiction, authority, or limitations, or short of statutory right.'" *North Dakota v. EPA*, 730 F.3d 750, 758 (8th Cir. 2013) (quoting 42 U.S.C. § 7607(d)(9)). "An agency action is arbitrary and capricious if the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise." *Nebraska v. EPA*, 812 F.3d 662, 666 (8th Cir. 2016) (internal quotation marks omitted).

STATEMENT OF THE CASE

I. The Clean Air Act's Mandate To Improve Visibility at National Parks and Wilderness Areas Through State or Federal Implementation Plans

In Section 169A of the 1977 amendments to the Clean Air Act (CAA), Congress established a program for the improvement of visibility in 156 national parks and federal wilderness areas, known as "mandatory class I Federal areas." *See* 42 U.S.C. §§ 7472(a), 7491(a)(1); 40 C.F.R. §§ 81.401-37. Section 169A directs EPA to promulgate regulations which, among other things, require States to create implementation plans (SIPs) aimed at reducing regional haze in Class I areas. *See* 42 U.S.C. § 7491(a)(4), (b). EPA defines regional haze as "visibility impairment caused by geographically dispersed sources emitting fine particles and their precursors into the air." *Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1, 3 (D.C. Cir. 2002). Among those precursors, and the one relevant to this case, is sulfur dioxide (SO_2). *Id.*

Pursuant to Section 169A, the regional haze SIPs are to include a requirement that "major stationary source[s]" emitting visibility-impairing pollutants in 1977, and which began operation after 1962, install

and operate the "best available retrofit technology" to reduce such impairment. 42 U.S.C. § 7491(b)(2)(A). The statute defines a "major stationary source" to be any of an enumerated list of facilities, including "kraft pulp mills,"[1] with the potential to emit 250 tons or more of any pollutant. *Id.* § 7491(g)(7).

Pursuant to its statutory mandate, EPA promulgated a Regional Haze Rule, which outlines the core components of a CAA-compliant SIP. *See* 40 C.F.R. § 51.308(a); *accord Texas v. EPA*, 829 F.3d 405, 412 (5th Cir. 2016). States were required to submit their plans no later than December 17, 2007, with an initial implementation period to run from 2009 to 2018. *See* 40 C.F.R. § 51.308(b), (f); *accord Texas v. EPA*, 829 F.3d at 413–14. The Rule calls for "comprehensive periodic revisions" of SIPs to occur every ten years, beginning in 2018. *See* 40 C.F.R. § 51.308(f).

Under the CAA, EPA is charged with reviewing the States' implementation plans and rejecting in whole or in part a plan not

[1] The kraft process is a method of converting wood to pulp that is used for paper and other products. *See Domtar Petition for Reconsideration*, Appellate Dkt. 4473717 (Nov. 23, 2016), at 1.

complying with the CAA's requirements. *See* 42 U.S.C. §§ 7410(a)(1); 7410(k)(3). If EPA rejects an SIP, or if a State fails to submit a plan, EPA must develop a federal implementation plan (FIP), unless the State is able to correct its deficiency and obtain EPA approval of its correction within two years. 42 U.S.C. § 7410(c)(1); *see also Nebraska v. EPA*, 812 F.3d at 664.

II. The Clean Air Act's Imposition of Best Available Retrofit Technology Limits To Achieve "Reasonably Anticipated" Visibility Improvements

One of Section 169A's core substantive requirements (and the only component of an SIP or FIP that is enforceable against emissions sources) is installation of the best available retrofit technology (BART) for controlling specific emissions at certain major stationary sources built between 1962 and 1977. *See* 42 U.S.C. § 7491(b)(2)(A); *Texas v. EPA*, 829 F.3d at 413. To determine what constitutes BART for a given source, the Act directs States (and likewise requires EPA) to consider five factors:

> [1] the costs of compliance, [2] the energy and nonair quality environmental impacts of compliance, [3] any existing pollution control technology in use at the source, [4] the remaining useful life of the source, and [5] the degree of improvement in visibility which may reasonably be

> anticipated to result from the use of such technology.

Id. § 7491(g)(2). These factors are commonly referred to as the "five statutory factors" or "BART factors." *E.g.*, 81 Fed. Reg. at 66,334. Considered together, they "determine whether 'the degree of improvement in visibility obtained from installing a particular set of emission controls' justifies the cost." *Nebraska v. EPA*, 812 F.3d at 667 (quoting *Am. Corn Growers Ass'n*, 291 F.3d at 7). The statute requires either the States or EPA to weigh the costs associated with implementing a particular set of controls against the degree of visibility improvement that those controls will likely yield. *See Am. Corn Growers Ass'n*, 291 F.3d at 6–7.

A State (or EPA), in determining the necessity of and imposing BART limits, must thus balance the enumerated factors. *See id.* Irrespective of the other factors, however, in order to justify imposing any BART limit, even if the controls are considered technically feasible and cost effective, there must be a "reasonably . . . anticipated" visibility improvement under the final BART factor. 42 U.S.C. § 7491(g)(2). It is therefore essential to the imposition of any BART limit that the State or

EPA determine that reasonably anticipated improvements in visibility will occur. *Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1148 (9th Cir. 2015) ("The predictability concern is important because the Act requires that any visibility improvement be 'reasonably … anticipated' as a result of BART installation." (quoting 42 U.S.C. § 7491(g)(2))).

EPA's Regional Haze Rule directly incorporates the statutory BART factors by requiring States to consider each factor when determining "the best system of continuous emission control technology available and associated emission reductions achievable" for a source. 40 C.F.R. § 51.308(e). To assist States in applying the BART factors on a case-by-case basis, EPA published Guidelines for BART Determinations Under the Regional Haze Rule. *See* 40 C.F.R. Pt. 51, App. Y. The Guidelines "provide states with a five-step process for making their source-specific BART determinations, and these five steps subsume" the five statutory BART factors. *Nat'l Parks Conservation Ass'n v. EPA*, 803 F.3d 151, 155 (3d Cir. 2015). Specifically, the Guidelines direct States to evaluate the impact of retrofit control technologies, including the cost of compliance, energy

impacts, non-air quality impacts, and the remaining useful life of the facility. 40 C.F.R. Pt. 51, App. Y(IV)(D)(4)(d). The States are to weigh these impacts against the anticipated visibility improvements from the BART controls on each source. *See* 40 C.F.R. Pt. 51, App. Y(IV)(D)(5).

III. Domtar A.W. LLC's Ashdown Mill Power Boiler No. 2

Domtar A.W. LLC (Domtar), a subsidiary of Domtar Corporation, is a manufacturer of paper, pulp, and personal care products. *Supplemental Comments from Domtar*, Dkt. EPA-R06-OAR-2015-0189-1070 (Aug. 7, 2015), at 2-1, [App. __]. Domtar owns a kraft pulp mill in Ashdown, Arkansas. *Id.* Ashdown is 80 kilometers south of Caney Creek Wilderness Area and 250 kilometers south of Upper Buffalo Wilderness Area, both mandatory Class I areas. *Id.* The Ashdown mill operates two boilers (only Power Boiler No. 2 is germane to this petition) that provide steam for the pulp and papermaking processes at the mill. *Id.* The pulping process emits sulfur containing off-gasses. *Domtar Petition for Reconsideration*, Appellate Dkt. 4473717 (Nov. 23, 2016), at 2, [App. __]. Incineration of these off-gasses is required under the Clean Air Act. *Id.*

During the incineration process, sulfur compounds are oxidized, creating SO_2, which is emitted together with smaller amounts of SO_2 from solid fuel used to fire Power Boiler No. 2. *See id.*

IV. EPA's Proposed BART Limits, Pursuant to an FIP, for SO_2 at Domtar's Ashdown Mill Power Boiler No. 2

The State of Arkansas submitted its initial SIP on September 23, 2008, and several revisions thereafter, which EPA approved in part and rejected in part. 77 Fed. Reg. 14,603, 14,604 (Mar. 12, 2012). Relevant to this petition, EPA rejected the SO_2 BART determinations for the Domtar Ashdown Mill Power Boiler No. 2. *Id.* at 14,607.

On April 8, 2015, EPA published a proposed FIP to replace rejected portions of Arkansas's plan, which included Arkansas' BART determinations for SO_2 for the Domtar Ashdown Mill Power Boiler No. 2. 80 Fed. Reg. 18,943 (Apr. 8, 2015). On this appeal, Domtar challenges portions of EPA's final September 2016 FIP that apply to SO_2 emissions from Domtar's Power Boiler No. 2.

EPA's April 8, 2015 proposed rule included a BART SO_2 emission limit for Power Boiler No. 2 of 0.11 lb./MMBtu (subsequently

converted to the equivalent measure of 91.5 lb/hr) on a 30-boiler-operating-day rolling average. *Id.* at 18,985. EPA's analysis underlying its proposal began with Power Boiler No. 2's existing SO_2 control technology, which includes a wet scrubber. *Id.* at 18,982. EPA then summarized a 2014 BART analysis conducted by Domtar, which evaluated various potential scrubber upgrades and add-on technologies. *Id.* at 18,982–83. Those upgrades and add-on technologies were viewed as not being cost effective and were removed from the BART analysis. *Id.* EPA instead elected to increase the SO_2 removal efficiency of the existing scrubber by requiring Domtar to use additional scrubbing reagent to achieve a 90% reduction in SO_2 emissions. *Id.* at 18,985. (Scrubbing reagent is a combination of caustic solution, bleach plant EO filtrate, and demineralizer in ion rinse water, which aids the scrubbers in removing sulfur dioxide. *Id.* at 18,982.)

Applying a 90% control efficiency to Power Boiler No. 2's average uncontrolled 2011–2013 SO_2 emission rate of 915.9 lb./hr., EPA concluded that BART for Power Boiler No. 2 is an SO_2 emission limit of "91.5 lb/hr." *Id.* at 18,984.

In an effort to satisfy the final, but most essential, BART requirement (that an improvement in visibility was reasonably anticipated to result from the 91.5 lb/hr SO_2 limit), EPA used the CALPUFF model. *See id.* at 18,985. Ignoring issues regarding CALPUFF's ability to predict very small visibility improvements, EPA relied on the model's output to meet this requirement. *See id.* More specifically, EPA took the CALPUFF value and stated its proposed BART SO_2 emission limit for Domtar's Power Boiler No. 2 would result in a very small 0.139 deciview (dv)[2] improvement in visibility at Caney Creek Wilderness Area, an even smaller 0.05 dv improvement in Upper Buffalo Wilderness Area, and miniscule improvements at two mandatory Class I areas outside Arkansas (Hercules-Glades and Mingo). *Id.* at 18,985.

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[2] The deciview measure:

> expresses uniform changes in haziness in terms of common increments across the entire range of conditions, from pristine to extremely impaired environments. A one deciview change in haziness is a small but noticeable change in haziness under most circumstances when viewing scenes in mandatory Class I Federal areas. The deciview is a means of expressing atmospheric light extinction . . . .

61 Fed. Reg. 41,138, 41,145 (July 31, 1997). A change of 1.0 deciview reflects a one deciview change in haziness while 0.139 reflects a change of 139/1000 of one deciview.

In its analysis, EPA did not take into account the CALPUFF model's margin of error or assess whether the tiny visibility improvements it predicted were within the model's technical limitations to give meaningful results.

V. The Ninth Circuit's Ruling in *National Parks Association v. EPA*

After EPA issued its proposed rule in this case, the Ninth Circuit vacated portions of a Montana regional haze FIP on the grounds that EPA failed to justify imposing BART limits on certain power plants based upon purported visibility improvements that fell within CALPUFF's margin of error. *Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134 (9th Cir. 2015). The court reasoned that EPA is obligated to demonstrate a rational basis to believe that the predicted visibility improvement is "reasonably . . . anticipated." *Id.* at 1146. By not addressing the margin of error, EPA failed to give a reasoned basis for imposing the BART limits. *Id.* at 1147.

VI. Domtar's Comments Opposing the Proposed SO_2 BART Limit for Power Boiler No. 2

During the comment period, Domtar raised substantive issues regarding EPA's proposed SO_2 emission limit for the Ashdown Mill Power Boiler No. 2. *See Comments from Domtar*, Dkt. EPA-R06-OAR-2015-0189-0161 (July 15, 2015), [App. __]; *Supplemental Comments from Domtar*, Dkt. EPA-R06-OAR-2015-0189-0170 (Aug. 7, 2015), [App.__].

Most significantly, Domtar objected that EPA could not show that its predicted visibility improvements were reasonably anticipated to occur, because the alleged improvements were within the CALPUFF model's margin of error—that is, the "threshold value below which CALPUFF predicted visibility improvements are mathematical noise." *Supplemental Comments from Domtar*, Dkt. EPA-R06-OAR-2015-0189-0170 (Aug. 7, 2015), at 1-1, 5-1, [App. __]. Domtar noted that EPA had failed to perform any assessment of the reliability of CALPUFF to predict such very small changes in visibility. *Id.* at 1-1, [App.__] ("[N]o assessment of the reliability of the model . . . was performed. . . . [T]he lack of such an analysis by the Agency is in itself a significant defect in the proposal . . . .).

As such, EPA's proposed rule failed to satisfy the reasonably anticipated visibility improvement requirement. Domtar specifically pointed to the decision in *Nat'l Parks Ass'n v. EPA*, 788 F.3d 1134, 1146 (9th Cir. 2015). *Supplemental Comments from Domtar*, Dkt. EPA-R06-OAR-2015-0189-0170 (Aug. 7, 2015), at 1-1, 5-1, [App. __].

Along with its objections, Domtar submitted a CALPUFF margin-of-error analysis prepared by Trinity Consultants, an environmental consulting firm engaged by Domtar to assess the CALPUFF model's "margin of error" associated with EPA's predicted visibility improvement for the Ashdown Mill's Power Boiler No. 2. *Supplemental Comments from Domtar*, Dkt. EPA-R06-OAR-2015-0189-0170 (Aug. 7, 2015), [App.__]. Trinity's analysis showed the minimum margin of error relating to the Ashdown Mill's Power Boiler No. 2 was 0.93 dv. *Id.* at 5-1. According to Trinity's study, using the lowest possible margin of error (0.93), EPA's CALPUFF model could not show, based on the limitations inherent to the model, that any visibility improvements will result from EPA's SO_2 BART controls. *Id.*

EPA's proposed BART limits would impose $1.96 million in annual operating costs for Domtar's Ashdown Mill, and an additional $200,000 in capital costs. 81 Fed. Reg. at 18,984. Domtar explained in its comments that while the per-ton cost of the pollution reduction may appear low, the proposed BART limits would adversely affect the Mill's competitiveness and economic viability in exchange for insignificant and imperceptible visibility improvements. *Comments from Domtar*, Dkt. EPA-R06-OAR-2015-0189-1016 (July 15, 2015), at 10, [App.__].

VII. EPA's Responses to Domtar Comments, and the Final Rule

EPA responded to Domtar's comments on August 31, 2016. *Response to Comments for the Federal Register Notice for the State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan*, Dkt. EPA-R06-OAR-2015-0189-0187 (Aug. 31, 2016), [App.__]. In response to Domtar's comments and analysis regarding EPA's failure to make a reasonable determination that visibility improvements would occur, EPA did not directly address what CALPUFF's margin of error is for the relevant sources. Although EPA criticized Trinity Consultants' margin-of-

error analysis, EPA did not itself provide any analysis of CALPUFF's margin of error. *See id.* at 407–28, [App.__]. Nor did it give any reasoned assessment as to whether CALPUFF's predicted visibility improvements are statistically significant in light of the model's margin of error. *See id.*

Instead, EPA defended its use of CALPUFF modeling generally. EPA asserted that CALPUFF is the model selected by EPA for predicting single-source contributions to visibility impairments, that EPA had concluded CALPUFF performed in a reasonable manner, and that its use is provided for by EPA's guidelines. *Id.* at 409–10, [App.__]. EPA further asserted that whether the visibility benefits lie below CALPUFF's margin of error as calculated by Trinity Consultants "is immaterial" to whether visibility benefits from BART controls "can reasonably be anticipated to occur." *Id.* at 409, [App.__].

EPA acknowledged that CALPUFF can both over- and under-predict visibility impacts. *Id.* at 411, [App.__]. EPA noted that it attempted to avoid reliance upon outlier results by using the model to estimate 98th percentile results, rather than highest impact values. *Id.* at 411, [App.__].

Notwithstanding any limitations of the CALPUFF model, EPA justified its action as to Domtar in part because BART determinations are "only made for sources that have already been shown to reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area." *Id.* at 412, 419, [App.__]. Finally, EPA asserted that the "magnitude of the visibility improvement is not the determinative factor in the BART determination, but only one factor and is considered on a relative basis to baseline impact and the benefits of other controls." *Id.*

EPA then finalized the SO_2 limit for Domtar's Power Boiler at 91.5 lb/hr based on a 30 boiler-operating-day rolling average (instead of 0.11 lb/MMBtu). 81 Fed. Reg. at 66,347. EPA's responses in the final rule to Domtar's comments largely mirrored, in more abbreviated form, its responses of August 31, 2016.

This appeal followed.

SUMMARY OF THE ARGUMENT

EPA's final rule imposing BART SO_2 limits for Domtar's No. 2 Power Boiler should be vacated. EPA failed to provide a reasoned analysis showing that the projected visibility improvements, which justified the SO_2 limits, were reasonably anticipated to occur. EPA is required to provide that reasoned analysis before it imposes costly (here $1.96 million per year) emissions limits.

Domtar submitted comments with analysis showing that the projected visibility improvements resulting from its Power Boiler No. 2 were within the "margin of error" of the model that EPA used. EPA criticized Domtar's analysis, but EPA did not, even after acknowledging the inherent limitations of EPA's own model, provide its own analysis of what the margin of error of the model actually was. EPA brushed aside Domtar's comment by asserting that the accuracy of the model was "immaterial" and by asserting that projected visibility improvements is only one of five BART factors, ignoring that it is the only factor that could justify any BART limits whatsoever. For these reasons, as more fully

explained below, EPA's SO_2 BART determinations for Power Boiler No. 2 at the Domtar Ashdown mill should be vacated.

ARGUMENT

EPA'S RELIANCE ON PURPORTED VISIBILITY IMPROVEMENTS WITHIN THE CALPUFF MODEL'S MARGIN OF ERROR WAS ARBITRARY AND CAPRICIOUS AND IN EXCESS OF EPA'S STATUTORY AUTHORITY.

EPA's imposition of BART-based SO_2 limits for Domtar's No. 2 Power Boiler was arbitrary and capricious and contrary to the Clean Air Act, because EPA failed to demonstrate in a reasoned analysis that the data upon which it relied support its conclusions. It is essential to the imposition of a BART limit that EPA demonstrate in a reasoned analysis that any professed visibility improvements be "reasonably . . . anticipated" as a result. *Nat'l Parks*, 788 F. 3d at 1147. Absent sufficient assurance of improvement, it is arbitrary and capricious to impose any—much less millions of dollars in—costs of compliance. *Id.*

In this case, EPA relied upon CALPUFF-generated visibility-improvement results without accounting for the model's margin of error. *Response to Comments*, Dkt. EPA-R06-OA-2015-0189-0187 (Aug. 31, 2016), at 407–28, [App.__]. Domtar duly objected to EPA's deficient analysis and demonstrated through the analysis of Trinity Consultants that all of EPA's

predicted visibility improvements were within the margin of error. *Supplemental Comments from Domtar*, Dkt. EPA-R06-OAR-2015-0189-0170 (Aug. 7, 2015), [App.__]. As such, no visibility improvement can be "reasonably anticipated" to occur. Although EPA criticized Trinity Consultants' analysis, EPA to this day has failed to justify the CALPUFF-generated results against Domtar's margin-of-error objection. *Response to Comments*, EPA-R06-OAR-2015-0189-0170 (Aug. 31, 2016), at 407–28, [App.__]. As a consequence, that portion of the rule should be vacated.

A. EPA's Predicted Visibility Improvements Are Within CALPUFF's Margin of Error As Calculated by Trinity Consultants.

EPA's conclusion that the costly SO_2 emission limits on Domtar's Ashdown Mill would improve visibility at the four named mandatory Class I areas was based *solely* upon the CALPUFF model. *See id.*; *see also* 81 Fed. Reg. at 66,392–401. As EPA concedes, CALPUFF has significant limitations. It is "less advanced" than newer models, and less accurate.[3] *E.g.*, 81 Fed. Reg. at 66,399 n.310; *see also Supplemental Comments*

[3] Because CALPUFF is "less advanced" than newer models, and less accurate, commenters criticized EPA's use of CALPUFF altogether. *E.g.*, 81 Fed. Reg. at 66,399 & n.310; *see also* (Continued)

from Domtar, Dkt. EPA-R06-OAR-2015-0189-0170 (Aug. 31, 2015), at 3-2, [App.__]. While CALPUFF can predict large changes in visibility, it cannot predict smaller visibility improvements, *see Supplemental Comments from Domtar*, Dkt. EPA-R06-OAR-2015-0189-0170 (Aug. 31, 2015), at 1-1, [App.__] (improvements "too insignificant for the model to measure"), nor can it accurately predict visibility changes in areas that are far away from the source of the pollution, *id.* at 3-2, [App.__].

Using CALPUFF, EPA predicted improvements of 0.139 dv at Caney Creek Wilderness Area, and improvements of 0.05 dv or less at Upper Buffalo Wilderness Area, Hercules-Glades and Mingo. 81 Fed. Reg. at 66,347–48. In its proposed rule, EPA provided no statement of or information about CALPUFF's margin of error, or how the margin of error compared to those predicted results. 80 Fed. Reg. at 18,985. In fact, EPA apparently did not make any attempt at all to factor for any margin of error. *See id.* This is curious, because all models can calculate changes only

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Dkt. EPA-R06-OAR-2015-0189-0170, at 3-2. On this appeal, Domtar does not challenge EPA's use of CALPUFF generally. Domtar's challenge is based upon EPA's failure to account for CALPUFF's margin of error in connection with the limits it imposed on Power Boiler No. 2.

of a certain size; changes below that level are within what can be deemed the model's "margin of error." *See Nat'l Parks*, 788 F.3d at 1147.

In support of its objection to the BART limits for Power Boiler No. 2, Domtar submitted a margin-of-error analysis of CALPUFF performed by Trinity Consultants. *See generally Supplement Comments from Domtar*, Dkt. EPA-R06-OAR-2015-0189-0170 (Aug. 7, 2015), [App.__]. In its analysis, Trinity demonstrated a site-specific minimum margin of error for the CALPUFF model of .93 dv. *Id.* at 5-1, [App.__]. As Trinity showed, EPA's visibility improvement calculations for all four relevant Class I areas were well within CALPUFF's margin of error. *See id.* at 5-2, [App.__]; *see also* 81 Fed. Reg. at 66,347. In fact, the greatest predicted improvement in visibility is lower that the lowest margin of error by a factor of greater than six. *Supplement Comments from Domtar*, Dkt. EPA-R06-OAR-2015-0189-0170 (Aug. 7, 2015), at 5-2, [App.__] (showing lowest margin of error as 0.93 dv and highest predicted visibility improvement as 0.139 dv). CALPUFF simply cannot accurately demonstrate that there will actually be *any* visibility improvements at all if the BART limits are implemented.

In short, EPA's calculated visibility improvement is merely "mathematical noise" and does not show any actual improvement in visibility will occur. *Id.* at 5-1, [App.__]. Because CALPUFF's margin of error is, at best, 0.93 dv for the Domtar Ashdown mill, any projected visibility improvement based on BART controls at the mill that are less than 0.93 dv cannot be said to "reasonably be anticipated" to occur. *See* 42 U.S.C. § 7491(g)(2).[4] When, as here, the agency's underlying data is flawed, an SIP (and, by extension, an FIP, which is held to the same scrutiny) does not fulfill the Clean Air Act's mandates. *Cf. North Dakota v. EPA*, 730 F.3d at 760–61 (flawed data required rejection of the plan).

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[4] Domtar A.W. LLC filed a petition for reconsideration with EPA on November 23, 2016, that contained additional new CAMx modeling further confirming that the BART controls imposed on Domtar will provide no improvements whatsoever. *Domtar Petition for Reconsideration*, Appellate Dkt. 4473717 (Nov. 23, 2016), at 2; *see also* 42 U.S.C. § 7607(d)(7)(B)(permitting objections to a rule to be made by a petition for reconsideration). The petition for reconsideration was attached to Domtar's petition for review in this Court. EPA's decision on the petition for reconsideration remains pending.

B. EPA Failed to Give a Reasoned Analysis for the BART Limits It Imposed Upon Domtar Power Boiler No. 2.

In response to Domtar's objections, EPA failed to give the reasoned justification for its imposition of BART limits that the Clean Air Act requires. EPA's primary response was to give a technical critique of Trinity Consultants' margin-of-error analysis. *Response to Comments*, Dkt. EPA-R06-OAR-2015-0189-0187, at 418–28, [App.__]. Domtar stands by Trinity's work. But regardless of the validity or invalidity of EPA's criticisms, they are an insufficient response to Domtar's objections, which were based both upon Trinity Consultant's margin-of-error calculations, as well as upon EPA's failure to do its own assessment of CALPUFF's reliability to predict extremely small variations in visibility. *Supplemental Comments from Domtar*, Dkt. EPA-R06-OAR-2015-0189-0170 (Aug. 7, 2015), at 1-1, [App.__].

In response to Domtar's challenge to the CALPUFF model's margin of error, the Clean Air Act required EPA to give a reasoned explanation for why the extremely small purported improvements in visibility could be reasonably anticipated. *Nat'l Parks*, 788 F.3d at 1146

("[I]f . . . the model is challenged, the agency must provide a full analytical defense." (quoting *Eagle-Picher Indus., Inc., v. EPA*, 759 F.2d 905, 922 (D.C. Cir. 1985))). It was not sufficient for EPA, as it did here, merely to criticize Domtar's consultant's work. It was obligated to provide an affirmative defense of CALPUFF's results.

EPA did not, even when challenged about CALPUFF's margin of error, supply alternative margin of error numbers for CALPUFF, either in the Final Rule or in its Response to Comments. *See* 81 Fed. Reg. at 66,392–401; *Reponse to Comments*, Dkt. EPA-R06-OAR-2015-0189-0187 (Aug. 31, 2016), at 407–28, [App.__]. Indeed, EPA did not even acknowledge the obvious point that CALPUFF must have some margin of error. Essentially, EPA's approach was to ignore the role of CALPUFF's margin of error in its own analysis. Inexplicably, EPA asserted that whether the visibility benefits lie below CALPUFF's margin of error calculated by Trinity Consultants was "immaterial" to whether visibility benefits from BART controls "can reasonably be anticipated to occur." 81 Fed. Reg. at 66,401.

This case is analytically indistinguishable from *Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134 (9th Cir. 2015). In that case, utilities and public interest organizations challenged the EPA regional haze FIP for the State of Montana. *Id.* at 1138. The Ninth Circuit vacated several portions of the FIP because EPA's explanations for its BART determinations were inadequate. *Id.* at 1145–47. In particular, the Court overturned EPA's decision to base BART determinations on anticipated visibility improvements that fell within the CALPUFF model margin of error. *Id.* at 1146–47. EPA's explanation of its BART determination did not "meaningfully address" the comments about CALPUFF's margin of error. *Id.* at 1146. EPA is required to give a "reasoned explanation" when it requires emissions sources to install expensive controls, especially when visibility improvements cannot be said to be "reasonably anticipated" to occur even if the technology is implemented. *Id.* at 1147.

In this case, EPA's response to Domtar's comments is equivalent to that in the *Nat'l Parks* case. While EPA offered a critique of Trinity Consultants' analysis, it failed to offer its own affirmative

justification for using CALPUFF's extremely small visibility improvement predictions. *See* 81 Fed. Reg. at 66,392–401. Instead, as in the Ninth Circuit's *Nat'l Parks* case, EPA's response is to defend CALPUFF generally. *See id.* For instance, EPA asserts that CALPUFF is the model it has chosen and prescribed in its guidance, and that it is confident in CALPUFF's results. *See id.* at 66,399. But EPA's defense of CALPUFF's continued utility for BART in general does not address why a specific projection within the model's margin of error can have any validity as something that reasonably is anticipated to occur. *See Nat'l Parks*, 788 F.3d at 1146. It cannot.

In lieu of a reasoned defense of CALPUFF's ability to meaningfully predict very small changes in visibility, EPA invokes several non-responsive justifications for its use of the CALPUFF results. First, EPA asserts that "BART determinations are only made for sources that have already been shown to reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area." 81 Fed. Reg. at 66,401. That argument begs the question. That a pollution source has been shown to

contribute to visibility impairment does not mean that any particular BART limit will improve visibility. EPA seems to be suggesting that imposing stricter limits on a source is always good and therefore justifiable. But the Clean Air Act requires more, and EPA has not made the necessary showing of a reasonably anticipated improvement in visibility.

Second, EPA's defense that it uses CALPUFF to estimate 98th percentile results, rather than the highest impact values, *Response to Comments*, Dkt. EPA-R06-OAR-2015-0189-0170 (Aug. 31, 2016), at 411, [App.__], is beside the point. As Trinity Consultants explained, "[w]hile this guidance addresses modeling uncertainty, it does not address the margin of error inherent in the CALPUFF models formulation." *Supplement Comments from Domtar*, Dkt. EPA-R06-OAR-2015-0189-0170 (Aug. 7, 2015), at 5-1, [App.__]. That is why the Ninth Circuit in *Nat'l Parks* rejected the same argument by EPA. 788 F.3d at 1146 (Petitioner "does not ask EPA to . . . run the model using different data points than the ones selected").

EPA's third argument—that the CALPUFF-predicted gains in visibility are only one factor in the analysis—is equally unavailing. *See* 81 Fed. Reg. at 66,399. While it is true that "reasonably [] anticipated" visibility improvements make up only one of the factors, the other factors are *counterbalanced against* any reasonably-anticipated visibility improvements (of which there are none here). *See* 42 U.S.C. § 7491(g)(2) (listing other BART factors as "the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source"); *see also Nebraska v. EPA*, 812 F.3d 662, 667 (8th Cir. 2016) (noting that all BART factors "were meant to be considered together").

Where, as here, there are no reasonably-anticipated benefits, the other factors (dealing with costs) cannot justify imposition of BART controls. *See Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 226 (2009) ("Whether it is 'reasonable' to bear a particular cost may well depend on the resulting benefits; if the only relevant factor was the feasibility of the costs, their reasonableness would be irrelevant."). Because EPA's

CALPUFF model cannot support a finding of reasonably anticipated visibility improvements, no costs can be justified.

EPA's failure to account for the margin of error is fatal to the Rule's imposition of SO_2 BART limits on Power Boiler 2. As the Clean Air Act makes clear, in order to impose BART controls, EPA must have a reasonable basis for anticipating that the controls will result in improvements in visibility at mandatory Class I areas. 42 U.S.C. § 7491(g)(2). Improvement cannot be "reasonably anticipated," however, when the output relied upon is within a model's margin of error. This is inherent in the concept of a margin of error—results within the margin are of no predictive significance and cannot support any reliable conclusion.

BART analysis requires a "sufficient factual basis" for the conclusions reached, *North Dakota v. EPA*, 730 F.3d at 761, and a "rational connection between the facts found and the choice made," *Nat'l Parks Conservation Ass'n v. EPA*, 803 F.3d 151, 166 (3d Cir. 2015) (quotation marks omitted). Where, as here, EPA's data do not logically support imposing

pollution controls, imposing those controls anyway is the very definition of arbitrary. *E.g.*, *Nebraska v. EPA*, 812 F.3d at 666.

Basing a costly emission reduction requirement on phantom visibility improvements unsupported by the CALPUFF model fails to meet the reasonably anticipated improvement standard required by 42 U.S.C. § 7491(g)(2), and as such, the EPA's action should be vacated.

CONCLUSION

For the foregoing reasons, EPA's Rule should be vacated with respect to Domtar's Power Boiler No. 2.

Dated: February 17, 2017

Respectfully submitted,

s/ Eric L. Maassen

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CERTIFICATE OF COMPLIANCE

Pursuant to Fed. R. App. P. 32(g), the undersigned hereby certifies that this brief complies with the type-volume limitation of Fed. R. App. P. 32(a)(7)(B)(i).

1. Exclusive of the exempted portions of the brief, as provided in Fed. R. App. P. 32(f), the brief contains 5,676 words.

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CERTIFICATE OF SERVICE

I hereby certify that on this 17th day of February, I caused an electronic version of the foregoing Brief of Petitioner Domtar A.W. LLC to be filed with the Clerk of the United States Court of Appeals for the Eighth Circuit by using the CM/ECF system. I certify that all participants in the case are registered CM/ECF users and that service will be accomplished by the CM/ECF system.

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No. 16-4298, 16-4300, 16-4304, 17-1283 (Consolidated with 16-4270)

IN THE UNITED STATES COURT OF APPEALS
FOR THE EIGHTH CIRCUIT

NO. 16-4270
STATE OF ARKANSAS, ET AL., Petitioners,
v.
U.S. EPA, and GINA MCCARTHY, Administrator, Respondents.

NO. 16-4298
ENTERGY ARKANSAS INC., ET AL., Petitioners,
v.
U.S. EPA, and GINA MCCARTHY, Administrator, Respondents.

NO. 16-4300
ARKANSAS ELECTRIC COOPERATIVE CORPORATION, Petitioner,
v.
U.S. EPA, and GINA MCCARTHY, Administrator, Respondents.

NO. 16-4304
ENERGY AND ENVIRONMENTAL ALLIANCE OF ARKANSAS, Petitioner,
v.
U.S. EPA, and GINA MCCARTHY, Administrator, Respondents.

NO. 17-1283
ENTERGY ARKANSAS INC., ET AL., Petitioners,
v.
U.S. EPA, and CATHERINE MCCABE, Acting Administrator, Respondents.

On Petition for Review of an Action of the
United States Environmental Protection Agency

BRIEF OF AMICUS CURIAE EDISON ELECTRIC INSTITUTE IN SUPPORT OF STATE OF ARKANSAS' PETITION TO VACATE FEDERAL IMPLEMENTATION PLAN

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RULE 26.1 AND 29(c) DISCLOSURES OF EDISON ELECTRIC INSTITUTE

Pursuant to Rules 26.1 and 29(c)(1) of the Federal Rules of Appellate Procedure, proposed *amicus curiae* Edison Electric Institute states that it has no parent corporation and that no publicly held corporation owns 10% or more of its stock.

Pursuant to Fed. R. App. P. 29(c)(5), *amicus curiae* states that no party or party's counsel authored this brief in whole or in part, and that no other person besides *amicus* or its counsel contributed money that was intended to fund preparing or submitting the brief.

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U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program* 1–2 (June 1, 2007) 3

INTEREST OF AMICUS CURIAE

The Edison Electric Institute ("EEI") is an association representing all investor-owned electric companies in the United States. EEI members provide electricity for more than 220 million Americans, operate throughout the nation, and directly employ nearly 500,000 workers. Collectively, EEI members invest more than $100 billion each year in maintaining and enhancing our nation's electric infrastructure. Safe, reliable, affordable, and clean electricity powers the economy and enhances the lives of all Americans.

EEI has a strong interest in the implementation of the Regional Haze Program and in maintaining environmental progress. EEI members are subject to requirements imposed through the Regional Haze program, including regarding the installation of Best Available Retrofit Technology ("BART"). Two member companies are subject to the challenged final rule; one of those will also be subject to additional emission controls based on the United States Environmental Protection Agency's ("EPA" or "Agency") determination of requirements related to the achievement of "reasonable progress" in addressing visibility.

Since 1990, EEI member companies have reduced visibility-related emissions for sulfur dioxide and nitrogen oxides by 86 and 79 percent, respectively. This effort continues as companies invest in the national transition to cleaner and more efficient energy sources. Because EEI has worked directly with

member companies in addressing regional haze issues over the past decade, EEI believes it can provide the Court a comprehensive, nationwide perspective that will be helpful to the Court. Because the Regional Haze Program will be implemented over at least the next five decades, EEI is also deeply interested in consistent application of the law and associated regulations as the Program moves forward.

This proposed amicus brief is accompanied by a motion seeking leave of the Court for filing, which if granted will authorize its filing pursuant to Fed. R. App. P. 29(a)(2).

SUMMARY OF ARGUMENT

Under the Clean Air Act ("CAA" or "Act"), EPA must provide "guidelines to the States" requiring that state implementation plans ("SIPs") "contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal [of preventing any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas]." CAA §§ 169A(a)(1), (b)(2), 42 U.S.C. § 7491(a)(1), (b)(2). This requirement to "make reasonable progress" originated in the 1977 CAA Amendments. *See* Pub. L. No. 95-95, § 406(d), 91 Stat. 685, 743 (1977).

Congress has not amended CAA § 169A, 42 U.S.C. § 7491,[1] in four decades. EPA has also not redefined, in regulation, what it means for a State to "make reasonable progress" since the Agency defined, in 1999, the metrics and timeframe for meeting natural visibility conditions by the year 2064. *See* 40 C.F.R. § 51.308(b)(1). Nor has EPA issued new guidance contradicting or qualifying its previous 2007 guidance that reasonable progress goals are "interim goals that represent incremental visibility improvement over time toward the goal of natural background conditions ...."[2]

In this case, EPA has departed from both the text of the Act and its own regulations and guidance without explanation when it considered the elements of Arkansas' SIP addressing visibility. Instead of measuring reasonable progress in terms of the State's overall measured improvement in achieving natural visibility conditions, as the statute, regulations, and guidance provide, EPA focused on emission reductions from an individual source. In doing so, EPA turned the statutory and regulatory scheme on its head, imposing emission control requirements on an individual source even though those controls were not

[1] Unless otherwise stated, all citations to the U.S. Code in this brief are to Title 42.
[2] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, 1–2 (June 1, 2007).

necessary for the State's SIP to achieve reasonable progress toward natural visibility. This is clear error for three reasons.

First, under the CAA, a SIP must address reasonable progress *as a whole*, through adoption of "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal [of preventing future and remedying existing visibility impairment in class I areas resulting from manmade air pollution.]" § 7491(a)(1), (b)(2). Neither the statute nor the regulations place this burden on any one source in a State, no matter how large or significant its contributions. States may, in their SIPs, choose which sources to regulate and how to regulate them, so long as they show they are making the required reasonable progress. In determining Arkansas' SIP was deficient because it did not require what EPA considered to be cost-effective reductions from a single source that EPA itself identified, EPA subverted this critical aspect of the regional haze program. EPA made this determination even though Arkansas' SIP, as a whole, showed it was in fact achieving improvements in visibility *exceeding* those needed to meet the national goal — in other words, even though the SIP was making "reasonable progress" as that term has long been understood.

Second, EPA's promulgation of a federal plan replacing parts of the Arkansas SIP is directly contradictory to its implementation and interpretation of

reasonable progress for other States. While EPA has allowed other States as many as 296 years to reach natural visibility, EPA insisted Arkansas reach the same goal in 48 years. This is arbitrary and capricious. It also violates longstanding EPA regulations requiring consistent interpretation and application of the Act across Regions.

Third, EPA's federal plan is impermissible because it imposes unnecessary controls on point sources in Arkansas while utterly ignoring the impact of emissions from *other* sources and source categories as required by law. EPA failed to conduct a sufficient analysis considering *all* sources of manmade pollution. Thus, the federal implementation plan ("FIP") EPA promulgated is contrary to statute and arbitrary and capricious.

This Court should vacate the final rule, remanding it to EPA for further action consistent with the CAA and EPA's own regulations.

ARGUMENT

I. EPA'S INTERPRETATION OF "REASONABLE PROGRESS" IS CONTRARY TO THE CLEAN AIR ACT AND APPLICABLE REGULATIONS

A. EPA'S INTERPRETATION OF "REASONABLE PROGRESS," AS EMBODIED IN THE FEDERAL PLAN FOR ARKANSAS, IS CONTRARY TO THE STATUTE.

The statutory term "reasonable progress" operates as a metric for measuring a *State's* overall progress toward the goal of natural visibility in Class I areas. It was never intended to serve as a criterion applicable to the emissions of a *single*

source. A review of the statute's history confirms this and demonstrates the unlawfulness of EPA's actions with regard to Arkansas. Even where a source might be large or significant in comparison to other similar sources, reasonable progress is focused on addressing all "manmade air pollution," not individual sources or groups of sources.

In the 1977 amendments to the CAA Congress declared, as a "national goal," "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." Pub. L. No. 95-95, §406(d), 91 Stat. 685, 742 (1977); § 7491(a)(1). The statute required that EPA promulgate regulations to "provide guidelines to the States … on appropriate techniques and methods" for addressing visibility impairment. § 7491(b)(1). These techniques and methods were then to be addressed in "each applicable implementation plan for a State in which any [mandatory class I Federal area] listed by the Administrator is located." § 7491(b)(2). Such plans were to "contain such emission limits, schedules of compliance and other measures as may be necessary to *make reasonable progress towards meeting the national goal . . . .*" *Id.* (emphasis added).

Congress did not specify in section 169A what particular actions any State must take or any specific sources that a State must regulate. Rather, Congress chose only to define what States must consider in determining *how* to achieve

reasonable progress, specifying that, "in determining reasonable progress there shall be taken into consideration the costs of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements." § 7491(g)(1). Thus, the choice of which sources to regulate to achieve the mandated "reasonable progress" was explicitly left to the individual States.

In 1990 Congress substantially amended the CAA, adding several new programs to control emissions from mobile and stationary sources, including requirements for new light-duty vehicle standards, standards addressing hazardous air pollutants, the acid rain program to control emissions of sulfur dioxide ("SO_2") and nitrous oxides ("NO_x") from electric generating units, and measures to address stratospheric ozone depletion. Pub. L. No. 101-549, 104 Stat. 2399 (1990). Congress also included an additional visibility section (169B) in the CAA, but it conspicuously left section 169A untouched.

Pursuant to the new visibility provisions in §169B, EPA was required to conduct studies regarding visibility impairment; Congress authorized $8 million dollars per year for these studies. § 7492(a). Then, after taking into consideration both the new visibility studies and other reports issued by visibility transport commissions (separately required under § 7492(d)(2)), EPA was directed to

promulgate regulations "to carry out the Administrator's regulatory responsibilities [under §169A], including criteria for measuring 'reasonable progress' toward the national goal." § 7492(e)(1).

Therefore, while nothing in the 1990 amendments altered the basic statutory construct of reasonable progress, measuring what constituted reasonable progress was to be addressed through additional regional haze regulations that took into account new information and the work of newly-required visibility transport commissions. Once this was done, States were required to revise their implementation plans "to address any emission limits, schedules of compliance and other measures as necessary to carry out the [new] regulations . . . ." § 7492(e)(2).

In its final rule imposing a FIP on Arkansas, EPA asserts that decisions "regarding the *controls* required to make reasonable progress and the establishment of the [reasonable progress goal] must be based on the [four] factors identified in [ ] CAA section 169A(g)(1) . . . ." 81 *Fed. Reg.* 66,331, 66,360 (Sept. 27, 2016). To support its preferred outcome with respect to what controls must be applied to an *individual* Arkansas electric generating facility, EPA illogically claims § 7491(b)(2) must "take into account other, more explicit, statutory *and regulatory* language" contained in § 7491(g)(1) and EPA's implementing regulations, 40 C.F.R. § 51.308(d)(1)(i)(A). *See* 81 *Fed. Reg.* at 66,360 (emphasis added).

We note, first, that this turns basic jurisprudence upside down. Statutory language does not need to "take into account" regulatory language; the latter derives from the former, and not the other way around. Simply, that is not how any of this works.

Further, and as explained above, that is also *not* what § 7491(g)(1) provides — that definitional section merely states that, in determining whether it is making reasonable progress overall, a State must consider the four identified factors. At no point does the text of § 7491(g)(1) require that the four factors applicable to a State's progress toward natural visibility be applied to any individual source or specifically to the determination of control technology. The actual *requirement* for which controls and other measures must be included in a state plan resides elsewhere — specifically, in § 7491(b)(2), which only requires that a State plan include such "emission limits, schedules of compliance and other measures *as may be necessary* to *make reasonable progress* toward meeting the national goal ….." (Emphasis added).

EPA presupposes that controls on an individual source will be necessary to ensure that reasonable progress goals are being met. However, the clear reading of "reasonable progress" is that it does not define the regulatory requirements that apply to any particular source located in a State. Rather, it is the yardstick by which SIPs are measured to determine whether the *entire plan* is sufficient to

ensure that the State will eventually achieve air quality representing natural conditions. As the Tenth Circuit noted, "Neither the Clean Air Act nor the Regional Haze Rule requires source-specific analysis in the determination of reasonable progress goals." *Wildearth Guardians v. EPA*, 770 F.3d 919, 944 (10th Cir. 2014).

That the factors informing "reasonable progress" in § 7491(b)(1) are not standard-setting factors that explicitly require *controls* on individual sources is readily apparent when § 7491 is compared to other standard-setting provisions of the CAA.[3] For example, EPA must take similar factors (*e.g.*, cost, nonair quality impacts) into account when setting hazardous air pollutant standards under CAA §112. *See* § 7412. But the standard-setting criteria in section 112 are clearly identified as such. *See* § 7412(d)(2) (specifying that, in setting emission standards, EPA shall "tak[e] into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements). In contrast, § 7491(b)(2) and (g)(1) lack *any* such context or direction in relation to the emissions of a particular controlled source. Compare relevant text from the two provisions below:

[3] This is because "Congress legislates with knowledge of … basic rules of statutory construction." *McNary v. Haitian Refugee Ctr.*, 498 U.S. 479, 496 (1991).

Hazardous Air Pollutant Standards § 7412(d)(2)	Requirements for Reasonable Progress § 7491(b)(2), (g)(1)
Emission standards ... applicable to new and existing sources of hazardous air pollutants shall require the maximum degree of emission reduction in emissions of the hazardous air pollutants subject to this section … that the Administrator, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is *achievable for new or existing sources in the category or subcategory to which such emission standard applies*, through application of measures, processes, methods, systems or techniques ….	Regulations … shall … *require each applicable implementation plan …* to contain such emission limits, schedules of compliance and other measures as may be *necessary to make reasonable progress* toward meeting the national goal …. *** [I]n determining reasonable progress there shall be taken into consideration the costs of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements….

An emission standard promulgated under § 7412 establishes an express limit on the operation of any source governed by that standard, providing a bright line between acceptable and unacceptable levels of emissions. "Reasonable progress" is another thing altogether. It does not establish any such source-specific emission limits, and EPA itself concedes that reasonable progress goals "are not enforceable." 81 *Fed. Reg.* at 66,362 ("The [reasonable progress goals] are intended to provide a degree of transparency regarding the rate of improvement in visibility anticipated for each Class I area over the planning period of the SIP. But the RPGs themselves are not enforceable."). EPA cannot have it both ways. If

reasonable progress goals are not directly enforceable,[4] they cannot therefore result in a binding emission limitation on an individual source.

Instead, under the Regional Haze program, a *State* is permitted to choose which sources to control, and how, so long as the State is achieving reasonable progress toward the natural visibility goal over the long term. And, as discussed below in Section B.1, EPA has provided a measurement tool known as the "uniform rate of progress" to assess the rate of progress being made by a SIP.

B. EPA'S INTERPRETATION OF "REASONABLE PROGRESS" IS CONTRARY TO ITS OWN REGULATIONS.

When EPA rejected parts of Arkansas' SIP in 2012, leading to its proposal and finalization of the federal plan at issue here, EPA failed to follow its own regulations in determining reasonable progress. Specifically, EPA elevated the *fourth* step of its required regulatory analysis — consideration of the four statutory factors in § 7491(g)(1) that define "reasonable progress" — to the *first* step in the methodical process it established by regulation in 1999. This fundamentally changed the nature of EPA's regulatory inquiry: rather than leading to a reasoned source-specific standard developed after EPA examined reasonable progress goals for Arkansas and the required rate of progress, EPA's approach resulted in the imposition of an ad hoc and unlawful emission limit on at least one source affected

[4] *See* 40 C.F.R. § 51.308(d)(1)(v).

by the rule — Entergy's Independence facility — without regard to whether the State was making reasonable progress toward the statutory visibility goal without that emission limit.

1. REGULATORY BACKGROUND

Some background may be helpful in understanding how EPA wandered so far astray from its own regulatory construct.

In 1980, following two more limited rulemakings to designate class I areas and identify the States to which the new visibility program would apply,[5] EPA promulgated the state guidelines required by 1977 amendments. *See* Visibility Protection for Federal Class I Areas, 45 *Fed. Reg.* 80,084 (Dec. 2, 1980). These regulations were designed "to assure reasonable progress toward" meeting the national visibility goal. *Id.* at 80,086. To that end, EPA declared that "responsibility for developing the program and making any substantive decisions will lie with the thirty-six States which contain mandatory Class I Federal areas." *Id.* at 80,084.

The 1980 regulations provided the basic framework of the visibility impairment program. They included definitions for various regulatory terms (40 C.F.R. § 51.301), required the submission of SIP revisions, and specified the basic provisions of such plans (*Id.* § 51.302). They also included provisions for source

[5] *See* 43 *Fed. Reg.* 7,721 (Feb. 24, 1978); 44 *Fed. Reg.* 69,122 (Nov. 30, 1979).

exceptions (*Id.* § 51.303), the identification of "integral vistas" and visibility monitoring requirements (*Id.* § 51.304), long-term strategies (*Id.* § 51.305), and for the review of new sources in areas in attainment or unclassified for national ambient air quality standards. (*Id.* § 51.307).[6]

Following the 1990 CAA Amendments, EPA was required to conduct additional studies and to "carry out the Administrator's regulatory responsibilities under [§ 7491], including criteria for measuring 'reasonable progress' toward the national goal." § 7492(e)(1). Therefore, after citing congressional "concern with 'hazes' and the potential corresponding need to control a 'variety of sources' and 'regionally distributed sources,'" EPA proposed additional regulations for what EPA now termed the "Regional Haze Program." 62 *Fed. Reg.* 41,138, 41,139 (July 31, 1997). EPA issued final rules for the program two years later. 64 *Fed. Reg.* 35,714 (July 1, 1999).

The 1999 rules both amended previous regulatory requirements and added two new sections to the existing regulations, 40 C.F.R. §§ 51.308, 51.309. Section 51.308 contains requirements for SIPS, plan revisions, and periodic progress

[6] EPA, however, deferred setting national rules, *i.e.*, requiring States that did not contain mandatory class I federal areas to address visibility, until "improvement in monitoring techniques provides more data on source-specific levels of visibility impairment, regional scale models become refined, and our scientific knowledge about the relationships between emitted air pollutants and visibility impairment improves. 64 *Fed. Reg.* 35,714, 35,717 (July 1, 1999) (referencing 45 *Fed. Reg.* 80,086).

reviews. Section 51.309 contained requirements related to the 16 Class I areas covered by the Grand Canyon Visibility Transport Commission, established by the 1990 amendments. *See* § 7492(f).

With regard to requirements related to reasonable progress, however, EPA maintained the yardstick by which it measured SIPs under the 1997 regulations. EPA stated that "[t]he final rule maintains the deciview as the principle [sic] visibility metric used in establishing reasonable progress goals, in defining baseline, current, and natural conditions, and in tracking changes in visibility conditions over time." 64 *Fed. Reg.* at 35,727. A deciview was defined as "a haze index derived from calculated light extinction, such that uniform changes in haziness corresponding to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired." 40 C.F.R. § 51.301. EPA also provided for its mathematical calculation. *Id.*

EPA further required States to establish ambitious "reasonable progress goals" measured in deciviews. 40 C.F.R. § 51.308(d)(1). Critically, these were to be "aimed at reaching natural background conditions in 60 years." 64 *Fed. Reg.* 35,731. In establishing this 60-year goal, EPA rejected comments arguing that 200 years should be allowed to reach such conditions. *Id.* Instead, EPA considered emission reductions that would be achieved through programs required by the CAA amendments of 1990 over the next 10 to 20 years. EPA stated that

"reductions from these and other CAA programs will result in a rate of improvement of approximately 3 deciviews over the period from the mid-1990's to about 2005." *Id.* "EPA calculated that if this rate of improvement could be sustained, these areas would reach the national goal in 60 years." *Id.*

Based on this analysis, EPA first required States to compare baseline visibility conditions in the years 2000–2004 (in deciviews) and then "determine the amount of progress needed to reach natural background conditions in 60 years, that is, by the end of 2064." *Id.* at 35,732. Next, EPA required States to identify a "uniform rate of progress over the 60-year period that would be needed to attain natural background conditions by the year 2064." *Id.* Third, each State was to determine the amount of progress that would result in the first 10-year implementation period for the Regional Haze program if this rate of progress could be achieved for each year, "or 0.3 deciviews for a year." *Id.* Finally, each State was to identify and analyze "the emissions measures that would be needed to achieve this amount of progress during the period covered by the first long-term strategy." *Id.* It was only at this last step that EPA directed the States to consider the four statutory factors contained in the "reasonable progress" definitional subsection, codified at § 7491(g)(1).

2. EPA REGULATIONS PROVIDE FOR A 60-YEAR GLIDEPATH FOR SIPS OVERALL, NOT AD HOC DECISIONS ON INDIVIDUAL SOURCE CONTROLS

As noted above, EPA's elevation of this last step — consideration of the four statutory factors contained in the "reasonable progress" definition — to the first and functionally most important step in determining source controls for sources within Arkansas is not just a ministerial or harmless error. Reasonable progress goals are a "core requirement for the implementation plan for regional haze." 40 C.F.R. § 51.308(d). When EPA promulgates a FIP, it "stands in the shoes of the state." 81 *Fed. Reg.* at 66,360. But in promulgating a FIP for Arkansas, EPA did not act as it specifically directs States to act in its own regulations. Instead, EPA flipped the process it described in its 1999 rules on its head and determined, after analyzing the statutory factors for determining reasonable progress, "there [were] *reasonable controls* available for Independence that would be *cost-effective* and would result in *meaningful visibility benefit* at Arkansas' Class I areas." *Id.* at 66,361 (emphasis added).

In other words, EPA made no inquiry as to the rate of progress needed for Arkansas to make reasonable progress toward meeting natural visibility conditions at Arkansas Class I areas, nor did EPA consider how far the State had already come in the 60-year journey towards natural conditions. Rather, EPA made a determination to require individual source controls *without assessing whether those*

controls were necessary to address visibility. EPA employed the upside down logic of the Queen of Hearts: "sentence first — verdict afterwards."[7]

Each part of EPA's analysis conflicts directly with longstanding regulatory requirements. First, the four statutory factors identified in § 7491(g)(1) are explicitly for the determination of reasonable progress, *not* reasonable controls. 40 C.F.R. § 51.308(d)(1)(i)(A) directs that the factors are to be "taken into consideration in selecting the [reasonable progress] goal" for any mandatory Class I Federal area within a State.

Second, whether controls might be cost-effective for a specific source is not at issue in determining what constitutes "reasonable progress" under a SIP. Cost-effectiveness is to be assessed with respect to the reasonable progress goal as contained in the SIP. *Id.* As a "core requirement" of SIP provisions to address regional haze, reasonable progress is to be assessed along with the calculation of baseline and natural visibility conditions (*Id.* § 51.308(d)(2)), a long-term strategy for regional haze (*Id.* § 51.308(d)(3)), and a monitoring strategy and other implementation plan requirements (*Id.* § 51.208(d)(4)).

Finally, EPA cannot force regulation of an individual source simply because regulating it may obtain a "meaningful visibility benefit," the standard EPA

[7] LEWIS CARROLL, ALICE'S ADVENTURES IN WONDERLAND 146 (Random House 1946).

applied in determining the specific emission limits EPA would apply to the Independence facility. *See* 81 *Fed. Reg.* at 66,351–52 ("Based on our reasonable progress analysis . . . SO_2 and NO_x controls at Independence would be cost-effective and would result in meaningful visibility benefits.... [W]e determined that SO_2 and NO_x controls at Independence would be cost effective and would result in meaningful visibility benefits…. Together, the modeling results … demonstrate that controls will provide meaningful visibility benefits toward the goal of natural visibility conditions.").

The term "meaningful visibility benefit" is not a term of art, and it appears nowhere within 40 C.F.R. Part 51, Subpart P, which contains *every single one* of the regulatory requirements for the Regional Haze Program. EPA's use of this benefit as a means to determine the proper level of controls for an individual source is thus unsupported by the regional haze regulations, completely divorced from whether or not the State is making what constitutes reasonable progress, and is inherently arbitrary and capricious. "The court must decide whether the agency considered the relevant factors and whether there has been a clear error in judgement." *Nat. Res. Def. Council, Inc. v. EPA*, 966 F.2d 1292 (9th Cir. 1992) (citing *Citizens to Preserve Overton Park, Inc. v. Volpe*, 401 U.S. 402, 416 (1971)). Here, EPA has patently strayed far afield from the factors the statute and EPA's own regulations specify. The FIP must be vacated.

C. EPA MISCHARACTERIZES THE RELEVANCE OF ARKANSAS' UNIFORM RATE OF PROGRESS.

EPA expends considerable space in the final rule reinterpreting its own regulations requiring States to establish a "uniform rate of visibility improvement." In the process, it makes this requirement meaningless. In determining reasonable progress, however, EPA's regulations expressly require States to "[a]nalyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064." 40 C.F.R. § 51.308(d)(1)(i)(A)–(B). While the four statutory factors in § 7491(g)(1) are required to be "taken into consideration in selecting the [reasonable progress] goal," States "*must consider the uniform rate of improvement* in visibility and the emission reduction measures needed to achieve it for the period covered by the implementation plan." 40 C.F.R. § 51.308(d)(1)(i)(A)–(B) (emphasis added).

EPA, however, suggests that since it "determined that there are reasonable controls available for Independence that would be cost-effective and would result in meaningful visibility benefit," it is required to adopt such controls for that source *even though they are greater than needed to attain a uniform rate of progress*.[8] But such an interpretation of EPA's regulations would render the State's

[8] EPA's own analysis shows that "Arkansas Class I areas and those outside of Arkansas most significantly impacted by Arkansas sources are projected to meet
(Continued...)

calculation of a uniform rate of progress moot anytime EPA believed that imposing controls on any source would be "cost-effective" and provide any level of "meaningful visibility benefit."

This criterion fails for two reasons. First, it is contrary to both the statute and EPA's own regulations. Second, even if it were somehow allowed under some reading of the two, it is arbitrary and capricious because EPA has nowhere defined what would comprise a "meaningful" visibility benefit. The standard EPA relies upon is therefore essentially standardless.

II. EPA'S FIP FOR ARKANSAS IS INCONSISTENT WITH IMPLEMENTATION OF THE REGIONAL HAZE PROGRAM IN OTHER STATES

Prior to promulgating the challenged federal plan for Arkansas, EPA reviewed the regional haze SIPs of several other States, including a SIP Arizona submitted. In that case, EPA determined it was *unreasonable* "to provide for rates of progress at Arizona's 12 Class I areas that would attain natural visibility conditions by 2064 (*i.e.,* the [uniform rate of progress])." 79 *Fed. Reg.* 52,420, 52,423 (Sept. 3, 2014). EPA thus rejected portions of the Arizona SIP and promulgated a FIP that provided a "significantly shorter time period to reach natural visibility conditions at each of Arizona's Class I areas . . ." *Id.* at 52,426.

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the [uniform rate of progress] for the first planning period." 80 *Fed. Reg.* 18,944, 18,992 (Apr. 8, 2015).

But in doing so, it is notable *just how long* a period EPA has allowed for Arizona to reach natural conditions. According to EPA's FIP and the reasonable progress goals for the class I areas considered, the years needed to reach natural conditions will vary from a low of 101 years to a high of 367 years. *Id.* at 52,469.

EPA also previously approved reasonable progress goals for California that would not result in meeting natural background concentrations there until well into the 2100s and beyond: in the case of the Desolation Wilderness Area, not until 2307; Yosemite National Park, not until 2160; and the Ansel Adams Wilderness Area, not until 2200. *Id.* (referencing 76 *Fed. Reg.* 13,944, 13,951 (Mar. 15, 2011)). And, when EPA similarly considered what reasonable progress goals should be implemented by Texas, the Agency proposed goals that would allow for the achievement of natural visibility conditions on the 20% worst days at affected mandatory Federal class I areas in the State — the Big Bend Wilderness area and the Guadalupe Mountains — in 194 years and 159 years, respectively.[9]

This treatment of regional progress goals in three other States, all completed within the past few years, diverges wildly from EPA's projection that the reasonable progress goals it will impose on Arkansas through its SIP will achieve natural visibility conditions by 2064, *i.e.*, within 49 years.

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[9] Arkansas Department of Environmental Quality comments on EPA's proposed FIP, Docket No. EPA-R06-OAR-2015-0189, at 21 (July 15, 2015) (referencing 79 *Fed. Reg.* 74,853, 74,887 (Dec. 16, 2014)).

EPA reaches such disparate conclusions regarding what constitutes "reasonable progress" — and promulgates such disparate results in final rules—by employing a seriously flawed methodology to measure reasonable progress that lacks a basis in either the statute or EPA's regulations. Specifically, while EPA claims it complied with the requirements of the CAA and 40 C.F.R. § 51.308(d)(1)(i)(A) in conducting its reasonable progress analysis, *see* 81 *Fed. Reg.* at 66,351, it is abundantly clear from the record that EPA back-calculated reasonable progress for Arkansas through directly considering source controls first and reasonable progress in improving visibility only as a mathematical calculation based on the imposition of source controls. Specifically:

1) EPA focused on point sources that contributed from 0.29% to 3.58% of total light extinction to the affected Arkansas class I areas (Caney Creek and Upper Buffalo) on the 20% worst days in 2018. 81 *Fed. Reg.* at 66,350.

2) From this limited group of identified sources, EPA selected a non-BART source (the Entergy Independence facility) on the basis that it represented 36% of SO_2 point-source emissions and 21% of NO_x emissions *from this group of sources*. *Id.*

3) EPA determined that reductions in SO_2 emissions from the Independence plant were likely to be "cost-effective" because the facility was "nearly identical" to a BART source, White Bluff. 80 *Fed. Reg.* at 18,991.

4) EPA selected specific control measures for the Independence facility on the basis of this cost-effectiveness analysis[10] and then determined what was "reasonable progress" based on the imposition of these controls.

EPA did not articulate *why* it addressed reasonable progress so differently in Arkansas than in these other States. Instead, EPA only compared the cost-effectiveness of controls measures in Arkansas in comparison with other States, indicating that installing pollution control equipment at Independence "far exceeds the cost-effectiveness standards reviewed and approved by EPA for the Kentucky and North Carolina Regional Haze [SIPs]." 81 *Fed. Reg.* at 66,368.

But a review of these decisions indicates that in Arizona, EPA proposed "non-quantified [reasonable progress goals]" and "explained that '[w]hile we would prefer to quantify these proposed [reasonable progress goals] for each of Arizona's 12 Class I areas based on the new State and Federal plans, we lack sufficient time and resources to conduct the type of regional-scale modeling required to develop such numerical [reasonable progress goals]."[11] In California, EPA accepted that "given strenuous efforts needed in California to achieve the emission reductions [to reach natural visibility] and the constraints and

[10] In its proposed rule, EPA estimated that installation of control technology at two generating units at the Entergy Independence facility would yield SO_2 reductions at a cost of $2,477 and $2,286 per ton. 80 *Fed. Reg.* at 18,992. These estimates were slightly changed in the final rule.
[11] 79 *Fed. Reg.* at 52,468 (referencing EPA's proposed FIP for Arizona, 79 *Fed. Reg.* 9,318, 9,363 (Feb. 18, 2014)).

uncertainties described … we believe it would be unreasonable to require the [California Regional Haze Plan] to meet the 2018 [uniform rate of progress] estimates." 76 *Fed. Reg.* 13,944, 13,958 (Mar. 15, 2011).

Where an Agency implements regulatory requirements on a different basis in different States with different methodologies yielding widely different results — a 49-year reasonable progress goal in Arkansas, a 194-year goal in Texas, and a nearly three-century-long goal in California — there is not "a rational connection between facts found and the choice made." *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quotation marks omitted).

Moreover, EPA's inconsistent application of § 7491 and EPA's Regional Haze regulations in the various States violates EPA's own "regional consistency" regulations, which require that EPA's Regional Offices "assure that actions taken under the [CAA]…[a]re as consistent as reasonably possible with the activities of the other Regional Offices…." 40 C.F.R. § 56.5(a)(2). There is simply no way that the wildly disparate "reasonable progress" goals EPA approved for Arkansas, California, Arizona, and Texas can be squared with one another. EPA's FIP for Arkansas must be vacated.

III. DESPITE A STATUTORY DUTY TO DO SO, EPA FAILED TO ADEQUATELY CONSIDER NON-POINT SOURCES

The Regional Haze Program is not a program directed at controlling emissions from electric generating units to the exclusion of all other stationary or

point sources. Neither is it a program directed at controlling emissions from stationary or point sources to the exclusion of all other possible sources. Instead, it is a program broadly directed to address visibility impairment that "results from manmade air pollution," no matter the source. § 7491(a)(1). As Congress clearly stated, "[m]anmade air pollution" is that which "results directly or indirectly from human activities." § 7491(g)(3).

Congress directed EPA to assess "sources of visibility impairing pollution and clean air corridors." § 7492(a)(1)(B). EPA was required to assess and evaluate "sources and source regions of visibility impairment, including natural sources as well as source regions of clean air for class I areas." § 7492(a)(2). And EPA was additionally required to assess progress "likely to result from the implementation of the Clean Air Act Amendments of 1990" apart from the visibility provisions of the Act. § 7492(b). As noted *supra*, Section I.A., the requirements of the 1990 amendments were not limited to point sources, but address various mobile sources and other pollutants that can be emitted from products like paint, solvents and other "fugitive" emissions.

Pursuant to amendments made to the CAA in 1990, only after taking account of air quality studies of "sources of visibility impairing pollution" and other research including monitoring, regional air quality models, and the atmospheric chemistry and physics of visibility, was EPA to "carry out the Administrator's

regulatory responsibilities under [§ 7491], including criteria for measuring 'reasonable progress' toward the national goal." § 7492(e)(1).

EPA initially made clear that attaining the national visibility goal and achieving reasonable progress is not targeted at any one group of sources. In 1999, EPA explained that there were "several overarching themes for the specific implementation plan requirements in the final [Regional Haze Rule]." 64 *Fed. Reg.* at 35,727. Among these overarching themes was that "[s]trategies for improving visibility should address all types of sources," while implementation plans were to give "specific attention to certain stationary sources built between 1962 and 1977 [*i.e.*, BART sources] . . . ." *Id.* at 35,728.

In the Arkansas FIP, however, EPA demurred on making such a wide-ranging assessment of the contribution of sources to visibility issues for the Caney Creek and Upper Buffalo Class I areas. Instead, EPA stated that

> [d]evelopment of refined numerical [reasonable progress goals] for Arkansas' Class I areas would require photochemical grid modeling of a multistate area, involving thousands of emission sources, unlike the comparatively simple single-source CALPUFF modeling used for individual BART assessments. In order to accurately reflect all emissions reductions expected to occur during this planning period, the new photochemical modeling would require an update on the emissions inventory for Arkansas and the surrounding states to include not just the actions under this FIP, but all EPA and state regulatory actions on point, area, and mobile sources. After the inventory is developed and reviewed by the affected states for accuracy, it must be converted to model-ready format before air quality modeling can be used to estimate the future visibility levels at the Class I area. The modeling would

> require specialized and extensive computing hardware and expertise. Developing all of the necessary input files, running the photochemical model, and post-processing the model outputs would take several months at a minimum. Therefore, we are not conducting new photochemical grid modeling to establish revised [reasonable progress goals] for Caney Creek and Upper Buffalo.

80 *Fed. Reg.* at 18,997.

Instead of conducting such an analysis and calculating reasonable progress goals on the basis of fulsome inputs, EPA "scaled the modeled visibility extinction components for sulfate (SO_4) and nitrate (NO_3) from point sources in Arkansas in proportion to the FIP's emission reductions for SO_2 and NO_x, respectively." *Id.* Such a truncated analysis does not comport with the specific analytical components contained in § 7492 outlined above.

In responding to comments in this area, EPA indicated that "[w]hile we agree that Arkansas mobile and area sources have visibility impacts in Arkansas' Class I areas, we disagree that Arkansas point sources do not. Our analysis of the CENRAP 2018 CAMx photochemical modeling showed that on the 20% worst days, Arkansas point sources contribute significantly to visibility impairment at Arkansas' Class I areas (greater than 4% of total visibility impairment at each Arkansas Class I area)."[12] But the fact that point sources have visibility impacts does not excuse EPA from its express statutory burden to address *all* sources of

[12] Response to Comments at 146.

manmade air pollution and visibility impairment in determining how to achieve reasonable progress toward natural visibility. Simply noting that point sources have an impact does not allow EPA to regulate them to the exclusion of all other emissions sources.

By not directly considering mobile sources when establishing a required level of reasonable progress in Arkansas, EPA has "entirely failed to consider an important aspect of the problem." *State Farm*, 463 U.S. at 43. Its FIP is thus unlawful, and it must be set aside.

CONCLUSION

For the reasons stated here, as well as for those in petitioners' briefs, EPA's federal implementation plan addressing Arkansas' compliance with the Regional Haze program must be vacated.

Date: February 24, 2017

Respectfully submitted,

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CERTIFICATE OF COMPLIANCE

I hereby certify that the foregoing Brief *Amicus Curiae* of Edison Electric Institute complies with the type-volume limitation of Fed. R. App. P. 29(a)(5) because it contains 6,499 words, excluding the parts of the brief exempted by Fed. R. App. P. 32(f). This Brief complies with the typeface requirements of Fed. R. App. P. 32(a)(5) and the type style requirements of Fed. R. App. P. 32(a)(6) because the Brief has been prepared in Times New Roman 14-point font using Microsoft Word 2010. This brief has been scanned for viruses and is virus free in compliance with 8th Cir. R. 28A(h).

Dated: February 24, 2017

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CERTIFICATE OF SERVICE

I hereby certify that on February 24, 2017, I electronically filed the foregoing with the Clerk of the United States Court of Appeals for the Eighth Circuit by using the CM/ECF system. I certify that all the participants in the case are registered CM/ECF users and that service will be accomplished by the CM/ECF system.

Dated: February 24, 2017

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No. 16-4298, 16-4300, 16-4304, 17-1283 (Consolidated with 16-4270)

IN THE UNITED STATES COURT OF APPEALS
FOR THE EIGHTH CIRCUIT

NO. 16-4270
STATE OF ARKANSAS, ET AL., Petitioners,
v.
U.S. EPA, and GINA MCCARTHY, Administrator, Respondents.

NO. 16-4298
ENTERGY ARKANSAS INC., ET AL., Petitioners,
v.
U.S. EPA, and GINA MCCARTHY, Administrator, Respondents.

NO. 16-4300
ARKANSAS ELECTRIC COOPERATIVE CORPORATION, Petitioner,
v.
U.S. EPA, and GINA MCCARTHY, Administrator, Respondents.

NO. 16-4304
ENERGY AND ENVIRONMENTAL ALLIANCE OF ARKANSAS, Petitioner,
v.
U.S. EPA, and GINA MCCARTHY, Administrator, Respondents.

17-1283
ENTERGY ARKANSAS INC., ET AL., Petitioners,
v.
U.S. EPA, and CATHERINE MCCABE, Acting Administrator, Respondents.

On Petition for Review of an Action of the
United States Environmental Protection Agency

OPENING BRIEF OF PETITIONERS ENTERGY ARKANSAS, INC., ENTERGY MISSISSIPPI, INC., ENTERGY POWER, LLC, ARKANSAS ELECTRIC COOPERATIVE CORPORATION, and ENERGY AND ENVIRONMENTAL ALLIANCE OF ARKANSAS

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SUMMARY OF THE CASE AND REQUEST FOR ORAL ARGUMENT

This consolidated appeal presents a challenge under the Clean Air Act ("CAA" or "the Act") to the U.S. Environmental Protection Agency's ("EPA" or "the Agency") final Federal Implementation Plan ("Final FIP") addressing regional haze and interstate visibility transport for Arkansas. The Regional Haze Program is concerned solely with visibility in federal Class I areas. Entergy Arkansas, Inc. ("EAI"), Entergy Mississippi, Inc. ("EMI"), Entergy Power, LLC ("EPI") (collectively, "Entergy"), Arkansas Electric Cooperative Corporation ("AECC"), and Energy and Environmental Alliance of Arkansas ("EEAA") (collectively, "Petitioners") challenge the Final FIP's sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") emissions limits for the White Bluff Electric Power Plant ("White Bluff") and the Independence Steam Electric Station ("Independence"). These limits do not comply with the CAA, are arbitrary and capricious, were improperly promulgated, and must be vacated. Petitioners also challenge EPA's failure to apply the requirements of the Cross-State Air Pollution Rule ("CSAPR") in lieu of best available retrofit technology ("BART") for eligible electric generating units ("EGUs").

Petitioners respectfully request 30 minutes for oral argument. Oral argument will assist fair consideration of the complicated legal issues and a voluminous administrative record, and will enable the parties to fully address the Court's questions and concerns.

CORPORATE DISCLOSURE STATEMENT

Pursuant to Rule 26.1 of the Federal Rules of Appellate Procedur e and Local Rule 26.1A, Petitioners make the following disclosures.

EAI has its principal place of business in Little Rock, Arkansas. EAI generates, transmits, distributes, and sells electric power to approximately 712,000 electric customers in portions of Arkansas. Entergy Corporation owns all of the common stock of EAI. No other entity with publicly -traded securities owns any common stock of EAI.

EMI has its principal place of business in Jackson, Mississippi. EMI generates, transmits, distributes, and sells electric power to approximately 447,000 electric customers in portions of Mississippi. Entergy Corporation owns all of the common stock of EMI. No other entity with publicly -traded securities owns any common stock of EAI.

EPI is a Delaware l imited liability company with its principal business office located in The Woodlands, Texas. It is an electric utility company that sells electric energy at wholesale. All of the outstanding membership interests in Entergy Power, LLC are owned by Entergy Asset Management, Inc., a Delaware corporation. No other entity or person owns any equity interests in Entergy Power, LLC. All of the capital stock of Entergy Asset Management, Inc. is owned by Entergy Power Investment Holding, Inc., the common stock of which is owned entirely by Entergy

Amalgamated Competitive Holdings, LLC. Entergy Corporation owns all of the membership interests in Entergy Amalgamated Competitive Holdings, LLC.

Entergy Corporation is a publicly traded company (symbol: ETR) incorporated in the State of Delaware, with its principal place of business in the city of New Orleans, Louisiana. Entergy Corporation does not have any parent companies that have a 10 percent (10%) or greater ownership interest. Further, there is no publicly-held company that has a 10 percent (10%) or greater ownership interest in Entergy Corporation.

AECC is an Arkansas non-profit corporation that is organized and operated as an electric cooperative. AECC supplies wholesale electricity to its 17 electric distribution cooperative members, which in turn provide electricity to approximately 500,000 consumers. No parent corporation or publicly held company owns 10 percent (10%) or more of AECC.

EEAA is an association of Arkansas electric utilities and other energy companies which advocates for sound and predictable regulation of Arkansas' utility industry and whose members are owners and operators of facilities subject to the Final FIP. No parent corporation or publicly held company owns ten percent (10%) or more of EEAA.

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GLOSSARY

ADEQ	Arkansas Department of Environmental Quality
AECC	Arkansas Electric Cooperative Corporation
AEP	American Electric Power
AFUDC	Allowance for funds used during construction
APA	Administrative Procedure Act
BART	Best Available Retrofit Technology
CAA or the Act	Clean Air Act
CENRAP	Central Regional Air Planning Association
CSAPR	Cross-State Air Pollution Rule
DSI	Dry sorbent injection
dv	Deciview
EAI	Entergy Arkansas, Inc.
EEAA	Energy and Environmental Alliance of Arkansas
EGU	electric generating unit
EMI	Entergy Mississippi, Inc.
Entergy	EAI, EMI and EPI, collectively
EPA or the Agency	U.S. Environmental Protection Agency
EPI	Entergy Power, LLC
FGD	Flue gas desulfurization technology

FIP	Federal Implementation Plan
JA	Joint Appendix
lb/mmBtu	Pounds per million British thermal units
LNB/SOFA	Low-NOx burners and separated overfire air
LTS	Long-term strategy
NOx	Nitrogen oxides
Q/D	Quantity of emissions over distance
RPG	Reasonable progress goal
SCR	Selective catalytic reduction
SIP	State Implementation Plan
SO_2	Sulfur dioxide
SWEPCO	Southwestern Electric Power Company
URP	Uniform rate of progress

JURISDICTIONAL STATEMENT

EPA published the Final FIP on September 27, 2016. 81 Fed. Reg. 66,332 (Sept. 27, 2016) (Addendum ("Add."), pp. 1 -91) (JA-___). The Petitioners filed with this Court petitions for review of the final rule on November 28, 2016, within the 60 - day period prescribed by Section 307(b)(1) of the CAA, 42 U.S.C. § 7607(b)(1), in Case Nos. 16-4298, 16-4300, and 16-4304. 42 U.S.C. § 7607(b)(1). Because the Final FIP applies only to Arkansas, this Court has jurisdiction as "the United States Court of Appeals for the appropriate circuit." *Id.*

The Petitioners filed administrative petitions for reconsideration and requests for stay of the Final FIP with EPA in November 2016. *See Administrative Petition for Reconsideration and Request for Stay of Entergy Arkansas Inc., et al.* (Nov. 23, 2016) ("Entergy Petition for Reconsideration") (JA-___); AECC, *Administrative Petition for Reconsideration and Request for Administrative Stay* (Nov. 23, 2016) ("AECC Petition for Reconsideration") (JA-___); EEAA, *Administrative Petition for Reconsideration and Request for Administrative Stays* (Nov. 28, 2016) ("EEAA Petition for Reconsideration") (JA-___). The filing of those administrative petitions did not affect the finality of the Final FIP for judicial review. 42 U.S.C. § 7607(b)(1). On or about February 1, 2017, EPA constructively denied those administrative petitions and, on February 7, 2017, Petitioners filed a joint petition for review of such constructive denial within the 60 - day period prescribed by the CAA. *Id. See* Case No. 17-1283. This was consolidated with Case No. 16-4270 on February 7, 2017.

The Petitioners or their members are co-owners and operators of the EGUs regulated by the Final FIP, including two coal-fired EGUs at White Bluff, two coal-fired EGUs at Independence, and four additional EGUs. The Final FIP establishes emissions limits for SO_2 and NOx at each coal-fired plant, which will require the installation of emission controls that cost over $2 billion. The Petitioners therefore have standing as a result of concrete and particularized injury that is fairly traceable to the Final FIP and that will be redressed by a decision that vacates the Final FIP in relevant part. *See, e.g.*, *Lujan v. Defenders of Wildlife*, 504 U.S. 555, 561-62 (1992).

STATEMENT OF ISSUES

1. Whether the BART SO_2 emissions limits for White Bluff are in excess of EPA's authority, contrary to law, and arbitrary and capricious because (a) EPA did not account for factors that the CAA requires be taken into consideration and (b) the excessive costs of controls cannot be justified in light of the imperceptible visibility improvements they will achieve.

   - 42 U.S.C. § 7491(g)(2)
   - 40 C.F.R. § 51.308(e)(1)(ii)(A)
   - *Dillmon v. NTSB*, 588 F.3d 1085, 1089-90 (D.C. Cir. 2009)
   - *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983)
   - *Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1 (D.C. Cir. 2002)

2. Whether EPA's Reasonable Progress emission limits for Independence are in excess of EPA's authority, contrary to law, and arbitrary and capricious because (1) the emissions reductions are not "necessary" or justified to achieve Reasonable Progress; (2) the limits will not achieve emissions reductions during the first planning period, as required by law; and (3) EPA unlawfully abandoned the standardized approach used in other FIPs to identify sources for a Reasonable Progress analysis.

   - 42 U.S.C. §§ 7491(b)(2) and 7601(a)(2)
   - 40 C.F.R. §§ 51.308(d)(1) and 56.3(a)-(b);

- *FCC v. Fox Television Stations, Inc.*, 129 S. Ct. 1800 (2009)
- *Michigan v. EPA*, 135 S. Ct. 2699 (2015)
- *Texas v. EPA*, 829 F.3d 405 (5th Cir. 2016)

3. Whether the White Bluff and Independence NOx requirements are unlawful because they are not logical outgrowths of the proposed FIP and they are unachievable.

    - 40 C.F.R. § 51.301
    - *CSX Transp., Inc. v. Surface Transp. Bd.,* 584 F.3d 1076 (D.C. Cir. 2009)
    - *Envtl. Integrity Project v. EPA*, 425 F.3d 992 (D.C. Cir. 2005)
    - *Nat'l Exch. Carrier Ass'n, Inc. v. FCC,* 253 F.3d 1 (D.C. Cir. 2001)
    - *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506 (D.C. Cir. 1983).

4. Whether EPA's decisi on to require BART sources to install NOx emissions controls is arbitrary and capricious and not in accordance with the law, because EPA's regulations authorize exemption of such sources from the requirement to install source-specific BART in states subject to CSAPR.

    - 40 C.F.R. § 51.308(e)

STATEMENT OF THE CASE

Section 169A of the CAA establishes a national goal of preventing future visibility impairment (*i.e.* "regional haze") and remedying existing visibility impairment caused by manmade air pollution in certain national parks, wilderness areas, and monuments (collectively defined as "Class I areas"). 42 U.S.C. § 7491(a)(1). To implement this goal, states must adopt State Implementation Plans ("SIPs") that include "emission limits, schedules of compliance and other measures *as may be necessary* to make Reasonable Progress toward meeting the national goal." 42 U.S.C. § 7491(b)(2) (emphasis added). SIPs must (1) require that certain major stationary sources meet emission limits based on BART, [1] and (2) include a long-term strategy ("LTS") for the state to make "reasonable progress" towards the national goal. 42 U.S.C. § 7491(b)(2). EPA promulgated the Regional Haze Rule in 1999 to implement section 169A. In recognition that the Regional Haze Program is intended to be implemented gradually, the Regional Haze Rule requires states to adopt SIPs that make Reasonable Progress in successive 10-year increments toward achieving natural visibility conditions in Class I areas by 2064. *See, e.g.,* 64 Fed. Reg. 35,714, 35,731 (July 1, 1999); 40 C.F.R. §§ 51.308(d), (f).

[1] BART is defined as "an emission limitation based on the degree of reduction available through the application of the best system of continuous emission reduction." 40 C.F.R. § 51.301.

Arkansas submitted its SIP to EPA in 2008 for the 2008-2018 "implementation period," with amendments submitted in 2010 and 2011. EPA partially disapproved Arkansas' SIP in 2012, 77 Fed. Reg. 14,604 (Mar. 12, 2012), triggering a two-year period for EPA to promulgate a FIP. 42 U.S.C. § 7410(c). Over three years later, EPA proposed a FIP for Arkansas. 80 Fed. Reg. 18,944 (Apr. 8, 2015) ("Proposed FIP") (JA-___). The Proposed FIP identified emission limits for six sources subject to BART, including White Bluff. It also included emission limits for one additional source—Independence—ostensibly to achieve Reasonable Progress toward natural visibility conditions in Arkansas' two Class I areas: Caney Creek Wilderness Area ("Caney Creek") and Upper Buffalo Wilderness Area ("Upper Buffalo"). Petitioners submitted timely comments on the Proposed FIP. *See* EAI Comments, Docket No. EPA-R06-OAR-2015-0189-0166 (JA-___); EMI Comments, Docket No. EPA-R06-OAR-2015-0189-0168 (JA-___); AECC Comments, Docket No. EPA-R06-OAR-2015-0189-0169 (JA-___); American Electric Power-Southwestern Electric Power Company ("AEP-SWEPCO") Comments, Docket No. EPA-R06-OAR-2015-0189-0164 (JA-___); EEAA Comments, Docket No. EPA-R06-OAR-2015-0189-0153 (JA-___). EPA issued the Final FIP on September 27, 2016. 81 Fed. Reg. 66,332 (Sept. 27, 2016) (Add. 1) (JA-___).

The Final FIP establishes emissions limits for both SO_2 and NOx at White Bluff and Independence. For White Bluff, EPA determined that BART requires SO_2 emissions limits based on the installation of dry flue gas desulfurization technology

("dry FGD") with compliance required five years after issuance of the Final FIP, *i.e.*, by October 27, 2021, and NOx emissions limits based on the installation of low-NOx burners and separated overfire air ("LNB/SOFA"), with a compliance deadline of 18 months from issuance of the Final FIP, *i.e.*, by April 27, 2018. *Id.* at 66,343-45 (Add. 13-15) (JA-___). For Independence, EPA determined that Reasonable Progress also requires emission limits based on dry FGD and LNB/SOFA, to be installed on the same timeframe as for White Bluff. *Id.* at 66,353-54 (Add. 23-24) (JA-___).

Petitioners challenge the Final FIP requirements for White Bluff and Independence as unlawful, arbitrary and capricious, and procedurally defective. The Final FIP unjustifiably imposes almost $2 billion in control costs on these plants for no perceptible visibility benefits. EPA unlawfully, arbitrarily, and capriciously failed to consider important economic and regulatory factors, failed to offer explanations for decisions that run counter to the evidence, and failed to provide a reasoned response to the comments. Additionally, EPA failed to provide notice and opportunity to comment on certain aspects of the Final FIP, and those aspects are not logical outgrowths of the Proposed FIP. Finally, Petitioners challenge the source-specific NOx emissions limits imposed on BART-eligible EGUs that also are subject to CSAPR.

LEGAL BACKGROUND

I. CLEAN AIR ACT VISIBILITY REQUIREMENTS

The Act requires states to reduce impairment of visibility in Class I areas resulting from manmade pollution. 42 U.S.C. § 7491. Congress tasked EPA with promulgating regulations to assure Reasonable Progress towa rd a long -term national goal of preventing future visibility impairment and remedying existing visibility impairment in these areas and to establish requirements for SIPs to address visibility impairment. *Id.* § 7491(a)(4). States must incorporate into their SIPs "emission limits, schedules of compliance, and other measures as may be necessary to make reasonable progress toward" the national goal. *Id.* § 7491(b)(1), (2). Where a state fails to submit an approvable SIP or where EPA disapproves a state's pl an, the CAA directs EPA to issue a FIP at any time within two years thereafter. *Id.* § 7410(c)(1). In doing so, EPA stands in the shoes of the state. *Central Arizona Water Cons. Dist. v. EPA* , 990 F.2d 1531, 1541 (9th Cir. 1993).

For certain major station ary sources built between 1962 and 1977 that "may reasonably be anticipated to cause or contribute to" visibility impairment in any Class I area, the Act requires the SIP to incorporate provisions for installation of BART to control emissions. 42 U.S.C. § 7491(b)(2)(A). In determining BART, the state must take into consideration five factors:

(i) the costs of compliance;

(ii) the energy and non-air quality environmental impacts of compliance;

(iii) any existing pollution control technology in use at the source;

(iv) the remaining useful life of the source; and

(v) the degree of visibility improvement that may reasonably be anticipated to result from the use of such technology.

Id. § 7491(g)(2).

SIPs also must include "a long -term (ten to fifteen yea rs) strategy for making reasonable progress toward meeting the national goal." *Id.* § 7491(b)(2)(B).

EPA'S REGIONAL HAZE RULE

To carry out the requirements of the Act and establish the requirements for regional haze SIPs, EPA promulgated its "Regional Haze Rule" at 40 C.F.R. § 51.308.[2] A SIP must include three primary components: (1) the establishment of Reasonable Progress Goals ("RPGs") for each Class I area in the state to "provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period;" (2) an LTS for regional haze that "must include enforceable emissions limitations, compliance schedules, and other measures as nece ssary to achieve the reasonable progress goals . . ."; and (3) implementation of BART for certain major stationary sources. 40 C.F.R. §§ 51.308(d)(1), (d)(3) and (e).

[2] EPA first promulgated regional haze regulations in 1999, 64 Fed. Reg. 35,714 (July 1, 1999), and revised them in 2005, 70 Fed. Reg. 39,104 (July 6, 2005), and 2017, 82 Fed. Reg. 3,078 (Jan. 10, 2017). The 2017 revisions to the Regional Haze Rule are not applicable to this case, as they became effective after EPA issued the Final FIP.

As part of setting an RPG,[3] the state must determine the "rate of progress" for each Class I area that would be needed during each implementation period to attain natural visibility conditions by 2064 (commonly referred to as the "glidepath" or the "uniform rate of progress" or "URP"). Then, in establishing the RPG, the state must consider "the emission reduction measures needed to achieve [the URP] for the period covered by the implementation plan." 40 C.F.R. § 51.308(d)(1)(i)(B). In recognition that the Regional Haze Program is meant to be implemented gradually, EPA has explained that states "should take into account the fact that the long-term goal of no manmade impairment encompasses several planning periods. It is reasonable for [the state] to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal." U.S. EPA, Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, at 1-4 (June 1, 2007) ("Reasonable Progress Guidance") Docket No. EPA-R06-OAR-2015-0189-0230 (JA-___).

In establishing an RPG, the state must take into consideration four factors: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. 42 U.S.C. § 7491(g)(1); 40 C.F.R.

[3] RPGs are expressed in "deciviews." 40 C.F.R. § 51.308(d)(1). According to EPA, "each deciview change is an equal incremental change in visibility perceived by the human eye. Most people can detect a change in visibility at one deciview." *See* 77 Fed. Reg. 30,248, 30,250 (May 22, 2012).

§ 51.308(d)(1)(i)(A). However, an RPG is just that —"a *goal* and not a mandatory standard which must be achieved by a particular date." 64 Fed. Reg. at 35,733 (emphasis in original).

SIPs also must include BART limitations for major stationary sources that meet specific statutory criteria. 42 U.S.C. § 7491(b)(2)(A). In establishing BART, the regulations require states to consider the technology available and the five statutory factors in CAA § 169A(g)(2) noted above, including the costs of compliance and the remaining useful life of the source. *Id.* § 7491(g)(2); *accord* 40 C.F.R. § 51.308(e)(ii)(A). EPA specifically recognizes that the remaining useful life of a source can affect the cost of compliance factor (*i.e.*, a shorter remaining useful life makes emissions controls more costly on an annualized basis). Accordingly, the Agency's guidelines on determining BART, which are binding for power plants larger than 750 MW such as White Bluff, require the states to factor remaining useful life into the cost of the control technology: "Where the remaining useful life is less than the [default] time period for amortizing costs, you should use this shorter time period in your cost calculations." 40 C.F.R. Pt. 51, App. Y, Section IV.D.4.k.1 (Add. 92).

For the first implementation period, EPA specifically recognized that installation of BART controls may be sufficient for a state's RPGs, without the need to require additional controls to achieve Reasonable Progress. Reasonable Progress Guidance at 4-1 (JA -___) ("Given the significant emissions reductions that we anticipate to result from BART" in combination with other CAA programs "it may be

all that is necessary to achieve reasonable progress in the first planning period."). EPA also noted that, due to the refined technical analyses required by the Regional Haze Rule, including the analyses of emissions and air quality, "some States may conclude that control strategies specifically for protection of visibility are not needed at this time because the analyses may show that existing measures are sufficient to meet reasonable progress goals." 64 Fed. Reg. at 35,721.

The Regional Haze Rule also allows states to adopt a trading program in lieu of source-specific BART for the pollutants covered by the trading program if the trading program will result in greater visibility improvement. 40 C.F.R. § 51.308(e). In 2011, EPA adopted CSAPR, which establishes, *inter alia*, an emissions trading program for ozone season NOx that applies to EGUs in certain states whose transported emissions affect air quality in other states. 76 Fed. Reg. 48,208 (Aug. 8, 2011). Arkansas is subject to CSAPR's ozone season NOx trading program. 40 C.F.R. § 52.184; § 97.510. In 2012, EPA promulgated a final rule finding that CSAPR provides for greater Reasonable Progress towards the national visibility goal than BART. 77 Fed. Reg. 33,642 (June 7, 2012). Accordingly, states subject to CSAPR can adopt CSAPR in lieu of source-specific BART for their EGUs for the pollutants for which the EGUs are subject to CSAPR. *See id.* at 33,647.

STATEMENT OF FACTS

I. ARKANSAS SIP SUBMITTAL

In September 2008, the Arkansas Department of Environmental Quality ("ADEQ") submitted a regional haze SIP to EPA for the first implementation period, with supplemental submittals in August 2010, and September 2011. 76 Fed. Reg. 64,186, 64,187 (Oct. 17, 2011); Arkansas SIP Submittal, Docket No. EPA -R06-OAR-2008-0727-0002 (Sept. 23, 2008) ("Arkansas SIP"). The Arkansas SIP imposed SO_2 and NOx BART limits on all six subject-to-BART sources in the state, including White Bluff. The state established RPGs for Caney Creek and Upper Buffalo for the first implementation period of 22.48 deciviews and 22.52 deciviews, respectively. Arkansas SIP at 65 Fig.10.5. Based on modeling conducted by the Central Regional Air Planning Association ("CENRAP"),[4] Arkansas concluded that controls other than BART were not needed to remain on the glidepath and demonstrate Reasonable Progress for the first implementation period. *Id.* at 74.

EPA disapproved portions of the Arkansas SIP in March 2012, including the SO_2 and NOx BART limits for White Bluff, finding that "the State did not satisfy all the regulatory and statutory requirements in making [its] BART determinations." 77 Fed. Reg. 14,604, 14,605 (Mar. 12, 2012). EPA also disapproved Arkansas' RPGs,

[4] CENRAP is a regional planning organization that includes Nebraska, Kansas, Oklahoma, Texas, Minnesota, Iowa, Missouri, Arkansas, and Louisiana. It is funded by EPA to address the interstate transport nature of the regional haze pollutants in the region.

finding that the State did not establish RPGs in accordance with the requirements of the Regional Haze Rule. *Id.* at 14,630.

II. PROPOSED FIP

In April 2015, more than three years after the SIP disapproval, EPA proposed a replacement FIP. 80 Fed. Reg. 18,944 (Apr. 8, 2015) (JA-___). EPA proposed to establish SO_2 BART limits of 0.06 lb/mmBtu (pounds per million British thermal units) on a rolling 30-boiler operating day basis for each White Bluff EGU (Units 1 and 2), based on dry FGD, with a compliance deadline of five years from the effective date of the Final FIP. *Id.* at 18,972-73 (JA-___). For NOx, EPA proposed rolling 30-boiler operating day average emission rates of 0.15 lb/mmBtu for each White Bluff EGU based on LNB/SOFA, with a compliance deadline of three years from the effective date of the final FIP. *Id.* at 18,974-75 (JA-___).

For Reasonable Progress, EPA stated it was appropriate to focus solely "on the Entergy Independence Power Plant because it is a significant source of SO_2 and NOx, as it is the second largest point source for both NOx and SO_2 point source emissions in the State," and the largest and third largest point sources already would be regulated under the BART requirements. *Id.* at 18,991-92 (JA-___). EPA concluded that the same SO_2 and NOx controls and emissions limits proposed for White Bluff should apply to the two EGUs at Independence and on the same compliance timeframe. *Id.* at 18,992-96 (JA-___). EPA did not evaluate controls for Reasonable Progress

purposes for any other sources in Ark ansas despite identifying the lack of such an analysis as a basis for its disapproval of Arkansas' RPGs. *See* 76 Fed. Reg. at 64,196.

III. COMMENTS ON THE PROPOSED FIP

Petitioners submitted extensive comments on the Proposed FIP. EAI explained in its commen ts that the proposed control requirements for White Bluff and Independence would impose approximately *$2 billion in costs* , all to obtain an imperceptible visibility improvement. EAI Comments at 2 (JA -___). Petitioners further explained that dry FGD shoul d not be considered cost -effective as BART for SO_2 at White Bluff in light of EPA's underestimation of costs coupled with EAI's proposal to permanently cease combusting coal at Units 1 and 2 by 2027 and 2028. EAI Comments at 5 -11 (Add. 94 -100) (JA-___); EEAA Comments at 6 -8 (JA-___); AECC Comments at 5-6 (JA-___).

Petitioners disputed EPA's basis for selecting Independence for evaluation of Reasonable Progress controls, explaining that it was contrary to the selection criteria EPA used in previous FIPs, and that EPA exceeded its statutory authority by proposing controls that were not "necessary to make reasonable progress." EAI Comments at 17 (citing 42 U.S.C. § 7491(b)(2)) (JA -___); EMI Comments at 4 -8 (JA-___); EEAA Comments at 8 -13 (JA -___). The comm ents further documented that, in 2015, actual visibility at Arkansas' two Class I areas was on track to meet EPA's proposed RPGs for 2018 and had improved significantly more than the URP, making controls on Independence *unnecessary* for Reasonable Progress purposes. EAI

Comments at 17 (JA-___); EMI Comments at 7-8 (JA-___); EEAA Comments at 12-13 (JA-___); AECC Comments at 3 (JA-___).

Petitioners also argued that EPA should adopt CSAPR instead of source-specific NOx BART controls for EGUs in the state. EAI Comments at 13 (JA-___); EEAA Comments at 4-5 (JA-___); AECC Comments at 6-7 (JA-___); AEP-SWEPCO Comments at 2-3 (JA-___).

IV. FINAL FIP

EPA issued the Final FIP in September 2016. 81 Fed. Reg. 66,332 (Sept. 27, 2016) (Add. 1) (JA-___). Despite EAI's proposal to permanently cease combusting coal at White Bluff, EPA determined that SO_2 BART for each unit should be a 30-boiler operating day rolling average emission limit of 0.06 lb/mmBtu, based on the installation of dry FGD. *Id.* at 66,335 (Add. 5) (JA-___). In evaluating the cost-effectiveness of dry FGD, EPA ignored EAI's proposal and applied a default remaining useful life of 30 years, *id.* at 66,360 (Add. 30) (JA-___), rather than the seven years resulting from EAI's proposal. EPA mischaracterized EAI's comments on the Proposed FIP, claiming that EAI's proposal did not include an enforceable commitment to cease coal-fired operation at White Bluff, and that it was predicated on EPA's acceptance of EAI's proposed emission limits for Independence, which EPA declined to do. *Id.* at 66,356-58 (Add. 26-28) (JA-___). For Independence, EPA finalized the SO_2 emission limits as proposed. *Compare* 81 Fed. Reg. at 66,339 Tbl.2 (Add. 9) (JA-___) *with* 80 Fed. Reg. at 18,994 (JA-___).

With respect to NOx for both White Bluff and Independence, EPA finalized limits based on the installation of LNB/SOFA. For operation at loads of 50-100 percent of maximum capacity, EPA finalized limits as proposed: 0.15 lb/mmBtu on a rolling 30-boiler operating day basis. 81 Fed. Reg. at 66,339 (Add. 9) (JA -___). However, EPA finalized a separate limit for operation at loads less than 50 percent of maximum capacity that was set at 671 lb NOx/hr to be met on a three-hour averaging period. *Id.* at 66,359 (Add. 29) (JA -___). EPA offered no justification for this new averaging period, nor any explanation of whether this new level would be appropriate. Further, EPA shortened the compliance period for meeting the NOx limits from three years to 18 months after the effective date of the Final FIP. *Id.* at 66,338 (Add. 8) (JA-___).

V. PETITIONS FOR RECONSIDERATION

Petitioners individually filed Administrative Petitions for Reconsideration and Requests for Stay of the Final FIP in November 2016. Each administrative petition argued that EPA must grant reconsideration because the Agency failed to provide adequate notice and opportunity to comment on significant requirements in the Final FIP that were not logical outgrowths of the Proposed FIP. Entergy Petition for Reconsideration at 2 (JA -___); AECC Petition for Reconsideration at 3 (JA -___); EEAA Petition for Reconsideration at 5 (JA -___). The administrative petitions also asserted that EPA should reconsider its findings in the Final FIP based on more recent visibility monitoring data, which became available after the close of the

comment period and demonstrated that visibility in Arkansas' Class I areas was already better than the RPGs and the URPs. Entergy Petition for Reconsideration at 4 (JA-___); AECC Petition for Reconsideration at 6 -7 (JA-___); EEAA Petition for Reconsideration at 3 -4 (JA -___). Furthermore, Entergy argued that EPA should reconsider the Final FIP because it contains clear errors, such as failing to evaluate the remaining useful life of White Bluff, Entergy Petition for Rec onsideration at 7 (JA -___), and the cost of SO_2 controls, *id.* at 5-6 (JA-___).

To avoid the significant, irreparable harms that already have begun to occur, Entergy requested that EPA take action on its Petition for Reconsideration by February 1, 2017. *Id.* at 1 (JA -___). EEAA's and AECC's Petitions for Reconsideration made the same request by reference to Entergy's petition. AECC Petition for Reconsideration at 1 (JA -___); EEAA Petition for Reconsideration at 3 (JA-___). EPA constructively denied all three Petitions for Reconsideration by failing to respond by February 1, 2017.

SUMMARY OF THE ARGUMENT

The Final FIP is replete with errors, resulting in final emissions limits for White Bluff and Independence that are unlawful, arbitrary and capricious, and must be vacated.

The SO_2 emissions limits for White Bluff are based on the installation of controls that were selected using a flawed BART analysis that unlawfully failed to

consider a mandatory statutory factor, the remaining useful life of the units, thereby artificially distorting the cost-effectiveness of those controls. EPA assumed a 30 -year life for the units instead of the six to seven years resulting from Entergy's commitment to cease burning coal. EPA's BART analysis further failed to properly consider the minimal visibility improvements the controls would produce. At a cost of almost $1 bil lion, amortized over just six to seven years, dry FGD cannot be justified in light of the undetectable visibility improvements it would achieve.

The final emissions limits for Independence are arbitrary and capricious, and based on an unlawful Reasonable Progress analysis. First, the controls are not "necessary" to achieve Reasonable Progress. Visibility in both Class I areas is better than EPA's own RPGs and is significantly below the glidepath. Furthermore, the nearly $1 billion in control costs would result in de minimis visibility benefits. Second, the SO_2 Reasonable Progress controls cannot be deemed necessary to achieve Reasonable Progress for *this* implementation period because they cannot be installed until the next implementation period. Third, EPA unlawfully deviated from the Reasonable Progress analysis it used in multiple prior FIPs.

The Final FIP also imposes on White Bluff and Independence unattainable NOx emissions limits that must be met only 18 months from the effective date of the Final FIP. In addition to being arbitrary, capricious and unattainable, these limits and timeline are not logical outgrowths the Proposed FIP.

Finally, EPA's decision to impose source -specific NOx emission limits on the BART-eligible EGUs in Arkansas is arbi trary and capricious in light of the Agency's own regulations, which authorize exemption of these units from source -specific BART for NOx because Arkansas is subject to the CSAPR ozone season NOx trading program. Accordingly, the NOx limits for such EGUs must be vacated.

ARGUMENT

I. STANDARD OF REVIEW

The Final FIP must be vacated if it is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law," or if it exceeds statutory authority. *North Dakota v. EPA* , 730 F.3d 750, 758 (8th Cir. 2013) (citing 42 U.S.C. § 7607(d)(9)); 5 U.S.C. § 706(2); *see also Missouri Limestone Producers Ass'n., Inc. v. Browner*, 165 F.3d 619, 621 (8th Cir. 1999).

Agency action is arbitrary and capricious if:

> the agency has relied on factors which Con gress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise.

Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co. , 463 U.S. 29, 43 (1983). Accordingly, courts consider whether the agency's decision was "based on a consideration of the relevant factors and wh ether there has been a clear error in judgment." *Ringsred v. Dole* , 828 F.2d 1300, 1302 (8th Cir. 1987) (quoting *Citizens to*

Preserve Overton Park, Inc. v. Volpe, 401 U.S. 402, 416 (1971)). An agency "must provide a satisfactory explanation for its actions based on relevant data." *Niobrara River Ranch, L.L.C. v. Huber*, 373 F.3d 881, 884 (8th Cir. 2004). This Court has described application of the standard of review as a "searching and careful" review of the administrative record to determine "whether the decision was based on a consideration of the relevant factors and whether there has been a clear error of judgment." *See Downer v. United States*, 97 F.3d 999, 1002 (8th Cir. 1996) (quoting *Marsh v. Oregon Natural Res. Council*, 490 U.S. 360, 378 (1989)).

II. EPA'S $1 BILLION SO_2 BART DETERMINATION FOR WHITE BLUFF IS UNLAWFUL, ARBITRARY, AND CAPRICIOUS.

The SO_2 emissions limits for White Bluff must be vacated because they are the product of a flawed BART analysis that unlawfully failed to consider a mandatory factor—the remaining useful life of the White Bluff units. EPA also failed to consider the imperceptible visibility improvements that dry FGD would achieve [5] in light of the nearly $1 billion it would cost.

A. EPA's SO_2 BART Analysis Arbitrarily and Capriciously Failed to Account for Remaining Useful Life.

EPA's SO_2 BART analysis for White Bluff Units 1 and 2 ignored the remaining useful life of those units —a factor the CAA *mandates* EPA take into account. This

[5] EPA's own analysis predicts controls on White Bluff would achieve imperceptible visibility improvements at Caney Creek and Upper Buffalo of only 0.813 dv and 0.762 dv, respectively. 81 Fed. Reg. at 66,343 Tbl.9 (Add. 13) (JA-___). According to EPA, one deciview reflects perceptible changes in visibility. *See* 77 Fed. Reg. at 30,250.

allowed EPA to improperly and artificially manipulate its cost-effectiveness analysis for the required controls, resulting in a flawed BART determination that must be vacated.

To qualify as BART, dry FGD must be cost-effective. 42 U.S.C. § 7491(g)(2); *accord* 40 C.F.R. §§ 51.308(e)(1)(ii)(A) & Pt. 51, App. Y, Section IV.D.4.k (Add. 92-93). But determining cost-effectiveness *requires* consideration of the remaining useful life of the units. *See id.* When remaining useful life is less than the standard period for amortizing the costs of controls (*e.g.*, 30 years), the shorter time period must be used in BART cost calculations. 40 C.F.R. Pt. 51, App. Y, Section IV.D.4.k (Add. 92-93). EPA acknowledges that BART controls, which may be cost-effective using the standard amortization period, may not be cost-effective when a source's remaining useful life is considered because the costs are amortized over a shorter amount of time. *See* 81 Fed. Reg. at 66,356 (Add. 26) (JA-___). Simply put, extremely expensive controls may not be worth installing on a plant that will operate for only a few more years.

In comments on the Proposed FIP, EAI explicitly proposed to cease combusting coal at White Bluff Units 1 and 2 in 2027 and 2028, limiting the amortization period for dry FGD to just six or seven years.[6] EAI Comments at 6 (Add. 95) (JA-___). EPA arbitrarily and capriciously disregarded this information

[6] The proposal did not state which unit would cease combusting coal first.

and, instead, assumed that the units would remain in service for 30 more years, dramatically reducing the annualized capital costs and artificially understating the cost of dry FGD per ton of SO_2 removed (the metric used by EPA). This made dry FGD appear to be cost-effective when it patently is not.

Had EPA used the six- to seven-year actual remaining useful life, as required by its regulations, and properly included all of the costs of dry FGD, the cost would have at least *tripled* from $2,421-$2,565 to $7,119-$8,004 per ton of SO_2 removed.[7] *Compare* 81 Fed. Reg. at 66,343 (JA-___) *with* Sargent & Lundy LLC, *Entergy Arkansas, Inc. - White Bluff Dry FGD Cost Estimate and Technical Basis*, Report No. SL-012831 (July 2015) (Ex. C to Entergy Petition for Reconsideration) ("Sargent & Lundy Report") (Add. 102-103) (JA-___). These costs vastly exceed the cost-effectiveness thresholds used by EPA in numerous other regional haze plans. *See* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. 9,318, 9,331-33 (Feb. 18, 2014), *finalized in* 79 Fed. Reg. 52,420, 52,436 (Sept. 3, 2014) (EPA declining to impose dry FGD as BART where average cost-effectiveness was **$5,090/ton**); Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. 58,570, 58,630 (Sept. 21, 2011), *finalized in* 77 Fed. Reg. 20,894, 20,896 (Apr. 6, 2012) (EPA approving state's determination that cost-effectiveness of **$6,525/ton** was excessive and did not constitute BART); Proposed Montana Regional

[7] EAI's comments on the Proposed FIP indicated that the costs would range from $7,689-$8,599 per ton of SO_2 removed, EAI Comments at 12 (Add. 101) (JA-___), but the more recent cost data from Sargent & Lundy indicate that the costs will range from approximately $7,119-8,004 per ton.

Haze FIP, 77 Fed. Reg. 23,988, 24,047 (Apr. 20, 2012) *finalized in* 77 Fed. Reg. 57,864, 57,866 (Sept. 18, 2012) (EPA determining that SO_2 controls were not cost-effective at **$5,442/ton** and **$6,365/ton**).

EPA's purported justifications for disregarding the remaining useful life of White Bluff Units 1 and 2 are meritless and unsupported by fact and law. *First*, EPA's assertion in the Final FIP that EAI did not offer to accept a binding limit on the remaining useful life of White Bluff Units 1 and 2 is patently incorrect. *See* 81 Fed. Reg. at 66,356 -57 (Add. 26 -27) (JA-___). EAI explicitly made such a commitment: "[EAI] proposes to cease burning coal at White Bluff Units 1 and 2 by 2027 and 2028, one unit per year, *and is prepared to take an enforceable commitment* to that effect." EAI Comments at 5 (emphasis added) (JA-___).

EPA's claim that EAI "does not propose ... adopting a binding requirement to burn only natural gas or completely shut down the units" is thus inexplicable. *See* 81 Fed. Reg. at 66,356 (Add. 26) (JA -___). An agreement to accept a binding requirement to cease burning coal *requires* EPA to assume that SO_2 emissions would be zero subsequent to the cessation of coal combustion. *Id.* at 66,356-57 (Add. 26-27) (JA-___). EPA's failure to consider EAI's proposal to accept such a binding requirement is thus arbitrary, capricious and unlawful.

Second, the record belies EPA's claim that EAI's proposal to cease using coal at White Bluff was dependent on EAI's separate proposal related to emission limits for Independence. *See id.* at 66,358 (Add. 28) (JA-___); EPA Response to Comments for

the State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan, Docket No. EPA-R06-OAR-2015-0189-0187, at 57 (September 27, 2016) ("EPA Response to Comments") (JA -___). Nowhere did EAI assert that its commitment to cease burning coal at White Bluff was contingent on EPA's agreement to the emission limits that EAI proposed for Independence. EAI proposed an approach to address all four coal-fired units at White Bluff and Independence, and provided modeling of its proposal demonstrating that its approach would achieve virtually the same visibility benefits as EPA's Proposed FIP for significantly less cost. EAI Comments at 45-46 (JA-___). But EAI never stated that its White Bluff proposal was contingent on its proposed emission limits for Independence. To the contrary, EAI explicitly stated that the interim emissions reductions it offered for Independence were a *complement* to its proposal for White Bluff. EAI Comments at 4 (JA-___) ("Entergy is prepared to offer meaningful interim emission reductions to complement its proposed commitment to cease coal-fired operations at White Bluff and assure that Arkansas remains on a path that is below the URP for the long term.").

Third, EPA's argument that Entergy's failure to provide information on dry sorbent injection ("DSI") as an interim SO_2 control somehow negated EPA's obligation to conduct a reasonable BART analysis, 81 Fed. Reg. at 66,356 (Add. 26) (JA-___), is a red herring. Whether DSI should be considered BART is irrelevant to whether dry FGD constitutes BART in light of the White Bluff units' six- or seven-

year remaining useful life. If EPA believed that DSI might constitute an alternative BART for the short term prior to the cessation of coal burning, it should have deferred its BART determination to evaluate DSI. However, it could not identify the lack of such analysis as a basis for disregarding a statutory obligation to consider the units' limited remaining useful lives.

None of these justifications is a reasonable explanation for EPA's failure to consider the remaining useful life of White Bluff in light of Entergy's commitment. EPA has entirely failed to consider "an important aspect of the problem:" one of the five factors that the CAA *requires* it to consider. *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43. Further, EPA's proffered explanation for its decision runs counter to the available information before the Agency. *Id.* Accordingly, EPA's BART determination is arbitrary, capricious and unlawful and must be vacated.

At a minimum, EPA should have included EAI's proposal as an alternative compliance option in the Final FIP and permitted EAI to choose which option to pursue. EPA's regulations specifically authorize it to establish alternative emissions limits depending on whether or not a source ultimately decides to cease the operations that produce emissions. 40 C.F.R. Pt. 51, App. Y, Section IV.D.4.k.3 (Add. 93). Here, EPA should have allowed EAI the option of installing dry FGD at White Bluff by 2021 or permanently ceasing coal combustion in 2027 and 2028, with a less stringent emission limit in the interim.

EPA has done exactly this for similar proposals in other FIPs, such as PacifiCorp's proposal to shut down a unit in Wyoming as an alternative to installing selective catalytic reduction ("SCR") to control NOx emissions. *See* 79 Fed. Reg. 5,032, 5,045 (Jan. 30, 2014). There, EPA provided that the unit could either install SCR by 2019, or cease operation by 2027, while complying with a less stringent emissions limit in the interim. *Id.* EPA could have done the same thing here, and did so for a different unit in the Final FIP. *See* 81 Fed. Reg. at 66,346 (Add. 16) (JA -___) (alternative BART standards if Domtar Power Boiler No. 1 burns only natural gas). EPA offered no reasoned basis to deviate from this precedent and for refusing to establish alternative BART standards for White Bluf f. *See Dillmon v. NTSB*, 588 F.3d 1085, 1089-90 (D.C. Cir. 2009) ("Reasoned decision making ... necessarily requires the agency to acknowledge and provide an adequate explanation for its departure from established precedent.") (citing *FCC v. Fox Television Stations, Inc.*, 129 S. Ct. 1800, 1811 (2009)); *see also* 40 C.F.R. § 56.5(a) (requiring EPA regional offices to ensure that their actions are "as consistent as possible with the activities of other Regional Offices").

Because EPA ignored the remaining us eful lives of the White Bluff units, a factor it statutorily *must* consider, the SO_2 limits for White Bluff are not in accordance with law.

B. The Exorbitant Costs for Dry FGD Are Too High to Constitute BART in Light of the Resulting Minimal Visibility Benefits.

Dry FGD cannot constitute SO_2 BART for White Bluff because the costs of these controls —approximately *$1 billion* —are grossly disproportionate to their anticipated visibility improvements. *See* EAI Comments at 2 (JA -___). The controls are clearly not cos t-effective in light of the degree of visibility improvements they are reasonably anticipated to achieve. EPA compounded its error by improperly excluding approximately *$495 million* in control costs for dry FGD. Sargent & Lundy Report at 2 (Add. 102) (JA -___) (By excluding certain costs, EPA claimed that dry FGD costs would be approximately $495 million for the White Bluff while Sargent & Lundy more accurately estimated costs at approximately $991 million).

The CAA requires EPA to consider the degree of anticipated visibility improvement from the installation of controls in establishing BART. 42 U.S.C. § 7491(g)(2). EPA cannot mandate that a source "spend millions of dollars for new technology that will have no appreciable effect on the haze." *Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1, 7 (D.C. Cir. 2002); *cf Michigan v. EPA,* 135 S.Ct 2699, 2707 (2015) (finding it irrational "to impose billions of dollars in economic costs" in a CAA rule to produce minimal benefits). Yet the Final FIP does exactly this.

EPA acknowledges that improvements predicted at Caney Creek and Upper Buffalo from controls on White Bluff Units 1 and 2 are only a fraction of one deciview, making them imperceptible to the human eye. 81 Fed. Reg. at 66,343 Tbl.9

(Add. 13) (JA-___) (visibility improvements ranging from 0.762 dv to 0.813 dv). But even these estimates greatly overstate the predicted visibility improvement from controls on White Bluff. EPA used unrealistic and distorting assumptions about background conditions that ign ore all other manmade sources of visibility impairment. Using rational, real -life impacts, the predicted improvements are far smaller. For example, EPA used these more comprehensive background conditions when it projected that the cumulative benefit of i nstalling *all* the controls in the Proposed FIP (*i.e.*, all BART controls plus controls at Independence) would result in visibility "benefits" at Upper Buffalo and Caney Creek of only 0.19 dv and 0.21 dv, respectively. 80 Fed. Reg. at 18,998 Tbl.67 (JA-___). White Bluff's contribution is but a small fraction of this impact. Given that visibility in both Class I areas is improving rapidly—and already is better than the RPGs and the URPs —the extraordinary costs are unjustifiable for such imperceptible visibility improvements.

Indeed, the cost -per-deciview of improvement at Caney Creek and Upper Buffalo that would be achieved from dry FGD at White Bluff is astronomical: ranging from approximately *$2.6 billion to $3.1 billion* per deciview. EAI Comments at 12 (Add. 101) (JA-___). These values are orders of magnitude higher than the cost -per-deciview values that EPA has rejected as unjustifiable in other FIPs. *See, e.g.*, Final Montana Regional Haze FIP; 77 Fed. Reg. 57,864, 57,895 (Sept. 18, 2012) (concluding that, although DSI was cost -effective on a cost -per-ton basis, the costs were not justified by the visibility improvement at $30 million per deciview).

EPA attempts to skew the cost analysis for White Bluff by *failing to include approximately $495 millio n* that Petitioners will be required to incur to install dry FGD—rendering EPA's White Bluff BART determination even more defective.[8] EPA improperly excluded from its calculation legitimate costs that Petitioners would incur to install dry FGD. For exampl e, EPA improperly excluded nearly $31 million of costs associated with "Balance of Plant" items, which are items not included in the dry FGD supplier's scope, but which are necessary to integrate the dry FGD system into the plant. *See* EAI Comments at 8 -9 (Add. 97 -98) (JA -___); 81 Fed. Reg. at 66,383-84 (Add. 53 -54) (JA -___); EPA Response to Comments at 336 (JA -___).[9] EPA also failed to account for $85 million by escalating outdated cost information to 2013 dollars instead of relying on more accurate and r ecent cost information from the dry FGD supplier. *See* EAI Comments at 8 (Add. 97) (JA -___); *id.* Ex. A at 12 (JA -___); 81 Fed. Reg. at 66,382 -83 (Add. 52 -53) (JA -___). In addition, EPA excluded $83 million of "owner's costs" that are unavoidable and necessary, which include tasks like site investigation to inform the project design, obtaining environmental permits, and mobilizing for construction. EAI Comments at 9 (Add. 98) (JA -___). Such costs

[8] These same cost errors infect the Independence Reasonable Progress analysis.

[9] EPA refused to consider these costs because EAI did not submit to the Agency highly confidential and propriety vendor quotes to support the detailed, line -item cost estimate that EAI already had pr ovided. EPA Response to Comments at 336 (JA-___). Despite the fact that EPA never requested the vendor quotes, they were subsequently provided (in redacted form) to EPA. *See* Entergy Petition for Reconsideration at 7-8 (JA-___).

are expressly allowed under EPA's own Coal Quality Environmental Cost model and should have been included in cost estimates for White Bluff. EPA, *Coal Utility Environmental Cost (CUECost) Workbook Development Documentation Version 5.0* (Sept. 2009). EPA also failed to include $30 to 60 million for Allowance for Funds Used During Construction ("AFUDC"). EAI Comments at 10-11 (Add. 99-100) (JA___); *id.* Ex. A at 12 (JA -___); 81 Fed. Reg. at 66,383 -84 (Add. 53 -54) (JA -___); EPA Response to Comments at 259 (JA-___).

Although EPA ultimately adjusted its calculated costs of dry FGD upward by a nominal amount in the Final FIP, EPA Response to Comments at 355 (JA -___), this correction still underestimates the true cost of dry FGD by hundreds of millions of dollars. *See* EAI Comments at 8 -11 (Add. 97 -100) (JA -___); Entergy Petition for Reconsideration at 7 -8 (JA -___); *id.*, Sargent & Lundy Report at 2 (Add. 102) (JA -___). When compared with the minimal visibility improvement that would result from the installation of dry FGD, it is clear that these controls cannot constitute SO_2 BART.

III. THE REASONABLE PROGRESS CONTROLS FOR INDEPENDENCE ARE UNLAWFUL AND UNNECESSARY.

EPA exceeded its authority under the CAA when imposing controls on Independence. EPA may impose control requirements only "as may be necessary" to make Reasonable Progress toward meeting the 2064 visibility goal. In Arkansas, the two Class I areas already meet the RPGs set by EPA and are more than two deciviews

below the URPs. Entergy Petition for Reconsideration at 4 (Add. 104) (JA -___). Spending $1 billion for visibility benefits so small they cannot be perceived certainly cannot be deemed "necessary" to meet the first implementation period's objectives. Indeed, the controls assuredly cannot be necessary for the current period because the controls cannot be installed until the next planning period. In addition, EPA's Reasonable Progress analysis unjustifiably deviated from the process used by EPA for other states, rendering it arbitrary, capricious, and unlawful.

A. The Emissions Limits Imposed on Independence Are Unnecessary and Cannot Be Justified in Light of Their Costs.

Independence is not subject to BART, which means that controls can only be justified if they are "necessary to make reasonable progress toward meeting the national goal." 42 U.S.C. § 7491(b)(2). All available data, including EPA's, belie the necessity of controls on Independence. In light of the astronomical costs associated with the controls, the already improved visibility in both Class I areas in Arkansas, and the extremely small visibility benefits, EPA's Reasonable Progress requirements for Independence are manifestly unreasonable and must be vacated.

Independence's contribution to visibility impairment at Upper Buffalo and Caney Creek is miniscule. The 2002 CENRAP modeling proves this point. The modeling demonstrates that sulfate formed as a result of SO_2 emissions from *all* Arkansas point sources is responsible for only 3.58% of the total visibility impairment at Caney Creek and 3.20% at Upper Buffalo. 80 Fed. Reg. at 18,990 (JA -___).

According to CENRAP, nitrates resulting from all Arkansas NOx point sources contribute even less to visibility impairment at Arkansas' Class I areas: only 0.29% of the total impairment at Caney Creek and 0.25% at Upper Buff alo. *Id.* Independence's share of this minimal contribution is but a fraction of these total contributions. EPA justified the need for NOx controls on Independence based on a false characterization of the plant's contribution to visibility impairment. E PA claimed that, "Entergy's [Quality Modeling with extensions] modeling shows that nitrate from Independence is responsible for 30 –40% of the visibility impairment in Arkansas' Class I areas on 2 of the 20% worst days." 81 Fed. Reg. at 66,359 (Add. 29) (JA-___).

EPA's statement is patently incorrect. In fact, nitrates are a minute portion of visibility impairment at Arkansas' two Class I areas and Independence's average total nitrate contribution to visibility impairment on the 20% worst days is only 0. 02% at Upper Buffalo and 0.03% at Caney Creek. *See* Entergy Scenario 01 Contribution 2015-1124_FINAL, Docket No. EPA -R06-OAR-2015-0189-0220 (Sept. 13, 2016) (JA-___). Thus, the actual contribution is over three orders of magnitude *less* than EPA claimed.

The installation of EPA's selected controls will yield *no discernible visibility improvements*. EPA's modeling demonstrated that the cumulative benefit (in 2018) of installing *all* the controls in the Proposed FIP (*i.e.*, BART controls at all BART sources plus controls at Independence) will be only 0.21 dv at Caney Creek and 0.19

dv at Upper Buffalo. 80 Fed. Reg. at 18,998 Tbl.67 (JA -___). Controlling emissions from Independence would contribute only a fraction to these minute changes of less than one-fifth of a deciview.[10]

Finally, when EPA finalized the FIP, Arkansas already had achieved visibility improvements in its Class I areas that surpassed EPA's final RPGs for the first planning period, and are significantly below the URPs, rendering the imposition of controls on Independence unnecessary. Analysis by ADEQ, cited in EAI's comments, demonstrated that visibility in Caney Creek and Upper Buffalo very likely would meet the levels EPA ultimately finalized as the RPGs for 2018, *even without any additional controls on Independence*. *See* EAI Comments at 19-22 (JA-___) (citing Arkansas Department of Environmental Quality, *State Implementation Plan Review for the Five -Year Regional Haze Progress Report*, at 55-56 (May 2015)).[11]

These predictions are confirmed by more recent data that became available after the close of the comment period. These data confirm that, as of 2015, visibility

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[10] Independence's emissions represent approximately 36% of the total SO_2 point source emissions and 21% of the NOx point source emissions in Arkansas. *See* 80 Fed. Reg. at 18,991 (JA-___).

[11] ADEQ's analysis showed that visibility was on track to meet the State's proposed RPGs of 22.48 dv for Caney Creek and 22.52 dv for Upper Buffalo. *See* EAI Comments at 19 -20 (JA-___). EPA's final RPGs of 22.47 dv for Caney Creek and 22.51 dv for Upper Buffalo both are only 0.01 dv lower than the levels proposed by Arkansas. 81 Fed. Reg. at 66,410 Tbl.21 (Add. 80) (JA -___). Accordingly, it was reasonable to conclude that visibility likely would meet the final RPGs, even without additional controls on Independence. Indeed, subsequent air monitoring data proved this to be true. *See supra*.

measurements in both Caney Creek and Upper Buffalo were better than both the final RPGs for 2018 and the more stringent RPGs in the Proposed FIP. Entergy Petition for Reconsideration at 4 (Add. 104) (JA -___); Trinity Consultants, *Regional Haze Modeling Assessment Report, Entergy Arkansas, Inc. - Independence Plant* (August 4, 2015) (Ex. A to Entergy's Petition for Reconsideration) (Add. 105) (JA -___). EPA itself recognized in the Proposed FIP that Arkansas' Class I areas were projected to meet the URPs for the first implementation period, even without controls on Independence, 80 Fed. Reg. at 18,992 (JA -___), effectively conceding that the controls are not "*necessary*" in the first implementation period to ensure Reasonable Progress towards the natural visibility goal. *See* 42 U.S.C. § 7491(b)(2).

EPA should have determined that no Reasonable Progress controls were appropriate since the explicit statutory mandate is to set emission limits and compliance schedules *"as may be necessary"* to remedy and prevent visibility impairment. 42 U.S.C. § 7491(b)(2) (emphasis added). EPA guidance states that, after considering other regulatory requirements to reduce emissions and establishment of BART controls, additional emissions reductions to achieve Reasonable Progress may be unnecessary during the first implementation period. Reasonable Progress Guidance at 4-3 (JA-___).

For the foregoing reasons, controls on Independence are not *"necessary"* to satisfy the CAA's Reasonable Progress requirements, and mandating the installation of almost $1 billion in controls is unreasonable and unlawful. In light of the

indiscernible visibility benefits of the required controls, and the fact that both of Arkansas' Class I areas have surpassed EPA's own metrics for the first planning period, the emissions limits for Independence are arbitrary and capricious, and cannot be justified. *Cf. Michigan* at 2707 (finding it irrational "to impose billions of dollars in economic costs" in a CAA rule to produce minimal benefits).

B. The SO_2 Limits Are Unlawful Because They Cannot Be Implemented During the First Implementation Period.

In addition to being unnecessary, the final emission limitations are unlawful because they require controls that cannot be installed during the current implementation period. EPA's regulations require SIPs to consider "the emission reduction measures needed to achieve [RPGs] *for the period covered by the implementation plan*." 40 C.F.R. § 51.308(d)(1)(i)(B) (emphasis added). Here, the first period ends in 2018, *see, e.g.*, 81 Fed. Reg. 66,338 (Add. 8) (JA -___), but SO_2 controls at Independence cannot be fully implemented until 2021, three years *after* the current period ends. *Id.* at 66,416-20 (Add. 86-90) (JA -___). Accordingly, the emissions reductions EPA expects would not be achieved until well into the second implementation period. This is precisely the situation the Fifth Circuit confronted last year when it granted a stay of a similar regional haze FIP in Texas. *Texas v. EPA*, 829 F.3d 405, 429 (5th Cir. 2016) ("EPA's federal implementation plan requires power plants in Texas to meet Reasonable Progress goals by installing scrubbers in 2019 and

2021. Petitioners persuasively argue that this exceeds the power granted by the Regional Haze Rule.").

As in Texas, EPA failed to explain why it is appropriate to require Reasonable Progress controls in a FIP for the first implementation period when the controls cannot be installed or produce visibility benefits in that implementation period. Further, the Regional Haze Rule grants EPA multiple bites at this apple. There are still four more planning periods over the 64-year program during which the necessity of Reasonable Progress controls can be evaluated and Arkansas has not been given an opportunity to even consider appropriate measure for the second implementation period.[12] Controls on Independence should not be imposed for an implementation period that will have ended well before any emissions reductions can be achieved. This is consistent with EPA's Reasonable Progress Guidance: "It is reasonable for [a state] to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal." Reasonable Progress Guidance at 1-4 (JA-___). That is precisely the situation here as visibility in Arkansas' two Class I areas already is better than the glidepath.

C. EPA's Reasonable Progress Analysis Arbitrarily and Capriciously Departed from the Approach Used in Other Regional Haze FIPs.

The final Reasonable Progress emissions limits for Independence must be vacated, as they are the product of an arbitrary methodology that unlawfully fails to

[12] Arkansas is due to submit its next SIP in 2021 to address the period of 2018-2028. 40 C.F.R. § 51.308(f).

conform with EPA's well -established precedent for evaluating Reasonable Progress. EPA's novel approach violates the Agency's obligation to adequately explain why its new approach is justified, and runs afoul of the CAA's "national uniformity mandate."

1. EPA's Reasonable Progress Analysis for Arkansas Is Arbitrary and Capricious.

EPA's Reasonable Progress analysis for Independence is wholly unique, and completely unlike the numerous Reasonable Progress analyses EPA has undertaken in other FIPs. An agency cannot simply reverse course for no reason. The Supreme Court has made clear that an agency must "show that there are good reasons for [a] new policy." *F.C.C. v. Fox Television Stations, Inc.* , 129 S. Ct. 1800, 1811 (2009). Likewise, this Court ha s explained that "a sudden and unexpected change in agency policy" may be characterized as arbitrary and capricious. *Friends of Boundary Waters Wilderness v. Dombeck*, 164 F.3d 1115, 1123 (8th Cir. 1999). *See also Gaitan v. Holder*, 671 F.3d 678, 685 (8th Cir. 2012) (Bye, J. concurring).

In prior FIPs, EPA followed a consistent multi-step evaluation that included: (1) a "Q/D analysis" (*i.e.*, total emissions divided by distance to the Class I area) for each point source and relevant Class I area to identi fy those point sources requiring further evaluation; (2) a photochemical modeling scenario utilizing source apportionment to quantify visibility impacts from the sources identified in the Q/D analysis; and (3) an extinction percentage threshold to arrive at what EPA claimed was a common breakpoint in potential visibility improvement. EAI Comments at 15 -16

(JA-___) (citing *Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans (FIP TSD)* , Docket No. EPA -R06-OAR-2014-0754-0007, App. A at A -4; A -15–A-26; A -49 (Nov. 2014)). This structure allowed EPA to determine for which sources the installation of controls would potentially be worthwhile. *See* Proposed Texas Regional Haze FIP, 79 Fed. Reg. 74,818, 74,839 (Dec. 16, 2014). *See also*, Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,352-53; Proposed Montana Regional Haze FIP, 77 Fed. Reg. at 24,058 -59; and Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. at 58,624-26. After narrowing the list of potential poin t sources in those other states, EPA then completed the required four-factor Reasonable Progress analysis. *See* Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,872; Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,352 -53; Proposed Montana Regiona l Haze FIP, 77 Fed. Reg. at 24,058 -59; Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. at 58,624-26.

Inexplicably, EPA's Region 6 office, the same office that drafted the Texas FIP, abandoned these established procedures when developing the Final F IP here. EPA did not perform a Q/D analysis, did not perform source apportionment modeling to quantify impacts from individual sources, and did not determine the threshold above which a potential visibility improvement could be achieved. Simply put, EPA did no evaluation to identify the Arkansas point sources that contribute to visibility impairment (or the scope of those contributions) at Caney Creek or Upper Buffalo. Instead, EPA pre-judged the matter and subjected only Independence to the

four-factor Reasonable Progress analysis, in which an evaluation of potential visibility impacts is completely absent. EPA's sole explanation is that Independence is a large source of emissions and EPA deemed it "unreasonable to ignore" the facility. 80 Fed. Reg. at 18,992 (JA-___). EPA provided no reasoned explanation for its new approach for analyzing Reasonable Progress in the Final FIP, rendering it arbitrary and capricious. *See F.C.C. v. Fox*, 129 S. Ct. at 1811.

EPA acknowledged that its approach in Arkansas diverges from the one it took in other states, EPA Response to Comments at 109 (JA -___). Yet EPA provided no rational justification for abandoning the approach used consistently in other states and firmly established in guidance as the proper methodology . *See* Reasonable Progress Guidance at 3-2 (JA-___) (directing the Agency to "consider a broad array of sources and activities when deciding which sources or source categories contribute significantly to visibility impairment.").

This stark departure *requires* a satisfactory explanation. *See Dillmon v. NTSB*, 588 F.3d at 1089 -90. EPA merely explained that it felt it sufficient to target the three largest point sources of SO_2 and NOx emissions in Arkansas for a potential Reasonable Progress analysis (White Bluff, Independence, and AEP's Flint Creek plant). *See* EPA Response to Comments at 108 -09 (JA-___). Because White Bluff and Flint Creek are subject to BART, EPA concluded that no additional controls were necessary at those sources, so the Reasonable Pro gress analysis fell solely on Independence. *Id.*

This explanation is wholly inadequate because it fails to address whether those three largest sources are in fact contributing to visibility impairment at Caney Creek and Upper Buffalo, or whether smaller sources in the state also may contribute to visibility impairment. And it ignores the possibility that smaller sources could be larger contributors to impairment, due to factors such as proximity, quantity, type and relative location to the Class I areas. It is unreasonable to simply assume that the three largest sources of emissions (and only those sources) contribute to visibility impairment that may be remedied by the installation of Reasonable Progress controls. Because EPA failed to provide a reasoned basis for ignoring these other emission sources for Reasonable Progress purposes, its novel approach is arbitrary and capricious.

2. EPA's Reasonable Progress Analysis for Arkansas Violates the CAA's National Uniformity Mandate.

The CAA's national uniformity mandate requires EPA to "assure fairness and uniformity in the criteria, procedures, and policies applied by the various regions in implementing and enforcing [the CAA]." 42 U.S.C. § 7601(a)(2). This language is unambiguous. EPA must uniformly implement and enforce the CAA across the country. EPA has adopted this requirement into its own regulations, which instruct the Agency to strive for "standardiz[ed] criteria, procedures and policies" when "implementing and enforcing the act." 40 C.F.R. §§ 56.3(a) and (b). The regulations further oblige EPA to ensure that actions taken under the CAA: (1) "[a]re carried out

fairly and in a manner that is consistent with the Act and Agency policy as set forth in the Agency rules and program directives" and (2) "[a]re as consistent as reasonably possible with activities of other Regional Offices." 40 C.F.R. § 56.5(a). *See Nat'l Envtl. Dev. Assoc.'s Clean Air Project v. EPA*, 752 F.3d 999, 1009–11 (D.C. Cir. 2014) (vacating, based on regional consistency regulations, EPA memorandum directing certain regional offices to use a different methodology in a certain type of permitting analysis).

EPA's Reasonable Progress analysis in the Final FIP disregarded this statutory and regulatory obligation to implement the CAA consistently and fairly across the country. As explained above, EPA's analysis in Arkansas was entirely different from its approach used in numerous other states. The Reasonable Progress control determination for Independence must be vacated for failure to comply with the CAA's national uniformity mandate.

IV. THE COMPLIANCE DEADLINE FOR NOX CONTROLS AT WHITE BLUFF AND INDEPENDENCE IS NOT A LOGICAL OUTGROWTH OF THE PROPOSAL AND IS ARBITRARY AND CAPRICIOUS.

The Final FIP imposes NOx emissions limits on White Bluff and Independence that must be met in an unduly short time—only 18 months from the date of the Final FIP. The compliance deadline is not a logical outgrowth of the Proposed FIP and must be vacated.

A. The 18-Month Compliance Deadline Is Not a Logical Outgrowth of the Proposed FIP.

In the Final FIP, EPA shortened the compliance deadline for the NOx emission limits for White Bluff and Independence from a proposed three-year period to 18 months, unexpectedly and unlawfully *halving* the time allotted for coming into compliance. 81 Fed. Reg. at 66,338, 66,354, 66,416, 66,420 (Add. 8, 24, 86, 90) (JA-___, JA -___, JA -___, JA -___). This extreme alteration of the compliance deadline violates the notice-and-comment requirements of the CAA and the APA, which permit EPA's "proposed rule and its final rule ... [to] differ only insofar as the latter is a 'logical outgrowth' of the former." *Envtl. Integrity Project v. EPA*, 425 F.3d 992, 996 (D.C. Cir. 2005). An agency's final rule may not "pull a surprise switcheroo on regulated entities," *id.* at 996, and thus is only a logical outgrowth of its proposal "if interested parties should have anticipated that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *CSX Transp., Inc. v. Surface Transp. Bd.*, 584 F.3d 1076, 1079–80 (D.C. Cir. 2009) (citation omitted). Courts have made clear that interested parties are not required to "divine [the agency's] unspoken thoughts," *id.* at 1080, and, without proper notice, are deprived of the opportunity "to offer comments that could persuade the agency to modify its rule." *Nat'l Exch. Carrier Ass'n, Inc. v. FCC*, 253 F.3d 1, 4 (D.C. Cir. 2001) (citation omitted).

EPA did not solicit comments on the proposed three -year NOx deadline f or White Bluff and Independence or even suggest it was considering a shorter compliance timeframe. This stands in stark contrast to EPA's express solicitation of comments regarding the compliance deadlines for other sources. *See, e.g.*, 80 Fed. Reg. at 18 ,985 (JA -___) (proposing three -year compliance deadline, but soliciting comments on one to five years); *id.* at 18,988 (JA -___) (proposing three -year compliance deadline of three years, but soliciting comments "on the appropriateness" of this date). EPA's specific requests for feedback on the appropriate length of certain deadlines indicated that the Agency was not considering alternatives to the other proposed deadlines for which it did not solicit comment. Accordingly, Petitioners had no reason to antici pate that a change to the deadlines for White Bluff or Independence was under consideration. *See CSX Transp., Inc.,* 584 F.3d at 1079.

Indeed, EPA itself suggested in the Final FIP that it had *not* been considering changing the proposed three -year deadline. In finalizing the shorter deadline, EPA stated that it made the change in response to comments it received from environmental groups. *See* 81 Fed. Reg. at 66,378 (Add. 48) (JA-___). EPA explained that the comments urged the Agency to shorten the compliance deadline "because the typical installation timeframe for low NOx burners is 6–8 months from bid evaluation through startup of the technology" and because Entergy "may have already started the process of installing LNB/SOFA controls in anticipation of the BART requirement." *Id.* at 66,342 (Add. 12) (JA-___). EPA's receipt of comments on the White Bluff and

Independence compliance deadline does not satisfy the Agency's obligation under the CAA and APA to provide proper notice; it is well -established tha t EPA "cannot bootstrap notice from a comment."[13] *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 549 (D.C. Cir. 1983); *Am. Fed'n of Labor v. Donovan* , 757 F.2d 330, 340 (D.C. Cir. 1985).

B. EPA's Decision to Shorten the Compliance Deadline to 18 Months Is Arbitrary and Capricious.

The unexpected curtailment of the compliance deadline is not harmless error. EPA provided no reasoned basis for its truncation of the compliance schedule, rendering the 18 -month deadline arbitrary and capricious. Contrary to EPA's unsupported assumptions, LNB/SOFA cannot be installed and properly commissioned at White Bluff and Independence within 18 months, in light of the extensive work that must go into planning, permitting, designing, engineering, procuring, installing, tuning, and testing such massive equipment on four units.[14] The environmental commenters' request for a shorter deadline was based on an expert

[13] The unexpected curtailment of the compliance deadline is not harmless error. EAI cannot ensure the LNB/SOFA equipment is inst alled and operating in a manner that will secure reliable and consistent compliance with the NOx limits at all four units by the 18-month deadline, even though EAI has truncated its internal procedures for the project and work already is underway. *See* Entergy Petition for Reconsideration at 10-12 (JA-___).

[14] EAI has obtained a permit for the installation of LNB/SOFA at White Bluff Units 1 and 2, and has the equipment onsite at Unit 1, but a massive amount of work still remains before LNB/SOFA can be permit ted, installed, and commissioned at all four units.

report, which, in turn, relied on a 10 -year-old vendor association report. Comments of Earthjustice, National Parks Conservation Association, and Sierra Club, Docket No. EPA -R06-OAR-2015-0189-0153, at 25 (Aug. 7, 2015) (JA -___); Victoria R. Stamper, Technical Support Document to Comments of Conservation Organizations, Docket No. EPA-R06-OAR-2015-0189-0171, at 46 (Aug. 5, 2015) (JA-___).

The vendor association report did not account for any site -specific factors, such as permitting considerations, a company's internal project development and approval process, site characteristics, or reliability concerns associated with outages necessary for the installation of LNB/SOFA at multiple units. To the contrary, the vendor association report explicitly acknowledged that deployment time may vary depending on the specific conditions of a given site. Entergy Petit ion for Reconsideration at 10 (JA -___) (citing Institute of Clean Air Companies, Typical Installation Timelines for NOx Emission Control Technologies on Industrial Sources, at 4 (Dec. 4, 2006)).

The outdated, generic information about timing included in the environmental group comments does not provide a reasonable basis for shortening the deadline for these *specific* units. EPA did not even attempt to explain how the shortened deadline is reasonable for White Bluff and Independence in light of site -specific and company -specific considerations, and Entergy was given no opportunity to provide such information to EPA.

EPA's about-face is even more arbitrary in light of the fact that the Agency typically provides five years for the installation of LNB/SOFA in regional haze FIPs. *See, e.g.*, Final Montana Regional Haze FIP, 77 Fed. Reg. at 57,875 (allowing five years where installation of additional controls was necessary); Final Wyoming Regional Haze FIP, 79 Fed. Reg. 5,032, 5,038-39 (Jan. 30, 2014) (same); Final North Dakota Regional Haze FIP, 77 Fed. Reg. 20,894, 20,907 (Apr. 6, 2012) (same).

In this case, Entergy has only acquired control equipment for one unit at White Bluff, and still must procure equipment for the second White Bluff unit and both Independence units (and install the equipment on all four units) to comply with the requirements in the Final FIP. Entergy Petition for Reconsideration at 11 n.46 (JA-___). It is arbitrary and capricious to require the same deadline in both circumstances when the amount of progress varies so greatly. Had EPA solicited comments on the shorter deadline for the NOx controls, Entergy would have explained the process required to install LNB/SOFA at four generating units and would have demonstrated that an 18-month deadline is infeasible. *See* Entergy Petition for Reconsideration at 13 (JA-___).

V. THE LOW-LOAD NOX EMISSIONS LIMIT APPLICABLE TO WHITE BLUFF AND INDEPENDENCE IS NOT A LOGICAL OUTGROWTH OF THE PROPOSED FIP AND IS UNACHIEVABLE.

The final emissions limit that applies to White Bluff and Independence during periods of low-load operation is not a logical outgrowth of the proposed NOx limits.

See Envtl. Integrity Project, 425 F.3d at 996. Petitioners did not have an opportunity to comment on EPA's novel approach to the emissions limit for low-load periods, which is unachievable. Therefore, the final low-load NOx emission limit applicable to White Bluff and Independence must be vacated.

The Proposed FIP included a single NOx emissions limit for all periods of operation, to be met by each White Bluff and Independence unit on a rolling 30-boiler operating day average basis. 80 Fed. Reg. at 18,974-75 (JA -___). EAI submitted comments explaining that EPA's proposed limits could not be met during low-load operations and offered an alternative low-load limit. *See* EAI Comments at 51 (JA-___) (proposing a 30-boiler operating day rolling average limit of 1,342.5 lb/hr for all periods of unit operation). In the Final FIP, EPA attempted to address low load operation by adopting a separate limit but its limit differs substantially from Entergy's proposed solution. 81 Fed. Reg. at 66,416-17 (Add. 86-87) (JA -___) (requiring the units to meet a three-hour rolling average limit of 671 lb/hr at loads of less than 50 percent of maximum heat input rating).

Petitioners had no opportunity to comment on the achievability of the level of the limit or the averaging period for compliance with the limit. Entergy Petition for Reconsideration at 13-14 (JA -___). Because Petitioners were deprived of the opportunity "to offer comments that could persuade the agency to modify" the NOx emissions limit, the low-load NOx limit should be vacated and remanded to EPA. *See Nat'l Exch. Carrier Ass'n, Inc.*, 253 F.3d at 4.

Had Petitioners been given the opportunity to comment, they would have explained to EPA that the low-load NOx emissions limits are not achievable. *See* Entergy Petition for Reconsideration at 13-14 (JA-___). This violates the requirement that, after conducting a BART or Reasonable Progress analysis, EPA adopt emissions limitations that can be *achieved* using the selected emission controls. 40 C.F.R. § 51.301 (BART is "an emission limitation based on the degree of reduction *achievable* through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility.") (emphasis added).

Here, EPA's adoption of a three-hour averaging period and an unreasonably low emission limit renders the limit unachievable during fluctuating load conditions. *See* Entergy Petition for Reconsideration at 13-14 (JA-___). White Bluff and Independence often operate as load-following, which requires the units to ramp up and down quickly, thereby potentially spiking NOx emissions to levels well above typical for short periods of time. EAI Comments at 51 (JA-___); Entergy Petition for Reconsideration at 13 (JA-___). While NOx emissions quickly stabilize, these brief spikes can cause an exceedance of EPA's low-load NOx limit when averaged over a short three-hour period.

EPA's introduction of the three-hour averaging period in the Final FIP means that a single short spike in NOx emissions could result in an exceedance of the low-load NOx emission limit for that period even if the required emission controls are operating properly. Entergy Petition for Reconsideration at 13-14 (JA-___).

Accordingly, the Court must vacate and remand this provision to EPA so it can establish achievable NOx limits at White Bluff and Independence during periods of low-load operation.

VI. THE FINAL FIP ARBITRARILY AND CAPRICIOUSLY IMPOSES NOX BART CONTROL REQUIREMENTS ON UNITS SUBJECT TO CSAPR

The Final FIP requires installation of source-specific NOx BART controls at EGUs that already are subject to the ozone-season NOx trading program under CSAPR. 40 C.F.R. § 52.38(b). The Regional Haze Rule explicitly provides that a "[s]tate . . . subject to a [Transport Rule] trading program [*i.e.*, CSAPR] . . . need not require BART-eligible [electric generating units]. . . to install, operate, and maintain BART" for the pollutant covered by such trading program. 40 C.F.R. § 51.308(e)(4). EPA's decision to impose costly BART control requirements on Arkansas sources, despite the Agency's determination that a state's participation in CSAPR satisfies BART obligations, is arbitrary and capricious. Accordingly, the Final FIP's NOx BART determinations for these sources should be vacated.

EPA has determined that participation in CSAPR provides greater Reasonable Progress towards the national visibility goal than BART with respect to emissions from EGUs in the CSAPR states. 77 Fed. Reg. 33,642, 33,643 (June 7, 2012) ("[T]he trading programs in the Transport Rule, also known as the Cross-State Air Pollution Rule (CSAPR), achieve greater reasonable progress towards the national goal of achieving natural visibility conditions in Class I areas than source-specific Best

Available Retrofit Technology (BART) in those states covered by the Transport Rule."). Arkansas is subject to CSAPR's ozone season NOx trading program 76 Fed. Reg. 48,208, 48,212 -13 (Aug. 8, 2011). However, despite the regulatory provisions allowing EGUs subject to a CSAPR trading program to rely on that program in lieu of BART, the Final FIP di sregards Arkansas' participation in CSAPR and imposes source-specific NOx BART requirements for BART-eligible EGUs.

EPA's failure to determine that CSAPR satisfies BART in Arkansas is arbitrary and capricious. EPA has historically allowed states to rely on participation in a trading program to satisfy BART requirements. *See, e.g.*, 81 Fed. Reg. 78,954, 78,958 (Nov. 10, 2016) (finding that recent changes to CSAPR do not adversely impact EPA's finding that CSAPR is better than BART for those states that co ntinue to participate in CSAPR). EPA's explanation for its inconsistent approach in Arkansas fails to show good reason for its change in policy. *See F.C.C. v. Fox*, 129 S. Ct. at 1811; *Friends of Boundary Waters Wilderness*, 164 F.3d at 1123.

EPA explain ed that it declined to consider CSAPR participation to satisfy BART because: (1) the choice to rely on CSAPR is discretionary; (2) in its 2008 BART SIP, ADEQ did not elect to rely on the predecessor transport rule that was vacated and subsequently replace d by CSAPR; and (3) the Agency was in the process of reconsidering state CSAPR emissions budgets at the time it was drafting Arkansas' FIP. EPA Response to Comments at 253 (JA -___). These explanations are not satisfactory. *See Niobrara River Ranch*, 373 F.3d at 884. First, regardless of whether

EPA has discretion to rely on CSAPR in lieu of BART, simply so stating does not establish that this discretion was exercised reasonably, particularly where EPA has established that participation in CSAPR will provide *greater* visibility improvement than source-specific BART. Second, whether ADEQ elected to rely on an entirely different trading program is irrelevant to EPA's independent determination that it would not rely on CSAPR. Third, the CSAPR ozone-season NOx emissions budget for Arkansas was not subject to EPA's reconsideration, and remained in effect through the duration of the rulemaking procedure. *See EME Homer City Generation, L.P. v. EPA,* 795 F.3d 118, 132 (D.C. Cir. 2015).[15] For these reasons, the requirement that Arkansas' EGUs must install BART NOx emission controls in addition to participation in the CSAPR trading program should be vacated.

CONCLUSION

Due to the numerous fatal flaws in the Final FIP, Petitioners respectfully request that the Court vacate the SO_2 and NOx requirements imposed upon White Bluff and Independence, and the source-specific NOx requirements for the BART EGUs in Arkansas that are subject to CSAPR.

[15] *See also* Proposed Texas BART FIP, 82 Fed. Reg. 912, 946 (Jan. 4, 2017) (proposing to rely on CSAPR to address NOx BART requirements for Texas EGUs, even though Texas budget was subject to reconsideration in *EME Homer City Generation, L.P. v. EPA*).

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Respectfully submitted,

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CERTIFICATE OF COMPLIANCE

The undersigned counsel states that this motion complies with FED. R. APP. P. 32(a)(7) because it contains 12,509 words, excluding the parts of the brief exempted by Fed. R. App. P. 32(f), as counted by a word processing system and, therefore, is within the 13,000 word limit. This motion also complies with typeface and type -style requirements of FED. R. APP. P. 27(a)(5) because it has been prepared in a proportionally spaced typeface in 14-point Garamond font.

Pursuant to Circuit Rule 28A(h), I also hereby certify that electronic files of this Brief and accompanying Addendum have been submitted to the Clerk via the Court's CM/ECF system and the files have been scanned for viruses and are virus free.

Dated: February 17, 2017

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CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing brief were served, this 17th day of February, 2017, through CM/ECF on all registered counsel.

/s/ Debra J. Jezouit

No. 16-4309

UNITED STATES COURT OF APPEALS
FOR THE EIGHTH CIRCUIT

NATIONAL PARKS CONSERVATION ASSOCIATION and SIERRA CLUB,

Petitioners,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, and CATHERINE MCCABE, Administrator, United States Environmental Protection Agency,

Respondents.

On Petition for Review of Final Action of
the United States Environmental Protection Agency

PROOF OPENING BRIEF OF PETITIONERS NATIONAL PARKS CONSERVATION ASSOCIATION AND SIERRA CLUB

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SUMMARY OF THE CASE AND REQUEST FOR ARGUMENT

The National Parks Conservation Association ("NPCA") and the Sierra Club challenge the Environmental Protection Agency's ("EPA") failure in the regional haze rule for Arkansas, 81 Fed. Reg. 66,332 (Sept. 27, 2016), to require sufficient pollution reductions from two of the state's largest sources of nitrogen oxide ("NO_X") air pollution, the Independence and Lake Catherine power plants, given the availability of reasonable pollution controls that have long been used in the industry. EPA's rule violates the Clean Air Act ("CAA") with respect to these NO_X limits in two ways. First, the controls required for reducing NO_X pollution from Independence are inadequate and are based on an approach to considering visibility benefits that has no basis in the statute and conflicts with EPA's long-standing interpretation of the CAA. Second, in failing to select more effective controls for reducing NO_X pollution from Lake Catherine, EPA departed from its well-established policy regarding which data to rely on when determining baseline emissions. These arbitrary actions led EPA to select the least-effective pollution controls for Independence and Lake Catherine, even though there are cost-efficient controls available that would improve air quality significantly.

Given the importance of the air pollution requirements at stake, NPCA and Sierra Club respectfully request that the Court hold argument and allot NPCA and Sierra Club 20 minutes.

CORPORATE DISCLOSURE STATEMENT

National Parks Conservation Association: NPCA has no parent companies, and there are no publicly held companies that have a 10% or greater ownership interest in NPCA. NPCA, a corporation organized and existing under the laws of the District of Columbia, is a nonprofit organization dedicated to protecting and enhancing America's national parks for present and future generations.

Sierra Club: Sierra Club has no parent companies, and there are no publicly held companies that have a 10% or greater ownership interest in Sierra Club. Sierra Club, a corporation organized and existing under the laws of the State of California, is a national nonprofit organization dedicated to the protection and enjoyment of the environment.

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GLOSSARY

BART	Best Available Retrofit Technology
BOOS	Burners out of Service
CAA	Clean Air Act
EPA	United States Environmental Protection Agency
FIP	Federal Implementation Plan
LNB+SOFA	Low-NO_X Burner and Separated Overfire Air
NO_X	Nitrogen Oxides or Oxides of Nitrogen
NPCA	National Parks Conservation Association
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide

JURISDICTIONAL STATEMENT

This Court has jurisdiction to review EPA's final rule "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan," published at 81 Fed. Reg. 66,332 on September 27, 2016 ("Final Rule" or "Arkansas regional haze FIP"), JA____. "A petition for review of the Administrator's action in approving or promulgating any implementation plan under section 7410 . . . which is locally or regionally applicable may be filed only in the United States Court of Appeals for the appropriate circuit." 42 U.S.C. § 7607(b)(1). EPA's promulgation of a regional haze FIP for Arkansas is locally applicable, and, therefore, both jurisdiction and venue are proper in this Court. *See id.*

NPCA and Sierra Club timely filed this petition for review on November 28, 2016, within the 60-day window allowed under the CAA from the rule's publication in the Federal Register, which occurred on September 27, 2016. *See id.*; 81 Fed. Reg. 66,332, JA____.

STATEMENT OF ISSUES

1. Are the limits on NO_X pollution from the Independence power plant set forth in the Arkansas regional haze FIP arbitrary and capricious or otherwise unlawful where EPA's consideration of visibility benefits is inconsistent with the CAA and agency policy and EPA failed to consider all of the visibility benefits of more effective controls?

Apposite Cases and Statutes:

- 42 U.S.C. § 7491(a)(1), (b)(2), (g)(1), (g)(2)
- *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983)
- *Grace Healthcare of Benton v. U.S. Dep't of Health & Human Servs.*, 603 F.3d 412 (8th Cir. 2009)

2. Are the limits on NO_X pollution from the Lake Catherine power plant set forth in the Arkansas regional haze FIP arbitrary and capricious or otherwise unlawful where EPA departed, without justification, from established agency policy on the use of data to determine baseline emissions and relied on unenforceable assumptions about the plant's operations?

Apposite Cases:

- *Encino Motorcars, LLC v. Navarro*, 136 S. Ct. 2117 (2016)

- *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502 (2009)
- *Grace Healthcare of Benton v. U.S. Dep't of Health & Human Servs.*, 603 F.3d 412 (8th Cir. 2009)
- *ANR Pipeline Co. v. FERC*, 71 F.3d 897 (D.C. Cir. 1995)

STATEMENT OF THE CASE AND FACTS

I. ENTERGY'S INDEPENDENCE AND LAKE CATHERINE POWER PLANTS

Emissions from Entergy's Independence and Lake Catherine power plants pollute the air in at least four Class I[1] areas: the Caney Creek and Upper Buffalo Wilderness Areas in Arkansas and the Hercules-Glades Wilderness Area and Mingo National Wildlife Refuge in Missouri. 80 Fed. Reg. 18,944, 18,946, 18,976 (Apr. 8, 2015), JA____, ____. Independence is a large coal-fired power plant and the second-largest stationary source of air pollution in Arkansas. *Id.* at 18,991, JA____. In 2011, Independence emitted more than 30,000 tons of sulfur dioxide ("SO_2") and more than 13,000 tons of NO_X. *Id.* Independence emits more SO_2 pollution than the next thirteen largest emitters in Arkansas, and Independence emits more NO_X pollution than the next eight largest emitters. *See id.* The Independence plant has not installed any post-combustion controls for reducing SO_2 or NO_X. *See* TSD for the Proposed FIP at 136, JA____.

Entergy's Lake Catherine Unit 4 is able to burn both natural gas and fuel oil to generate electricity, although Entergy states that the unit has not burned fuel oil since prior to 2001. 80 Fed. Reg. at 18,975, JA____. Unit 4 began commercial operation in 1970. In the more than forty years the unit has been operating,

[1] The CAA classifies certain national parks and wilderness areas as "Class I areas," 42 U.S.C. § 7472(a), which receive the highest protections under the Act.

Entergy has not installed any post-combustion pollution controls for NO_X at Unit 4. *See id.* at 18,977, JA____ ("Lake Catherine Unit 4 is not currently equipped with any NO_X pollution control equipment."). Entergy's consultant estimated that Unit 4 emits more than 1,200 tons of NO_X pollution per year. Trinity Consultants, BART Five Factor Analysis, Lake Catherine Steam Electric Station, EPA Docket ID No. EPA-R06-OAR-2015-0189-0050, at 6-7 (Mar. 2013), JA____.

II. THE CLEAN AIR ACT'S REGIONAL HAZE PROGRAM

In what has been lauded as "America's best idea," Congress first set aside national parks and wilderness areas in the nineteenth century to preserve some of the nation's most spectacular scenery and wildlife habitat.[2] Today, air pollution is "perhaps the greatest threat" to those national treasures.[3] Indeed, most national parks and wilderness areas now suffer from air pollution that both obscures scenic vistas and is dangerous to human health. 64 Fed. Reg. 35,714, 35,715 (July 1, 1999). Much of the air pollution in national parks stems from power plant emissions of SO_2 and NO_X, which react in the atmosphere to form "haze" pollution many miles away from the power plants.

In 1977, to protect the "intrinsic beauty and historical and archaeological

[2] John Copeland Nagle, *The Scenic Protections of the Clean Air Act*, 87 N.D. L. Rev. 571, 576 (2011).

[3] *Id.* at 573.

treasures"[4] of the nation's public lands, Congress set "as a national goal" clearing the nation's parks and wilderness areas of man-made visible air pollution and returning these Class I areas to their natural state. 42 U.S.C. § 7491(a)(1). To reach the goal of achieving natural visibility conditions by 2064, the deadline set forth in the CAA's implementing regulations, 40 C.F.R. § 51.308(d)(1)(i)(B), the states are directed to create regional haze plans, which are then submitted to EPA for its review and approval. *See* 42 U.S.C. §§ 7410(a), 7491(b)(2). EPA evaluates each state's plan and either approves or disapproves it in whole or in part. *Id.* § 7410(k)(3). If EPA determines that a state's plan does not comply with the CAA, then EPA must promulgate a federal plan that remedies the shortcomings. *Id.* § 7410(c)(1); *see North Dakota v. EPA*, 730 F.3d 750, 762 (8th Cir. 2013).

A. <u>BART Emission Limits</u>

Each state's regional haze plan must include emissions limits on sources of air pollution within the state as necessary to protect visibility at all impacted Class I areas, both inside and outside the state. *See* 42 U.S.C. § 7491(a)(4), (b)(2). In particular, a state implementation plan ("SIP") must include emissions limits reflecting installation and operation of the best available retrofit technology, or BART. *Id.* § 7491(b)(2)(A). BART is defined as:

> an emissio n limitation based on the degree of reduction achievable through the application of the best system of continuous emission

[4] H.R. Rep. No. 95-294, at 203 (1977), *reprinted in* 1977 U.S.C.C.A.N 1077, 1282.

> reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

40 C.F.R. § 51.301; *see also* 42 U.S.C. § 7491(g)(2) (setting forth the factors to be considered when determining BART). BART is required at eligible sources[5] that are reasonably anticipated to cause or contribute to visibility impairment at national parks, wilderness areas, wildlife refuges, and other "Class I areas" where air quality should be pristine. 42 U.S.C. § 7491(b)(2)(A). BART is an essential component of the regional haze program as it compels emissions reductions from older, disproportionately polluting sources that often have escaped control under other CAA programs.

B. Reasonable Progress

In addition to requiring BART, each state must evaluate whether and what other measures are necessary to assure reasonable progress toward the national goal of eliminating haze pollution. *See* 42 U.S.C. § 7491(b)(2); 40 C.F.R. § 51.308(f)(2). These additional controls are referred to as reasonable progress

[5] A source is BART-eligible if it is a stationary source within one of 26 enumerated categories, was not in operation before August 7, 1962, but was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any pollutant. 42 U.S.C. § 7491(b)(2)(A), (g)(7).

controls. Both the statute and implementing regulations provide that reasonable progress controls should be based on a consideration of "the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources . . . ." 40 C.F.R. § 51.308(d)(1)(i)(A); *see also* 42 U.S.C. § 7491(g)(1).

After EPA has considered the four statutory factors to determine what set of controls constitutes reasonable progress, EPA sets reasonable progress goals. The reasonable progress goals are not enforceable goals, 40 C.F.R. § 51.308(d)(1)(v), but instead are a quantitative measure of anticipated progress in visibility conditions. The reasonable progress goals represent the visibility conditions that would exist if all of the measures in the applicable haze plan were implemented. EPA developed the concept of reasonable progress goals as a tool for tracking the progress that states are making towards the mandate of natural visibility. By first considering the four factors in 42 U.S.C. § 7491(g)(1), EPA can develop reasonable progress goals that are based on the pollution controls which the four-factor analysis shows are reasonable.

III. DEVELOPMENT OF THE REGIONAL HAZE PLAN FOR ARKANSAS

A. <u>The Haze Plan Submitted by the State of Arkansas</u>

The State of Arkansas failed to submit a haze plan to EPA by the Regional Haze Rule's December 17, 2007 deadline, 40 C.F.R. § 51.308(b). In 2008, the

State submitted an incomplete plan, which it supplemented in 2010. Then, nearly four years after the deadline, on September 27, 2011, the state finally submitted a complete regional haze plan. 81 Fed. Reg. at 66,333, JA____.

EPA found that for nearly all of the State's BART determinations, "the State did not satisfy all the regulatory and statutory requirements." 77 Fed. Reg. 14,604, 14,605 (Mar. 12, 2012), JA____. EPA "conclude[d] that the flaws and omissions in the State's BART analyses were significant, and that the State therefore lacked adequate record support and a reasoned basis for its analyses . . . ." *Id.* In addition to disapproving the State's BART determinations, EPA disapproved the corresponding portions of the State's long-term strategy. *Id.* at 14,676-77, JA____-__. No party challenged the 2012 rule disapproving parts of Arkansas's haze plan, and EPA's disapproval of the Arkansas SIP is not at issue in this proceeding.

B. <u>The FIP Developed by EPA</u>

Under the CAA, EPA's final disapproval of the SIP triggered a requirement for EPA either to approve a corrected SIP or to issue a FIP within two years of the disapproval. 42 U.S.C. § 7410(c)(1). When EPA failed to approve or issue a corrected plan within two years, Sierra Club filed a lawsuit to compel EPA to comply with the Act. The district court ordered EPA either to approve a corrected SIP or issue a FIP by August 31, 2016. Opinion and Order, *Sierra Club v.*

McCarthy, No. 4:14-cv-643-JLH, Doc. 93 (E.D. Ark. Nov. 3, 2015).

The State failed to submit a corrected plan, so EPA issued a FIP, which was published in the Federal Register on September 27, 2016. 81 Fed. Reg. 66,332, JA____. EPA's plan establishes BART emission limits for SO_2, NO_X, and particulate matter for several sources that contribute to visibility impairment at Caney Creek and Upper Buffalo in Arkansas, as well as Hercules-Glades and Mingo in Missouri. The plan also establishes emission limits for SO_2 and NO_X for the Entergy Independence power plant pursuant to the reasonable progress and long-term strategy provisions of the CAA. The plan will cut about 68,500 tons of SO_2 emissions per year and 15,100 tons of NO_X per year, which will better protect the parks and refuge areas from hazy conditions, while also providing health and environmental benefits.[6]

C. Provisions of the FIP Regarding Independence and Lake Catherine

1. NO_X Controls for Independence

The primary technologies for reducing NO_X emissions range from the least effective controls, low-NO_X burners and separated overfire air ("LNB+SOFA"), to selective non-catalytic reduction ("SNCR"), to the most effective control, selective catalytic reduction ("SCR"). *See* 80 Fed. Reg. at 18,973, JA____. LNB+SOFA

[6] Press Release, EPA, EPA Addresses Arkansas Regional Haze Goals (Sept. 1, 2016), https://www.epa.gov/newsreleases/epa-addresses-arkansas-regional-haze-goals.

remove only between 43% and 50% of NO_X emissions.[7] SCR, however, can reduce NO_X emissions by between 79% to 82%.[8] In its analysis of NO_X controls for Independence, EPA considered only a single option, which is also the least-effective option: LNB+ SOFA. 81 Fed. Reg. at 66,353, JA____. EPA did not analyze more effective NO_X controls for Independence, such as SCR, opting instead to rely on the analysis it had conducted for a different facility, White Bluff. *See* 80 Fed. Reg. at 18,995, JA____ ("Since our proposed BART determination for the White Bluff facility is that LNB/SOFA is more cost effective (lower $/ton) than SNCR or SCR, and that the additional visibility benefits obtained as a result of the greater level of control SNCR and SCR offer over combustion controls are not worth the additional cost of SNCR or SCR, we expect that the same would apply to Independence Units 1 and 2.").

EPA relied on the White Bluff analysis even though White Bluff is subject to the BART requirements, *see* 81 Fed. Reg. at 66,338, JA____, whereas Independence is not subject to BART but is instead subject to the reasonable progress requirements. *See id.* Under the Clean Air Act, BART must be

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[7] *See* 80 Fed. Reg. at 18,973, JA____ (LNB+SOFA would remove 3,104 tons per year of the 7,249 tons which White Bluff Unit 1 emits); *id.* (LNB+SOFA would remove 4,125 tons per year of the 8,185 tons which White Bluff Unit 2 emits).

[8] *See id.* (LNB+SOFA+SCR would remove 5,729 tons of the 7,249 tons which White Bluff Unit 1 emits each year, and LNB+SOFA+SCR would remove 6,697 tons out of the 8,185 tons which White Bluff Unit 2 emits annually). In other haze plans, EPA has found that SCR can remove a higher percentage of NO_X emissions.

determined after considering the visibility improvement from controls, 42 U.S.C. § 7491(g)(2), whereas the statute does not require consideration of visibility improvement in determining reasonable progress, *id.* § 7491(g)(1).

After considering only the least-effective option for reducing NO_X, EPA selected the only option it had considered: LNB+SOFA. 81 Fed. Reg. at 66,353, JA____. EPA claimed that the incremental costs of more effective controls such as SCR were too high to justify the allegedly small incremental benefits of such controls. Response to Comments at 95-96, JA____-__.

In every control determination EPA made in the Final Rule except for Independence, EPA considered the cumulative visibility benefits that would be achieved at both the Arkansas and Missouri Class I areas. *Id.* at 374, JA____.[9] EPA explained that "[g]iven that the national goal of the program is to improve visibility at all Class I areas, it would be short-sighted to limit the evaluation of the visibility benefits of a control to only the most impacted Class I area." *Id.*

Similarly, in other haze plans EPA has issued, EPA has considered the

[9] When determing BART controls for each facility, EPA calculated and considered the visibility impacts at the four most affected Class I areas: Caney Creek, Upper Buffalo, Hercules-Glades, and Mingo. *See* 80 Fed. Reg. at 18,950, 18953-54, 18,956, JA____, ____-__, ____ (AECC Bailey Unit 1), 18,959, 18,961, 18,964, JA____, ____, ____ (AECC McClellan Unit 1), 18,966, 18,968, JA____, ____ (Flint Creek Unit 1), 18,972, 18,974 (White Bluff Unit 1), 18,978, JA____ (Lake Catherine Unit 4), 18,981, 18,983, 18,985, 18,987, JA____, ____, ____, ____ (Domtar Power Boiler Nos. 1 and 2).

visibility benefits of controls at each Class I area affected by the source. *See, e.g.*, 77 Fed. Reg. 23,988, 24,065, 24,067 (Apr. 20, 2012) (Montana) (when evaluating reasonable progress controls for NO_X at Colstrip Units 3 and 4, considering visibility benefits at out-of-state areas in Wyoming, the North Absaroka and Washakie Wilderness Areas); 77 Fed. Reg. 33,022, 33,056 (June 4, 2012) (Wyoming) (in evaluating reasonable progress controls for NO_X at Dave Johnston Units 1 and 2, considering visibility benefits at an out-of-state Class I area in South Dakota, Wind Cave National Park); 79 Fed. Reg. 5032, 5048 (Jan. 30, 2014) (Wyoming) (in approving the most stringent NO_X controls for Jim Bridger Units 3 and 4, noting that "[w]e also considered the visibility improvements at other impacted Class I areas," including out-of-state Class I areas such as Yellowstone National Park in Montana and Rocky Mountain National Park in Colorado).[10]

But in rejecting more effective controls such as SCR for Independence, EPA considered only the visibility benefits that controls would achieve at Arkansas's Class I areas. Response to Comments at 96, JA____ ("The visibility improvement

[10] EPA also has approved analyses by states which considered how a reasonable progress source would impact visibility at out-of-state Class I areas. *E.g.*, 77 Fed. Reg. 11,452, 11,467 (Feb. 27, 2012) (proposing to approve the State of Georgia's reasonable progress analysis for Savannah Mill, after noting that the State evaluated the mill's visibility impacts "at the Cape Romain area in South Carolina, and . . . at the Swanquarter area in North Carolina"); 76 Fed. Reg. 33,662, 33,675 (June 9, 2011) (proposing to approve Tennessee's reasonable progress analysis for a INVISTA facility which impacts the Cohutta Wilderness Area in Georgia).

projected to take place at Hercules-Glades and Mingo [in Missouri] due to controls at Independence did not affect our proposed decision for reasonable progress controls.”).

2. *NO_X Controls for Lake Catherine*

For the Lake Catherine power plant, EPA determined that the BART limits for NO_X should be based on the use of Burners out of Service (“BOOS”), which EPA estimated would reduce annual NO_X emissions by roughly 54%. 80 Fed. Reg. at 18,977, JA____. BOOS was the least-effective control technology which EPA evaluated for Lake Catherine, as more effective controls such as SCR would reduce emissions by approximately 94%. *Id.*

EPA rejected more effective controls (*e.g.,* SNCR) because the incremental cost-effectiveness allegedly was too high relative to the visibility benefits of such controls. *Id.* at 18,978, JA____. EPA rejected the most effective control technology (*e.g.,* SCR) because both the average and incremental cost-effectiveness allegedly were too high relative to the visibility benefits of that technology. *Id.*

One of the key components of a BART determination is establishing baseline emissions. *See* 40 C.F.R. pt. 51, app. Y § IV(D)(4)(d). In the BART analysis for Lake Catherine, EPA determined baseline emissions using an

unenforceable 10% capacity factor,[11] TSD for Proposed FIP at 96, JA____, meaning that EPA assumed the unit would generate only 10% of the maximum amount of electricity the unit is capable of generating. EPA arrived at this capacity factor by relying on data from 2011-2015, as well as data from 2003 to 2012. *See* Response to Comments as 314-15, JA____-__.

However, for all other BART determinations in the Final Rule, EPA followed a different policy. EPA's policy was to determine baseline emissions for BART sources by using 2001-2003 data, except where a source had installed new pollution controls after the 2001-2003 time period. *See* 80 Fed. Reg. at 18,948, JA____ (using 2001-2003 emissions data for the Georgia-Pacific Mill), 18,950, JA____ (using 2001-2003 emissions data for AECC Bailey), 18,957, JA____ (using 2001-2003 emissions data for AECC McClellan), 18,964, JA____ (using 2001-2003 emissions data for Flint Creek), 18,969, JA____ (using 2001-2003 emissions data for the SO_2 analysis for White Bluff).[12] Lake Catherine did not install new pollution controls for NO_X after 2001-2003. *See id.* at 18,977, JA____

[11] "Capacity factor" is calculated by dividing the actual amount of electricity generated by the maximum possible amount of electricity a plant could generate in a given period of time.

[12] Other than Lake Catherine, the only exceptions to EPA's policy of using 2001-2003 data were sources which had installed new pollution controls after the 2001-2003 time period. 80 Fed. Reg. at 18,969, JA____ (using 2009-2011 data for the NO_X analysis for White Bluff because new NO_X controls were installed after 2003), 18,979, JA____ (using 2009-2011 emissions data for SO_2 for Domtar Power Boiler No. 1 because the source installed new pollution controls after 2003).

("Lake Catherine Unit 4 is not currently equipped with any NO_X pollution control equipment.").

The baseline emissions rate plays a key role in BART determinations because EPA places great weight on cost-effectiveness, which is the cost of pollution controls divided by the tons of pollutants removed. *See* 40 C.F.R. pt. 51, app. Y § IV(D)(4)(b)-(c). The capital cost for controls at a given source is largely independent of how much the unit runs. However, the tons of pollutants removed depend heavily on how much a unit runs and, therefore, emits. All other things being equal, if a source has a high capacity factor, it will emit more pollutants and, thus, controls will remove more pollutants. Here, Lake Catherine had a much higher capacity factor during the 2001-2003 time period which EPA used for other BART analyses. During 2001-2003, Lake Catherine's average capacity factor was 21.23%, more than double the 10% capacity factor EPA used in its analysis. *See* Response to Comments at 314, JA____.

In the prior rulemaking in which EPA disapproved the State of Arkansas's haze plan, EPA proposed to disapprove the State of Arkansas's NO_X BART determination for Lake Catherine because it was based on the use of a 10% capacity factor, which was unenforceable and did not reflect periods during which the unit ran at much higher capacity factors. *See* 76 Fed. Reg. 64,186, 64,204 (Oct. 17, 2011). "Any cost effectiveness analysis based on a 10% capacity factor is

likely to significantly inflate the cost per ton of controlling this unit," and "the assumed 10% capacity utilization should be supported by an enforceable limit." *Id.*

EPA pointed out this identical flaw for another of the State's BART determinations: White Bluff. EPA proposed to disapprove the State's BART determination for the White Bluff power plant, in part, because the BART analysis used a capacity factor that was not enforceable. "Since the two [White Bluff] units are technically and legally capable of operating at 100% utilization, a cost estimate assuming 85% utilization may underestimate the amount of emission reductions achieved by the controls and therefore under-represent the potential cost-effectiveness of such controls." *Id.* at 64,206.

Despite EPA's statements in the prior rulemaking that it was inappropriate to use a 10% capacity factor for Lake Catherine, and despite EPA's contrary approach to other BART sources, the final BART determination for Lake Catherine is based on the use of an unenforceable 10% capacity factor.

SUMMARY OF THE ARGUMENT

EPA arbitrarily selected pollution limits reflecting the least effective controls for reducing NO_X pollution at the Independence and Lake Catherine power plants, despite the availability of cost-efficient controls that have long been used in the industry and would improve air quality significantly. The Court should remand the

NO_X limits for Independence and Lake Catherine in the Arkansas regional haze FIP with specific instructions to EPA to consider more stringent pollution controls consistent with the appropriate statutory and regulatory standards and EPA past practice. The Court should uphold and leave in place all other provisions of the Arkansas regional haze FIP.

Given that Independence is the second-largest source of air pollution in Arkansas, 80 Fed. Reg. at 18,991, JA____, EPA's failure to require cost-effective reductions in NO_X pollution from Independence will prevent Arkansas and Missouri Class I areas from making reasonable progress toward the CAA's visibility goal. The Final Rule requires Independence to install the least-effective pollution controls for NO_X, namely, LNB+SOFA. 81 Fed. Reg. at 66,353, JA____. EPA did not even consider more effective, technically feasible NO_X controls for Independence but, instead, opted to rely on an analysis for a different power plant, the White Bluff plant, which is subject to different legal requirements. *See* 80 Fed. Reg. at 18,995, JA____. Without conducting the proper analysis under the correct statutory standard, EPA rejected more effective technologies for reducing NO_X pollution from Independence on the ground that the incremental costs of more effective controls are allegedly too high to justify the allegedly small incremental benefits of such controls. Response to Comments at 95-96, JA____-__.

EPA's use of its analysis for White Bluff to determine controls for

Independence is unlawful for two reasons. First, under the CAA, White Bluff and Independence are subject to two separate legal requirements, each of which has its own set of factors that must be considered. White Bluff is subject to the BART requirements in 42 U.S.C. § 7491(g)(2), whereas Independence is subject to the reasonable progress requirements in 42 U.S.C. § 7491(g)(1). EPA acted unlawfully by substituting the legal standard for BART for the different legal standard for reasonable progress.

Second, EPA erred by considering the visibility benefits from controls at Independence in a manner that has no basis in the statute and which conflicts with EPA's stated policy. Whereas for White Bluff, EPA considered the visibility benefits which controls would produce in both Arkansas and Missouri, for Independence, EPA considered only the benefits in Arkansas. *See* Response to Comments at 96, JA____. EPA's failure to consider the visibility benefits in Missouri is inconsistent with the statutory mandate to make reasonable progress at *all* Class I areas; is inconsistent with EPA's approach in other haze rulemakings; and is illogical, because it considers all relevant costs but not all relevant benefits. Moreover, by placing primary weight on visibility benefits, EPA has inserted a factor which does not appear in the statutory definition of reasonable progress.

For the Lake Catherine power plant, EPA also required the least-effective technology it considered for reducing NO_X pollution. EPA's BART analysis for

Lake Catherine arbitrarily departed from EPA's past practice and its own BART guidelines regarding the calculation of baseline emissions. In the Final Rule, for every BART determination except for Lake Catherine, EPA used 2001-2003 data to determine baseline emissions, unless a source had installed new pollution controls after the 2001-2003 time period.

EPA found that Lake Catherine had not installed new pollution controls for NO_X after 2001-2003, yet EPA refused to rely on 2001-2003 data, as it had done for every other BART source. Instead, EPA relied on more recent data, which showed the plant running less than it had during 2001-2003. Specifically, EPA calculated baseline emissions by using more recent data which assume the plant produces only 10% of its maximum output, *i.e.*, that the plant has a 10% capacity factor. As a consequence of assuming that the plant will produce such little electricity, EPA also assumed the plant will produce fewer emissions, which makes the cost to remove each ton of pollution higher than it would be if the plant produced more electricity. This led EPA to reject more effective control technologies, on the grounds that such controls would cost too much to remove each ton of pollution.

EPA's use of more recent data in the Lake Catherine analysis arbitrarily conflicts with EPA's past approach to Lake Catherine and with EPA's policy on the data to use for BART determinations. EPA proposed to disapprove the State's

BART analysis for Lake Catherine precisely because EPA found that the use of a 10% capacity factor was inappropriate. EPA noted that Lake Catherine had a higher capacity factor in prior years, namely, 2001-2003, and that the plant is legally authorized to run as much as it wants, up to a 100% capacity factor. After leveling these criticisms of the State's use of a 10% capacity factor, EPA turned around and committed the same mistake in the FIP. Moreover, in haze rulemakings around the country, EPA routinely uses 2001-2003 data for baseline emissions. EPA's unjustified departure from its own precedent in this rule, and in other haze rules, renders the NO_X BART determination for Lake Catherine arbitrary and capricious.

ARGUMENT

I. STANDARD OF REVIEW

Provisions in the Arkansas regional haze FIP must be vacated if the decision was arbitrary, capricious, an abuse of discretion, or otherwise inconsistent with the CAA and implementing regulations. *See* 42 U.S.C. § 7607(d)(9). The CAA standard of review the Court uses for evaluating a FIP is the same standard as that prescribed by the Administrative Procedures Act, 5 U.S.C. § 706(2). *See North Dakota*, 730 F.3d at 758.

"[U]nexplained departure from prior agency practice is arbitrary and capricious." *Grace Healthcare of Benton v. U.S. Dep't of Health & Human Servs.*,

603 F.3d 412, 422 (8th Cir. 2009) (citing *Minnesota v. Ctrs. for Medicare & Medicaid Servs.*, 495 F.3d 991, 998 (8th Cir. 2007)). In addition, this Court has found agency actions to be arbitrary and capricious where the agency's decision violated applicable statutory or regulatory provisions or where the agency failed to provide a rational explanation for its final decision. *Barthel v. U.S. Dep't of Agric.*, 181 F.3d 934, 937-38 (8th Cir. 1999); *Friends of the Boundary Waters Wilderness v. Dombeck*, 164 F.3d 1115, 1124-25 (8th Cir. 1999); *Menorah Med. Ctr. v. Heckler*, 768 F.2d 292, 295 (8th Cir. 1985). If the agency has not supported its conclusions, courts will vacate and remand for further explanation. *New York v. EPA*, 413 F.3d 3, 34-36 (D.C. Cir. 2005); *Dakota Underground, Inc. v. Sec'y of Labor*, 200 F.3d 564, 568 (8th Cir. 2000).

II. NPCA AND SIERRA CLUB HAVE STANDING.

NPCA and Sierra Club have standing to challenge the Arkansas regional haze FIP. To satisfy Article III's standing requirements, "a plaintiff must show (1) it has suffered an 'injury in fact' that is (a) concrete and particularized and (b) actual or imminent, not conjectural or hypothetical; (2) the injury is fairly traceable to the challenged action of the defendant; and (3) it is likely, as opposed to merely speculative, that the injury will be redressed by a favorable decision." *Friends of the Earth, Inc. v. Laidlaw Envtl. Servs. (TOC), Inc.*, 528 U.S 167, 180-81 (2000) (citing *Lujan v. Defenders of Wildlife*, 504 U.S. 555, 560-561 (1992)). "An

association has standing to bring suit on behalf of its members when its members would otherwise have standing to sue in their own right, the interests at stake are germane to the organization's purpose, and neither the claim asserted nor the relief requested requires the participation of individual members in the lawsuit." *Friends of the Earth, Inc.*, 528 U.S. at 181 (citing *Hunt v. Wash. State Apple Adver. Comm'n*, 432 U.S. 333, 343 (1977)). The presence of one party with standing is sufficient to satisfy Article III's case-or-controversy requirement. *Rumsfeld v. Forum for Academic and Inst. Rights, Inc.*, 547 U.S. 47, 52 n.2 (2006).

NPCA and Sierra Club members would have standing in their own right to challenge provisions of the Final Rule that do not adequately reduce haze pollution. In the FIP, EPA established BART limits for controlling NO_X pollution from the Lake Catherine power plant and reasonable progress limits for the Independence power plant that are far less protective of visibility and human health than power plants across the country have been able to achieve with readily-available, cost-effective pollution control technology. The installation of more stringent, cost-effective NO_X pollution controls at Lake Catherine and Independence not only would yield significant visibility benefits at Arkansas and Missouri Class I areas, but also would result in significant health benefits for thousands of people across 14 states, including NPCA and Sierra Club members.

See Declaration of George Thurston ¶¶ 47-48, tbls. 1-3 (Jan. 15, 2017);[13] *see also* H. Andrew Gray, Visibility Modeling, Technical Support Document to Comments of Conservation Organizations, EPA Docket ID No. EPA-R06-OAR-2015-0189-0171, at 5-8 (Aug. 7, 2015), JA____-__. Because EPA's Final Rule does not require the Independence and Lake Catherine power plants to meet readily-achievable, cost-effective limits for NO_X pollution, the rule is not sufficiently protective of wilderness areas and wildlife refuges that NPCA and Sierra Club members use and enjoy or the air that they breathe.

By failing to require adequate reductions in NO_X pollution from the Arkansas power plants that cause haze, the Final Rule harms the protected recreational, environmental, aesthetic, and health interests of the thousands of NPCA and Sierra Club members who use and enjoy Arkansas's and Missouri's Class I areas and breathe the air in Arkansas and Missouri.[14] As the declarations

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[13] All declarations cited in this brief are in the addendum to this brief.

[14] *See, e.g.*, Declaration of Janet Nye ¶ 6 (Dec. 7, 2016) (haze pollution in the Upper Buffalo diminishes the "vistas of the Ozarks"); Declaration of Don Castleberry ¶¶ 3, 6 (Jan. 26, 2017) (describing regular visits to the Upper Buffalo Wilderness Area to hike, boat, and take photographs and describing the haze can be seen in the Upper Buffalo from places "such as Hawksbill Overlook"); Declaration of G. Thomas McKinney ¶ 10 (Jan. 12, 2017) ("nothing more dispiriting" than traveling to places in the Upper Buffalo and "finding the view ruined by haze"); Declaration of Robert Allen ¶¶ 5-6 (Jan. 9, 2017); Declaration of Jennifer Conner ¶ 8 (Dec. 7, 2016); Declaration of Jonathan Hickey ¶¶ 8-9 (Jan. 6, 2017); Declaration of Glen Hooks ¶¶ 14, 16 (Jan. 5, 2017) ("concerned about the impacts of haze pollution" on health); *see also* Declaration of Huda Fashho ¶ 4

submitted with this brief demonstrate, members of NPCA and Sierra Club visit and enjoy the spectacular views and breathe the air in the Class I areas in Arkansas and Missouri that are impaired by air pollution from Arkansas sources. NPCA and Sierra Club members hike, canoe, birdwatch, identify wildflowers, and enjoy and photograph the panoramic views in the Upper Buffalo Wilderness Area, especially the scenic views of the Upper Buffalo River bluffs and from the top of Hawksbill Crag (which locals refer to as Whitaker Point). Allen Decl. ¶¶ 4-5; Conner Decl. ¶ 8; Hooks Decl. ¶¶ 9-11; McKinney Decl. ¶¶ 7-8; Nye Decl. ¶ 3; Castleberry Decl. ¶¶ 3, 7. Sierra Club member Thomas McKinney also hikes in the Caney Creek Wilderness Area. McKinney Decl. ¶ 9. In Missouri, Sierra Club member Jonathan Hickey has been visiting the Mingo National Wildlife Refuge—which he refers to as the "Serengeti of Missouri" because of its huge vistas and abundant wildlife—for decades to canoe and kayak with friends and family. Hickey Decl. ¶¶ 6-9. Sierra Club member Jennifer Conner enjoys visiting the Hercules-Glades Wilderness Area because of its unique wildlife and the magnificent views from some of the tallest Ozark peaks in the region. Conner Decl. ¶¶ 5-7. Each of these NPCA and Sierra Club members regularly visits these parks to enjoy the unique vistas, and therefore each is harmed by the haze that diminishes views in these

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(Nov. 29, 2016) (Sierra Club has 2,597 members who live in Arkansas, and 9,000 members in Missouri).

otherwise wild places. Allen Decl. ¶ 5; Conner Decl. ¶¶ 7-8; Hickey Decl. ¶ 9; Hooks Decl. ¶ 11; McKinney Decl. ¶¶ 9-10.

Each of these NPCA and Sierra Club members, along with thousands of other members, also live or work in Arkansas or Missouri, Allen Decl. ¶ 2; Castleberry Decl. ¶3; Conner Decl. ¶ 2; Hickey Decl. ¶ 2; Hooks Decl. ¶ 2; McKinney Decl. ¶ 2; Nye Decl. ¶ 3, and are therefore harmed by breathing excess air pollution from Arkansas power plants. *See generally* Thurston Decl. ¶¶ 3, 6-7, 47-50 (describing adverse human health impacts associated with breathing air pollution from power plants, and modeling and quantifying public health impacts in 14 states from pollution emitted by the Arkansas power plants at issue). As demonstrated by modeling conducted by Dr. George Thurston, requiring more stringent pollution controls for NO_X at Independence and Lake Catherine would avoid more than $70 million *annually* in public health costs associated with the increased incidence of asthma and cardiovascular illness, premature mortality, and lost work and school days caused by pollution from those two power plants. *See* Thurston Decl. ¶ 44, tbl. 3. Thus, NPCA and Sierra Club members are reasonably concerned about the adverse health and environmental impacts of EPA's decision not to require more stringent pollution controls for NO_X at Independence and Lake Catherine. *See, e.g.*, Allen Decl. ¶¶ 8, 11-13; Hickey Decl. ¶¶ 12-13, 17; Hooks Decl. ¶¶ 14-16, 21-22; McKinney Decl. ¶¶ 12, 15-16. The Supreme Court and this

Circuit have long held that "reasonable concerns" about harm to aesthetic, recreational, or health interests are sufficient to demonstrate injury-in-fact for purposes of Article III standing.[15]

Further, these injuries to the NPCA and Sierra Club members' aesthetic, recreational, and health interests are fairly traceable to EPA's failure to require adequate pollution controls for the Lake Catherine and Independence power plants. If NPCA and Sierra Club were to prevail, and EPA were to require more stringent pollution controls at these three power plants, then there would be a reduction in the haze pollution that harms NPCA and Sierra Club members' recreational, aesthetic, and health interests. The causal link between NPCA and Sierra Club members' injuries and the inadequate pollution limits in the Final Rule satisfies the traceability requirement for Article III standing. *See Nat'l Wildlife Fed'n v. Agric. Stabilization & Conservation Serv.*, 901 F.2d 673, 677-78 (8th Cir. 1990) (finding that plaintiffs' alleged injuries stemming from the destruction of wetlands were fairly traceable to an exemption from a law that discouraged converting wetlands to cropland).

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[15] *See Friends of the Earth, Inc.*, 528 U.S. at 183-84 (noting "environmental plaintiffs adequately allege injury in fact when they aver that they use the affected area and are persons 'for whom the aesthetic and recreational values of the area will be lessened' by the challenged activity," or when they allege "reasonable concerns about the effects" of a particular activity on their protected interests (citation omitted)); *Sierra Club v. U.S. Army Corps of Eng'rs*, 645 F.3d 978, 989 (8th Cir. 2011).

Further, these aesthetic, recreational, and health harms caused by the Final Rule would be redressed by the Court granting this petition for review. *Id.* (finding that harm stemming from the destruction of wetlands could be redressed by a decision that would prevent further destruction). On remand, if EPA adopts more stringent requirements for the reduction of NO_X pollution from Independence and Lake Catherine power plants, then the aesthetic, recreational, and health harms to NPCA and Sierra Club members would be redressed. Allen Decl. ¶¶ 12-13; Conner Decl. ¶ 13; Hickey Decl. ¶¶ 18-19; Hooks Decl. ¶¶ 22-23; McKinney Decl. ¶¶ 16-17; *see generally Franklin v. Massachusetts*, 505 U.S. 788, 801-03 (1992) (holding redressability prong satisfied by request for declaratory relief even though any actual relief would require discretionary determination by President); *Bennett v. Spear*, 520 U.S. 154, 170-71 (1997) (plaintiffs satisfied the "relatively modest" redressability requirement where a finding that the agency had acted illegally would require the agency to reevaluate its final decision); *cf. Iowa League of Cities v. EPA*, 711 F.3d 844, 871 (8th Cir. 2013) (concluding that petitioners satisfied Article III's standing requirement "because 'there is some possibility that the requested relief,' namely remanding to the EPA for application of notice and comment procedures, would 'prompt the [EPA] to reconsider the decision that allegedly harmed'" the petitioners (quoting *Massachusetts v. EPA*, 549 U.S. 497, 518 (2007))).

Finally, NPCA and Sierra Club satisfy the requirements of associational standing because the interests at stake are germane to the purposes of both of the organizations,[16] and the defense of EPA's haze plan does not require the participation of any individual members. *See Mausolf v. Babbitt*, 85 F.3d 1295, 1302 (8th Cir. 1996) (conservation organization had standing to intervene in a lawsuit seeking to lift restrictions on snowmobiling in national parks, which would have directly impacted the conservationists' concrete aesthetic and recreational interests); *Int'l Union, United Auto., Aerospace and Agric. Implement Workers of Am. v. Brock*, 477 U.S. 274, 287-88 (1986) (holding union workers had associational standing where lawsuit raised a "pure question of law" and did not require evaluation of any of the "unique facts" personal to the union's members). Thus, NPCA and Sierra Club have standing to bring this case.

III. THE INADEQUATE LIMITS ON NO_X POLLUTION FROM THE INDEPENDENCE POWER PLANT ARE ARBITRARY AND CAPRICIOUS.

EPA unlawfully failed to require adequate reductions in NO_X pollution from

[16] Sierra Club's mission is to protect and restore wild places, and the organization has advocated across the country, including in Arkansas and Missouri, for regional haze plans that adequately protect human health and natural areas. Hooks Decl. ¶¶ 4-7; Hickey Decl. ¶ 4. Similarly, NPCA is a nonprofit organization with a mission of protecting and enhancing America's national parks for the use and enjoyment of present and future generations. Declaration of Stephanie Kodish ¶¶ 4, 6-8 (Dec. 7, 2016) (describing NPCA's mission and long-standing work to improve air quality in parks and wilderness areas in Arkansas). Over the past several years, NPCA has worked for effective regional haze plans and has participated in the rulemaking to develop the Arkansas regional haze plan. *Id.* ¶¶ 4-8.

the Independence power plant, the second-largest source of air pollution in Arkansas. 80 Fed. Reg. at 18,991, JA____. Independence emits over 13,000 tons of NO_X each year, which is more than double the NO_X emissions from the next-largest emitter. *Id.* Despite having been built decades ago, Independence still lacks post-combustion pollution controls for NO_X. *See* TSD for the Proposed FIP at 136, JA____.

The Final Rule requires Independence to install the least-effective pollution controls for NO_X, namely, LNB+SOFA. 81 Fed. Reg. at 66,353, JA____. EPA did not even analyze more effective NO_X controls for Independence. Instead, EPA relied on the analysis it had conducted for White Bluff, a different facility. 80 Fed. Reg. at 18,995, JA____ ("Since our proposed BART determination for the White Bluff facility is that LNB/SOFA is more cost effective (lower $/ton) than SNCR or SCR, and that the additional visibility benefits obtained as a result of the greater level of control SNCR and SCR offer over combustion controls are not worth the additional cost of SNCR or SCR, we expect that the same would apply to Independence Units 1 and 2."). EPA claimed that the incremental costs of more stringent controls such as SCR and SNCR are too high to justify the allegedly small incremental benefits of such controls. Response to Comments at 95-96, JA____-__.

EPA's use of the White Bluff NO_X analysis for Independence is unlawful for

two reasons. First, White Bluff and Independence are subject to two separate legal requirements, each of which has a different legal standard. White Bluff must install controls under BART, whereas Independence must install controls under reasonable progress. EPA acted unlawfully by substituting the legal standard for BART for the different legal standard for reasonable progress.

Second, EPA's purported reliance on the BART analysis for White Bluff to determine reasonable progress controls for Independence fails because EPA altered the White Bluff analysis in one critical, and unlawful, way when it applied it to Independence. While visibility improvement is not a consideration in a reasonable progress analysis per the statutory factors, where EPA considered it anyway, the agency should have made the cumulative assessment part of the consideration. Whereas EPA considered the visibility benefits that controls at White Bluff would produce in both Arkansas and Missouri, EPA expressly declined to consider the benefits in Missouri from controls at Independence. Response to Comments at 96, JA____ ("The visibility improvement projected to take place at Hercules-Glades and Mingo due to controls at Independence did not affect our proposed decision for reasonable progress controls."). EPA's failure to consider the benefits in Missouri is inconsistent with the statutory mandate to make reasonable progress at all Class I areas in the country, is inconsistent with EPA's approach to comparable analyses in other rules, and is illogical, because it considers all relevant costs but not all

relevant benefits. While EPA suggests that its approach is compelled by its prior approval of parts of the Arkansas haze plan, nothing in the prior approval action required or even authorized EPA's failure to consider all of the benefits of pollution controls at Independence.

A. EPA Considered the Wrong Factors when it Determined the Reasonable Progress Controls for NO_X for Independence.

The fundamental flaw in EPA's approach to NO_X controls for Independence is that EPA considered the wrong statutory factors. EPA required reductions in NO_X pollution from Independence under the statutory requirement to make reasonable progress toward eliminating haze pollution, 42 U.S.C. § 7491(b)(2). The CAA instructs states, or EPA, to determine what constitutes reasonable progress by considering four factors: "the costs of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements." *Id.* § 7491(g)(1).

Instead of applying these four statutory factors to technologies available for reducing NO_X pollution from Independence, EPA relied on the BART analysis it had conducted for White Bluff to reject the most effective technologies, SNCR and SCR. 80 Fed. Reg. at 18,995, JA____ ("Since our proposed BART determination for the White Bluff facility is that LNB/SOFA is more cost effective (lower $/ton) than SNCR or SCR, and that the additional visibility benefits obtained as a result

of the greater level of control SNCR and SCR offer over combustion controls are not worth the additional cost of SNCR or SCR, we expect that the same would apply to Independence Units 1 and 2.”).

EPA analyzed Independence under the requirement to make reasonable progress, which must be determined based on the four factors listed in 42 U.S.C. § 7491(g)(1). In contrast, White Bluff is subject to BART, which must be based on five factors: “the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.” 42 U.S.C. § 7491(g)(2). The BART factors include two factors—existing pollution controls in use, and visibility improvement—which are not included in the definition of the reasonable progress requirement to which Independence is subject. *Compare id.* § 7491(g)(2), *with id.* § 7491(g)(1).

Recognizing that the expected visibility improvement from controls is not a statutory factor for reasonable progress, *see id.* § 7491(g)(1), EPA’s draft guidance recommends that visibility not be considered at all in determining reasonable progress controls for a facility. EPA, Draft Guidance on Progress Tracking

Metrics at 15 (July 2016)[17] ("After the screening step, we recommend that states consider only the four statutory factors to determine whether control measures are necessary to achieve reasonable progress. . . . we do not recommend that states model visibility benefits and weigh those benefits against the four statutory factors to identify appropriate control measures."). If visibility is nonetheless considered, EPA recommends that visibility improvement be given less weight than the four factors listed in the CAA in 42 U.S.C. § 7491(g)(1). *Id.* ("[V]isibility is not an explicit fifth factor and does not have the same weight as the four statutory factors.").

In short, EPA erred by relying on the White Bluff NO_X analysis as the basis for rejecting the most effective NO_X controls for Independence, given that White Bluff is subject to the BART requirements but Independence is subject to the reasonable progress requirements. By relying on BART factors that are not included in the statutory definition of reasonable progress, EPA considered factors that Congress did not intend the agency to consider. *See Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) ("Normally, an agency rule would be arbitrary and capricious if the agency has relied on factors which Congress has not intended it to consider . . . .").

[17] *Available at* https://www.epa.gov/sites/production/files/2016-07/documents/draft_regional_haze_guidance_july_2016.pdf.

B. Had EPA Considered the Proper Statutory Factors for Reasonable Progress, the NO_X Controls for Independence Likely Would Have Been Different.

Had EPA used the proper legal test for reasonable progress controls, EPA likely would have reached a different decision because the four statutory factors all weighed in favor of more effective pollution controls than what EPA required. For the first statutory factor, "the costs of compliance," 42 U.S.C. § 7491(g)(1), EPA's analysis for White Bluff found that SCR, the most effective technology for reducing NO_X pollution, has an average cost-effectiveness of between roughly $2,700 and $3,500 per ton,[18] 80 Fed. Reg. at 18,973, JA____, which is well within the range for reasonable progress controls that EPA has required in other haze rules. *See, e.g.*, 79 Fed. Reg. 74,818, 74,876, 74,882-83 (Dec. 16, 2014) (requiring dry scrubbers at Tolk which would cost $2,998/ton and $3,178/ton at each of the units); 78 Fed. Reg. 34,738, 34,754-56, 34,757-78 (June 10, 2013) and 79 Fed. Reg. at 5185 (for Jim Bridger power plant Units 2 and 3, requiring SCR that would cost $3,015/ton and $2,961/ton); 77 Fed. Reg. 18,052, 18,082, 18,084, 18,087 (Mar. 26, 2012) and 77 Fed. Reg. 76,871 (Dec. 31, 2012) (approving requirements that Nixon Unit 1 install a scrubber that would cost $3,744/ton and that Craig Unit 3 install SNCR that would cost $4,887/ton).

[18] As noted previously, EPA used the analysis of SNCR and SCR it had conducted for White Bluff as part of its analysis for Independence because EPA found that "the White Bluff and Independence Plants are sister facilities." 80 Fed. Reg. at 18,992, JA____.

For the second factor, "the time necessary for compliance," 42 U.S.C. § 7491(g)(1), it would be feasible to install SCR within 5 years, the standard compliance deadline. 80 Fed. Reg. at 18,973, JA____. For the third factor, "the energy and nonair quality environmental impacts of compliance," 42 U.S.C. § 7491(g)(1), EPA did not identify any significant, adverse impacts that would result from operation of SCR. *See* 80 Fed. Reg. at 18,973, JA____. For the fourth and final factor, "the remaining useful life of any existing source subject to such requirements," 42 U.S.C. § 7491(g)(1), EPA made no findings that weighed against SCR. *See* 80 Fed. Reg. at 18,973, JA____. Thus, all four of the statutory factors weighed in favor of SCR or were neutral.

EPA not only gave visibility improvement the same weight as the four statutory factors for reasonable progress but also ignored half of the visibility improvement from NO_X controls at Independence. EPA calculated that pollution controls would have the biggest benefits at two areas in Arkansas and two areas in Missouri. *Id.* at 18,996, tbl. 66, JA____ (showing that NO_X controls would improve visibility at Caney Creek and Upper Buffalo in Arkansas, and Hercules-Glades and Mingo in Missouri). Yet EPA refused to consider the benefits at the Missouri areas. Specifically, EPA deliberately failed to consider the visibility improvement at Missouri Class I areas. Response to Comments at 96, JA____ ("The visibility improvement projected to take place at Hercules-Glades and

Mingo due to controls at Independence did not affect our proposed decision for reasonable progress controls.”).

EPA’s decision to consider some visibility benefits (even though visibility is not one of the statutory factors in a reasonable progress determination) yet ignore the visibility benefits at Missouri Class I areas, cannot be reconciled with the statutory mandate that each haze plan make reasonable progress toward improving visibility at each Class I area. Where EPA considered visibility anyway, it should have made the cumulative visibility benefits assessment part of the consideration. The statute requires “each applicable implementation plan for a State . . . to contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal specified in subsection (a) of this section.” 42 U.S.C. § 7491(b)(2). Subsection (a), in turn, states that “Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution.” *Id.* § 7491(a)(1).

By considering visibility benefits, EPA has unlawfully attempted to rewrite the statute, an error compounded by the agency’s decision to exclude consideration of benefits at out-of-state areas in Missouri. The national goal is to eliminate existing haze pollution “in mandatory class I Federal areas.” *Id.* § 7491(a)(1).

EPA's action here rests on impermissibly rewriting the statutory goal as the elimination of haze "in mandatory *in-state* class I Federal areas." But it is a "core administrative-law principle that an agency may not rewrite clear statutory terms to suit its own sense of how the statute should operate." *Util. Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427, 2446 (2014). Further, statements elsewhere in the rulemaking contradict EPA's decision to exclude the visibility benefits for out-of-state Class I areas in its analysis regarding Independence. In defending other decisions in the Final Rule, EPA stated that it should consider impacts at *all* affected Class I areas:

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

Response to Comments at 374, JA____ (emphasis in original).

In addition to being inconsistent with the statute and EPA's approach elsewhere in this rule, EPA's failure to consider visibility benefits at Missouri Class I areas is inconsistent with EPA's actions in other haze rules. For example, EPA found that the State of Arizona violated the CAA when the state failed to

consider visibility improvement at all affected Class I areas from NO_X controls at Unit 1 of the Cholla power plant; because of the State's legal violation, EPA disapproved the State's proposed NO_X controls for Cholla Unit 1. 77 Fed. Reg. 42,834, 42,849 (July 20, 2012) ("[The Arizona Department of Environmental Quality] also overlooked comparable benefits at seven Class I areas besides Petrified Forest, thereby understating the full visibility benefits of the candidate controls."). In federal plans, EPA has routinely considered the visibility benefits of NO_X controls at both in-state and out-of-state Class I areas. *See, e.g.*, 77 Fed. Reg. at 24,065, 24,067 (Montana) (when evaluating reasonable progress controls for NO_X at Colstrip Units 3 and 4, considering visibility benefits at out-of-state areas in Wyoming, the North Absaroka and Washakie Wilderness Areas); 77 Fed. Reg. at 33,056 (Wyoming) (in evaluating reasonable progress controls for NO_x at Dave Johnston Units 1 and 2, considering visibility benefits at an out-of-state Class I area in South Dakota, Wind Cave National Park); 79 Fed. Reg. at 5048 (Wyoming) (in approving the most stringent NO_X controls for Jim Bridger Units 3 and 4, noting that "[w]e also considered the visibility improvements at other impacted Class I areas," including out-of-state Class I areas such as Yellowstone National Park in Montana and Rocky Mountain National Park in Colorado). Without any rational explanation, EPA arbitrarily deviated from its past practice and failed to consider how reducing NO_X emissions from Independence would improve

visibility in Missouri. *See Grace Healthcare of Benton*, 603 F.3d at 422 ("unexplained departure from prior agency practice is arbitrary and capricious").

Finally, EPA's decision to ignore half of the benefits from NO_X controls at Independence is irrational, given that EPA considered all of the costs of such controls. *See* Response to Comments at 95-96, JA____-__. It is fundamentally irrational to conduct a cost-benefit analysis that considers all of the costs but only half the benefits.

In short, EPA's failure to consider the full visibility benefits of more effective NO_X controls and the failure to weigh such benefits appropriately renders the NO_X limits for Independence arbitrary and capricious and otherwise unlawful. Accordingly, the Court should remand the NO_X limits for Independence contained in 40 C.F.R. § 52.173(c)(24) with appropriate instructions to the agency to correct its errors.

C. EPA's Prior Approval of Parts of the Arkansas Haze Plan Neither Compelled Nor Authorized EPA to Ignore the Benefits at Missouri Class I Areas.

In response to comments, EPA suggested that its reasonable progress analysis for Independence did not have to consider how pollution controls would improve visibility at Missouri's Class I areas because EPA already had approved the consultation between Arkansas and other states, including Missouri, and approved Arkansas's determination that no additional emission reductions are

needed to address Arkansas's impacts to out-of-state Class I areas. *See* Response to Comments at 96, JA__; *see also* 76 Fed. Reg. at 64,215; 77 Fed. Reg. at 14,605, 14,625, JA____, ____. EPA's argument confuses the issues. NPCA and Sierra Club did not contend that EPA must analyze whether pollution controls are *necessary* at Independence solely in order to make progress at out-of-state Class I areas, such as those in Missouri. Instead, NPCA and Sierra Club argued that given that EPA considered a factor—visibility benefits—not included in the definition or reasonable progress, consideration of visibility benefits at all Class I areas is necessary to accurately determine control requirements.

Having concluded that additional controls at Independence would be cost effective, EPA cannot simply ignore its own evidence that such controls would lead to significant benefits in Missouri. *See* 80 Fed. Reg. at 18,996, JA____ (calculating how installing controls at Independence would improve visibility at Hercules-Glades National Wildlife Refuge and the Mingo Wilderness Area in Missouri). In the Response to Comments document, EPA did not identify any passage in EPA's prior approval of parts of the Arkansas plan in which EPA stated that it was lawful to ignore visibility benefits at Missouri Class I areas.

EPA's failure to identify any passage in the prior approval action which either requires or authorizes its action here is unsurprising. As discussed above, *supra* pages 39-40, EPA's action here is inconsistent with its actions in other haze

rulemakings. Given that EPA has not provided a rational explanation for taking action inconsistent with its past practice of considering visibility benefits at all affected Class I areas, EPA's NO_X limits for Independence are arbitrary and capricious. *See Encino Motorcars, LLC v. Navarro*, 136 S. Ct. 2117, 2126 (2016) ("[A]n '[u]nexplained inconsistency' in agency policy is 'a reason for holding an interpretation to be an arbitrary and capricious change from agency practice.'" (quoting *Nat'l Cable & Telecomm. Ass'n v. Brand X Internet Servs.*, 545 U.S. 967, 981 (2005))).

IV. THE LAKE CATHERINE NO_X BART DETERMINATION IS INCONSISTENT WITH EPA'S PRIOR APPROACH TO LAKE CATHERINE AND WITH EPA'S POLICY FOR ALL OTHER BART SOURCES.

EPA concluded that Lake Catherine need not install more stringent NO_X pollution control technologies, namely SCR or SNCR, based on an approach to baseline emissions that is arbitrary and inconsistent with EPA's approach both in the four corners of this rule and in other rules.

Using a consistent approach for calculating baseline emissions is critical in determining whether a particular control technology is cost-effective, which EPA recognizes,[19] and cost-effectiveness is one of the main criteria EPA uses in determing the appropriate pollution control requirement. To explain: When a plant

[19] "Average cost effectiveness means the total annualized costs of control divided by annual emissions reductions" from the pollution controls in question. 40 C.F.R. pt. 51, app. Y § IV(D)(4)(c).

has higher baseline emissions, it means the plant emits more total tons of pollution than another plant with lower baseline emissions. In turn, any control technology (which reduces emissions by a certain percentage) added to a plant with higher baseline emissions will reduce more total tons of pollution as compared to the tons of pollution reduced by the same technology at the plant with lower baseline emissions.

A plant may have higher baseline emissions if it runs more than another plant, which is reflected in a higher capacity factor. By contrast, the capital cost to install pollution controls are relatively fixed and largely independent of how much a plant operates. So, installing a certain control technology on a plant with higher baseline emissions may be deemed cost-effective (when comparing tons of pollutant removed to the capital cost to install the control), while installing that same control technology on a plant with lower baseline emissions may be deemed not cost-effective (because fewer tons of pollutant are removed for the same price).

For Lake Catherine, EPA departed from its policy of using 2001-2003 data to determine baseline emissions and, instead, used more recent data to calculate a lower emissions baseline. But Lake Catherine had a much higher capacity factor during the 2001-2003 time period which EPA used for other BART analyses. During 2001-2003, Lake Catherine's average capacity factor was 21.23%, more than double the 10% capacity factor EPA used in its analysis. *See* Response to

Comments at 314, JA____. EPA arbitrarily disregarded the 2001-2003 data and instead relied on an unenforceable, and dramatically lower capacity factor for Lake Catherine. This skewed the BART analysis to make more stringent controls appear less cost-effective than they really are. As explained below, EPA's BART determination for Lake Catherine is arbitrary and capricious for three reasons.

A. EPA Violated the Agency's Own Guidelines, Without Adequate Explanation.

First, in failing to require Lake Catherine to install readily-available, cost-effective controls for NO_X pollution, the agency arbitrarily departed from its own regulations and guidance. In conducting source-specific BART determinations, EPA guidelines provide that the emissions baseline "should represent a realistic depiction of anticipated annual emissions" for the unit. 40 C.F.R. pt. 51, app. Y § IV(D)(4)(d)(1). In implementing these guidelines, EPA's long-standing policy is to use 2001-2003 emissions data to determine baseline emissions, unless a source has installed new pollution controls after the 2001-2003 time period. *See, e.g.*, 81 Fed. Reg. 43,894, 43,904 (July 5, 2016) ("we continue to use a baseline period for emissions (2001-2003) that predates the installation of LNB/SOFA at the four BART units"); 80 Fed. Reg. 50,591, 50,592 (Aug. 20, 2015) (proposing to approve a BART limit where "Florida set this limit by considering NO_X emissions data for Unit 1 from 2001-2003, the baseline period used by the State as the basis for its BART determination for McIntosh."), 80 Fed. Reg. 64,344 (Oct. 23, 2015)

(finalizing what EPA had proposed). Where, as here, a utility projects that in the future it "will differ from past practice, and if this projection has a deciding effect in the BART determination," then EPA "must" make those operating parameters or assumptions legally enforceable. 40 C.F.R. pt. 51, app. Y § IV(D)(4)(d)(2). In the absence of an enforceable limitation, EPA's guidance requires the agency to calculate baseline emissions "based upon continuation of past practice"—that is, based upon 2001-2003 emissions data. *See id.*

Here, EPA's cost-effectiveness analysis for Lake Catherine is arbitrarily based on an unenforceable 10% capacity factor. In other words, EPA assumed that Lake Catherine will run at only 10% of its maximum operating capacity, even though, legally, the plant can run at 100% capacity. Moreover, there is no evidence in the record that Lake Catherine installed new controls to reduce NO_X emissions after 2001-2003. *See* Victoria R. Stamper, Technical Support Document to Comments of Conservation Organizations, EPA Docket ID No. EPA-R06-OAR-2015-0189-0171, at 52 (Aug. 5, 2015), JA____ ("Stamper Report"). EPA provided no rational explanation for departing from its own regulations and policy, which require emissions to be based on a 2001-2003 baseline or an *enforceable* emission limit. "Agencies are free to change course as their expertise and experience may suggest or require, but when they do so they must provide a 'reasoned analysis indicating that prior policies and standards are being

deliberately changed, not casually ignored.'" *Ramaprakash v. Fed. Aviation Admin.*, 346 F.3d 1121, 1124-25 (D.C. Cir. 2003) (quoting *Greater Boston Television Corp. v. FCC*, 444 F.2d 841, 852 (D.C. Cir. 1970)).

B. EPA Committed the Same Error EPA Faulted the State for Making.

Second, EPA's reliance on an unenforceable, 10% capacity factor is inconsistent with EPA's disapproval of the Arkansas regional haze SIP and with EPA's BART determinations for other Arkansas facilities. EPA proposed to disapprove the State of Arkansas's NO_X BART determination for Lake Catherine precisely because it was based on the use of a 10% capacity factor, which was unenforceable and did not reflect periods during which the unit ran at capacity factors much higher than 10%. *See* 76 Fed. Reg. at 64,204. "Any cost effectiveness analysis based on a 10% capacity factor is likely to significantly inflate the cost per ton of controlling this unit," and "the assumed 10% capacity utilization should be supported by an enforceable limit." *Id.*

In this rulemaking, commenters echoed EPA's criticism by pointing out that the use of a 10% capacity factor did not account for prior years in which Lake Catherine had a capacity factor higher than 10%, namely, 2001-2003. *See* Stamper Report at 52, JA____. Indeed, between 2001-2003, Lake Catherine operated at more than double the capacity factor EPA used in its analysis. *See id.* EPA's reliance on Lake Catherine's recent, unenforceable operations to avoid imposing

more stringent NO_X limits cannot be reconciled with the agency's statements proposing to disapprove the State's analysis.

In the FIP, EPA arbitrarily reversed its position and found that it was reasonable to determine baseline emissions for Lake Catherine using a 10% capacity factor. Moreover, EPA declined to make the 10% capacity factor enforceable. EPA's rationale was that the agency places greater weight on the last five years of data, which show the unit operating below a 10% capacity factor; and that, even over the last 10 years, the average capacity factor is below 10%. Response to Comments at 314-15, JA____-__.

EPA's rationale is arbitrary and capricious because it conflicts with EPA's approach to every other BART determination in the FIP. For all facilities other than Lake Catherine, EPA did not use the last 5 years of emissions data or use an average of the last 10 years of data. Instead, for all other BART sources, EPA determined baseline emissions using data from 2001-2003. *See* 80 Fed. Reg. at 18,948, JA____ (using 2001-2003 emissions data for the Georgia-Pacific Mill), 18,950, JA____ (using 2001-2003 emissions data for AECC Bailey), 18,957, JA____ (using 2001-2003 emissions data for AECC McClellan), 18,964, JA____ (using 2001-2003 emissions data for Flint Creek), 18,969, JA____ (using 2001-2003 emissions data for the SO_2 analysis for White Bluff).

Other than Lake Catherine, the only exceptions to EPA's policy of using 2001-2003 data were sources which had installed new pollution controls after the 2001-2003 time period. *Id.* at 18,969, JA____ (using 2009-2011 data for the NO_X analysis for White Bluff because new NO_X controls were installed after 2003), 18,979, JA____ (using 2009-2011 emissions data for SO_2 for Domtar Power Boiler No. 1 because the source installed new pollution controls after 2003). But unlike those two sources, Lake Catherine did not install new pollution controls after 2001-2003.

C. EPA's Approach to Lake Catherine is Inconsistent with the Agency's Approach to BART Determinations in Other Rules.

Finally, EPA's BART analysis for Lake Catherine is inconsistent with the agency's BART determinations in other haze plans. EPA has consistently followed the policy of using 2001-2003 emissions data to determine baseline emissions for BART sources, unless a source has installed new pollution controls after the 2001-2003 time period. *See* 81 Fed. Reg. at 43,920 ("Because the LNB/OFA were installed pursuant to Utah's proposed BART determination, we used the period 2001-2003, prior to the installation of LNB/OFA at the Hunter and Huntington BART units, for baseline emissions, which in turn we used to evaluate the cost-effectiveness and visibility of control options."); 79 Fed. Reg. 46,514, 46,527 (Aug. 8, 2014) (noting that the BART Guidelines "direct[] BART

determinations to conduct the five-factor analysis generally using a 2001-2003 baseline."); *see also id.* at 5104.

In the Response to Comments, EPA claimed that in other rules it had used data from years other than 2001-2003 to determine baseline emissions, but the only rule EPA pointed to, the Texas reasonable progress rule, is inapposite. *See* Response to Comments at 315 n.609, JA____. In that rule, EPA imposed controls under the reasonable progress requirements. But EPA required controls at Lake Catherine under BART, not reasonable progress, so the Texas rule EPA points to does not support its action regarding Lake Catherine.

EPA's arbitrary decision to treat Lake Catherine differently than other BART sources directly affected its choice of NO_X controls for Lake Catherine. EPA based the NO_X BART limits for Lake Catherine on burners out of service, or BOOS, which EPA estimated would reduce annual NO_X emissions by about 54%, whereas more stringent controls such as SNCR or SCR would reduce emissions by approximately 70% or 94%, respectively. *See* 80 Fed. Reg. at 18,977, JA____. EPA rejected the more stringent pollution control technology SNCR because the incremental cost-effectiveness was allegedly too high, *id.* at 18,978, JA____, and rejected the most stringent pollution control, SCR, because the average and incremental cost-effectiveness of SCR were allegedly too high. *Id.*

Had EPA used a realistic capacity factor based on Lake Catherine's permitted emission limits, the analysis would have differed substantially and would have favored controls more stringent than EPA required in the Final Rule. Indeed, using a more appropriate, higher capacity factor for the Lake Catherine BART analysis, the cost for SNCR and SCR to remove each ton of NO_X would have been lower. As a result, EPA would have been more likely to require one of these more stringent technologies, which are more effective than the technology EPA selected in the Final Rule.[20]

In sum, by calculating baseline emissions for Lake Catherine in a manner inconsistent with the agency's approach to other BART determinations in this rule and other haze rules, EPA's BART determination for NO_X for Lake Catherine is arbitrary and capricious. *See Encino Motorcars, LLC*, 136 S. Ct. at 2125-26 ("When an agency changes its existing position . . . the agency must at least 'display awareness that it is changing position' and 'show that there are good reasons for the new policy.'" (quoting *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009)); *Fox Television Stations, Inc.*, 556 U.S. at 515 ("An agency may not, for example, depart from a prior policy *sub silentio* . . ."); *Grace*

[20] During 2001-2003, for example, Lake Catherine's average capacity factor was 21.23%, more than double the 10% capacity factor EPA used in its analysis. *See* Response to Comments at 314, JA____. Using an appropriate baseline, more stringent NO_X controls would likely be well within the range of costs that EPA has deemed acceptable. *See* Stamper Report at 54-55, JA____-__.

Healthcare of Benton, 603 F.3d at 422 ("unexplained departure from prior agency practice is arbitrary and capricious").

The Court should vacate and remand the NO_X BART determination for Lake Catherine contained in 40 C.F.R. § 52.173(c)(12) with instructions to the agency directing its reconsideration. *See ANR Pipeline Co. v. FERC*, 71 F.3d 897, 901 (D.C. Cir. 1995) ("[W]here an agency departs from established precedent without a reasoned explanation, its decision will be vacated as arbitrary and capricious.").

CONCLUSION

For the foregoing reasons, NPCA and Sierra Club respectfully request that this Court remand the NO_X emission limits for the Independence power plant contained in 40 C.F.R. § 52.173(c)(24)[21] and the NO_X emission limits for the Lake Catherine power plant contained in 40 C.F.R. § 52.173(c)(12) with specific instructions for the EPA to consider more stringent pollution controls consistent with the appropriate statutory and regulatory standards and EPA past practice. The Court should uphold and leave in place all other provisions of the Arkansas regional haze FIP.

[21] NPCA and Sierra Club are not challenging the SO_2 emission limits for Independence contained in 40 C.F.R. § 52.173(c)(24).

Respectfully submitted this 17th day of February, 2017.

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CERTIFICATE OF COMPLIANCE

The undersigned counsel states that this brief complies with FED. R. APP. P. 32(a)(7)(B) because it contains 11,966 words, excluding the sections excluded by Fed. R. App. P. 32(a)(7)(B)(iii), and therefore is within the 13,000 word limit.

This brief and the addendum required under Eighth Circuit Rule 28A(g), which is being filed electronically as a separate document per Eighth Circuit Rule 28A(g)(5), have been scanned for viruses and are virus-free.

Dated: February 17, 2017

/s/ Mary Whittle
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CERTIFICATE OF SERVICE

I hereby certify that on February 17, 2017, I electronically filed the foregoing proof brief with the Clerk of the Court for the United States Court of Appeals for the Eighth Circuit by using the CM/ECF system. Participants in the case who are registered CM/ECF users will be served by the CM/ECF system.

/s/ Mary Whittle
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IN THE UNITED STATES COURT OF APPEALS
FOR THE EIGHTH CIRCUIT

NATIONAL PARKS CONSERVATION ASSOCIATION and SIERRA CLUB Petitioners, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, and GINA MCCARTHY, Administrator, United States Environmental Protection Agency Respondents	No. 16-4309 (Consolidated with 16-4270)

MOTION OF ENTERGY ARKANSAS INC., ENTERGY MISSISSIPPI INC., ENTERGY POWER, LLC, ARKANSAS ELECTRIC COOPERATIVE CORPORATION, AND ENERGY AND ENVIRONMENTAL ALLIANCE OF ARKANSAS FOR LEAVE TO INTERVENE IN SUPPORT OF RESPONDENT EPA

Pursuant to Rule 15(d) of the Federal Rules of Appellate Procedure, Entergy Arkansas Inc., Entergy Mississippi Inc., and Entergy Power, LLC (collectively "Entergy"), Arkansas Electric Cooperative Corporation ("AECC"), and Energy and Environmental Alliance of Arkansas ("EEAA") (collectively "Proposed Intervenors") respectfully move for leave to intervene in support of Respondents

Environmental Protection Agency and Gina McCarthy ("EPA") in the above-captioned case ("Motion").

Counsel for EPA has authorized Proposed Intervenors to represent that EPA consents to this Motion provided that all industry intervenors file a single standard-length intervenor brief. Counsel for petitioners National Parks Conservation Association and Sierra Club (collectively "Petitioners") have authorized Proposed Intervenors to represent that Petitioners take no position on this Motion.

INTRODUCTION

The Petitioners in this case challenge a final EPA rule published in the *Federal Register* at 81 Fed. Reg. 66,332 (Sept. 27, 2016), entitled "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan" ("FIP"). Entergy and EEAA members, including AECC, are co-owners of four coal-fired electric generating units ("EGUs") regulated by the FIP, two at the White Bluff Electric Power Plant ("White Bluff") and two at the Independence Steam Electric Station ("Independence"). EEAA members, including AECC, also are co-owners of the coal-fired EGU at Flint Creek Electric Power Plant ("Flint Creek"), which also is regulated by the FIP. The FIP establishes emissions limits for sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") at all three power plants, which will require controls that will impose costs exceeding $2 billion, and also establishes the

compliance deadlines for the installation of these controls. The Proposed Intervenors move to intervene to defend against more stringent regulatory requirements sought by Petitioners that would impose even greater costs on White Bluff, Independence, and Flint Creek.

ARGUMENT

A. Proposed Intervenors Are Entitled to Intervention Under Fed. R. App. P. 15(d)

Intervention under the Federal Rules of Appellate Procedure requires that a party seeking to intervene file a motion within 30 days after the petition for review is filed and include "a concise statement of interest of the moving party and the grounds for intervention." Fed. R. App. P. 15(d).[1] Intervention is appropriate when the intervenor has a direct and substantial interest in the outcome of the action. *See, e.g.*, *Yakima Valley Cablevision, Inc. v. FCC*, 794 F.2d 737, 744 (D.C. Cir. 1986). Here, the requirements of Rule 15(d) are easily satisfied.

Proposed Intervenors have a direct and substantial interest in the outcome of Case Number 16-4309. EPA has promulgated a rule that imposes emissions limits for SO_2 and NOx on the White Bluff, Independence, and Flint Creek plants based on the installation of certain control technologies, along with deadlines for

[1] Rule 15(d) controls because the statutory provision of the Clean Air Act ("CAA"), the statute under which the FIP is promulgated, governing judicial review of EPA's decision is silent about motions to intervene by third parties. *See* 42 U.S.C. § 7607(b), (d)(8); Fed. R. App. P. 15(d); *see also U.S. Steel Corp. v. EPA*, 614 F.2d 843, 844 (3d Cir. 1979) (holding intervenor properly filed within thirty days pursuant to Rule 15(d) because the CAA is "silent with regard to intervention").

compliance with the limits. The Petitioners filed comments with EPA raising arguments regarding the appropriate controls for White Bluff, Independence, and Flint Creek, and specifically requested more stringent emission limits based, in part, on more expensive controls for all three plants. Given that EPA rejected Petitioners' arguments with respect to the emissions limits that should apply to the three plants, Petitioners may raise at least some of those arguments in this case. Specifically, Petitioners may argue that EPA must impose NOx emissions limits based on the installation of even more stringent and expensive technology on the White Bluff, Independence, and Flint Creek plants. For example, in their comments, the Petitioners urged EPA to adopt more stringent NOx limits at White Bluff, claiming that "EPA has overestimated the costs of SCR [selective catalytic reduction], underestimated the visibility benefits of SNCR [selective non-catalytic reduction] and SCR, and underestimated the cost effectiveness of SCR and SNCR." Sierra Club Comments on Proposed FIP, at 22 (attached as Exhibit A to this Motion). The Petitioners similarly argued that the Clean Air Act "require[s] far more than EPA is proposing as NOx controls for Independence. . . . EPA has set up a false choice by failing to consider more stringent controls such as SCR." *Id.* at 35. The Petitioners made similar arguments with respect to the Flint Creek plant. *Id.* at 15-18.

The Petitioners also may argue that EPA should require more stringent SO_2 emissions limits on all three plants, based on the alleged emission reduction capabilities of the control technology that EPA determined should be installed. *See id.* at 10-14, 20-22, 31-34 (arguing that EPA should impose emissions limits of 0.04 lb/MMBtu, instead of the finalized limit of 0.06 lb/MMBtu). The Petitioners' challenge therefore poses a direct threat to Proposed Intervenors' interests. Those interests cannot be adequately represented in this case without Proposed Intervenors' participation as a full party to this action.

Proposed Intervenors' Motion is timely because it was filed within 30 days from November 28, 2016, the date Petitioners filed their Petition for Review. *See* Fed. R. App. P. 15(d). Intervention by Proposed Intervenors in this case will not disrupt the proceedings because the parties have not yet made any substantive filings and Petitioners' opening brief is not due until January 9, 2016.[2]

B. Proposed Intervenors Are Entitled to Intervention as of Right Under Fed. R. Civ. P. 24(a)

Rule 24(a) of the Federal Rules of Civil Procedure supports intervention as of right. *See Int'l Union v. Scofield*, 382 U.S. 205, 216-17, 217 n.10 (1965) ("The Federal Rules of Civil Procedure, of course, apply only in the federal district courts. Still, the policies underlying intervention may be applicable in appellate

[2] On December 15, 2016, State and Industry Petitioners and Respondents filed a joint motion to extend the briefing schedule for this case. If the motion is granted, Petitioners' opening brief would be due on February 17, 2017.

courts. Under Rule 24(a)(2) or Rule 24(b)(2), we think the charged party would be entitled to intervene."); *see also Sierra Club, Inc. v. EPA*, 358 F.3d 516, 517-18 (7th Cir. 2004) ("Rule 15(d) does not provide standards for intervention, so appellate courts have turned to the rules governing intervention in the district courts under Fed. R. Civ. P. 24."). Rule 24 is to be construed liberally and doubts resolved in favor of proposed intervenors. *See Kansas Pub. Employees Retirement Sys. v. Reimer & Koger Assoc.*, 60 F.3d 1304, 1307 (8th Cir. 1995).

Under Rule 24(a)(2), a timely motion to intervene as of right must be granted when: (1) the movant has a recognized interest in the subject matter of the litigation; (2) the interest might be impaired by the disposition of the case; and (3) the interest will not be adequately protected by the existing parties. *See South Dakota ex rel Barnett v. U.S. Dept. of Interior*, 317 F.3d 783, 785 (8th Cir. 2003). As discussed above, this Motion is timely because it was filed less than 30 days after Petitioners filed their petition for review.

Proposed Intervenors clearly satisfy the first two requirements for intervention as of right. As explained above, the Petitioners seek to force EPA to impose more stringent emissions limits on the White Bluff, Independence, and Flint Creek plants, which would increase the costs of installing control technologies well above the $2 billion currently required by the FIP. *See supra* Section A. Proposed Intervenors have a substantial and direct interest in the

subject of this case that could be impaired by the outcome of this action because a ruling by this Court in favor of the Petitioners would require Proposed Intervenors to spend significant sums of money on the installation of more stringent control technologies at their power plants by FIP-mandated deadlines in 2018 and 2020. *See Nat'l Parks Conservation Ass'n v. U.S. EPA*, 759 F.3d 969, 976 (8th Cir. 2014) (holding that power plant owner's property interests in its facility and its financial stake in the litigation are sufficient to satisfy the recognized interest requirement of Rule 24(a)(2), and a court order requiring EPA to impose control technology requirements on the power plant would impair these interests); *Mille Lacs Band of Chippewa Indians v. Minnesota*, 989 F.2d 994, 997-98 (8th Cir. 1993) (proposed intervenors' property interests, and a judgment favorable to the opposing party that may impair those interests, "easily satisfy" the first two requirements for intervention as of right).

Proposed Intervenors also satisfy the third requirement to show that current parties to the litigation "may be" inadequate to represent Proposed Intervenors' interests. The Supreme Court has noted that "the burden of making that showing should be treated as minimal." *Trbovich v. United Mine Workers*, 404 U.S. 528, 538 n.10 (1972); *see also Mausolf v. Babbitt*, 85 F.3d 1295, 1303 (8th Cir. 1996); *Sierra Club v. Robertson*, 960 F.2d 83, 86 (8th Cir. 1992) (noting that intervention by right is justified when the proposed intervenor's interest is minimally disparate

even where both parties share the same legal goal). As discussed above, Proposed Intervenors' interests are directly opposed to those of Petitioners, and hence Petitioners will not represent Proposed Intervenors' interests.

Further, EPA cannot adequately represent Proposed Intervenors because it has a broader duty to the public as a whole and cannot focus solely on Proposed Intervenors' particular business and economic interests. *See, e.g.*, *John Doe #1 v. Glickman*, 256 F.3d 371, 381 (5th Cir. 2001) ("[A] governmental agency … must represent the broad public interest, not just the [Intervenors'] concerns."). No presumption of adequate representation by a government party arises when the proposed intervenor seeks to protect local and individual interests not shared by the general citizenry, as is the case here. *Mille Lacs* , 989 F.2d at 1000-01. *See also Mausolf*, 85 F.3d at 1303 (no presumption applies when the proposed intervenors' concern is not a matter of "sovereign interest" because "there is no reason to think the government will represent it"). Proposed Intervenors' interests are not adequately represented by EPA because EPA already has imposed burdensome regulations on White Bluff, Independence, and Flint Creek in the FIP that are contrary to Proposed Intervenors' interests and Proposed Intervenors have filed their own petitions for review to challenge the FIP. *See* Petition for Review, *Entergy Arkansas, et al., v. EPA*, No. 16-4298 (8th Cir. Nov. 28, 2016); Petition for Review, *Arkansas Electric Cooperative Corporation v. EPA*, No. 16-4300 (8th

Cir. Nov. 28, 2016); *Energy and Environmental Alliance of Arkansas v. EPA,* No. 16-4304 (8th Cir. Nov. 28, 2016). This demonstrates that EPA cannot adequately represent Proposed Intervenors' interests and may resolve or defend this action in a manner that does not correspond with Proposed Intervenors' interests.

Additionally, EPA does not suffer any regulatory uncertainty or harm from its rulemaking and therefore does not have the same interests at stake as Proposed Intervenors, who must make long-range plans and budgeting decisions concerning White Bluff, Independence and Flint Creek based on the outcome of EPA's rulemaking. The interests of Proposed Intervenors are divergent from EPA's interests because the economic stakes of these decisions are high and will directly impact the Proposed Intervenors and the customers whose power is generated by White Bluff, Independence, and Flint Creek. For example, collectively, Entergy and EEAA members (including AECC) that co-own White Bluff and Independence will be required to spend approximately $2 billion to install the control technologies currently required by the FIP; these costs would increase if the Petitioners are successful in their suit. *See* Entergy Petition for Reconsideration and Request for Administrative Stay, at 2 (attached as Exhibit B to this Motion[3]). This would pose an extreme hardship for AECC, for which these costs will be additive to the costs of control installation for Flint Creek, in which

[3] Exhibits to the Petition have been omitted for brevity.

AECC owns a fifty percent interest. AECC is a not-for-profit electric utility owned by 17 distribution cooperatives across the state of Arkansas ("members"), which in turn are owned by the utility customers they serve. *See* Arkansas Electric Cooperative Corporation's Petition for Reconsideration and Request for Administrative Stay, at 1 (attached as Exhibit C to this Motion). AECC's mission is to provide reliable, affordable, responsible electric service to its members. As a result, AECC is a consumer advocate representing more than 38 percent of the residential consumers in Arkansas, i.e. approximately 520,000 end-use consumers. *Id.* AECC's wholesale cost to its members is one of the lowest in the country at approximately 4.9 cents/kilowatt hour (kwh). Similarly, other EEAA members that co-own White Bluff and Independence are publicly owned municipal utilities responsible for providing affordable electricity to the communities they serve. This affordability is absolutely necessary for the large proportion of the low income households served by the Proposed Intervenors: Arkansas has the ninth lowest per capita income in the United States, and 19.1 percent of its citizens and 26 percent of the state's children live below the poverty level. *Id.* at 2. Additionally, as the majority owner of White Bluff and Independence, Entergy will carry most of the financial burden associated with installation of control technology, which may influence costs for consumers.

This case is analogous to *National Parks Conservation Association v. EPA*, in which this Court held that a power plant owner's interests in its facility diverged from EPA's general interests in assuring that the proper regulatory procedures are followed, thus satisfying the third prong of the Rule 24(a) test. 759 F.3d 969, 977 (8th Cir. 2014). In that case, as here, the proposed intervenor owned the power plant targeted by environmental groups for the installation of pollution control technology, and it sought "to protect a more narrow and 'parochial' financial interest not shared by [the general public]." *Id.* (internal citations omitted). As this Court previously has noted, "EPA is ultimately tasked with the much broader responsibility of executing the CAA's goal of preventing and remedying visibility impairments ....[and] would 'shirk its duty were it to advance the narrower interest of a private entity.'" *Id.* (quoting *Conservation Law Found. of New England, Inc. v. Mosbacher*, 966 F.2d 39, 44 (1st Cir. 1992)). Finally, as in *National Parks Conservation Association v. EPA*, Proposed Intervenors can provide expertise on the issues in this dispute and cannot be assured that EPA's current position will remain static or unaffected by unanticipated policy shifts. *Id.*

Additionally, Proposed Intervenor's interests in this case are not adequately represented in their independent challenges to the FIP. Proposed Intervenors' suits will address the inadequacies in EPA's FIP and the Agency's decision-making process in promulgating the FIP. Proposed Intervenors will be unable to address

arguments that Petitioners may make that the FIP should impose even more stringent requirements on White Bluff, Independence, and Flint Creek, because the possibility of stricter requirements are not at issue in Proposed Intervenors' own cases. Accordingly, Proposed Intervenors meet the minimal inadequate representation requirement and are entitled to intervene as of right.

C. Alternatively, Proposed Intervenors Are Entitled to Permissive Intervention Under Fed. R. Civ. P. 24(b)

Even if Proposed Intervenors are not entitled to intervene as of right, they should be permitted to intervene under Rule 24(b). Permissive intervention is appropriate if a party "has a claim or defense that shares with the main action a common question of law or fact." Fed. R. Civ. P. 24(b)(1)(B). The principal consideration is "whether the intervention will unduly delay or prejudice the adjudication of the original parties' rights." Fed. R. Civ. P. 24(b)(3); *see South Dakota*, 317 F.3d at 787 (citing *U.S. v. Pitney Bowes, Inc.*, 25 F.3d 66, 73 (2d Cir. 1994)).

The common question at issue here is what emission limits EPA should impose on the White Bluff, Independence, and Flint Creek plants. Proposed Intervenors only seek adequate representation of their interests in defending against stricter limits than promulgated in the FIP. Neither EPA nor the Petitioners' rights would be prejudiced by the addition of Proposed Intervenors because their only interest in this case is to prevent the strengthening of the

requirements applicable to facilities that are co-owned by the Proposed Intervenors.

D. Proposed Intervenors Have Constitutional Standing to Intervene

Proposed Intervenors have Article III standing to intervene here.[4] "To demonstrate [Article III] standing, a plaintiff must clearly allege facts showing an injury in fact, which is an injury to a legally protected interest that is 'concrete, particularized, and either actual or imminent.' . . . The plaintiff must also show that the alleged injury is fairly traceable to the defendant's conduct and that a favorable decision will likely redress the injury." *United States v. Metro. St. Louis Sewer Dist.*, 569 F.3d 829, 833-34 (8th Cir. 2009) (internal citations omitted).

Proposed Intervenors will suffer significant injury in fact if Petitioners are successful. If this litigation results in a determination that stricter emissions limits apply to the White Bluff, Independence, and Flint Creek plants, Proposed Intervenors would be forced to install more costly control technology by deadlines falling in 2018 and 2021, or shut down the units by those dates and seek replacement generation.

Second, these concrete and particularized injuries would be directly traceable to Petitioners' challenge, and could be favorably redressed by the Court's

[4] The standing requirement is most clearly applicable to plaintiff intervenors, whereas Proposed Intervenors are the equivalent of defendant intervenors. Proposed Intervenors nonetheless address the standing requirement, which they easily meet, out of an abundance of caution.

denial of the Petition. *See Metro. St. Louis Sewer Dist.*, 569 F.3d at 834 (citing *Lujan*, 504 U.S. at 560) (a causal connection exists if the injury is fairly traceable to the challenged action and is not the result of a third party's independent action). An adverse decision by this Court would directly impact how much of an investment Proposed Intervenors would need to make in White Bluff, Independence, and Flint Creek to keep those plants in compliance with the FIP. EPA's FIP currently requires an investment of more than $2 billion in control technology on the plants; the imposition of more stringent controls sought by the Petitioners would require an even larger expenditure. If this Court affirms EPA's FIP, the onerous burdens posed from stricter emission limits would no longer be a threat to Proposed Intervenors, thus satisfying the redressability prong. *See Nat'l Parks Conservation Ass'n v. EPA*, 759 F.3d at 975 (holding that proposed intervenor EGU owner established injury in fact, causation, and redressibility because the control technology the environmental groups sought to impose could cost more than $280 million, and a rejection of the environmental groups' claims would redress this injury). Proposed Intervenors therefore have Article III standing for this proceeding.

CONCLUSION

For the foregoing reasons, Proposed Intervenors respectfully request that this Court grant their motion to intervene as party-respondents.

Dated December 22, 2016

Respectfully submitted,

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CERTIFICATE OF COMPLIANCE

The undersigned counsel states that this motion complies with FED. R. APP. P. 27(d)(2)(A) because it contains 3,334 words, excluding the caption and signature blocks, as counted by a word processing system and, therefore, is within the 5,200 word limit. This motion also complies with typeface and type-style requirements of FED. R. APP. P. 27(d)(1)(E) because it has been prepared in a proportionally spaced typeface in 14-point Times New Roman font.

Dated: December 22, 2016

/s/ Debra J. Jezouit

Counsel for Entergy Arkansas Inc., Entergy Mississippi Inc., and Entergy Power, LLC

CERTIFICATE OF SERVICE

I hereby certify that the copies of the foregoing State and Industry Petitioners' and Respondents' Joint Reply in Support of Their Motion to Extend Briefing Schedule was served, this 22nd day of December, 2016, through CM/ECF on all registered counsel.

/s/ *Debra J. Jezouit*

EPA-HQ-2017-010177 Production Set #2

ADEQ
ARKANSAS
Department of Environmental Quality

Arkansas Department of Environmental Quality

State of Arkansas
Regional Haze Rule
State Implementation Plan

Air Division
Planning and Air Quality Analysis Branch
5301 Northshore Drive
North Little Rock, Arkansas 72218-5317

A Member of Central Regional Air Planning Association (CENRAP)

September 09,2008

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STATE OF ARKANSAS
MIKE BEEBE
GOVERNOR

July 29, 2008

Richard Greene, Regional Administrator
United States Environmental Protection Agency- Region 6
1445 Ross Avenue, Suite 1200
Mail Code 6RA
Dallas, TX 75202-2733

Dear Mr. Greene:

The State of Arkansas is hereby submitting a State Implementation Plan (SIP) to address requirements for regional haze visibility protection in mandatory federal Class I areas. This SIP contains the necessary measures to ensure that the State of Arkansas is working toward the national goal for visibility contained in 42 U.S.C. 7491-Visibility protection for federal Class I areas. It fulfills requirements under 40 C.F.R. Part 51, Requirements for Preparation, Adoption, and Submittal of Implementation Plans, Subpart P- Protection of Visibility.

The Clean Air Act (CAA) and the United States Environmental Protection Agency (EPA) regulations require states to submit SIPs to make "reasonable progress" in reducing visibility impairment in federal Class I areas resulting from anthropogenic pollution. The CAA, 169A(a)(1), "declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory federal Class I areas, where impairment results from man-made air pollution." Class I areas are national parks, containing more than 6,000 acres, and wilderness areas, containing more than 5,000 acres, which Congress has recognized as significant sites. Arkansas has two such areas: the Upper Buffalo Wilderness Area in the Ozark National Forest and the Caney Creek Wilderness Area in the Ouachita National Forest.

The Regional Haze Rule focuses on older emission sources that have not been regulated under other provisions of the Clean Air Act. Such older sources that could contribute to visibility impairment in Class I areas may be required to install Best Available Retrofit Technology (BART). Regional Haze SIPs must contain such emission limits, schedules of compliance, and other measures as may be necessary to make reasonable progress toward meeting the national goal, including requiring installation, operation, and maintenance of BART, as determined by the State on certain existing stationary sources.

STATE CAPITOL, SUITE 250 • LITTLE ROCK, AR 72201
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The EPA Regional Haze Rule strongly encourages states to work together in regional partnerships to reduce haze. As a member of the Central Regional Air Planning Association (CENRAP), Arkansas has worked closely with Kansas, Louisiana, Iowa, Missouri, Nebraska, Minnesota, Oklahoma, and Texas, as well as with federal agencies, tribal areas, and other interested parties to improve air quality in our region and the country.

The State of Arkansas hereby submits to the EPA that it has met the requirements for regional haze visibility protection in mandatory federal Class I areas under 40 C.F.R. §51.308. We are enclosing two hard copies and one electronic copy of the State Implementation Plan for your review.

We look forward to your prompt review of this SIP submission. If you have any questions, please contact Mike Bates, Air Division Chief of the Arkansas Department of Environmental Quality, at 5301 Northshore Drive, North Little Rock, AR 72218-5317, or by phone at (501) 682-0750. Thank you for your attention to this matter.

Sincerely,

Mike Beebe

cc: Mike Bates, Chief – Air Division, Arkansas Department of Environmental Quality

Enclosure

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1. Background and Overview of the Federal Regional Haze Regulation

1.1. General Background / History of Federal Regional Haze Rule

In amendments to the Clean Air Act (CAA) in 1977, Congress added Section 169 (42 U.S.C. 7491) setting forth the following national visibility goal of restoring pristine conditions in national parks and wilderness areas:

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

Over the following years modest steps were taken to address the visibility problems in Class I areas. The control measures taken mainly addressed "Plume Blight" from specific pollution sources, and did little to address regional haze issues in the Eastern United States. Plume blight is the visual impairment of air quality that manifests itself as a coherent plume. This results from specific sources, such as a power plant smoke stack, emitting pollutants into a stable atmosphere. The pollutants are then transported in some direction with little or no vertical mixing.

When the CAA was amended in 1990, Congress added Section 169B (42 U.S.C. 7492), authorizing further research and regular assessments of the progress made so far. In 1993, the National Academy of Sciences concluded that "current scientific knowledge is adequate and control technologies are available for taking regulatory action to improve and protect visibility."

In addition to authorizing creation of visibility transport commissions and setting forth their duties, Section 169B(f) of the CAA specifically mandated creation of the Grand Canyon Visibility Transport Commission (GCVTC) to make recommendations to the U.S. Environmental Protection Agency (EPA) for the region affecting the visibility of the Grand Canyon National Park. In June 1996, following four years of research and policy development, the GCVTC submitted its report to EPA. This report, as well as the many research reports prepared by the Commission, contributed invaluable information to EPA in its development of the federal regional haze rule.

EPA's Regional Haze Rule was adopted July 1, 1999, and went into effect on August 30, 1999, see Appendix 1.1 Regional Haze Regulations –Final Rule. The Regional Haze Rule aimed at achieving national visibility goals by 2064. This rulemaking addressed the combined visibility effects of various pollution sources over a wide geographic region. EPA concluded that this meant that many states – even those without Class I Areas – would be required to participate in haze reduction efforts. EPA designated five Regional Planning Organizations (RPOs) to assist with the coordination and cooperation needed to address the visibility issues that states in the five regions share or have in common. Those states that make up the midsection of the contiguous United States were designated as the Central Regional Air Planning Association (CENRAP). Figure 1.1 is a map depicting the five RPO regions.

Fig. 1.1 – Regional Planning Organizations

On May 24, 2002 the US Court of Appeals, DC District Court ruled on the challenge brought by the American Corn Growers Association against EPA's Regional Haze Rule of 1999. The Court remanded to EPA the Best Available Retrofit Technology (BART) provisions of the rule, and denied industry's challenge to the haze rule goals of natural visibility and no degradation requirements. On July 6, 2005, EPA issued a revised BART rule.

The federal requirements for visibility protection are contained in 40 CFR Chapter 51 Subpart P – Visibility Protection. The regional haze program requirements are located at 40 CFR 51.308. Arkansas submitted a Part I Visibility Plan on March 25, 1985 that was subsequently approved by EPA. The approved SIP meets the currently applicable requirements of 40 CFR § 51.302 and 51.306.

To facilitate the review of this State Implementation Plan (SIP) by the Environmental Protection Agency (EPA), Federal Land Managers (FLM), stakeholders and the public, ADEQ has prepared a cross-referenced "Guide to Locating Section 308 Requirements" that is included as Appendix 1.2 herein. Appendix 1.2 is based on a checklist that was prepared by EPA for its use in review of regional haze SIP submittals that includes references and citations for specific Section 51.308 requirements. ADEQ updated this checklist by inserting references to locations where these requirements are address in this SIP.

1.2 Identification of Class I Areas

In accordance with the requirements of 40 CFR 51.308, CENRAP and ADEQ have conducted assessments of emissions and modeled visibility impacts on a regional scale. These assessments, further described herein, indicate that various emissions sources located within the State of

Arkansas are likely to cause, or contribute to, regional haze in Class I Areas located both within and outside of the boundaries of the State.

The State of Arkansas has two federal Class I areas within its borders. ADEQ has determined that sources located in Arkansas also contribute to regional haze in two additional Class I Areas that are located in the State of Missouri. Both of Arkansas's Class I Areas are designated as federally protected wilderness areas for which the United States Department of Agriculture (USDA) Forest Service is the FLM.

In Arkansas, mandatory Class I Federal areas include the 14,460 acre Caney Creek Wilderness in Ouachita National Forest at Polk County (CACR) and the 11,801 acre Upper Buffalo Wilderness in the Ozark National Forest at Newton County (UPBU). The Upper Buffalo Class I Area includes the original wilderness area and the additions to it, but does not include the Buffalo National River.

Potentially affected areas in other states are the two Class I areas in Missouri. These are the 12,315 acre Hercules Glades Wilderness in the Mark Twain National Forest, located in Taney County Missouri (HEGL), approximately 25 miles (40 km) north of Boone County Arkansas; and the 8,000 acre Mingo National Wildlife Refuge located in Wayne and Stoddard Counties (MING), approximately 30 miles (48 km) north of Clay County, Arkansas. The respective FLMs are the USDA Forest Service and the U.S. Fish and Wildlife Service under the U.S. Department of Interior. Figure 1.2 depicts the mandatory federal Class I areas throughout the country.

The emission reductions achieved through implementation of this SIP and other federal, state and local measures will result in visibility improvements at Class I areas both within, and outside of, the State of Arkansas. These measures will also improve visibility throughout the region.

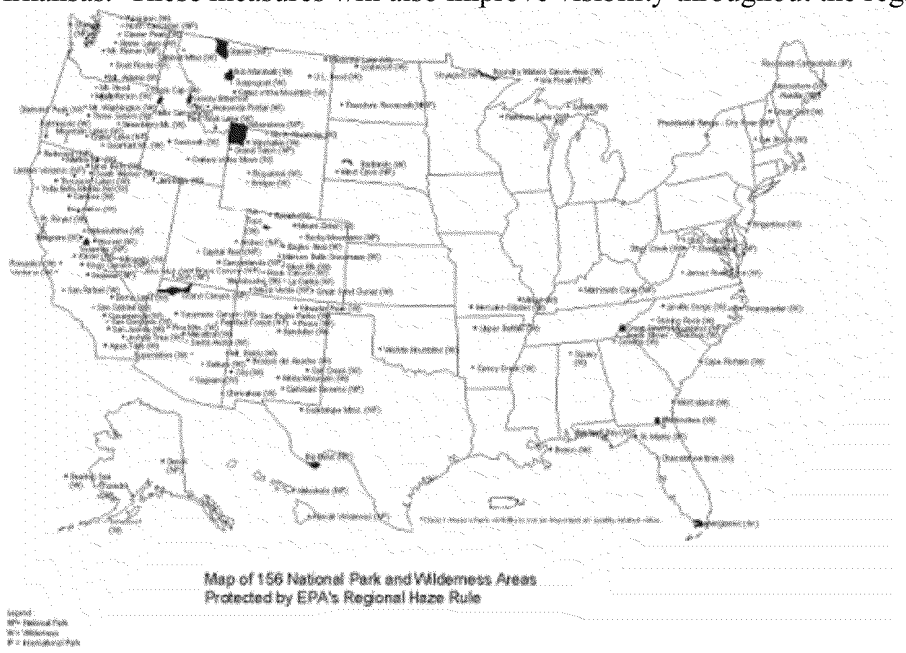

Fig. 1.2 – Mandatory Federal Class I Areas

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1.1 Regional Haze Regulations –Final Rule
1.2 Guide to Locating Section 308 Requirements

2. General Planning Provisions

Pursuant to the requirements of 51.308(a) and (b), Arkansas submits this SIP submission as adopted to meet the requirements of EPA's Regional Haze Rules that were adopted to comply with requirements set forth in the CAA. Elements of this plan address the core requirements pursuant to CFR 40 51.308(d) and the Best Available Retrofit Technology (BART) components of 40 CFR 51.308(e). In addition, this SIP addresses Regional Planning, State and FLMs coordination, and contains a commitment to provide plan revisions and adequacy determinations.

Arkansas has adopted this SIP in accordance with State laws and rules. Arkansas has the authority to adopt the SIP in accordance with local laws and rules, see Appendix 2.1(a).

As required in Section 2.1(f) of Appendix V to 40 CFR Part 51, Arkansas provided public notice of the opportunity to comment on the SIP on June 7, 2008 in a statewide newspaper, the Arkansas Democrat Gazette. Included in the notice to the public was announcement that a public hearing had been scheduled for on July 7, 2008. A copy of the draft Regional Haze SIP was made available at the ADEQ Headquarters, Public Records Center, Room 127, 5301 Northshore Drive, North Little Rock, Arkansas 72218.

Arkansas provided the FLMs a draft copy of the Regional Haze SIP and solicited comments comment on the draft SIP on February 22, 2008, see Appendix 2.1(b).

Arkansas held public hearings regarding the SIP on July 7, 2008. Public comments, inclusive of those made by the FLMS are addressed and are summarized in Appendix 2.1c. A responsive summary of all comments is provided in the final SIP document Appendix 2.1.

List of Chapter 2 Appendices

2.1 Summary of (a) legal authority; (b) public participation process; and, (c) public comments and responses (inclusive of FLMS comments and responses).

3. Regional Planning

In 1999, EPA and affected States/Tribes agreed to create five RPOs to facilitate interagency coordination on Regional Haze SIPs. The State of Arkansas is a member of the Central Regional Air Planning Association (CENRAP) RPO. Members of CENRAP are in the geographical areas listed in Table 3.1. Figure 3.1 shows a map of all five regional planning organizations.

Table 3.1 CENRAP Geographical Area*

Arkansas	Iowa
Kansas	Louisiana
Minnesota	Missouri
Nebraska	Oklahoma
Texas	

*Includes both state and tribal areas

Figure 3.1 - Geographical Areas of Regional Planning Organizations

The governing body of CENRAP is the Policy Oversight Group (POG). The POG is made up of eighteen (18) voting members representing the states and tribes within the CENRAP region and non-voting members representing local agencies, the EPA, the Fish and Wildlife Service, Forest Service, and National Park Service. The POG facilitates communication with FLMs, stakeholders, the public, and with CENRAP staff.

Since its inception, CENRAP has established an active committee structure to address both technical and non-technical issues related to regional haze. The work of CENRAP is accomplished through five standing workgroups: Data Analysis and Monitoring; Emission Inventory; Modeling; Communications; and Implementation and Control Strategies. Participation in workgroups is open to all interested parties. *Ad hoc* workgroups may be formed by the POG to address specific issues. Ultimately, policy decisions are made by the CENRAP POG.

CENRAP has adopted the approach that the Regional Haze Rule requires the "States to establish goals and emission reduction strategies for improving visibility in all 156 mandatory Class I parks and wilderness areas." The rule also encouraged states and tribes to work together in regional partnerships.

This SIP utilizes data analysis, modeling results and other technical support documents prepared for CENRAP members. By coordinating with CENRAP and other RPOs, the State of Arkansas has worked to ensure that its long-term strategy and BART determinations provide sufficient reductions to mitigate visibility impacts on affected Class I areas. Data analyses, modeling results and other technical support documents are provided to CENRAP members through either the CENRAP website (cenrap.org) or through a protocol (ftp) that allows users to copy files between their local system and the CENRAP network.

List of Chapter 3 Appendices

There are no Appendices in Chapter 3.

4. Arkansas and Federal Land Manager Coordination

The 40 CFR 51.308(i) require coordination between the State of Arkansas and the Federal Land Managers (FLMs). FLMs are an integral part of CENRAP's POG and the membership on standing committees. FLMs have contributed to the development of technical and non technical work as a result of that participation. In addition, opportunities have been provided by CENRAP for FLMs to review and comment on each of the technical documents developed by CENRAP and included in this SIP. The Arkansas Department of Environmental Quality (ADEQ) has provided agency contacts to the FLMs as required. In development of this plan, the FLMs were consulted in accordance with the provisions of 40 CFR 51.308(i)(2).

ADEQ provided FLMs an opportunity for consultation, in person and at least 60 days prior to holding any public hearing on an implementation plan or plan revision. The FLMs comments can be found in Appendix 2.1(c).

During the consultation process, the FLMs reviewed the SIP to evaluate:

- Assessment of the impairment of visibility in any Class I areas
- Recommendations on the development of reasonable progress goals
- Recommendations on the development and implementation of strategies to address visibility impairment.

ADEQ sent the draft SIP to the FLMs on February 22, 2008. ADEQ notified the FLMs of public hearings held on July 7, 2008. ADEQ considered/incorporated the FLMs comments on the SIP draft as noted in Appendix 2.1(c).

ADEQ will continue to coordinate and consult with the FLMs during the development of future progress reports and plan revisions, as well as during the implementation of programs having the potential to contribute to visibility impairment in the mandatory Class I areas. The FLMs must be consulted in the following instances:

- Development and review of implementation plan revisions
- Review of 5-year progress reports
- Development and implementation of other programs that may contribute to impairment of visibility in Class I areas.

Arkansas has consulted in person with FLMs during CENRAP meetings, and commits to continued consultation with them during the implementation of other programs having the potential to contribute to visibility impairment in the mandatory Class I areas.

<u>List of Chapter 4 Appendices</u>

4.1 Updated ADEQ Contact for FLMs

5. Assessment of Baseline and Current Conditions and Estimate of Natural Conditions in Class I Areas

The goal of the Regional Haze Rule is to restore natural visibility conditions to the 156 Class I areas identified in the 1977 Clean Air Act Amendments. Sec. 51.301(q) defines natural conditions: "Natural conditions includes naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration." The Regional Haze SIPs must contain measures that make "reasonable progress" toward this goal by reducing anthropogenic emissions that cause haze. For each Class I area, there are three metrics of visibility that are part of the determination of reasonable progress:

1) baseline conditions
2) natural conditions
3) current conditions

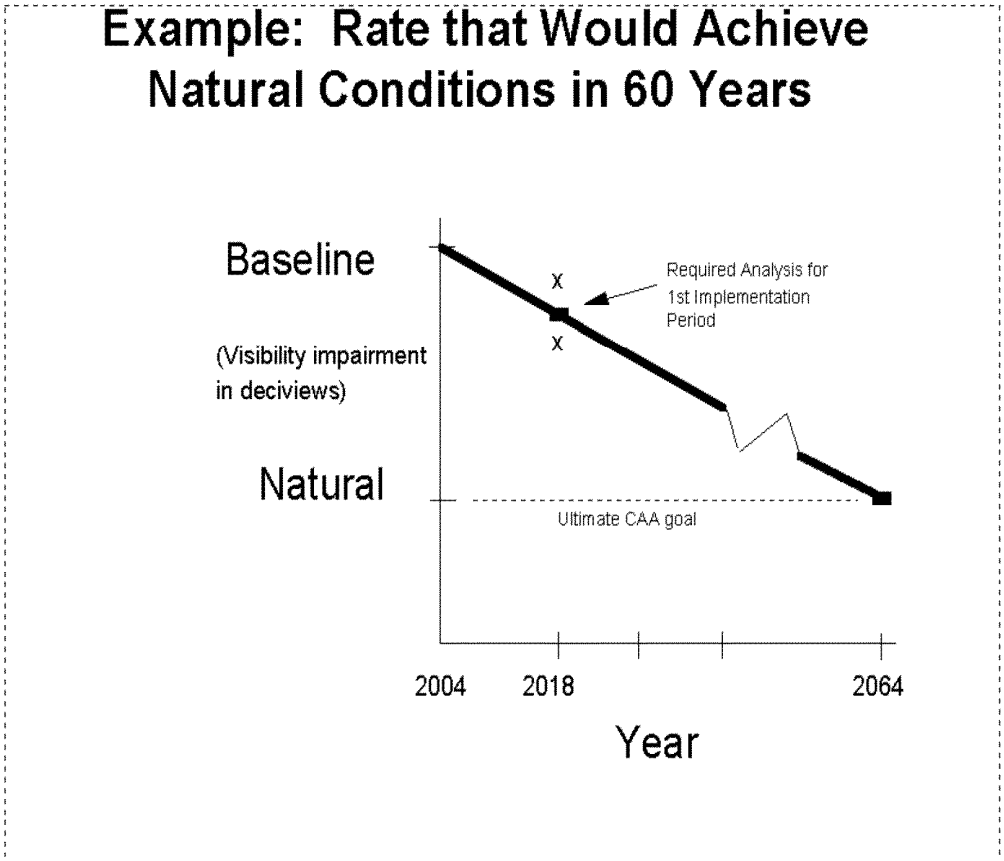
Each of the three metrics includes the concentration data of the visibility pollutants as different terms in the light extinction algorithm, with respective extinction coefficients and relative humidity factors. Total light extinction when converted to deciviews (dv) is calculated for the average of the 20 percent best and 20 percent worst visibility days.

"Baseline" visibility is the starting point for the improvement of visibility conditions. It is the average of the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data for 2000 through 2004 and can be thought of as "current" visibility conditions for this initial period. The comparison of initial baseline conditions to natural visibility conditions indicates the amount of improvement necessary to attain natural visibility by 2064. Natural visibility is determined by estimating the natural concentrations of visibility pollutants and then calculating total light extinction with the light extinction algorithm. (See Figure 5.1 as an example.) Each state must estimate natural visibility levels for Class I areas within its borders in consultation with FLMs and other states (51.308(d)(2)). "Current conditions" are assessed every five years as part of the SIP review where actual progress in reducing visibility impairment is compared to the reductions committed to in the SIP.

<u>Default and refined values for natural visibility conditions</u>

EPA's "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program" (Sept 2003) provides states a "default" estimate of natural visibility. The default values of concentrations of visibility pollutants are based on a 1990 National Acid Precipitation Assessment Program report (Trijonis, J.C. (1990) NAPAP State of Science & Technology, vol. III). In the guidance, the United States is divided into "East" and "West" along the western boundary of the states one tier west of the Mississippi River. This division divides the CENRAP states into "East" which includes Arkansas (AR), Iowa (IA), Louisiana (LA), Minnesota (MN), and Missouri (MO) with seven Class I areas, and "West" which includes Kansas (KS), Nebraska (NE), Oklahoma (OK), and Texas (TX) with three Class I areas. In the two equations, only sulfate and organic carbon have different values, but the calculated deciview difference is significant. (See Appendix 5.2 for further discussion of the default equation.)

Figure 5.1 Determination of Natural Background



In the guidance, EPA also provides that states may use a "refined approach" to estimate the values that characterize the natural visibility conditions of the Class I areas. The purpose of refinement would be to provide more accurate estimates with changes to the extinction algorithm that may include the following: the concentration values; factors to calculate extinction from a measured particular species and particle size; the extinction coefficients for certain compounds; geographical variation (by altitude) of a fixed value; and/or the addition of visibility pollutants. States can choose between the default and refined equations. One equation is used to calculate baseline and current conditions of visibility due to haze-causing pollutants and, with natural concentrations of the same pollutants the same equation is used to calculate natural visibility.

Equation 1: The old (default) algorithm

$$
\begin{aligned}
b_{ext} \approx\ & 3 \times f(RH) \times [Sulfate] \\
& + 3 \times f(RH) \times [Nitrate] \\
& + 4 \times [Organic\ Carbon] \\
& + 10 \times [Elemental\ Carbon] \\
& + 1 \times [Fine\ Soil] \\
& + 0.6 \times [Coarse\ Mass] \\
& + 10
\end{aligned}
$$

Equation 2: The new (refined) algorithm:
Differences from the default are in bold.

$$
\begin{aligned}
b_{ext} \approx\ & 2.2 \times f_S(RH) \times [Small\ Sulfate] + 4.8 \times f_L(RH) \times [Large\ Sulfate] \\
& + 2.4 \times f_S(RH) \times [Small\ Nitrate] + 5.1 \times f_L(RH) \times [Large\ Nitrate] \\
& + 2.8 \times [Small\ Organic\ Carbon] + 6.1 \times [Large\ Organic\ Carbon] \\
& + 10 \times [Elemental\ Carbon] \\
& + 1 \times [Fine\ Soil] \\
& + 1.7 \times f_{SS}(RH) \times [Sea\ Salt] \\
& + 0.6 \times [Coarse\ Mass] \\
& + Rayleigh\ Scattering\ (Site\ Specific) \\
& + 0.33 \times [NO_2\ ppb]
\end{aligned}
$$

T c h bh e eo o t tsid f h wwoet er defh e ieae mu e l dt e q
m fee Ct a Iarlr i mrai sh tesss y hidsvr ot ahC hIta l ielcra s oAhs cas ac t
i t 4 Co 5) F l Rt s hwlim eit0 al ht8 la ee(o tb dfean n) osd va(me i2 sil su) ri
e c o I iwa tts idc lc tia cu ht l sl iu a dv to ts it avt ch e tha re mi ot sr o se sn
a v f iift psneho wa car lo att (lk fC 45l eF 0le aRv tr t))n lf) fa ea a8 s t(
d e a" v r pe e ig a f oce s oCgpa loarl rlc mra ed'h æss lass l. e

The refined equation was used by ADEQ to calculate visibility metrics for the purpose of developing its reasonable progress goal. Please refer to Appendix 5.2 for the IMPROVE Steering Committee's report on the justification for the use of the "refined" IMPROVE algorithm.

The IMPROVE Steering Committee recommended to EPA a change to the light extinction equation. With this revision, a second set of "refined" numbers is being added to the IMPROVE and VIEWS websites for baseline and current condition values for each Class I area. States that choose the "corrected" algorithm that incorporate recent visibility research and analysis can also adopt new natural conditions values and document the reasonableness of these changes to EPA.

Consultation Regarding the Visibility Metrics

Consultation among states is a requirement that is repeated in the Regional Haze Rule. As part of a "long-term strategy" for regional haze, a state whose emissions are "reasonably anticipated" to contribute to impairment in other states' Class I area(s) must consult with those states; likewise, the state must consult with any states whose emissions affect its own Class I area(s) (40 CFR 51.308(d)(3)).

A chief purpose of the RPO is to provide a means for states to confer on all aspects of the regional haze issue, including consultation on reasonable progress goals and long-term strategies based on the current (baseline) and natural visibility determinations. (This process is described in Chapter 3 "Regional Planning"). CENRAP has provided a forum for the member States and Tribes to consult on the determination of baseline and natural visibility conditions in each of the Class I areas.

In addition, states in CENRAP have conferred with neighboring Class I area states outside CENRAP, both individually and by way of the states' RPO. Description of Arkansas's consultation process is located in Chapter 10 Section 3.

The 40 CFR 51.308(i) requires Class I area states' coordination with FLMs which includes consultation on implementation, the assessment of visibility impairment, and recommendations regarding the reasonable progress goal and strategies for improvement. This consultation requirement is treated in Chapter 4.

Through participation in CENRAP and as a state, Arkansas has completed this regulatory requirement. Chapter 4 provides details of actions taken to meet this requirement.

5.1 Baseline Visibility Conditions

Caney Creek WA has an established baseline visibility of 11.24 deciviews for the cleanest 20 percent of the sample days and 26.36 deciviews for the 20 percent worst visibility days. This is based on sampling data collected at the IMPROVE monitoring site located on Eagle Mountain, Polk County, Arkansas. A three year average (2002 to 2004) was calculated for each value (both best and worst) in accordance with 40 CFR 51.308(d)(2). The light extinction and deciview visibility values for these worst and best days are based on data and calculations included in Appendix 5.1 of this SIP. The summary data with the concentration values, light extinction calculations, and deciview values are presented in tables in Appendix 5.1

Upper Buffalo Wilderness Area (WA) has an established baseline visibility of 11.71 deciviews for the cleanest 20 percent of the sample days and 26.27 deciviews for the 20 percent worst visibility days. This is based on sampling data collected at the IMPROVE monitoring site located in Deer, Newton County, Arkansas. A five year average (2000 to 2004) was calculated

for each value (both best and worst) in accordance with 40 CFR 51.308(d)(2). The light extinction and deciview visibility values for these worst and best days are based on data and calculations included in Appendix 5.1 of this SIP. The summary data with the concentration values, light extinction calculations, and deciview values are presented in tables in Appendix 5.1.

5.2 Natural Visibility Conditions

The state of Arkansas has within her boundary two mandatory Class I federal areas (Class I area), Upper Buffalo WA and Caney Creek WA which are managed by the United States Forest Service. Table 5.2 contains the natural conditions for the 20 percent (%) best days and the 20% worst days as well as the baseline visibility conditions for the 20% best and 20% worst days for each Class I area in Arkansas. Appendix 5.3 provides calculations and methodologies for estimating natural visibility conditions.

5.1 Visibility Metrics for the Class I Areas in Arkansas

Natural Background Conditions				
Class I Area	Average for the 20% Worst Days (deciview)	Average for the 20% Best Days (deciview)	Average for the 20% Worst Days B_{ext} (Mm^{-1})	Average for the 20% Best Days B_{ext} (Mm^{-1})
Caney Creek	11.58	4.23	21.16	4.33
Upper Buffalo	11.57	4.18	21.54	4.23
Baseline Visibility Conditions 2000 - 2004				
Class I Area	Average for the 20% Worst Days (deciview)	Average for the 20% Best Days (deciview)	Average for the 20% Worst Days B_{ext} (Mm^{-1})	Average for the 20% Best Days B_{ext} (Mm^{-1})
Caney Creek	26.36	11.24	134.1	20.61
Upper Buffalo	26.27	11.71	131.95	22.19

List of Chapter 5 Appendices

5.1 Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data
5.2 Determination of Baseline Visibility Conditions
5.3 Estimate of Natural Visibility Conditions

6. Monitoring Strategy

Section 51.308(d)(4) of the federal regional haze rule requires a monitoring strategy for measuring, characterizing, and reporting regional haze visibility impairment that is representative of all mandatory Class I areas within the State of Arkansas. The monitoring strategy relies upon participation in the Interagency Monitoring of Protected Visual Environments (IMPROVE) network.

Current Monitoring Strategy

Upon the creation of CENRAP, the newly formed Monitoring Workgroup identified that there were large visibility data voids in Southern Arkansas, Iowa, Kansas, Southern Minnesota, Nebraska, and Oklahoma. Only five (5) IMPROVE sites were located in the CENRAP region. Between 2000 and 2003, five (5) more IMPROVE sites and 15 IMPROVE Protocol Sites were installed (see Figure 6.1). In Arkansas, IMPROVE sites are located at the 14,460 acre Caney Creek Wilderness area in the Ouachita National Forest in Polk County, and the 11,801 acre Upper Buffalo Wilderness area in the Ozark National Forest in Newton County. The Upper Buffalo Class I area includes the original wilderness and the additions to it. It does not include the Buffalo National River (see Figure 6.2). In addition to the IMPROVE monitor, the Upper Buffalo Wilderness area site also includes a National Parks Service maintained nephelometer, and a meteorological monitor. Arkansas commits to meeting the requirements under 40 CFR 51.308(d)(4)(iv) to report to EPA visibility data for each of the Arkansas Class I areas annually.

The filter samples from the IMPROVE modules are sent for analysis to the Crocker Nuclear Laboratory of the University of California in Davis and the data is posted to the IMPROVE website [http://vista.cira.colostate.edu/improve/] and the Visibility Information Exchange Websystem (VIEWS) website [http://vista.cira.colostate.edu/views/]. This fulfills Arkansas's reporting requirement of visibility data (electronic) under subsection (iv). Details regarding the monitors (location, date of installation etc.) and monitoring data are found in Appendices 6.1, and 6.2.

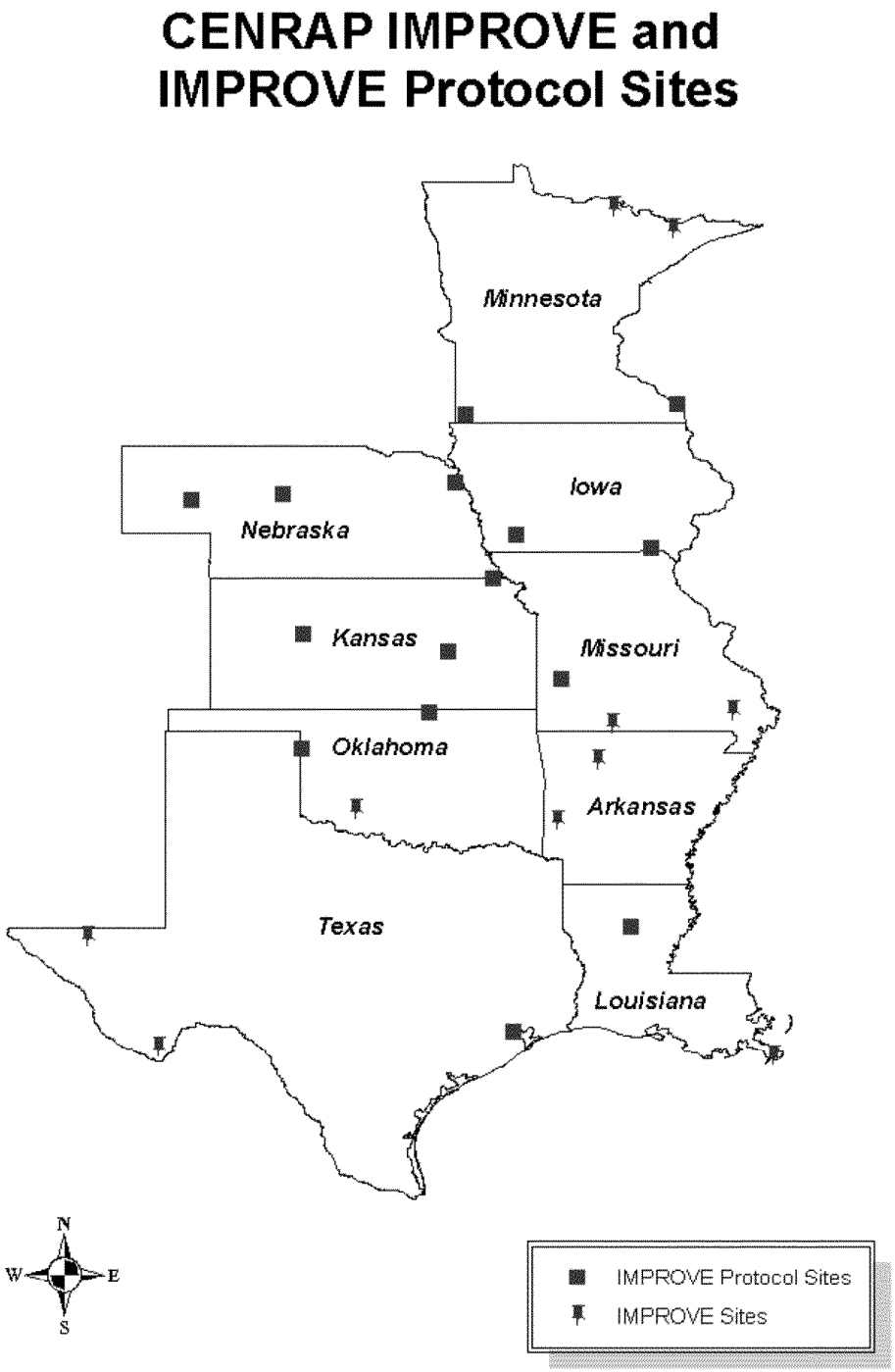


Figure 6.1 CENRAP IMPROVE and IMPROVE Protocol Sites

Figure 6.2 Class I areas in Arkansas

Future Monitoring Strategy

In order to assess progress in reducing visibility impairment in Class I areas, the existing IMPROVE and IMPROVE Protocol sites will be maintained contingent upon continued national funding to measure, characterize and report regional haze visibility impairment to satisfy requirements of subsection (i). The State will evaluate the monitoring network periodically including evaluation technology changes and the need for new monitors. Where economically feasible or with national funds, the State anticipates making those changes needed to be able to assess whether reasonable progress goals are being achieved in each of Arkansas's mandatory Class I areas.

Special Monitoring Studies

As funding permits, CENRAP, in cooperation with states and tribes, intends to study impacts of ammonia and carbon on visibility impairment in the CENRAP region. Preliminary monitoring studies and monitoring data analysis suggests that these two air constituents contribute to a large portion of visibility impairment in the CENRAP geographical area.

List of Chapter 6 Appendices

6.1 Monitoring and Data Analysis to Support the Regional Haze Rule
6.2 CENRAP Regional Haze Monitoring Strategy

7.0 Emission Inventory

The 40 CFR 51.308(d)(4)(v) requires a statewide emission inventory of pollutants that are reasonably anticipated to cause, or contribute, to visibility impairment in any mandatory Class I area. As specified in the applicable EPA guidance, the pollutants inventoried by Arkansas include volatile organic compounds (VOCs), nitrogen oxides (NO_X), fine particulate ($PM_{2.5}$), coarse particulate (PM_{10}), ammonia (NH_3), carbon monoxide (CO), and sulfur dioxide (SO_2). An inventory was developed for the baseline year 2002, and ADEQ will update the emission inventory according to the policy issued by the EPA. A summary of those inventory results follows; the 2002 emission inventory developed by Environ International Corporation has been submitted as Appendix 7.1 A.

Table 7.1 2002 Emissions Inventory Summary

	VOC	NOx	PM2.5	PM10	NH3	CO	SO2
Point	44,329	72,419	7,837	12,406	1	56,366	92,205
Nonpoint	93,548	27,450	68,000	148,433	152,436	436,525	29,889
Nonroad Mobile	54,785	62,472	5,220	5,673	49	272,627	5,490
On-Road Mobile	48,599	141,894	3,021	3,784	2,480	669,214	3,902
Biogenics	1,385,666	18,960				136,688	
TOTAL	1,626,927	323,195	84,078	170,296	154,967	1,571,419	131,485

Overview of the 2002 Emission Inventory

The 2002 point source inventory was completed in-house with Emission Inventory Questionnaires (EIQs). We contracted with Environ to prepare our on-road, nonroad, and nonpoint sources 2002 emission inventory (see enclosed document in Appendix 7.1 A). We accepted the EPA's biogenic source inventory. The nonpoint source inventory included emitters of ozone pollutants (i.e., VOC, NOx and CO) such devices that combust fuel (e.g., wood stoves, commercial and industrial boilers), disperse industrial and commercial VOC sources (e.g., dry cleaners, degreasing and industrial surfaces coating), gasoline distribution, asphalt paving and fires and open burning (e.g., agricultural burning, structural fires wildfires, prescribed burning).

For some source categories, the methodologies actually used in the Arkansas nonpoint source inventory are different than those originally proposed due to newly developed methodologies. Also, because some data were not available, alternate sources of data for some source categories were used. The industrial fuel combustion categories in the Arkansas nonpoint inventory were reconciled with industrial nonpoint fuel data in order to prevent potential double counting of emissions. The industrial point source fuel data were obtained from ADEQ's Emission Inventory Questionnaire (ADEQ 2004). The 2002 EIQs were being processed and could not be used; The 2001 EIQ were used instead. All EIQ fuel use data were being processed and could not be used; The 2001 EIQ were used instead. All EIQ fuel use data were directly input "as is" into a spread sheet form the EIQ forms. The only adjustments made were to the EIQ data were

conversions units (i.e., natural gas to 10^6 ft^3, distillate and residual fuel oil to 10^3 gallons, and coal to tons) and corrections of obvious inconsistencies (e.g., wood combustion reported in units of 10^6 ft^3 for a natural gas boiler was switched to natural gas combustion, etc.). Facilities with ambiguous fuel types, quantities or units were omitted from the reconciliation. The reconciliation was performed by subtracting state level EIQ industrial nonpoint fuel use from the nonpoint inventory's state level industrial combustion fuel use. Fuel use from utility facilities listed in the EIQ was not included in the EIQ fuel use totals. Distillate fuel oil, residual fuel oil, natural gas and coal were included in the reconciliation; LPG use was not identified in the EIQ fuel use data. As a result of the reconciliation, state level industrial fuel use in the nonpoint inventory was adjusted (i.e., distillate fuel oil reduced by 4.3 percent, natural gas reduced by 45.0 percent and coal reduced by 16.8 percent). For residual fuel oil, the EIQ fuel use data exceeded the industrial fuel combustion nonpoint fuel use estimate. Therefore, industrial fuel combustion or residual fuel oil in the nonpoint inventory was adjusted to zero. Reconciliation for other area source categories (i.e., industrial surface coating or degreasing) was not preformed because data were unavailable on the EIQ forms.

On-road Source Inventory

The on-road mobile source emissions included emissions from vehicles certified for highway use – cars, trucks, and motorcycles. Emissions from these sources were estimated by combining EPA emission factors from the MOBILE6 model, expressed in grams per mile (g/mile), with vehicle miles traveled (VMT) activity data. For all of the Arkansas counties, county-level Highway Performance Monitoring System (HPMS) VMT data were used. The data collected as part of the on-road inventory were reviewed prior to use in emission calculations. All modeling inputs, data processing and calculation spreadsheets were checked by a technical supervisor. Annual average daily HPMS VMT data were provided by the Arkansas Highway and Transportation Department (AHTD). These data were reported separately for urban and rural areas and within those categories, by county and HPMS facility class. The AHTD provided data for 2007 and 2010 and these were exponentially extrapolated back to 2002. To arrive at month-specific estimates, the annual average was adjusted using seasonal factors derived based upon data provided by AHTD. Finally, to obtain weekday VMT (for the summer and winter reporting requirements) the monthly values were corrected using Texas statewide average weekday/annual average daily factors: there were no default factors from EPA and these were considered to be the best, given the limited data available from only a few states. For each county, MOBILE6 emission was used in combination with the VMT data to estimate emissions by roadway type and vehicle type and vehicle class. National average speeds derived from HMPS data for each facility class were utilized. Monthly emissions were first estimated from which annual total, summer weekday and winter weekday emissions were derived.

Nonroad Emission Inventory

Nonroad mobile sources encompass a wide variety of equipment types that either move under their own power or are capable of being moved from site-to-site. More specifically, these sources, which are not licensed or certified as highway vehicles, are defined as those that move

or are moved within a 12-month period and are convered under the EPA's emissions regulations as nonroad mobile sources. Where feasible and appropriate, local activity data for specific source categories were gathered and used to develop the inventory.

US EPA's draft NONROAD2002 model (June 2003 version) was used to estimate emissions for most nonroad sources. The NONROAD model estimates emissions from non-road equipment in the following categories:

- Agricultural equipment, such as tractors, combines and balers
- Airport ground support, such as terminal tractors
- Construction equipment, such as graders and back hoes
- Industrial and commercial equipment, such as fork lifts and sweepers
- Residential and commercial lawn and garden equipment, such as leaf and snow blowers
- Logging equipment, such as shredders and large chain saws
- Recreational equipment, such as off-road motorbikes and snowmobiles and
- Recreational marine vessels, such as power boats

Aircraft, commercial marine and locomotive emissions were also included in the non-road inventory, but these sources were estimated separately since they were not included in the NONROAD model. General EPA methodologies were followed to estimate emissions for these three categories. For all source categories, annual average emissions have been estimated in tons per year and ozone season and winter season daily emissions are estimated in tons per day. All data collected as part of nonroad sources emission inventory were thoroughly reviewed to ensure that they were the most appropriate and up-to-date emission factors available.

Point Source Inventory

ADEQ is responsible for compiling the point source inventory. The Air Division Emission Inventories and Data Management Section is accountable for identifying point sources meeting the threshold criteria, collecting facility emissions data, processing, managing data, compilation and displaying the results. Emissions data provided by the facilities are estimates of actual emissions for the facility during the previous year. Estimations methodologies are required to follow state and federal guidelines. Point Sources are large, stationary, emissions sources that release pollutants into the atmosphere. According to the Consolidated Emissions Reporting Rule (CERR), States are required to report data for larger point sources, or Type A point sources, on an annual basis, starting with 2001 inventory. Type B sources refer to all point sources,

including Type A sources. The reporting frequency for Type B sources has been established as once every 3 years, starting with the 2002 base year inventory.

Actual measurement with continuous emissions monitoring systems (CEMS) is the desired method of calculation emissions from a point source. In lieu of CEMS data, emissions may be calculated using other stack test data, material balance or emissions factors from AP-42 or approved engineering journals. Since the data are used for modeling and other purposes, data elements include parameters and coordinates, control devices and efficiencies, actual emissions, emission factors, process codes and parameters. All data are processed into the i-STEPS database which automatically applies minimum quality assurance and quality control checks. Further, the data is processed for inaccuracies those that cannot be readily resolved are referred back to the facility for clarification/correction.

Following the submission of our 2002 Emission Inventory to the CDX, additional quality assurance, and revision of the data was completed through CENRAP. E. H. Pechan & Associates (Pechan) was contracted to QC the data and fill in the gaps where needed. Pechan would call us with errors they detected in the 2002 inventory and we would make corrections over the phone and sometimes via email. Pechan's work is included in (Appendix 7.1 B and C): *The Consolidation of Emissions Inventories* (April 28, 2005) and *Refinement of CENRAP's 2002 Emissions Inventories* (August 31, 2005).

The majority of the nonroad mobile inventory was developed by Sonoma Technology under a contract with CENRAP. The methods and data used by Sonoma are described in the report (Appendix 7.1 D) *Emission Inventory Development for Mobile Sources and Agricultural Dust Sources for the Central States* (October 28, 2004).

Table 7.2 2018 Emissions Inventory Summary

	VOC	NOx	PM2.5	PM10	NH3	CO	SO2
Point	55,603	71,107	13,775	19,799	2,575	75,708	106,461
Nonpoint	107,387	31,531	69,585	148,592	201,722	448,760	31,169
Nonroad Mobile	31,475	34,305	3,387	3,678	49	293,734	211
On-Road Mobile	19,924	33,640	949	949	3,412	367,152	443
Biogenics	1,385,666	18,960				136,688	
TOTAL	1,600,055	189,542	87,695	173,019	207,758	1,322,043	138,283

Overview of the 2018 Emission Inventory

The 2002 emissions were grown to 2018 by using growth and control factors derived from the EGAS6, MOBILE6, and NONROAD models. The Integrated Planning Model (IPM) was used to forecast 2018 electric generating unit (EGU) emissions. Table 7.2 provides a summary of the 2018 BaseG emissions inventory. The summary data provided in Table 7.2 was compiled through a contract with E. H. Pechan.

The 2018 point source emission inventory was prepared by CENRAP. For the non-EGUs, the 2002 emission were projected by applying growth and control factors using the SMOKE model. The growth and control factors were prepared by Pechan and are documented in the report (Appendix 7.2 E): *Development of Growth and Control Inputs for CENRAP 2018 Emissions Draft Technical Support Document* (May 2005). The control factors for non-EGU point sources account for Maximum Achievable Control Technology (MACT) standards and the NOx SIP Call for industrial boilers.

The Integrated Planning Model (IPM) version 2.1.9 model out put for 2018 was used for 2018 EGU point source emissions. The SMOKE IDA formatted version of the 2018 Integrated Planning Model (IPM) was prepared by Pechan for CENRAP. See the Pechan report, *Refinement of CENRAP's 2002 Emissions Inventories* (August 31, 2005), in Appendix 7.1 C for additional information. The IPM conducted by ICF specifically address the emission reductions to be realized through implementation of CAIR assuming all states participated in the EPA's trading program, Acid Rain Program (Title IV-Phases I and II), NOx SIP Call, State and local regulations, while incorporating unit-level updates provided by power company stakeholders. The University of California-Riverside (UCR) ran the smoke Model for the 2018 point sources. The edited IPM file for EGUs was processed in SMOKE without adjustments. The growth and control factors for non-EGUs were applied using the SMOKE model. The technical support document in Appendix 8.1 describes UCR's work on the 2018 point source inventory.

To prepare the nonpoint inventories for modeling, UCR made several modifications to the IDA files by removing selected sources either to model them as separate source categories or to omit them from simulations completely. Fugitive and road dust sources were extracted from all stationary nonpoint inventories and adjusted by transport factors following *Methodology to Estimate the Transportable Fraction (TF) of Fugitive Dust Emissions for Regional and Urban Scale Air Quality Analyses* (Pace 2005).

The 2018 nonpoint source emissions inventory was based on data provided by CENRAP states. Nonpoint source growth and control factors were prepared by Pechan and are documented in the following report in Appendix 7.2 E: *Development of Growth and Control and Control Inputs for CENRAP 2018 Emission Draft Technical Support Document* (May 2005). The control factors reflect New Source Performance Standards (NSPS) for residential wood combustion and Stage I vapor recovery controls, including onboard vapor recovery. UCR ran the SMOKE model for the 2018 area source emissions. The growth and control factors for nonpoint sources were applied within SMOKE. The technical support document in Appendix 8.1describes UCR's work on the 2018 nonpoint inventory. Windblown dust from non-agricultural land use categories and fire emissions were held constant from 2002 to 2018.

The 2018 nonroad mobile inventory was based on inputs from CENRAP states. Growth and control factors for locomotives, aircraft, and commercial marine vessels were prepared by Pechan. The control factors accounted for federal standards for commercial marine vessels and locomotives. For the remaining nonroad mobile categories, Pechan ran the EPA's

NONROAD2004 model for 2018. EPA's NONROAD2004 model accounts for growth in equipment population and incorporates the effects of most final federal standards, including the Tier 4 diesel engine standards and the exhaust emission standards for large spark-ignition engines, diesel marine, and land-based recreational engines. Pechan's methods are described in detail in Appendix 7.2 E: *Development of Growth and Control inputs for CENRAP 2018 Emissions Draft Technical Support Document* (May 2005). UCR applied the growth and control factors to NONROAD categories using the SMOKE model. In addition, UCR processed NONROAD-model categories in SMOKE without adjustments. The technical support document Appendix 8.1 describes UCR's work on the 2018 nonroad inventory.

Pechan prepared the VMT and MOBILE inputs for the 2018 on-road mobile source emissions inventory. The VMT growth factors and MOBILE6 input files were provided in SMOKE format. The MOBILE6 model accounts for motor vehicle controls, including light duty diesel engine standards and low-sulfur diesel. The technical support document in Appendix 8.1 describes UCR's onroad mobile emissions inventory processing.

UCR generated biogenic emissions by running the BEIS3 model within the SMOKE framework. BEIS3 is a system integrated into SMOKE for deriving emissions estimates of biogenic gas-phase pollutants from land use information, emissions factors for different plant species, and hourly, gridded meteorology data. Biogenic emissions were held constant from 2002 to 2018. The technical support document in Appendix 8.1 describes the development of the biogenic emission inventory.

The increase in SO2 from 127,290 in 2002 to 138,284 in 2018 is attributed to growth in Electrical Generating Units (EGU) use in Arkansas. We anticipate additional coal fired plants being built between 2002 and 2018. See figures 7.1 and 7.2 for a comparison of the 2002 and 2018 inventory by source category.

The point source inventories will be updated on an annual basis and the nonpoint, on-road, nonroad mobile inventories will be updated every three years according to the Consolidated Emissions Reporting Rule.

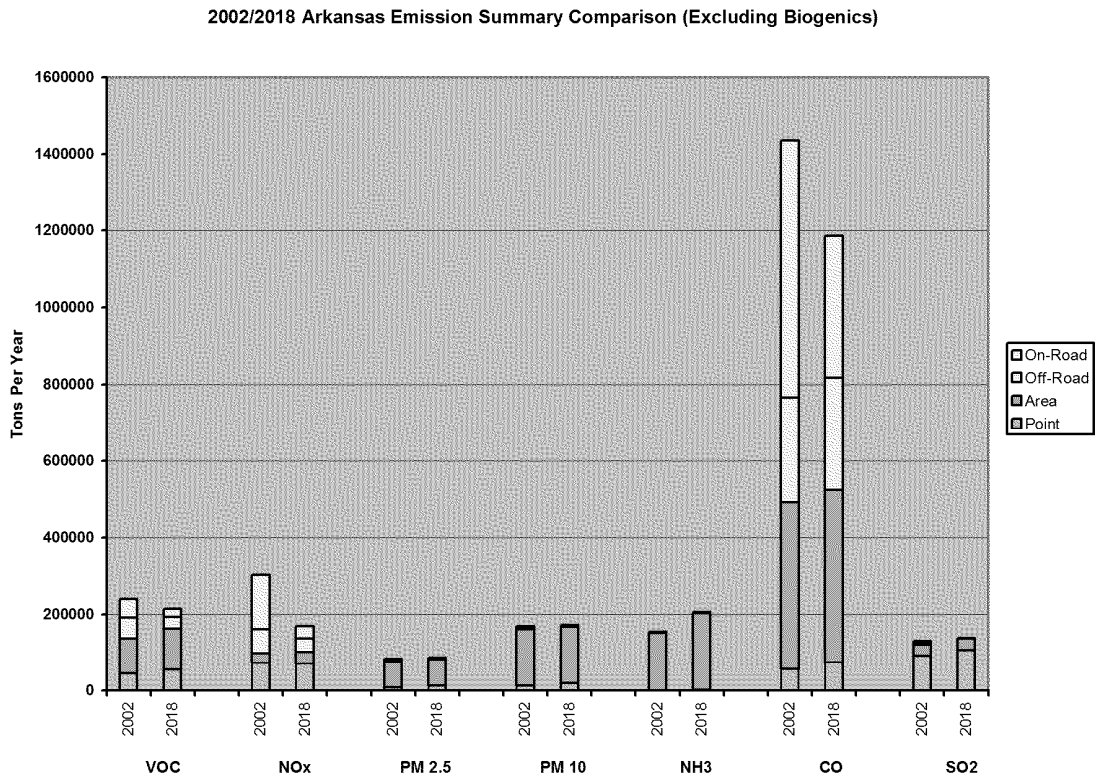


Figure 7.1. 2002/2018 Arkansas Emission Summary Comparison (Excluding Biogenics)

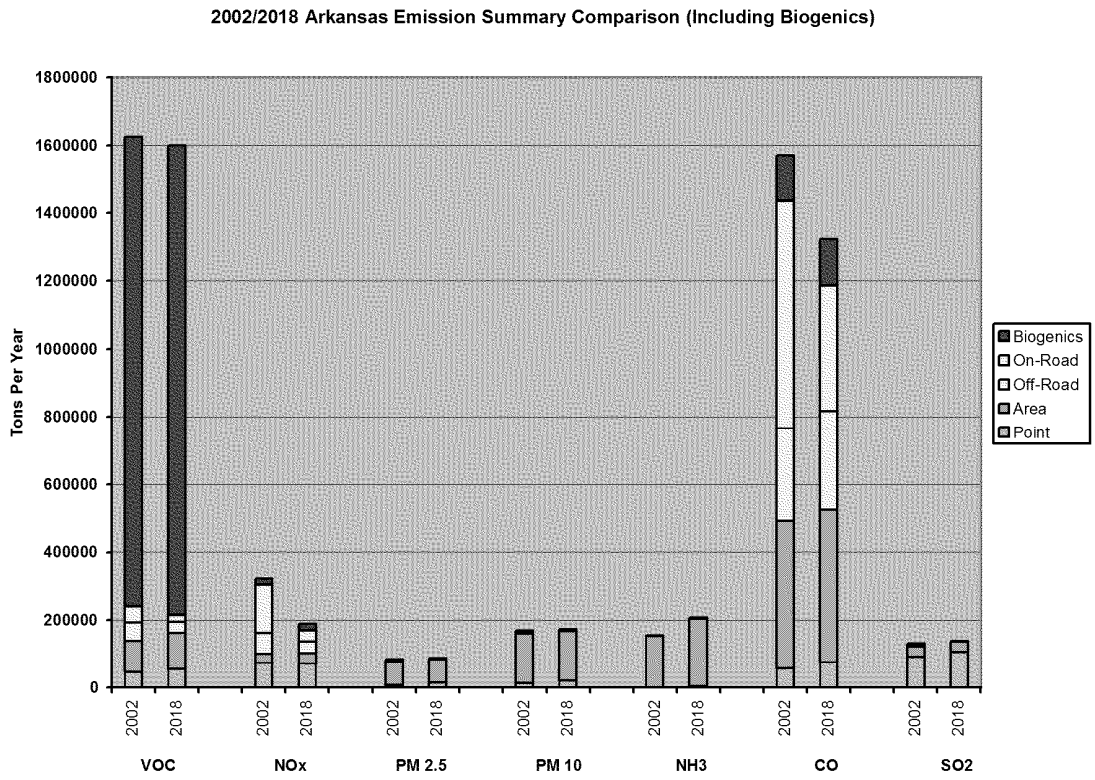


Figure 7.2. 2002/2018 Arkansas Emission Summary Comparison (Including Biogenics)

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7.1 Statewide/Tribal 2002 Emissions Inventory – Parts A-D
7.2 2002 Emissions Inventory Short Summary (Chapter 8 Appendix 8.1 TSD includes all CENRAP contractor work)

8. Modeling Assessment

The 40 CFR Part 51, Appendix W provides modeling guidelines for conducting regional-scale modeling for particulate matter and visibility. The U.S. EPA recommends the use of one of the three following models to simulate pollutants impairing visibility: Community Multiscale Air Quality (CMAQ), the Comprehensive Air quality Model (CAMx), and Regional Modeling System for Aerosols and Deposition (REMSAD). CENRAP contractors performed regional modeling using CMAQ and CAMx.

The CMAQ model is an Eulerian model that simulates the atmospheric and surface processes affecting the transport, transformation and deposition of air pollutants and their precursors. A Eulerian model computes the numerical solution of partial differential equations of plumes on a fixed grid; other models may lose accuracy or need regridding as the plumes expand.

CAMx is a computer modeling system for the integrated assessment of photochemical and particulate air pollution. CAMx incorporates all of the technical attributes demanded of state-of-the-art photochemical grid models, including two-way grid nesting, a subgrid-scale Plume-in-Grid module to treat the early dispersion and chemistry of point source NOx plumes, and a fast chemistry solver.

Particulate Matter (PM) Modeling: CAMx Mechanism 4 (M4) provides "1-atmosphere" modeling for fine and coarse PM and ozone. Aqueous phase chemistry is modeled using the RADM mechanism. Inorganic sulfate/nitrate/ammonium chemistry is modeled with ISORROPIA. ISORROPIA is a model that calculates the composition and phase state of an ammonia-sulfate-nitrate-chloride-sodium-water inorganic aerosol in thermodynamic equilibrium with gas phase precursors. Secondary organic aerosols are modeled using a semi-volatile scheme called Simple Object Access Protocol (SOAP). Wet and dry deposition processes are included for gasses and particles. Gridded deposition information is output along with the concentrations.

In the July 1, 1999 publication of the Regional Haze Rule in the Federal Register, EPA defined the uses of regional modeling as follows:

- Analyses and determination of the extent of emissions reductions needed from individual states
- Analyses and determination of emissions needed to meet the progress goal for the Class I area
- Analyses to support conclusion that the Long-Term Strategy provides for reasonable progress
- Analyses to calculate the resulting degree of visibility improvement that would be achieved at each Class I area
- Analyses to compare visibility improvement between proposed control strategies

8.1 Model Inputs

8.1.1. Selection of Episodes
The calendar year 2002 was selected for the base year for CENRAP regional haze annual modeling consistent with EPA guidance. The Technical Support Document provides additional information on the selection of 2002 as the base year for regional haze modeling and is found at Appendix 8.1.

8.1.2. Selection of Modeling Domain
CENRAP conducted emissions and air quality modeling on the 36 km national RPO domain. This domain consists of a 148 by 112 array of 36 km by 36 km grid cells and covers the continental United States, see Figure 8.1. The Technical Support Document provides additional information on the modeling domain and is found at Appendix 8.1.

8.1.3 Emission Inventories - The emissions inventory includes VOC, NO_X, CO, SO_2, PM_{10}, $PM_{2.5}$, and NH_3 emissions from all anthropogenic and biogenic sources. The emissions inventory information submitted by state, tribal, and local agencies to the 2002 NEI formed the basis of the 2002 CENRAP emissions inventory. The NEI data was supplemented with non-point source emissions inventories developed for CENRAP by Sonoma Technology. These CENRAP-specific inventories addressed agricultural and prescribed burning, onroad and offroad mobile sources, agricultural tilling and livestock dust, and agricultural ammonia. In addition, Pechan assisted CENRAP by quality-assuring the emissions inventory and preparing day- and hour-specific emissions for EGUs based on Continuous Emissions Monitor (CEM) data for the model performance evaluation. Emissions inputs for the air quality model were prepared using the SMOKE emissions modeling system. The CENRAP modeling emissions inventory consists of several distinct datasets: the 2002 base case for model performance evaluation, 2002 typical, 2018 base case, and the 2018 control strategy scenario. Its spatial extent is the RPO 36 km modeling domain, which covers. The Technical Support Document (TSD) provides the methodologies for this process and is found in Appendix 8.1. Emission inventory information can be found in Chapter 7.

8.1.3. Meteorology - The Fifth-Generation NCAR / Penn State Mesoscale Model (MM5) is the latest in a series that developed from a mesoscale model used by Anthes at Penn State in the early 70's that was later documented by Anthes and Warner (1978). Since that time, it has undergone many changes designed to broaden its usage. These changes include: a multiple-nest capability; nonhydrostatic dynamics, which allows the model to be used at a few-kilometer scale; multitasking capability on shared- and distributed-memory machines; a four-dimensional data-assimilation capability; and more physics options. The model (known as MM5) is supported by several auxiliary programs, which are referred to collectively as the MM5 modeling system. Since MM5 is a regional model, it requires an initial condition as well as a lateral boundary condition to run. To produce a lateral boundary condition for a model run, gridded data to

cover the entire time period that the model is integrated is needed The TSD provides the methodologies for this process and is found at Appendix 8.1.

8.2 2002 Model Year

8.2.1 Model Year Selection

The calendar year 2002 was selected for CENRAP regional haze annual modeling as described in the CENRAP Modeling Protocol prepared at the end of 2004. EPA's applicable guidance on $PM_{2.5}$/Regional Haze modeling at that time (EPA, 2001) identifies specific goals to consider when selecting modeling periods for use in demonstrating reasonable progress in attaining the regional haze goals. Due to limited available resources CENRAP was restricted to modeling a single Calendar Year (CY). The RHR uses the five-year baseline of 2000-2004 period as the starting point for projecting future-year visibility. Thus, the modeling year should be selected from this five-year baseline period. The 2002 calendar year, which lies in the middle of the 2000-2004 Baseline, was selected for the following reasons:

- Based on available information, 2002 appears to be a fairly typical year in terms of meteorology for the 5-year Baseline period of 2000-2004;
- 2003 and 2004 appeared to be colder and wetter than typical in the eastern US;
- The enhanced IMPROVE and IMPROVE Protocol and Supersites PM monitoring data were fully operational by 2002. Much less IMPROVE monitoring data was available during 2000-2001, especially in the CENRAP region;
- IMPROVE data for 2003 and 2004 were not yet available at the time the CENRAP modeling was initiated; and
- 2002 is being used by the other RPOs.

The CMAQ and CAMx models were operated separately for each of four quarters of the 2002 year using a ~15 day spin up period (i.e., the models were started approximately 15 days before the first day of interest in each quarter in order to limit the influence of the assumed initial concentrations, e.g., start June 15 for quarter 3 whose first day of interest is July 1). Boundary Conditions (BCs) (i.e., the assumed concentrations along the later edges of the 36 km modeling domain, see Figure 8.1) were based on a 2002 simulation by the GEOS-CHEM global circulation/chemistry model. GEOS-CHEM is a three-dimensional global chemistry model driven by assimilated meteorological observations from the Goddard Earth Observing System (GEOS) of the NASA Global Modeling and Assimilation Office. It is applied by research groups around the world to a wide range of atmospheric composition problems, including future climates and planetary atmospheres using general circulation model meteorology to drive the model. Central management and support of the model is provided by the Atmospheric Chemistry Modeling Group at Harvard University

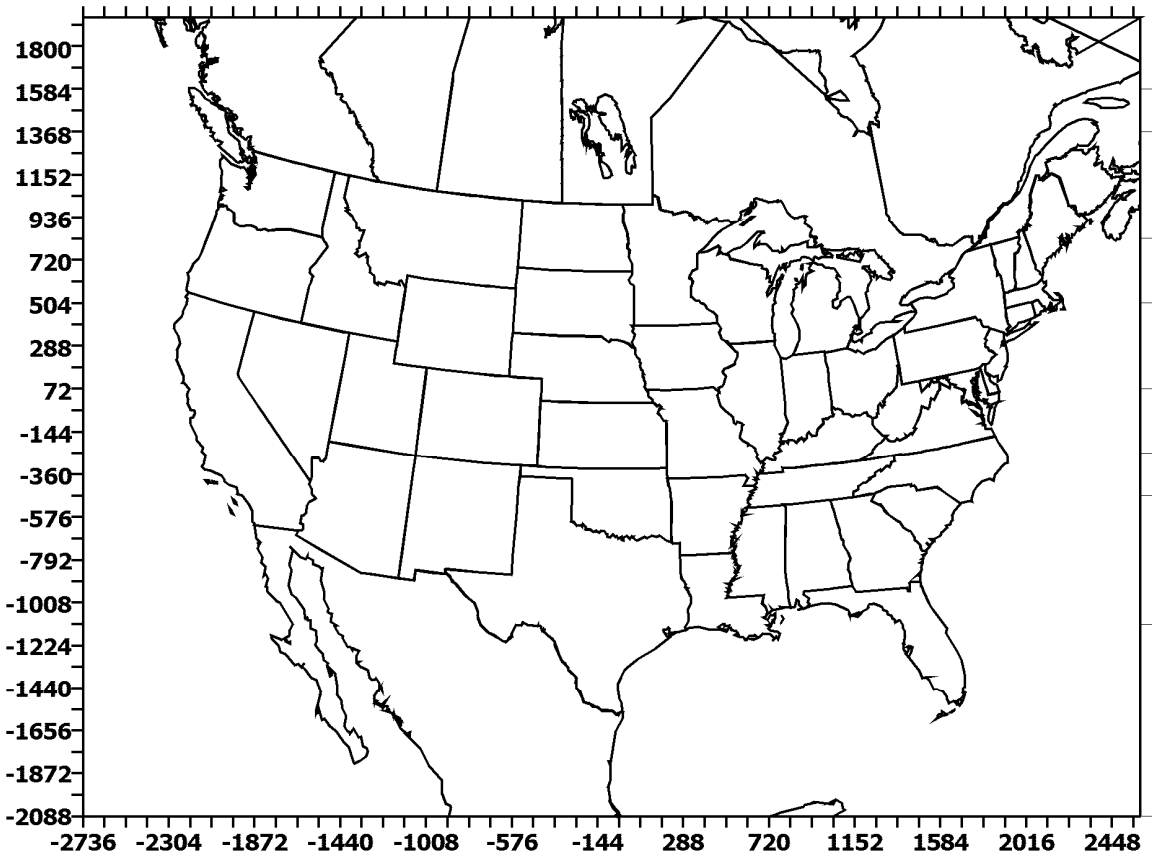

Figure 8.1. National Inter-RPO 36 km modeling domain used for the CENRAP 2002 annual SMOKE, CMAQ and CAMx modeling.

8.2.2 Emissions Input Preparation

The CENRAP SMOKE emissions modeling was based on an updated 2002 emissions data for the U.S. (Pechan, 2005c,e; Reid et al., 2004a,b), 1999 emissions data for Mexico (ERG, 2006), and 2000 emissions data for Canada. These data were used to generate a final base 2002 Base G Typical (Typ02G) annual emissions database. Numerous iterations of the emissions modeling were conducted using interim databases before arriving at the final Base G emission inventories (e.g., Morris et al., 2005). The 2018 Base G base case emissions (Base18G) for most source categories in the U.S. were based on projections of the 2002 inventory assuming growth and control (Pechan, 2005d).

8.2.3 Meteorological Input Preparation

The 2002 36 km MM5 meteorological modeling was conducted by the Iowa Department of Natural Resources (IDNR) who also performed a preliminary model performance evaluation (Johnson, 2004). CENRAP performed an additional MM5 evaluation of the CENRAP 2002 36

km MM5 evaluation that included a comparative evaluation against the final VISTAS 2002 36 km MM5 and an interim WRAP 2002 36 km simulation (Kemball-Cook et al., 2004).

8.2.4 Photolysis Rates Model Inputs

Several chemical reactions in the atmosphere are initiated by the photodissociation of various trace gases. To accurately represent the complex chemical transformations in the atmosphere, accurate estimates of these photodissociation rates must be made. The Models-3 CMAQ system includes the JPROC processor, which calculates a table of clear-sky photolysis rates (or J-values) for a specific date.

8.2.5 Air Quality Input Preparation

Air quality data used with the CMAQ and CAMx modeling systems include: (1) Initial Concentrations (ICs) that are the assumed three-dimensional concentrations through the modeling domain at the very start of the simulation; (2) the Boundary Conditions (BCs) that are the concentrations assumed along the lateral edges of the RPO national 36 km modeling domain; and (3) air quality observations that are used in the model performance evaluation are discussed in Section 3 and Appendix C of Appendix 8.1.

8.2.6 Model Performance Evaluation

The CMAQ and CAMx models were evaluated against ambient measurements of PM species, gas-phase species and wet deposition. Table 8.1 summarizes the networks used in the model evaluation, the species measured and the averaging times and frequency of the measurements.

Table 8.1. Ground-level ambient data monitoring networks and stations available in the CENRAP states for calendar year 2002 use in the model performance evaluation.

Monitoring Network	Chemical Species Measured	Sampling Frequency; Duration	Approximate Number of Monitors
IMPROVE	Speciated $PM_{2.5}$ and PM_{10}	1 in 3 days; 24 hr	11
CASTNET	Speciated $PM_{2.5}$, Ozone	Hourly, Weekly; 1 hr, 1 Week	3
NADP	WSO4, WNO3, WNH4	Weekly	23
EPA-STN	Speciated $PM_{2.5}$	Varies; Varies	12
AIRS/AQS	CO, NO, NO_2, NO_x, O_3	Hourly; Hourly	25

Numerous iterations of CMAQ and CAMx 2002 base case simulations and model performance evaluations were conducted during the course of the CENRAP modeling study, most of which have been posted on the CENRAP modeling website (http://pah.cert.ucr.edu/aqm/cenrap/cmaq.shtml) and presented in previous reports and

presentations for CENRAP (e.g., Morris et al., 2005; 2006a,b). Details on the final 2002 Base F 36 km CMAQ base case modeling performance evaluation are provided in Chapter 3 and Appendix C of Appendix 8.1, (because of the similarity between 2002 Base F and 2002 Base G and resource constraints the model evaluation was not re-conducted for Base G). In general, the model performance of the CMAQ and CAMx models for sulfate (SO4) and elemental carbon (EC) was good. Model performance for nitrate (NO3) was variable, with a summer underestimation and winter overestimation bias. Performance for organic mass carbon (OMC) was also variable, with the inclusion of the SOAmods enhancement in CMAQ Version 4.5 greatly improving the CMAQ summer OMC model performance (Morris et al., 2006c). Model performance for Soil and coarse mass (CM) was generally poor. Part of the poor performance for Soil and CM is believed to be due to measurement-model incommensurability. The IMPROVE measured values are due, in part, to local fugitive dust sources that are not captured in the model's emission inputs and the 36 km grid resolution is not conducive to modeling localized events.

8.3 2018 Base G Model Year

8.3.1 2018 Emissions Inventory

The 2018 Base G modeling run reflects emissions growth and "on the books" controls, which are state and federal controls that will be implemented between the 2002 base year and the 2018 future year.2018 emissions for Electrical Generating Units (EGUs) were based on simulations of the Integrated Planning Model (IPM) that took into the account the effects of the Clean Air Interstate Rule (CAIR) on emissions from EGUs in CAIR states using an IPM realization of a CAIR cap-and-trade program. Thus the Emissions for on-road and non-road mobile sources were based on activity growth and emissions factors from the EPA MOBILE6 and NONROAD models, respectively. Area sources and non-EGU point sources were grown to 2018 levels.

The following sources were assumed to remain constant between the 2002 and 2018 base case simulations:

• Biogenic VOC and NOx emissions from the BEIS3 biogenic emissions model;
• Wind blown dust associated with non-agricultural sources (i.e., natural wind blown fugitive dust);
• Off-shore emissions associated with off-shore marine and oil and gas production activities;
• Emissions from wildfires;
• Emissions from Mexico; and
• Global transport (i.e., emissions due to BCs from the 2002 GEOS-CHEM global chemistry model.

8.3.2 Model Performance Evaluation

In this section, and in section 3 of Appendix 8.1, the results of the model performance evaluation at each of Arkansas's Class I areas for the worst and best 20 percent days are presented. Performance on these days is critical since they are the days used in the 2018 visibility projections discussed in Chapter 8.6. The 2002 and 2018 modeling results were used in a relative sense to scale the observed PM concentrations from the 2000-2004 Baseline and the IMPROVE monitoring network to obtain the 2018 PM projections. The 2018/2002 modeled scaling factors are called Relative Response Factors (RRFs) and are constructed as the ratio of modeling results for the 2018 model simulation to the 2002 model simulation. Two important regional haze metrics are the average visibility for the worst 20 percent and best 20 percent days from the 2000-2004 five-year Baseline. For the 2018 visibility projections, EPA guidance recommends developing Class I area and PM species specific RRFs using the average modeling results for the worst 20 percent days during the 2002 modeling period and the 2002 and 2018 emission scenarios. For each Class I area we compared the predicted and observed extinction of the worst and best 20 percent days below. In Appendix C of Appendix 8.1 the PM species specific extinction is also compared for the worst 20 percent days.

EPA guidance recommends using the model in a relative sense to project future-year visibility conditions (EPA, 2007a). This projection is made using Relative Response Factors (RRFs) that are defined as the ratio of the future-year modeling results to the base-year modeling results. The RRFs are applied to the baseline visibility conditions to project future-year visibility. The major features of EPA's recommended visibility projection approach are as follows :

• Monitored data are used to define current visibility Baseline Conditions using IMPROVE monitoring data from the 2000-2004 five-year base period.

• Monitored concentrations of PM_{10} are divided into six major components, the first five of which are assumed to be $PM_{2.5}$ and the sixth is coarse mass (CM or $PM_{2.5-10}$).

- SO4 (sulfate) that is assumed to be ammonium sulfate [$(NH_4)_2SO_4$];
- NO3 (particulate nitrate) that is assumed to be ammonium nitrate [NH_4NO_3];
- OC (organic carbon) that is assumed to be total organic mass carbon (OMC)
- EC (elemental carbon);
- IP (other fine inorganic particulate or Soil); and
- CM (coarse mass).

Models are then used in a relative sense to develop RRFs between baseline and future predicted concentrations of each component. Final projections were based on these RRFs, and indicate that while the model results may be off in absolute terms, the model still responds to increases or decreases in pollutants responsible for visibility impairment. This can lead to over or underestimation of light extinction for the various pollutants while still showing model applicability.

8.3.2.1 Caney Creek Wilderness Area Modeling

The ability of the CMAQ model to estimate visibility extinction at the CACR Class I area on the 2002 worst and best 20 percent days is provide in Figure 8.2. On most of the worst 20 percent

days at CACR total extinction is dominated by SO4 extinction with some extinction due to OMC. On four of the worst 20 percent days extinction is dominated by NO3. The average extinction across the worst 20 percent days is underestimated by -33% (Figure 8.2), which is primarily due to a -51% underestimation of SO4 extinction combined with a 6% overestimation of NO3 extinction. Performance for OMC extinction at CACR on the worst 20 percent days is pretty good with a -20% bias and 36% error. EC extinction is systematically underestimated. Soil extinction has low bias (-19%) buts lots of scatter and high error (74%), while CM extinction is greatly underestimated (bias of -153%).

On the best 20 percent days at CACR the observed extinction ranges from 20 to 40 Mm^{-1}, whereas, the modeled extinction has a much larger range from 15 to 120 Mm^{-1}. Much of the modeled overestimation of total extinction on the best 20% days (+44% bias) is due to NO3 overestimation (+94% bias).

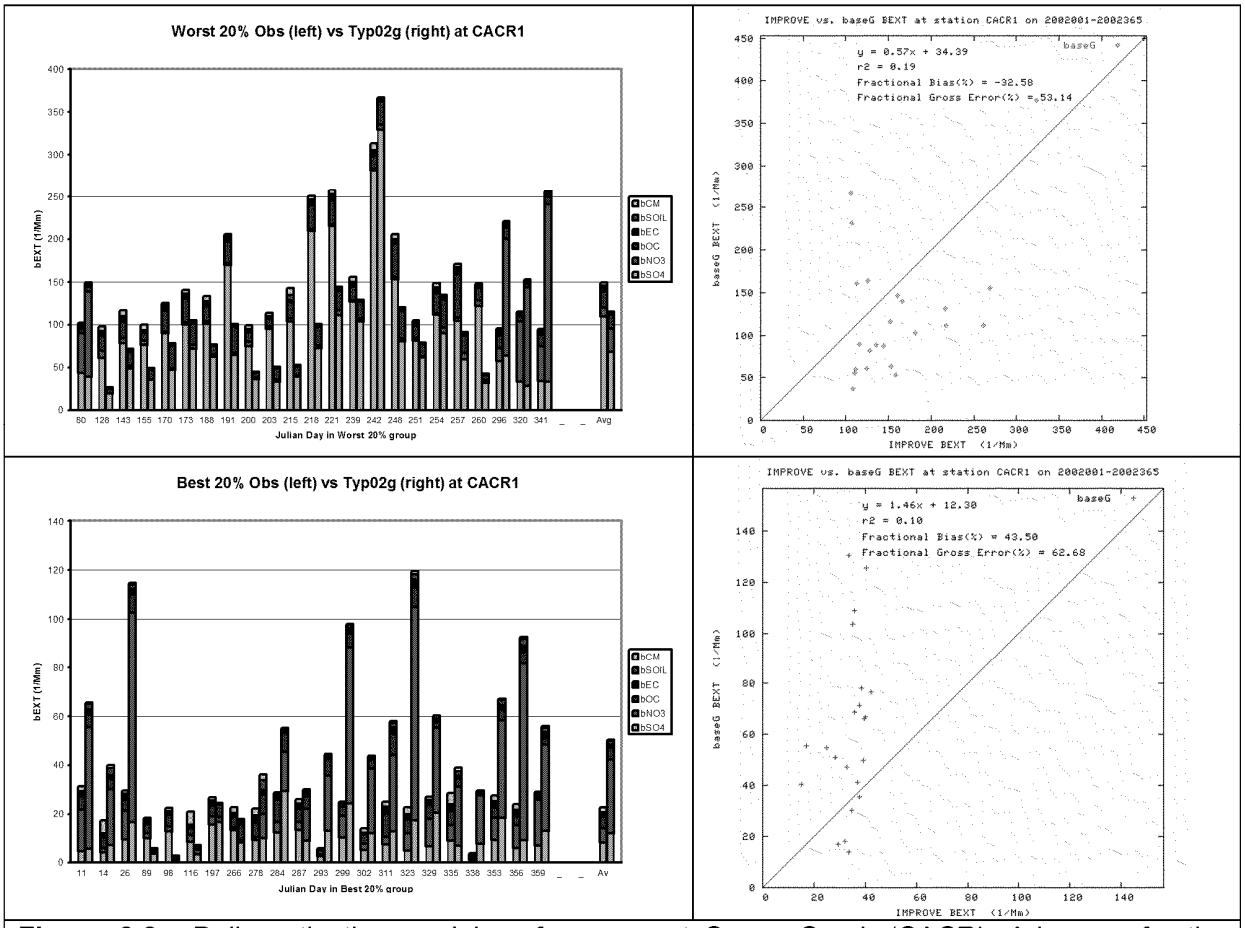

Figure 8.2. Daily extinction model performance at Caney Creek (CACR), Arkansas for the worst (top) and best (bottom) 20 percent days during 2002.

8.3.2.2 Upper Buffalo Wilderness Area Modeling

Model performance at the UPBU Class I area for the worst and best 20 percent days is shown in Figure 8.3. On most of the worst 20 percent days at UPBU, visibility impairment is dominated by SO4, although there are also two high NO3 days. The model underestimates the average of the total extinction on the worst 20 percent days at UPBU by -40% (Figure 8.3), which is due to an underestimation of extinction due to SO4, OMC and CM by -46%, -33% and - 179%, respectively.

On the best 20 percent days at UPBU, the model performs reasonably well with a low bias (2%) and error (42%). But again, the model has a much wider range in extinction values across the best 20 percent days (15 to 120 Mm^{-1}) than observed (20 to 45 Mm^{-1}). There are five days in which the modeled NO3 overprediction is quite severe and when those days are removed the range in the modeled and observed extinction on the best 20 percent days is quite similar to the observed, although the model gets much cleaner on the very cleanest modeled days.

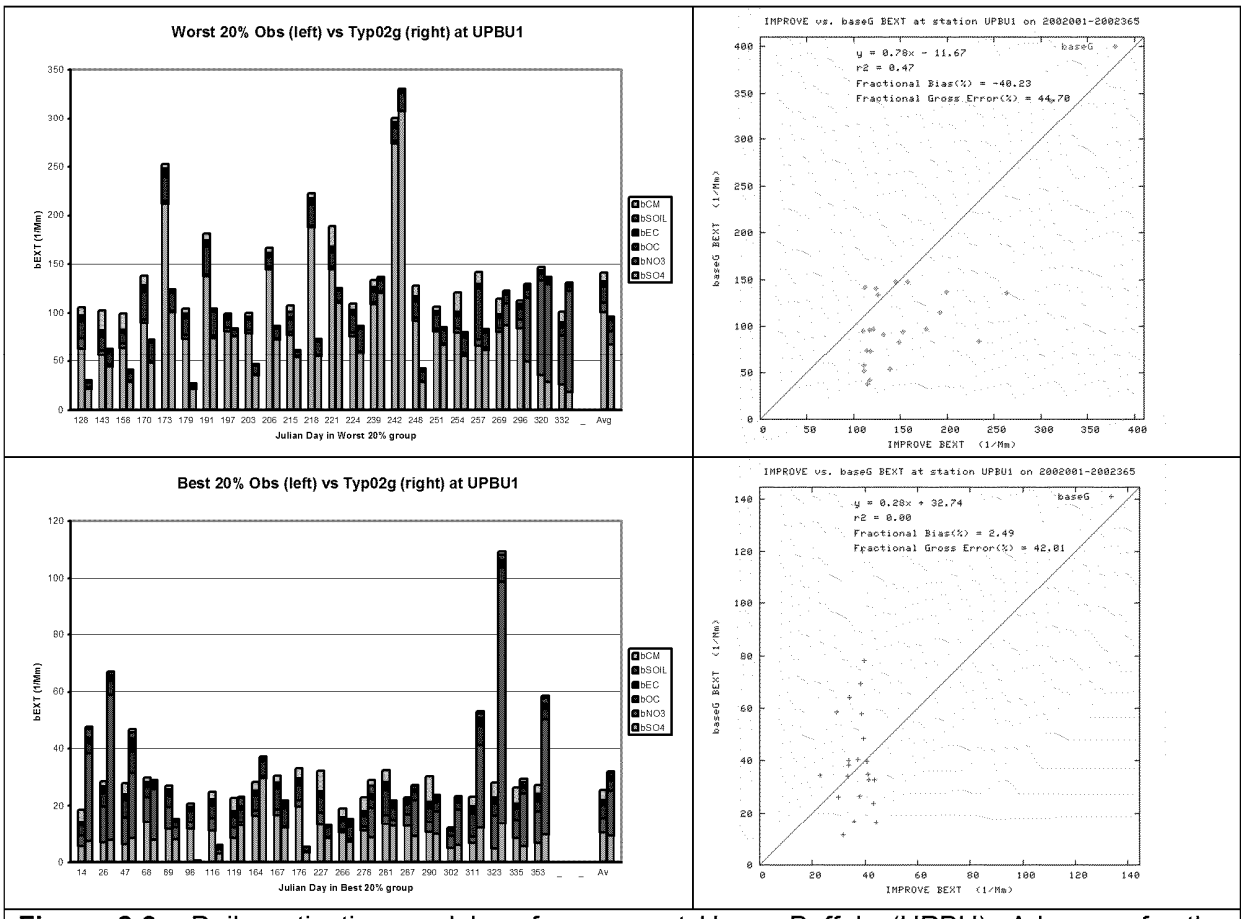

Figure 8.3. Daily extinction model performance at Upper Buffalo (UPBU), Arkansas for the worst (top) and best (bottom) 20 percent days during 2002.

8.4 Information from Modeling Performed by Other RPOs

2018 visibility projections for CENRAP and nearby Class I area have also been performed by the other RPOs. Thus, it is useful to compare the CENRAP 2018 visibility projections with those from the other RPOs as a quality assurance (QA) check and to foster confidence in the CENRAP modeling results. Detailed information concerning other RPOs modeling is found in Appendix 8.1.

The CENRAP 2018 Base G visibility projections were compared to the following other RPO visibility projections:

• VISTAS 2018 visibility projections based on their CMAQ 12 km 2002 annual modeling results for the 2002 Base G and 2018 Base G2a emissions scenarios.
• MRPO 2018 visibility projections based on their CAMx 36 km 2002 annual modeling for the Run 4 Scenario 1a (R4S1a) emissions scenario.
• WRAP 2018 visibility results based on their Plan02b and Base18b CMAQ 36 km modeling of the 2002 calendar year.

Figure 8.4 displays a DotPlot comparison of the four RPO visibility projections expressed as a percentage of achieving the 2018 URP point at CENRAP and nearby Class I areas. For the four CENRAP Class I areas just west of the Mississippi River in Arkansas and Missouri (CACR, UPBU, HEGL and MING), 2018 visibility projections are available from the CENRAP, VISTAS and MRPO RPOs. At HEGL, the three RPOs 2018 visibility projections are in close agreement with each other (estimated to achieve 99%, 101% and 95% of the 2018 URP point). The CENRAP and VISTAS 2018 visibility projections are also very close at the other three Arkansas-Missouri CENRAP Class I areas: CACR (112% and 116%), UPBU (109% and 112%) and MING (118% and 114%). But the MRPO 2018 visibility projections are approximately 12 to 25 percentage points lower than the CENRAP and VISTAS projections at these three Class I areas, with values of 97% to 100%. The reasons why the MRPO 2018 visibility projections are less optimistic than CENRAP and VISTAS are unclear. However, the MRPO focused on visibility projections at their northern Class I areas and likely did not use the latest CENRAP emission estimates. In addition, the CENRAP 2018 visibility projections included BART controls on several sources in CENRAP states not included in the MRPO projections. Such BART controls are even more important in those states not covered by CAIR.

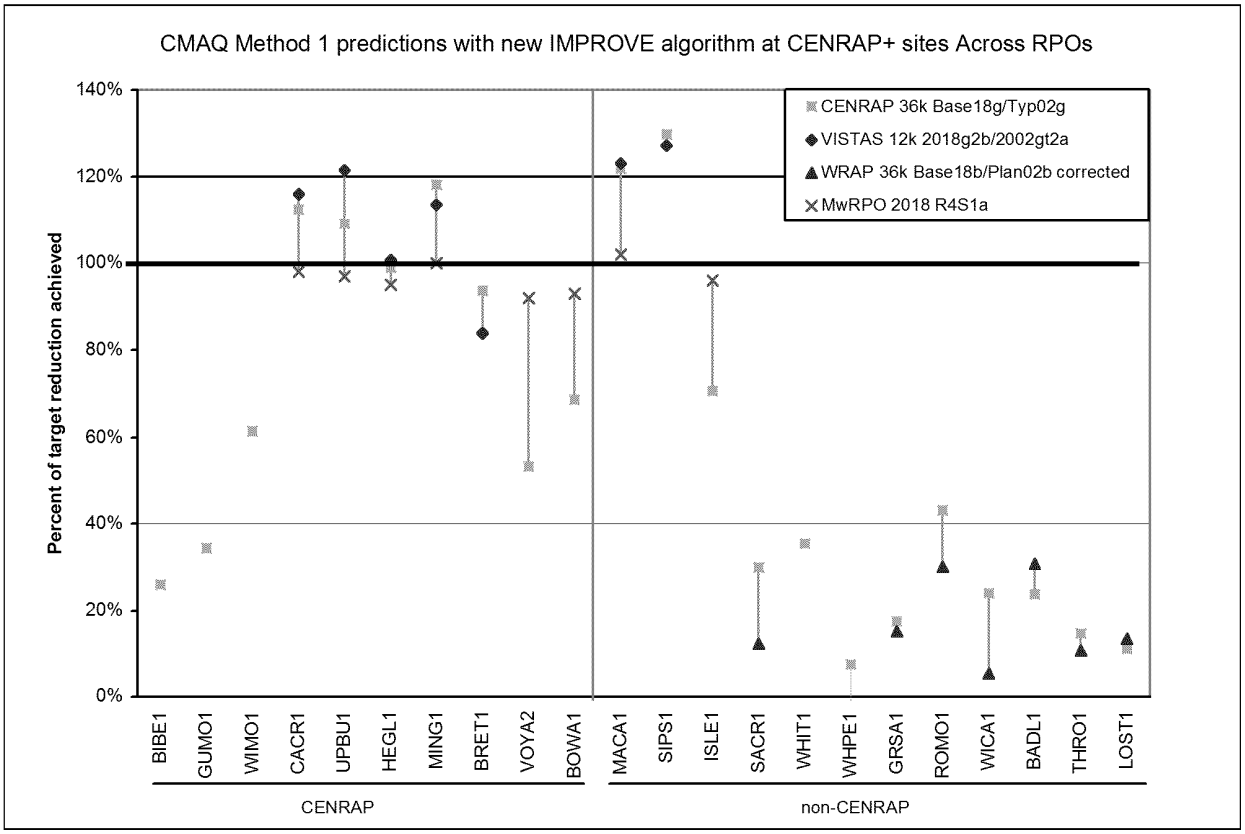

Figure 8.4. DotPlot comparing the CENRAP, VISTAS, MRPO and WRAP 2018 visibility projections expressed as a percentage of achieving the 2018 URP goal.

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8.1 Technical Support Documentation for CENRAP Emissions and Air Quality Modeling to Support Regional Haze State Implementation.

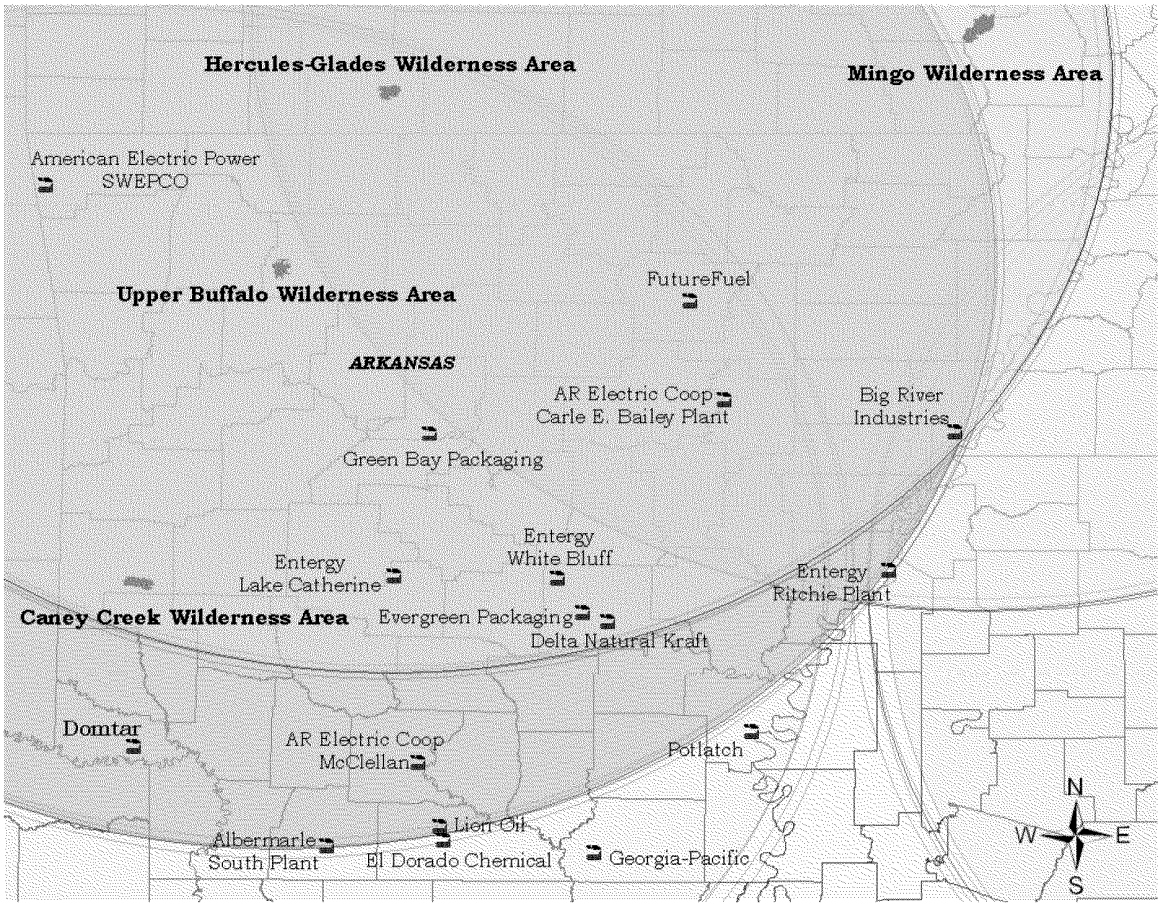
9. Best Available Retrofit Technology

The U.S. EPA's 1999 Regional Haze Rule (RHR) requires certain emission sources "that may reasonably be anticipated to cause or contribute" to visibility impairment in downwind Class I areas to install Best Available Retrofit Technology (BART) controls. States are required to determine the "degree of improvement in visibility which may reasonably result from the use of such technology." On July 6, 2005, EPA published final amendments to its 1999 RHR in the *Federal Register*, including Appendix Y, "Guidelines for BART Determinations Under the Regional Haze Rule" ("Guidelines"), the final guidance for Best Available Retrofit Technology (BART) determinations (70 FR 39104-39172).

The Arkansas Department of Environmental Quality (ADEQ) is requiring sources subject to BART to install, operate, and maintain BART rather than implement an emission trading program, or other alternative measure, in place of BART.

9.1 BART – Eligible Sources in the State of Arkansas

The facilities with BART-eligible units in Arkansas are shown in Figure 9.1 and Table 9.1. A detailed description of each BART-eligible emission units is included in Appendix 9.1A.



BART-eligible Sources
Hercules-Glade Wilderness Area, MO
Upper Buffalo Wilderness Area, AR
Caney Creek Wilderness Area, AR
Mingo Wilderness Area, MO
Sipsey Wilderness Area, AL

Figure 9.1 Map showing Arkansas's BART-eligible sources and the 300 km radius buffer zones around five separate receptors (north, south, east, west, and center) located in the following Class I areas: Upper Buffalo, Caney Creek, Hercules Glade, Mingo, and Sipsey. This map was developed to determine which Class I areas will be assessed during the BART determination modeling.

Table 9.1 Facilities with BART-eligible Units in the State of Arkansas

BART Sources Category Number and Name	Facility Name/Location	SIC	Facility ID	AFIN	Unit ID	Unit Description
1. Fossil fuel-fired Electric Plants > 250 MMbtu/hour-Electric Generating Units (EGUs)	American Electric Power/Gentry (SWEPCO)*	49	05-007-00107	04-0017	SN-01	Boiler
	AR Electric Cooperative/Augusta*	49	05-147-00024	74-00024	SN-01	Boiler 1350 mm
	AR Electric Cooperative/Camden*	49	05-103-00055	52-00055	SN-01	Boiler
	Entergy-Lake Catherine/Jones Mills	49	05-059-00011	30-00011	SN-02	Unit 4 Boiler
	Entergy-Ritchie Plant/Helena	49	05-107-00017	54-00017	SN-02	Unit2
	Entergy-White Bluff/Redfield	49	05-069-00110	35-00110	SN-01	Unit 1
	Entergy-White Bluff/Redfield	49	05-069-00110	35-00110	SN-02	Unit 2
	Entergy-White Bluff/Redfield	49	05-069-00110	35-00110	SN-05	Auxiliary Boiler
3. Kraft Pulp Mills	Domtar, Inc./Ashdown	26	05-081-00002	41-00002	SN-03	#1 Power Boiler
	Domtar, Inc./Ashdown	26	05-081-00002	41-00002	SN-05	#2 Power Boiler
	Delta Natural Kraft/Pine Bluff	26	05-069-00017	35-00017	SN-02	Recovery Boiler
	Evergreen Packaging/Pine Bluff	26	05-069-00016	35-00016	SN-04	# 4 Recovery Boiler
	Georgia-Pacific Paper/Crossett	26	05-003-00013	02-00013	SN-22	9A Boiler
	Green Bay Packaging/Morrilton	26	05-029-00001	15-00001	SN-05A	Recover Boiler
	Potlatch/McGehee	26	05-041-00036	21-00036	SN-04	Power Boiler
11. Petroleum Refineries	Lion Oil/El Dorado	29	05-139-00016	70-00016	SN-809	#7 Catalyst Regenerator
15. Sulfur Recovery Plant	Albermarle-South Plant/Magnolia	28	05-027-00028	14-00028	SR-01	Tail Gas Incinerator
19. Sintering Plants	Big River Industries/West Memphis	32	05-035-00082	18-00082	SN-01	Kiln A
21. Chemical Processing Plants	Albermarle-South Plant/Magnolia	28	05-027-00028	14-00028	BH-01	Boiler #1
	Albermarle-South Plant/Magnolia	28	05-027-00028	14-00028	BH-02	Boiler #2
	FutureFuels Chemical/Batesville	28	05-063-00036	31-00036	6M01-01	3 Coal Boiler
	El Dorado Chemical/El Dorado	28	05-139-00040	70-00040	SN-08	West Nitric Acid Plant
	El Dorado Chemical/El Dorado	28	05-139-00040	70-00040	SN-09	East Nitric Acid Plant
	El Dorado Chemical/El Dorado	28	05-139-00040	70-00040	SN-10	Nitric Acid Concentrator

* Please note: American Electric Power/Gentry (SWEPC) is permitted as Flint Creek Power Plant; AR Electric Cooperation/Augusta is permitted as Arkansas Electric Cooperation Carl E. Bailey Plant; and AR Electric Cooperation/Camden is permitted as AR Electric Cooperation Corporation – John L. McClellan Generating Station

The BART-eligible sources were identified using the methodology in the "Guidelines". (40 CFR Part 51, Appendix Y) To identify as BART-eligible emission units, ADEQ used the following "Guidelines" criteria:

- One, or more, emission(s) units at the facility fit within one of the twenty-six (26) categories listed in the "Guidelines";
- The emission unit(s) were in existence on August 7, 1977 and began operation at some point on, or after, August 7, 1962; and
- The sum of the potential emissions from all emission unit(s) identified using the previous two criteria were greater than 250 tons, or more, per year of the visibility-impairing pollutants: sulfur dioxide (SO_2), nitrogen oxide (NO_x), and PM_{10}.

The "Guidelines" recommend addressing the visibility-impairing pollutants: SO_2, NO_x, and Particulate Matter (PM). ADEQ addressed these three pollutants and used PM less than ten (10) micrometers (μm) in diameter (PM_{10}) as an indicator for PM in the initial step of identifying BART-eligible units. Consistent with the "Guidelines", ADEQ did not evaluate emissions of Volatile Organic Compounds (VOCs) and ammonia (NH_3) in BART determinations, because only specific VOCs form secondary organic aerosols that affect visibility. These compounds are a fraction of the total VOCs reported in the emissions inventory, and ADEQ does not have the breakdown of VOC emissions necessary to model those that only impair visibility. Further, the prescribed screening model (CALPUFF) cannot simulate formation of particles from anthropogenic VOCs, nor their visibility impacts. Ammonia from specific sources will not be evaluated in this process, although ammonia is included in the modeling as a background concentration. The appropriate VOCs and ammonia emission data can, and will be, included in regional scale modeling used for the Regional Haze SIP.

BART-eligible sources were determined by a review of ADEQ's emission inventory database and a review of the permits and permit applications. A detailed description of the process is located in Appendix 9.1B. As shown in Table 9.1, this analysis indicated there were 27 facilities in Arkansas with BART-eligible units.

9.2 Determination of Sources Subject-to-BART

Under the "Guidelines", ADEQ has the following options regarding its BART-eligible sources: a) make BART determinations for all sources or b) consider exempting some sources from BART because they do not cause or contribute to visibility impairment in a Class I area. ADEQ has chosen option b. If a State chooses option b, the "Guidelines" suggest the following three modeling options for determining which sources may be exempt:

(1) Individual source attribution approach (dispersion modeling).
(2) Use of model plants to exempt sources with common characteristics.
(3) Cumulative modeling to show that no sources in a state are subject to BART.

ADEQ has chosen sub-option 1 above to determine which sources are subject to BART. ADEQ performed a source-specific analysis to determine which sources cause or contribute to visibility impairment using the CALPUFF model. The CALPUFF modeling protocol used for determining which facilities are subject-to-BART is included in Appendix 9.2A. In accordance with the "Guidelines", a contribution threshold of a 0.5 change (delta Δ) in deciview (dv) was used for determining which sources were subject to BART. The "Guidelines" provide States the discretion to set a lower dv threshold than 0.5 dv if "the location of a large number of BART-eligible sources within the State and in proximity to a Class I area justifies this approach." The 0.5 dv threshold was selected because ADEQ followed EPA's BART Modeling Guidance (p 42) in sitting a threshold limit in determining whether a BART-eligible source is either subject-to-BART or exempt. According to the aforementioned modeling guidance, an individual source will be considered to "cause visibility impairment" if the emissions results in a Δ dv that is greater than or equal to 1.0 dv on the visibility in a Class I area. Additionally, if the emissions from a source results in a Δ in visibility that is greater than or equal to 0.5 dv in a Class I area the source will be considered to "contribute to visibility impairment" (BART Final Rule, 40 CFR 51 p 39113). Thus, ADEQ has set the threshold limit at 0.5 dv.

Please note that ADEQ used the original (default) IMPROVE algorithm (Equation 1) in the BART determination modeling because the CALPUFF model was developed using Equation 1.

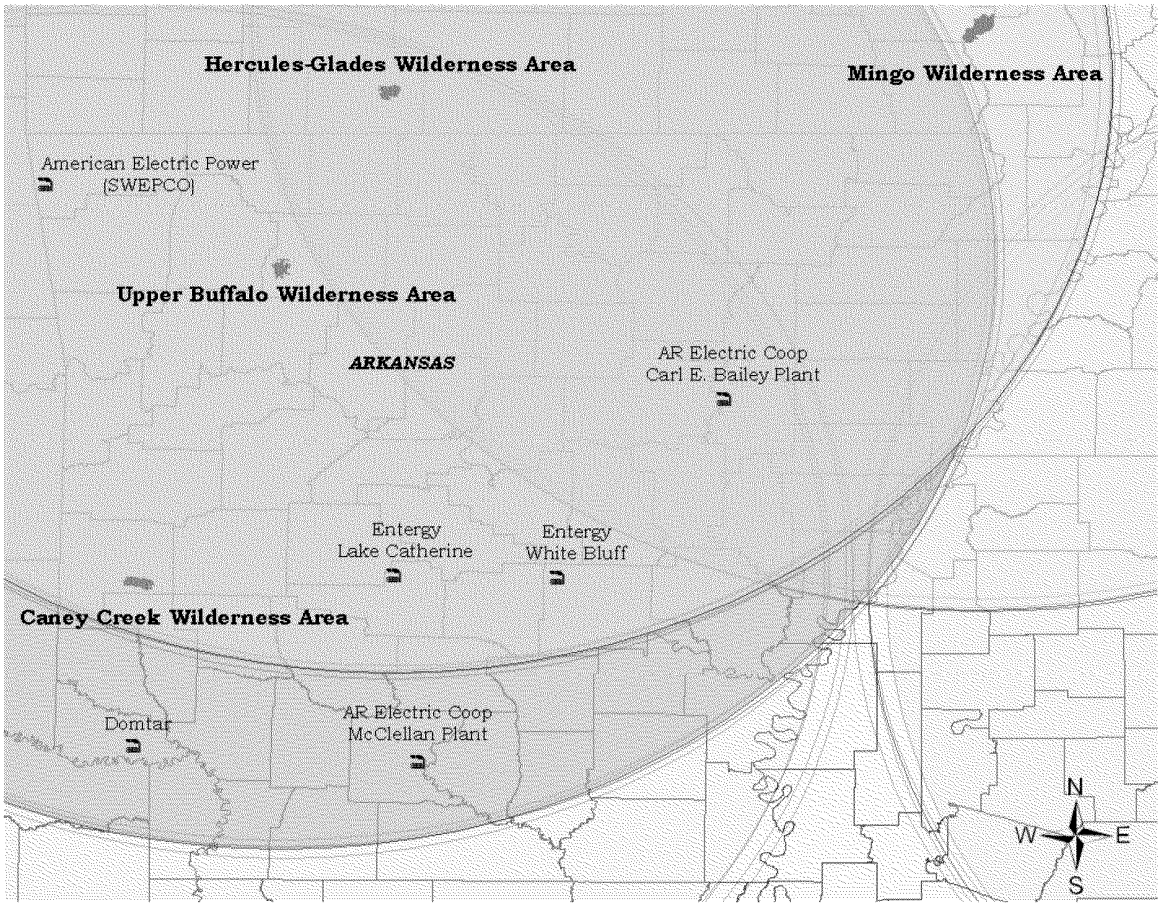
Equation 1

$$\begin{aligned} b_{ext} \approx\ & 3 \times f(RH) \times [Sulfate] \\ & + 3 \times f(RH) \times [Nitrate] \\ & + 4 \times [Organic\ Carbon] \\ & + 10 \times [Elemental\ Carbon] \\ & + 1 \times [Fine\ Soil] \\ & + 0.6 \times [Coarse\ Mass] \\ & + 10 \end{aligned}$$

The facilities with BART-eligible units found to be subject-to-BART by ADEQ are shown in Table 9.2 and Figure 9.2. Appendix 9.2B contains the CALPUFF modeling input and output files for each BART-eligible source. Facilities found to be subject-to-BART must complete a BART analysis. However, ADEQ worked closely with the facilities in their preparation of the BART engineering analyses. Additionally, it is ultimately the responsibility of ADEQ to either approve or reject the BART sources' engineering analysis during the permitting process. Appendix 9.2C contains the post-control CALPUFF modeling input and output files for each subject-to-BART source.

Table 9.2 Subject-to-BART sources in Arkansas

BART Source Category Name	Facility Name	Facility ID	Emission Units Subject-to-BART	Pollutants Evaluated in BART Determination	Contribution to Visibility Impairment (Δ dv)
1. Fossil fuel-fired Electric Plants > 250 MMbtu/hour – Electric Generating Units (EGUs)	American Electric Power/SWEPCO	05-007-00107	Boiler SN-01	SO_2, NO_x, PM_{10}, and $PM_{2.5}$	See Appendix 9.2B
	AR Electric Coop Bailey Plant	05-147-00024	Boiler 1350 mm SN-01	SO_2, NO_x, PM_{10}, and $PM_{2.5}$	See Appendix 9.2B
	AR Electric Coop McClellan Plant	05-103-00055	Boiler SN-01	SO_2, NO_x, PM_{10}, and $PM_{2.5}$	See Appendix 9.2B
	Entergy Lake Catherine Plant	05-059-00011	Unit 4 Boiler SN-03	SO_2, NO_x, PM_{10}, and $PM_{2.5}$	See Appendix 9.2B
	Entergy White Bluff Plant	05-069-00110	Unit 1 SN-01	SO_2, NO_x, PM_{10}, and $PM_{2.5}$	See Appendix 9.2B
			Unit 2 SN-02	SO_2, NO_x, PM_{10}, and $PM_{2.5}$	See Appendix 9.2B
			Auxiliary Boiler SN-05	SO_2, NO_x, PM_{10}, and $PM_{2.5}$	See Appendix 9.2B
3. Kraft Pulp Mills	Domtar	05-081-00002	# 1 Power Boiler SN-03	SO_2, NO_x, and $PM_{2.5}$	See Appendix 9.2B
			# 2 Power Boiler SN-05	SO_2, NO_x, and $PM_{2.5}$	See Appendix 9.2B



Subject to BART Sources
Hercules-Glade Wilderness Area, MO
Upper Buffalo Wilderness Area, AR
Caney Creek Wilderness Area, AR
Mingo Wilderness Area, MO
Sipsey Wilderness Area, AL

Figure 9.2 Map showing Arkansas' subject to BART sources and the 300 km buffers around Caney Creek Wilderness Area, Arkansas, Upper Buffalo Wilderness Area, Arkansas, Hercules-Glade Wilderness Area, Missouri, Mingo Wilderness Area, Missouri, and Sipsey Wilderness Area, Alabama

Cumulative Impact of Subject-to-BART Sources on Visibility

Additionally, in accordance to *Federal Register* (FR 39105) notice promulgating the "Guidelines", ADEQ contracted with ENVIRON International Corporation and Alpine Geophysics, LLC to perform a cumulative BART modeling analysis of the 6 subject-to-BART facilities in Arkansas to evaluate the cumulative visibility impacts due to the aforementioned

facilities at nearby Class I areas. Please refer to Appendix 9.2C for a detailed description of ENVIRON and Alpine Geophysics' methodology and the Class I areas studied.

Clean Air Interstate Rule and BART

The Clean Air Interstate Rule was finalized in May 2005 by EPA and applies to states in the eastern U.S. Reconsiderations were finalized March 2006. This rule addresses air pollution transport across state borders. EPA determined which states must reduce which pollutants based on modeling which showed how the travel of pollution affects non-attainment in other states. CAIR requires states to reduce NO_x and/or SO_2 emissions. Of the three programs in CAIR, Arkansas is required to participate in only the Ozone-Season NO_x reductions program. Although EPA's BART Modeling Guidance allows CAIR states to participate in the CAIR cap and trade program, the state of Arkansas is not eligible for the aforementioned trading program because Arkansas is in CAIR only for NO_x during the ozone season. Therefore, in Arkansas CAIR is not better than BART. Thus BART-eligible EGUs will be modeled for BART determination/exemption by ADEQ.

9.3 Determination of BART Requirements for Subject-to-BART Sources

BART-level emissions reductions for the subject to BART sources in Arkansas are shown in Tables 9.3a through 9.3d for each visibility impairing pollutant. The BART requirements in the RHR are intended to reduce emissions specifically from large emission units that, due to age, were exempted from other control requirements of the CAAA. BART emission limits for each pollutant are based on the following: the degree of reduction achievable through the application of the best system of continuous emission reduction, taking into consideration the technology available; the costs of compliance; the energy and the non-air quality environmental impacts of compliance; any pollution control equipment in use or in existence at the source; the remaining useful life of the source; and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. However, a State is not required to make a determination of BART for SO_2 or NO_x if a BART-eligible source has the potential to emit less than forty (40) tons per year of such pollutant(s), or less than fifteen (15) tons per year for PM_{10}.

The BART analysis conducted by the facility for each subject-to-BART source is included in Appendix 9.3A. BART for each subject-to-BART source was determined by ADEQ using the methodology in the "Guidelines." These BART emission standards will be included in the Title V operating permit for each source after this implementation plan is approved by EPA. A copy of Regulation 19 which contains these BART limits is included in Appendix 9.3C. Additionally, response to EPA comments concerning the BART analyses performed by the subject-to-BART facilities is included in Appendix 9.3B. All correspondence between ADEQ, subject-to-BART sources, and EPA is located in Appendix 9.4B.

ADEQ is requiring that each subject-to-BART source install and operate BART as expeditiously as practicable, but in no event later than six years after the effective day of Arkansas Regulation

19, Chapter 15 or five years after approval of the SIP or plan revision by EPA, whichever comes first.

Table 9.3a BART-Level Emissions Reductions from the 2002 Baseline, Sulfur Dioxide (SO_2)

Source and Unit	Maximum 24-Hour Actual Emissions (lb/day)	Baseline Peak 24-hour Emissions (lb/hr)	BART Level of Control % Removal[1]	Future Peak 24-hour Emission Rate (lb/hr)	Emission Limit[2]
04-00107 276-AOP-R1 American Electric Power/SWEPCO SN-01	113483.81	4728.49	78.3%	1026.08	0.15 lb/MMBtu
74-00024 154-AOP-R0 AR Electric Coop Bailey Plant SN-01	57018.10	2375.75	55%	1069.09	1034.17 lb/hr (1% S fuel oil)
52-00055 181-AOP-R1 AR Electric Coop McClellan Plant SN-01	65942.06	2747.59	65%	961.66	982.47 lb/hr (1% S fuel oil)
41-00002 287-AOP-R2 Domtar SN-03	10620	442.5	0%	442.5	1.12 lb/MMBtu
41-00002 287-AOP-R2 Domtar SN-05	18916.8	788.2	0% (using existing scrubber)	788.2	1.20 lb/MMBtu
30-30-00011 1717-AOP-R1 Entergy Lake Catherine Plant SN-03 *oil*	126647.84	5276.99	46%	2860.4	0.562 lb/MMBtu (0.5% S fuel oil)
35-00110 263-AOP-R1 Entergy White Bluff Plant SN-01	186319.32	7763.3	82%	1400.8	0.15 lb/MMBtu (Bituminous & sub-bituminous coal)
35-00110 263-AOP-R1 Entergy White Bluff Plant SN-02	187799.35	7825.0	80%	1533.2	0.15 lb/MMBtu (Bituminous & sub-bituminous coal)
35-00110 263-AOP-R1 Entergy White Bluff Plant SN-05	No emission standards have been established for this source. Rather the state has established work practice standards for this source pursuant to 40 CFR 51.308(e)(1)(iii).				

1. Only listed if facility is adding controls or taking limits that will reduce emission per BART requirements. Facilities which are not adding controls or using controls which are already installed have a 0% BART control efficiency.
2. 30-day rolling average

Table 9.3b BART-Level Emissions Reductions from the 2002 Baseline, Oxides of Nitrogen (NO_x)

Source and Unit	Maximum 24-Hour Actual Emissions (lb/day)	Baseline Peak 24-hour Emissions (lb/hr)	BART Level of Control % Removal[1]	Future Peak 24-hour Emission Rate (lb/hr)	Emission Limit[2]
04-00107 276-AOP-R1 American Electric Power/SWEPCO SN-01	46680.0	1945	16.8%	1618.24	0.23 lb/MMBtu
41-00002 287-AOP-R2 Domtar SN-03	4309.0	179.54	0%	179.54	0.46 lb/MMBtu
41-00002 287-AOP-R2 Domtar SN-05	12643.2	526.8	30%	368.76	0.450 lb/MMBtu
30-00011 1717-AOP-R1 Entergy Lake Catherine Plant SN-03 *gas*	58960.0	2456.67	69.6%	746.82	0.15 lb/MMBtu
30-00011 1717-AOP-R1 Entergy Lake Catherine Plant SN-03 *oil*	60273.0	2511.38	47.6%	1315.96	0.25 lb/MMBtu
35-00110 263-AOP-R1 Entergy White Bluff Plant SN-01	104920.0	4371.7	69%	1355.23	0.28 lb/MMBtu (bituminous coal)
35-00110 263-AOP-R1 Entergy White Bluff Plant SN-01	104920.0	4371.7	69%	1355.22	0.15 lb/MMBtu (sub-bituminous coal)
35-00110 263-AOP-R1 Entergy White Bluff Plant SN-02	113540.0	4730.8	69%	1466.56	0.28 lb/MMBtu (bituminous coal)
35-00110 263-AOP-R1 Entergy White Bluff Plant SN-02	113540.0	4730.8	69%	1466.56	0.15 lb/MMBtu (sub-bituminous coal)
35-00110 263-AOP-R1 Entergy White Bluff Plant SN-05	No emission standards have been established for this source. Rather the state has established work practice standards for this source pursuant to 40 CFR 51.308(e)(1)(iii).				

1. Only listed if facility is adding controls or taking limits that will reduce emission per BART requirements. Facilities which are not adding controls or using controls which are already installed have a 0% BART control efficiency.
2. 30-day rolling average

Table 9.3c BART-Level Emissions Reductions from the 2002 Baseline, Particulate Matter 10 micrometers (PM_{10})

Source and Unit	Maximum 24-Hour Actual Emissions (lb/day)	Baseline Peak 24-hour Emissions (lb/hr)	BART Level of Control % Removal[1]	Future Peak 24-hour Emission Rate (lb/hr)	Emission Limit[2]
41-00002 287-AOP-R2 Domtar SN-03	4068.0	169.5 (filterable)	76%	40.6	0.07 lb/MMBtu
41-00002 287-AOP-R2 Domtar SN-05	1958.4	81.6 (filterable)	29.7% (using existing scrubber)	57.4	0.10 lb/MMBtu

1. Only listed if facility is adding controls or taking limits that will reduce emission per BART requirements. Facilities which are not adding controls or using controls which are already installed have a 0% BART control efficiency.
2. 30-day rolling average

Table 9.3d BART-Level Emissions Reductions from the 2002 Baseline, Particulate Matter 2.5 micrometers ($PM_{2.5}$)

Source and Unit	Maximum 24-Hour Actual Emissions (lb/day)	Baseline Peak 24-hour Emissions (lb/hr)	BART Level of Control % Removal[1]	Future Peak 24-hour Emission Rate (lb/hr)	Emission Limit[2]
30-00011 1717-AOP-R1 Entergy Lake Catherine Plant SN-03 *oil*	6810.0	283.75	69.4%	86.83	0.037lb/MMBtu (filterable & condensable) 0.5% S fuel oil

1. Only listed if facility is adding controls or taking limits that will reduce emission per BART requirements. Facilities which are not adding controls or using controls which are already installed have a 0% BART control efficiency.
2. 30-day rolling average

9.4 Results and Conclusions

To determine if there was a statistical significant improvement to visibility from the post-control emissions of Arkansas' subject-to-BART sources, a student t (TTEST function in Excel) was performed. Tables 9.4a through 9.4g contain the maximum change (delta Δ) in deciview (dv) from the pre-control emissions, the maximum Δ dv from the post-control emissions, the percent decrease, the P value, and the number of days the Δ dv from the pre-control emissions were greater than or equal to (≥) a Δ dv of 0.5.

Table 9.4a American Electric Power results comparing the pre-control emissions and the post-control emissions to Caney Creek Wilderness Area (CACR) and Upper Buffalo Wilderness Area (UPBU), Arkansas and Hercules-Glade Wilderness Area (HEGL), Missouri

Class I area	Pre-control Maximum Δ dv	Post-control Δ dv	Percent Change	Is P < 0.05	Number of Days Pre-control Δ dv ≥ 0.5
CACR	3.970	1.573	60.38	Yes	106
UPBU	3.781	2.089	44.75	Yes	139
HEGL	3.983	1.541	61.31	Yes	117

Table 9.4b Arkansas Electric Coop – Carl E. Bailey results comparing the pre-control emissions and the post-control emissions to Caney Creek Wilderness Area (CACR) and Upper Buffalo Wilderness Area (UPBU), Arkansas and Hercules-Glade Wilderness Area (HEGL) and Mingo Wilderness Area (MING), Missouri

Class I area	Pre-control Maximum Δ dv	Post-control Δ dv	Percent Change	Is P < 0.05	Number of Days Pre-control Δ dv ≥ 0.5
CACR	1.841	0.897	51.28	Yes	28
UPBU	1.232	0.574	53.41	Yes	23
HEGL	1.594	0.809	49.25	Yes	30
MING	1.660	0.766	53.86	Yes	45

Table 9.4c Arkansas Electric Coop – McClellan results comparing the pre-control emissions and the post-control emissions to Caney Creek Wilderness Area (CACR) and Upper Buffalo Wilderness Area (UPBU), Arkansas

Class I area	Pre-control Maximum Δ dv	Post-control Δ dv	Percent Change	Is P < 0.05	Number of Days Pre-control Δ dv ≥ 0.5
CACR	2.197	1.011	53.98	Yes	58
UPBU	1.196	0.487	59.28	Yes	23

Table 9.4d Domtar results comparing the pre-control emissions and the post-control emissions to Caney Creek Wilderness Area (CACR) and Upper Buffalo Wilderness Area (UPBU), Arkansas

Class I area	Pre-control Maximum Δ dv	Post-control Δ dv	Percent Change	Is P < 0.05	Number of Days Pre-control Δ dv ≥ 0.5
CACR	2.262	2.038	9.90	Yes	149
UPBU	1.181	1.029	12.87	No	18

Table 9.4e Entergy – Lake Catherine results comparing the pre-control emissions from natural gas and the post-control emissions from natural gas to Caney Creek Wilderness Area (CACR) and Upper Buffalo Wilderness Area (UPBU), Arkansas and Hercules-Glade Wilderness Area (HEGL), Missouri

Class I area	Pre-control Maximum Δ dv	Post-control Δ dv	Percent Change	Is P < 0.05	Number of Days Pre-control Δ dv ≥ 0.5
CACR	3.209	1.111	63.48	Yes	87
UPBU	2.186	0.753	66.55	Yes	54
HEGL	1.663	0.558	66.45	Yes	23

Table 9.4f Entergy – Lake Catherine results comparing the pre-control emissions from fuel oil and the post-control emissions from fuel oil to Caney Creek Wilderness Area (CACR) and Upper Buffalo Wilderness Area (UPBU), Arkansas and Hercules-Glade Wilderness Area (HEGL), Missouri

Class I area	Pre-control Maximum Δ dv	Post-control Δ dv	Percent Change	Is P < 0.05	Number of Days Pre-control Δ dv ≥ 0.5
CACR	6.607	3.671	36.49	Yes	201
UPBU	2.953	1.636	44.60	Yes	188
HEGL	4.129	2.397	41.95	Yes	134

Table 9.4g Entergy – White Bluff results comparing the pre-control emissions and the post-control emissions from to Caney Creek Wilderness Area (CACR) and Upper Buffalo Wilderness Area (UPBU), Arkansas and Hercules-Glade Wilderness Area (HEGL), Missouri

Class I area	Pre-control Maximum Δ dv	Post-control Δ dv	Percent Change	Is P < 0.05	Number of Days Pre-control Δ dv ≥ 0.5
CACR	8.677	2.665	69.29	Yes	245
UPBU	7.948	2.167	72.74	Yes	242
HEGL	6.631	2.030	97.97	Yes	234

The results from the ENVIRON cumulative modeling using Comprehensive Air-quality Model with extensions (CAMx) PM Source Apportionment Technology (PSAT) is estimated to result in substantial improvements in visibility to all 10 Class I areas studied, with the largest visibility improvement of 5 Δ dv at Mingo Wilderness Area, Missouri. (Please refer to Appendix 9.2C for ENVIRON and Alpine Geophysics' final report.) The highest cumulative visibility impacts due

to all PM species in the pre-control base case ranged from 4 to 11 Δ dv across the Class I areas, whereas the highest visibility impacts in the post-control case ranged from 1 to 7 Δ dv. Despite these apparent visibility improvements, the cumulative visibility impacts due to all Arkansas BART sources in the post-control case still exceed 1 Δ dv at most Class I areas of interest.

During the modeling process, ADEQ was informed that the emissions provided for the Domtar Arkansas subject-to-BART source were understated. To address this issue, a sensitivity analysis was performed by ENVIRON using the corrected Domtar emissions for both the pre- and post-control scenarios was conducted. The analysis suggested that the revised (higher) Domtar emissions worsen the visibility improvement in the post-control case, specifically by 2 Δ dv at Caney Creek Wilderness Area, Arkansas.

In summary, there is an improvement in visibility from the post-control emissions of the State of Arkansas's subject-to-BART sources at all Class I areas assessed by ADEQ. Appendix 9.4A contains charts comparing the pre- and post-control emissions of Arkansas' subject-to-BART sources. These charts also indicate there is a considerable improvement to visibility from the post-control emissions of Arkansas's subject-to-BART sources.

List of Chapter 9 Appendices

9.1A Detailed Description of BART-eligible Emission Units
9.1B Method of Identifying BART-Eligible Sources in the State of Arkansas
9.2A Modeling Protocol Used to Determine Subject-to-BART Sources
9.2B BART-exemption CALPUFF Modeling Input and Output Files
9.2C Subject-to-BART CALPUFF Post-control Modeling Input and Output Files
9.2D ENVIRON Final Report
9.3A BART Analyses for the Subject-to-BART Sources
9.3B Response to EPA Comments on BART Engineering Analyses
9.3C Copy of Regulation 19
9.3D Regulation 19 Supporting Documents
9.4A Charts Comparing Arkansas's subject-to-BART Sources' Pre- and Post-control
9.4B Correspondence

10. Reasonable Progress Goals

Federal regulations at 40 CFR 51.308(d)(1) require the State of Arkansas to establish Reasonable Progress Goals (RPGs) for achieving natural visibility for each Class I area within the state. The State is required to develop RPGs that provide for visibility improvement for the most impaired days and ensure no degradation in visibility for the least impaired days throughout the year. These goals are expressed in units of deciviews (dv). A deciview is a measurement of haze, implemented in a Haze Index (HI), derived from calculated light extinction. The RPGs are established in the State Implementation Plan (SIP) and are used to track progress towards the ultimate goal of achieving natural visibility conditions by 2064.

In September 2003, EPA released a technical guidance document describing the techniques used to determine baseline and natural visibility conditions[1]. The EPA has also released guidance describing various procedures that might be used to establish RPGs[2]. The goals must provide improvement in visibility for the most impaired days, and ensure no degradation in visibility for the least impaired days for the duration of the SIP. The State must also provide an assessment of the number of years it would take to attain natural visibility conditions if improvement continues at the rate represented by the RPG. The above-referenced EPA guidance describes the meaning of the term Reasonable Progress Goal:

> States must establish RPGs, measured in deciviews (dv) for each Class I area for the purpose of improving visibility on the haziest days and ensuring no degradation in visibility on the clearest days over the period of each implementation plan. RPGs are interim goals that represent incremental visibility improvement over time toward the goal of natural background conditions and are developed in consultation with other affected States and Federal Land Managers (FLMs).
>
> In determining what would constitute reasonable progress, Section 169A(g) of the CAA requires States to consider the following four factors:
>
> - The costs of compliance,
> - The time necessary for compliance,
> - The energy and non-air quality environmental impacts of compliance, and
> - The remaining useful life of existing sources that contribute to visibility impairment.

States must demonstrate in their SIPs how these factors are taken into consideration in selecting the RPG for each Class I area in the State.

1 Guidance for Tracking Progress Under the Regional Haze Rule, EPA – 09/03.
2 Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, EPA – 06/01/07

The "Uniform Rate of Progress" (URP) described in the EPA guidance, described as "uniform rate of improvement" in 40 CFR 51.308(d)(1)(i)(B), is graphed on a timeline as a line between the "baseline conditions" representing visibility for the best and worst days at the time the regional haze program is established and natural background levels in 2064. Table 10.1 provides the URP for Class I Areas in the State of Arkansas. Figures 10.1 and 10.2 depict the URP for each Class I area in Arkansas as a "glide path."

Table 10.1 - Uniform Rate of Progress for Arkansas Class I Areas

Class I Area	Deciview Improvement Needed by 2018 assuming URP (dv)	Progress Annually to 2018 assuming URP (dv/yr)	Deciview Improvement Needed by 2064 (dv)
Caney Creek	3.45	- 0.25	14.78
Upper Buffalo	3.43	- 0.25	14.70

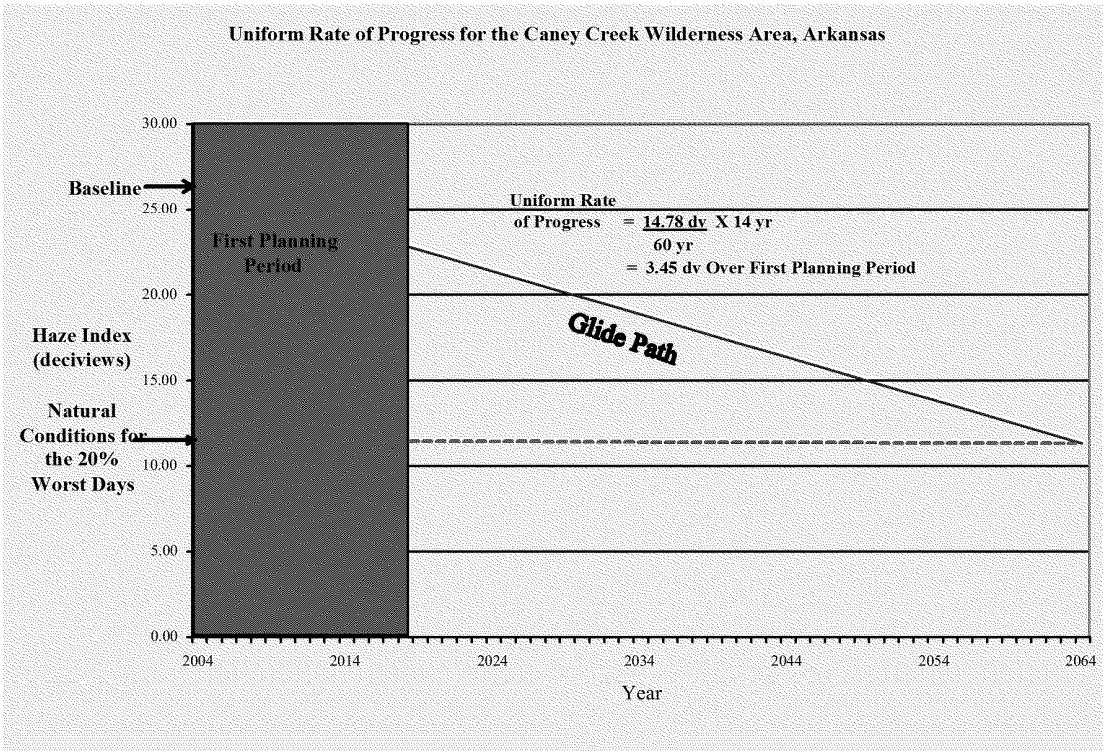

Uniform Rate of Progress for the Caney Creek Wilderness Area, Arkansas
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Baseline
Haze Index (deciviews)
Natural Conditions for the 20% Worst Days
First Planning Period
Uniform Rate of Progress = 14.78 dv X 14 yr / 60 yr
= 3.45 dv Over First Planning Period
Glide Path
2004
2014
2024
2034
2044
2054
2064
Year

Fig.10.1

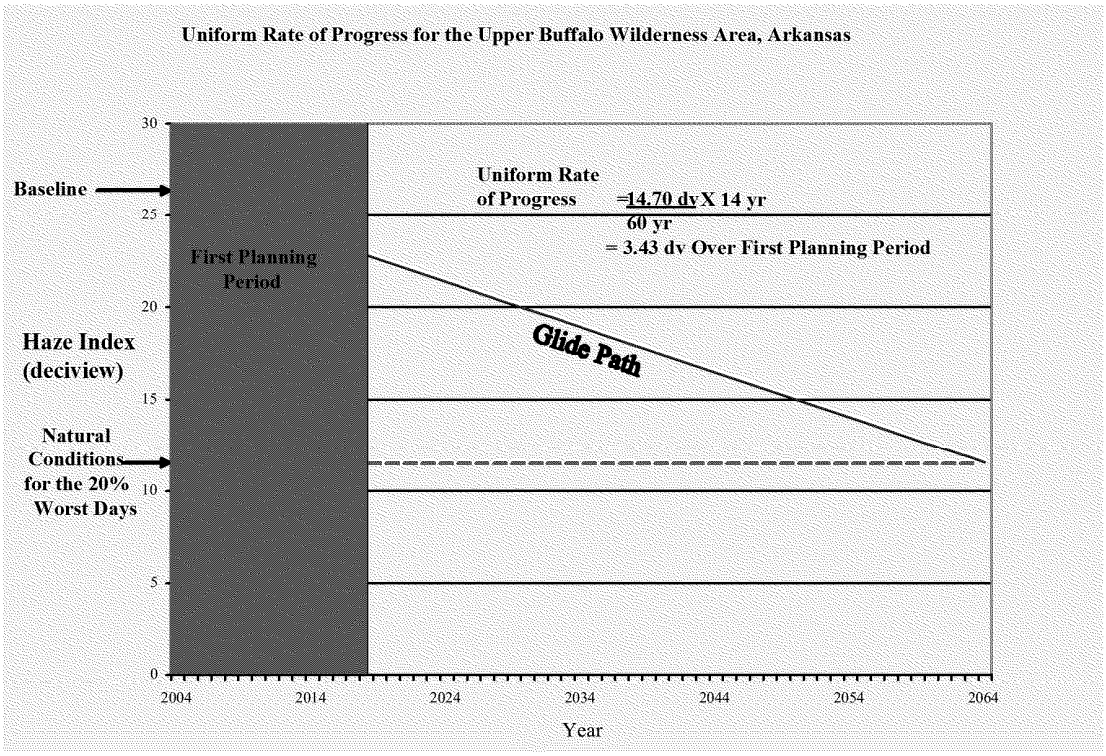

Uniform Rate of Progress for the Upper Buffalo Wilderness Area, Arkansas
Baseline
Haze Index (deciview)
Natural Conditions for the 20% Worst Days
First Planning Period
Uniform Rate of Progress
=14.70 dv X 14 yr
60 yr
= 3.43 dv Over First Planning Period
Glide Path
30
25
20
15
10
5
0
2004
2014
2024
2034
2044
2054
2064
Year

Fig. 10.2

10.2 Determination of Reasonable Progress Goals

The State of Arkansas has determined that the rates of visibility improvement by 2018 that are expressed in Table 10.2 are reasonable and hereby adopts them as the Reasonable Progress Goals for the listed Class I areas. An analysis showing that these goals are reasonable is provided in Appendix 10.1, - Analysis of Control Strategies and Determination of Reasonable Progress Goals. Figures 10.3 - 10.6 show comparisons of URP, RFP and anticipated improvement in visibility on best days for each Class I Area. The established RPGs show that Caney Creek Wilderness Area can attain the goal of background conditions by CY 2062 and the Upper Buffalo Wilderness Area can achieve background conditions by CY 2063. These RPGs exceed the URPs established for these areas and would result in a return to natural background conditions prior to CY 2064.

Table 10.2 - Reasonable Progress Goals for Arkansas Class I Areas

Class I Area	Deciview Improvement Projected by CY 2018 using RPG (dv)	Deciview Improvement by CY 2018 at URP (dv)	Projected Annual Rate of Improvement 2008-2018 (dv/yr)	Projected Deciview Improvement by CY 2064 (dv)
Caney Creek	3.88	3.45	- 0.32	15.38
Upper Buffalo	3.75	3.43	- 0.28	15.02

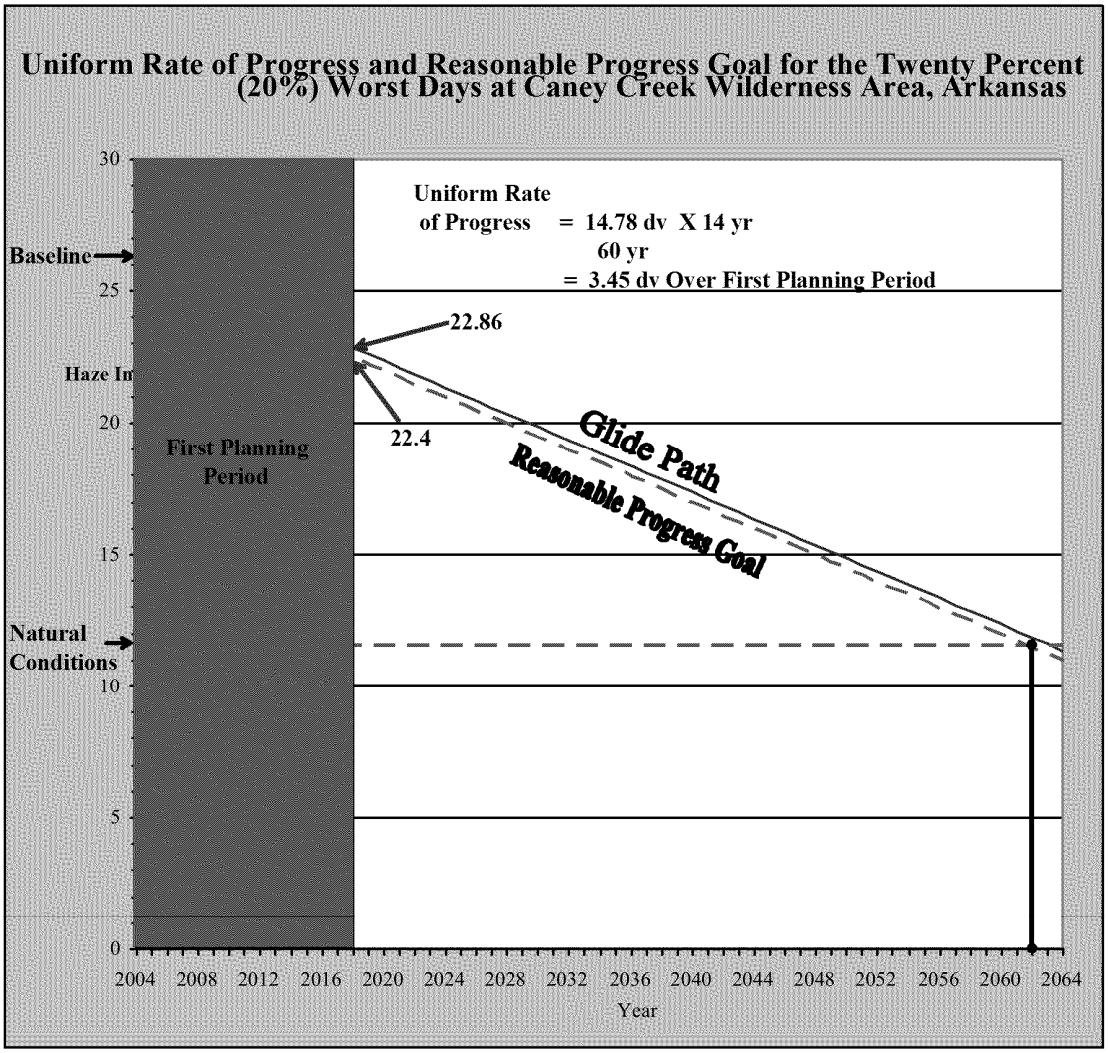

Uniform Rate of Progress and Reasonable Progress Goal for the Twenty Percent (20%) Worst Days at Caney Creek Wilderness Area, Arkansas
Uniform Rate
of Progress = 14.78 dv X 14 yr
60 yr
= 3.45 dv Over First Planning Period
Baseline
Haze In
Natural Conditions
First Planning Period
22.86
22.4
Glide Path
Reasonable Progress Goal
30
25
20
15
10
5
0
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
Year

Fig. 10.3

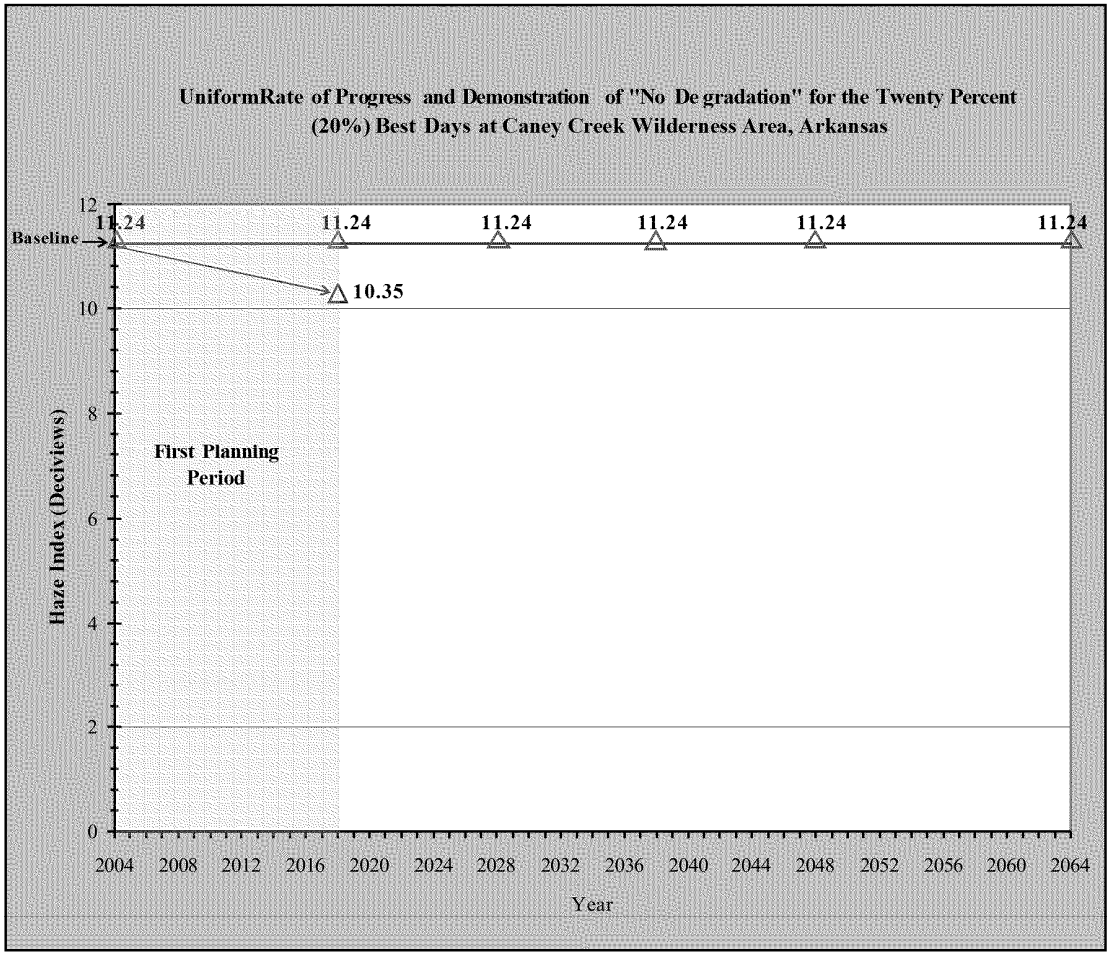

UniformRate of Progress and Demonstration of "No Degradation" for the Twenty Percent (20%) Best Days at Caney Creek Wilderness Area, Arkansas
Baseline
11.24
11.24
11.24
11.24
11.24
11.24
10.35
First Planning Period
Haze Index (Deciviews)
0
2
4
6
8
10
12
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
Year

Fig. 10.4

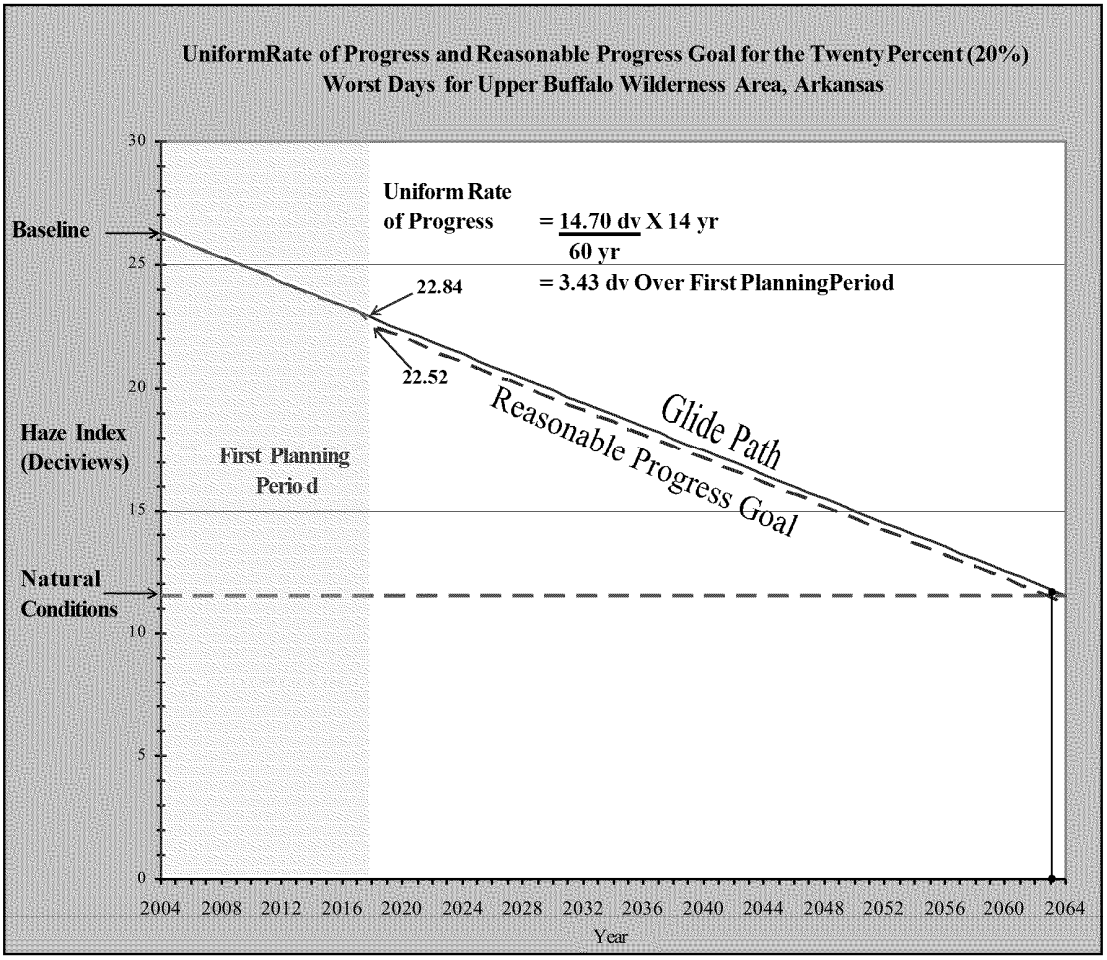

UniformRate of Progress and Reasonable Progress Goal for the Twenty Percent (20%)
Worst Days for Upper Buffalo Wilderness Area, Arkansas
Baseline
Natural Conditions
Haze Index (Deciviews)
First Planning Period
Uniform Rate of Progress = 14.70 dv X 14 yr / 60 yr
= 3.43 dv Over First PlanningPeriod
22.84
22.52
Glide Path
Reasonable Progress Goal
30
25
20
15
10
5
0
2004 2008 2012 2016 2020 2024 2028 2032 2036 2040 2044 2048 2052 2056 2060 2064
Year

Fig. 10.5

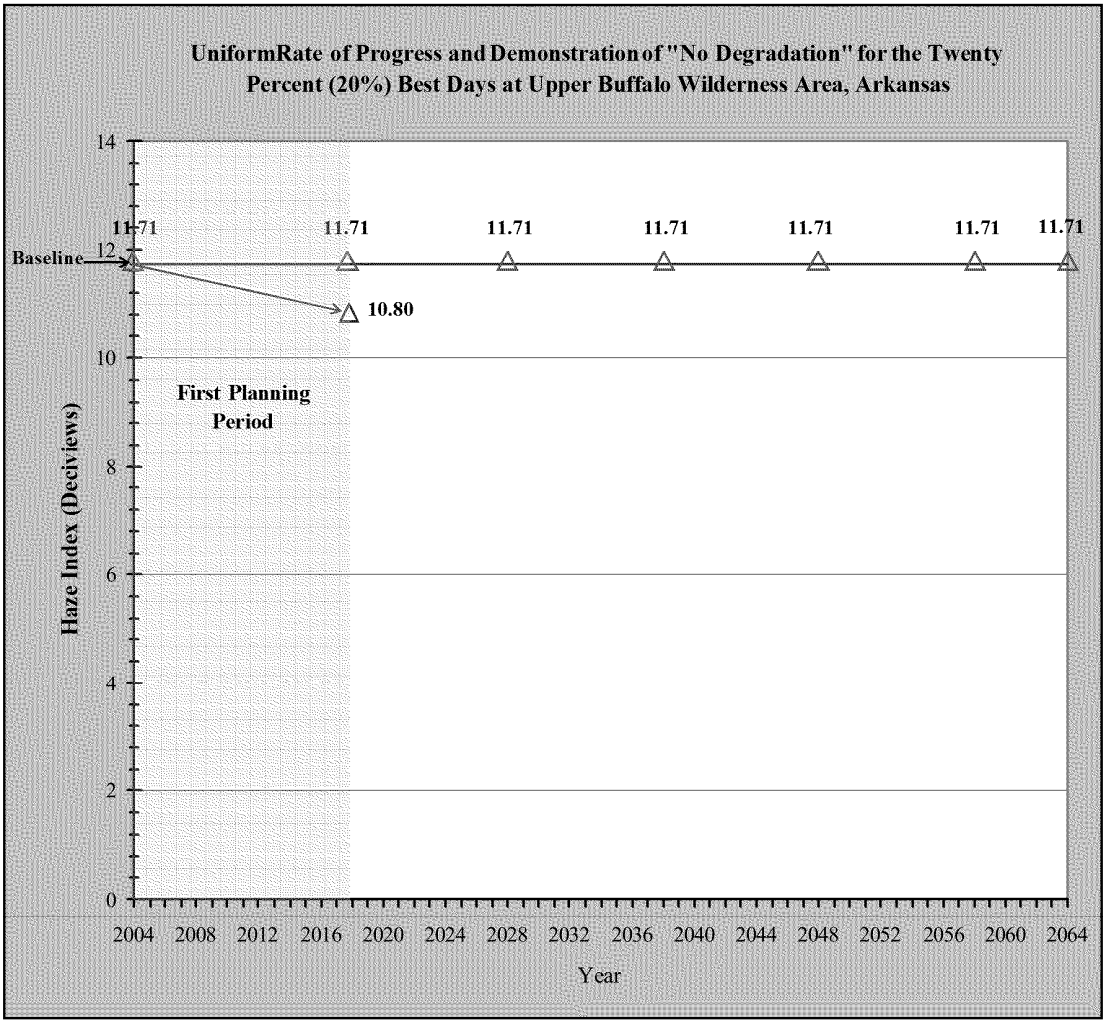

UniformRate of Progress and Demonstration of "No Degradation" for the Twenty Percent (20%) Best Days at Upper Buffalo Wilderness Area, Arkansas
Baseline
11.71
11.71
11.71
11.71
11.71
11.71
11.71
10.80
First Planning Period
Haze Index (Deciviews)
14
12
10
8
6
4
2
0
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
Year

Fig. 10.6

10.3 Consultation

In determining a reasonable progress rate for each Class I area, the State of Arkansas has consulted with the other states and Tribes which are reasonably anticipated to cause or contribute to visibility impairment in each of these Class I areas. A description of the consultations that were hosted by Arkansas and Missouri is provided in Appendix 10.2., Interagency Consultation Process in Establishing Reasonable Progress Goals.

On February 26, 2007, an invitation letter was sent to 12 States and tribes in the region. The invitation included a consultation plan that detailed the procedures and timelines for identifying possible contributors to regional haze in Arkansas and Missouri Class I Areas. These consultations were accomplished through a series of conference calls and letters. Calls were held on April 3, May 11 and June 7, 2007. Participants included States and tribes, EPA personnel, FLMs and other Regional Planning Organizations. A summary of these conference calls can be found on the CENRAP website. Correspondence between Arkansas, FLMs, Oklahoma, Kentucky, Tennessee, Missouri and Texas is included in Appendix 10.3 – Arkansas Consultation Letters.

10.4 Reporting

Progress will be reported to the EPA every five years in accordance with the requirements of 51.308 (g).

List of Chapter 10 Appendices

10.1 Analysis of Control Strategies and Determination of Reasonable Progress Goals
10.2 Interagency Consultation Process in Establishing Reasonable Progress Goals
10.3 Arkansas Consultation Letters

11. Long-term Strategy to Reach Reasonable Progress Goals

11.1 Federal Requirements

40 CFR 51.308(d)(3) requires the State of Arkansas to submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I federal area within and outside the State which may be affected by emissions from within the State. The long-term strategy must include any enforceable emissions limitations, compliance schedules and other measures considered necessary to achieve the RPGs described in Chapter 10. This chapter describes the long-term strategy of the State of Arkansas.

11.2 Consultation

40 CFR 51.308(d)(3)(i) requires Arkansas to consult with other states and tribes to develop coordinated emission strategies. This requirement applies both where emissions from the State are reasonably anticipated to contribute to visibility impairment in Class I areas outside the State and when emissions from other states or tribes are reasonably anticipated to contribute to visibility impairment in Class I areas within the State.

The State of Arkansas has consulted with other states and tribes by its on-going participation in CENRAP. The monitoring analysis, emission inventory, modeling assessments and control strategy assessments that have been conducted by CENRAP on behalf of its member states and tribes have all been done through a collaborative process that is inherently consultative in nature. In addition, the State of Arkansas has participated in discussions focused on Class I areas through-out the CENRAP region and in neighboring states which involved the states and tribes listed in Appendix 10.2 – Interstate Consultations. Strategy development considered the impacts of the State's emissions on Class I areas within and outside the State.

The manner in which the State of Arkansas has coordinated with FLMs on long-term strategy development is described in Chapter 4.

Arkansas will continue to consult with states, tribes, FLMs, EPA and other stakeholders to the extent necessary to assure that RPGs are achieved. Progress reports and plan updates will be communicated to stakeholders as they become available. On-going consultations will be in the form of written communications, conference calls and meetings on an as-needed basis.

In addition to the consultations held jointly by Arkansas and Missouri, Arkansas participated in consultations hosted by Oklahoma. No other states or Tribes have indicated that Arkansas was potentially contributing to visibility impairment in their Class 1 areas.

11.3 Share of Emission Reductions

40 CFR 51.308(d)(3)(ii) requires the State of Arkansas to demonstrate that its implementation plan includes all measures necessary to obtain its fair share of emission reductions needed to meet RPGs in other Class 1 areas.

Arkansas and Missouri relied on technical analyses developed by CENRAP, additional weight of evidence analyses prepared by Missouri as part of the Central Class 1 Areas Consultation Plan and in-house screening of BART-eligible sources to determine which states might reasonably cause or contribute to haze in its Class 1 areas. In addition to its own sources, states with emissions that were determined to have potential impacts on Arkansas's Class 1 areas included Iowa, Nebraska, Missouri, Illinois, Indiana, Ohio, Kentucky, Tennessee, Oklahoma and Texas. These states and tribal representatives from these states were included in the consultation process described in the Consultation Plan. CENRAP-modeled visibility projections indicate that the emission reductions planned for these states are sufficient to achieve the RPGs for all Class 1 areas located in Arkansas and Missouri.

CENRAP and ADEQ analyses indicate that the impact of anthropogenic emissions from Arkansas sources have not been shown to appreciably affect visibility in Class 1 areas other than the four located in Arkansas and Missouri. Visibility projections for each of these areas show that they will all be able to demonstrate a better than uniform rate of progress through the implementation of existing and forthcoming State and federal emission reduction programs. The emission reductions described elsewhere herein are sufficient to constitute a fair share of emission reductions needed to meet RPGs in affected Class I areas.

The demonstration of attainment of RPGs relies on the analysis of monitored and modeled data in a weight of evidence analysis to determine whether visibility is improved on days when it is usually poor and does not deteriorate on days when it is usually good. Current visibility is estimated from monitored components of PM2.5 and coarse mass. Models are used in a relative sense to estimate how current concentrations respond to emission reduction measures. Data analysis is used to identify source categories and regions. Current concentrations of particulate matter components are adjusted by the relative modeled response to estimate concentrations at the end the first implementation period in 2018. Future visibility is estimated from estimated component concentrations of PM2.5 and coarse particulate matter at the end of the first implementation period. The difference between present visibility and future estimated visibility is compared with the reasonable progress goal to determine if the goal is met.

The CENRAP technical report on current visibility conditions is found in Appendix 5.1, Determination of Baseline Visibility Conditions. CENRAP technical reports on current and projected inventories and regional modeling are found in Chapters 7 and 8 respectively. All applicable measures reflected in the modeling demonstration and weight-of-evidence analyses have been incorporated in the State's long-term strategy.

11.4 Long-term Strategy Elements

40 CFR 51.308(d)(3)(v) requires the State of Arkansas to consider several factors in developing its long-term strategy. These are discussed below.

11.4.1 Emission Reductions due to On-going Air Pollution Programs.

40 CFR 51.308(d)(3)(v)(A) requires the State of Arkansas to consider emission reductions from ongoing pollution control programs in the development of its long-term strategy.

The State of Arkansas considered the following ongoing programs in developing its long-term strategy:

11.4.1.1 Clean Air Interstate Rule (CAIR)

40 CFR 96 Subparts AAAA-HHHH (with the exception of Subpart EEEE) for the CAIR NO_x Ozone Season Trading Program, as finalized by the U.S. EPA on May 12, 2005, and further revised by EPA on April 28, 2006, with correcting amendments on December 13, 2006, were incorporated by reference as Chapter 14 of Arkansas Pollution Control and Ecology Commission Regulation No. 19 – Regulations of the Arkansas Plan of Implementation for Air Pollution Control on September 28, 2007.

By 2015, the State ozone season trading budget for annual NO_x allocations will be capped at 9,596 tons. This represents a reduction of 1,919 tons NO_x per period from 2009's budget of 11,515 tons NO_x per period.

11.4.1.2 Best Available Retrofit Technology (BART Rule)

Chapter 15 of Arkansas Pollution Control and Ecology Commission Regulation No. 19 – Regulations of the Arkansas Plan of Implementation for Air Pollution Control identifies BART eligible sources, subject to BART sources, numeric emissions limits for NO_x, SO_2 and particulate matter and other requirements applicable to BART sources. These controls are required to be in place by no later than CY 2013.

11.4.1.3 Tier 2 Vehicle Emission Standards

Federal Tier 2 Vehicle Emission standards for passenger cars and light trucks have been in effect since 2004 and were fully implemented in 2007. Similar rules for heavy trucks are scheduled to be fully implemented by 2009. These rules will result in reductions of emissions of particulate matter, ozone precursor pollutants and non-methane organic compounds. Reductions in these

pollutants will contribute to improvements in visibility in Class I areas and throughout the country.

11.4.1.4 Ultra Low Sulfur Diesel, Clean Air Highway and Nonroad Diesel Rules

These federal rules will result in significant reductions in visibility-related pollutants emitted from diesel engines. The low sulfur content mandated by the Ultra Low Sulfur Diesel Rule will result in being able to better control particulate emissions from diesel engines by allowing installation of control devices that were technically infeasible for fuels with higher sulfur content.

11.4.1.5 Measures to mitigate the impacts of construction activities.

40 CFR 51.308(d)(3)(v)(B) requires the State of Arkansas to consider measures to mitigate the impacts of construction activities.

In Arkansas, ADEQ is responsible for all air pollution control programs. Due to certain limitations on regulatory authorities that are included in the Arkansas Water and Air Quality Control Act, the opportunities to mitigate air emissions from construction activities are limited[3]. ADEQ does anticipate that current and future federal programs will result in some mitigation and has undertaken efforts to provide incentives for voluntary measures that can result in emission reductions.

The federal General Conformity program requires assessments of the potential impacts of any construction activity-related emissions of criteria air pollutants from federal projects in areas that have been designated as not attaining the National Ambient Air Quality Standard (NAAQS) for that pollutant. These criteria pollutants include, among others, PM 2.5 and ozone (some ozone precursor compounds contribute to visibility conditions). At the current time, there is only one county in Arkansas in non-attainment for the ozone standard and no counties in non-attainment for other criteria pollutants.

ADEQ has undertaken several initiatives to obtain reductions from on-road and off-road engines, including construction equipment throughout the State. Grant funds have been directed to fleet managers and equipment suppliers as a means of subsidizing diesel retrofits and the biodiesel market. ADEQ participates in a regional "Blue Skyways" group that works collaboratively on

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

the introduction of innovative, regional-scale, transportation-related programs and projects. These efforts are on-going.

11.4.1.6 Source retirement and replacement schedules

40 CFR 51.308(d)(3)(v)(D) requires the State of Arkansas to consider source retirement and replacement schedules in developing reasonable progress goals. Retirement and replacement will be managed in conformance with existing SIP requirements pertaining to PSD and New Source Review. Source retirement and replacement will be tracked through on-going point source inventories.

Emission limitations and schedules of compliance.

40 CFR 51.308(d)(3)(v)(C) requires the State of Arkansas to identify additional measures to meet RPGs when on-going programs alone are not sufficient to meet the RPGs. The State of Arkansas has determined that on-going State and federal air pollution control programs are sufficient to meet RPGs through 2018. Emissions reductions at non-BART facilities or new control programs for other anthropogenic source categories will not be required at this time.

11.4.1.7 Agricultural and Forestry Smoke Management

40 CFR 51.308(d)(3)(v)(E) requires Arkansas to consider smoke management techniques for the purposes of agricultural and forestry management. In 2007, the Arkansas Forestry Commission, approved revisions to the Arkansas Smoke Management Plan (SMP). The Arkansas Smoke Management Plan is designed to assure that prescribed fires are planned and executed in a manner designed to minimize impacts associated with the smoke produced by prescribed fires.

Arkansas has adopted a basic Smoke Management Program (SMP), in which owners/managers voluntarily notify state officials of fire plans. Documentation of this program is in Appendix 11.1.

Arkansas's SMP recommends a written fire plan that includes measures that can be taken to reduce residual smoke from burning activities. Arkansas's SMP recommends these actions to reduce smoke impacts where applicable:

- Reduce the fuel loading in the area to be burned by mechanical means or by using frequent, low-intensity burns to gradually reduce fuels.

- Reduce the amount of fuel consumed by the fire by burning when fuel moistures for larger fuels and duff moistures are high.

- Rapid and complete mop-up after the burn or mop-up of certain fuels.
- Reference "Smoke Management Guide for Prescribed Fire and Wildland Fire" by National Wildfire Coordinating Group Fire Use Working Team, publication NFES 1279.

In addition, the Arkansas SMP has a process to evaluate potential smoke impacts at sensitive receptors and schedule fires to minimize exposure of sensitive populations and avoid visibility impacts in Class I areas. Arkansas's SMP details procedures for the identification of smoke-sensitive targets and minimization of their exposure to smoke. Methodologies to reduce smoke exposure include smoke emissions estimates using determination of available fuels and identification of the category day based on local weather conditions forecast.

Arkansas's SMP details the AFC Dispatch Center's role in locating each prescribed fire in the center of an airshed. This system estimates the range in tons of fuel that can be allocated to an airshed based upon downwind distance to the nearest smoke sensitive target and monitors the total fuel loading tonnage burned within each air shed, each day, in order to ensure compliance with permissible limits. If the AFC Dispatch center determines that the fuel tonnage for a single prescribed fire causes the air pollution tonnage for a given airshed to exceed these limits, the AFC Dispatch Center will recommend to the prescribed fire manager that the plan should be altered by measures such as delaying the burn and reducing the acreage to be burned.

Arkansas has a public notification process and exposure reduction process in place to reduce the impacts of burning. The AFC, in cooperation with the Arkansas Prescribed Fire Committee, will explain the use and importance of fire for ecosystem management, the implications of smoke to public health and safety, and the goals of the SMP. This public awareness effort will use posters, pamphlets, news releases, and public presentations. Prescribed fire managers are encouraged to train on-the-ground personnel to understand the SMP. AFC will cooperate with organizations and government agencies such as Arkansas Lung Association or ADEQ to make the public aware of planned prescribed fires.

Arkansas's SMP states monitoring of the smoke from the prescribed fire should match the size of the fire. For small or short duration fires (such as those in grass or leaf litter), visual monitoring of the directions of the smoke plume and monitoring nuisance complaints by the public may be sufficient. Other monitoring techniques include posting personnel on vulnerable roadways to look for visibility impairment and to initiate safety measures for motorists; posting personnel at other smoke sensitive areas to look for smoke intrusions; using aircraft to track the progress of smoke plumes; and continued tracking of meteorological conditions during the fire. For prescribed fires in fuels with longer duration burning (such as timber litter or slash), and which are expected to last more than one day, locating real-time particulate matter (PM) monitors at smoke- sensitive areas may be warranted to facilitate timely response to smoke problems.

The AFC has established a policy to issue health advisories when necessary. State and federal prescribed fire managers routinely notify landowners adjacent to prescribed burns of the potential for exposure to smoke. AFC Dispatch is currently developing a daily listing of planned prescribed fires on the AFC website (www.forestry.state.ar.us). The planned prescribed burn listing will have the county, nearest community, legal description, planned ignition time and acres of the prescribed burn.

Arkansas's SMP has provisions for an annual review by the Arkansas Forestry Commission that will include the following activities:

- Collect and review information on acres burned by prescribed fire and wildfire
- Review the reference, continuous, and IMPROVE monitoring station data maintained by ADEQ
- Use information from reports of nuisance complaints or significant smoke intrusions to measure the effectiveness of the SMP
- Provide recommendations to ADEQ and Arkansas Prescribed Fire Committee concerning the SMP

Pursuant to the EPA's Interim guidance cited above, Arkansas has adopted a program that should help prevent NAAQS violations and addresses visibility impairment due to fires. This program established the documentation of basic parameters: contact information of person in charge, purpose of prescribed burn, fuel type and tonnage, ignition time and duration of fire, wind speed, direction, location, and distance to sensitive receptors. Prescribed fire managers are required under Arkansas law to notify the AFC Dispatch Center on the morning of the prescribed fire by calling 1-800-830-8015. See Arkansas Code Annotated §20-22-302.

11.4.1.8 Additional Control Measures

The CENRAP modeling shows that Arkansas's Class 1 areas can achieve the 2018 RPGs without additional control measures beyond those described above. In the situation where anticipated emission reductions produce a 2018 outcome that meets the goal of natural background conditions, it is not immediately necessary to evaluate the need for additional control measures. A four-factor analysis was included as part of the engineering analysis for all BART eligible sources in Arkansas. Since Arkansas has demonstrated that it can meet or exceed established URPs, it is not necessary to evaluate the emission reductions potential of point sources other than those BART-eligible sources that are specifically regulated in accordance with the requirements of the Regional Haze Rule.

The Regional Haze Rule requires states to review progress in reaching their established RPGs every five years. If, in the future, it is demonstrated that the actual rate of progress is not meeting the established goals, Arkansas will reevaluate the need for additional control measures. This would require a four-factor analysis to be conducted as a means of determining which facilities, in addition to those already regulated under the BART Rule, would be potentially subject to additional control measures.

11.4.6 Enforceability of emission limitations and control measures

40 CFR 51.308(d)(3)(v)(F) requires the State of Arkansas to ensure that emission limitations and control measures used to meet RPGs are enforceable.

The State of Arkansas has ensured that all emission limitations and control measures used to meet RPGs are enforceable by embodying these in State-adopted rules. Arkansas has determined that emission limitations or control measures other than BART are not currently required in order to meet the established RPGs. Appendix 11.2 is a copy of these regulations.

List of Chapter 11 Appendices

11.1 Agricultural and Forestry Smoke Management
11.2 Arkansas Pollution Control and Ecology Commission Regulation No. 19 – Regulations of the Arkansas Plan of Implementation for Air Pollution Control

12. Comprehensive Periodic Implementation Plan Revisions

The 40 CFR 51.308(f) requires a State to revise its regional haze implementation plan and submit a plan revision to EPA by July 31, 2018, and every ten (10) years thereafter. In accordance with the requirements listed in 40 CFR 51.308(f) of the federal rule for regional haze, Arkansas commits to revising and submitting this regional haze implementation plan by July 31, 2018, and every ten (10) years thereafter.

In addition, 40 CFR 51.308(g) requires periodic reports evaluating progress towards the RPG established for each mandatory Class I area. In accordance with the requirements listed in 40 CFR 51.308(g) of the federal rule for regional haze, Arkansas commits to submitting a report on reasonable progress to EPA every five years following the initial submittal of the SIP. The reasonable progress report will evaluate the progress made towards the RPG for each mandatory Class I area located within Arkansas and in each mandatory Class I area located outside Arkansas, which may be affected by emissions from within Arkansas. All requirements listed in 51.308(g) shall be addressed in any SIP revision for reasonable progress.

List of Chapter 12 Appendices

There are no Appendices in Chapter 12.

13. Determination of the Adequacy of the Existing Plan

Depending on the findings of the five-year progress report, Arkansas commits to taking one of the actions listed in 40 CFR 51.308(h). The findings of the five-year progress report will determine which action is appropriate and necessary.

List of Possible Actions – 40 CFR 51.308(h)

1) Arkansas determined that the existing SIP required no further substantive revision in order to achieve established goals. Arkansas provided to the Administrator a negative declaration that further revision of the SIP is not needed at this time>
2) Arkansas determined that the existing SIP may be inadequate to ensure reasonable progress due to emissions from other states which participated in the regional planning process. Arkansas provided notification to the Administrator and the states that participated in regional planning. Arkansas collaborated with states through the regional planning process to address the SIP's deficiencies.
3) Arkansas determined that the current SIP may be inadequate to ensure reasonable progress due to emissions from another country. Arkansas provided notification, along with available information, to the Administrator.
4) Arkansas determined that the existing SIP is inadequate to ensure reasonable progress due to emissions within the Arkansas, Arkansas will revise/has revised its SIP to address the plan's deficiencies (State must address the deficiencies within one year.)

List of Chapter 13 Appendices

There are no Appendices in Chapter 13.

Guidance Documents

Assessment of Baseline, Natural and Current Conditions
EPA is to develop guidance on calculating *baseline and current* visibility. EPA is to develop guidance on calculating baseline in the absence of on-site data. EPA is to develop technical guidance on estimating *natural* visibility conditions. EPA to revise the Interim Air Quality Policy on Wildland and Prescribed Fires which includes guidance on determining the contribution of fire to natural visibility conditions. States should include in the SIP "appropriate methods for estimating natural conditions. It is assumed that the States procedures will use these guidance documents to establish the *Baseline, Background* and *Current* conditions in each Class I Area.

Best Available Retrofit Technology
Controlling SO_2 Emissions: A Review of Technologies, EPA Office of Research and Development, EPA-600/R-00-093

Guidelines for Determining Best Available Retrofit Technology for Coal-fired Power Plants and Other Existing Stationary Facilities. EPA-450/3-80-009b. November 1980. This document addresses reasonably attributable BART not regional haze BART. However, it will be the basis for regional haze BART guidance being developed by EPA. The RH BART engineering analysis will be similar to the RA BART guidance of 1980.

40 CFR part 51 Regional Haze Regulations; Final Rule. EPA. Federal Register Vol. 64, No 126/ Thursday, July 1, 1999. The preamble discusses RH BART in detail.

Guidance for Demonstrating Attainment of Air Quality Goals for $PM_{2.5}$ and Regional Haze. EPA. Draft 2.1, January 2, 2001.

This document provides guidance on how to use modeled and monitored data to estimate if visibility goals for regional haze will be met by a proposed control strategy.

Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and a Backstop Market Trading Program. An Annex to the Report of the Grand Canyon Visibility Transport Commission. Western Regional Air Partnership. October 1, 2000.

This document describes an emissions trading program and provides a model rule and draft memorandum of understanding between states and tribes for implementing an interagency emissions trading program.

Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations. EPA. Draft January 12, 2001. This document, when finalized in 2001, will provide the guidance on RH BART. It was recently proposed in the Federal Register. The final document will be Appendix Y of Part 51. It will address the RH BART engineering analysis, cumulative visibility assessment, and emission trading alternatives.

Improving Air Quality with Economic Incentive Programs. EPA - 452/R-01-001. January 2001. This document provides guidance for economic incentive programs including emission trading programs that states may incorporate in their strategies for meeting air quality standards and addressing visibility impairment in national parks and wilderness areas.

Long Term Strategy

Guidance for Demonstrating Attainment of Air Quality Goals for $PM_{2.5}$ and Regional Haze (EPA, OAQPS, draft 2.1, January 2, 2001)

Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations (EPA-454/R-99-006, April 1999)

Proposed Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations. This proposal will be published in the *Federal Register* soon.

Monitoring Strategy and Emissions Inventory

Visibility Monitoring Guidance document, (EPA-454/R-99-003, June 1999)
http://www.epa.gov/ttn/amtic/files/ambient/visible/r-99-003.pdf

IMPROVE Particulate Monitoring Network - Procedures for Site Selection, (Crocker Nuclear Laboratory, University of California, February 24, 1999)
http://www.epa.gov/ttn/amtic/files/ambient/visible/select22.pdf

IMPROVE Particulate Monitoring Network – Standard Operating Procedures Air Quality, (Crocker Nuclear Laboratory, University of California, October 15, 1998)
http://www2.nature.nps.gov/ard/vis/sop/index.html

National Park Service Visibility Monitoring internet site,
http://www2.nature.nps.gov/ard/vis/vishp.html

EPA Consolidated Emission Reporting Rule, (Federal Register: May 23, 2000, Volume 65, Number 100, Proposed Rules, Page 33268-33280.)
http://www.epa.gov/ttn/chief/cerr/CERR_FR.pdf

Emissions Inventory Guidance for Implementation of Ozone and Particulate Matter National Ambient Air Quality Standards (NAAQS) and Regional Haze Regulations (EPA-454/R-99-006, April 1999). http://www.epa.gov/ttn/chief/eidocs/eidocfnl.pdf

Reasonable Progress Goals

Controlling SO_2 Emissions: A Review of Technologies, EPA Office of Research and Development, EPA-600/R-00-093

EPA Clean Air Technology Center - Control Cost Manual (5th edition) - http://www.epa.gov/ttn/catc/products.html

EPA BART guidelines (soon to be proposed) - http://www.epa.gov/ttn/oarpg/t1pfpr.html

EPA Guidelines for Preparing Economic Analyses - http://www.epa.gov/economics/

Guidelines for Determining Natural Background, to be developed by EPA.

Guidelines for interpreting statutory factors, to be developed by EPA.

Regional Haze Regulations, Final Rule, 40 CFR, Part 51, July 1, 1999.

Weight of Evidence

Guidance for Improving Weight of Evidence Through Identification of Additional Emission Reductions, Not Modeled. http://www.epa.gov/scram001/guidance/guide/addwoe1h.wpd

Appendix 10.1

Analysis of Control Strategies and Determination of Reasonable Progress Goals

The federal Regional Haze Rule requires States to evaluate, select and apply control strategies that will result in emission reductions sufficient to accomplish the goal of re-attaining natural background conditions for visibility in Class 1 Areas by 2064. The determination of appropriate control strategies is left to the discretion of the States. Arkansas has two Class 1 Areas, Caney Creek Wilderness Area and Upper Buffalo Wilderness Area.

Chapter 10 describes the Uniform Rate of Progress for both of these Class 1 Areas and includes a Table showing the Reasonable Progress Goals that the State of Arkansas has determined are appropriate for these areas.. This appendix describes how these Reasonable Progress Goals were determined.

The Regional Haze Rule requires States to consider four factors when developing RPGs. "In establishing a reasonable progress goal for any mandatory Class 1 federal area within the State, the State must: (A) Consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal."[1] It is important to note that, in this grammatical construct, the clause "of any potentially affected sources" modifies all of the listed factors. For this reason, this "four factor analysis" is only required for "potentially affected sources." A source is "potentially affected" only in the instance where the State determines that control of that source might be considered necessary "--- in order to provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period."[2] The following discussion demonstrates how, in the case where it can be demonstrated that the anticipated rate of progress toward a return to natural background conditions results in achieving that goal prior to the statutorily-mandated timeframe, the four factor analysis becomes an unnecessary exercise.

Using the results of visibility modeling conducted by the Central Regional Air Planning Association (CENRAP) and other analyses conducted by the Air Division of the Arkansas Department of Environmental Quality (ADEQ), ADEQ has established RPGs in the manner described herein.

The Regional Haze Rule requires State Implementation Plans to contain emissions limitations representing Best Available Retrofit Technology (BART) for certain major sources that have been determined to have a significant potential for contributing to visibility degradation in any Class 1 Area. The process of "BART determination", a list of sources that will be required to install BART and the resulting emissions limits for each "BART source" are contained in Chapter 9.

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[1] 40 CFR 51.308(d)(1)(i)
[2] 40 CFR 51.308(d)(1)

The modeling conducted by CENRAP contains projections of the visibility conditions that are anticipated to be realized at each Class 1 Area in CY 2064. These projections are, among other things, based on an assessment of the visibility improvements associated with federal, State and local control programs that are either currently in effect or with mandated future-year emission reductions schedules that predate the target year and with BART emissions limitations established to date. A review of these projections indicates that the rate of progress that is anticipated for each of Arkansas's Class I Areas is faster than that representing a URP and would thus result in a return to natural background conditions prior to 2064. The relationship between URP and these modeled visibility projections is depicted in Figs. 10-5 through 10-8. ADEQ considers these to represent RFP for each of its Class I Areas.

As demonstrated herein, it is apparent that the combination of already mandated controls, including BART emission limitations, will provide for a rate of progress that improves visibility conditions on the worst days, prevents degradation on the best days and surpasses a URP. With this understanding, it is not currently necessary to consider additional control measures on otherwise unregulated entities or source categories. In the event that future-year progress reviews indicate the need for additional control measures, it might become necessary to develop and implement new control strategies. Until such time, ADEQ asserts that the requirement to demonstrate RFP is presumed to have been met. This assertion is supported by EPA guidance on setting reasonable progress goals.

> Given the significant emissions reductions that we anticipate to result from BART, the CAIR, and the implementation of other CAA programs, including the ozone and $PM_{2.5}$ NAAQS, for many States this will be an important step in determining your RPG, and it may be all that is necessary to achieve reasonable progress in the first planning period for some States.[3]

[3] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program (rev.) – EPA (06/01/07)

Appendix 10.2

Interagency Consultation Process in Establishing Reasonable Progress Goals

UNITED STATES
Central Class I Areas Consultation Plan

Scope

This consultation plan establishes the objectives, activities, and timelines to facilitate stakeholder input for meeting visibility requirements in the federal Regional Haze Rule for the following federal Class I areas:

- Hercules Glades Wilderness Area (Missouri)
- Mingo Wilderness Area (Missouri)
- Caney Creek Wilderness Area (Arkansas)
- Upper Buffalo Wilderness Area (Arkansas)

Background

The U.S. Environmental Protection Agency (EPA) promulgated the federal Regional Haze Rule on July 1, 1999. The federal Regional Haze Rule and the Clean Air Act require consultation between the states, tribes, and the Federal Land Managers (FLM) for managing Class I areas. Since regional haze often results from pollution emitted across broad regions, this multi-state planning effort will help in developing the most cost-effective controls for regional haze. This consultation process will provide a coordinated effort to achieve the federal visibility requirements and aid in developing regional strategies for meeting progress goals.

Plan Objectives

This consultation plan provides state air quality agencies with technical information including emission sources, modeling analysis, and source apportionment for Missouri and Arkansas' Class I areas. These state agencies are being given the opportunity to review this analysis and to participate in consultation to develop plans for meeting regional haze reduction requirements for these Class I areas. Regional Planning Organizations (RPOs), FLMs, and the EPA will also be contacted with the opportunity to participate in the development of actions and control strategies for meeting the federal Regional Haze Rule requirements. This plan includes:

1. Consultation Process
2. Technical Analyses
3. Agency Roles/Responsibilities

1. Consultation Process

Consultation discussion will focus on the primary reasonable progress issues including:

- Source area identifications
- State contribution apportionment
- Emission management strategies

The consultation process will be initiated in early 2007. Draft and final documents will be circulated via email to participating consulting agencies. After the initial kick-off, most consultation discussions will occur through conference calls. However, there will be some instances where a meeting may be desirable (e.g. unresolved issues, complex technical discussions, etc.).

The Missouri Department of Natural Resources' Air Pollution Control Program will work with the Arkansas Department of Environmental Quality and the Central States Regional Air Partnership (CENRAP) to set up conference calls/meetings for the consultation process. Technical documents will be provided for discussion before conference calls or meetings.

Draft and final documents will include supporting materials that describe analytical methods, assumptions, and conclusions that were relied upon in developing the documents. Comments on any draft documents will be requested from the consultation group members.

All consultation activities will be documented, including who participated in consultation discussions and on what dates, outcomes of consultation discussions (issues agreed, disagreed, resolutions) and justification for long term strategy. Each contributing state will be requested to share documentation confirming implementation of emission controls being relied on to meet regional haze Uniform Reasonable Progress (URP) goals.

Documents and consultation logs will be posted on the Missouri Department of Natural Resources' Air Pollution Control Program website for public viewing. All conference call/meeting minutes will also be posted on the agency website. When new documents are posted on the website, the Missouri Department of Natural Resources' Air Pollution Control Program will email all consultation participants to inform them that new information has been posted.

MDNR/ADEQ will work with the FLMs and EPA for consultation through conference calls/meeting. This will include an opportunity for consultation with FLMs in person and at least 60 days prior to holding any public hearing on a state implementation plan as required by federal rule.

Action Items

Participate in kick-off
Comment on the draft consultation plan

satisfy the URP goals. Pertinent "attribution of haze" documents were evaluated. These documents include CENRAP Comprehensive Air Quality Model with extensions (CAMx)/Community Multiscale Air Quality (CMAQ) modeling system visibility modeling results, fine particulate modeling results for the central US, and other technical reports, papers, and analyses bearing directly on the quantification of emissions-source/visibility-receptor impacts at the ten CENRAP Class I and twelve adjoining areas.

Current Regional Haze modeling continues to indicate visibility shortfalls to reaching the necessary URP goals for deciview increments for some of the Central Class I areas in CENRAP. A deciview is a haze index used to quantify incremental changes in visibility perception, where higher deciview values indicate greater levels of visibility impairment. In some of the areas,

Table 1: Consultation Process Timeline

2006 Fall	2006 Winter	2007 Early Spring	2007 Spring	2007 Late Spring	2007 Summer
Develop Baseline and URP Goals →	Develop a Consultation Plan →	Initiate Collaboration with States →	Develop Long Term Strategy (LTS) →	Negotiate Changes to LTS →	Document Consultation
Back trajectory & Factor analysis	Identify issues for discussion	Consultation log	Follow consultation plan	Emission reduction requirements/ strategies	Who met and when (FLM, RPO, EPA) and discussion
Identify probable area of influence	Review baseline, URP goals, and emissions reduction targets	Discuss URP Goals & contributions assessment	Discuss emissions reduction strategies	Emission budget discrepancies	Consultation outcome Issues agreed, disagreed, resolutions
Apportion state contributions	Develop Action items	Follow consultation plan	Consult with FLM & EPA	Tribal Impacts	Justification of LTS
Develop initial emission cuts to meet 2018 URP Goals	Issues for FLM & EPA input	Consult with FLM & EPA (thru RPO?)	Note areas of irreconcilable disagreement	Additional control strategies	
	Timetable for resolution	Evaluate and identify sources upwind (BART, non-BART, CAMR, other)			

URP goals are expected to be met based on modeling results, but consultation may be necessary to ensure that the emission reductions used in the modeling are actually planned to occur.

Individual Class I Area Characteristics

The Central Class I areas each have individual characteristics. Individual examination of each area elicits a greater understanding of how the Regional Haze problem affects each, and what aspects are of greatest significance.

Hercules Glades

Situated in extreme southwest Missouri, Taney County, Hercules Glades is managed by the United States Department of Agriculture (USDA) Forest Service. The area is 12,315 acres and in some of the most rugged hills of the Missouri Ozarks. The closest urban area is the Springfield/Branson metropolitan statistical area, 40 miles to the west/northwest.

Mingo National Wildlife Refuge

The Mingo National Wildlife Refuge is managed by the federal Fish and Wildlife Service. The Refuge is situated in the Mississippi Flyway. Only part of it is a Class I area (7,730 acres). Memphis to the south and St. Louis to the north are some of the largest urban areas nearby, although there are a few smaller population centers mostly to the east. Proximity to sources in the Ohio River Valley is a consideration.

Upper Buffalo National Area

The Upper Buffalo Class I area (2,200 acres) is managed by the National Park Service in conjunction with overseeing the Buffalo National River. This area in north central Arkansas is south of Springfield, Missouri and east of Fayetteville and Fort Smith. It is an area of low mountains and largely forested, with bisecting streams.

Caney Creek Class I Area

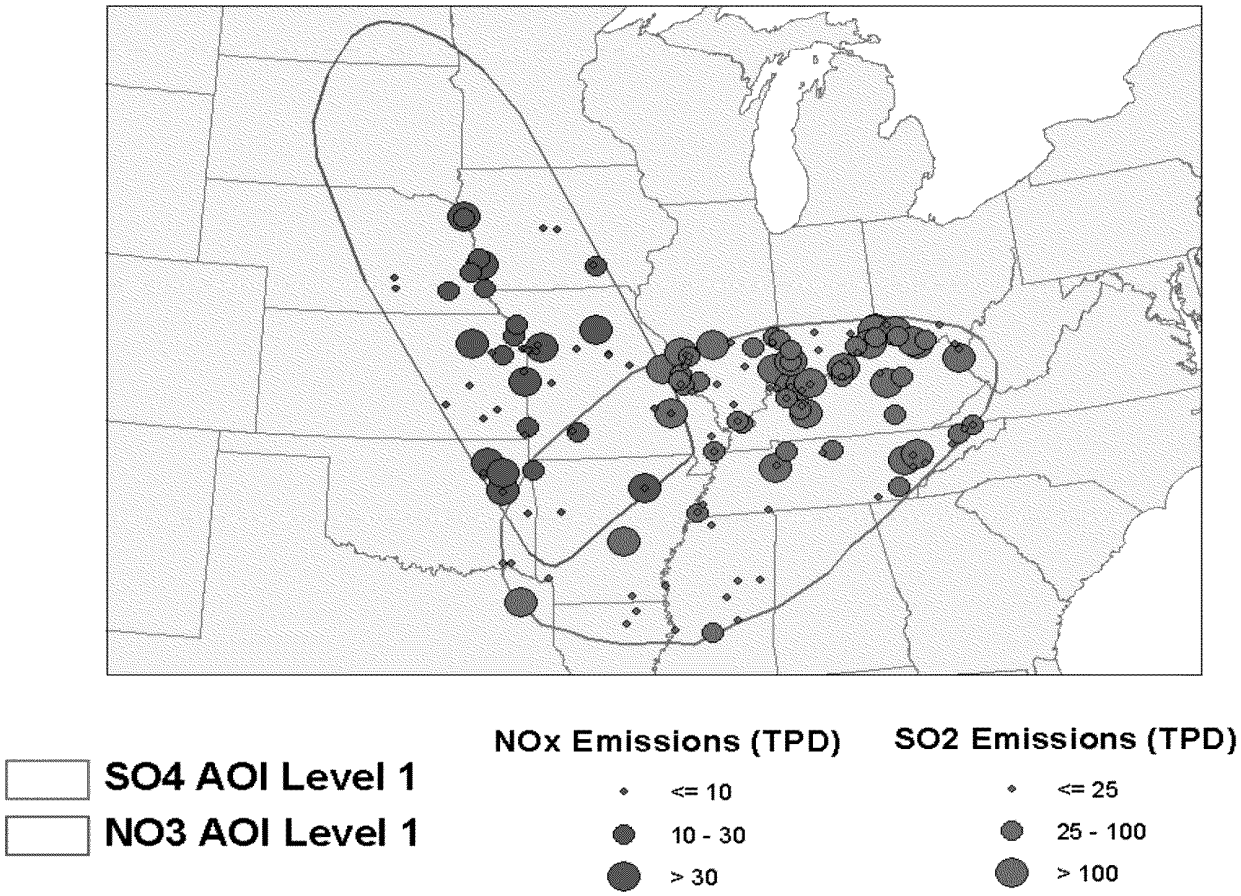
Caney Creek is a 14,460 acre area in the Oachita Mountains of west-southwest Arkansas, the tallest mountain range between the Appalachians and the Rockies. It is south of Fort Smith and west of Little Rock. The area is managed by the USDA Forest Service.

Identification of Source Areas (Areas of Influence)

Source areas must be determined in order to focus the consultation process. That is, locations of significant sources that are likely to affect each Class I area must be identified, and sources within those areas considered for control. Alpine, under its contract to CENRAP, identified Areas of Influence (AOIs), using a variety of data and analyses. In combining the AOI information with emission inventories for the areas, we are able to identify a number of large sources which are of interest.

Figure 1 indicates two Level I AOI's for the Central Class I Areas, one for nitrate (NO_3), and a second grouped collectively for sulfate (SO_4), elemental carbon (EC), organic carbon (OC), coarse mass, and fine soil, along with indicators for sources contained in those areas.

Figure 1 – Alpine AOI's for Central Class I Areas



Attachment B identifies total emissions reductions necessary for level 1 AOI's based on control of sulfate and nitrate species across all four Class I areas. Attachment B also includes inventory tables developed listing possible sources where emissions can be reduced in each state to meet the goals. These emissions provide an overall frame of reference for any reductions in those species.

Contributing States

Source apportionments have recently been conducted on modeling (using Particulate Matter Source Apportionment Technology; PSAT, a source apportionment tool implemented in CAMx) and monitoring data (using positive matrix factorization; PMF/Trajectories) for all four Class I Areas. Attachment C provides both model and monitoring data source apportionment results. Attachment D provides a list of results for Q/D (emissions/distance) used as a third analysis measure. All these, along with Alpine sulfate AOI's described above have been analyzed in tables in attachment E to determine a list of contributing states for each Class I area.

Methodology

Table 2 and 3 (for illustration) below indicate the overall (average) significant contributing states to decreased visibility due to sulfate and nitrate precursor emissions at the Mingo Site. A decision on whether a given state was a contributor was based on the combined analysis results of the four approaches, i.e., PMF/Trajectories, AOI, PSAT, and Q/D. If a state is found to be a major contributor in at least 3 of the 4 approaches, it is believed that inclusion of this state is appropriate. All states in red/bold in the Average row are determined to have sources that are significant contributors to decreased visibility.

Specific to each analysis type, inclusion of a state under the PMF/Trajectories approach depended on the level of probability that an air mass originated from the state during the days of high contribution by sulfate or nitrate sources where the emission impact potential was significant. A state with a high potential of emission impact would be considered a significant contributor.

States were included in the AOI listing if they were part of the level 1 group as determined by Alpine Geophysics. This AOI was based primarily on residence time of air masses, along with evaluation of source emissions of, in this case, nitrate and sulfate.

PSAT analysis was determined based on the 2018 Modeled sulfate and nitrate contribution to average extinction for the 20% worst days. Any state with the contribution of 2.0 deciview or higher was identified as a candidate.

Lastly, Q/D was determined by dividing total SO_2 and NO2 precursor emissions for the state by distance from a state geographic centroid. If totals were less than 200, the state was not indicated as a significant contributor under Q/D.

Table 2 – Contributing States for the Mingo Wildlife Refuge Area Sulfate

Q/D*	PMF/ Trajectories	AOI	PSAT	Average
MN	MN	MN	MN	MN
SD	SD	SD	SD	SD
WI	WI	WI	**WI**	WI
IA	IA	IA	IA	IA
NE	NE	NE	NE	NE
KS	KS	KS	KS	KS
MO	**MO**	**MO**	**MO**	**MO**
IL	**IL**	**IL**	**IL**	**IL**
IN	**IN**	**IN**	**IN**	**IN**
OH	**OH**	**OH**	**OH**	**OH**
MI	MI	MI	**MI**	MI
KY	**KY**	**KY**	**KY**	**KY**
TN	**TN**	**TN**	**TN**	**TN**
AR	AR	**AR**	AR	AR
OK	OK	**OK**	OK	OK
TX	**TX**	**TX**	TX	**TX**
LA	LA	LA	LA	LA
MS	MS	**MS**	MS	MS
AL	AL	AL	AL	AL

*Informational

State in Red/Bold = Major Contributing States

Table 3 – Contributing States for the Mingo Wildlife Refuge Area Nitrate

Q/D*	PMF/ Trajectories	AOI	PSAT	Average
MN	MN	MN	MN	MN
SD	SD	SD	SD	SD
WI	WI	WI	WI	WI
IA	IA	**IA**	IA	IA
NE	NE	**NE**	NE	NE
KS	KS	**KS**	KS	KS
MO	**MO**	**MO**	**MO**	**MO**
IL	**IL**	IL	**IL**	**IL**
IN	**IN**	IN	IN	IN
OH	OH	OH	OH	OH
MI	MI	MI	MI	MI
KY	**KY**	KY	KY	KY
TN	**TN**	TN	TN	TN
AR	**AR**	**AR**	AR	**AR**
OK	OK	**OK**	OK	OK
TX	TX	TX	TX	TX
LA	**LA**	LA	LA	LA
MS	**MS**	MS	MS	MS
AL	**AL**	AL	AL	AL

*Informational

State in Red/Bold = Major Contributing States

State list

Following are lists of the contributing states for Central Class 1 Areas in Missouri and Arkansas based on the analysis described above;

Hercules Glades

Missouri, Illinois, Indiana, Kentucky, Tennessee, Arkansas, and Texas

Mingo National Wildlife Refuge

Missouri, Illinois, Indiana, Ohio, Kentucky, Tennessee, Arkansas, and Texas

Upper Buffalo National Area

Missouri, Illinois, Indiana, Ohio, Kentucky, Tennessee, Arkansas, Oklahoma, and Texas

Caney Creek Class I Area

Missouri, Illinois, Indiana, Kentucky, Tennessee, Arkansas, Oklahoma, and Texas

3. Agency Roles/Responsibilities

The agencies listed in this section are being requested to participate in the consultation process for the federal Regional Haze Rule. Part of this process is the opportunity for States to review the foregoing analysis and the attachments to this plan and provide feedback, and to consider necessary controls available that will assist in meeting the goals prescribed by the regional haze requirements. Federally enforceable measures to control emissions and thereby achieve the URP will be our ultimate measure of success.

Proposed Roles and/or responsibilities are as follows:

- Missouri Department of Natural Resources' Air Pollution Control Program
  - Co-lead consultation effort for Central Class I areas (Missouri and Arkansas) (i.e. schedule conference calls/meetings, etc. and lead discussions)
  - Evaluate regional haze modeling for reasonable progress
  - Evaluate emissions data
  - Identify air pollutants for Missouri Class I areas
  - Evaluate back trajectory analysis
  - Evaluate probable source area identifications
  - Evaluate state contribution apportionment
  - Share upwind source information (including Best Achievable Retrofit Technology (BART), non-BART, Clean Air Mercury Rule (CAMR), etc.)

  - Determine emission management strategies necessary to meet federal Regional Haze Rule requirements
  - Provide detailed description of methods used in the SIP to calculate baseline, natural condition, and uniform rate (including supporting documentation for any methods that are not previously established, documented, or supported)
  - Document consultation process

- Arkansas Department of Environmental Quality
  - Co-lead consultation effort for Central Class I areas (Missouri and Arkansas) (i.e. schedule conference calls/meetings, etc. and lead discussions)
  - Evaluate regional haze modeling for reasonable progress
  - Evaluate emissions data
  - Identify air pollutants for Arkansas Class I areas
  - Evaluate back trajectory analysis
  - Evaluate probable source area identifications
  - Evaluate state contribution apportionment
  - Share upwind source information (including BART, non-BART, CAMR, etc.)
  - Determine emission management strategies necessary to meet federal Regional Haze Rule requirements
  - Document consultation process
- Illinois Environmental Protection Agency, Ohio Environmental Protection Agency, Indiana Department of Environmental Management, Kentucky Department of Environmental Protection, Tennessee Department of Environment and Conservation, Oklahoma Division of Environmental Quality, Iowa Department of Natural Resources, Kansas Department of Health and Environment, Texas Commission on Environmental Quality, and Louisiana Department of Environmental Quality
- United Keetoowah Band of Cherokee Indians in Oklahoma, Eastern Shawnee Tribe of Oklahoma, Alabama Coushatta Tribe of Texas, Sac and Fox Nation of Missouri, Kickapoo Tribe in Kansas, Potawatomi Nation
  - Participate in consultation effort for Central Class I areas (Missouri and Arkansas) (i.e. conference calls/meetings, discussions, etc.)
  - Provide feedback on reasonable progress analysis (modeling, emissions data, back trajectory, source area identifications, state contribution apportionment)
  - Share upwind source information (including BART, non-BART, CAMR, etc.)
  - Determine emission management strategies necessary to meet federal Regional Haze Rule requirements
- EPA
  - Participate in consultation effort for Central Class I areas (Missouri and Arkansas) (i.e. conference calls/meetings, discussions, etc.)
  - Provide comments on approvability of consultation plan
  - Provide reconciliation on unresolved issues

- FLMs (US Fish and Wildlife Service, National Park Service and the US DA Forest Service)
  - Participate in consultation effort for Central Class I areas (Missouri and Arkansas) (i.e. conference calls/meetings, discussions, etc.)
  - Provide feedback on reasonable progress analysis (modeling, emissions data, back trajectory, source area identifications, state contribution apportionment)
  - Provide feedback on controls necessary to meet federal Regional Haze Rule requirements
- Regional Planning Organization
  - Participate in consultation effort for Central Class I areas (Missouri and Arkansas) (i.e. conference calls/meetings, discussions, etc.)
  - Provide updates and summaries of any work in process (e.g. development of baselines and natural conditions, inventories, modeling efforts and contribution assessments)

Attachment A

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Attachment B

Table 1. EMISSION REDUCTIONS NEEDED TO MEET THE 2018 RPG IN CENTRAL CLASS I AREAS

			Level 1 AOI		Emissions Reductions Needed (Tons)			
			sulfate/SO2	nitrate/NOx	One pollutant control		Proportionate Controls	
Class I Area	ST	Name	DV	DV	Sulfate	Nitrate	Sulfate	Nitrate
Big Bend Nat'l	TX	BIBE	-0.004	-0.002	133,000	265,000	82,000	10,000
Boundary Wate	MN	BWCA	-0.006	-0.004	91,000	136,000	39,000	51,000
Breton Island	LA	BRET	-0.002	-0.002	96,000	96,000	70,000	9,000
Caney Creek	AR	CACR	-0.002	-0.002	18,000	12,000	11,000	2,000
Guadalupe Mo	TX	GUMO	-0.004	-0.01	147,000	59,000	58,000	7,000
Hercules-Glade	MO	HEGL	-0.002	-0.002	200,000	127,000	113,000	23,000
Mingo	MO	MING	-0.002	-0.002	235,000	149,000	118,000	33,000
Upper Buffalo	AR	UPBU	-0.002	-0.002	112,000	71,000	65,000	11,000
Voyageurs	MN	VOYA2	-0.006	-0.004	43,000	65,000	11,000	24,000
Wichita Mounta	OK	WIMO	-0.001	-0.005	368,000	74,000	158,000	22,000

Table 2. SO4 Inventory Tables For Level I AOI Contributing States

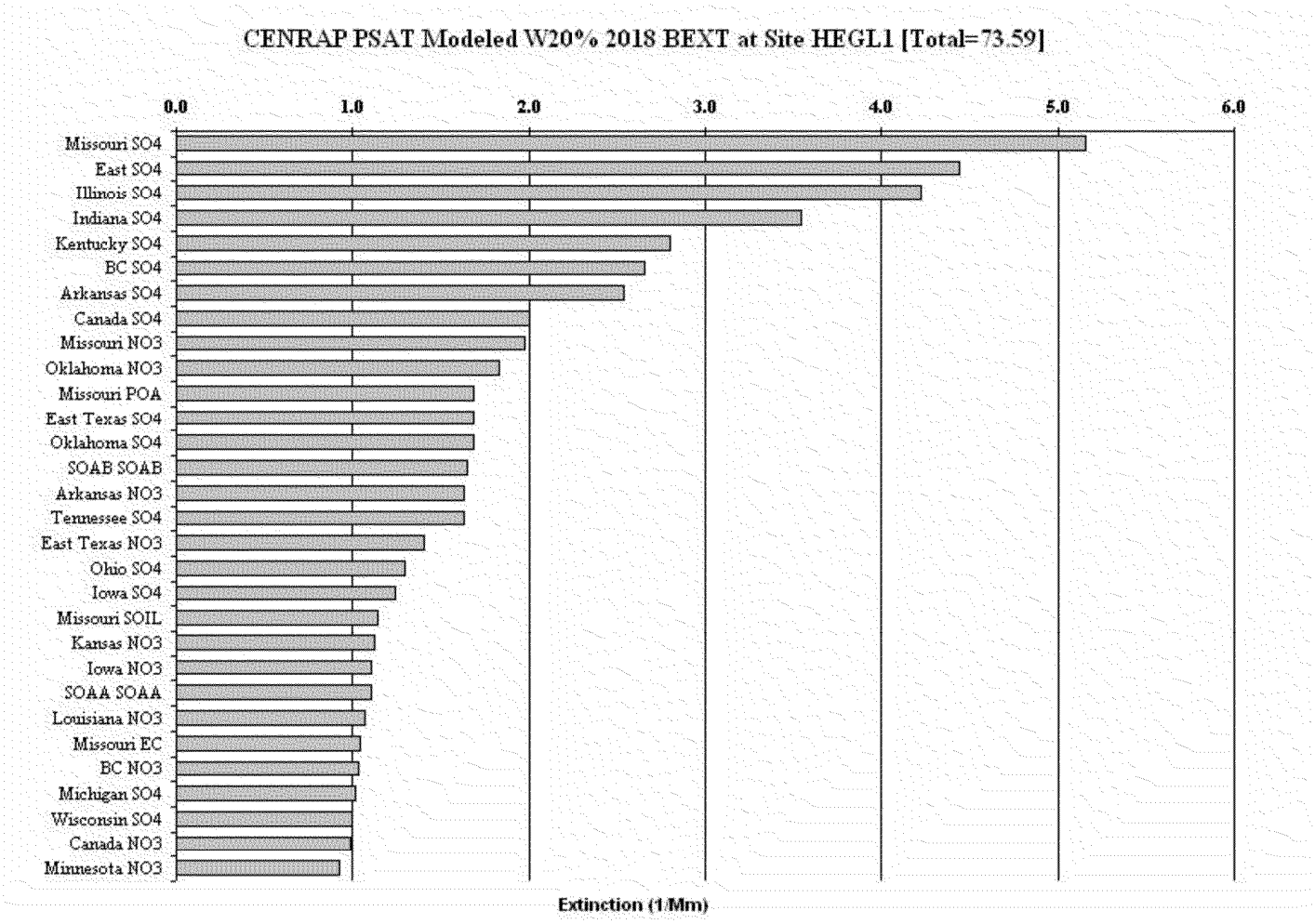
(tons/summer day)

PLANT ID	STATE	PLANT NAME	SIC	SIC DESCRIPTION	SO2_TPD	NOX_TPD
4800310	Texas	FULLERTON GAS PLANT	1321	NATURAL GAS LIQUIDS	6.50599	0.00000
484691	Texas	EI DU PONT DE NEMOURS	2869	INDUSTRIAL ORGANIC CHEMICALS,NEC	0.00000	10.33888
470850011	Tennessee	TVA JOHNSONVILLE FOSSIL PLANT	4911	ELECTRIC SERVICES	300.62585	68.40613
470730007	Tennessee	TVA JOHN SEVIER FOSSIL PLANT	4911	ELECTRIC SERVICES	98.99900	28.54810
471650025	Tennessee	TVA GALLATIN FOSSIL PLANT	4911	ELECTRIC SERVICES	94.72930	33.50815
471630003	Tennessee	EASTMAN CHEMICAL COMPANY	2869	INDUSTRIAL ORGANIC CHEMICALS,NEC	66.36360	35.39940
4715700528	Tennessee	ALLEN FOSSIL PLANT	4911	ELECTRIC SERVICES	52.32034	40.03523
471610011	Tennessee	TVA CUMBERLAND FOSSIL PLANT	4911	ELECTRIC SERVICES	45.79200	137.25500
471070012	Tennessee	BOWATER NEWSPRINT & DIRECTORY - CALHOUN	2611	PULP MILLS	25.40730	17.57016
470374703700002	Tennessee	E I DUPONT DE NEMOURS & CO INC	2869	INDUSTRIAL ORGANIC CHEMICALS,NEC	18.74385	0.00000
470630197	Tennessee	LIBERTY FIBERS CORPORATION	2823	CELLULOSIC MAN-MADE FIBERS	14.73094	5.63459
470090008	Tennessee	ALUMINUM COMPANY OF AMERICA - SOUTH PLAN	3334	PRIMARY ALUMINUM	11.24313	0.00000
471050081	Tennessee	A.E. STALEY MANUFACTURING COMPANY	2046	WET CORN MILLING	9.40970	5.27573
4715700475	Tennessee	LUCITE INTERNATIONAL INC.	2819	INDUSTRIAL INORGANIC CHEMICALS	9.39796	0.00000
470710002	Tennessee	PACKAGING CORPORATION OF AMERICA	2631	PAPERBOARD MILLS	8.02611	7.42406
4715700045	Tennessee	CARGILL CORN MILLING	2046	WET CORN MILLING	7.53864	0.00000
470653070	Tennessee	SIGNAL MOUNTAIN CEMENT CO.	3241	CEMENT, HYDRAULIC	7.45430	14.19100
470010020	Tennessee	U.S. DEPARTMENT OF ENERGY Y-12 PLANT	3499	FABRICATED METAL PRODUCTS, NEC	6.45058	0.00000
470850010	Tennessee	INLAND PAPERBOARD & PACKAGING INC.	2679	CONVERTED PAPER PRODUCTS, NEC	6.05144	0.00000
471390004	Tennessee	INTERTRADE HOLDINGS INC.	2819	INDUSTRIAL INORGANIC CHEMICALS	5.12497	0.00000
470730026	Tennessee	AFG INDUSTRIES - GREENLAND PLANT	3211	FLAT GLASS	0.00000	5.53680
471630007	Tennessee	SEAMAN CORPORATION	2295	COATED FABRICS, NOT RUBBERIZED	0.00000	13.59050
40097799	Oklahoma	GRAND RIVER DAM AUTH	4911	ELECTRIC SERVICES	43.79260	38.29550
400891733	Oklahoma	WEYERHAEUSER - VALLIANT	2631	PAPERBOARD MILLS	6.85920	8.73920
40031211	Oklahoma	PUBLIC SVC CO OF OK	4911	ELECTRIC SERVICES	0.00000	8.07136
390310616000000	Ohio	CONESVILLE POWER PLANT	4911	ELECTRIC SERVICES	415.59965	80.90937
390251413100008	Ohio	CINERGY CG&E WC BECKJORD STATION	4931	ELEC & OTHER SERVICES COMBINED	189.03354	48.73621
390010701000060	Ohio	DP&L KILLEN GENERATING STATION	4911	ELECTRIC SERVICES	62.09508	24.70857
391390370020002	Ohio	SHELBY MUNICIPAL LIGHT PLANT	4911	ELECTRIC SERVICES	10.97583	0.00000
390690335010105	Ohio	CAMPBELL SOUP COMPANY	2032	CANNED SPECIALTIES	9.19665	0.00000
390030302020012	Ohio	PREMCOR REFINING GROUP	2911	PETROLEUM REFINING	8.63332	5.82966
390611431390903	Ohio	THE PROCTER AND GAMBLE CO.	2841	SOAP AND OTHER DETERGENTS	5.06495	0.00000
3100100042	Nebraska	Whelan Energy Center	4911	ELECTRIC SERVICES	6.04710	0.00000
290990016	Missouri	AMERENUE-RUSH ISLAND PLANT	4911	ELECTRIC SERVICES	61.58000	10.63480
291890010	Missouri	AMERENUE-MERAMEC PLANT	4911	ELECTRIC SERVICES	42.16141	22.98658
291430004	Missouri	ASSOCIATED ELECTRIC COOPERATIVE INC-NEW	4911	ELECTRIC SERVICES	38.72200	98.94600
290990003	Missouri	DOE RUN COMPANY-HERCULANEUM SMELTER	3339	PRIMARY NONFERROUS METALS, NEC	38.52199	0.00000
290830001	Missouri	KANSAS CITY POWER & LIGHT CO-MONTROSE GE	4911	ELECTRIC SERVICES	24.74788	8.80744
290950021	Missouri	TRIGEN ENERGY CORPORATION-GRAND AVENUE S	4911	ELECTRIC SERVICES	23.22464	0.00000
290770005	Missouri	CITY UTILITIES OF SPRINGFIELD MISSOURI-J	4911	ELECTRIC SERVICES	18.58675	19.25697
295100003	Missouri	ANHEUSER-BUSCH INC-ST. LOUIS	2082	MALT BEVERAGES	17.82469	0.00000
291860001	Missouri	MISSISSIPPI LIME COMPANY-MISSISSIPPI LIM	3274	LIME	16.44205	7.57345
290770039	Missouri	CITY UTILITIES OF SPRINGFIELD MISSOURI-S	4911	ELECTRIC SERVICES	11.91107	7.09601
290930009	Missouri	DOE RUN COMPANY-BUICK SMELTER	3339	PRIMARY NONFERROUS METALS, NEC	11.47904	0.00000
291430008	Missouri	NORANDA ALUMINUM INC-NORANDA ALUMINUM IN	3334	PRIMARY ALUMINUM	11.21103	0.00000
291510002	Missouri	CENTRAL ELECTRIC POWER COOPERATIVE-CHAMO	4911	ELECTRIC SERVICES	10.40103	7.95615
291950010	Missouri	MARSHALL MUNICIPAL UTILITIES-MARSHALL MU	4911	ELECTRIC SERVICES	8.36287	0.00000
290190002	Missouri	COLUMBIA MUNICIPAL POWER PLANT-COLUMBIA	4911	ELECTRIC SERVICES	5.23420	0.00000
281212812100036	Mississippi	PURSUE ENERGY CORPORATION THOMASVILLE G	2819	INDUSTRIAL INORGANIC CHEMICALS	33.21600	0.00000
280592805900058	Mississippi	CHEVRON PRODUCTS COMPANY PASCAGOULA REF	2911	PETROLEUM REFINING	15.54386	11.21247
280192801900011	Mississippi	CHOCTAW GENERATION LLP RED HILLS GENERA	4911	ELECTRIC SERVICES	12.12464	0.00000
280232802300031	Mississippi	MAGNOLIA RESOURCES INC PACHUTA HARMONY	1321	NATURAL GAS LIQUIDS	6.16490	0.00000
281372813700025	Mississippi	TRUNKLINE GAS COMPANY INDEPENDENCE COMP	4922	NATURAL GAS TRANSMISSION	0.00000	5.90938
281492814900027	Mississippi	ENTERGY MISSISSIPPI INCBAXTER WILSON PL	4911	ELECTRIC SERVICES	0.00000	21.38220
281512815100048	Mississippi	ENTERGY MISSISSIPPI INC GERALD ANDRUS P	4911	ELECTRIC SERVICES	0.00000	16.13000
220750015	Louisiana	CONOCOPHILLIPS COALLIANCE REFINERY	2911	PETROLEUM REFINING	9.05244	6.99716
220050004	Louisiana	CF INDUSTRIES INC.DONALDSONVILLE NITRO	2873	NITROGENOUS FERTILIZERS	0.00000	9.40132
220710014	Louisiana	ENTERGY NOMICHOUD	4911	ELECTRIC SERVICES	0.00000	12.34510
211772117700006	Kentucky	TVA PARADISE STEAM PLANT	4911	ELECTRIC SERVICES	231.14800	129.45000
210912109100003	Kentucky	WESTERN KY ENERGY CORP COLEMAN STATION	4911	ELECTRIC SERVICES	136.73500	18.52110
210412104100010	Kentucky	KENTUCKY UTILITIES CO GHENT GENERATING S	4911	ELECTRIC SERVICES	128.63700	53.32750
211672116700001	Kentucky	KENTUCKY UTILITIES CO BROWN FACILITY	4911	ELECTRIC SERVICES	126.12264	22.49524
211272112700003	Kentucky	KENTUCKY POWER CO BIG SANDY PLANT	4911	ELECTRIC SERVICES	116.35500	40.56600
211612116100009	Kentucky	EAST KY POWER COOP SPURLOCK ST. MAYSVILL	4911	ELECTRIC SERVICES	114.74800	22.85900
211452114500006	Kentucky	TVA-ENVIRONMENTAL AFFAIRS SHAWNEE PLANT	4911	ELECTRIC SERVICES	93.72150	52.22210
211110127	Kentucky	LOU GAS & ELEC MILL CREEK	4911	ELECTRIC SERVICES	62.90400	40.62600
211992119900005	Kentucky	EAST KY POWER COOP JOHN SHERMAN COOPER P	4911	ELECTRIC SERVICES	60.98100	12.39360
211110126	Kentucky	LOU GAS & ELEC CANE RUN	4911	ELECTRIC SERVICES	41.51100	17.38838
211772117700001	Kentucky	KENTUCKY UTILITIES CO GREEN RIVER STATIO	4911	ELECTRIC SERVICES	36.53400	0.00000
212332123300001-B	Kentucky	WESTERN KY ENERGY CORP REID	4911	ELECTRIC SERVICES	26.99800	0.00000
210492104900003	Kentucky	EAST KY POWER COOP WILLIAM C DALE PLANT	4911	ELECTRIC SERVICES	25.84360	6.17140
211832118300069	Kentucky	WESTERN KY ENERGY CORP WILSON STATION	4911	ELECTRIC SERVICES	24.39500	22.78500
212232122300002	Kentucky	LOUISVILLE GAS & ELECTRIC TRIMBLE CO GEN	4911	ELECTRIC SERVICES	23.13700	14.14800
210592105900027	Kentucky	OWENSBORO MUNICIPAL UTIL ELMER SMITH STA	4911	ELECTRIC SERVICES	19.66360	25.20099

Attachment C – Source Apportionment Analysis

Source Apportionment for the Hercules Glades Class I Area

PSAT Model Source Apportionment



Hercules Glades Projected 2018 – Worst 20%

Monitoring Data Source Apportionment

The Coal Combustion Factor at the Hercules Glades Class I Area

The Secondary Nitrate plus Oil Combustion Factor at the Hercules Glades Class I Area

E. Public notification and exposure reduction procedures.

The prescribed fire plan should identify actions that will be taken to notify people and authorities at smoke-sensitive areas before the prescribed fire. The prescribed fire plan should identify contingency actions that will be taken during a prescribed fire to reduce the exposure of people at smoke-sensitive areas if smoke intrusions occur. Appropriate contingency actions may include:

- Notifying the affected public (especially sensitive persons) of elevated pollutant concentrations,
- Suggesting actions to be taken by sensitive persons to minimize their exposure (e.g., remain indoors, avoid vigorous activity, avoid exposure to tobacco smoke and other respiratory irritants), and
- Halting ignitions of any new prescribed burning that could add smoke to the same area.

F. Monitor air quality.

The prescribed fire plan should include monitoring of the smoke from the prescribed fire. Visibility in Class I areas will be monitored. The extent of the monitoring should match the size of the fire. For small, or short duration fires (such as those in grass or leaf litter), visual monitoring of the directions of the smoke plume and monitoring nuisance complaints by the public may be sufficient. Other monitoring techniques include posting personnel on vulnerable roadways to look for visibility impairment and to initiate safety measures for motorists; posting personnel at other smoke sensitive areas to look for smoke intrusions; using aircraft to track the progress of smoke plumes; and continued tracking of meteorological conditions during the fire. For prescribed fires in fuels with longer duration burning (such as timber litter or slash), and which are expected to last more than one day, locating real-time particulate matter (PM) monitors at smoke- sensitive areas may be warranted to facilitate timely response to smoke problems.

COMPONENTS OF PRESCRIBED FIRE PLANS

Prescribed fire managers should prepare a prescribed fire plan for each burn (or, if the units are small and the burn objectives and prescription is the same, one plan may cover several burn units). These plans are written following protocols specific to each agency. At a minimum, the prescribed fire plan should include the following information:

- Location and description of the area to be burned.
- AFC Dispatch Center, local fire department or sheriff's office to be contacted.
- Occupants in all dwellings within ¼ mile of prescribed fire to be contacted.
- Personnel responsible for managing the fire.
- Type of vegetation to be burned.
- Number of acres to be burned.
- Amount of fuel to be consumed (tons/acre).
- Fire prescription including weather, ignition techniques, personnel and equipment.
- If available, documentation (along with any maps or tables) from atmospheric dispersion

models/ smoke dispersion prediction models which present information on what impact the smoke may have on any smoke sensitive areas.
- Actions needed to stop a burn if weather conditions degrade from the forecast values.
- Criteria the fire manager will use for making burn/no burn decisions.
- Safety precautions for personnel on the prescribed fire.

SMOKE EVALUATION

Determining tons of fuel to be consumed for the prescribed fire completes an important part of the analysis. Prescribed fire managers should examine the results of their analysis to determine if the prescribed fire could be divided into smaller units since others may be burning near them on the same day.

If weather parameters are questionable, the prescribed fire manager should conduct a test burn to determine feasibility of the burn.

The prescribed burn managers should evaluate frequently traveled roads within one mile of the prescribed fire, especially if these roads are down smoke-drainage of the burn. Residual smoke flows and settles in low areas during the night and early morning and may contribute to heavy fog, which creates hazardous road conditions.

Predicting visibility and smoke drift is more difficult at night. Winds may lessen or die out completely, and smoke will tend to stay near the ground. Although burning at night may help achieve other objectives, it may aggravate smoke management problems. Night time burning will require the same planning as daytime burns. For night burns, consider the following recommendations:

1. Burn in light fuels.
2. Use backing fire.
3. Burn when humidity is 80 percent or less.
4. Do not burn if overnight low is within 5 degrees of dew point.
5. Burn with surface wind speed of 4 miles per hour or more.
6. Obtain a night time dispersion index. (See Table 5.)
7. Monitor down drainage and low areas, especially populated areas, airports or roads near the burn site.

The following situations could result in smoke impacting the surface downwind, particularly when there has been a large production of smoke:

1. Transport wind speed exceeds 25 mph, and average surface wind speed is over 20 mph with stronger gusts.
2. Transport wind direction carries smoke over a large lake.
3. A thick layer of smoke from a large burn significantly reduces the heating of the ground.

4. Transport wind direction moves smoke from a fire on the slope of a ridge toward and over the top of the ridge. Smoke may return to the ground in the eddy that can develop on the lee side of the ridge.

To ensure optimum dispersal of smoke during prescribed fire, the mixing layer must be sufficiently deep and transport wind speed adequate. Table 5 uses mixing height, transport wind speed and stability class to produce an index that describes the ability of the atmosphere to disperse smoke. The dispersion index will be included as part of the daily fire weather forecast by AFC Dispatch Center. Estimates of the dispersion index for each hour of the day for Arkansas can be obtained from http://shrmc.ggy.uga.edu. Prescribed fire managers who intend to ignite burns in the morning should consult their local National Weather Service office to determine the anticipated dispersion at the time of ignition. A low dispersion index indicates the atmosphere has poor capacity to disperse smoke; the ignition of a prescribed fire is discouraged. A high dispersion index indicates the possibility of losing control of the prescribed fire.

Table 5. Relationship between dispersion index and atmospheric conditions to disperse air pollution. (Lavdas 1996).

Dispersion Index	**Burning Condition**
100	Very good burning conditions; fires may be difficult to control. Reassess decision to burn.
61-100	Good-preferred range for prescribed fires.
41-60	Generally OK afternoon climatological values in most inland-forested areas fall in this range.
21-40	Fair-stagnation may be indicated if accompanied by low windspeeds. Reassess decision to burn.
13-20	Generally poor-do not burn. Stagnant if persistent, although better than average for a night burn.
7-12	Poor-do not burn. Stagnant during the day, but not near or above average at night.
1-6	Very poor-represents the majority of nights at many locations.

SURVEILLANCE AND ENFORCEMENT

Trained and experienced people should supervise prescribed fires. The prescribed burn manager ensures that the burn is conducted in accordance with the prescribed fire plan.

ADEQ will enforce national and Arkansas air quality regulations and laws. ADEQ will investigate smoke nuisance complaints.

PUBLIC EDUCATION AND AWARENESS

The AFC in cooperation with the Arkansas Prescribed Fire Committee will explain the use and importance of fire for ecosystem management, the implications of smoke to public health and safety, and the goals of the SMP. This public awareness effort will use posters, pamphlets, news releases, and public presentations. Prescribed fire managers should train on-the-ground personnel to understand the SMP.

AFC Dispatch will maintain a daily listing of planned prescribed fires on the AFC website (www.forestry.state.ar.us). The planned prescribed burn listing will have the county, nearest community, legal description, planned ignition time and acres of the prescribed burn. AFC will cooperate with organizations and government agencies such as Arkansas Lung Association or ADEQ to make the public aware of planned prescribed fires.

PROGRAM EVALUATION

The AFC will annually:

1. Collect and review information on acres burned by prescribed fire and wildfire.
2. Review the reference, continuous, and IMPROVE monitoring station data maintained by ADEQ.
3. Use information from reports of nuisance complaints or significant smoke intrusions to measure the effectiveness of the SMP.
4. Provide recommendations to ADEQ and Arkansas Prescribed Fire Committee concerning the SMP.

GLOSSARY

Air shed – the atmosphere covering a 36 square mile area (6 miles by 6 miles) approximately 23,040 acres. The amount of fuel that can be burned in the air shed depends on the distance to the nearest downwind smoke sensitive area and meteorological conditions.

Ambient air – the surrounding air external to a building, which the public is exposed to.

Air quality – characteristics of the ambient air, as indicated by concentrations of the six air pollutants for national standards, have been established. For the purposes of this document, concentrations of PM 2.5 are the primary indicator of ambient air quality.

Available fuel - an estimate of the tons of fuel per acre that will actually be consumed by a burn under a specific set of burning conditions. It is influenced by fuel moisture and other factors.

Category day - a scale from 1 to 5 based on transport wind speed and mixing height. For smoke dispersal, 1 is poor and 5 is excellent.

Class I area – an area set aside under the Clean Air Act to receive the most stringent protection from air quality degradation. Designated Class I areas in Arkansas are Caney Creek and upper Buffalo Wilderness.

Cooperator - those forest landowners or managers that have agreed to carry out prescribed burning consistent with the Smoke Management Plan.

Dispersion index - this index is an estimate of the atmosphere's capacity to disperse smoke from prescribed burns over a 1,000-square-mile area. It takes into account mixing height, transport wind, and stability near the ground.

Fuel loading – total amount of fuel at the prescribed burn site.

Inversion - increase of temperature with height in the atmosphere. This condition often exists in the morning and prevents smoke from rising into the atmosphere.

Mixing height - the layer of the atmosphere that pollutants are dispersed into due to turbulent mixing. A forecast of mixing height indicates the height of the top of the layer with respect to mean sea level.

National Ambient Air Quality Standards – established procedures that Federal agencies must follow in making decisions on Federal actions, which may impact the environment.

National Fire Danger Rating System (NFDRS) – system used by the USFS and other organizations to integrate the effects of topography, fuels, and weather on fire behavior.

Ozone Action Day – an action day is declared when the ozone concentrations are expected to reach a level that will affect the health of sensitive groups such as children, the elderly, and people with respiratory disease.

Particulate matter - any airborne finely divided material except water vapor, which exists as a solid or liquid at standard conditions.

PM 2.5 – particles with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers.

Prescribed fire – any fire ignited by management actions to meet specific objectives.

Prescribed fire manager – person responsible for managing a prescribed fire from planning to ignition and mop up.

Residual smoke - smoke that continues after the initial burn has passed through the fuel.

Screening distance - the area to examine for possible sensitive targets.

Sensitive area - areas that can be harmed by smoke. Examples: Airports, major highways, communities, Class 1 areas, recreation areas, schools, hospitals, nursing homes, and factories, etc.

Smoke management - conducting a prescribed fire under fuel moisture, meteorological conditions, and firing techniques that keep the impact of the smoke on the environment within acceptable limits.

Smoke plume – the column of smoke resulting from prescribed fire.

Stagnant air - conditions under which pollutants build up faster than the atmosphere can disperse them.

Transport wind – the average wind speed and direction through the mixing layer. Higher wind speeds allow for more rapid transport of pollutants downwind.

Ventilation rate - the mixing height times the transport wind speed gives a rate indicating the ability of the lower atmosphere to diffuse and disperse smoke.

Wind direction – compass direction from which the wind is blowing.

To: Anderson, Lea[anderson.lea@epa.gov]
Cc: HertzWu, Sara[HertzWu.Sara@epa.gov]; Lorang, Phil[Lorang.Phil@epa.gov]; Jones, Rhea[Jones.Rhea@epa.gov]; Beaver, Melinda[Beaver.Melinda@epa.gov]
From: Algoe-Eakin, Amy
Sent: Thur 1/19/2017 4:48:20 PM
Subject: ATTACHED- Nebraska Regional Haze FIP Remand Proposal
RA signature pre publication FR Proposal NE RH Remand.pdf
Appendix A TSD.pdf
Region 7 TSD.pdf

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 7
11201 Renner Boulevard
Lenexa, Kansas 66219

Appendix A

Technical Support Document

Cost of Controls Calculations for the Nebraska Public Power District Gerald Gentleman Regional Haze Federal Implementation Plan (Cost TSD)

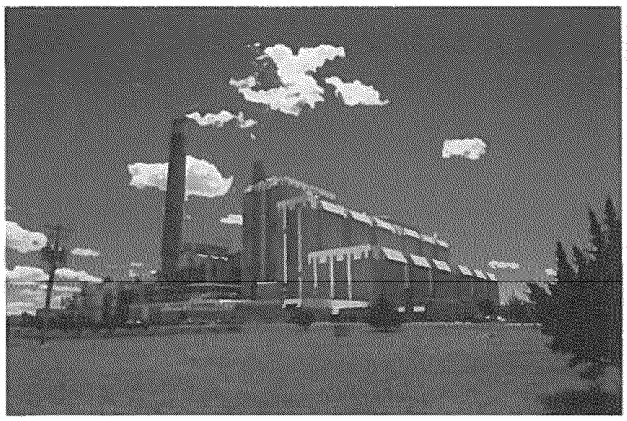
Printed on Recycled Paper

Technical Support Document for the Cost of Controls Calculations for the Nebraska Public Power District Gerald Gentleman Regional Haze Federal Implementation Plan

1 Introduction

This Technical Support Document (TSD) summarizes the cost analyses to retrofit the Nebraska Public Power District (NPPD) Gerald Gentleman units with spray dryer absorbers (SDA), wet flue gas desulfurization (wet FGD), and Dry Sorbent Injection (DSI). This work is a part of our reconsideration of the Nebraska regional haze Federal Implementation Plan (FIP).

The Gerald Gentleman plant is located near Sutherland, Nebraska, in Lincoln County. Units 1 and 2 have nameplate capacities of 681 MW, are dry-bottom, wall-fired and utilize coal from the Powder River Basin. The units began commercial operation in 1979 and 1982, respectively.
Neither unit utilizes control for sulfur dioxide (SO_2). Both units employ low NO_x burners (LNB) and overfire (OFA) for NO_x control and baghouses for control of particulate matter.



The results of the analysis, along with a summary of the control technologies reviewed, are available in the Docket.[1] The spreadsheets contain the underlying data used in the analysis, including but not limited to information from EPA's Air Markets Program Data (AMPD) public information database[2]. We rely upon this information for our analysis, confirmed when possible through other public sources of information, including the DOE-EIA website, permitting files and trade journals.

[1] IPM Cost Summary for SDA, Wet Scrubber and DSI - NPPD Gerald Gentleman (2016-03-22).xlsx, IPM DSI Cost Estimate - NPPD Gerald Gentleman (2016-03-22).xlsx, IPM SDA Cost Estimate - NPPD Gerald Gentleman (2016-03-22).xlsx and IPM Wet FGD Cost Estimate - NPPD Gerald Gentleman (2016-03-22).xlsx
[2] http://ampd.epa.gov/ampd/

2 Cost Analyses Methodology

In developing cost estimates for the Gerald Gentleman units, we relied on the methodologies described in EPA's Air Pollution Control Cost Manual (the Control Cost Manual, or Manual).[3] The Control Cost Manual uses the "overnight" method of cost estimation which is widely used in the utility industry. The U.S. Energy Information Administration (EIA) defines ''overnight cost'' as ''an estimate of the cost at which a plant could be constructed assuming that the entire process from planning through completion could be accomplished in a single day. This concept is useful to avoid any impact of financing issues and assumptions on estimated costs.'' EIA presents all of its projected plant costs in terms of overnight costs. The overnight cost is the present value cost that would have to be paid as a lump sum up front to completely pay for a construction project. The overnight method is appropriate for BART determinations because it allows different pollution control equipment to be compared in a meaningful manner. Because ''different controls have different expected useful lives and will result in different cash flows, the first step in comparing alternatives is to normalize their returns using the principle of the time value of money ... The process through which future cash flows are translated into current dollars is called present value analysis. When the cash flows involve income and expenses, it is also commonly referred to as net present value analysis. In either case, the calculation is the same: Adjust the value of future money to values based on the same point in time (generally year zero of the project), employing an appropriate interest (discount) rate and then add them together.''

To estimate the costs for DSI, SDA scrubbers, and wet FGD scrubbers for the Gerald Gentleman units, we used three spreadsheets prepared by EPA Region 6. The spreadsheets implement the cost methodologies used in EPA's IPM model, Version 5.13.[4] These cost algorithms calculate the Total Project Cost (TPC), Fixed Operating and Maintenance (Fixed O&M) costs, and Variable Operating and Maintenance (Variable O&M) costs. They also calculate the annualized costs per ton of SO_2 removed ($/ton). Region 6 initially verified the spreadsheets by reproducing the costs estimated by Sargent & Lundy Cost Development Methodologies.

Our spreadsheets, entitled "IPM DSI Cost Estimate - NPPD Gerald Gentleman (2016-03-22).xlsx", "IPM SDA Cost Estimate - NPPD Gerald Gentleman (2016-03-22).xlsx" and "IPM Wet FGD Cost Estimate - NPPD Gerald Gentleman (2016-03-22).xlsx" can be found in the Docket. We discuss the inputs and outputs for the DSI, SDA, and wet FGD cost models below.

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[3] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002 available at https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf.

[4] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5-5: DSI Cost Methodology, downloaded from http://www.epa.gov/airmarkets/progsregs/epa- ipm/docs/v513/attachment5_5.pdf on 12-18-13.
IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5-2: SDA FGD Cost Methodology, downloaded from http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/attachment5_2.pdf.
IPM Model – Updates to Cost and Performance for APC Technologies, wet FGD Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5-1: SDA FGD Cost Methodology, downloaded from http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/attachment5_1.pdf.

The IPM cost algorithms estimate costs based on 2012 dollars.[5] We adjusted estimated cost figures to 2014 dollars using the Chemical Engineering Plant Cost Index (CEPCI)[6] and present the results in a spreadsheet titled "IPM Cost Summary for SDA, Wet Scrubber and DSI - NPPD Gerald Gentleman (2016-03-22).xlsx". The CEPCI cost index for 2015 was not available at the time we performed the cost estimates. However, the 2015 aggregate CEPCI factor is now available, and while we didn't make any further adjustments to our cost estimates, the factor indicates that the escalation factor is 4.8% lower than in 2012, which would only lower our cost estimates further. Section 3, 4, and 5 below describe the inputs used in our cost analyses.

3 Overview of DSI Cost Model Input Parameters

Table 1, below, depicts the input section of the DSI cost spreadsheet. Sample input parameters for the DSI cost calculation are represented by yellow highlighted cells. The input values designated "A" through "U" have the same meaning as those contained within the documentation for the IPM DSI cost algorithms (hereafter referred to as the "IPM DSI documentation") referenced above. The last four input values, (e.g. interest rate, equipment lifetime, gross load, and baseline) were added to calculate the annualized costs per ton of SO_2 removed ($/ton). Cells not highlighted in yellow are interim calculations performed by the spreadsheet.

[5] Ibid., p.1: "The data was converted to 2012 dollars based on the Chemical Engineering Plant Index (CEPI) data."
[6] http://www.chemengonline.com/pci-home

Table 1. Sample DSI Input Parameters

PM DSI Cost Estimate Tool
Sample Calculations

Variable	Designation	Units	Value	Calculation	Comments
nit Size (Gross)	A	MW	500	<---- User Input	
etrofit Factor	B		1	<---- User Input (An "average" retrofit has a factor = 1.0)	
ross Heat Rate	C	Btu/kWh	9,500	<---- User Input	Max annual value from 2009-2013
02 Rate	D	lb/MMBtu	2.00	<---- User Input	Max monthly value from 2009-2013
ype of Coal	E		PRB	<---- User Input (PRB, BIT, LIG, or LIG-PRB Blend)	
HV Bituminous		Btu/lb	11,000	<---- User Input (default is 11,000 Btu/lb if applicable; else no meaning)	
HV PRB		Btu/lb	8,400	<---- User Input (default is 8,400 Btu/lb if applicable; else no meaning)	Three year average from 2009-2013, excluding max and min
HV Lignite		Btu/lb	7,200	<---- User Input (default is 7,200 Btu/lb if applicable; else no meaning)	values
ercent Lignite if Blended			50	<---- User Input (If Type of Coal = "LIG-PRB Blend," Enter % Lignite. Remainder assumed PRB. If not "LIG-PRB Blend," no meaning)	
articulate Capture	F		ESP	<---- User Input	
illed Trona	G		TRUE	<---- User Input	
emoval Target	H	%	50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with a BGH = 80% Milled Trona with a BGH = 90%	
eat Input	J	Btu/hr	4,750,000,000	A*C*1000	
SR	K		1.43	Unmilled Trona with an ESP = If(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = If(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with a BGH = If(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with a BGH = If(H<40,0.0160*H,0.208e^(0.0281*H))	Pg 3 of the documentation lists example calculated NSRs which differ from those calculated from the formulae here. Per emails from Bill Stevens, the documentation is in error.
ona Feed Rate	M	ton/hr	16.33	(1.2011*10^-6)*K*A*C*D	
orbent Waste Rate	N	ton/hr	11.65	(0.7387-0.00073696*H/K)*M; Based on a final reaction product of NA2SO4 and unreacted drysorbent as NA2CO3. Waste product adjusted for a maximum of 5% inert in the Trona sorbent.	
clude Fly Ash Waste Rate in VOM	P	ton/hr	13.57	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV= 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV= 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2 HHV= 7200 For Blend Coal: Ash is proportional to lignite and PRB; Boiler Ash Removal = 0.2; HHV is proportional to lignite and PRB	Assume fly ash waste rate is included in VOM
clude Aux Power in VOM	Q	%	0.65	If Milled Trona M*20/A, else M*18/A	Assume aux power is included in VOM
ona Cost	R	$/ton	170	<---- User Input	Based on input from Solvay
aste Disposal Cost	S	$/ton	50	<---- User Input (Disposal cost with fly ash = $50. Without fly ash, the sorbent waste alone will be more difficult to dispose = $100)	Default Value
ux Power Cost	T	$/kWh	0.06	<---- User Input	Default Value
perating Labor Rate	U	$/hr	60	<---- User Input (Labor cost including all benefits)	Default Value
terest Rate		%	7	<---- User Input	
quipment Lifetime		years	30	<---- User Input	
ross Load		MW-hours	4,000,000	<---- User Input	Max annual value from 2009-2013
02 Emission Baseline		tons/year	30,000	<---- User Input	3-yr avg. 2009-2013, excluding max and min

3.1 Selection of DSI Cost Model Input Parameters

Our overall goal was to select input parameters that result in costs that are reasonably conservative. We selected maximum inputs, including inlet SO_2 rate, gross heat rate, and gross load, from 2011 – 2015 to ensure the DSI system is designed to address any operating conditions the unit had experienced in the last five years.

Below, we review the DSI Cost Model input values and procedures used to evaluate the costs for the Gerald Gentleman units. For selected input parameters, we also discuss any uncertainties and how we dealt with them.

Unit Size (Gross). This is the nameplate capacity, expressed in megawatts (MW), as reported on the DOE-EIA "Electric Generating Capacity" website[7]. Although our intent was to use gross and not net values, we are aware that MW values are often reported incorrectly or inconsistently, or the reported values are not specified as to whether they are gross or net values. We therefore invite comments on the accuracy of the values used.

[7] http://www.eia.gov/electricity/capacity/

Retrofit Factor. The retrofit factor represents a subjective estimation of the average retrofit difficulty. Because we are not aware of any significant retrofit issues at any of the facilities we evaluated, we adopted the default retrofit value of 1.0, which represents an average retrofit difficulty.

Gross Heat Rate. Gross heat rate was calculated by dividing heat input (mmBtu) by gross load (MW-h), downloaded from the AMPD website, and multiplying the result by 1000W/kW to get (btu/kWh). We chose the gross heat rate to be the maximum annual gross heat rate (Btu/kWh) value from 2011 – 2015 for each unit.

SO_2 Rate. The SO_2 emission rate was calculated from monthly emission data downloaded from the AMPD website.[8] The maximum monthly value from 2011 – 2015 was used in the analysis.

Type of Coal. The Gerald Gentleman units utilize coal from the Powder River Basin.

Particulate Capture. The Gerald Gentleman units use baghouse controls to capture particulate matter. Baghouses generally achieve greater SO_2 removal efficiencies than ESPs by virtue of the filter cake on the bags, which allows for longer reaction time between the sorbent solids and the flue gas.[9] We assumed the existing particulate control devices have the capacity to handle the additional load due to the addition of the trona. We invite comment from the affected facilities as to whether this assumption is valid.

Milled Trona. As discussed in the IPM DSI documentation, trona is the most commonly used sodium-based sorbent material for DSI installations and the DSI cost algorithms assume trona. For a given mass, increasing the surface area of the trona has the effect of improving its ability to remove SO_2 from the flue gas. One common method for increasing the surface area is to mill the trona to a particle size of 30 μm or smaller, using in-line mills. This usually results in slightly higher capital costs, but the overall cost effectiveness of trona milling improves (lower $/ton), due to the reduction in trona required to achieve a given SO_2 removal target. We assumed that milled trona would be used in all cases.

We note, however, that other reagents have important advantages over the use of trona. Hydrated lime, for example, is less sensitive to the conditions of the pneumatic transport air, so less dehumidification or cooling is required for handling; the waste generated by lime injection is not soluble, so normal landfill disposal is feasible without encapsulation, lowering disposal costs; milling is not required; and hydrated lime is usually cheaper.

Removal Target. The removal target, expressed as a percentage, is the reduction in SO_2 desired from the SO_2 rate discussed above. The IPM DSI documentation suggests removal percentages of up to 90% may be attained when using milled trona along with baghouse controls. Performance drops to 80% when using unmilled trona. Since the Gerald Gentleman units are equipped with baghouses, the IPM Cost Tool suggests that SO_2 removals in the range of 80-90% are achievable using DSI.[10] Solvay Chemicals, Inc., a manufacturer of DSI sorbents, provides general performance information:[11]

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[8] http://ampd.epa.gov/ampd/

[9] IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO2 Control Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy, p.1.

[10] Ibid. Pages 7-8.

[11] "Dry Sorbent Injection of Sodium Sorbents," presented at the LADCO Lake Michigan Air Directors Consortium, Emission Control and Measurement Technology for Industrial Sources Workshop, March 24, 2010. We note that a number of different DSI trona SO2 performance curves exist and our use of these curves is as a general reference only.

Figure 1. Typical Trona SO_2 Removal Rates with Electrostatic Precipitator or Baghouse Installations

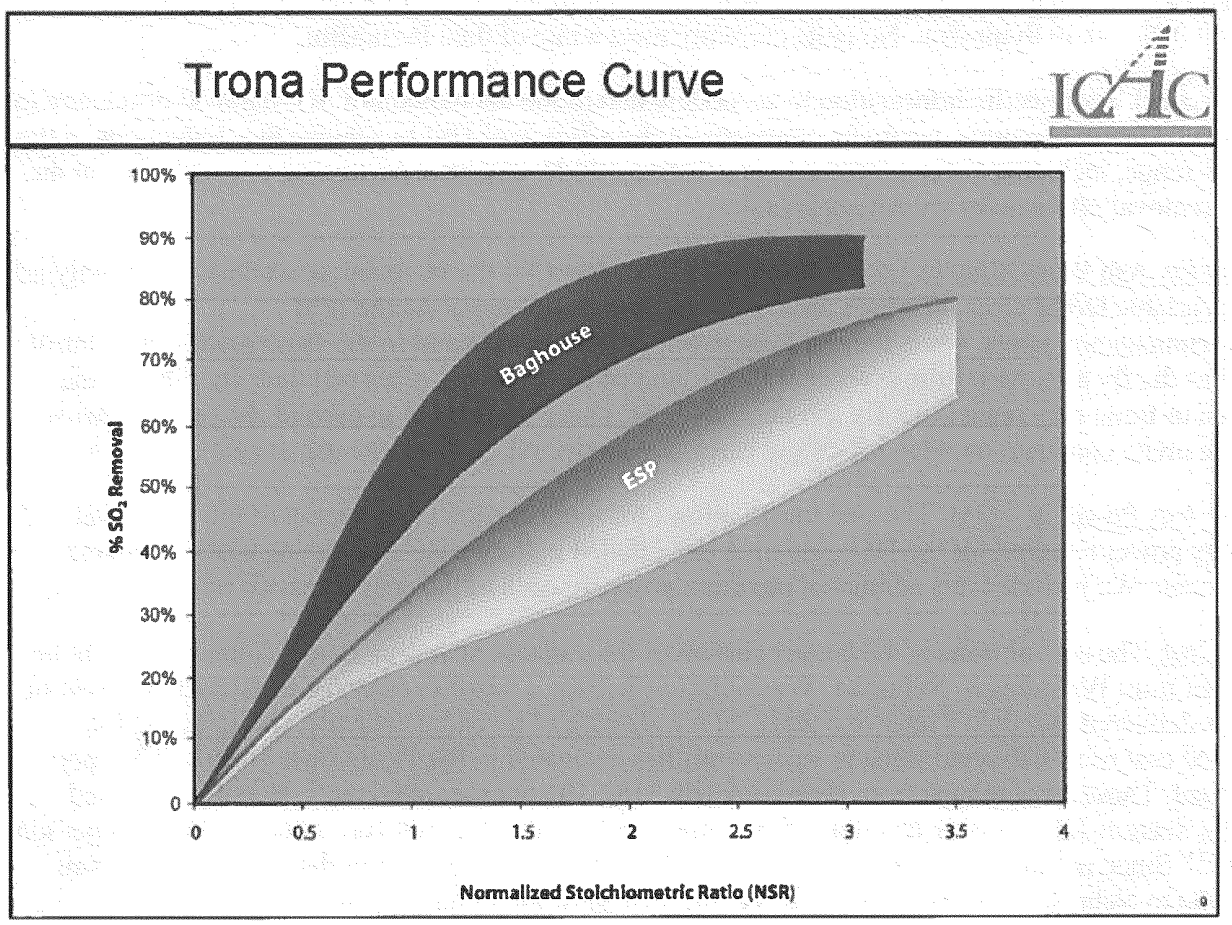

Figure 1 illustrates a number of important concepts concerning the performance potential of DSI:

- SO_2 removal efficiencies for trona DSI installations perform better when a baghouse, rather than an electrostatic precipitator (ESP), particulate control device is employed.
- The Normalized Stoichiometric Ratio (NSR), which is a measure of the actual usage needed compared to the theoretical need, governs the SO_2 removal efficiency. In other words, for a given particulate control device, greater SO_2 removal efficiencies require increasingly greater amounts of trona, with diminishing returns.

We used the IPM Cost Tool to look at the cost of DSI at reduction efficiencies of 50, 80 and 90%. The 50% threshold, relative to NPPD Gerald Gentleman, roughly corresponds to a unit that would achieve an SO2 emission rate around 0.30 lb/mmBtu. The 80% control threshold corresponds to a unit that would meet a SO2 emission rate of approximately 0.12 lb/mmBtu. Lastly, the 90% control rate corresponds to a unit that is achieving scrubber-like control for SO2 of 0.06 lb/mmBtu, and allows direct comparison to the costs of SDA and wet FGD to determine if DSI can result in substantially lower cost while achieving similar SO_2 removal efficiencies.

Using the IPM Cost Tool to estimate the theoretical cost of DSI controls is important, but it is also relevant to know whether any units are achieving substantive SO2 reductions through the use of DSI.

We explore these practical considerations in more detail in Section 7. In brief, three units are meeting SO_2 rates in the range of 0.08 – 0.09 lb/mmBtu. Three additional units are meeting SO2 rates in the range of 0.23 – 0.40 lb/mmBtu. No units currently meet a rate of 0.06 lb/mmBtu.

Since we lack site specific information to accurately determine the maximum SO_2 removal efficiency for the Gerald Gentleman units, we invite comment on the efficacy of DSI to achieve SO_2 reductions in the 80-90% range, including but not limited to any testing NPPD may have performed to conclude that the higher removal efficiencies are not achievable.

Include Fly Ash Waste Rate in VOM. The cost model allows for the inclusion or exclusion of the fly ash in the Variable O&M costs for waste disposal via a drop down menu. As the IPM DSI documentation notes, when sodium sorbent (e.g., trona) is captured in the same particulate control device as the fly ash, the resulting waste must be land filled. Facilities often sell their fly ash and the addition of trona may render that fly ash unsalable. We chose this option in each of the cost scenarios run. We invite comment on what effect any carry-over trona will have on the use or sale of fly ash.

Include Aux Power in VOM. The cost model allows for the inclusion or exclusion of the additional auxiliary power required for the DSI system to be included in the variable operating costs via a drop down menu. We included this additional auxiliary power in each of the cost scenarios run.

Trona Cost. The cost of trona is the largest portion of the variable operating costs. Trona is likely to be delivered from Wyoming to Nebraska. We contacted Solvay, a supplier of trona, to estimate the cost of trona as delivered, but didn't receive a reply. In the absence of a vendor estimate, we looked at the estimated cost of as-delivered trona to various utilities evaluated in the Texas Cost Technical Support Document. These costs ranged from approximately $181-195 per ton delivered[12]. We also reviewed NPPD's Section 114 response and noted they estimated the cost of as-delivered trona to be $145 per ton in 2011[13]. Since rail distance from Wyoming to Nebraska is substantially less than rail distance from Wyoming to Nebraska, we use a conservative figure of $170/ton in our cost analysis.

Waste Disposal Cost. The waste disposal cost is the second largest portion of the variable operating costs. The cost model suggests a cost of $50/ton if trona waste and fly ash are comingled and disposed of together, and $100/ton, if the trona waste is not comingled with fly ash and is disposed of separately. We assumed trona waste and fly ash were comingled and disposed of together for all cases, and therefore set this value to $50/ton. We note that the waste disposal cost is an area in which our cost analysis that could under predict costs. Because adding trona to the fly ash increases the water solubility of the waste, an upgraded landfill may also be required.[14] We invite comments on this issue.

Aux Power Cost. Auxiliary power cost is the additional power required by the DSI control system. It is the smallest portion of the variable operating costs. Based on information used by NPPD in its 2008 BART four-factor analysis, we believe the default value of $0.06/kWh used in our current analysis is conservative.

Operating Labor Rate. The operating labor rate is the largest portion of the fixed operating and maintenance cost. We chose the default value of $60/hour for all cases.

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[12] Texas Cost Technical Support Document, November, 2014, page 9.

[13] NPPD Section 114 Response, NPPDRH114_0001311.pdf, page 3 of 8.

[14] The Ins and Outs of SO_2 Control, Lindsay Morris, Power Engineering, 6-1-2012. "Jonas Klingspor, vice president of business development and marketing for URS, said one potential concern for using DSI systems with trona is the disposal of the product. 'Unless you have a double-lined, capped landfill, the water soluble byproduct may be a serious concern.'"

Interest Rate. The interest rate is used in the calculation of the capital recovery factor, which itself is used in the calculation of the annualized capital costs. This input value is not a part of the IPM DSI cost algorithms and was added to calculate the cost effectiveness in $/ton. For cost analyses related to government regulations, an appropriate "social" interest (discount) rate should be used, unless site specific information is available. EPA used interest rates of 3 and 7 percent in calculating capital recovery factors for the Regulatory Impact Analysis (RIA) for the BART Guidelines.[15] Further, Office of Management and Budget recommends use of a 7 percent interest rate.[16] Information provided by NPPD in its 2008 BART four-factor analysis suggests its interest rate is substantially less than 7 percent, so we believe the use of 7 percent in our current analysis is conservative.

Equipment Lifetime. The equipment lifetime is another factor used in the in the calculation of the capital recovery factor. This input value is not a part of the IPM DSI cost algorithms and was added to calculate the cost effectiveness in $/ton. It represents the actual or service life of the equipment in question. Because a DSI system is relatively simple and reliable, we have no reason to conclude that its service life would be any less than what we typically use for scrubber cost analyses. We therefore adopt that same value here, which is 30 years.

Gross Load. Gross load (MW-h) was obtained from the AMPD website.[17] We used the highest one-in-five-year period from 2011 to 2015 to conservatively maximize the cost. This input value is not a part of the IPM DSI cost algorithms. It was added to convert variable and operating costs, which the cost algorithms express in $/MW-h and $/kW-yr, respectively, into dollars which are subsequently used in calculating cost effectiveness in dollars per ton of SO_2 removed ($/ton).

SO_2 Emission Baseline. The SO_2 emission baseline is calculated from emissions data obtained from the AMPD website[18]. We used the highest one-in-five-year period, from 2011 – 2015. The SO_2 baseline is not a part of the IPM DSI cost algorithms, but was added to calculate the annual SO_2 emission reduction from installation of DSI, which is needed to calculate the cost effectiveness in $/ton.

3.2 DSI Cost Model Output

A sample of the IPM DSI cost model output is depicted in Table 3. The cost algorithms calculate capital, engineering and construction cost (CECC) and fixed and variable operating costs (FOM and VOM, respectively). Building on these estimates, the spreadsheets also calculate the capital recovery factor, based on the interest rate and the equipment lifetime, to annualize the CECC. Consistent with the OAQPS Cost Manual, we exclude any "allowance for funds used during construction" (AFUDC) and "owner's costs."[19] Lastly, we add FOM and VOM to the annualized CECC to arrive at the total annualized costs and divide by the SO_2 emissions reduction to calculate the cost effectiveness in $/ton.

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[15] Regulatory Impact Analysis for the Final Clean Air Visibility Rule or the Guidelines for Best Available Retrofit Technology (BART) Determinations Under the Regional Haze Regulations, EPA-0452/R-05-004 (June 2005).
[16] A 7.0 percent interest rate is recommended by Office of Management and Budget, Circular A-4, Regulatory Analysis, http://www.whitehouse.gov/omb/circulars-a004-a-4/.
[17] http://ampd.epa.gov/ampd/
[18] Ibid.
[19] We exclude any AFUDC and "owner's costs" from regional haze control cost calculations, as they are disallowed by the "overnight" cost method used in the Control Cost Manual. In this case, however, AFUDC is assumed by the cost algorithms to be zero anyway, since a DSI project is expected to be completed within one year.

Table 3. Sample DSI Output

ıpital Cost Calculation		Explanation of Calculation	Comments
		Includes: equipment, installation, buildings, foundations, electrical, and retrofit difficulty.	
3M ($)	$12,527,000	Base DSI module includes all equipment from unloading to injection.	
3M ($/kW)	18	Base module cost per kW	
ɔtal Project Cost			
A1	$626,000	Engineering and construction management costs	
A2	$626,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc..	
A3	$626,000	Contractor profit and fees	
CECC($)	$14,405,000	Capital, engineering and construction cost subtotal	excludes owner's costs
CECC($/kW)	21	Capital, engineering and construction cost subtotal per kW	excludes owner's costs
31	$720,000	Owners costs including "home office" costs (owner engineering, management, and procurement activities)	
TPC ($)	$15,125,000	Total project cost without AFUDC	includes owner's costs
TPC ($/kw)	22	Total project cost per kW without AFUDC	includes owner's costs
32	$0	AFUDC (zero for less than 1 year engineering and construction cycles)	
TPC ($)	$15,125,000	Total project cost	includes owner's costs and AFUDC
TPC ($/kw)	22	Total project cost per kW	includes owner's costs and AFUDC
xed O&M Cost			
FOMO ($/kW yr)	0.37	Fixed O&M additional operating labor costs. Based on two additional operators.	
FOMM ($/kW yr)	0.18	Fixed O&M maintenance material and labor costs	
FOMA ($/kW yr)	0.01	Fixed O&M additional addministrative labor costs	
FOM ($/kW yr)	0.56	Total Fixed O&M costs	
ariable O&M			
VOMR ($/MWh)	1.06	Variable O&M costs for trona reagent	
VOMW ($/MWh)	1.58	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the	
VOMP ($/MWh)	0.08	Variable O&M costs for additional auxillary power required (refer to Aux Power % above)	
VOM ($/MWh)	2.72	Total variable O&M costs	
nnualization			
ıpital, engineering and construction cost	$14,405,000	Excludes owner's costs and AFUDC	
ıpital Recovery factor	0.0806		
ınnualized capital costs	$1,160,847		
ariable operating costs	$14,356,274	VOM*(Gross Load)	
xed operating costs	$339,736	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)	
ɔtal annualized costs	$15,856,857		
)2 emissions reduction (tons)	7,416	H/(100%)*(SO2 emission baseline)	
'ton	2,138		
ɔsts are all based on 2012 dollars			

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3.3 Summary of DSI Cost Model Results

Below is a summary of our DSI cost model results:

Table 4. Summary of DSI Cost Model Results

IPM Dry Sorbent Injection (DSI) Cost Estimate Summary
NPPD Gerald Gentleman Units 1 and 2

Facility	Unit	SO2 Rate lb/mmBtu	Control %	SO2 Baseline tpy	SO2 Reduction tpy	Capital Cost	Annualized Capital Cost	Variable Operating Cost	Fixed Operating Cost	Total Annualized Cost	Cost Effectiveness $/ton
Gerald Gentleman	1	0.322	50	14,832	7,416	$14,405,000	$1,160,847	$14,356,274	$339,736	$15,856,857	$2,138
Gerald Gentleman	1	0.129	80	14,832	11,866	$18,303,000	$1,474,973	$23,883,079	$370,081	$25,728,133	$2,168
Gerald Gentleman	1	0.064	90	14,832	13,349	$19,824,000	$1,597,545	$29,320,048	$381,931	$31,299,524	$2,345
Gerald Gentleman	2	0.317	50	15,942	7,971	$14,480,000	$1,166,891	$15,349,161	$354,334	$16,870,387	$2,116
Gerald Gentleman	2	0.127	80	15,942	12,754	$18,396,000	$1,482,467	$25,446,885	$386,099	$27,315,452	$2,142
Gerald Gentleman	2	0.063	90	15,942	14,348	$19,923,000	$1,605,523	$31,209,679	$398,493	$33,213,696	$2,315

The majority of total annualized cost of DSI is due to the variable operating cost, VOM. This is due to the relatively low capital cost of the equipment and relatively high cost of trona. Unlike the cost effectiveness of scrubbers, which is discussed below, the cost effectiveness of DSI worsens (higher $/ton) with increasing control levels. This is due to the inefficient use of the sorbent in DSI systems. Unlike scrubbers, in which the reaction of the reagent and the SO_2 in the exhaust gas occurs within a large vessel (e.g., an absorber), which can be highly controlled, DSI lacks an absorber. Greater SO_2 removal efficiencies require increasingly greater amounts of trona, with diminishing returns.

4 Overview of SDA Cost Model Input Parameters

Table 5, below, shows an example of the inputs for the SDA cost spreadsheet. Sample input parameters for the SDA cost calculation are represented by the yellow highlighted cells. The input values designated "A" through "T" have the same meaning as those contained within the documentation for the IPM SDA cost algorithms referenced above. The last four input values, (e.g. interest rate, equipment lifetime, gross load, and baseline) were added to calculate the annualized costs per ton of SO_2 removed ($/ton). Cells not highlighted in yellow are interim calculations performed by the spreadsheet.

Table 5. Sample SDA Input Parameters

IPM SDA Cost Estimate Tool
NPPD Gerald Gentleman Unit 1

Variable	Designation	Units	Value	Calculation	Comments
Unit Size (Gross)	A	MW	681	<--- User Input (Greater than 50 MW)	
Retrofit Factor	B		1	<--- User Input (an "average" retrofit has a factor =1.0)	
Gross Heat Rate	C	Btu/kWh	9,541	<--- User Input	High 1 in 5 years (2011-2015)
SO_2 Rate	D	lb/MMBtu	0.644	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO_2 Rate)	High 1 in 60 months (2011-2015)
Type of Coal	E		PRB	<--- User Input (PRB, BIT, or LIG)	
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07	
Heat Rate Factor	G		0.9541	C/10000	
Heat Input	H	Btu/Hr	6,497,421,000	A*C*1000	
Operating SO_2 Removal	J	%	90.68	<--- User Input (Used to adjust actual operating costs)	Assume 95%. If outlet < 0.06 lbs/MMBtu, then assume % control for 0.06 lbs/MMBtu.
Lime Rate	K	Ton/Hr	3	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)	
Waste Rate	L	Ton/Hr	7	(0.8016*(D^2)+31.1917*D)*A*G/2000 (Based on 95% SO2 removal)	
Include Aux Power in VOM	M	%	1.31	(0.000547*D^2+0.00649*D+1.3)*F*G	Assume aux power is included in VOM
Makeup Water Rate	N	1000 gph	38	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000	
Lime Cost	P	$/Ton	95	<--- User Input	Default - appears reasonable - see USGS lime report
Waste Disposal Cost	Q	$/Ton	30	<--- User Input	Default Value
Aux Power Cost	R	$/kWh	0.06	<--- User Input	Default Value
Makeup Water Cost	S	$/1000 gal	1	<--- User Input	Default Value
Operating Labor Rate	T	$/hr	60	<--- User Input (Labor cost including all benefits)	Default Value
Elevation adjustment if > 500 Feet		ft	3,130	<--- User Input (no entry needed if less than 500 feet)	Altitude: 3,130 ft. See "Reference" tab for adjustment factor.
Interest Rate		%	7	<--- User Input	
Equipment Lifetime		years	30	<--- User Input	
Gross Load		MW-hours	5,279,809	<--- User Input	High 1 in 5 years (2011-2015)
SO_2 Emission Baseline		tons/year	14,832	<--- User Input	High 1 in 5 years (2011-2015)

4.1 Selection of SDA Cost Model Input Parameters

Many of the inputs to the SDA cost model are similar to those already discussed for DSI. For those that are different, we describe their use below.

Operating SO_2 Removal. The operating SO_2 removal is the percentage reduction in SO_2 desired from the SO_2 rate. The IPM SDA documentation states: "The curve fit was set to represent proprietary in-house cost data of a "typical" SDA retrofit for removal of 95% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufacturers of SDA systems, are 0.06 lb/MmBtu." Since a 95% removal efficiency results in SO_2 rates less than 0.06 lb/mmBtu for the Gerald Gentleman units, we limited the control efficiency in the cost algorithm to just under 91% to assure that any performance guarantees can be met.

Lime Cost. The cost of lime is the largest portion of the variable operating costs. At most SDA facilities, the lime reagent is produced by onsite slaking of quicklime, or calcium oxide, to produce a slurry of solid hydrated lime, or calcium hydroxide, particles.[20] Therefore, we assume in our cost model that quicklime is delivered to the facility where it is then slaked onsite, and that this cost is a part of the "base reagent preparation and waste recycle/handling" cost module.[21]

In 2008, as part of its four factor analysis, NPPD estimated the cost of lime to be $95/ton delivered. This is the value used in our current analysis. We invite comment on this assumption.

[20] Primex Process Specialists. "Optimizing Scrubber Performance," p. 3. Available at http://www.primexprocess.com/pdf/Paper_4.pdf

[21] IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology, Final, March 2013. Sargent & Lundy, p. 3

Waste Disposal Cost. The waste disposal cost is the second largest portion of the variable operating costs. The cost model default is $30/ton and that is what we used in our current analysis.

Elevation Adjustment. The IPM SDA documentation notes the SDA cost methodology is based on a unit located at or below 500 feet of sea level.[22] The actual elevation of the site should be considered separately and factored into the cost due to the effects on the flue gas volume. The base absorber island and balance of plant costs are directly impacted by the site elevation. These two base cost modules should be increased based on the ratio of the atmospheric pressure between sea level and the unit location. As an example, a unit located 1 mile above sea level would have an approximate atmospheric pressure of 12.2 psia. Therefore, the base absorber island and balance of plant costs should be increased by:

14.7 psia/12.2 psia = 1.2 multiplier to the base absorber island and balance of plant costs.

The example spreadsheet found in the IPM documentation does not include the elevation adjustment as an input to the model. Consequently, Region 6 incorporated an elevation correction factor using a NASA procedure[23] to adjust atmospheric pressure change by elevation. To find the elevation of the Gerald Gentleman plant, we input the latitude and longitude into an online service[24] to estimate elevation above sea level. See Table 6 for a summary.

Table 6. Location and Elevation of the Gerald Gentleman Plant

	Latitude	Longitude	Elevation
Gerald Gentleman Plant	41.080914°	-101.141507°	3,130 ft

Since the Gerald Gentleman plant is located at an elevation that exceeds 500 feet above sea level, an elevation adjustment was included. This correction has the effect of increasing cost effectiveness ($/ton) by approximately 4.2%.

4.2 SDA Cost Model Output

A sample of the IPM SDA cost model output is shown in Table 7. As with our DSI cost model, the SDA cost algorithm calculates CECC, FOM and VOM. We use a capital recovery factor, based on the interest rate and the equipment lifetime, to annualize the CECC. AFUDC and "owner's costs" are excluded. Lastly, we add FOM and VOM to the annualized CECC to arrive at the total annualized costs and divide by the SO_2 emissions reduction to calculate the cost effectiveness in $/ton.

[22] IPM SDA documentation, p. 2.

[23] http://exploration.grc.nasa.gov/education/rocket/atmosmet.html. It should be noted that in addition to the NASA algorithm, this calculation requires converting the input feet to meters (multiplying elevation*0.3048) and K-Pa to psi (multiplying the calculation by 0.145038).

[24] https://www.freemaptools.com/elevation-finder.htm

Table 7. Sample SDA Output

Capital Cost Calculation		Explanation of Calculation	Comments
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit difficulty	
BMR($)	65,601,000	Base module absorber island cost	
BMF($)	32,125,000	Base module reagent preparation and waste recycle/handling cost	
BMB($)	94,046,000	Base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.)	
BMBA($)	105,370,421	Adjustment to base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.). If elevation is greater than 500 feet. See page 2 of the S&L documentation.	
BM($)	**203,096,000**	Total Base module cost including retrofit factor	Page 6 of the S&L report gives BM=BMR+BMF+BMW+BMB. BMW appears to be an error (holdover from wet scrubber algorithm), as no formula is given for BMW.
BM($/kW)	298	Base module cost per kW	
Total Project Cost			
A1	20,310,000	Engineering and Construction Mnagement costs	
A2	20,310,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.	
A3	20,310,000	Contractor profit and fees	
CECC ($)	**264,026,000**	Capital, engineering and construction cost subtotal	Excludes Owner's Costs
CECC($/kW)	**388**	Capital, engineering and construction cost subtotal per kW	Excludes Owner's Costs
B1	13,201,000	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)	
TPC' ($)	**277,227,000**	Total project cost without AFUDC	Includes Owner's Costs
TPC' ($/kw)	**407**	Total project cost per kW without AFUDC	Includes Owner's Costs
B2	27,723,000	AFUDC (Based on a 3 year engineering and construction cycle)	
TPC ($)	**304,950,000**	Total Project Cost (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
TPC ($/kW)	**448**	Total Project Cost per kW (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
Fixed O&M Cost			
FOMO ($/kW-yr)	1.47	Fixed O&M additional operating labor costs. Based on eight additional operators.	
FOMM ($/kW-yr)	4.47	Fixed O&M costs for waste disposal	
FOMA ($/kW-yr)	0.10	Fixed O&M additional administrative labor costs	
FOM ($/kW-yr)	**6.04**	Total Fixed O&M costs	
Variable O&M Cost			
VOMR ($/MWh)	0.39	Variable O&M costs for lime reagent	
VOMW ($/MWh)	0.28	Variable O&M costs for waste disposal	
VOMP ($/MWh)	0.78	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)	In the calculation, the factor of "10" results from dividing the conversion from kilo to mega (1000) by 100%, since the input for M is a percentage.
VOMM ($/MWh)	0.06	Variable O&M costs for makeup water	
VOM ($/MWh)	**1.50**	Total Variable O&M Costs	
Annualization			
Capital, engineering and construction cost	$264,026,000	Excludes owner's costs and AFUDC	
Capital Recovery factor	0.0806		
Annualized capital costs	$21,276,906		
Variable operating costs	$7,943,635	VOM*(Gross Load)	
Fixed operating costs	$3,638,743	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)	
Total annualized costs	**$32,859,284**		
SO_2 emissions reduction (tons)	13,450	J/(100%)*(SO2 emission baseline)	
$/ton	2,443		
Costs are all based on 2012 dollars			

4.3 Summary of SDA Cost Model Results

Below is a summary of our SDA cost model results:

Table 8. Summary of SDA Cost Model Results

'M SDA Cost Estimate Summary
PPD Gerald Gentleman Units 1 and 2

Facility	Unit	SO2 Rate lb/mmBtu	Control %	SO2 Baseline tpy	SO2 Reduction tpy	Capital Cost	Annualized Capital Cost	Variable Operating Cost	Fixed Operating Cost	Total Annualized Cost	Cost Effectiveness $/ton
erald Gentleman	1	0.060	90.7	14,832	13,450	$264,026,000	$21,276,906	$7,943,635	$3,638,743	$32,859,284	$2,443
erald Gentleman	2	0.060	90.5	15,942	14,431	$267,902,000	$21,589,259	$8,492,800	$3,830,525	$33,912,583	$2,350

5 Overview of Wet FGD Cost Model Input Parameters

Table 9, depicts the input section of the wet FGD cost spreadsheet. Sample input parameters for the wet FGD cost calculation are represented by the yellow highlighted cells. Input values designated "A" through "T" have the same meaning as those contained within the documentation for the IPM wet FGD cost algorithms referenced above. The last four input values, (e.g., interest rate, equipment lifetime, gross load, and baseline) were added to calculate annualized costs per ton of SO_2 removed ($/ton). Cells not highlighted in yellow are interim calculations performed by the spreadsheet.

Table 9. Sample Wet FGD Input Parameters

IPM Wet Scrubber Cost Estimate Tool
NPPD Gerald Gentleman Unit 1

Variable	Designation	Units	Value	Calculation	Comments
Unit Size (Gross)	A	MW	681	<--- User Input (Greater than 50 MW)	S&L has a drop down menu for selection of an additional WWTP facility, but no capital or operational cost are implemented so it is not reproduced here.
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor =1.0)	
Gross Heat Rate	C	Btu/kWh	9,541	<--- User Input	High 1 in 5 years (2011-2015)
SO2 Rate	D	lb/MMBtu	0.644		High 1 in 60 months (2011-2015)
Type of Coal	E		PRB	<--- User Input (PRB, BIT, or LIG)	If blending, run once for PRB and one for LIG
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07	
Heat Rate Factor	G		0.9541	C/10000	
Heat Input	H	Btu/Hr	6,497,421,000	A*C*1000	
Operating SO_2 Removal	J	%	93.79	<--- User Input (Used to adjust actual operating costs)	Assume 98%. If outlet < 0.04 lbs/MMBtu, then assume % control for 0.04 lbs/MMBtu.
Design Limestone Rate	K	Ton/Hr	4	(17.52*A*D*G/2000 (Based on 98% SO2 removal)	
Design Waste Rate	L	Ton/Hr	7	1.811*K (Based on 98% SO2 removal)	
Include Aux Power in VOM	M	%	1.16	(1.05e^(0.155*D+1.3))*F*G	Assume aux power is included in VOM
Makeup Water Rate	N	1000 gph	52	(1.674*D+74.68)*A*F*G/1000	
Limestone Cost	P	$/Ton	26	<--- User Input	Default - appears reasonable - see USGS lime report
Waste Disposal Cost	Q	$/Ton	30	<--- User Input	Default Value
Aux Power Cost	R	$/kWh	0.06	<--- User Input	Default Value
Makeup Water Cost	S	$/1000 gal	1	<--- User Input	Default Value
Operating Labor Rate	T	$/hr	60	<--- User Input (Labor cost including all benefits)	Default Value
Elevation adjustment if > 500 Feet		feet	3,130	<--- User Input (no entry needed if less than 500 feet)	Altitude: 3,130 ft. See "Reference" tab for adjustment factor.
Interest Rate		%	7	<--- User Input	
Equipment Lifetime		years	30	<--- User Input	
Gross Load		MW-hours	5,279,809	<--- User Input	High 1 in 5 years (2011-2015)
SO2 Emission Baseline		tons/year	14,832	<--- User Input	High 1 in 5 years (2011-2015)

5.1 Selection of Wet FGD Cost Model Input Parameters

Many of the inputs to the wet FGD cost model are similar to those already discussed for DSI and SDA. For those that are different, we describe their use below.

Operating SO_2 Removal. The operating SO_2 removal is the percentage reduction in SO_2 desired from the SO_2 rate. The IPM wet FGD Documentation states: "The least squares curve fit of the data was defined as a "typical" wet FGD retrofit for removal of 98% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufacturers of wet FGD systems, are 0.04 lb/mmBtu."[25]

We ran two cost analyses, one at 0.04 and the other at 0.06 lb/mmBtu. The first analysis evaluates wet FGD at the lowest rate vendors will guarantee. Since a 98% removal efficiency results in SO_2 rates less than 0.04 lb/mmBtu for the Gerald Gentleman units, we limited the control efficiency in the cost algorithm to just under 94% to assure that any performance guarantees can be met. The second analysis allows direct comparison to SDA at similar reduction efficiencies of just under 91%.

Limestone Cost. Unlike the DSI and SDA cost algorithms, the wet FGD cost algorithms are fairly insensitive to the cost of the reagent – limestone. We note that the cost of limestone is partly dependent on the delivery cost, but limestone is widely available in Nebraska. In 2008, as part of its four factor analysis, NPPD estimated the cost of limestone to be $26/ton delivered. This is the value used in our current analysis. We invite comment on this assumption.

Elevation Adjustment. Our wet FGD cost model incorporates the same elevation adjustment used in the SDA cost model. Since the Gerald Gentleman plant is located at an elevation that exceeds 500 feet above sea level, an elevation adjustment was included. This correction has the effect of increasing cost effectiveness ($/ton) by approximately 5.1%.

Wastewater Treatment. The IPM wet FGD documentation includes a base capital cost for minor physical and chemical wastewater treatment, but notes more extensive wastewater handling may be required. The IPM algorithms do not currently estimate these potential additional wastewater treatment costs. We invite comment whether more extensive wastewater treatment may be required, and if so, what the associated costs may be.

5.2 Wet FGD Cost Model Output

A sample of the IPM wet FGD cost model output is depicted below in Table 10. As with our DSI and SDA cost models, the SDA cost algorithm calculates CECC, FOM and VOM. We use a capital recovery factor, based on the interest rate and the equipment lifetime, to annualize the CECC. AFUDC and "owner's costs" are excluded. Lastly, we add FOM and VOM to the annualized CECC to arrive at the total annualized costs and divide by the SO_2 emissions reduction to calculate the cost effectiveness in $/ton.

[25] IPM Model – Updates to Cost and Performance for APC Technologies, wet FGD Cost Development Methodology, Final March 2013, Project 12847-002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy. Documentation for v.5.13: Chapter 5: Emission Control Technologies, Attachment 5-1: SDA FGD Cost Methodology, downloaded from http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/attachment5_1.pdf.

Table 10. Sample Wet FGD Output

Capital Cost Calculation		Explanation of Calculation	Comments
		Includes: Equipment, installation, buildings, foundations, electrical, and retrofit difficulty	
BMR($)	61,034,000	Base absorber island cost	
BMF($)	18,639,000	Base reagent preparation and waste recycle/handling cost	
BMW($)	9,092,000	Base reagent	
BMB($)	114,348,000	Base balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.)	The cost algorithms present an additional factor, BMWW, for a possible future base wastewater treatment facility. It is currently not used, so it is not included here.
BMBA($)	128,117,059	Adjustment to base module balance of plant costs (including ID or booster fans, piping, ductwork, electrical, etc.), if elevation is greater than 500 feet. See page 2 of the S&L documentation.	
BM($)	216,882,000	Total Base module cost including retrofit factor	
BM($/kW)	318	Base cost per kW	
Total Project Cost			
A1	21,688,000	Engineering and Construction Mnagement costs	
A2	21,688,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc.	
A3	21,688,000	Contractor profit and fees.	
CECC ($)	**281,946,000**	Capital, engineering and construction cost subtotal	Excludes Owner's Costs
CECC($/kW)	**414**	Capital, engineering and construction cost subtotal per kW	Excludes Owner's Costs
B1	14,097,000	Owner's costs including all "home office" costs (owner's engineering, management, and procurement activities)	
TPC' ($)	**296,043,000**	Total project cost without AFUDC	Includes Owner's Costs
TPC' ($/kw)	**435**	Total project cost per kW without AFUDC	Includes Owner's Costs
B2	29,604,000	AFUDC (Based on a 3 year engineering and construction cycle)	
TPC ($)	**325,647,000**	Total Project Cost (Including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
TPC ($/kW)	**478**	Total Project Cost per kW (including AFUDC and owner's costs)	Includes Owner's Costs and AFUDC
Fixed O&M Cost			
FOMO ($/kW-yr)	2.93	Fixed O&M additional operating labor costs. IF MW > 500, then 16 operators, else 12 operators	The cost algorithms present additional factors, FOMWW and VOMWW, for a possible future base wastewater treatment facility. They are currently not used, so they are not included here.
FOMM ($/kW-yr)	4.78	Fixed O&M additional maintenance material and labor costs	
FOMA ($/kW-yr)	0.15	Fixed O&M additional administrative labor costs	
FOM ($/kW-yr)	**7.85**	Total Fixed O&M costs	
Variable O&M Cost			
VOMR ($/MWh)	0.13	Variable O&M costs for limestone reagent	
VOMW ($/MWh)	0.28	Variable O&M costs for waste disposal	
VOMP ($/MWh)	0.70	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)	In the calculation, the factor of "10" results from dividing the conversion from kilo to mega (1000) by 100% , since the input for M is a percentage.
VOMM ($/MWh)	0.08	Variable O&M costs for makeup water	
VOM ($/MWh)	**1.19**	Total Variable O&M Costs	
Annualization			
Capital, engineering and construction cost	$281,946,000	Excludes owner's costs and AFUDC	
Capital Recovery factor	0.0806		
Annualized capital costs	$22,721,014		
Variable operating costs	$6,267,556	VOM*(Gross Load)	
Fixed operating costs	$4,734,099	FOM*(Gross Load)*(1000kw/MW)*(8760 hours/year)	
Total annualized costs	$33,722,669		
SO2 emissions reduction (tons)	13,911	)/(100%)*(SO2 emission baseline)	
$/ton	2,424		
Costs are all based on 2012 dollars			

5.3 Summary of Wet FGD Cost Model Results

Below is a summary of wet FGD cost model results for the Gerald Gentleman units:

Table 11. Summary of Wet FGD Cost Model Results

IPM Wet Scrubber Cost Estimate Summary
NPPD Gerald Gentleman Units 1 and 2

Facility	Unit	SO2 Rate lb/mmBtu	Control %	SO2 Baseline tpy	SO2 Reduction tpy	Capital Cost	Annualized Capital Cost	Variable Operating Cost	Fixed Operating Cost	Total Annualized Cost	Cost Effectiveness $/ton
Gerald Gentleman	1	0.04	93.8	14,832	13,911	$281,946,000	$22,721,014	$6,267,556	$4,734,099	$33,722,669	$2,424
Gerald Gentleman	2	0.04	93.7	15,942	14,935	$286,179,000	$23,062,136	$6,708,822	$4,974,874	$34,745,833	$2,327
Gerald Gentleman	1	0.06	90.7	14,832	13,450	$281,946,000	$22,721,014	$6,195,212	$4,734,099	$33,650,326	$2,502
Gerald Gentleman	2	0.06	90.5	15,942	14,431	$286,179,000	$23,062,136	$6,630,811	$4,974,874	$34,667,822	$2,402

6 Comparison of DSI, SDA and Wet FGD Cost Model Results

This section compares the capital cost and cost effectiveness of the three technologies discussed in the TSD and earlier cost estimates made for the Nebraska Regional Haze BART SIP. Table 12 summarizes the costs for SDA, wet FGD and DSI using the IPM cost models.

Table 12. Capital cost and cost effectiveness of DSI, SDA and wet FGD for Gerald Gentleman

IPM Cost Analysis

Control Type	Facility	Unit	SO2 Rate lb/mmBtu	Control %	SO2 Baseline tpy	SO2 Reduction tpy	Capital Cost	Annualized Capital Cost	Variable Operating Cost	Fixed Operating Cost	Total Annualized Cost	Cost Effectiveness $/ton
Scrubber	Gerald Gentleman	1	0.060	90.7	14,832	13,450	264,026,000	21,276,906	$7,943,635	3,638,743	$32,859,284	2,443
	Gerald Gentleman	2	0.060	90.5	15,942	14,431	267,902,000	21,589,259	$8,492,800	3,830,525	$33,912,583	2,350
	Gerald Gentleman	1 & 2			30,774	27,881	531,928,000	42,866,164	16,436,435	7,469,268	66,771,867	2,395
Scrubber	Gerald Gentleman	1	0.060	90.7	14,832	13,450	281,946,000	22,721,014	6,195,212	4,734,099	33,650,326	2,502
	Gerald Gentleman	2	0.060	90.5	15,942	14,431	286,179,000	23,062,136	6,630,811	4,974,874	34,667,822	2,402
	Gerald Gentleman	1 & 2			30,774	27,881	568,125,000	45,783,150	12,826,024	9,708,974	68,318,148	2,450
	Gerald Gentleman	1	0.040	93.8	14,832	14,090	281,946,000	22,721,014	$6,267,556	4,734,099	$33,722,669	2,424
	Gerald Gentleman	2	0.040	93.7	15,942	15,145	286,179,000	23,062,136	$6,708,822	4,974,874	$34,745,833	2,327
	Gerald Gentleman	1 & 2			30,774	29,235	568,125,000	45,783,150	12,976,378	9,708,974	68,468,502	2,342
	Gerald Gentleman	1	0.322	50.0	14,832	7,416	14,405,000	1,160,847	14,356,274	339,736	15,856,857	2,138
	Gerald Gentleman	2	0.317	50.0	15,942	7,971	14,480,000	1,166,891	15,349,161	354,334	16,870,387	2,116
	Gerald Gentleman	1 & 2		50.0	30,774	15,387	28,885,000	2,327,738	29,705,435	694,070	32,727,243	2,127
	Gerald Gentleman	1	0.129	80.0	14,832	11,866	$18,303,000	$1,474,973	$23,883,079	$370,081	$25,728,133	$2,168
	Gerald Gentleman	2	0.127	80.0	15,942	12,754	$18,396,000	$1,482,467	$25,446,885	$386,099	$27,315,452	$2,142
	Gerald Gentleman	1 & 2		80.0	30,774	24,619	36,699,000	2,957,440	49,329,964	756,180	53,043,584	2,155
	Gerald Gentleman	1	0.064	90.0	14,832	13,349	19,824,000	1,597,545	29,320,048	381,931	31,299,524	2,345
	Gerald Gentleman	2	0.063	90.0	15,942	14,348	19,923,000	1,605,523	31,209,679	398,493	33,213,696	2,315
	Gerald Gentleman	1 & 2		90.0	30,774	27,697	39,747,000	3,203,068	60,529,728	780,424	64,513,220	2,329

d on 2012 dollars

The IPM model algorithms use 2012 dollars to estimate the cost of controls. We used the CEPCI, Chemical Engineering Plant Cost Index, to adjust costs to 2014 dollars. The 2014 index was the latest available when performing the cost estimates. Costs were not recalculated for 2015, but the 2015 index suggests costs would be approximately 3.4% lower than those estimated for 2014. See Table 13 for the 2014 adjusted control costs.

Table 13. 2014 Adjusted Cost of SO_2 Controls for Gerald Gentlemen

2016 IPM Cost Analysis

SO2 Control Type	Facility	Unit	SO2 Rate lb/mmBtu	Control %	Total Annualized Cost	Cost Effectiveness $/ton	CEPCI Escalation Adjustment	Years	Adjusted Annualized Cost	Adjusted Cost Effectiveness
SDA Scrubber	Gerald Gentleman	1	0.060	90.7	$32,859,284	2,443	-1.45%	2012-2014		
	Gerald Gentleman	2	0.060	90.5	$33,912,583	2,350				
	Gerald Gentleman	1 & 2			66,771,867	2,395			65,801,014	2,360
Wet Scrubber	Gerald Gentleman	1	0.060	90.7	33,650,326	2,502				
	Gerald Gentleman	2	0.060	90.5	34,667,822	2,402				
	Gerald Gentleman	1 & 2			68,318,148	2,450			67,324,812	2,415
	Gerald Gentleman	1	0.040	93.8	$33,722,669	2,424				
	Gerald Gentleman	2	0.040	93.7	$34,745,833	2,327				
	Gerald Gentleman	1 & 2			68,468,502	2,342			67,472,980	2,308
DSI	Gerald Gentleman	1	0.322	50.0	15,856,857	2,138				
	Gerald Gentleman	2	0.317	50.0	16,870,387	2,116				
	Gerald Gentleman	1 & 2		50.0	32,727,243	2,127			32,251,394	2,096
	Gerald Gentleman	1	0.129	80.0	$25,728,133	$2,168				
	Gerald Gentleman	2	0.127	80.0	$27,315,452	$2,142				
	Gerald Gentleman	1 & 2		80.0	53,043,584	2,155			52,272,338	2,123
	Gerald Gentleman	1	0.064	90.0	31,299,524	2,345				
	Gerald Gentleman	2	0.063	90.0	33,213,696	2,315				
	Gerald Gentleman	1 & 2		90.0	64,513,220	2,329			63,575,207	2,295

From 2012 to 2014, plant costs generally declined by 1.45%, so the costs estimated by the IPM model have been reduced accordingly.

The total annualized cost of wet FGD is approximately 2% higher than SDA and 5% higher than DSI. However, wet FGD delivers significant improvements in cost effectiveness as the tonnage of SO_2 removal increases due to the greater level of control (94% v. 91%) of wet FGD over SDA, which tends to offset the higher capital cost of wet FGD.

At a control rate of 0.06 lb/mmBtu, DSI, SDA and wet FGD are in the range of $2,300 to $2,500 per ton SO_2 removed. DSI is approximately $100 less, per ton SO_2 removed basis, than SDA and $150 less than wet FGD. Likewise, SDA is approximately $50 less than wet FGD. At a rate of 0.04 lb/mmBtu for the wet FGD, the additional 1,400 tons of SO_2 removed per year brings the cost effectiveness in line with a SDA at 0.06 lb/mmBtu. Since all three controls provide similar SO_2 reductions and comparable cost effectiveness at the RFP rate of 0.06 lb/mmBtu proposed in this action, NPPD Gerald Gentlemen will have the flexibility to implement whatever control they believe will result in the most cost effective SO_2 reductions.

The estimated costs from the IPM models shown in Tables 12 and 13 are contrasted with the SDA cost estimates made for the Nebraska Regional Haze BART SIP, shown in Table 14. The estimates are shown in both 2012 and 2014 adjusted dollars. For more information on the BART cost estimates, see Docket EPA-R07-OAR-2012-0158[26].

[26] Approval, Disapproval and Promulgation of Implementation Plans; Nebraska; Regional Haze State Implementation Plan; Federal Implementation Plan for Best Available Retrofit Technology Determination; https://www.regulations.gov/#!docketDetail;D=EPA-R07-OAR-2012-0158

Table 14. EPA's 2012 BART Action and Associated Costs of SO_2 Control

SO2 Control Type	Facility	Unit	SO2 Rate lb/mmBtu	SO2 Baseline tpy	SO2 Reduction tpy	Total Annualized Cost	Cost Effectiveness $/ton	CEPCI Escalation Adjustment	Years	Adjusted Annualized Cost	Adjusted Cost Effectiveness
NPPD's 2008 Cost Analysis											
SDA Scrubber	Gerald Gentleman	1 & 2	0.150	49,785	39,815	108,517,000	2,726	0.12%	2008-2014	108,649,016	2,729
Wet Scrubber	Gerald Gentleman	1 & 2	0.150		39,815	108,450,000	2,724			108,581,934	2,727
EPA BART Proposed Cost Analysis											
SDA Scrubber	Gerald Gentleman	1 & 2	0.150	49,785	39,815	60,315,000	2,726				
	Gerald Gentleman	1 & 2	0.150	31,513	23,147	53,480,426	2,310	0.12%	2008-2014	53,545,487	2,313
	Gerald Gentleman	1 & 2	0.110		25,202	54,323,062	2,156			54,389,148	2,159
	Gerald Gentleman	1 & 2	0.060		28,166	55,538,425	1,972			55,605,990	1,974
EPA BART Revised Final Cost Analysis											
SDA Scrubber	Gerald Gentleman	1 & 2	0.150	49,785	39,815	66,534,000	1,671	0.12%	2008-2014	66,614,942	1,673
	Gerald Gentleman	1 & 2	0.110		42,473	67,869,001	1,598			67,951,567	1,600
	Gerald Gentleman	1 & 2	0.060		45,797	69,537,937	1,518			69,622,533	1,520

The current IPM and earlier 2012 BART analyses compare closely on a total annualized cost basis. However, total cost effectiveness in the earlier analysis were lower because the SO_2 emission baselines used in the 2012 analysis were substantially higher (e.g. 31,513 and 49,785 tons) than baseline emissions used in the current IPM analysis (e.g. 30,774). The baseline used in the current IPM analysis closely approximates that used in EPA's BART proposal and is representative of how the Gerald Gentlemen units have operated over the last five years. Sensitivity runs using higher SO_2 emissions baselines result in little or no change to total annualized cost, but lower overall cost effectiveness because more emissions are being controlled.

7 Practical Feasibility of DSI Controls

As described earlier, we used the IPM tool to estimate costs for three levels of DSI; at 50%, 80% and 90% control. To determine whether any units are currently achieving the 0.06 lb/mmBtu rate achieved by 90% control, we looked at data from EPA's AMPD database.[27] We pulled monthly data, including heat input, SO_2 mass and associated SO_2 controls for all units in the U.S. We then calculated weighted SO_2 rates for each unit and used the type of SO_2 control to filter for units utilizing DSI. The results are shown in Table 15.

[27] http://ampd.epa.gov/ampd/

Table 15. SO_2 Rates for Units Utilizing DSI.

Stat	Facility Name	Unit	Unit Type	Fuel Type (Primary)	SO2 Control(s)	Year	Month	Heat Input (MMBtu)	SO2 (tons)	SO2 Rate	Weighted SO2 Rate
IL	Baldwin Energy Complex	3	Tangentially-fired	Coal	Dry Lime FGD & Dry Sorbent Injection	2014					0.0
IL	Baldwin Energy Complex	3	Tangentially-fired	Coal	Dry Lime FGD & Dry Sorbent Injection	2015					0.0
IL	Baldwin Energy Complex	3	Tangentially-fired	Coal	Dry Lime FGD & Dry Sorbent Injection	2016					0.0
IL	Kincaid Generating Station	1	Cyclone boiler	Coal	Dry Sorbent Injection	2014					0.0
IL	Kincaid Generating Station	1	Cyclone boiler	Coal	Dry Sorbent Injection	2015					0.0
IL	Kincaid Generating Station	1	Cyclone boiler	Coal	Dry Sorbent Injection	2016					0.0
IL	Kincaid Generating Station	2	Cyclone boiler	Coal	Dry Sorbent Injection	2014					0.0
IL	Kincaid Generating Station	2	Cyclone boiler	Coal	Dry Sorbent Injection	2015					0.0
IL	Kincaid Generating Station	2	Cyclone boiler	Coal	Dry Sorbent Injection	2016					0.0
IL	Powerton	61	Cyclone boiler	Coal	Dry Sorbent Injection	2014					0.3
IL	Powerton	61	Cyclone boiler	Coal	Dry Sorbent Injection	2015					0.3
IL	Powerton	61	Cyclone boiler	Coal	Dry Sorbent Injection	2016					0.3
IL	Powerton	62	Cyclone boiler	Coal	Dry Sorbent Injection	2014					0.3
IL	Powerton	62	Cyclone boiler	Coal	Dry Sorbent Injection	2015					0.3
IL	Powerton	62	Cyclone boiler	Coal	Dry Sorbent Injection	2016					0.3
IL	Waukegan	7	Tangentially-fired	Coal	Dry Sorbent Injection	2014					0.3
IL	Waukegan	7	Tangentially-fired	Coal	Dry Sorbent Injection	2015					0.2
IL	Waukegan	7	Tangentially-fired	Coal	Dry Sorbent Injection	2016					
IN	R Gallagher	2	Dry bottom wall-fired boiler	Coal	Dry Sorbent Injection	2014					0.7
IN	R Gallagher	2	Dry bottom wall-fired boiler	Coal	Dry Sorbent Injection	2015					0.7
IN	R Gallagher	4	Dry bottom wall-fired boiler	Coal	Dry Sorbent Injection	2014					0.7
IN	R Gallagher	4	Dry bottom wall-fired boiler	Coal	Dry Sorbent Injection	2015					0.7
MN	Boswell Energy Center	4	Tangentially-fired	Coal	Dry Sorbent Injection	2015					0.0
NC	NC Renewable Power - Lumberton LLC	UNIT1	Stoker	Coal	Dry Sorbent Injection	2014					
NC	NC Renewable Power - Lumberton LLC	UNIT1	Stoker	Coal, Wood	Dry Sorbent Injection	2015					0.0
OR	Boardman	1SG	Dry bottom wall-fired boiler	Coal	Dry Sorbent Injection	2014					0.4
OR	Boardman	1SG	Dry bottom wall-fired boiler	Coal	Dry Sorbent Injection	2015					0.3
WI	J P Madgett	B1	Dry bottom turbo-fired boiler	Coal	Dry Sorbent Injection	2014					0.3
WI	J P Madgett	B1	Dry bottom turbo-fired boiler	Coal	Dry Sorbent Injection	2015					0.0
WI	J P Madgett	B1	Dry bottom turbo-fired boiler	Coal	Dry Sorbent Injection	2016					0.0

AMPD indicates 11 units currently employ some form of DSI. Six units meet an SO_2 weighted rate of 0.10 lb/mmBtu or less, with two that achieve less than 0.05 lb/mmBtu. Upon further examination, three of the six units (e.g. Baldwin, Boswell and NC Renewable Power) utilize DSI in conjunction with other SO_2 controls, including co-control with wet scrubbers and or reduced-sulfur fuels like wood, including the two units with very low SO_2 rates. This leaves three units (e.g. Kincaid 1 and 2 and JP Madgett) that achieve SO_2 rates in the range of 0.08 to 0.09 lb/mmBtu using DSI. The Kincaid and JP Madgett units are Consent Decree units under EPA's National Power Plant Enforcement Initiative[28] and are required to meet a rate of 0.10 and 0.09 lb/mmBtu, starting in 2014 and 2015, respectively.

Because no units currently meet the 0.06 lb/mmBtu rate proposed in today's action, with the use of DSI alone, EPA is unable to say that DSI will achieve similar control to SDA and wet FGD at the NPPD Gerald Gentleman units. Nevertheless, we do not foreclose NPPD from using DSI to meet the 0.06 lb/mmBtu rate if site specific engineering allows. As described earlier, the IPM Model predicts DSI costs at 90% control are competitive with SDA and wet FGD, and therefore DSI may be used if the required reductions and associated SO_2 compliance rate can be achieved.

[28] https://www.epa.gov/enforcement/coal-fired-power-plant-enforcement

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6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA-R07-OAR-2017-0039; FRL-_____ Region 7]

Approval and Promulgation of Air Quality Implementation Plans; Nebraska Regional Haze Federal Implementation Plan; Reconsideration

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing to revise portions of the Nebraska Regional Haze Federal Implementation Plan (FIP) applicable to the Gerald Gentleman Station, owned and operated by the Nebraska Public Power District (NPPD). In 2012, EPA finalized a partial approval/partial disapproval of Nebraska's State Implementation Plan (SIP) that addressed regional haze for the first implementation period and finalized a FIP addressing the deficiencies in Nebraska's plan. EPA's final action was challenged in the United States Court of Appeals for the 8th Circuit. In the litigation, EPA requested and was granted a remand related to EPA's reliance on the Cross-State Air Pollution Rule (CSAPR) to satisfy the deficiencies in Nebraska's

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regional haze plan related to the long-term strategy (LTS) requirements at the Gerald Gentleman Station for sulfur dioxide (SO_2). Upon remand, EPA has re-evaluated our record and basis for the original FIP. In this action, EPA is proposing a revised FIP that will limit SO_2 emissions at the Gerald Gentleman Station. EPA believes that SO_2 emission reductions are needed to make reasonable progress toward Congress' natural-visibility goal at Class I areas affected by visibility-impairing emissions from Nebraska. This proposal addresses only the remanded portion of the Nebraska FIP.

DATES: Comments must be received on or before **[INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. Requests for a public hearing and inquiries regarding the status of the public hearing should be made to Amy Algoe-Eakin using the contact information provided below or they may consult the following link: http://www.epa.gov/region7/public notices/.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA-R07-OAR-2017-0039, to http://www.regulations.gov. Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from Regulations.gov. EPA may publish any comment received to our public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information

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whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. EPA will generally not consider comments or comment contents located outside of the primary submission (i.e., on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit http://www2.epa.gov/dockets/commenting-epa-dockets..

FOR FURTHER INFORMATION CONTACT: Amy Algoe-Eakin, Environmental Protection Agency, Air Planning and Development Branch, 11201 Renner Boulevard, Lenexa, Kansas 66219 at 913-551-7942, or by email at algoe-eakin.amy@epa.gov.

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SUPPLEMENTARY INFORMATION: Throughout this document "we," "us," or "our" refer to EPA. This section provides additional information by addressing the following:

I. What is Being Addressed in this Document?
II. What Action is EPA Taking?
III. Background
A. *Summary of Statutory and Regulatory Requirements of the Regional Haze Rule*
B. *Summary of 40 CFR 51.308(d)(1) and (d)(3)*
C. *History of the Nebraska Long-Term Strategy FIP Determination*
IV. EPA's Reconsideration of Long-Term Strategy for SO_2 at the Gerald Gentlemen Station
A. *Approach to Reasonable Progress and Long-Term Strategy*
1. Factor 1 - The Costs of Compliance
a. EPA's Evaluation of Costs in the 2012 Proposed and Final Rule
b. EPA's Updated Cost Evaluation
2. Factor 2 - The Time Necessary for Compliance
3. Factor 3 - The Energy and Non-Air Quality Environmental Impacts of Compliance
4. Factor 4 - The Remaining Useful Life of the Source
Regarding the analysis of remaining useful life, the BART Guidelines advise:
B. *Proposed Long-Term Strategy Determinations for Gerald Gentleman Station*
V. Statutory and Executive Order Reviews

I. What is Being Addressed in this Document?

EPA is addressing the portion of the Nebraska Regional Haze FIP[1] that was remanded by the 8th Circuit upon motion by EPA. EPA is proposing a new FIP provision to address the long-term strategy requirements of the Regional Haze Rule for SO_2 at the Gerald Gentleman Station. This is the only aspect of the FIP on

[1] 77 FR 40149 (July 6, 2012).

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which we are requesting comment. EPA is not reopening our prior partial approval and disapproval of Nebraska's Regional Haze SIP, nor is EPA soliciting comment on our previous analysis of the Nebraska SIP.

II. What Action is EPA Taking?

EPA has reviewed our record on the previous action, undertaken an analysis of the long-term strategy requirements in the FIP for Nebraska in accordance with the Regional Haze Rule and is proposing an SO_2 emission limit of 0.060 lb/mmBtu calculated on a 30-boiler operating day average rate, for each unit at the Gerald Gentleman Station. EPA believes that this SO_2 emission rate is necessary to make reasonable progress at Class 1 areas affected by sources in Nebraska and will help to achieve natural visibility conditions.

III. Background

A. Summary of Statutory and Regulatory Requirements of the Regional Haze Rule

Congress created a program for protecting visibility in the nation's national parks and wilderness areas in section 169A of the 1977 Amendments to the Clean Air Act (CAA). This section of the CAA establishes as a national goal the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment

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results from man-made air pollution."[2] It also directs states to evaluate the use of retrofit controls at certain larger, often uncontrolled, older stationary sources in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the CAA requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress towards the natural visibility goal, including a requirement that certain categories of existing major stationary sources built between 1962 and 1977 procure, install, and operate best available retrofit technology (BART) controls. These sources are referred to as "BART-eligible" sources.[3] In addition, the CAA requires states to adopt long-term strategies for making reasonable progress towards remedying visibility impairment. In the 1990 CAA Amendments, Congress amended the visibility provisions in the CAA to focus attention on the problem of regional haze, which is visibility impairment produced by a multitude of sources and activities located across a broad geographic area.[4]

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[2] CAA section 169A(a)(1); 42 U.S.C. 7941(a)(1).
[3] 40 CFR 51.301.
[4] See CAA section 169B, 42 U.S.C. 7492.

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We promulgated the Regional Haze Rule in 1999, which requires states to develop and implement SIPs to ensure reasonable progress toward improving visibility in mandatory Class I Federal areas[5] by reducing emissions that cause or contribute to regional haze.[6] Under the Regional Haze Rule, states are directed to conduct BART determinations for BART-eligible sources that may be anticipated to cause or contribute to visibility in a Class I area[7] and to develop long-term strategies to address regional haze.

The Regional Haze Rule provides that the long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures necessary to achieve the reasonable progress goals established by states having mandatory Class I areas.[8] There are a number of requirements a state must meet when establishing their long-term strategy, including the following: (1) states must consult with downwind states to develop coordinated management strategies that address regional haze visibility;[9] (2) where multiple states cause or contribute

[5] Areas designated as mandatory Class I Federal areas consist of national parks exceeding 6000 acres, wilderness areas, and national memorial parks exceeding 5000 acres, and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). When we use the term "Class I area" in this action, we mean a "mandatory Class I Federal area."
[6] See generally 40 CFR 51.308.
[7] 40 CFR 51.308(e).
[8] 40 CFR 51.308(d)(3).
[9] 40 CFR 51.308(d)(3)(i).

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to visibility impairment in a Class I area, each state must demonstrate that it has included in their SIP all measures necessary to obtain their share of emissions reductions needed to meet the progress goal for the Class I area;[10] and (3) each state must provide and document the technical basis on which the state is relying to determine their share of emissions reductions necessary to achieve reasonable progress for the Class I area it affects.[11]

The Regional Haze Rule requires that where a state has emissions that are reasonably anticipated to contribute to visibility impairment in any mandatory Class I area located in another state or states, it must consult with the other state(s) to develop coordinated emissions management strategies.[12] The Regional Haze Rule requires that the state document the technical basis including modeling, monitoring, and emissions information, on which it is relying to determine their apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I area it affects.[13]

[10] 40 CFR 51.308(d)(3)(ii).
[11] 40 CFR 51.308(d)(3)(iii)-(iv).
[12] 40 CFR 51.308(d)(3)(i).
[13] 40 CFR 51.308(d)(3)(iii).

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In addition to enacting section 169A, Congress also amended section 110 of the CAA to require that all SIPs "contain adequate provisions prohibiting ... any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will ... interfere with measures required to be included in the applicable implementation plan for any other State ... to protect visibility."[14] A Senate Committee Report described this provision and similar requirements as being "intended to equalize the positions of the States with respect to interstate pollution by making a source at least as responsible for polluting another State as it would be for polluting its own State."[15]

A full background of the Regional Haze Rule can be found in our 2012 final action as well as in other regional haze actions.[16] [17]

B. Summary of 40 CFR 51.308(d)(1) and (d)(3)

Section 51.308(d)(1) of the Regional Haze Rule requires states with Class I areas to "establish goals (expressed in deciviews) that provide for reasonable progress towards

[14] CAA Section 110(a)(2)(D)(i)(II).
[15] S. Rep. No. 95–127, at 41 (1977).
[16] 79 FR 74818 (February 16, 2014).
[17] EPA recently published revisions to the Regional Haze Rule. *See* EPA-HQ-OAR-2015-0531 (December 14, 2016) The revisions do not substantively affect 40 CFR 51.308(d) which applied to our original action and applies to this reconsideration.

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achieving natural visibility conditions."[18] In establishing a reasonable progress goal (RPG), a state must consider the four statutory factors outlined in section 169A(g)(1) of the CAA—"the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources."[19] This requirement is commonly referred to as a four-factor analysis. States analyze the four factors to determine a reasonable set of control measures that will reduce visibility impairing emissions. The visibility improvement that will result from these emission reductions is then factored into the state's reasonable progress goals.

In addition to conducting a four-factor analysis to determine what control measures are reasonable for a state's own sources, the state with a Class I area or areas, i.e., a downwind state, "must consult with those States which may reasonably be anticipated to cause or contribute to visibility impairment in the mandatory Class I Federal area,"[20] i.e., an upwind states. The purpose of the consultation requirement is to ensure that the upwind states that affect visibility in a Class I area adopt control measures sufficient to address their

[18] 40 CFR 51.308(d)(1).
[19] Id. 51.308(d)(1)(i)(A).
[20] Id. n 51.308(d)(1)(iv).

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apportionment of emission reductions necessary to achieve reasonable progress and that the downwind state's reasonable progress goals properly account for the visibility improvement that will result from the reasonable control measures identified and included in the upwind states' long-term strategies. Where a downwind state and an upwind state cannot agree on the proper apportionment of emission reductions necessary to achieve reasonable progress, the downwind state "must describe in its [SIP] submittal the actions taken to resolve the disagreement."[21]

Section 51.308(d)(3) of the Regional Haze Rule requires all states (both downwind and upwind) to "submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the State which may be affected by emissions from the State."[22] As explained in other actions, a state's long-term strategy is inextricably linked to the reasonable progress goals because the long-term strategy "must include enforceable emission limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals established by states having mandatory Class I Federal areas."[23] In

[21] Id.
[22] Id. 51.308(d)(3).
[23] Id.

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establishing their long-term strategy, a state must meet a number of requirements, three of which pertain to visibility transport. First, as a corollary to section 51.308(d)(1)(iv), upwind states "must consult with [downwind] State(s) in order to develop coordinated management strategies."[24] Second, where multiple states cause or contribute to visibility impairment in a Class I area, each state must demonstrate that it has included in their implementation plan "all measures necessary to obtain its share of the emission reductions needed to meet the progress goal for the area."[25] This requirement directly addresses situations where an upwind state agrees to achieve certain emission reductions during the consultation process, and downwind states rely upon those reductions when setting their reasonable progress goals, but the upwind state ultimately fails to include sufficient control measures in their long-term strategy to ensure that the emission reductions will be achieved. Finally, each state "must document the technical basis, including modeling, monitoring and emissions information, on which the State is relying to determine its apportionment of emission reduction obligations necessary for achieving

[24] Id. 51.308(d)(3)(i).

[25] Id. 51.308(d)(3)(ii). Similarly, ''[i]f the State has participated in a regional planning process, the State must ensure it has included all measures needed to achieve its apportionment of emission reduction obligations agreed upon through that process.'' Id.

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reasonable progress in each mandatory Class I Federal area it affects."[26] To reiterate, section 169A(g)(1) of the CAA requires states to determine "reasonable progress" by considering the four statutory factors.[27] Therefore, this provision requires states to consider both their own Class I areas and downwind Class I areas when they develop the technical basis underlying their four-factor analyses. This documentation is necessary so that the interstate consultation process can proceed on an informed basis and so that downwind states can properly assess whether any additional upwind emission reductions are necessary to achieve reasonable progress at their Class I areas. The regulations further provide that, "States may meet this requirement by relying on technical analyses developed by the regional planning organization and approved by all State participants."[28] Thus, states have the option of meeting this requirement by relying on the four-factor analyses and associated technical documentation prepared by a regional planning organization on behalf of their member states,[29] to the extent that such analyses and documentation were conducted. In

[26] Id. 51.308(d)(3)(iii).
[27] 42 U.S.C. Section 7491(g)(1).
[28] 40 CFR 51.308(d)(3)(iii).
[29] See *WildEarth Guardians v. EPA*, 2014 U.S. App. LEXIS 20145, at *55 (10th Cir. October 21, 2014) (explaining that 40 CFR 51.308(d)(3)(iii) ''permits a State conducting a reasonable-progress determination'' ''to rely on [a regional planning organization's] four-factor analysis.'').

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situations where a regional planning organization's analyses are limited, incomplete or do not adequately assess the four factors, however, then states must fill in any remaining gaps to meet this requirement.

C. History of the Nebraska Long-Term Strategy FIP Determination

On July 6, 2012, EPA took final action on Nebraska's Regional Haze SIP for the first planning period.[30] In that final action, EPA partially approved and partially disapproved the state's SIP. EPA disapproved the state's SO_2 BART determinations for Gerald Gentleman Station Units 1 and 2 and the state's long-term strategy, which had relied on the state's flawed BART determinations. The reasons for EPA's disapproval are outlined in both the proposed rule and the final rule.[31] In the same action, EPA also promulgated a FIP to address the deficiencies in Nebraska's Regional Haze Plan. For those deficiencies associated with the state's SO_2 control decisions for Gerald Gentleman Station Units 1 and 2, EPA relied on CSAPR to meet both the BART and long-term strategy requirements.[32] Specifically, EPA relied on our finding in a separate national

[30] 77 FR 40149.
[31] See 77 FR 12770 (March 2, 2012) (proposed rule); 77 FR 40149 (July 6, 2012) (final rule).
[32] The Eighth Circuit upheld EPA's SIP disapproval and BART FIP. Nebraska v. EPA, 812 F.3d 662 (8th Cir. 2016).

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rulemaking that found that CSAPR provides for greater reasonable progress on average across all affected Class I areas than source-specific BART in those states covered by CSAPR (the "Better than BART Rule").[33] In that separate rulemaking, EPA revised our regulations to provide that states could choose to rely on CSAPR as an alternative to BART. Consistent with this regulatory provision, EPA relied in our FIP on CSAPR as an alternative to BART for SO_2 emissions from the Gerald Gentleman Station. In addition, EPA concluded in our FIP that reliance on CSAPR would remedy the deficiency in Nebraska's long-term strategy associated with the state's reliance on their faulty SO_2 BART analysis for the Gerald Gentleman Station.

Subsequently, Sierra Club, the NPCA, the State of Nebraska, and NPPD filed petitions for review challenging EPA's final action in the Eighth Circuit Court of Appeals.[34] In response to arguments raised by the Sierra Club and NPCA during briefing on the petitions, EPA moved for a voluntary remand without vacatur of the long-term strategy FIP for Nebraska as it related to SO_2 for the Gerald Gentleman Station.[35] EPA explained in the motion

[33] 77 FR 33642.
[34] NPPD dismissed their petition voluntarily, but remained as an intervenor in the other petitions. See Order, Neb. Pub. Power Dist. v. EPA, No. 12-3061 (8th Cir. November 4, 2014).
[35] EPA's Motion for Partial Voluntary Remand, *Nebraska. v. EPA*, 812 F.3d 662 (8th Cir. 2015) (No.12-3084).

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that the agency's rationale for declining to require additional SO_2 controls at the Gerald Gentleman Station as part of the long-term strategy was not fully or clearly explained. EPA also stated that the explanation in the record could potentially be construed in a manner that is inconsistent with EPA's interpretation of the relevant statutory and legal requirements. As a result, EPA determined that a remand was appropriate to afford the agency an opportunity to amend or further explain our rationale for declining to require additional SO_2 controls beyond CSAPR to address the long-term strategy, more fully respond to comments submitted by the public, or to take further action if necessary.

IV. EPA's Reconsideration of Long-Term Strategy for SO_2 at the Gerald Gentlemen Station

In this action, EPA is proposing to act on the remanded portion of our FIP as it relates to long-term strategy requirements for SO_2 for the Gerald Gentleman Station. Upon reconsideration, EPA is proposing that our record for the original action is incomplete and that the complete record we have created in this action indicates that a different action is appropriate. In EPA's final action, EPA relied on the implementation of the previously adopted CSAPR FIP for all Nebraska EGUs to satisfy the long-term strategy requirements of

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the Regional Haze Rule for SO_2, including for the Gerald Gentleman Station. At the time of the final action, EPA did not further evaluate whether, with respect to the Gerald Gentleman Station, CSAPR was an appropriate and sufficient measure needed for reasonable progress towards natural visibility conditions at the Badlands, Wind Cave, and Rocky Mountain National Parks. The environmental petitioners pointed out this deficiency in their briefing challenging EPA's final action. EPA is now clarifying the record in accordance with the Regional Haze Rule.

Nebraska participated in the Central Regional Air Planning Association (CENRAP), and incorporated the CENRAP-developed visibility modeling into their regional haze SIP. The SIP relied on the CENRAP modeling, which assumed SO_2 controls at a rate of 0.15 lb/mmBtu at Gerald Gentleman Station[36]. Nebraska consulted with both South Dakota and Colorado during the first planning period. As explained in our prior action on the Nebraska regional haze SIP, source-specific CALPUFF modeling shows a significant visibility impact from Gerald Gentleman Station on South Dakota's Class I areas, Wind Cave and Badlands National Parks.[37] The Colorado Department of Public Health and the

[36] For comparison, the SO_2 emission rate at Gerald Gentleman Station was about 0.58 lb/mmBtu during 2002, which was the period used as the baseline by Nebraska when it developed its SIP and is about 0.57 lb/mmBtu in 2015. The proposed FIP emission limit is 0.060 lb/mmBtu.
[37] 77 FR at 12776.

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Environment also commented on Nebraska's regional haze SIP, requesting that the state reconsider the question of whether the Gerald Gentleman Station should install SO_2 controls, given Gerald Gentleman Station's impacts on Rocky Mountain National Park[38]. Based on their BART determination, Nebraska did not require BART-level controls at Gerald Gentleman Station as part of their long-term strategy in their regional haze SIP.

Nebraska used CENRAP CAMx photochemical source apportionment modeling to identify the pollutants (e.g., sulfates, nitrates) and source categories (e.g., elevated point EGUs) that most impact visibility at Class I areas located in surrounding states. A summary of the annual emissions used for Nebraska elevated point sources and Gerald Gentleman Station in the 2002 base year and 2018 future year CENRAP modeling is shown in table 1 of the Technical Support Document for this action.

The 2018 CENRAP modeling included an SO_2 control rate of 0.15 lb/mmBtu at Gerald Gentleman Station. The modeling showed combined Gerald Gentleman Station Units 1 and 2 SO_2 emissions decreasing from 32,152 ton per year (tpy) in 2002 to 8,732 tpy in 2018 (with controls to achieve the 0.15 lb/mmBtu SO_2 emission limit assumed to be in operation in 2018). This reduction of

[38] 77 FR 12776-12777.

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modeled SO_2 emissions at Gerald Gentleman Station helps lower the projected SO_2-caused light extinction at Badlands National Park contributed by Nebraska elevated point sources from 0.98 MM^{-1} in 2002 to 0.47 MM^{-1} in 2018. The decrease in the SO_2 extinction at Badlands National Park from Nebraska elevated point sources is due to the decrease in modeled emissions from 2002 to 2018, and in particular the decrease in modeled SO_2 emissions at Gerald Gentleman Station due to the assumption of the achievement of a 0.15 lb/mmBtu emission rate in 2018.

In 2012, EPA evaluated Nebraska's SIP and determined that Nebraska's SIP, among other things, did not appropriately address the long-term strategy requirements of the Regional Haze Rule related to Gerald Gentleman Station. Although there were modeled visibility impacts and improvements from the installation of cost-effective controls at Gerald Gentleman Station at Class I areas, Nebraska did not require any reduction in SO_2 emissions from Gerald Gentleman Station. EPA partially disapproved Nebraska's long-term strategy based on the state's deficient SO_2 control determination for Gerald Gentleman Station. EPA promulgated a FIP in which we relied on CSAPR to address this deficiency in Nebraska's SIP. Based on the modeling done by CENRAP, EPA knew at the time that Gerald Gentleman Station contributed to visibility impairment at the Wind Cave and

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Badlands National Parks in South Dakota and at Rocky Mountain National Park in Colorado, and that cost-reasonable controls were available, but EPA did not evaluate whether additional controls beyond CSAPR at Gerald Gentleman Station were required to ensure reasonable progress. As a result, the record for our FIP was incomplete.

In order to properly evaluate whether CSAPR was sufficient to satisfy Nebraska's obligation to address the visibility impacts of their emissions at the Class I areas it affects, EPA has reviewed the record from the proposed and final actions. EPA has found that the reductions expected (and now observed) from the implementation of CSAPR do not equate to the reductions presumed by the CENRAP modeling that were found to be achievable at a reasonable cost by both Nebraska and EPA. Moreover, we are proposing to conclude that the CSAPR budgets for Nebraska are inadequate to ensure reasonable progress at neighboring Class I areas.

EPA's determination in 2012 that CSAPR provides for greater reasonable progress than BART was based on an assessment that CSAPR would provide for greater visibility improvement, on average, across all affected Class I areas.[39] In our assessment

[39] 77 FR 33642 (June 7, 2012).

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of the relative impacts of CSAPR and BART on visibility, EPA considered separately the average visibility improvement across the 60 Class I areas in the eastern portion of the CSAPR modeling domain and the average impact across all 140 Class I areas in the 48 contiguous states with sufficiently complete monitoring data to support our analysis.[40] In both cases, the Agency concluded that CSAPR would provide for greater reasonable progress than BART on a regional basis. Both assessments showed, however, that BART would provide for greater visibility improvement than CSAPR in a number of Class I areas west of the Mississippi River but east of the Rocky Mountains, including at the Wind Cave and Badlands National Parks in South Dakota.[41] As EPA has explained in the past, the fact that an alternative to BART would provide for greater reasonable progress on average across a number of Class I areas does not mean that the alternative satisfies all reasonable progress requirements.[42]

The CSAPR budget for Nebraska resulted in some emission reductions of SO_2 for the state of Nebraska, but did not result in significant SO_2 emission reductions at Gerald Gentleman Station. In assessing the impacts of CSAPR on SO_2 emissions from

[40] 76 FR 82219, 82225-82227(December 30, 2011).
[41] 77 FR at 33650; TSD for CSPAR > BART found at https://www.regulations.gov/document?D=EPA-HQ-OAR-2011-0729-0014
[42] 70 FR. 39104, 39143-144 (July 6, 2005).

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Nebraska, EPA estimated that CSAPR would result in a overall 1,900 ton reduction in SO_2 emissions as compared to the state's 2014 base case emissions. Further, CSAPR did not drive significant SO_2 reductions at the Gerald Gentleman Station. Given the scale of reductions required by CSAPR in Nebraska coupled with the history outlined above regarding Nebraska's consultation with neighboring states, EPA is proposing to conclude that it is inappropriate to rely on CSAPR to ensure reasonable progress without further consideration of appropriate SO_2 control measures for Gerald Gentleman Station.

Because in our previous final action, EPA did not conduct a four-factor analysis as required by the Regional Haze Rule, in this action, EPA has undertaken a four-factor analysis to assure that we appropriately consider whether additional emission reduction measures are necessary at the Gerald Gentleman Station to fulfill the long-term strategy requirements of the Regional Haze Rule.

A. Approach to Reasonable Progress and Long-Term Strategy

To complete the reasonable progress four-factor analysis EPA must look at the following: the costs of compliance; the time necessary for compliance; the energy and non-air environmental impacts of compliance; and the remaining useful

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life of any potentially affected sources.[43] Our Reasonable Progress Guidance[44] notes the similarity between some of the reasonable progress factors and the BART factors contained in 40 CFR § 51.308(e)(1)(ii)(A), and suggests that the BART Guidelines be consulted regarding cost, energy and non-air quality environmental impacts, and remaining useful life. We are therefore relying on our BART Guidelines for assistance in quantifying and considering those reasonable progress factors, as applicable.

Each of the elements of the four-factor analysis is discussed below.

1. Factor 1 - The Costs of Compliance

a. EPA's Evaluation of Costs in the 2012 Proposed and Final Rule

In the 2012 proposed and final action, EPA and Nebraska evaluated the cost of installation of wet FGD on Gerald Gentleman Station. Nebraska, in their SIP, concluded that these costs were reasonable on a cost per ton basis for both units combined ($2,726/ton). Nebraska also evaluated controls at Gerald Gentleman Station on a dollars per deciview basis.[45]

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[43] 40 CFR 51.308(d)(1)(i).

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

[45] As explained in the final action in 2012, the BART Guidelines require the costs of controls to be evaluated on a dollar per ton basis. In their BART determinations, Nebraska used a threshold of $40 million/dv/year; in their review

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Nebraska determined that while costs on a dollar per ton basis were reasonable, costs on a dollar per deciview basis were not reasonable.[46] Nebraska also saw water consumption of wet flue-gas desulfurization (FGD) controls as significant and concluded that because of this unique situation, wet FGD controls were unreasonable for Gerald Gentleman Station Units 1 and 2.[47]

EPA agreed with Nebraska that the cost per ton for FGD was reasonable and that Nebraska's analysis showed significant visibility improvement both at Badlands National Park and on a cumulative basis.[48] EPA also found that Nebraska inappropriately ruled out dry sorbent injection (DSI), because EPA found that costs were reasonable and visibility improvement was significant.[49]

EPA also found that Nebraska made several errors in determining the cost of controls.[50] EPA determined that Nebraska made incorrect assumptions about Gerald Gentleman Station's SO_2 emissions and the capability of certain controls. Nebraska also

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of the BART analysis for GGS, EPA concluded that Nebraska had overestimated the cost of control and underestimated the control efficiency of scrubbers and ignored the cumulative visibility impacts of controls at GGS. If Nebraska had appropriately estimated the cost of control and considered cumulative benefits, scrubbers would have been found to be cost effective on a dollars per deciview basis under the threshold set by Nebraska. See 77 FR 40157.

[46] 77 FR 12770 at 12779.

[47] Id.

[48] 77 FR 12770 at 12780.

[49] Id.

[50] Id.

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deviated from EPA's Cost Control Manual when evaluating costs.[51] EPA did our own evaluation in accordance with the Cost Control Manual and found that the cost per ton of SO_2 controls ranged from $1,972 to $2,310 for each Gerald Gentleman Station unit.[52] EPA determined that the costs for control were reasonable and visibility improvement was significant and disapproved Nebraska's SIP.[53] EPA's disapproval of Nebraska's SO_2 BART determination for Gerald Gentleman Station was upheld by the 8th Circuit and we are not reconsidering that decision in this proposed rulemaking.[54]

b. EPA's Updated Cost Evaluation

In this action, EPA has again evaluated the feasibility and costs of installing several types of SO_2 control systems at Gerald Gentleman Station.[55] Specifically, EPA has analyzed costs for DSI, spray dry absorber (SDA), and wet FGD. We have looked at each of these control technologies at various control rates to determine which rate/control scenarios are cost effective. EPA proposes to determine that spray dry absorber to meet an

[51] Id.
[52] Id. This analysis and determination were conducted consistent with previous actions where cost of control analyses were submitted with deviations from the Control Cost Manual. 77 FR 12770 (March 2, 2012); 77 FR 40149 (July 6, 2012); 79 FR 74817 (December 26, 2014); 81 FR 295 (Janaury 5, 2016).
[53] Id.; 77 FR 40149.
[54] State of Nebraska v. EPA, 812 F.3d 662 (8th Cir. 2015).
[55] EPA has included in the record for this action documents submitted by NPPD pursuant to the CAA Section 114 request that have not been claimed as Confidential Business Information (CBI) by NPPD.

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emission limit of 0.060 lb/mmBtu are feasible at Gerald Gentleman Station and will have a cost per ton that is reasonable.[56] As explained below, EPA is proposing that a FIP emission limit of 0.060 lb/mmBtu, which is based on dry scrubbing, is necessary to make reasonable progress and will fill the gap resulting from our previous disapproval of the reasonable progress element of Nebraska's regional haze plan. This emission limit can also be met cost-effectively with wet FGD, and the owners of Gerald Gentleman Station could use wet FGD to meet a final FIP emission limit of 0.060 lb/mmBtu if EPA finalizes that limit. EPA is also proposing to conclude that an emission limit of 0.040 lb/mmBtu could be cost-effectively met with wet FGD. However, we are not proposing that an emission limit of 0.040 lb/mmBtu is necessary to make reasonable progress, because of its higher water requirements. EPA is not relying on the possible use of wet FGD to support the proposed 0.060 lb/mmBtu BART emission limit. While EPA has also investigated DSI, we are not proposing to rely on any conclusions about the cost or effectiveness of DSI. The owners of Gerald Gentleman Station may or may not be able to use DSI to meet the proposed FIP emission limit.

[56] EPA has included in the record for this action documents submitted by NPPD pursuant to the CAA Section 114 request that have not been claimed as Confidential Business Information (CBI) by NPPD.

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EPA used cost methodologies used in the IPM model, Version 5.13. These methodologies are described in detail in appendix A of the TSD, available in the docket of this proposed action.[57]

EPA evaluated the cost of DSI at Gerald Gentleman Station Units 1 and 2 using control efficiency rates of 50, 80, and 90 percent.[58] Units 1 and 2 do not differ with respect to any design feature that affects the estimated cost of DSI. EPA is proposing to find that the cost of DSI would be $2,138/ton; $2,168/ton and $2,315/ton, respectively, for these levels of control. We are proposing to conclude that each control scenario using DSI is cost effective.

EPA has also evaluated the cost of dry scrubbers using a control efficiency rate of just under 91 percent at Gerald Gentleman Station Units 1 and 2, corresponding to an emission rate of 0.060 lb/mmBtu. EPA analyzed the cost of dry scrubbers using this removal rate and emission limit because the lowest available SO_2 emission guarantees from original equipment manufacturers of SDA systems are 0.060 lb/mmBtu. EPA is proposing

[57] The use of the IPM cost model is consistent with other EPA Regional Haze actions and is based on reliable and accurate technical tools widely utilized by EPA to asses control scenarios at electric generating units and other large sources.

[58] The 50 percent rate for DSI was selected based on known operating performance of installed DSI systems. The 80 percent rate for DSI was selected based on the use of milled trona along with a baghouse. Both GGS units have baghouses installed. EPA included the higher rate (90%) for comparison to other SO_2 control technologies. As discussed in more detail in the Cost TSD, a 90% removal efficiency for a DSI system alone has not been demonstrated at any currently operating DSI system.

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to find that the cost of dry scrubbing to meet this emission limit is cost effective for both units, at $2,443/ton for Unit 1 and $2,350/ton for Unit 2. The cost of a baghouse to collect the particles from the operation of the dry scrubbers was not included in our cost estimate because Gerald Gentleman Station currently operates a baghouse on both units. EPA invites comment on the feasibility and cost-effectiveness of a higher control efficiency, and lower emission rate, using dry scrubbing at Gerald Gentleman, supported by evidence.

Finally, EPA has evaluated the cost of a wet scrubber at Gerald Gentleman Station Units 1 and 2. EPA used control efficiencies of 91 percent and 94 percent corresponding to emission rates of 0.060 and 0.040 lb/mmBtu, respectively.[59] EPA is proposing to determine that wet scrubber controls are cost effective at both units and both control efficiencies. EPA is proposing to find the costs to be $2,424/ton and $2,327/ton at 94 percent control efficiency at Units 1 and 2, respectively.

[59] EPA analyzed the cost of wet scrubbers based on limits of 0.040 and at 0.060 lb/mmBtu. The first analysis at 0.040 lb/mmBtu evaluates wet FGD which is the lowest rate that vendors of the technology will guarantee. The IPM presumptive control model uses a removal efficiency of 98 percent. Because a 98 percent removal efficiency results in SO_2 rates less than 0.040 lb/mmBtu for the Gerald Gentleman Station units, we limited the control efficiency in the cost algorithm to just under 94 percent to assure that NPPD can obtain a performance guarantee for the wet scrubber. The second analysis allows direct comparison to SDA at similar reduction efficiencies of just under 91 percent.

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EPA is proposing to find the costs to be $2,502/ton and $2,402/ton at 91 percent control efficiency at Units 1 and 2, respectively.

Based on our cost assessment, EPA is proposing to conclude that NPPD can meet an SO_2 emission limit of 0.060 lb/mmBtu with cost effective controls.

The remaining useful life affects the cost effectiveness estimates for the control technologies. As discussed in more detail in appendix A of the TSD, available in the docket of this proposal, and in section IV.A.4. below, EPA has used 30 years as the remaining useful life of the units and any new controls installed on them. EPA believes that even if the remaining useful life of the units is as short as 20 years, the proposed control rate and associated control technologies are still cost effective.

2. Factor 2 - The Time Necessary for Compliance

EPA believes five years is the appropriate time period for installation of wet FGD or SDA except where there are unusual circumstances. In response to a section 114 information request, NPPD submitted several documents that demonstrate that between 2009 and 2014 NPPD considered installing wet FGD controls on

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Gerald Gentleman Station Units 1 and 2[60]. The engineering documents and requests for bids from this process included a timeline of five years from design to completion. EPA believes this is an appropriate timeframe for installation of wet FGD controls at Gerald Gentleman Station. We believe that SDA could be installed within the same timeframe. DSI may be able to be installed in a time frame of two to three years.

Due to the timing of this action, it is highly unlikely that the SO_2 controls that EPA is proposing will be installed and operational within the first planning period, which ends in 2018. Therefore, we request that Nebraska consider the visibility improvements anticipated from any necessary FIP controls implemented after 2018 when the state develops their next regional haze SIPs due July 31, 2021.[61] Further, EPA anticipates that Colorado and South Dakota will account for the additional controls on Gerald Gentleman Station when they set 2028 reasonable progress goals in the second implementation period.

[60] *See* NPPD Clean Air Act Section 114 Response; NPPDRH114_0000892,NPPDRH114_0001321, NPPDRH114_0001584,NPPDRH114_0002059,NPPDRH114_0005017

[61] On December 14, 2016, EPA finalized Protection of Visibility: Amendments to Requirements for State Plans rule, which moves the state deadline for the second round of regional haze SIPs to July 31, 2021. 81 FR 26942, May 4, 2016. The final rule was published on January 10, 2017. 82 FR 3078 (January 10, 2017).

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3. Factor 3 - The Energy and Non-Air Quality Environmental Impacts of Compliance

To analyze energy impacts, the BART Guidelines advise, "You should examine the energy requirements of the control technology and determine whether the use of that technology results in energy penalties or benefits."[62] As discussed above in our cost analyses for DSI, SDA, and wet FGD, our cost model allows for the cost of additional auxiliary power required for pollution controls to be included in the variable operating costs. EPA chose to include this additional auxiliary power in all cases. Consequently, we believe that any energy impacts of compliance have been adequately considered in our analyses.

Regarding the analysis of non-air quality environmental impacts, the BART Guidelines advise:

> Such environmental impacts include solid or hazardous waste generation and discharges of polluted water from a control device. You should identify any significant or unusual environmental impacts associated with a control alternative that have the potential to affect the selection or elimination of a control alternative. Some control technologies may have potentially significant secondary

[62] 70 FR 39168 (July 6, 2005).

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environmental impacts. Scrubber effluent, for example, may affect water quality or land use. Alternatively, water availability may affect the feasibility and costs of wet FGD. Other examples of secondary environmental impacts could include hazardous waste discharges, such as spent catalysts or contaminated carbon. Generally, these types of environmental concerns become important when sensitive site-specific receptors exist, or when the incremental emission reductions potential of the more stringent control is only marginally greater than the next most-effective option. However, the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BART, particularly if the control device has been applied to similar facilities elsewhere and the solid or liquid waste is similar to those other applications. On the other hand, where you or the source owner can show that unusual circumstances at the proposed facility create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control alternative as BART.[63]

[63] 70 FR 39169 (July 6, 2005).

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As referenced above, non-air environmental impacts may also take into account water availability to operate scrubbers. The Nebraska's Regional Haze SIP, the record for our previous actions on Nebraska's SIP, and information more recently obtained from NPPD, contain extensive information about water availability in the area of Gerald Gentleman Station.

In summary, Gerald Gentleman Station is located in western Nebraska, a semi-arid region dominated by agriculture. Water quantity in western Nebraska, both surface and groundwater availability, is governed by state statute and agreements with neighboring states and Federal agencies, such as the U.S. Fish and Wildlife Service, to protect, increase, and allocate the state's water resources. Specifically, the Nebraska Department of Natural Resources has responsibility for management of hydrologically connected surface water and groundwater resources, and must identify river basins that are fully or over-appropriated. Gerald Gentleman Station is located in a portion of the Twin Platte Natural Resource District that has been designated as over-appropriated, and pursuant to their Integrated Management Plan, construction of new groundwater wells greater than 50 gallons per minute or increasing irrigated acres is prohibited. New water needs must instead be obtained

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through offsets of existing groundwater wells, such as irrigation wells, which must be retired before drilling a new groundwater well.

In addition, in 2007, the U.S. Department of the Interior, Colorado, Wyoming, and Nebraska entered into the Platte River Recovery and Implementation Program (PRRIP) to restore shortages to U.S. Fish and Wildlife Service target flows in the Platte River, thereby protecting endangered and threatened species whose habitat includes the Platte River. The threatened and endangered species identified for protection include the piping plover, pallid sturgeon, least tern, and whooping crane. Substantial offsets to current water use are required in order to meet the PRRIP needs; however, as was previously commented by the USFWS, the PRRIP inherently provides options to offset consumptive uses, and was developed knowing that it would be untenable to prevent all new water uses.[64] Thus, the approach was to devise ways to provide for the water-dependent needs of listed species while accommodating new uses.

While there is no question that any new surface water depletions to central Platte River flows in order to operate SO_2 controls would require surface or ground water offsets, those

[64] EPA-R07-OAR-2012-0158, Appendices to State Submittal Documents, Chapter 3.

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offsets could be obtained at a cost. In EPA's previous BART cost analyses for wet FGD, we factored in potentially higher costs associated with obtaining water, including the cost of obtaining the fee title to irrigated land necessary to offset the water usage of wet FGD, and still found the costs to be reasonable, increasing the cost per ton by only $313 per ton.[65] These costs would be lower for use of SDA, which uses less water and therefore would require less offsets. DSI would require less water than either wet FGD or SDA, which would be used for regular maintenance of the system.

In addition, based on information EPA received from NPPD, it appears NPPD has multiple lines of access to additional supplies of groundwater. Based on an area well survey,[66] NPPD already has access to additional water supply from groundwater wells it currently owns and leases to other parties for irrigation and livestock watering, totaling approximately 4.17 million gallons per day (173,880 gallons per hour), and currently unused groundwater well capacity of 316,800 gallons per day (13,200 gallons per hour). This capacity is more than

[65] As explained in our previous action, this figure is considered conservative for several reasons. First, NPPD's estimates of water use to operate wet FGD were 31 percent higher than the average of other facilities NDEQ provided in its SIP. Second, we did not offset the cost due to rental income from the property, value due to production of dry land crops, or the future value of the land in 20 years. 77 FR 40150, 40162.

[66] Information received from NPPD pursuant to a Clean Air Act section 114 information request issued to NPPD on March 21, 2016.

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enough to operate SDA. In addition, NPPD may acquire groundwater offsets from surrounding areas and drill new wells.

EPA also notes that the overall water requirements of scrubbers at Gerald Gentleman Station would be a very small percentage of the water use requirements for Gerald Gentleman Station overall, only approximately 0.22-0.30 percent of total plant needs, which are largely for cooling. Therefore, we do not believe that the increase in water usage due to operation of scrubbers, in general, is prohibitive.

EPA acknowledges the water availability concerns, and the great care Nebraska takes in managing limited water resources. We also acknowledge the goals of the Integrated Management Plans and obligations of the Platte River Recovery Plan. As was noted above, the BART Guidelines provide that these types of environmental concerns become important when the incremental emission reduction potential of the more stringent control is only marginally greater than the next most-effective option. As discussed in the cost analysis above, wet FGD requires approximately 2.54 million gallons per day (106,000 gallons per hour), compared to SDA at 1.85 million gallons per day (77,000 gallons per hour), and is only marginally more effective at an achievable rate of 0.040 lb/mmBtu, compared to 0.060 lb/mmBtu, respectively, a difference of 1,354 tons per year.

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The SO_2 control technologies EPA considered in our analyses - DSI, SDA, and wet FGD - are in wide use in the coal-fired electricity generation industry. All three technologies would add spent reagent to the waste stream already generated by Gerald Gentleman Station, but do not present any unusual environmental waste impacts. As discussed in our cost analyses for DSI, SDA, and wet FGD, our cost model includes waste disposal costs in the variable operating costs. Therefore, EPA believes that any non-air quality environmental impacts related to waste have been adequately considered in our analyses.

4. Factor 4 - The Remaining Useful Life of the Source

Regarding the analysis of remaining useful life, the BART Guidelines advise:

> The "remaining useful life" of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's OAQPS Control Cost Manual requires the use of a specified time period for amortization that varies based upon the type of control. If the remaining useful life will clearly exceed this time period, the remaining useful life essentially has no effect on control costs and on the BART determination process. Where the remaining useful life is less than the time

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> period for amortizing costs, you should use the shorter time period in your cost calculations.

In determining the cost of scrubbers in the original SIP submission, Nebraska did not provide a specific useful life for the Gerald Gentleman Station:

> The useful remaining life of Gerald Gentleman Station Units 1 and 2 is greater than 20 years under the current NPPD energy resource plan. Therefore, the remaining useful life has no impact on the annualized estimated control technology cost at this time. Nebraska Regional Haze SIP Section 10.6.4.9.

NPPD did not provide any additional information regarding the remaining useful life of the Gerald Gentleman Station Units in their section 114 response. NPPD's Integrated Resource Plan also does not provide any specific information regarding the remaining useful life of the units. The Integrated Resource Plan does indicate that NPPD intends to utilize the units for a significant period of time into the future.

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EPA has used a 30 year lifetime approach in prior actions.[67] Therefore, we have used 30 years in the cost module of the IPM model when calculating costs for controls at the Gerald Gentleman Station.

EPA sees no reason to assume that a DSI system installation, which is a much less complex and costly (capital costs, as opposed to annualized costs) technology in comparison to a scrubber installation, should have a shorter lifetime. As with an wet FGD or SDA, we expect the boiler to be the limiting factor when considering the lifetime of a coal-fired power plant. EPA has therefore similarly assumed that the lifetime of a DSI system is 30 years. We propose to conclude that Units 1 and 2 have a remaining usful life of 30 years.

B. Proposed Long-Term Strategy Determinations for Gerald Gentleman Station

EPA believes the information described above supports this proposal that an SO_2 rate of 0.060 lb/mmBtu at the Gerald Gentleman Station is necessary to make reasonable progress at Class I areas affected by sources in Nebraska. The previous record showed that there would be positive visibility benefits to the affected Class I areas, if Gerald Gentleman Station

[67] See 76 FR 52388 (August 22, 2011); 76 FR 81728 (December 28, 2011); Oklahoma v. EPA, 723 F.3d 1201 (July 19, 2013), cert. denied (U.S. May 27, 2014).

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installed SO_2 controls. Although visibility is not a required element of the four-factor analysis, EPA reviewed the visibility information from the original Nebraska Regional Haze SIP record to verify the impacts of Gerald Gentleman Station on the nearest Class I Federal Areas of Badlands, Wind Cave, and Rocky Mountain National Parks. Upon review, EPA confirmed that the existing record, which includes both the CENRAP and Nebraska CALPUFF modeling, showed significant impacts on the affected Class I areas.

Overall, both the previous CENRAP CAMx modeling and NDEQ BART CALPUFF modeling relied upon in the Nebraska Regional Haze SIP indicate a visibility improvement with the installation of SO_2 controls at Gerald Gentleman Station. The 2018 CENRAP modeling shows improvements in the visibility impairment contribution from Nebraska elevated sources at Badlands due to decreases in emissions from the SO_2 BART controls assumed at Gerald Gentleman Station in the modeling. CALPUFF modeling with either wet FGD or DSI at a control rate of 0.15 lb/mmBtu produced significant visibility improvements at the two South Dakota Class I areas and Rocky Mountain National Park when averaged over the 2001-2003 modeling period.

Therefore, although visibility is not a required element of the four-factor analysis, there will be significant visibility

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benefit to the Class I areas as a result of meeting the proposed SO_2 emission rate at Gerald Gentleman Station. By meeting this proposed rate, EPA will ensure that Nebraska is achieving their fair share of emission reductions to allow Class I areas to reach natural visibility conditions.

As discussed in more detail in the Cost TSD (Appendix A), EPA is not able to find information showing that any coal-fired units in the U.S. are currently meeting the 0.060 lb/mmBtu rate proposed in this action with the use of DSI alone. Therefore, EPA is unable to say that use of DSI at the Gerald Gentleman Station can achive the proposed 0.060 lb/mmBtu emission limit. Nevertheless, this proposed action only proposes a rate, not a control technology. Therefore, it does not foreclose NPPD from using DSI to meet the 0.060 lb/mmBtu rate, if site specific engineering factors allow. As described earlier, the IPM Model predicts DSI annualized capital and operating costs at 90 percent control are competitive with SDA and wet FGD. DSI has lower capital costs and higher operating costs, which may be a consideration that is important to NPPD. EPA wants to make clear that our proposed SO_2 emission rate of 0.060 lb/mmBtu is not tied to the feasibility of meeting this emission using DSI, since it is justified on the basis of the cost-effectiveness of both SDA and wet FGD.

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Given the regional water concerns and greater water usage, EPA is proposing to eliminate the control efficiency rate of 0.040 lb/mmBtu from further consideration based on the non-air environmental impacts of water availability, because it can only be achieved with wet FGD.[68]

Based on the four-factor analysis, EPA proposes that NPPD meet an emission rate of 0.060 lb/mmBtu on the basis of a rolling 30-boiler operating day averaging period. This rate would apply at all times, including periods of startup and shut down, which is consistent with our SSM policy.[69]

V. Statutory and Executive Order Reviews

A. Executive Order: 12866 Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This proposed action is not a "significant regulatory action" under the terms of Executive Order 12866[70] and is therefore not subject to review under Executive Orders 12866 and 13563.[71] The proposed FIP only applies to one facility. It is therefore not a rule of general applicability.

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[68] See, 79 FR 74818, 74874 (February 16, 2014); 81 FR 296 at 320 (January 5, 2016); 77 FR 18052, 18061 (March 3, 2012)

[69] This proposed control rate will require the GGS units to be retrofitted with SO_2 control technology. NPPD will be required to obtain any permits necessary under the Nebraska SIP.

[70] 58 FR 51735 (October 4, 1993).

[71] 76 FR 3821 (January 21, 2011).

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B. *Paperwork Reduction Act*

This proposed action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. Section 3501 et seq. Because this rule does not affect 10 or more entities, it does not contain any information collection activities the Paperwork Reduction Act does not apply. See 5 CFR 1320(c).

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises and small governmental jurisdictions. For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) a small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small

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organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of this proposed rule on small entities, I certify that this action will not have a significant impact on a substantial number of small entities. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule. This proposed rule does not impose any requirements or create impacts on small entities.

D. Unfunded Mandates Reform Act (UMRA)

This action contains no Federal mandates under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531-1538 for state, local, or tribal governments or the private sector. The EPA has determined that the proposed action does not include a Federal mandate that may result in estimated costs of $100 million or more to either state, local, or tribal governments in the aggregate, or to the private sector. This action proposes to approve or disapprove

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pre-existing requirements under state or local law, and imposes no new requirements. Accordingly, no additional costs to state, local, or tribal governments, or to the private sector, result from this action.

E. Executive Order 13132: Federalism

This action does not have Federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. This proposed rule does not impose significant economic costs on state or local governments. Thus, Executive Order 13132 does not apply to this proposed action. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed rule from State and local officials.

F. Executive Order 13175: Coordination with Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. This action applies to one facility in Nebraska and will affect Federal Class I areas in South Dakota and Colorado. This action does not apply on any Indian reservation land or any other areas where EPA or an Indian tribe

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has demonstrated that a tribe has jurisdiction, or non-reservation areas of Indian county. Thus Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children from Environmental Health and Safety Risks

Executive Order 13045: Protection from Environmental Health Risks and Safety Risks applies to any rule that: (1) is determined to be economically significant as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate risk to children. Moreover, "regulation" or "rule" is defined in Executive Order 12866 as "an agency statement of general applicability and future effect." E.O. 12866 does not define "statement of general applicability" but this term commonly refers to statements that apply to groups or classes, as opposed to statements which apply only to named entities. The proposed FIP, therefore, is not a rule of general applicability because its requirements apply and are tailored to only one individually identified facility. Thus it is not a "rule" or "regulation" within in the meaning of E.O. 12866. However, as this action will limit emissions of SO_2, it will have a beneficial effect on children's health by reducing air pollution.

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H. Executive Order 13211: Actions that Significantly Affect Energy Supply, Distribution or Use

This proposed action is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer Advancement Act

This proposed action involves technical standards. Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law 104-113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities, unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to us available and applicable voluntary consensus standards. This proposed rule would require the affected facility to meet the applicable monitoring requirements of 40 CFR part 75. Part 75 already incorporates a number of voluntary consensus standards. Consistent with the Agency's Performance Based Measurement (PBMS), part 75 sets forth performance criteria that allow the

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use of alternative methods to the ones set forth in part 75. The PBMS approach is intended to be more flexible and cost-effective for the regulated community; it is also intended to encourage innovation in analytical technology and improved data quality. At this time, EPA is not recommending any revisions to part 75; however, EPA periodically revises the test procedures set forth in part 75. When EPA revises the test procedures set forth in part 75 in the future, EPA will address the use of any new voluntary consensus standards that are equivalent. Currently, even if a test procedure is not set forth in part 75, EPA is not precluding the use of any method, whether it constitutes a voluntary consensus standard or not, as long as it meets the performance criteria specified; however any alternative methods must be approved through the petition process under 40 CFR 75.66 before they are used.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

EPA believes the human health or environmental risk addressed by this proposed action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income, or indigenous populations because it increases the level of environmental

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protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. This proposed FIP limits emissions of SO_2 from one facility in Nebraska.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Visibility, Interstate transport of pollution, Regional haze.

Dated: 01-18-2017 /s/ Mark Hague

January 18, 2017.

Mark Hague,
Regional Administrator,
Region 7.

IDENTIFICATION OF DOCUMENT: Proposed rule; EPA-R07-OAR-2017-0039; Approval and Promulgation of Air Quality Implementation Plans; Nebraska Regional Haze Federal Implementation Plan; Reconsideration

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For the reasons stated in the preamble, EPA proposes to amend 40 CFR part 52 as set forth below:

Part 52 - APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

1. The authority citation for part 52 continues to read as follows:

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

Subpart CC - NEBRASKA

2. § 52.1437 is proposed to be revised to read as follows:

§ 52.1437 Visibility protection.

(b) Measures Addressing Partial Disapproval Associated with SO_2. The deficiencies associated with the SO_2 BART determination, including those provisions of the long-term strategy addressing SO_2 emissions, for Nebraska Public Power District, Gerald Gentleman Station, Units 1 and 2 identified in EPA's partial disapproval of the regional haze plan submitted by Nebraska on July 13, 2011, are satisfied by § 52.1429 and subsection (c) of this section.

(c) Requirements for Gerald Gentleman Station Units 1 and 2 affecting visibility.

(1) *Applicability*. The provisions of this section shall apply to each owner, operator, or successive owners or operators of the coal burning equipment designated as Gerald Gentleman Station Units 1 and 2.

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(2) *Compliance Dates*. Compliance with the requirements of this section is required by 5 years from the effective date of this rule for Gerald Gentleman Station Units 1 and 2.

(3) *Definitions*. All terms used in this part but not defined herein shall have the meaning given to them in the Clean Air Act and in parts 51 and 60 of this title. For the purposes of this section:

24-hour period means the period of time between 12:01 a.m. and 12 midnight.

Air pollution control equipment includes baghouses, particulate or gaseous scrubbers, sorbent injection systems, and any other apparatus utilized to control emissions of regulated air contaminants which would be emitted to the atmosphere.

Boiler-operating-day means any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in a steam generating unit.

Heat input means heat derived from combustion of fuel in a unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources. Heat input shall be calculated in accordance with 40 CFR Part 75.

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Owner or Operator means any person who owns, leases, operates, controls, or supervises any of the coal burning equipment designated in paragraph (a) of this section.

Regional Administrator means the Regional Administrator of Region 7 or his/her authorized representative.

Unit means each individual coal-fired boiler covered under paragraph (a) of this section.

(4) *Emissions Limitations*. SO_2 emission limit. The sulfur dioxide emission limit for each individual unit shall be as listed in the following table in pounds per million British thermal units (lb/mmBtu) as averaged over a rolling 30 boiler-operating-day period.

Unit	SO_2 Emission limit (lbs/mmBtu)
Gerald Gentleman Station Unit 1	0.060
Gerald Gentleman Station Unit 2	0.060

For each unit, SO_2 emissions for each calendar day shall be determined by summing the hourly emissions measured in pounds of SO_2. For each unit, heat input for each boiler-operating-day shall be determined by adding together all hourly heat inputs, in millions of Btu. The 30-day rolling average SO_2 emision rate for each boiler-operating-day of the 30-day rolling average for a unit shall be determined by adding together the pounds of SO_2 from that day and the preceding 29 boiler-operating-days and

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dividing the total pounds of SO_2 by the sum of the heat input during the same 30 boiler-operating-day period. The result shall be the 30 boiler-operating-day rolling average in terms of lb/mmBtu emissions of SO_2. Each 30 Boiler Operating Day Average Rate shall include all emissions that occur during all periods of operation within an operating day, including startup, shutdown and malfunction. If valid SO_2 pounds per hour or heat input is not available for any hour for a unit, that heat input and SO_2 pounds per hour shall not be used in calculation of the 30 boiler-operating-day rolling average for SO_2.

(5) *Testing and Monitoring.*

(i) No later than the compliance date of this regulation, the owner or operator shall install, calibrate, maintain and operate Continuous Emissions Monitoring Systems (CEMS) for sulfur dioxide (SO_2), diluent (%CO_2 or %O_2) and flow, for each unit listed in Section (1) in accordance with 40 CFR 60.8 and 60.13(e),(f),and (h), and appendix B of Part 60. The owner or operator shall comply with the quality assurance procedures for CEMS found in 40 CFR part 75. The SO_2, diluent, and flow CEMS data, expressed in units of the standard, shall be used to verify compliance for each unit.

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(ii) Continuous emissions monitoring shall apply during all periods of operation of the coal burning equipment including periods of startup, shutdown, and malfunction, except for CEMS breakdowns, repairs, calibration checks, and zero and span adjustments. Continuous monitoring systems for measuring SO_2 and diluent gas shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Hourly averages shall be computed using at least one data point in each 15-minute quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant in an hour) if data are unavailable as a result of performance of calibration, quality assurance, preventative maintenance activities, or backups of data from data acquisition and handling system, and recertification events. When valid pounds per million Btu emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks or zero and span adjustments, emission data must be obtained by using other monitoring systems approved by EPA to provide emission data for a minimum of 18 hours in each 24-hour period and at least 22 out of 30 successive boiler operating days.

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(6) *Recordkeeping and Reporting Requirements.* Unless otherwise stated all requests, reports, submittals, notifications and other communications to the Regional Administrator required by this section shall be submitted unless instructed otherwise to the Director, Air and Waste Management Division, U.S. Environmental Protection Agency, Region 7, 11201 Renner Boulevard, Lenexa, Kansas 66219. For each unit subject to the emissions limitation in this section and upon completion of CEMS as required in this section, the owner or operator shall comply with the following requirements:

(i) The following information shall be reported to the Regional Administrator, EPA Region 7, and the Nebraska Department of Environmental Quality, for each **boiler operating day.** The report shall be submitted no later than 30 days following the end of each semi-annual calendar period (e.g. June 30, December 31).

(1) Calendar date.

(2) The average SO_2 emission rates, in lb/mmBtu, for each 30 successive boiler operating day period, ending with the last 30-day period in the semi-annual reporting period; reasons for non-compliance with the emission standards; and, description of corrective actions taken.

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(3) Identification of the boiler operating days for which pollutant or diluent data have not been obtained by an approved method for at least 75 percent of the hours of operation of the facility; justification for not obtaining sufficient data; and description of corrective actions taken.

(4) Identification of the "F" factor used for calculations, method of determination, and type of fuel combusted.

(5) Identification of times when hourly averages have been obtained based on manual sampling methods.

(6) Identification of the times when the pollutant concentration exceeded full span of the CEMS.

(7) Description of any modifications to CEMS which could affect the ability of the CEMS to comply with Performance Specifications 2 or 3 of 40 CFR 60.51 Subpart Da.

(7) *Equipment Operations*. At all times, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and operate the unit including the associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable

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operating and maintenance procedures are being used will be based on information available to the Regional Administrator which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the unit.

(8) *Enforcement*.

(i) Notwithstanding any other provision in this implementation plan, any credible evidence or information relevant as to whether the unit would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed, can be used to establish whether or not the owner or operator has violated or is in violation of any standard or applicable implementation plan.

(ii) Emissions in excess of the level of the applicable emission limit or requirement that occur due to startup, shutdown or malfunction shall constitute a violation of the applicable emission limit.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 7
11201 Renner Boulevard
Lenexa, Kansas 66219

Nebraska Regional Haze: Technical Support Document for Action on Remand of Federal Implementation Plan for Long-Term Strategy for Sulfur Dioxide at the Gerald Gentleman Station

Prepared by:

Air Planning and Development Branch, Air & Waste Management Division, U.S. EPA

January 2017

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List of Acronyms

BART	Best Available Retrofit Technology
BOD	Boiler Operating Day
BTU	British Thermal Units
CCM	Control Cost Manual
CENRAP	Central Regional Air Planning Association
CFR	Code of Federal Regulations
CSAPR	Cross-State Air Pollution Rule
DSI	Dry Sorbent Injection
EGU	Electric Generating Units
EPA	Environmental Protection Agency
FGD	Flue-Gas Desulfurization
FIP	Federal Implementation Plan
GGS	Gerald Gentleman Station
IPM	Integrated Planning Model
IRP	Integrated Resource Plan
lb/mmBTU	Pounds per Million BTU
NDEQ	Nebraska Department of Environmental Quality
NPCA	National Parks Conservation Association
NPPD	Nebraska Public Power District
OAQPS	Office of Air Quality Planning and Standards
PM	Particulate Matter
PRRIP	Platte River Recovery and Implementation Program
PSAT	PM Source Apportionment Technology
RH	Regional Haze
SDA	Spray Dryer Absorber
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SSM	Startup Shutdown or Malfunction
TPY	Tons Per Year
TSD	Technical Support Document
USFWS	United States Fish and Wildlife Service

I. Introduction

This document provides a detailed explanation for our proposed action to address the Eighth Circuit Court of Appeals' remand without vacatur of the Nebraska regional haze Federal Implementation Plan's (FIP) long-term strategy for sulfur dioxide (SO_2) for the first planning period (2008-2018). Consistent with EPA's longstanding interpretation of the Regional Haze Rule, 40 CFR 51. 308-309, and our conclusion upon remand that we did not have a sufficient basis for our original decision to rely on the Cross-State Air Pollution Rule (CSAPR) to satisfy the long-term strategy requirement for SO_2 emissions from the Nebraska Public Power District (NPPD) Gerald Gentleman Station (GGS), we are proposing a new action on remand and are taking comment on this action. Specifically, we are proposing that SO_2 emission limits of 0.06 lb/mmBTU, calculated on a 30-boiler operating day (BOD)[1] average rate, for each unit. We believe that meeting the proposed SO_2 emission rate is necessary to make reasonable progress toward Congress' natural-visibility goal at the Badlands National Park in South Dakota and other Class I areas affected by visibility-impairing emissions from Nebraska.

II. Background of EPA's Action on the Nebraska Regional Haze SIP

On July 6, 2012, EPA took final action on Nebraska's regional haze state implementation plan (SIP) for the first planning period.[2] In that final action, EPA partially approved and partially disapproved the state's SIP. In this action, EPA disapproved the state's SO_2 best available retrofit technology (BART) determinations for GGS Units 1 and 2 and the state's long-term strategy, which had relied on the state's flawed BART determinations. The reasons for EPA's disapproval are outlined in both the proposed rule and the final rule.[3] To satisfy EPA's FIP obligation resulting from these disapprovals, EPA promulgated a FIP that relied on the July 6, 2011, CSAPR for both the BART and long-term strategy requirements.[4] Specifically, EPA relied on its separate national rulemaking[5] that found that CSAPR provides for greater reasonable progress, on average, nationally than source-specific BART and which promulgated a FIP requiring electric generating units (EGUs) in Nebraska to comply with CSAPR.

Subsequently, Sierra Club, the National Parks Conservation Association (NPCA), the State of Nebraska, and NPPD filed petitions for review challenging EPA's final action in the Eighth Circuit Court of Appeals.[6] In response to arguments raised by the Sierra Club and NPCA during briefing of the petitions, EPA moved for a voluntary remand without vacatur of the long-term strategy FIP for Nebraska as it related to GGS.[7] EPA explained in the motion that the agency's rationale for declining to require

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[1] A "30 Boiler Operating Day Average Rate" means an emission limit, expressed in lb/mmBTU, and calculated in accordance with the following procedure: first, sum the total pounds of SO_2 emitted for each unit during an operating day and the previous twenty-nine (29) operating days; second, sum the total heat input to each unit, in mmBTU, during an operating day and the previous twenty-nine (29) operating days; and third, divide the total number of pounds of SO_2 emitted for each unit during the thirty (30) operating days by its respective total heat input during the thirty (30) operating days. A new 30 Boiler Operating Day Average Rate shall be calculated for each unit for each new operating day. Each 30 Boiler Operating Day Average Rate shall include all emissions that occur during all periods of operation within an Operating Day, including Startup, Shutdown and Malfunction. Boiler operating day means any day on which a unit fires fossil fuel.

[2] 77 FR 40150.

[3] See 77 FR 12770 (March 2, 2012) (proposed rule); 77 FR 40150 (July 6, 2012) (final rule).

[4] The Eighth Circuit upheld EPA's SIP disapproval and BART FIP. *Nebraska v. EPA*, 812 F.3d 662 (8th Cir. 2016).

[5] 77 FR 33642.

[6] NPPD dismissed its petition voluntarily, but remained as an intervenor in the other petitions. *See* Order, *Neb. Pub. Power Dist. v. EPA*, No. 12-3061 (8th Cir. Nov. 4, 2014).

[7] EPA's Motion for Partial Voluntary Remand, *Nebraska. v. EPA*, 812 F.3d 662 (8th Cir. 2015) (No.12-3084).

additional controls at GGS, as part of the long-term strategy, was not fully or clearly explained. EPA also stated that the explanation in the record could potentially be construed in a manner that is inconsistent with EPA's interpretation of the relevant statutory and legal requirements. As a result, EPA determined that a remand was appropriate to afford the agency an opportunity to amend or further explain its rationale for declining to require additional controls, more fully respond to comments submitted by the public, or to take further action if necessary. The Eighth Circuit granted EPA's motion.[8]

III. EPA's Reconsideration of Long-Term Strategy for SO_2 at the Gerald Gentlemen Station

In this proposed action, EPA is acting on the remanded portion of its FIP as it relates to long-term strategy for SO_2 for GGS. Upon reconsideration, EPA has determined that its record for the original action is incomplete. In EPA's 2012 final action, EPA implemented a CSAPR FIP to satisfy the long-term strategy requirements of the 1999 Regional Haze Rule for SO_2 at GGS. At the time of the 2012 final action, EPA did not specifically evaluate whether CSAPR was an appropriate long-term strategy that would achieve natural visibility conditions at the following Class 1 Areas: Badlands, Wind Cave, and Rocky Mountain National Park. The environmental petitioners pointed out this deficiency in their briefing, which challenged EPA's final action. EPA is now clarifying the record in accordance with the 1999 Regional Haze Rule.[9]

Nebraska participated in the regional planning organization, the Central Regional Air Planning Association (CENRAP), and incorporated the CENRAP-developed visibility modeling into its 2011 Regional Haze SIP, which assumed controls of 0.15 lb/mmBTU at GGS. Nebraska consulted with both South Dakota and Colorado during the first planning period, Nebraska did not conduct any specific modeling nor provide an analysis as to why the state did not require controls at GGS for its long-term strategy in its 2011 Regional Haze SIP. It is significant that Nebraska did not include an adequate justification explaining why these controls, were not included as part of the LTS but the modeling included proposed controls at GGS Units 1 & 2.

The Nebraska Department of Environmental Quality (NDEQ) used CENRAP CAMx photochemical source apportionment modeling to identify the pollutants (e.g., sulfates, nitrates) and source categories (e.g., elevated point EGUs) that most-impact visibility at Class I areas located in surrounding states. A summary of the annual emissions used for Nebraska elevated point sources and GGS in the 2002 base year and 2018 future year CENRAP modeling is shown in Table 1.[10] Table 1 also gives the 2002 and 2018 CAMx PM Source Apportionment Technology (PSAT) modeling results for the Badlands Class I area in SD.[11] From PSAT, the SO_2 extinction (inverse megameters (1/Mm)) and % total SO_2 extinction impacts at Badlands attributed to Nebraska elevated point sources on the worst 20% visibility days can be calculated.

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[8] Order, *Nebraska v. EPA*, 812 F.3d 662 (8th Cir. 2015) (No. 12-3084).

[9] EPA recently published revisions to the Regional Haze Rule. *See* EPA-HQ-OAR-2015-0531 (Dec. 14, 2016) The revisions do not substantively affect 40 CFR 51.308(d) which applied to our original action and applies to this reconsideration.

[10] NE elevated point source modeled emissions are derived from the CENRAP 2002 and 2018 emission inventory SMOKE Reports that were provided by NDEQ. GGS modeled emissions are from CENRAP's raw emissions inventory files (IDA format files). Emission summaries for Nebraska Elevated Point Sources and GGS is included in the docket: "CENRAP_NE_Elevated_Point_Emissions_Summary.xlsx"

[11] Derived from 2007 CENRAP PSAT Tool and Database developed by ENVIRON for the CENRAP States (CENRAP_PSAT_Tool_ENVIRON_Aug_27_2007.mdb of the docket). A summary of the PSAT tool results for Nebraska sources impacts on Badlands NP is provided in "CENRAP_PSAT_Tool_Summary.xlsx".

Table 1 shows the controls at GGS were assumed and included in the 2018 CENRAP modeling emissions inventory, with the combined GGS Unit 1 & 2 SO_2 emissions decreasing from 32,152 tons per year (tpy) in 2002 to 8,732 tpy in 2018. The 23,420 tpy reduction from assumed SO_2 controls at GGS represents over half of the reductions seen in the 2018 Nebraska elevated point source inventory when compared to the 2002 inventory. These modeled emission reductions led to a decrease of the SO_2 extinction at Badlands that is attributed to Nebraska elevated point sources (from 0.98 1/Mm in 2002 to 0.47 1/Mm in 2018). The percent of the total extinction impacts from Nebraska elevated point sources fell from 2.19% in 2002 to 1.15% in 2018. The decrease in the SO_2 extinction at Badlands from Nebraska elevated point is due to the decrease in modeled emissions from 2002 to 2018, and in particular the decrease in modeled SO_2 emissions at GGS due to the assumption of scrubbing in 2018.

Table 1. 2002 and 2018 CENRAP modeled annual SO_2 emissions for Nebraska point sources and GGS. Also, the SO_2 extinction (1/Mm) and the percent of total SO_2 extinction contribution from Nebraska elevated point at Badlands from PSAT for the average of the 20% most impaired days.

	Nebraska Elevated Point Source SO_2 Emissions (tpy)	Gerald Gentleman Station Unit 1 & 2 combined SO_2 emissions (tpy)	SO_2 Extinction (1/Mm) Contribution of Nebraska Elevated Point	Percent of Total SO_2 Extinction from Nebraska Elevated Point
2002 CENRAP modeling	69,217	32,152	0.98	2.19%
2018 CENRAP modeling	23,951	8,732	0.47	1.15%
Difference from 2002 to 2018 modeling	45,266	23,420	0.51	1.04%

In 2012, EPA evaluated Nebraska's SIP and determined that Nebraska's SIP did not appropriately address the long-term strategy requirements of the 1999 RHR related to GGS because although there was a visibility impact from emissions at GGS on Class I areas, Nebraska did not require cost-reasonable controls. Instead, EPA implemented the CSAPR FIP in place of Nebraska's SIP. Based on the modeling done by CENRAP, EPA recognized at the time that GGS contributed to visibility impairment at the Class I areas in both South Dakota and Colorado, and that cost-reasonable controls were available, but EPA did not take the next step of evaluating additional controls beyond CSAPR at GGS and therefore, the record was incomplete.

In this proposed action, EPA determined that in order to properly evaluate whether CSAPR was sufficient to satisfy Nebraska's fair share of emission reductions at the Class I areas it affects, EPA reviewed the record from the proposed and final action. EPA found that the reductions assumed by CSAPR did not equate to the reductions presumed by the CENRAP modeling that were found to be cost reasonable by both Nebraska and EPA. The CENRAP modeling assumed a control rate of 0.15 lb/mmBTU of SO_2, which would equate to emissions at GGS of 6,533 tons/year in 2015. The CSAPR budget for Nebraska resulted in emission reductions of SO_2 for the state of Nebraska, but did not result in significant SO_2 emission reductions at GGS. The 2014 SO_2 CSAPR budget allocation for GGS was 28,896 tons/year. GGS's current emissions are under the CSAPR budget, however, the additional emission reduction beyond CASPR is not permanent or enforceable.[12]

Therefore, EPA is now required to conduct a four-factor analysis to determine the appropriate federal implementation plan to assure that Nebraska is achieving its fair share of emission reductions to meet the natural visibility conditions at the Class I areas affected by GGS.

[12] In 2015, GGS emitted 25,014 tons of SO_2.

40 C.F.R. § 51.308(d)(3)(ii) requires that if Nebraska emissions cause or contribute to impairment in another state's Class I area(s), Nebraska must demonstrate that it has included in its RH SIP all measures necessary to obtain its share of emission reductions needed to meet the progress goal for that Class I area. 40 C.F.R. § 51.308(d)(3)(iii) requires states to consider the four factors used in determining reasonable progress in developing the technical basis for downwind Class I areas. This demonstration is necessary so that the interstate consultation process can proceed on an informed basis and so that downwind states can properly assess whether any additional upwind emission reductions are necessary to achieve reasonable progress at their Class I area.

IV. EPA's Four-Factor Analysis for SO_2 Emissions from GGS

The reasonable progress four-factor analysis requires that EPA look at the following: the costs of compliance; the time necessary for compliance; the energy and non-air environmental impacts of compliance; and the remaining useful life of any potentially affected sources.[13] Our Reasonable Progress Guidance[14] notes the similarity between some of the reasonable progress factors and the BART factors contained in 40 CFR § 51.308(e)(1)(ii)(A), and suggests that the BART Guidelines be consulted regarding cost, energy and non-air quality environmental impacts, and remaining useful life. We are therefore relying on our BART Guidelines for assistance in quantifying and considering those reasonable progress factors, as applicable. Each of the elements of the four-factor analysis is discussed below.

A. Factor 1 – The Costs of Compliance

a. EPA's Evaluation of Costs in the 2012 Proposed and Final Rule

In the 2012 proposed and final action, EPA and Nebraska evaluated the cost of installation of a scrubber on GGS. Nebraska, in its SIP, concluded that these costs were reasonable on a cost per ton basis ($2,726/ton). Nebraska also evaluated controls at GGS on a dollars per deciview basis. Nebraska determined that while costs on a dollar per ton basis were reasonable, costs on a dollar per deciview basis were not reasonable.[15] Nebraska also saw water consumption of wet Flue-Gas Desulfurization (FGD) controls as significant and concluded that because of this unique situation, wet FGD controls were unreasonable for GGS Units 1 and 2.[16]

EPA agreed with Nebraska that the cost per ton for wet FGD was reasonable and that Nebraska's analysis showed significant visibility improvement both at Badlands and on a cumulative basis.[17] EPA also found that Nebraska inappropriately ruled out Dry Sorbent Injection (DSI) because costs were reasonable and visibility improvement was significant.[18]

EPA also found Nebraska made several errors in determining the cost of controls.[19] EPA determined that Nebraska made incorrect assumptions about GGS' SO_2 emissions and the capability of certain controls.

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[13] 40 C.F.R. 51.308(d)(1)(i).
[14] Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, June 1, 2007.
[15] 77 FR at 12779.
[16] Id.
[17] 77 FR at 12780.
[18] Id.
[19] Id.

Nebraska also deviated from EPA's Cost Control Manual when evaluating costs.[20] EPA did its own evaluation in accordance with the Cost Control Manual and found that the cost per ton of SO_2 controls ranged from $1,972 to $2,958.[21] EPA determined that the costs for control were reasonable and visibility improvement was significant and disapproved Nebraska's SIP.[22]

b. EPA's Updated Cost Evaluation

In this action, EPA has again evaluated the costs of installing SO_2 control equipment at GGS using the most recent Integrated Planning Model (IPM) and updated cost information from NPPD.[23] EPA evaluated several emission control scenarios using several different types of control equipment. EPA, consistent with the existing record, has determined that the cost per ton of SO_2 controls at GGS are reasonable.[24]

EPA analyzed costs for DSI, Spray Dryer Absorber (SDA), and wet FGD. We looked at each of these control technologies at various control rates to determine which rate/control scenarios were cost effective. EPA used cost methodologies used in the IPM model, Version 5.13. These methodologies are described in detail in Appendix A of this Technical Support Document (TSD) and are consistent with other regional haze actions.[25]

EPA's goal was to select input parameters that result in costs that are reasonably conservative. We selected maximum inputs, including inlet SO_2 rate, gross heat rate, and gross load from 2011-2015 to ensure that the controls would address any operating scenarios that the unit had experienced in the last five years.

EPA evaluated the cost of DSI at GGS Units 1 and 2 using control efficiency rates of 50, 80, and 90 percent.[26] Units 1 and 2 do not differ with respect to any design feature that affects the estimated cost of DSI. EPA found the cost of DSI to be $2,138/ton; $2,168/ton and $2,315/ton, respectively, for these levels of control. Each control scenario using DSI is cost effective.

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[20] Id.

[21] Id. This analysis and determination were conducted consistent with previous actions where cost of control analyses were submitted with deviations from the Control Cost Manual. 77 FR 12770 (March 2, 2012); 77 FR 40150 (July 6, 2012); 79 FR 74817 (Dec. 26, 2014); 81 FR 295 (Jan. 5, 2016).

[22] Id.; 77 FR 40150.

[23] EPA has included in the record for this action documents submitted by NPPD pursuant to the CAA Section 114 request that have not been claimed as Confidential Business Information (CBI) by NPPD.

[24] In the proposed and final action on Nebraska's Regional Haze Plan in 2012, the cost of water was an issue raised by the State. EPA responded to several comments made by the State and others in the final action. EPA re-evaluated the cost of water for this action. EPA updated the cost of water based on available information. Appendix A to the Cost TSD discusses this issue in more detail. We propose to determine that the cost to obtain water is reasonable. EPA also sent an information request under Clean Air Act Section 114 (42 U.S.C. § 7414) to NPPD. NPPD provided EPA some updated information on the cost and availability of water. EPA used that information in its cost analysis. This information is also discussed in this TSD in the "Energy and Non-Air Environmental Impacts" Section.

[25] The use of the IPM cost model is consistent with other EPA Regional Haze actions and is based on reliable and accurate technical tools widely utilized by EPA to asses control scenarios at electric generating units and other large sources.

[26] The 50 percent rate for DSI was selected based on known operating performance of installed DSI systems. The 80 percent rate for DSI was selected based on the use of milled trona along with a baghouse. Both GGS units have baghouses installed. EPA included the higher rate (90%) for comparison to other SO_2 control technologies. As discussed in more detail in the Cost TSD, a 90% removal efficiency for a DSI system alone has not been demonstrated at any currently operating DSI system.

EPA evaluated the cost of SDA using a control efficiency rate of 90% at GGS Units 1 and 2.[27] EPA found the cost of SDA to be cost effective for both units, at $2,443/ton at Unit 1 and $2,350/ton at Unit 2. The cost of a baghouse was not included because GGS currently operates a baghouse on both units.

Finally, EPA evaluated the cost of a wet FGD at GGS Units 1 and 2. EPA used control efficiencies of 91% and 94%[28]. EPA determined that the cost of controls were effective at both units and both control efficiencies. EPA found the costs to be $2,424/ton and $2,327/ton at 94% control efficiency at Units 1 and 2, respectively. EPA found the costs to be $2,502/ton and $2,402/ton at 91% control efficiency at Units 1 and 2, respectively.

The total annualized cost of wet FGD is approximately 2% higher than SDA and 5% higher than DSI. However, wet FGD delivers significant improvement in cost effectiveness as the tonnage of SO_2 removal increases due to the greater level of control (94% v. 91%) of wet FGD over SDA, which tends to offset the higher capital cost of wet FGD.

At a control rate of 0.06 lb/mmBTU, DSI, SDA and wet FGD are in the range of $2,300 to $2,500 per ton SO_2 removed. DSI is approximately $100 less, on a per ton SO_2 removed basis, than SDA and $150 less than wet FGD. Likewise, SDA is approximately $50 less than wet FGD. At a rate of 0.04 lb/mmBTU for the wet FGD, the additional 1,400 tons of SO_2 removed per year brings the cost effectiveness in line with a SDA at 0.06 lb/mmBTU. Based on our cost assessment, all three SO_2 controls are cost effective at a rate of 0.06 lb/mmBTU.

The remaining useful life affects the cost effectiveness estimates for the control technologies. As discussed in more detail in the Cost TSD, and in Section D, below, EPA has used 30 years as the remaining useful life of the units and any new controls installed on them. Thirty years represents a life span for a unit that is used consistently across EPA's regulatory programs. Further, EPA has no basis to deviate from this number. EPA believes that even if the remaining useful life of the units is less than 30 years, the proposed control rate and associated control technologies are still cost effective.

B. Factor 2 – The Time Necessary for Compliance

EPA believes 5 years is the appropriate time period for installation of SO_2 controls to meet the proposed SO_2 limit. NPPD submitted several documents that demonstrate that NPPD has previously considered installing wet FGD controls on GGS Units 1 and 2. The engineering documents and requests for bids from this process included a timeline of 5 years from design to completion. EPA believes this is an appropriate timeframe for installation of wet FGD controls. We believe that SDA could be installed within the same timeframe. DSI may be able to be installed in a time frame of 2-3 years.

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[27] EPA ran the cost analysis using a 90% removal rate because the lowest available SO_2 emission guarantees from original equipment manufacturers of SDA systems are 0.06 lb/mmBTU. Because higher control efficiencies result in lower SO_2 rates, we limited the control efficiency in the cost algorithm to just under 91% to ensure that any performance guarantees can be met.

[28] EPA ran two cost analyses, at 0.04 and at 0.06 lb/mmBTU. The first analysis evaluates wet FGD at the lowest rate vendors will guarantee. Because a 98% removal efficiency results in SO_2 rates less than 0.040 lb/mmBTU for the Gerald Gentleman units, we limited the control efficiencies in the cost algorithm to just under 94% to assure that the equipment can meet any performance guarantees. The second analysis allows direct comparison to SDA at similar reduction efficiencies of just under 91%.

Due to the timing of this action, it is highly unlikely that the SO_2 controls will be installed and operational within the first planning period, which ends in 2018. Therefore, we request that Nebraska consider the visibility improvements anticipated from any necessary FIP controls implemented after 2018 with the submission of their next regional haze SIPs due July 14, 2018.[29] Further, we anticipate that Colorado and South Dakota will account for the additional controls on GGS when they set 2028 reasonable progress goals in the second implementation period.

C. Factor 3 - The Energy and Non-Air Quality Environmental Impacts of Compliance

a. Auxiliary Energy Power

To analyze energy impacts, the BART Guidelines advise, "You should examine the energy requirements of the control technology and determine whether the use of that technology results in energy penalties or benefits."[30] As discussed above in our cost analyses for DSI, SDA, and wet FGD, the IPM cost model allows for the cost of additional auxiliary power required for pollution controls to be included in the variable operating costs. We chose to include this additional auxiliary power in all cases. Consequently, we believe that any energy impacts of compliance have been adequately considered in our analyses.

b. Non-Air Quality Environmental Impacts

Regarding the analysis of non-air quality environmental impacts, the BART guidelines advise:

> Such environmental impacts include solid or hazardous waste generation and discharges of polluted water from a control device. You should identify any significant or unusual environmental impacts associated with a control alternative that have the potential to affect the selection or elimination of a control alternative. Some control technologies may have potentially significant secondary environmental impacts. Scrubber effluent, for example, may affect water quality or land use. Alternatively, water availability may affect the feasibility and costs of wet scrubbers. Other examples of secondary environmental impacts could include hazardous waste discharges, such as spent catalysts or contaminated carbon. Generally, these types of environmental concerns become important when sensitive site-specific receptors exist, or when the incremental emission reductions potential of the more stringent control is only marginally greater than the next most-effective option. However, the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BART, particularly if the control device has been applied to similar facilities elsewhere and the solid or liquid waste is similar to those other applications. On the other hand, where you or the source owner can show that unusual circumstances at the proposed facility create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control alternative as BART.[31]

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[29] EPA issued an NPRM which proposes to move the state deadline for the second round of regional haze SIPs to either July 31, 2018 or July 31, 2021. 81 FR 26942, May 4, 2016.
[30] 70 FR 39168 (July 6, 2005).
[31] 70 FR 39169 (July 6, 2005).

As referenced previously, non-air environmental impacts may also take into account water availability to operate scrubbers. The record for our previous actions, including Nebraska's Regional Haze State Implementation Plan,[32] EPA's previous actions on Nebraska's SIP,[33] and information more recently obtained from NPPD,[34] contains extensive information about water availability in the area of GGS. GGS is located in western Nebraska, a semi-arid region dominated by agriculture. Water quantity in western Nebraska, both surface and groundwater availability, is governed by state statute and agreements with neighboring states and federal agencies, such as the U.S. Fish and Wildlife Service, to protect, increase, and allocate its water resources. Specifically, the Nebraska Department of Natural Resources has responsibility for management of hydrologically connected surface water and groundwater resources, and must identify river basins that are fully or over-appropriated. GGS is located in a portion of the Twin Platte Natural Resource District that has been designated as over-appropriated, and pursuant to its Integrated Management Plan, construction of new groundwater wells greater than 50 gallons per minute or increasing irrigated acres is prohibited. New water needs must instead be obtained through offsets of existing groundwater wells, such as irrigation wells, which must be retired before drilling a new groundwater well.

In addition, in 2007, the Department of the Interior, Colorado, Wyoming, and Nebraska entered into the Platte River Recovery and Implementation Program (PRRIP) to restore shortages to U.S. Fish and Wildlife Service (USFWS) target flows in the Platte River, thereby protecting endangered and threatened species whose habitat includes the Platte River. The threatened and endangered species identified for protection include the piping plover, pallid sturgeon, least tern, and whooping crane. Substantial offsets to current water use are required in order to meet the PRRIP needs; however, as was previously commented by the USFWS the PRRIP inherently provides options to offset consumptive uses, and was developed knowing that it would be untenable to prevent all new water uses.[35] Thus, the approach was to devise ways to provide for the water-dependent needs of listed species while accommodating new uses.

While there is no question that any new surface water depletions to central Platte River flows in order to operate SO_2 controls would require surface or ground water offsets, those offsets could be obtained at a cost. In our previous BART cost analyses for wet FGD, we factored in potentially higher costs associated with obtaining water, including the cost of obtaining the fee title to irrigated land necessary to offset the water usage of wet FGD, and still found the costs to be reasonable, increasing the cost per ton by only $313 per ton.[36] These costs would be lower for use of SDA, which uses less water and therefore would require less offsets. DSI would require less water than either wet FGD or SDA, which would be used for regular maintenance of the system. The IPM model used in the cost analyses accounts for cost of water and the explanation provided previously describes how cost of water was considered for this proposed action.

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[32] Nebraska State Implementation Plan for Regional Haze and Best Available Retrofit Technology, submitted on July 13, 2011.

[33] Notice of Proposed Rulemaking, 77 FR 12770 (March 2, 2012); Final Rule, 77 FR 40150 (July 6, 2012).

[34] Information received pursuant to a Clean Air Act Section 114 information request, issued to NPPD on March 21, 2016.

[35] EPA-R07-OAR-2012-0158, Appendices to State Submittal Documents, Chapter 3.

[36] As explained in our previous action, this figure is considered conservative for several reasons. First, NPPD's estimates of water use to operate wet FGD were 31 percent higher than the average of other facilities NDEQ provided in its SIP. Second, we did not offset the cost due to rental income from the property, value due to production of dry land crops, or the future value of the land in 20 years. 77 FR 40150, 40162.

Based on information we received from NPPD in 2016, it appears NPPD has access to additional supplies of groundwater. Based on an area well survey,[37] NPPD already has access to additional water supply from groundwater wells it currently owns and leases to other parties for irrigation and livestock watering, totaling approximately 2,898 gallons per minute, and currently unused groundwater well capacity of 220 gallons per minute. This capacity is more than enough to operate SDA scrubbers. In addition, as discussed above, NPPD may acquire groundwater offsets from surrounding areas and drill new wells.

EPA also notes that the overall water requirements of scrubbers at GGS would be a very small percentage of the water use requirements for GGS overall, only approximately 0.22-0.30 % of total plant needs, which are largely for cooling. Therefore, we do not believe that the increase in water usage due to operation of scrubbers, in general, is prohibitive.

The EPA acknowledges the water availability concerns, and the great care Nebraska takes in managing limited water resources. We also acknowledge the goals of the Integrated Management Plans and obligations of the Platte River Recovery Plan. As was noted above, the BART Guidelines provide that these types of environmental concerns become important when the incremental emission reduction potential of the more stringent control is only marginally greater than the next most-effective option. As discussed in the cost analysis, wet FGD requires approximately 2.54 million gallons per day (106,000 gallons per hour), compared to SDA at 1.85 million gallons per day (77,000 gallons per hour), and is only relatively slightly more effective at an achievable rate of 0.04 lb/mmBTU, compared to 0.06 lb/mmBTU, respectively, a difference of 1,354 tons per year.

The SO_2 control technologies we considered in our analyses – DSI, SDA, and wet FGD – are in wide use in the coal-fired electricity generation industry. All three technologies add spent reagent to the waste stream already generated by GGS, but do not present any unusual environmental waste impacts. As discussed in our cost analyses for DSI, SDA and wet FGD, our cost model includes waste disposal costs in the variable operating costs. Therefore, we believe that any non-air quality environmental impacts related to waste have been adequately considered in our analyses.

D. Factor 4 – The Remaining Useful Life of the Source

Regarding the analysis of remaining useful life, the BART Guidelines advise:

> The "remaining useful life" of source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual (CCM) requires the use of a specified time period for amortization that varies based upon the type of control. If the remaining useful life will clearly exceed this time period, the remaining useful life essentially has no effect on control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, you should use the shorter time period in your cost calculations.

[37] Information received from NPPD pursuant to a Clean Air Act Section 114 information request issued to NPPD on March 21, 2016.

In determining the cost of scrubbers in the 2011 SIP submission, Nebraska did not provide a specific useful life for GGS:

> The useful remaining life of GGS Units 1 and 2 is greater than 20 years under the current NPPD energy resource plan. Therefore, the remaining useful life has no impact on the annualized estimated control technology cost at this time.[38]

NPPD did not provide any additional information regarding the remaining useful life of the GGS Units in its Section 114 response. NPPD's Integrated Resource Plan (IRP) also does not provide any specific information regarding the remaining useful life of the units. The IRP does indicate that NPPD intends to utilize the units for a significant period of time into the future. The IRP does not, however, provide a specific time frame for future use. We have used a 30 year lifetime approach in prior actions.[39] Therefore, 30 years is used in the IPM when calculating costs for controls at GGS.

We see no reason to assume that a DSI system installation, which is a much less complex and costly (capital costs, as opposed to annualized costs) technology in comparison to a scrubber installation, should have a shorter lifetime. As with a wet FGD or SDA, we expect the boiler to be the limiting factor when considering the lifetime of a coal-fired power plant. We have therefore similarly assumed that the lifetime of a DSI system is 30 years. These considerations are consistent with the assumptions used in the IPM model.

E. Selection of Emission Rate

Based on the four-factor analysis, EPA is proposing that NPPD meet an emission rate of 0.06 lb/mmBTU on a 30—boiler operating day average rate at GGS Units 1 and 2. This rate must apply at all times, including periods of startup and shut down, which is consistent with our Startup, Shutdown and Malfunction (SSM) policy.[40] By selecting this rate, EPA also finds that there will be visibility improvement at the affected Class I areas. This rate is based on the cost-effectiveness of SO_2 controls that can be installed to meet that rate, the reasonable time necessary to install controls to meet the proposed rate, the evaluation of water impacts and availability, and the remaining useful life of the GGS.

As discussed in the Cost TSD, the maximum level of control for SDA and wet FGD technologies was evaluated. For SDA, the maximum level of control was assumed to be 91%, corresponding to a 0.06 lb/mmBTU limit. The wet FGD level of maximum control was assumed to be 94%, corresponding to a 0.04 lb/mmBTU limit. The cost effectiveness at these maximum levels were $2,395 and $2,342 per ton SO_2 removed, respectively for SDA and wet FGD, and we find the cost/benefit of these control rates to be reasonable.

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[38] Nebraska Regional Haze State Implementation Plan Section 10.6.4.9.

[39] See 76 FR 52388 (Aug 22, 2011); 76 FR 81728 (Dec. 28, 2011); *Oklahoma v. EPA*, 723 F.3d 1201 (July 19, 2013), cert. denied (U.S. May 27, 2014).

[40] This proposed control rate will require the GGS units to be retrofitted with SO_2 control technology. This will require the source to obtain a construction permit from the permitting authority. The limit proposed in this notice would be included in the construction permit for the control technology and subsequently in the source's Title V permit.

Given the significant regional water concerns, relatively minimal additional emission reductions, and significantly greater water usage, EPA eliminated the control efficiency rate of 0.04 lb/mmBTU from further consideration based on the non-air environmental impacts of water availability, because it can only be achieved with wet FGD scrubbing. This is consistent with previous actions in which SDA was selected due to scarce water availability.[41] For example, as part of EPA's approval of Colorado's Regional Haze Plan, EPA agreed with Colorado's analysis, finding that wet FGD consumes approximately 23% more water than SDA, there may be insufficient water appropriations available in the State to accommodate the added demands of wet FGD controls, and the demands of wet FGD would compete for what already is a scarce resource needed for Colorado's domestic, agricultural, and industrial demands. Although wet FGD can achieve a slightly higher level of SO_2 control than SDA, Colorado determined, and EPA agreed, that the impacts of water scarcity outweighed any incremental improvement in SO2 emission reductions that would result from the use of wet FGD versus SDA.[42]

DSI was also evaluated with an assumed 90% control in order to compare to SDA and wet FGD control technologies, although EPA is not able to find information showing that any coal-fired units in the U.S. are currently meeting the 0.06 lb/mmBTU rate proposed in today's action with the use of DSI alone. Therefore, EPA is unable to say that DSI would achieve similar control to SDA and wet FGD at the GGS units. Nevertheless, today's action only proposes a rate, not a control technology, and it does not foreclose NPPD from using DSI to meet the 0.06 lb/mmBTU rate, if site specific engineering factors allow. As described earlier, the IPM Model predicts DSI annualized capital and operating costs at 90% control are competitive with SDA and wet FGD. DSI has lower capital costs and higher operating costs, which may be a consideration that is important to NPPD Gerald Gentleman for business reasons. We want to make clear that our proposed emission rate of 0.06 lb/mmBTU is not tied to the feasibility of meeting this emission using DSI, since it is justified on the basis of the cost-effectiveness of both SDA and wet FGD.

Although visibility is not a required element of the four-factor analysis, EPA reviewed the visibility information from the 2011 Nebraska Regional Haze SIP record to verify the impacts of GGS on the nearest Class I Federal Areas of Badlands, Wind Cave, and Rocky Mountain National Park. Upon review, EPA confirmed that the existing record, which includes both modeling for BART determinations and reasonable progress, showed that GGS Units 1 and 2 had significant impacts on the affected Class I areas. The previous record showed that there would be positive visibility impacts on the affected Class I areas, if GGS installed SO_2 controls.

In addition to the CENRAP modeling for reasonable progress discussed in Section III of this TSD, NDEQ also provided CALPUFF modeling analysis as part of its BART SO_2 determination for GGS.[43] The CALPUFF modeling, which followed the recommended modeling approach in the BART Guidelines, was used to evaluate the visibility impacts of pre- and post- emission controls at GGS for the years of 2001-2003. The results of the CALPUFF visibility impact modeling are summarized and shown in Table 2. The average 2001-2003 modeled 98th percentile deciview (dv) impact of GGS without controls at the South Dakota Class I areas of Badlands and Wind Cave is 2.93 dv and 2.39 dv, respectively. The impact of GGS at Rocky Mountain in Colorado is 1.15 dv.

[41] *See,* 77 FR 18052, 18061 (March 3, 2012)
[42] 77 FR 18052, 18061 (March 3, 2012).
[43] As stated previously, the BART determination is final, was upheld by the Eighth Circuit, and is not part of this action.

Table 2. GGS's 2001-2003 98th percentile visibility impact (dV) at Badlands, Wind Cave, and Rocky Mountain Class I areas from CALPUFF modeling as part of NDEQ's BART SO_2 determination. Only Badlands was evaluated for DSI control.

		2001	2002	2003	2001-2003 Average	2001-2003 Average Visibility Improvement
Baseline (no SO_2 control)	Badlands	2.85	2.83	3.12	2.93	-
	Wind Cave	2.45	2.59	2.13	2.39	-
	Rocky Mountain	1.14	1.25	1.05	1.15	-
Wet-FGD control (0.15 lb/mmBTU)	Badlands	1.84	2.13	2.48	2.15	0.78
	Wind Cave	1.61	1.42	1.44	1.49	0.90
	Rocky Mountain	0.61	0.82	0.65	0.69	0.46
DSI control (0.15 lb/mmBTU)	Badlands	1.76	2.15	2.31	2.07	0.86

With a wet FGD system with control rate assumed at a 0.15 lb/mmBTU rate, the modeled 98th percentile visibility improvements are 0.78 dv at Badlands, 0.90 dv at Wind Cave, and 0.46 dv at Rocky Mountain. NDEQ also provided CALPUFF modeling that evaluated DSI at an assumed control rate of 0.15 lb/mmBTU. The visibility modeling of benefits at Badlands from DSI showed a modeled 98th percentile improvement of 0.86 dv. The different visibility improvement results between wet FGD and DSI are due to lower modeled stack temperatures and exit velocities associated with wet FGD control.

Overall, both the previous CENRAP CAMx modeling and BART determination CALPUFF modeling relied upon in the 2011 Nebraska Regional Haze SIP indicate a visibility improvement with the installation of SO_2 controls at GGS. The 2018 CENRAP modeling shows improvements in the visibility impairment contribution from Nebraska elevated sources at Badlands due to decreases in emissions from the SO_2 BART controls assumed at GGS in the modeling. CALPUFF modeling with either wet FGD or DSI at a control rate of 0.15 lb/mmBTU produced significant visibility improvements at the two South Dakota Class I areas and Rocky Mountain when averaged over the 2001-2003 modeling period. Since both the CAMx reasonable progress modeling and BART determination modeling assumed a control rate of 0.15 lb/mmBTU, the proposed cost effective control rate of 0.06 lb/mmBTU would lead to even greater visibility benefits than what the CAMx and CALPUFF modeling showed from the previous record.

Therefore, although visibility is not an element of the four-factor analysis, there will be significant visibility benefit to the Class I areas as a result of installation of controls at GGS. By installing controls, Nebraska will ensure that it is achieving its fair share of emission reductions to allow Class I areas to reach natural visibility conditions.

To: Anderson, Lea[anderson.lea@epa.gov]
Cc: Smith, Kristi[Smith.Kristi@epa.gov]
From: Graham, Cheryl
Sent: Mon 11/28/2016 3:47:01 PM
Subject: FW: State of Arkansas v. EPA, et al, US APP CA8 16-4270
Courtlink_Docket_US_APP_CA8_16-4270_11.22.2016.htm
Courtlink_Document_US_APP_CA8_16-4270 11.22.2016.pdf

Cheryl R. Graham

From: Turley, Jennifer
Sent: Monday, November 28, 2016 9:53 AM
To: Doster, Brian <Doster.Brian@epa.gov>; Graham, Cheryl <Graham.Cheryl@epa.gov>; Lee, Michael <lee.michaelg@epa.gov>; Rodman, Sonja <Rodman.Sonja@epa.gov>; Schmidt, Lorie <Schmidt.Lorie@epa.gov>; Zenick, Elliott <Zenick.Elliott@epa.gov>; Orlin, David <Orlin.David@epa.gov>; Smith, Kristi <Smith.Kristi@epa.gov>; Srinivasan, Gautam <Srinivasan.Gautam@epa.gov>
Subject: State of Arkansas v. EPA, et al, US APP CA8 16-4270

To: Anderson, Lea[anderson.lea@epa.gov]; Nann, Barbara[nann.barbara@epa.gov]; Medina, Dayana[Medina.Dayana@epa.gov]
From: Donaldson, Guy
Sent: Mon 11/28/2016 2:40:15 PM
Subject: FW: Petition for Reconsideration and Request for Stay or Arkansas Regional Haze Federal Implementation Pl
removed.txt
Cover Letter for Entergy Petition for Reconsideration.pdf
Entergy Petition for Reconsideration and Request for Stay.pdf
Exhibits to Entergy Petition - no Confidential Business Information.pdf

From: debra.jezouit@bakerbotts.com [mailto:debra.jezouit@bakerbotts.com]
Sent: Wednesday, November 23, 2016 5:45 PM
To: Curry, Ron <Curry.Ron@epa.gov>; Donaldson, Guy <Donaldson.Guy@epa.gov>
Cc: kmcque1@entergy.com; William Bumpers <william.bumpers@bakerbotts.com>; allison.mallick@bakerbotts.com; twebster@sidley.com; rmartella@sidley.com; jvisser@sidley.com
Subject: Petition for Reconsideration and Request for Stay or Arkansas Regional Haze Federal Implementation Pl

Gentlemen:

Enclosed please find a cover letter, Petition for Reconsideration and Request for Stay of Entergy Arkansas Inc., Entergy Mississippi Inc. and Entergy Power LLC of the final Arkansas Regional Haze FIP, and exhibits to the Petition. Two of the exhibits to the Petition contain confidential business information and have not been included with this email. They will be provided separately, as addressed in the cover letter.

If you have any questions about the attached documents, please do not hesitate to contact me.

Debra J. Jezouit

Partner

Baker Botts L.L.P.

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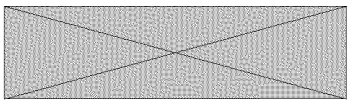

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To: Anderson, Lea[anderson.lea@epa.gov]
From: Smith, Kristi
Sent: Fri 11/25/2016 2:15:20 PM
Subject: Fwd: Petition for Reconsideration and Administrative Stay - Arkansas Regional Haze FIP - EPA-R06-OAR-2015-0189
2016-11-23 AECC Petition for Reconsideration and Administrative Stay.pdf
ATT00001.htm

FYI

- Kristi

Kristi M. Smith * Asst. General Counsel * US EPA, Office of General Counsel
* smith.kristi@epa.gov * (202) 564-3068*

CONFIDENTIAL communication for internal deliberations only; may contain deliberative, attorney-client, attorney work product, or otherwise privileged material; do not distribute outside EPA or DOJ.

Sent from my iPhone

Begin forwarded message:

From: "McCabe, Janet" <McCabe.Janet@epa.gov>
Date: November 23, 2016 at 4:01:43 PM EST
To: "Page, Steve" <Page.Steve@epa.gov>, "Schmidt, Lorie" <Schmidt.Lorie@epa.gov>, "Koerber, Mike" <Koerber.Mike@epa.gov>, "Wood, Anna" <Wood.Anna@epa.gov>, "Smith, Kristi" <Smith.Kristi@epa.gov>
Subject: FW: Petition for Reconsideration and Administrative Stay - Arkansas Regional Haze FIP - EPA-R06-OAR-2015-0189

fyi

From: Jennifer Loiacano [mailto:Jennifer.Loiacano@aecc.com]
Sent: Wednesday, November 23, 2016 3:14 PM
To: Mccarthy, Gina <McCarthy.Gina@epa.gov>; McCabe, Janet <McCabe.Janet@epa.gov>; 'curry.ron@epa.gov'; 'coleman.sam@epa.gov'; 'gray.david@epa.gov'; 'stenger.wren@epa.gov'; 'hansen.mark@epa.gov'; 'donaldson.guy@epa.gov'; 'medina.dayana@epa.gov'; Nann, Barbara <nann.barbara@epa.gov>
Cc: Stephen Cain <Stephen.Cain@aecc.com>
Subject: Petition for Reconsideration and Administrative Stay - Arkansas Regional Haze FIP - EPA-R06-OAR-2015-0189

Dear Administrator McCarthy,

Please find attached a Petition for Reconsideration and Administrative Stay filed on behalf of Arkansas Electric Cooperative Corporation (AECC). AECC will also be filing a Petition for Review today challenging the final rule. Paper copies of this request will follow by mail. If you have any questions about the Petition for Reconsideration and Administrative Stay, please contact me (contact information below) or Stephen Cain at (501) 570-2420 or Stephen.Cain@aecc.com.

Thank you in advance for your consideration of this request.

Thank you,

Jennifer L. Loiacano

Counsel for Arkansas Electric Cooperative Corporation

1 Cooperative Way

Little Rock, AR 72209

(501) 570-2187

Jennifer.Loiacano@aecc.com

To: Nann, Barbara[nann.barbara@epa.gov]
Cc: Medina, Dayana[Medina.Dayana@epa.gov]; Marks, Matthew[Marks.Matthew@epa.gov]; Lorang, Phil[Lorang.Phil@epa.gov]; Beaver, Melinda[Beaver.Melinda@epa.gov]; Anderson, Lea[anderson.lea@epa.gov]
From: Donaldson, Guy
Sent: Tue 11/22/2016 6:39:27 PM
Subject: FW: Petition for Reconsideration and Administrative Stay - Arkansas Regional Haze FIP - Docket No. EPA-R06-OAR-0189
2016-11-22 ADEQ Petition for Reconsideration and Adminstrative Stay EPA-R06-OAR-2015-0189.pdf
Appendix A - ADEQ Regional Haze FIP Petition for Reconsideration.pdf
Appendix B - ADEQ Regional Haze FIP Petition for Reconsideration.pdf
Appendix C - ADEQ Regional Haze FIP Petition for Reconsideration.pdf

I haven't looked at.

From: Stenger, Wren
Sent: Tuesday, November 22, 2016 10:13 AM
To: Hansen, Mark <Hansen.Mark@epa.gov>; Donaldson, Guy <Donaldson.Guy@epa.gov>; Medina, Dayana <Medina.Dayana@epa.gov>
Subject: Fw: Petition for Reconsideration and Administrative Stay - Arkansas Regional Haze FIP - Docket No. EPA-R06-OAR-0189

From: Jamie Ewing <jamie.ewing@arkansasag.gov>
Sent: Tuesday, November 22, 2016 10:08 AM
To: Mccarthy, Gina; McCabe, Janet; Curry, Ron; Coleman, Sam; Gray, David; Stenger, Wren; Hansen, Mark; Donaldson, Guy; Medina, Dayana; Nann, Barbara
Cc: keogh@adeq.state.ar.us; Chapman, Julie (Chapman@adeq.state.ar.us); rouse@adeq.state.ar.us; Stuart Spencer; Montgomery, William (Montgomery@adeq.state.ar.us); Sarah Tacker
Subject: Petition for Reconsideration and Administrative Stay - Arkansas Regional Haze FIP - Docket No. EPA-R06-OAR-0189

Dear Administrator McCarthy,

Please find attached a Petition for Reconsideration and Administrative Stay, with appendices, filed on behalf of the Arkansas Department of Environmental Quality (ADEQ). The State will also be filing a Petition for Review today challenging the final rule. Paper copies of this request will follow by mail. If you have any questions about the Petition for Reconsideration and A dministrative Stay, including contacting ADEQ to begin a reconsideration proceeding, please contact Stuart Spencer, Associate Director of the Office of Air Quality, ADEQ at spencer@ adeq.state.ar.us or (501) 682-0750.

Thank you for your consideration of this request.

Sincerely,

Jamie Leigh Ewing

Assistant Attorney General

Office of Arkansas Attorney General Leslie Rutledge

323 Center Street, Suite 200

Little Rock, Arkansas 72201

Office: 501.682.5310 | Fax: 501.682.3895

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UNITED STATES COURT OF APPEALS
FOR THE EIGHTH CIRCUIT

STATE OF ARKANSAS, *Petitioner*, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*, *Respondents.*	No. 16-4270 (and consolidated case nos. 16-4296, 16-4298, 16-4300, 16-4302, and 16-4304)

MOTION FOR LEAVE TO INTERVENE OF NATIONAL PARKS CONSERVATION ASSOCIATION AND SIERRA CLUB

Sierra Club and the National Parks Conservation Association ("NPCA") (collectively, "Conservation Groups") respectfully move for leave to intervene in support of the respondents United States Environmental Protection Agency and EPA Administrator Gina McCarthy (collectively, "EPA") in the above-captioned consolidated petitions for review. This Court has allowed citizen groups, including Sierra Club and NPCA, to intervene in cases seeking review of EPA actions and should do so again here.[1]

INTRODUCTION

These cases involve challenges to an EPA rule that requires installation of

[1] *See, e.g.*, Order Granting Intervention, *Nebraska v. EPA*, No. 12-3084 (8th Cir. Oct. 26, 2012).

pollution controls to protect national parks and wilderness areas from harmful air pollution that mars visibility and adversely impacts human health. *Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan*, Final Rule, 81 Fed. Reg. 66,332 (Sept. 27, 2016). The plan will reduce excessive, and in some cases uncontrolled, air pollution from seven facilities that contribute to visibility impairment at the Caney Creek and Upper Buffalo Wilderness Areas in Arkansas, Hercules Glades Wilderness Area and Mingo National Wildlife Refuge in Missouri, as well as a dozen other national parks and wilderness areas across five states in the central United States.[2] Overall, the plan will cut about 68,500 tons of sulfur dioxide emissions and 15,100 tons of nitrogen oxides *per year*[3], which will better protect the parks and the refuge areas from hazy conditions, while also providing significant health, environmental, and economic benefits to the people who live, work, and breathe air near these facilities, as well as the many thousands of people who visit and work in Arkansas and Missouri wilderness areas and refuges each year.

The State of Arkansas, operators of two facilities required to reduce

---

[2] *See* EPA-R06-OAR-2015-0189-0218 CAMx Modeling.xls at "entscn01 Contribution Results" tab.

[3] U.S. EPA, News Releases from Region 06, EPA Addresses Arkansas Regional Haze Goals (Sept. 1, 2016), *available at* https://www.epa.gov/newsreleases/epa-addresses-arkansas-regional-haze-goals.

emissions under the rule, and associated industry groups filed petitions for review of the final plan for Arkansas in this Court, which were consolidated in this proceeding.[4] The petitions seek to weaken or set aside entirely the final plan for Arkansas, thereby threatening benefits that the plan promises. As explained further below, none of the parties to this proceeding represents the Conservation Groups' legally protectable interests in EPA's haze plan. Therefore, the Conservation Groups respectfully move to intervene on the side of EPA and in defense of the haze rule under Federal Rule of Appellate Procedure 15(d).

EPA consents to this motion, while Entergy Arkansas Inc., Entergy Mississippi Inc., Entergy Power, LLC, Domtar A.W. LLC, the Arkansas Electric Cooperative Corporation, the Energy and Environmental Alliance of Arkansas, the State of Arkansas, and the Arkansas Affordable Energy Coalition take no position on the motion.

BACKGROUND

I. THE CLEAN AIR ACT'S REGIONAL HAZE PROVISIONS

Visible air pollution, or "haze," has long marred the otherwise scenic

[4] Petitioners include the State of Arkansas, Case No. 16-4270, Entergy Arkansas Inc., Entergy Mississippi Inc., Entergy Power, LLC and Domtar A.W. LLC, which own sources directly affected by EPA's final rule, and various utility industry associations, including the Arkansas Affordable Energy Coalition, Arkansas Electric Cooperative Corporation and the Energy and Environmental Alliance of Arkansas (collectively, "State" or "Industry Petitioners"). Case Nos. 16-4296, 16-4298, 16-4300, 16-4302, and 16-4304.

landscapes in our nation's treasured parks and wilderness areas. In 1977, Congress set "a national goal" of eliminating haze caused by humans and restoring air quality to natural conditions in national parks and wilderness areas ("Class I areas").[5] 42 U.S.C. § 7491(a). To reach the goal of achieving natural visibility conditions by 2064, the deadline set forth in the Clean Air Act's implementing regulations, 40 C.F.R. § 51.308(d)(1)(i)(B), each state must steadily reduce visibility impairing pollution through a regional haze State Implementation Plan ("SIP") that must be revised every 10-15 years until the Clean Air Act objective is acheived. 42 U.S.C. §§ 7410(a), 7491(b)(2). EPA is obligated to evaluate each state plan and either approve or disapprove it in whole or in part. *Id.* § 7410(k)(3). If EPA's evaluation reveals that a state plan does not comply with the Clean Air Act, EPA must disapprove the plan and may promulgate a Federal Implementation Plan ("FIP") that remedies the shortcomings. *Id.* § 7410(c)(1).

The overarching requirement for each haze plan is that it must contain the "emission limits" and "other measures as necessary to make reasonable progress toward the national goal" of eliminating haze pollution. *Id.* § 7491(b)(2). The determination of what constitutes "reasonable progress" must be made by considering four factors: the cost of pollutions controls, the time necessary for

[5] The Clean Air Act defines Class I areas to include certain national parks, wilderness areas, and international parks. 42 U.S.C. § 7472(a).

compliance, energy and non-air-quality impacts of controls, and the remaining useful life of each source. *Id.* § 7491(g)(1). In addition, state plans must include emissions limits reflecting installation and operation of the Best Available Retrofit Technology ("BART") at eligible sources[6] that are reasonably anticipated to cause or contribute to visibility impairment at national parks, wilderness areas, wildlife refuges, and other "Class I areas." *Id.* § 7491(b)(2)(A). BART is an essential component of the regional haze program because it compels emissions reductions from older, disproportionately polluting sources that often have escaped control under other Clean Air Act programs. *See id.* § 7491(b)(2)(A).

II. HAZE POLLUTION IN ARKANSAS

Arkansas contains two Class I areas, the Caney Creek and Upper Buffalo Wilderness Areas. 80 Fed. Reg. 18,944, 18,946 (proposed Apr. 8, 2015). In addition, air pollution originating in Arkansas harms air quality in Class I areas in neighboring states, particularly the Hercules Glades Wilderness Area and the Mingo National Wildlife Refuge in Missouri. 76 Fed. Reg. 64,186, 64,193 (proposed Oct. 17, 2011).

The two largest sources of haze pollution in Arkansas are the White Bluff and Independence power plants. 80 Fed. Reg. at 18,991. These power plants were

[6] A source is BART-eligible if it is a stationary source within one of 26 enumerated categories, was not in operation before August 7, 1962 but was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any pollutant. *Id.* § 7491(b)(2)(A), (g)(7).

built decades ago, but still lack any air pollution controls for sulfur dioxide and nitrogen oxides, the two most-significant haze-causing pollutants in Arkansas. *See id.* at 18,970, 18,973, 18,992-93, 18,995-96. Each plant emits more than 30,000 tons of sulfur dioxide and over 13,000 tons of nitrogen oxides per year. *Id.* at 18,991. To put that in perspective, White Bluff and Independence each emit more harmful sulfur dioxide pollution than the next ten-largest sources in Arkansas combined. *See id.*

The same pollutants that cause visibility impairment also cause significant public health impacts. Sulfur dioxide emissions are harmful to human health on their own,[7] and contribute to the formation of fine particulate matter, which can penetrate deep into the lungs and cause aggravated asthma, chronic bronchitis, heart attacks, and premature death.[8] Exposure to nitrogen oxides on their own causes asthma and other respiratory problems,[9] and contributes to formation of

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[7] Sulfur dioxide is a highly reactive gas that "directly impairs human health." *Am. Lung Ass'n v. EPA*, 134 F.3d 388, 389 (D.C. Cir. 1998). "SO_2 emissions that cause visibility impairment also contribute to increased asthma symptoms, lead to increased hospital visits, and can form particulates that aggravate respiratory and heart diseases and cause premature death." 76 Fed. Reg. 81,728, 81,752 (Dec. 28, 2011).

[8] Both short-and long-term exposure to fine particulate matter increases the risk of death from cardiovascular and respiratory diseases. 78 Fed. Reg. 3,086, 3,103, 3,105-06 (Jan. 15, 2013).

[9] U.S. EPA, Basic Information About NO_2, *available at* https://www.epa.gov/no2-pollution/basic-information-about-no2#Effects (last accessed Dec. 8, 2016).

ground-level ozone that also causes respiratory and cardiovascular diseases.[10]

III. THE STATE OF ARKANSAS'S SIP SUBMISSION

The State of Arkansas failed to submit a haze plan to EPA by the deadline of December 17, 2007, 40 C.F.R. § 51.308(b). The State submitted an incomplete plan on September 23, 2008, and then submitted a supplemental plan and supplemental information on August 3, 2010 and September 27, 2011, respectively, finally submitting a complete plan four years after the deadline. 81 Fed. Reg. 66,332, 66,333 (Sept. 27, 2016).

EPA found that for nearly all of the State's BART determinations, "the State did not satisfy all the regulatory and statutory requirements." 77 Fed. Reg. 14,604, 14,605 (Mar. 12, 2012). EPA "determined it is appropriate to finalize our proposed disapproval of the State's BART determinations for these units, because we conclude that the flaws and omissions in the State's BART analyses were significant, and that the State therefore lacked adequate record support and a reasoned basis for its analyses . . . ." *Id.* In addition to disapproving the State's BART determinations, EPA disapproved the corresponding portions of the State's long-term strategy. *Id.* at 14,676-77. Neither Arkansas nor any of the Industry Petitioners challenged that final agency action.

Under the Clean Air Act, EPA's final disapproval of the State's plan

[10] U.S. EPA, Ozone Basics, *available at* https://www.epa.gov/ozone-pollution/ozone-basics#effects (last accessed Dec. 8, 2016).

triggered a requirement for EPA to either approve a corrected state plan or issue a federal plan within two years of the disapproval. 42 U.S.C. § 7410(c)(1). When EPA failed to approve or issue a corrected plan within two years, Sierra Club filed a lawsuit to compel EPA to comply with the Clean Air Act. The district court ordered EPA either to approve a corrected state plan or issue a federal plan by August 31, 2016. Opinion and Order, *Sierra Club v. McCarthy*, No. 4:14-cv-643-JLH, Doc. 93 (E.D. Ark. Nov. 3, 2015).

With the State having not submitted a corrected plan, EPA signed a final, federal plan on August 31, which was published in the Federal Register on September 27, 2016. 81 Fed. Reg. 66,332. The plan establishes BART emission limits for sulfur dioxide, nitrogen oxides, and particulate matter for nine units at six facilities that contribute to visibility impairment at Caney Creek and Upper Buffalo in Arkansas, as well as the Hercules Glades Wilderness Area and the Mingo National Wildlife Refuge in Missouri. The plan also establishes emission limits for sulfur dioxide and nitrogen oxides for the Entergy Independence Plant pursuant to the reasonable progress and long-term strategy provisions of the Clean Air Act and haze regulations. The plan will cut about 68,500 tons of sulfur dioxide and 15,100 tons of nitrogen oxides emissions every year,[11] which will significantly

[11] U.S. EPA, News Releases from Region 06, EPA Addresses Arkansas Regional Haze Goals (Sept. 1, 2016), *available at* https://www.epa.gov/newsreleases/epa-addresses-arkansas-regional-haze-goals.

improve visibility in Arkansas and Missouri wilderness and refuge areas, while also providing significant health, economic, and environmental benefits across the central United States.

ARGUMENT

I. LEGAL STANDARD FOR INTERVENTION

A motion for leave to intervene need only "contain a concise statement of the interest of the moving party and the grounds for intervention." FED. R. APP. P. 15(d). Although the rule does not specify the factors a court should consider in ruling on such a motion, the Supreme Court has noted that "the policies underlying intervention [under FED. R. CIV. P. 24] may be applicable in appellate courts." *Int'l Union v. Scofield*, 382 U.S. 205, 217 n.10 (1965); *see also Sierra Club, Inc. v. EPA*, 358 F.3d 516, 517-18 (7th Cir. 2004) ("Rule 15(d) does not provide standards for intervention, so appellate courts have turned to the rules governing intervention in the district courts under Fed. R. Civ. P. 24.").

Intervention as of right is permitted under Federal Rule of Civil Procedure 24(a)(2) if the moving party: (1) filed a timely motion; (2) claims an interest relating to the subject of the action; (3) disposing of the action may impair or impede the moving party's ability to protect its interest; and (4) the moving party's interest is not adequately represented by existing parties. FED. R. CIV. P. 24(a)(2); *Little Rock Sch. Dist. v. N. Little Rock Sch. Dist.*, 378 F.3d 774, 780 (8th Cir.

2004). A party may intervene permissively if it has a conditional right to intervene under a statute or a claim or defense that shares a question of law or fact with the main action, and that intervention will not unduly delay or prejudice the rights of the original parties. FED. R. CIV. P. 24(b)(1)(B). "Rule 24 is construed liberally, and we resolve all doubts in favor of the proposed intervenors." *United States v. Union Elec. Co.*, 64 F.3d 1152, 1158 (8th Cir. 1995). All material allegations in the motion to intervene must be construed in favor of the proposed intervenor. *NPCA v. EPA,* 759 F.3d 969, 973 (8th Cir. 2014).

Finally, in this Circuit, an intervenor must establish Article III standing in addition to satisfying the requirements of Rule 24. *Mausolf v. Babbitt*, 85 F.3d 1295, 1300-01 (8th Cir. 1996); *United States v. Metro. St. Louis Sewer Dist.,* 569 F.3d 829, 833 (8th Cir. 2009). "[T]o satisfy Article III's standing requirements, a plaintiff must show (1) it has suffered an 'injury in fact' that is (a) concrete and particularized and (b) actual or imminent, not conjectural or hypothetical; (2) the injury is fairly traceable to the challenged action of the defendant; and (3) it is likely, as opposed to merely speculative, that the injury will be redressed by a favorable decision." *Friends of the Earth, Inc. v. Laidlaw Envtl. Servs. (TOC), Inc.*, 528 U.S 167, 180-81 (2000) (citing *Lujan v. Defenders of Wildlife*, 504 U.S. 555, 560-561 (1992)); *see also Metro. St. Louis Sewer Dist.*, 569 at 834. In assessing the proposed intervenor's interest, the court should "assume the plaintiff

will receive the relief it seeks and, from that assumption, assess the sufficiency of the prospective intervenor's motion." *NPCA*, 759 F.3d at 973.

II. CONSERVATION GROUPS HAVE STANDING TO INTERVENE.

Sierra Club and NPCA have standing to intervene as respondents. "An association has standing to bring suit on behalf of its members when its members would otherwise have standing to sue in their own right, the interests at stake are germane to the organization's purpose, and neither the claim asserted nor the relief requested requires the participation of individual members in the lawsuit." *Friends of the Earth, Inc.*, 528 U.S. at 181 (citing *Hunt v. Wash. State Apple Advertising Comm'n*, 432 U.S. 333, 343 (1977)).

Sierra Club's and NPCA's members would have standing in their own right to defend against the State and Industry Petitioners' lawsuits to protect their ability to use and enjoy Class I areas affected by pollution from Arkansas sources. For example, Sierra Club members hike, canoe, and enjoy the panoramic views in the Upper Buffalo Wilderness Area, especially the tremendous views of the Upper Buffalo River bluffs and from the top of Hawksbill Crag (which locals refer to as Whitaker Point). Declaration of Robert Allen ¶ 4 (attached at DEC10) ("Allen Decl."); Declaration of Jennifer Conner ¶ 8 (attached at DEC14) ("Conner Decl."); Declaration of Glen Hooks ¶¶ 10-11 (attached at DEC27) ("Hooks Decl."); Declaration of G. Thomas McKinney ¶ 7(attached at DEC35) ("McKinney Decl.").

Sierra Club member Thomas McKinney also hikes in the Caney Creek Wilderness Area. McKinney Decl. ¶ 8. In Missouri, Sierra Club member John Hickey has been visiting the Mingo National Wildlife Refuge—which he refers to as the "Serengeti of Missouri" because of its huge vistas and abundant wildlife—for decades to canoe and kayak with friends and family. Declaration of John Hickey ¶¶ 6-9 (attached at DEC21) ("Hickey Decl."). Sierra Club member Jennifer Conner enjoys visiting the Hercules Glades Wilderness Area because of its unique wildlife and the magnificent views from some of the tallest Ozark peaks in the region. Conner Decl. ¶¶ 5-7. Each of these Sierra Club members visits these parks to enjoy the unique vistas, Allen Decl. ¶ 5; Conner Decl. ¶¶ 7-8; Hickey Decl. ¶ 9; Hooks Decl. ¶ 12; McKinney Decl. ¶ 9, and therefore each is harmed by the haze that diminishes views in these otherwise wild places.

NPCA member Janet Nye regularly visits the Upper Buffalo Wilderness Area to hike, birdwatch, and identify wildflowers. Declaration of Janet Nye ¶ 3 (attached at DEC7) ("Nye Decl."). When she hikes in the Upper Buffalo, haze pollution diminishes the "vistas of the Ozarks." *Id.* ¶ 6. NPCA member Don Castleberry regularly visits the Upper Buffalo Wilderness Area and National River to hike, boat, and take photographs. Declaration of Don Castleberry ¶¶ 3, 7 (attached at DEC1) ("Castleberry Decl."). As Mr. Castleberry describes, haze can be seen in the Upper Buffalo from places "such as Hawksbill Overlook." *Id.* ¶ 6.

If the State and Industry Petitioners succeed in reducing or eliminating the pollution reductions that the final rule promises, haze pollution will increase, which will make Ms. Nye's and Mr. Castleberry's injuries worse. *See id.* ¶¶ 6-7.

If the State and Industry Petitioners were to prevail in their lawsuits, the regional haze plan for Arkansas would be weaker and haze pollution would increase, which in turn would harm the recreational and aesthetic interests of Sierra Club members Robert Allen, Jennifer Conner, John Hickey, Glen Hooks, and G. Thomas McKinney, and many other of Sierra Club's 2,597 Arkansas members and its 9,000 Missouri members. Declaration of Huda Fashho ¶ 4 (attached at DEC20). Janet Nye, Don Castleberry, and other NPCA members would suffer similar injuries were the State and Industry Petitioners to succeed in weakening or overturning entirely the Arkansas haze plan. *See* Declaration of Stephanie Kodish ¶¶ 6-8 (attached at DEC4) ("Kodish Decl.") (describing NPCA's long-standing work to improve air quality in parks and wilderness areas in Arkansas).

The Supreme Court and this Circuit have long held that such aesthetic and recreational interests in public lands demonstrate injury-in-fact for purposes of satisfying Article III standing requirements. *See Laidlaw*, 528 U.S. at 183 ("We have held that environmental plaintiffs adequately allege injury in fact when they aver that they use the affected area and are persons 'for whom the aesthetic and recreational values of the area will be lessened' by the challenged activity."

(quoting *Sierra Club v. Morton*, 405 U.S. 727, 735 (1972))); *Sierra Club v. U.S. Army Corps of Eng'rs*, 645 F.3d 978, 989 (8th Cir. 2011).

These aesthetic and recreational injuries would be fairly traceable to the relief sought by the State and Industry Petitioners. While the Petitioners have not yet filed their opening briefs and have not yet stated the grounds for their petitions, the comments filed by the State and Industry Petitioners on the proposed rule give an indication of the arguments they might raise. *See* 42 U.S.C. § 7607(d)(7)(B) (limiting judicial review of certain final actions taken by EPA under the Clean Air Act to claims first presented to the agency in comments). In comments, the State and Industry Petitioners argue against emission limits and pollution controls and oppose the Arkansas haze rule. If the State and Industry Petitioners were to prevail in this lawsuit, there would be a significantly smaller reduction in the haze pollution that harms Robert Allen, Jennifer Conner, John Hickey, Glen Hooks, G. Thomas McKinney, Janet Nye, Don Castleberry, and other Sierra Club and NPCA members and thus, Sierra Club's and NPCA's members would be deprived of the benefits from EPA's rule. The causal link between Sierra Club's and NPCA's members' injuries and the State and Industry Petitioners prevailing in their lawsuits satisfies traceability under Article III. *See Nat'l Wildlife Fed'n v. Agric. Stabilization & Conservation Serv.*, 901 F.2d 673, 677-78 (8th Cir. 1990) (finding that plaintiffs' alleged injuries stemming from the destruction of wetlands were

fairly traceable to an exemption from a law that discouraged converting wetlands to cropland).

The aesthetic and recreational injuries that would be caused by the State and Industry Petitioners prevailing would be redressed by the court denying their petitions for review. While the Conservation Groups maintain that certain provisions of the final regional haze rule are legally inadequate, they seek to defend the other provisions of the rule which comply with the Clean Air Act and will reduce the pollution that harms their members. Thus, denying the State and Industry petitions for review would protect the benefits that Sierra Club and NPCA members stand to gain from EPA's rule, which will reduce the air pollution that causes aesthetic and recreational injuries to members' interests. *Cf.* *Nat'l Wildlife Fed'n*, 901 F.2d at 677-78 (finding that harm stemming from the destruction of wetlands could be redressed by a decision that would prevent further destruction).

Finally, the Conservation Groups satisfy the requirements of associational standing because the interests at stake are germane to the Sierra Club's and NPCA's purposes,[12] and the Conservation Groups' defense of EPA'shaze plan

[12] Sierra Club's mission is to protect and restore wild places, and the organization has advocated across the country, including in Arkansas and Missouri, for regional haze plans that adequately protect human health and natural areas. Hooks Decl. ¶¶ 4-7; Hickey Decl. ¶ 4. Similarly, NPCA is a nonprofit organization with a mission of protecting and enhancing America's national parks for the use and enjoyment of present and future generations. Kodish Decl. ¶ 4. Over the last several years,

does not require the participation of any individual members. *See Mausolf*, 85 F.3d at 1302 (conservation organization had standing to intervene in a lawsuit seeking to lift restrictions on snowmobiling in national parks, which would have directly impacted the conservationists' concrete aesthetic and recreational interests); *Int'l Union, United Auto., Aerospace and Agr. Implement Workers of Am. v. Brock*, 477 U.S. 274, 287-88 (1986) (holding union workers had associational standing where lawsuit raised a "pure question of law" and did not require evaluation of any of the "unique facts" personal to the union's members). Thus, Sierra Club and NPCA have standing to intervene as respondents.

III. CONSERVATION GROUPS SATISFY ALL OF THE REQUIREMENTS FOR INTERVENTION.

Sierra Club and NPCA meet the requirements to intervene as of right because the motion is timely, they have recognized interests in the actions, disposing of the actions may impair those interests, and the existing parties do not adequately represent their interests. *See* FED. R. CIV. P. 24(a)(2). In addition, the Conservation Groups meet the requirements for permissive intervention because the motion is timely and there are common questions of law and fact between Conservation Groups' defenses and the main actions. *See* FED. R. CIV. P. 24(b)(1)(B).

NPCA has worked for effective regional haze plans, and has participated in the rulemaking to develop the Arkansas regional haze plan. *Id.* ¶¶ 4-8.

A. This Motion Is Timely.

The State of Arkansas filed its petition for review of the Arkansas regional haze rule on Nov. 22, 2016. Conservation Groups are filing this motion within 30 days after the filing of the first petition in this consolidated proceeding, and no substantive filings have occurred. *See* FED. R. APP. P. 15(d) (providing a 30-day period for filing a motion to intervene in a petition for review of agency action).

B. NPCA and Sierra Club Have Recognized and Legally-Protectable Interests in These Cases.

Both Sierra Club and NPCA have substantial and legally-protectable interests in the fate of the regional haze plan for Arkansas and, thereby, satisfy the requirement to have a recognized interest in these actions. *See Union Elec. Co.*, 64 F.3d at 1161. While the State and Industry Petitioners have not yet submitted their opening briefs, they will be limited to claims they raised in comments to EPA. *See* 42 U.S.C. § 7607(d)(7)(B). Given the comments submitted by the State and Industry Petitioners, they are likely to argue that EPA's haze plan is unlawful in whole or in part.[13]

[13] *See, e.g.*, Arkansas Attorney General comments, Docket ID No. EPA-R06-OAR-2015-0189-0162; Arkansas Department of Environmental Quality comments, Docket ID No. EPA-R06-OAR-2015-0189-0160; Arkansas Electric Cooperative Corporation comments, Docket ID No. EPA-R06-OAR-2015-0189-0169; Domtar A.W. LLC comments, Docket ID No. EPA-R06-OAR-2015-0189-0161; Energy and Environmental Alliance of Arkansas comments, Docket ID No. EPA-R06-OAR-2015-0189-0173; Entergy Arkansas Inc. comments, Docket ID No. EPA-R06-OAR-2015-0189-0166; Entergy Mississippi Inc. comments, Docket ID No.

As demonstrated above, the members of Sierra Club and NPCA have aesthetic and recreational interests in using the public lands that are damaged by haze pollution from sources in Arkansas, and have worked for several years to protect those interests in various proceedings. *See supra* at 11-13; *see also* Allen Decl. ¶¶ 4-5; Conner Decl. ¶¶ 5-8; Hickey Decl. ¶¶ 6-9; Hooks Decl. ¶¶ 10-12; McKinney Decl. ¶¶ 6-7; Kodish Decl. ¶¶ 4-7. To the extent that the State and Industry Petitions seek to weaken or eliminate the pollution limits contained in the final plan, their lawsuits threaten the interests of Sierra Club and NPCA members in reducing haze pollution. Accordingly, Sierra Club and NPCA have recognized interests to intervene here. *See Mausolf*, 85 F.3d at 1302 (conservation organization had recognized interest sufficient to justify intervention where it "consistently demonstrated its interest in the Park's well-being (as it sees it) and has worked hard over the years, in various proceedings, to protect that interest").

C. Resolution of the Cases Without the Participation of the NPCA and Sierra Club May Impair the Conservation Group's Interests.

This Circuit has noted that an intervenor need only show that the resolution of an action *may*, as a practical matter, impair the intervenor's interests. *See Union*

EPA-R06-OAR-2015-0189-0168. Sierra Club and NPCA could not locate comments from Petitioner Arkansas Affordable Energy Coalition in the EPA docket for the rulemaking but certain members of the industry group did submit comments, like Nucor Steel-Arkansas, a division of Nucor Corporation, and Nucor-Yamato Steel Company, which filed joint comments. Docket ID No. EPA-R06-OAR-2015-0189-0163.

Elec. Co., 64 F.3d at 1161. The Conservation Groups easily satisfy that standard. Indeed, the State and Industry claims seek to set aside or weaken EPA's haze plan, which directly threatens NPCA's and Sierra Club's recognized aesthetic and environmental interests in a regional haze plan that effectively reduces haze pollution. Thus, resolving these petitions without the participation of the Conservation Groups "may as a practical matter impair or impede" their ability to protect their interests. FED. R. CIV. P. 24(a)(2).

D. The Existing Parties Do Not Adequately Represent Sierra Club's or NPCA's Interests.

Finally, the existing parties do not adequately represent the interests of Sierra Club and NPCA. *See* FED. R. CIV. P. 24(a)(2). In this Circuit, establishing that the existing parties do not adequately represent the interests of a proposed intervenor is a "minimal burden." *Mausolf*, 85 F.3d at 1303. An intervening party need only show that the current parties "may be" inadequate to represent its interests. *Sierra Club v. Robertson*, 960 F.2d 83, 85-86 (8th Cir. 1992).[14]

[14] Neither the State nor Industry Intervenors can represent the Environmental Groups's interests. Indeed, Sierra Club and NPCA have filed their own petition for review to challenge certain provisions in the final rule that fall short of what is required under the Clean Air Act, whereas the State and Industry Petitioners will argue that the plan exceeds permissible limits on pollution. The State and Industry Petitioners advocate positions regarding the Arkansas regional haze rule that directly conflict with the position of Sierra Club and NPCA and, thus, the State and Industry Petitioners cannot represent Sierra Club's and NPCA's interests.

Here, EPA may not adequately represent Sierra Club's and NPCA's interests for two reasons. First, the agency's obligation to balance the broad (and often conflicting) interests of the public, the states, and regulated entities under the Clean Air Act is fundamentally different than Sierra Club's and NPCA's "narrower and more parochial interests" in the prompt issuance of a lawful plan for reducing visibility pollution in the Caney Creek, Hercules Glades, and Upper Buffalo Wilderness Areas, and the Mingo National Wildlife Refuge. *Mille Lacs Band of Chippewa Indians v. Minnesota*, 989 F.2d 994, 1001 (8th Cir. 1993); *see also South Dakota v. Ubbelohde*, 330 F.3d 1014, 1025 (8th Cir. 2003) (holding that the government did not represent the interests of the proposed intervenors where the government was forced to weigh competing interests and might have to favor one over another). This is so even if the government shares common positions or seeks the same relief in a particular lawsuit. *Robertson*, 960 F.2d at 86 (no adequate representation of interests where the state was "obliged to represent the interests of all of its citizens," and the plaintiff environmental groups represented the "interests of their members and answer only to their members")

Second, Sierra Club and NPCA have a history of disagreements with EPA over the Arkansas haze plan that precludes EPA from adequately representing Sierra Club's and NPCA's interests. *See Mausolf*, 85 F.3d at 1303. Indeed, Sierra Club was forced to sue EPA in district court to obtain an order compelling the

agency to comply with the Clean Air Act and finalize a state or federal plan for regional haze in Arkansas. Opinion and Order, *Sierra Club v. McCarthy*, No. 4:14-cv-643-JLH, Doc. 93 (E.D. Ark. Nov. 3, 2015). The disagreement between the Conservation Groups and EPA over the Arkansas haze plan continues today, as evidenced by the petition for review which Sierra Club and NPCA filed. *See NPCA v. EPA*, No. 16-4309 (8th Cir. petition filed Nov. 28, 2016). Given the history of adverse litigation between EPA and the Conservation Groups regarding the rule at issue, EPA cannot adequately represent the Conservation Groups' interests. *See Mausolf*, 85 F.3d at 1303 (government did not adequately represent an association of snowmobiling advocates where conservationists had earlier sued the government to impose the current restrictions, and it was "unquestioned that, in the past, the Government has waived and failed to enforce regulations against snowmobile use in the Park").

In sum, the Conservation Groups satisfy each of the elements of Federal Rule of Civil Procedure 24(a)(2) for intervention as of right.[15]

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[15] In addition to meeting the standards for intervention as of right, the Conservation Groups meet the requirements for permissive intervention. The Conservation Groups intend to assert defenses of EPA's regional haze plan that share questions of law and fact with Arkansas and the Industry Petitioners' challenges, including whether the final haze plan is consistent with the Clean Air Act and supported by the evidence contained in the agency's record. FED. R. CIV. P. 24(b)(1). Moreover, the motion is timely filed. Thus, intervention would not unduly delay or unduly prejudice State or Industry Petitioners. FED. R. CIV. P. 24(b)(3).

CONCLUSION

For the foregoing reasons, Sierra Club and NPCA respectfully request that this Court grant their motion to intervene in support of respondent EPA in Case Nos. 16-4270, 16-4296, 16-4298, 16-4300, 16-4302, and 16-4304.

Respectfully submitted this 12th day of December, 2016.

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CERTIFICATE OF COMPLIANCE

The undersigned counsel states that this motion complies with FED. R. APP. P. 27(d)(2)(A) because it contains 5,088 words, excluding the caption and signature blocks, as counted by a word processing system and, therefore, is within the word limit. This motion also complies with typeface requirements of FED. R. APP. P. 27(d)(1)(E) because it has been prepared in a proportionally spaced typeface in 14-point Times New Roman font.

Dated: December 12, 2016

/s/ Mary Whittle
MARY WHITTLE

Counsel for Proposed Intervenors National Parks Conservation Association and Sierra Club

CERTIFICATE OF SERVICE

I hereby certify that on December 12, 2016, I electronically filed the foregoing motion and attached declarations with the Clerk of the Court for the United States Court of Appeals for the Eighth Circuit by using the CM/ECF system. Participants in the case who are registered CM/ECF users will be served by the CM/ECF system.

I further certify that the foregoing motion and attached declarations have been sent by First-Class Mail, postage prepaid to the following non-CM/ECF participants:

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Honorable Regina McCarthy
U.S. ENVIRONMENTAL
PROTECTION AGENCY
William Jefferson Clinton Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

/s/ Mary Whittle
MARY WHITTLE

Counsel for Proposed Intervenors National Parks Conservation Association and Sierra Club

UNITED STATES COURT OF APPEALS
FOR THE EIGHTH CIRCUIT

DECLARATIONS IN SUPPORT OF MOTION TO INTERVENE IN CASE Nos. 16-4270, 16-4296, 16-4298, 16-4300, 16-4302, and 16-4304

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DECLARATION OF DON CASTLEBERRY
IN SUPPORT OF MOTION TO INTERVENE IN CASE Nos. 16-4270, 16-4296, 16-4298, 16-4300, 16-4302, 16-4304

I, DON CASTLEBERRY, state and declare that the following statements are true and correct to the best of my knowledge, information, and belief and are based on my personal experiences.

1. I am a member of the National Parks Conservation Association ("NPCA"). I joined in 1996 because I was very impressed with the work NPCA does to protect national parks. Having retired from the National Park Service after 32 years of serving in such roles as Superintendent, Regional Director, and Associate Director - Operations, I understand the importance of non-profits and the significant impact they can make for effective change. I transitioned from government work to becoming a Board member for NPCA until 2001 when I then served on NPCA's National Council until 2012. Today, I continue to work closely with NPCA's Southeast Regional Office and their ongoing issues, particularly those involving my home State of Arkansas.

2. National Parks Conservation Association represents my interest in restoring the clear views and clean air in our country's special Class I national parks and wilderness areas. I have been personally involved in the protection of this region since the late 1960's.

3. I live in Little Rock, Arkansas. I enjoy visiting and hike, boat, and

conduct casual photography in the Upper Buffalo Wilderness Area. I was there last in the summer of 2015 to walk the historic trails and view the waterfalls.

4. In 2017 and in future years, I intend to continue to visit the Upper Buffalo Wilderness Area to hike and take pictures.

5. I value the natural resources of the Upper Buffalo Wilderness Area and believe that Congress was right in making the protection and restoration of our nation's pristine Class I areas a priority. I have an academic and professional science background in geology and hold a Masters degree in Environmental Management, from Indiana University, where I've served as adjunct lecturer for classes made up of elected public officials. I understand the general composition of air pollution and how this pollution impacts entire ecosystems. I have read, specifically, how it can be detrimental to water and wildlife.

6. Haze in the Upper Buffalo Wilderness Area exists and is evident when viewing the vistas of the Ozarks such as Hawksbill Overlook. I am aware that some of this haze is caused by air pollution from manmade sources—specifically from Independence and White Bluff. I understand that the proposed haze plan for the state of Arkansas would require these facilities to reduce their SO_2 emissions, which would reduce haze pollution overall.

7. Although air pollution exists in the Upper Buffalo Wilderness Area, I plan to return to hike on a regular basis as long as I am physically able.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the forgoing is true and correct. Executed in Little Rock, Arkansas, on this 9th day of December, 2016.

DON CASTLEBERRY

DECLARATION OF STEPHANIE KODISH

I, STEPHANIE KODISH, state and declare as follows:

1. I am of legal age and competent to give this declaration. All information herein is based on my own personal knowledge unless otherwise indicated.

2. I work at 706 Walnut Street, Suite 200, Knoxville, Tennessee 37902.

3. I am director and counsel for the National Parks Conservation Association's ("NPCA") Clean Air Program. I direct the work of NPCA around the country to protect and improve air quality in our national parks.

4. The mission of the National Parks Conservation Association is to protect and enhance America's national parks for the use and enjoyment of present and future generations. Since NPCA was established in 1919, it has advocated for protection of the natural environment, including air quality, in and around the national parks and other federal lands. NPCA is a membership-based organization and has members in Arkansas and Missouri.

5. For many years, NPCA has been working to ensure that the Clean Air Act's regional haze program be implemented and result in meaningful progress toward eliminating visible air pollution in our national parks and wilderness areas. NPCA has participated in the state and federal processes for developing regional haze plans for a significant number of states. For example, NPCA has retained

experts to analyze proposed regional haze plans and has submitted comments on those plans to both states and EPA. NPCA has prepared and published reports on the regional haze program and undertaken a variety of communications, outreach, litigation, and policy initiatives to advocate for regional haze plans that improve air quality in our national parks. This work, advocating for strong, legally adequate haze plans, is central to NPCA's mission to protect and enhance America's national parks and wilderness areas.

6. As NPCA has done in other states, NPCA submitted comments on the proposed, federal haze plan for Arkansas. When EPA issued the final regional haze rule for Arkansas, and failed to correct various legal errors, NPCA filed a petition for review challenging the plan. NPCA also intends to move to intervene in the petitions filed by the State of Arkansas and industry challenging the final haze plan.

7. Emissions from Arkansas sources impair visibility in several Class I areas, including the Caney Creek and Upper Buffalo Wilderness Areas in Arkansas and the Hercules-Glades Wilderness Area and the Mingo National Wildlife Refuge in Missouri. NPCA has worked to protect the overall environment, including the air quality, in these areas, particularly the Upper Buffalo Wilderness Area. For example, NPCA was involved in stopping the Bear Creek Dam, which would have been located approximately 20 miles from the boundary of the Buffalo National

River which resulted in a watershed-based interpretation of Section 7(a) of the Wild and Scenic River Act. Currently, NPCA is also working to guard the Buffalo National River air and watershed from pollution related to C&H Farms' sizeable confined animal feeding operation and experimental swine waste disposal system located in Newton County, Arkansas.

8. In addition, NPCA has been deeply involved in protecting Caney Creek from haze pollution caused by emissions from Texas sources. NPCA submitted comments on the State of Texas's haze plan as well as EPA's replacement haze plan, and NPCA is an intervenor-respondent in the litigation in multiple circuit courts over EPA's federal haze plan for Texas.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the forgoing is true and correct.

Executed in Knoxville, Tennessee, on December 7th, 2016.

Stephanie Kodish

STEPHANIE KODISH

DECLARATION OF JANET NYE
IN SUPPORT OF MOTION TO INTERVENE IN
CASE Nos. 16-4270, 16-4296, 16-4298, 16-4300, 16-4302, 16-4304

I, JANET NYE, state and declare that the following statements are true and correct to the best of my knowledge, information, and belief and are based on my personal experiences and knowledge.

1. I am a member of the National Parks Conservation Association ("NPCA"). I joined in 1990 because I am passionate about the national parks and realized that NPCA was a strong advocate in protecting the parks that fill my soul. Twenty years later, I enhanced my support and became a Trustee for the Parks because I wanted to make a stronger impact for NPCA's ongoing work regionally, and in regards to air quality, wildlife, and water protection.

2. National Parks Conservation Association representsmy interest in restoring the clear views and clean air in our country's special Class I national parks and wilderness areas.

3. I live in Maumelle, Arkansas. I also own a second home in Gilbert, Arkansas located just over an hour's distance from the Upper Buffalo and I regularly visit and hike in the Upper Buffalo Wilderness Area. This area provides me the solitude I crave and is a favorite place of mine to birdwatch and identify wildflowers in the spring. I plan my visits to coincide with the natural cycles o f the seasons and usually visit in both the spring and autumn.

4. In 2017 and in future years, I intend to continue to visit the Upper Buffalo Wilderness Area to hike and observe the flora and fauna.

5. I value the natural resources of the Upper Buffalo Wilderness Area and believe that Congress was correct in making the protection and restoration of our nation's pristine Class I areas a priority. I pride myself on leaving no trace and these places are perfect for me to practice these beliefs. I also firmly believe that we must remind ourselves that we share this planet and these special places with other organisms—all of which are harmed by poor air quality.

6. Haze in the Upper Buffalo Wilderness Area exists and is evident when viewing the vistas of the Ozarks. I am aware that some of this haze is caused by air pollution from manmade sources—specifically from power plants such as Independence and White Bluff. I understand that the final haze plan for the State of Arkansas would require these facilities to reduce their SO_2 emissions, which would reduce haze pollution overall.

7. I also understand that the State of Arkansas and various companies have filed lawsuits challenging the haze plan for Arkansas. I don't believe that they should win the ability to continue to pollute at the levels that they do—they need to be accountable. I believe in a haze plan that would allow the air over the Upper Buffalo Wilderness to be free of haze. I want to be able to look out from the bluffs and see clearly to the distant ridgeline. I want a plan to provide a certainty that all

that is seen beneath the skies, the flora and fauna, and the water and soil, have a healthy environment needed to sustain this area for generations to come.

8. Although air pollution exists in the Upper Buffalo Wilderness Area, I plan to return to hike on a regular basis as long as I am physically able.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the forgoing is true and correct.

Executed in Maumelle, Arkansas, on this 7th day of December, 2016.

JANET NYE

DECLARTION OF ROBERT ALLEN

1. My name is Robert Allen. I am of legal age and competent to give this declaration. All information herein is based on my own personal knowledge unless otherwise indicated.

1. I live in Dover, Arkansas. I have lived in the Ozark region of Arkansas for over 35 years.

2. I am an active member of Sierra Club and have been a member for the past 20 years. I am on the Executive Committee of Sierra Club's Arkansas Chapter and have served in that capacity since 2010. I became a member of Sierra Club because I support and believe in its activist stance on environmental issues. I am proud that Sierra Club takes action to improve the environment in Arkansas and around the country. I am also a member of a few other environmental non-profit organizations.

3. One of my favorite things about living in Arkansas is the many opportunities for outdoor activity that we have here. In fact, part of the reason I moved to the Ozarks was to spend more time outdoors. I enjoy camping, hiking, canoeing, and fishing, among other activities. I plan to continue to engage in these outdoor activities.

4. I live approximately 60 miles south of the Upper Buffalo Wilderness Area. I have hiked a beautiful trail called the Hawksbill Crag Trail that lies within the Upper Buffalo Wilderness Area. The trail leads to a peak called Hawksbill Crag that commands a panoramic view of the Upper

Buffalo Wilderness Area and other natural areas of northwest Arkansas. The wilderness area is a beautiful forested area of predominately oak and hickory.

5. I am very concerned about the impacts of haze pollution on the Upper Buffalo Wilderness Area, Caney Creek Wilderness Area, and other nearby natural areas. My enjoyment of the Hawksbill Crag Trial and other natural areas in this part of Arkansas is greatly diminished by haze. An important part of the experience of visiting Upper Buffalo Wilderness Area is to stand on Hawksbill Crag and admire the magnificent surrounding mountains and forests. Haze decreases visibility and my ability to take in the views from Hawksbill Crag, lessening my enjoyment of that hike and others in the Ozarks. I intend to hike the Hawksbill Crag Trial again in the future, and expect to do so next year. However, if haze pollution persists and visibility continues to worsen, I will be less likely to visit and enjoy these areas in the future.

6. I understand that air pollution from power plants and other industrial facilities in Arkansas causes or contributes to haze that diminishes visibility in the Upper Buffalo Wilderness Area, Caney Creek Wilderness Area, and other natural areas in the Ozarks. I share Sierra Club's strong interest in protecting the Upper Buffalo Wilderness Area, Caney Creek Wilderness Area, and other natural areas in Arkansas from haze pollution.

7. In September 2016, the U.S. Environmental Protection Agency ("EPA") finalized a federal plan to address the haze problem in Arkansas. I understand that EPA's federal plan requires significant reductions in sulfur dioxide ("SO_2") pollution from industrial sources that when implemented will significantly improve visibility in the Caney Creek and Upper Buffalo Wilderness Areas. I also understand that once these pollution reductions go into effect, they will go a long way toward eventually helping return air quality in the Caney Creek and Upper Buffalo Wilderness Areas to natural conditions.

8. I support this aspect of EPA's plan to clean up haze pollution at the Caney Creek and Upper Buffalo Wilderness Areas without further delay. If the plan is implemented, I believe it will benefit me and other Sierra Club members who use and enjoy these parks by lessening the impacts of air pollution at the Caney Creek and Upper Buffalo Wilderness Areas, improving the views, and helping to protect human health. If EPA's haze reduction plan is implemented in Arkansas, hiking and other outdoor activities in places such as the Upper Buffalo Wilderness Area and Caney Creek Wilderness Area will be more enjoyable for me. If EPA's plan is set aside or delayed, those benefits will be lost.

9. There are other aspects of EPA's rule, however, that I believe are insufficiently protective of air quality at places like the Caney Creek and

Upper Buffalo Wilderness Areas. It is my understanding, for example, that while EPA's federal plan requires significant reductions in SO_2 pollution, EPA required only modest reductions in other visibility impairing pollutants, like nitrogen oxides ("NOx"), from power plants such as Independence and Lake Catherine. I further understand that EPA could have required more significant reductions in NOx pollution, which would have achieved even more substantial improvement in visibility at these parks.

10. While EPA's haze plan is a critical measure to protect air quality in Arkansas, I also believe that I am harmed by EPA's unwillingness to require more significant reductions in NOx pollution, which would have resulted in even more improvement in visibility at places like the Caney Creek and Upper Buffalo Wilderness Areas. I support Sierra Club's effort to require more significant reductions in NOx pollution from Arkansas sources because I believe it would go a long way toward eliminating man-made haze pollution at places like the Caney Creek and Upper Buffalo Wilderness Areas, and it would improve my own use and enjoyment of those important places.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: December 5th, 2016

Robert Allen

DECLARATION OF JENNIFER CONNER

1. My name is Jennifer Conner. I am of legal age and competent to give this declaration. All information herein is based on my own personal knowledge unless otherwise indicated.

2. I live in Pierce City, Missouri.

3. I am an active member of Sierra Club and have been a member since 2012. I serve on the executive committees for the Missouri Chapter and for the Missouri Chapter's White River group. In recent years, I have been involved in Sierra Club's work educating the public on pollution issues related to coal-burning power plants, focusing mostly on halting the construction of a coal ash landfill on fragile karst topography near Springfield, Missouri. I am a member and volunteer leader of Sierra Club because I support its advocacy on environmental issues.

4. I recreate in wild places throughout Missouri and in other states, including Arkansas. I enjoy camping, hiking, backpacking, kayaking, and birding, among other activities. I plan to continue to engage in these outdoor activities.

5. I have visited the Hercules Glades Wilderness Area approximately twenty times in my life, having first gone there about 15 years ago when I was in college in Springfield, Missouri. During college, I visited the Hercules Glades Wilderness Area many times for research and

recreation. Over the years, I have visited the Hercules Glades Wilderness Area with friends and my husband, but on most of my trips there, I visited alone. About ten years ago, I spent an entire week backpacking in the Hercules Glades Wilderness Area by myself. I wrote an article for Ozark Outdoors magazine, published in 2013, about the Hercules Glades Wilderness Area, which described the ecology of the Area and chronicled one of my visits. I now live about a two hours' drive from Hercules Glades Wilderness Area and plan to visit many times in the future. Specifically, I am planning an overnight backpacking trip there with my husband in January 2017.

6. The abundance of wildlife, including many plants and animals that are rare in Missouri, has drawn me to the Hercules Glades Wilderness Area. On a trip a few years ago, a friend and I found tarantulas. I have seen many snakes in the Hercules Glades Wilderness Area, including a pygmy rattlesnake and a cottonmouth, which I almost stepped on while hiking the Long Creek trail, within the Wilderness Area boundary. I have also encountered collared lizards that are uncommon in other Missouri habitats but are common in Ozark glade areas. There are flowers that grow in Hercules Glades Wilderness Area that are uniquely common in Ozark glade areas, including my favorite, the limestone calamint, which is a tiny purple flower that lets off a powerful, wonderful aroma. At night, while camping

inside the Hercules Glades Wilderness Area, I have heard the calls of coyotes and bobcats.

7. My enjoyment of the Hercules Glades Wilderness Area and other natural areas in Missouri is diminished by haze. The tremendous views are one of my favorite things about visiting the Hercules Glades Wilderness Area. Glades are by definition an area with large swaths of rock outcroppings and few trees, and the Hercules Glades Wilderness Area contains some of the tallest Ozark Mountains in the nearby region. Because there are few trees obstructing views, some of these relatively tall outcroppings provide a magnificent view of the surrounding region. The existence of haze, which decreases visibility, diminishes my enjoyment of the Hercules Glades Wilderness Area and negatively affects the whole wilderness experience for me by inserting a man-made pollutant in an otherwise wild place. To illustrate the importance of this place and its vistas, I wrote a novel in 2016, in which the main character visits the Hercules Glades Wilderness Area in part to take in the tremendous views and to connect with nature.

8. I have also visited Upper Buffalo Wilderness Area in Arkansas three or four times. My husband and I have been on multi-day river float trips on the Upper Buffalo River that go through the Upper Buffalo Wilderness Area. On one of these trips, we witnessed bald eagles actively

hunting fish. The views of large bluffs are magnificent in the Upper Buffalo Wilderness Area. Haze decreases visibility and therefore lessens my enjoyment of visiting the Upper Buffalo Wilderness Area. I intend to visit the Upper Buffalo Wilderness Area again in the future.

9. I understand that air pollution from power plants and other industrial facilities in Arkansas causes or contributes to haze that diminishes visibility in the Hercules Glades Wilderness Area, other natural areas in Missouri, and in the Upper Buffalo Wilderness Area in Arkansas. I share Sierra Club's strong interest in protecting these parks and other natural areas in Arkansas and Missouri from haze pollution. I am concerned about the impacts of haze pollution on the health of the people of Missouri and on the scenic views at the Hercules Glades Wilderness Area, Upper Buffalo Wilderness Area, and other natural areas in the Ozarks.

10. In September 2016, the U.S. Environmental Protection Agency ("EPA") finalized a federal plan to address the haze problem caused by pollution sources in Arkansas that impact visibility in Arkansas and Missouri, including at the Hercules Glades Wilderness Area and Upper Buffalo Wilderness Area. I understand that EPA'sfederal plan requires significant reductions in sulfur dioxide ("SO_2") pollution from Arkansas industrial sources that when implemented will significantly improve visibility in the Hercules Glades Wilderness Area, Upper Buffalo Wilderness

Area, and other natural areas in the Ozarks. I also understand that once these pollution reductions go into effect, they will go a long way toward eventually helping return air quality in the Hercules Glades Wilderness Area and Upper Buffalo Wilderness Area to natural conditions.

11. I support this aspect of EPA'splan to clean up haze pollution at the Hercules Glades Wilderness Area and Upper Buffalo Wilderness Area without further delay. If the plan is implemented, I believe it will benefit me and other Sierra Club members who use and enjoy these parks by lessening the impacts of air pollution at the Hercules Glades Wilderness Area and Upper Buffalo Wilderness Area, improving the views, and helping to protect human health. If EPA'shaze reduction plan is implemented, camping, hiking, and other outdoor activities in places such as the Hercules Glades Wilderness Area will be more enjoyable for me and my family. If EPA's plan is set aside or delayed, those benefits will be lost.

12. There are other aspects of EPA's rule, however, that I believe are insufficiently protective of air quality at places like the Hercules Glades Wilderness Area and Upper Buffalo Wilderness Area. It is my understanding, for example, that while EPA'sfederal plan requires significant reductions in SO_2 pollution, EPA required only modest reductions in other visibility impairing pollutants, like nitrogen oxides ("NOx"), from Arkansas power plants such as Independence and Lake Catherine. I further

understand that EPA could have required more significant reductions in NOx pollution, which would have achieved even more substantial improvement in visibility at these Arkansas and Missouri parks.

13. While EPA'shaze plan is a critical measure to protect air quality in Arkansas and Missouri, I also believe that I am harmed by EPA's unwillingness to require more significant reductions in NOx pollution, which would have resulted in even more improvement in visibility at places like the Hercules Glades Wilderness Area and Upper Buffalo Wilderness Area. I support Sierra Club's effort to require more significant reductions in NOx pollution from Arkansas sources because I believe it would go a long way toward eliminating man-made haze pollution at places like the Hercules Glades Wilderness Area and Upper Buffalo Wilderness Area, and it would improve my own and family's use and enjoyment of those important places.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 12/7/16

Jennifer Conner

DECLARATION OF HUDA FASHHO

I, Huda Fashho, state and declare as follows:

1. I am a Sierra Club employee. My title is Associate Director, Member Care. I have held this position for approximately five years.

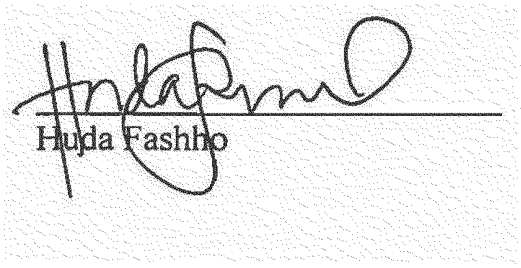
2. In my role, I manage aspects of Sierra Club's customer service functions related to members, including maintaining an accurate list of members and managing the organization's member databases.

3. When a person becomes a member of Sierra Club, that person's current residential address is recorded in our membership database. This database is regularly updated to add new members, reflect address changes, and change membership status for those who are no longer active members.

4. Sierra Club currently has 643,964 members in the United States, including 2,597 in Arkansas and 9,000 in Missouri.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Executed on November 29, 2016.



Huda Fashho

DECLARATION OF JOHN HICKEY

1. My name is John Hickey. I am of legal age and competent to give this declaration. All information herein is based on my own personal knowledge unless otherwise indicated.

2. I live in Saint Louis, Missouri.

3. I am an active member of Sierra Club and first became a member in 1997. I have been the Director of Sierra Club's Missouri Chapter since November 2010, and was a volunteer leader on the Missouri Chapter's executive committee before that. I am a member and staffer of Sierra Club because I support and believe in its advocacy on environmental issues. I am proud that Sierra Club takes action to improve the environment in Missouri and around the country.

4. Sierra Club's mission includes protecting and restoring the quality of wild places, such as national parks, forests, and wilderness areas, including the Hercules Glades Wilderness Area and Mingo National Wildlife Refuge in Missouri. Sierra Club's Missouri Chapter and its Missouri members have a strong interest in protecting visibility in our state's parks and wilderness areas, including the Hercules Glades Wilderness Area and Mingo National Wildlife Refuge, as well as protecting human health and the environment from air pollution.

5. In addition to being the Director of the Missouri Chapter, I am also an active Sierra Club member who enjoys recreating in wild places

throughout Missouri. I enjoy camping, hiking, canoeing, kayaking, and birding, among other activities throughout Missouri. I plan to continue to engage in these outdoor activities.

6. I have visited the Mingo National Wildlife Refuge around ten times in my life, having first gone there about 25 years ago. Over the years, I have visited the Mingo National Wildlife Refuge with friends and family. Recent trips have been with my wife and two children. Our most-recent trip was in May 2016. I plan to visit the Mingo National Wildlife Refuge again soon, likely next year.

7. The Mingo National Wildlife Refuge encompasses a large cypress swamp. My trips there have been multi-day and have involved canoeing or kayaking within the swamp. My companions and I also hike on the dry areas within the swamp. The Mingo National Wildlife Refuge is a special, wild place—there are no marked trails—that is difficult to match in Missouri. In all the years of going there, I have only once run into another person in the wilderness area, a park ranger.

8. I call the Mingo National Wildlife Refuge the "Serengeti of Missouri" because of its huge vistas and abundant wildlife. My two teenage children are wildlife enthusiasts, and they enjoy visiting the Refuge as much as I do to see this wildlife. Over the years, I have observed otters, bobcats, beavers, and bald eagles, including nesting adults with chicks. I have seen

many species of amphibians and reptiles, including some, like the cottonmouth, that are rarely encountered this far north. I have seen scores of bird species, including the majestic pileated woodpecker, resplendent prothonotary warbler, and several species of hawks.

9. My enjoyment of Mingo National Wildlife Refuge and other natural areas in Missouri is diminished by haze. Missouri is a relatively flat and heavily wooded state. Large, open vistas are therefore rare in Missouri. The Mingo National Wildlife Refuge is one of the few places in this state where one can enjoy a truly large, open vista because much of the landscape is open water dotted with the occasional cypress tree. Haze decreases visibility and therefore lessens my enjoyment of visiting the Mingo National Wildlife Refuge.

10. I have not yet visited the Hercules Glades Wilderness Area but hope to do so in the future.

11. I understand that air pollution from power plants and other industrial facilities in Arkansas causes or contributes to haze that diminishes visibility in the Mingo National Wildlife Refuge, Hercules Glades Wilderness Area, and other natural areas in Missouri. I share Sierra Club's strong interest in protecting these parks and other natural areas in Missouri from haze pollution. I am concerned about the impacts of haze pollution on the health of the people of Missouri and on the scenic views at the Hercules

Glades Wilderness Area, Mingo National Wildlife Refuge, and other natural areas of the state.

12. In September 2016, EPA finalized a federal plan to address the haze problem caused by pollution sources in Arkansas that impact visibility in Missouri, including at the Hercules Glades Wilderness Area and Mingo National Wildlife Refuge. I understand that EPA's federal plan requires significant reductions in sulfur dioxide ("SO_2") pollution from Arkansas industrial sources that when implemented will significantly improve visibility in the Mingo National Wildlife Refuge and Hercules Glades Wilderness Area. I also understand that once these pollution reductions go into effect, they will go a long way toward eventually helping return air quality in the Mingo National Wildlife Refuge and Hercules Glades Wilderness Area to natural conditions.

13. I support this aspect of EPA's plan to clean up haze pollution at the Mingo National Wildlife Refuge and Hercules Glades Wilderness Area without further delay. If the plan is implemented, I believe it will benefit me and other Sierra Club members who use and enjoy these parks by lessening the impacts of air pollution at the Mingo National Wildlife Refuge and Hercules Glades Wilderness Area, improving the views, and helping to protect human health. If EPA's haze reduction plan is implemented, canoeing, camping, hiking, and other outdoor activities in places such as the

Mingo National Wildlife Refuge will be more enjoyable for me and my family. If EPA's plan is set aside or delayed, those benefits will be lost.

14. There are other aspects of EPA's rule, however, that I believe are insufficiently protective of air quality at places like the Hercules Glades Wilderness Area and Mingo National Wildlife Refuge. It is my understanding, for example, that while EPA's federal plan requires significant reductions in SO_2 pollution, EPA required only modest reductions in other visibility impairing pollutants, like nitrogen oxides ("NOx"), from Arkansas power plants such as Independence and Lake Catherine. I further understand that EPA could have required more significant reductions in NOx pollution, which would have achieved even more substantial improvement in visibility at these Missouri parks.

15. While EPA's haze plan is a critical measure to protect air quality in Missouri, I also believe that I am harmed by EPA's unwillingness to require more significant reductions in NOx pollution, which would have resulted in even more improvement in visibility at places like the Hercules Glades Wilderness Area and Mingo National Wildlife Refuge. I support Sierra Club's effort to require more significant reductions in NOx pollution from Arkansas sources because I believe it would go a long way toward eliminating man-made haze pollution at places like the Hercules Glades

Wilderness Area and Mingo National Wildlife Refuge, and it would improve my own and my family's use and enjoyment of those important places.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 12/2/2016

John Hickey

DECLARATION OF GLEN HOOKS

1. My name is Glen Hooks. I am of legal age and competent to give this declaration. All information herein is based on my own personal knowledge unless otherwise indicated.

2. I live in Little Rock, Arkansas. I was born and raised in Arkansas and have lived in Arkansas for over 40 years.

3. I am an active member of Sierra Club and have been a member for the past 13 years. I have been the Director of Sierra Club's Arkansas Chapter since February 2014, and was an Arkansas-based member of Sierra Club's national staff from March 2003 until being named Chapter Director. I am a member and staffer of Sierra Club because I support and believe in its advocacy on environmental issues. I am proud that Sierra Club takes action to improve the environment in Arkansas and around the country.

4. Sierra Club is a national non-profit, member-based public interest organization incorporated under the laws of the State of California, with its principal place of business in Oakland, California. It is a recognized not-for-profit corporation under Section 501(c)(3) and (c)(4) of the U.S. Internal Revenue Code. Sierra Club is subdivided into local chapters, campaigns, committees, and task forces, with a presence in every state.

5. Sierra Club's mission is to explore, enjoy, and protect the wild places of the earth; to practice and promote the responsible use of the Earth's resources and ecosystems; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out those objectives. The Club's activities also include public education, advocacy, and litigation to enforce environmental laws.

6. For decades, Sierra Club has worked to strengthen, enforce, and help implement the Clean Air Act and its regulations to reduce air pollution and protect air quality across the United States. For many years, but especially in the last decade, Sierra Club has focused on pollution caused by coal-burning power plants.

7. Sierra Club's mission includes protecting and restoring the quality of wild places, such as national parks, forests, and wilderness areas enjoyed by our members for their scenic views and vistas, including the Caney Creek and Upper Buffalo Wilderness Areas in Arkansas. Our organization has undertaken numerous efforts to combat regional haze in many states, including Arkansas. Sierra Club regularly comments, for example, on rulemakings affecting regional haze, including rulemakings regarding regional haze caused by sources of pollution in Arkansas. In

particular, Sierra Club submitted extensive comments regarding the federal haze plan for Arkansas at issue in this case, including more than 3,400 pages of legal comments and expert technical analysis and more than 220 separate comments from individual Sierra Club members.

8. Sierra Club's Arkansas Chapter and its Arkansas members have a strong interest in protecting visibility in our state's parks and wilderness areas, including the Caney Creek and Upper Buffalo Wilderness Areas, as well as protecting human health and the environment from air pollution.

9. In addition to being the Director of the Arkansas Chapter, I am also an active Sierra Club member who enjoys recreating in wild places throughout Arkansas. My appreciation and passion for the environment dates back to my childhood. When I was a kid, my family camped often, perhaps because my parents were not wealthy and camping together was our relatively inexpensive form of entertainment. In the summers of my childhood, we camped nearly every weekend, and we camped in spring and fall as well. As a result, I developed a deep appreciation for nature and wild places. After my two sons were born, we camped throughout Arkansas together. I continue to enjoy camping, hiking, canoeing, and birding, among other activities throughout Arkansas. I plan to continue to engage in these outdoor activities.

10. I have hiked and explored many areas in the Upper Buffalo Wilderness Area, including Hemmed-in-Hollow, Boxley Valley, and others. I have hiked Hawksbill Crag (locals refer to it as Whitaker Point). I visited Hemmed-in-Hollow within the last three years. I have visited Boxley Valley on a Sierra Club outing with a team of scientists; we were looking for slime molds. I expect to continue to visit the Upper Buffalo Wilderness Area in the future.

11. I have hiked many of the trails in the Upper Buffalo Wilderness Area with my sons. One particular visit to the Upper Buffalo Wilderness with my sons stands out. My sons were aged seven and four years old and we went on a canoeing trip. For most of the trip, both boys were loudly talking. I distinctly remember rounding a bend in the Upper Buffalo River and both boys immediately became quiet as they gazed at the cliffs. This experience vividly demonstrated to me the power of wild places and natural vistas to command human attention. I have visited the Upper Buffalo often since then, go at least once a year in most years, and I plan to return next summer. I have also visited Upper Buffalo with the Unitarian Church of Little Rock.

12. My enjoyment of these and other natural areas in this part of Arkansas is diminished by haze. An important part of the experience of

visiting Upper Buffalo Wilderness Area is to view the magnificent mountains and forests of this part of the state. Haze decreases visibility and therefore lessens my enjoyment of that hike and others in the Ozarks. In particular, Whitaker Point is one of the most beautiful and most scenic places in the state. My enjoyment of the panoramic views from Whitaker Point is diminished on hazy days. The continued pollution in places like the Caney Creek and Upper Buffalo Wilderness Areas also makes me feel as though my children are missing out on an important part of growing up and exploring the Ozarks.

13. I have not yet visited the Caney Creek Wilderness Area but hope to do so in the future.

14. I understand that air pollution from power plants and other industrial facilities in Arkansas causes or contributes to haze that diminishes visibility in the Upper Buffalo Wilderness Area, Caney Creek Wilderness Area, and other natural areas in the Ozarks. I share Sierra Club's strong interest in protecting the Upper Buffalo Wilderness Area, Caney Creek Wilderness Area, and other natural areas in Arkansas from haze pollution.

15. I am concerned about the impacts of haze pollution on the health of the people of Arkansas and on the scenic views at the Upper Buffalo Wilderness Area, Caney Creek Wilderness Area, and other natural

areas of the state. For years, I have advocated for reductions in haze-forming pollution in this state, including, for example, by giving comments at a public hearing regarding the proposed haze plan for Arkansas issued by the U.S. Environmental Protection Agency ("EPA").

16. I have long been frustrated by the State of Arkansas's delay in addressing the haze problem in this state. The State of Arkansas missed the deadline for submitting a haze plan to EPA by four years, finally submitting a plan in 2011. And after EPA disapproved significant parts of the State's plan in 2012 for failing to comply with Clean Air Act requirements, the State has subsequently taken no action to correct its deficient plan. I understand that Arkansas is one of the last states to have a final, approved Clean Air Act haze plan in place. Arkansas's non-compliance with the requirements of the Clean Air Act has directly resulted in a lack of action to protect visibility in places like the Caney Creek and Upper Buffalo Wilderness Areas. Prompt action to address the haze problem in this state is needed.

17. In September 2016, EPA finalized a federal plan to address the haze problem in Arkansas. I understand that EPA's federal plan requires significant reductions in sulfur dioxide ("SO_2") pollution from industrial sources that when implemented will significantly improve visibility in the

Caney Creek and Upper Buffalo Wilderness Areas. I also understand that once these pollution reductions go into effect, they will go a long way toward eventually helping return air quality in the Caney Creek and Upper Buffalo Wilderness Areas to natural conditions.

18. I support this aspect of EPA's plan to clean up haze pollution at the Caney Creek and Upper Buffalo Wilderness Areas without further delay. If the plan is implemented, I believe it will benefit me and other Sierra Club members who use and enjoy these parks by lessening the impacts of air pollution at the Caney Creek and Upper Buffalo Wilderness Areas, improving the views, and helping to protect human health. If EPA's haze reduction plan is implemented in Arkansas, hiking and other outdoor activities in places such as the Upper Buffalo Wilderness Area and Caney Creek Wilderness Area will be more enjoyable for me and my family. If EPA's plan is set aside or delayed, those benefits will be lost.

19. There are other aspects of EPA's rule, however, that I believe are insufficiently protective of air quality at places like the Caney Creek and Upper Buffalo Wilderness Areas. It is my understanding, for example, that while EPA's federal plan requires significant reductions in SO_2 pollution, EPA required only modest reductions in other visibility impairing pollutants, like nitrogen oxides ("NOx"), from power plants such as Independence and

Lake Catherine. I further understand that EPA could have required more significant reductions in NOx pollution, which would have achieved even more substantial improvement in visibility at these parks.

20. While EPA's haze plan is a critical measure to protect air quality in Arkansas, I also believe that I am harmed by EPA's unwillingness to require more significant reductions in NOx pollution, which would have resulted in even more improvement in visibility at places like the Caney Creek and Upper Buffalo Wilderness Areas. I support Sierra Club's effort to require more significant reductions in NOx pollution from Arkansas sources because I believe it would go a long way toward eliminating man-made haze pollution at places like the Caney Creek and Upper Buffalo Wilderness Areas, and it would improve my own and family's use and enjoyment of those important places.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: December 5th, 2016

Glen Hooks

Glen Hooks

DECLARATION OF G. THOMAS MCKINNEY

1. My name is G. Thomas McKinney. I am of legal age and competent to give this declaration. All information herein is based on my own personal knowledge unless otherwise indicated.

1. I live in West Fork, Arkansas, in the northwest corner of the state, and have lived here for 30 years. I grew up in nearby Fayetteville, Arkansas and have lived in the state for most of my life. Both my parents are from Arkansas.

2. I am an active member of Sierra Club and have been a member since 1975. I currently serve as the Conservation Chair for the Arkansas Chapter and the Ozarks Headwaters Group. I also serve on the executive committee of both the Arkansas Chapter and the Ozarks Headwaters Group. At one time or another over the last 30 years, I have held nearly every leadership position with Sierra Club's Arkansas Chapter.

3. I am a member and active leader of Sierra Club because I support and believe in its environmental work. My interest in the environment and wildlife goes back to my youth. As a child, I spent a lot of time with my grandfather fishing and enjoying the Ozark woods. Those times with my grandfather are some of my happiest memories. When I was in my early 20s, I had a summer job at the Philmont Scout Ranch in New Mexico. I was impressed then by the beauty of the open spaces of New

Mexico. When I returned to Arkansas, I wanted to help protect the wild, open spaces of my state as well.

4. In the 1970s and 80s, I became actively engaged with Sierra Club to oppose various plans of the U.S. Forest Service to convert large expanses of hardwood forests to pine forests. My work on those Forest Service plans led me to engage, as a member and leader of Sierra Club, in efforts to expand wilderness area protections in Arkansas.

5. When I first joined Sierra Club I appreciated that it is a grassroots organization that empowers local people. I continue to see this empowerment of local people as one of Sierra Club's great strengths. I am proud that Sierra Club takes action to improve the environment in Arkansas and around the country.

6. I enjoy camping, hiking, canoeing, and doing nature photography in the wild places of Arkansas. I will continue to engage in these outdoor activities. I enjoy visiting the wild places of Arkansas to enjoy the views, to see wild animals and wildflowers, and to do things like search creeks for salamanders.

7. The Upper Buffalo Wilderness Area is approximately a two-hour drive from my house. I have visited the Upper Buffalo Wilderness Area many times. Approximately two year ago, I visited Hawksbill Crag (which I and other locals refer to as Whitaker Point). I have visited

Whitaker Point (Hawksbill Crag) many times. Last year, I visited a part of the Ozark National Forest near Fallsville, Arkansas that commands views of the Upper Buffalo Wilderness Area. I expect to continue to visit the Upper Buffalo Wilderness Area in the future as it is one of the closest truly wild parts of Arkansas to my house, and I intend to do so next year. I am particularly interested in visiting a place in the Upper Buffalo Wilderness Area called Terrapin Hollow, where there are excellent opportunities for wildlife photography.

8. I have also visited the Caney Creek Wilderness Area at least two times that I can recall. I intend to visit the Caney Creek Wilderness Area again as well.

9. Haze pollution has diminished my enjoyment of the Upper Buffalo Wilderness Area, Caney Creek Wilderness Area, and other natural areas in this the state. I enjoy the views and vistas of these wild places in Arkansas, particularly Whittaker Point (Hawksbill Crag) in the Upper Buffalo Wilderness Area. There is nothing more dispiriting to me than traveling to a place like Whitaker Point (Hawksbill Crag) and finding the view ruined by haze. That has happened to me many times over the years, unfortunately.

10. I understand that air pollution from power plants and other industrial facilities in Arkansas causes or contributes to haze that diminishes

visibility in the Upper Buffalo Wilderness Area, Caney Creek Wilderness Area, and other natural areas in the Ozarks. I share Sierra Club's strong interest in protecting the Upper Buffalo Wilderness Area, Caney Creek Wilderness Area, and other natural areas in Arkansas from haze pollution.

11. In September 2016, the U.S. Environmental Protection Agency ("EPA") finalized a federal plan to address the haze problem in Arkansas. I understand that EPA's federal plan requires significant reductions in sulfur dioxide ("SO_2") pollution from industrial sources that when implemented will significantly improve visibility in the Caney Creek and Upper Buffalo Wilderness Areas. I also understand that once these pollution reductions go into effect, they will go a long way toward eventually helping return air quality in the Caney Creek and Upper Buffalo Wilderness Areas to natural conditions.

12. I support this aspect of EPA's plan to clean up haze pollution at the Caney Creek and Upper Buffalo Wilderness Areas without further delay. If the plan is implemented, I believe it will benefit me and other Sierra Club members who use and enjoy these parks by lessening the impacts of air pollution at the Caney Creek and Upper Buffalo Wilderness Areas, improving the views, and helping to protect human health. If EPA's haze reduction plan is implemented in Arkansas, hiking and other outdoor activities in places such as the Upper Buffalo Wilderness Area and Caney

Creek Wilderness Area will be more enjoyable for me. Cleaning up the haze problem would also be an important vindication of the three decades of work that I have done to protect the wild places of Arkansas. If EPA's plan is set aside or delayed, those benefits will be lost.

13. There are other aspects of EPA's rule, however, that I believe are insufficiently protective of air quality at places like the Caney Creek and Upper Buffalo Wilderness Areas. It is my understanding, for example, that while EPA's federal plan requires significant reductions in SO_2 pollution, EPA required only modest reductions in other visibility impairing pollutants, like nitrogen oxides ("NOx"), from power plants such as Independence and Lake Catherine. I further understand that EPA could have required more significant reductions in NOx pollution, which would have achieved even more substantial improvement in visibility at these parks.

14. While EPA's haze plan is a critical measure to protect air quality in Arkansas, I also believe that I am harmed by EPA's unwillingness to require more significant reductions in NOx pollution, which would have resulted in even more improvement in visibility at places like the Caney Creek and Upper Buffalo Wilderness Areas. I support Sierra Club's effort to require more significant reductions in NOx pollution from Arkansas sources because I believe it would go a long way toward eliminating man-made haze pollution at places like the Caney Creek and Upper Buffalo Wilderness

Areas, and it would improve my own use and enjoyment of those important places.

Pursuant to 28 U.S.C. § 1746, I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: Dec. 5, 2016

G. Thomas McKinney

G. Thomas McKinney

To: Anderson, Lea[anderson.lea@epa.gov]
From: Stoltzfus, Robert
Sent: Mon 4/3/2017 4:47:51 PM
Subject: RE: Regional Haze - Cost of SO2 Controls

Lea,

Has there been any more recent developments in the R6 matter you referenced below? Thanks for any update.

Bob

J. Robert Stoltzfus / US EPA, Region III / Office of Regional Counsel / Mail Code 3RC10 / 1650 Arch Street, Philadelphia, PA 19103 / 215-814-2695 / stoltzfus.robert@epa.gov

From: Anderson, Lea
Sent: Monday, February 06, 2017 2:30 PM
To: Stoltzfus, Robert <Stoltzfus.Robert@epa.gov>; Marks, Matthew <Marks.Matthew@epa.gov>
Subject: Re: Regional Haze - Cost of SO2 Controls

Ex. 5 - Attorney Client

From: Stoltzfus, Robert
Sent: Monday, February 6, 2017 12:44 PM
To: Anderson, Lea; Marks, Matthew
Subject: RE: Regional Haze - Cost of SO2 Controls

Thanks Lea.

Ex. 5 - Attorney Client

Bob

J. Robert Stoltzfus / US EPA, Region III / Office of Regional Counsel / Mail Code 3RC10 / 1650 Arch Street, Philadelphia, PA 19103 / 215-814-2695 / stoltzfus.robert@epa.gov

From: Anderson, Lea
Sent: Monday, February 06, 2017 10:15 AM
To: Marks, Matthew <Marks.Matthew@epa.gov>; Stoltzfus, Robert <Stoltzfus.Robert@epa.gov>
Subject: Re: Regional Haze - Cost of SO2 Controls

Ex. 5 - Attorney Client

What kind of facility is at issue?

From: Marks, Matthew
Sent: Friday, February 3, 2017 3:32 PM

To: Stoltzfus, Robert; Anderson, Lea
Subject: Re: Regional Haze - Cost of SO2 Controls

I'm sure there must be an example out there, but nothing is jumping to mind immediately. Ex. 5 - Attorney Client

Ex. 5 - Attorney Client

From: Stoltzfus, Robert
Sent: Friday, February 3, 2017 3:29:22 PM
To: Anderson, Lea; Marks, Matthew
Subject: FW: Regional Haze - Cost of SO2 Controls

Ex. 5 - Attorney Client

Thanks again for your assistance.

Bob

J. Robert Stoltzfus / US EPA, Region III / Office of Regional Counsel / Mail Code 3RC10 / 1650 Arch Street, Philadelphia, PA 19103 / 215-814-2695 / stoltzfus.robert@epa.gov

From: Anderson, Lea
Sent: Friday, February 03, 2017 11:04 AM
To: Marks, Matthew <Marks.Matthew@epa.gov>; Stoltzfus, Robert <Stoltzfus.Robert@epa.gov>
Subject: Re: Regional Haze - Cost of SO2 Controls

Ex. 5 - Attorney Client

Ex. 5 - Attorney Client

From: Marks, Matthew
Sent: Friday, February 3, 2017 9:48 AM
To: Stoltzfus, Robert; Anderson, Lea
Subject: Re: Regional Haze - Cost of SO2 Controls

Hi Bob,

This recent notice should help you out. Ex. 5 - Attorney Client

Ex. 5 - Attorney Client

Matt

https://www.federalregister.gov/documents/2017/01/04/2016-30713/promulgation-of-air-quality-implementation-plans-state-of-texas-regional-haze-and-interstate

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From: Stoltzfus, Robert
Sent: Friday, February 3, 2017 9:45:47 AM
To: Anderson, Lea; Marks, Matthew
Subject: Regional Haze - Cost of SO2 Controls

Lea and Matt,

Could either of you point me in the right direction to allow me to get a feel for what the agency has accepted in the way of the cost to control SO2?

Ex. 5 - Attorney Client

Bob

J. Robert Stoltzfus / US EPA, Region III / Office of Regional Counsel / Mail Code 3RC10 / 1650 Arch Street, Philadelphia, PA 19103 / 215-814-2695 / stoltzfus.robert@epa.gov

To: Anderson, Lea[anderson.lea@epa.gov]
From: Beaver, Melinda
Sent: Mon 4/3/2017 1:28:14 PM
Subject: FW: Updated Regional Haze Paper
Texas_ Arkansas Reg Haz two Pager March 31 2017a.docx
Final RH Paper - March 21a.docx

Hi Lea,

Looks like Mike sent the "sticking points" on TX and AR document forward on Friday afternoon. **Ex. 5 - Deliberative Process**

Ex. 5 - Deliberative Process

Melinda

From: Koerber, Mike
Sent: Friday, March 31, 2017 12:56 PM
To: Wood, Anna <Wood.Anna@epa.gov>; Kornylak, Vera S. <Kornylak.Vera@epa.gov>; Jones, Rhea <Jones.Rhea@epa.gov>; Werner, Christopher <Werner.Christopher@epa.gov>; Beaver, Melinda <Beaver.Melinda@epa.gov>
Subject: FW: Updated Regional Haze Paper

Thanks again for your help. Here is the final version sent to OAR.

Mike

From: Koerber, Mike
Sent: Friday, March 31, 2017 12:55 PM
To: Lewis, Josh <Lewis.Josh@epa.gov>
Cc: Cyran, Carissa <Cyran.Carissa@epa.gov>
Subject: FW: Updated Regional Haze Paper

Josh – On Monday's 1-on-1, Sarah requested a pager on the "sticking points" for Texas and Arkansas regional haze. Ex. 5 - Deliberative Process Ex. 5 - Deliberative Process We worked with Region 6 and OGC to produce the attached pager. Also attached is our recent regional haze paper, which Sarah indicated she might want to send this along with the "sticking points" pager. Let me know if you have any questions.

Mike

From: Koerber, Mike
Sent: Tuesday, March 21, 2017 12:35 PM
To: Lewis, Josh <Lewis.Josh@epa.gov>
Cc: Atkinson, Emily <Atkinson.Emily@epa.gov>
Subject: Updated Regional Haze Paper

Josh – Please share this version with Sarah Ex. 5 - Deliberative Process Ex. 5 - Deliberative Process She mentioned yesterday that she might hand this to Mandy today. If so, then please use this version. Thanks.

Mike

To: OGC ARLO[OGC_ARLO@epa.gov]
From: Graham, Cheryl
Sent: Fri 3/31/2017 10:41:56 AM
Subject: 04/03/17 Reg Review Agenda Updates
17-04-03 agenda.docx

Attached is the strikeout version of the reg agenda, if you have any additions/deletions please let me know by 11:00 Monday. Reg Review is scheduled for Monday (4/3) at 2:30pm in room 4045.

Thank you

Cheryl R. Graham
OGC/ARLO
(202) 564-5473

To: Greenglass, Nora[Greenglass.Nora@epa.gov]; Odendahl, Steve[Odendahl.Steve@epa.gov]; Laumann, Sara[Laumann.Sara@epa.gov]; Anderson, Lea[anderson.lea@epa.gov]
Cc: Carfora, Debra (ENRD)[Debra.Carfora@usdoj.gov]
From: Talbert, Stephanie (ENRD)
Sent: Mon 3/20/2017 3:01:42 PM
Subject: PacifiCorp brief
Document (1).pdf

To: Greenglass, Nora[Greenglass.Nora@epa.gov]; Laumann, Sara[Laumann.Sara@epa.gov]; Odendahl, Steve[Odendahl.Steve@epa.gov]; Anderson, Lea[anderson.lea@epa.gov]
Cc: Carfora, Debra (ENRD)[Debra.Carfora@usdoj.gov]
From: Talbert, Stephanie (ENRD)
Sent: Mon 3/20/2017 2:59:55 PM
Subject: Desert brief
Document.pdf

To: Greenglass, Nora[Greenglass.Nora@epa.gov]; Laumann, Sara[Laumann.Sara@epa.gov]; Odendahl, Steve[Odendahl.Steve@epa.gov]; Anderson, Lea[anderson.lea@epa.gov]
Cc: Carfora, Debra (ENRD)[Debra.Carfora@usdoj.gov]
From: Talbert, Stephanie (ENRD)
Sent: Mon 3/20/2017 2:57:42 PM
Subject: County brief
Document.pdf

Consolidated Nos. 16-9541, 16-9542, 16-9543, 16-9545

IN THE UNITED STATES COURT OF APPEALS
FOR THE TENTH CIRCUIT

STATE OF UTAH, on behalf of the Utah Department of Environmental Quality, Division of Air Quality, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al., Respondents. ---------- CARBON COUNTY, UTAH, et al., Petitioners - Intervenors, and HEAL UTAH et al., Respondents - Intervenors.	No. 16-9541
PACIFICORP, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al.,	No. 16-9542

Respondents. ---------- CARBON COUNTY, UTAH, et al., Petitioners - Intervenors, and HEAL UTAH, et al., Respondents - Intervenors.	
UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al., Respondents. ---------- CARBON COUNTY, UTAH, et al., Petitioners - Intervenors, and HEAL UTAH, et al., Respondents - Intervenors.	No. 16-9543

DESERET GENERATION & TRANSMISSION CO-OPERATIVE, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al., Respondents. ---------- CARBON COUNTY, UTAH, et al., Petitioners - Intervenors, and HEAL UTAH, et al., Respondents - Intervenors.	No. 16-9545

On Petition for Review of Final Action of the United States Environmental Protection Agency and Scott Pruitt, Administrator of the United States Environmental Protection Agency*

PRELIMINARY OPENING BRIEF OF PETITIONER PACIFICORP
(Deferred Appendix Appeal)

E. Blaine Rawson
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Ray Quinney & Nebeker, P.C.
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Attorneys for Petitioner PacifiCorp

* Pursuant to Fed. R. App. P. 43(c)(2), Scott Pruitt is automatically substituted for Gina McCarthy as Administrator of the United States Environmental Protection Agency.

ORAL ARGUMENT REQUESTED

RULE 26.1 CORPORATE DISCLOSURE STATEMENT

Pursuant to Rule 26.1 of the Federal Rules of Appellate Procedure, PacifiCorp submits the following statement:

PacifiCorp's common stock is 100% owned by PPW Holdings, LLC, a Delaware limited liability company, which is, in turn, wholly owned by Berkshire Hathaway Energy Company. Berkshire Hathaway Energy Company is a majority-owned subsidiary of Berkshire Hathaway Inc., a publicly held corporation. No publicly held company directly owns ten percent (10%) or more of PacifiCorp's common stock.

DATED this 17th day of March, 2017.

/s/ E. Blaine Rawson
E. Blaine Rawson
Marie Bradshaw Durrant
Ray Quinney & Nebeker, P.C.
36 South State Street, Suite 1400
Salt Lake City, UT 84111
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Attorneys for Petitioner PacifiCorp

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STATEMENT OF RELATED CASES

Pursuant to 10th Cir. Rule 28.2(C)(1), the following is a statement of related cases:

PacifiCorp's Petition for Review is related to three other petitions pending before this Court: *State of Utah v. EPA*, No. 16-9541 (10th Cir. Sep. 1, 2016); *Utah Associated Municipal Power System v. EPA*, No. 16-9543 (10th Cir. Sep. 6, 2016); and *Deseret Generation and Transmission Cooperative v. EPA*, No. 16-9545 (10th Cir. Sep. 6, 2016). Also, in a previously decided case, this court addressed similar issues regarding the same air quality programs in Utah. *See WildEarth Guardians v. EPA*, 770 F.3d 919 (10th Cir. 2014).

GLOSSARY OF ACRONYMS AND ABBREVIATIONS

98% Metric	CALPUFF computer modeling results of the 98% highest visibility-impacted day averaged over three years
BART	Best Available Retrofit Technology
BART alternative	An alternative measure allowed by the regional haze regulations as a substitute for the BART requirements. This term, without a capital "a" is used to reference the alternative measure option in general or BART alternatives of other states. *C.f.* **Utah BART Alternative** in this glossary.
BART Guidelines	40 C.F.R. pt. 51, app. Y (guidance for BART determinations that is obligatory for certain large BART-eligible sources)
CAA	Clean Air Act
CALPUFF	CALPUFF is a non-steady state meteorological and air quality computer modeling system.
Class I Areas	Certain identified national parks and wilderness areas
CWE	"Clear Weight of the Evidence," a qualitative option that considers "all available information" to justify a BART alternative, instead of the other two quantitative, visibility-focused options, all of which are included in the applicable regulations.
dv	Deciview
EPA	Environmental Protection Agency
FIP	Federal Implementation Plan
Final Rule	"Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze," 81 Fed. Reg. 43,894 (July 5, 2016)
JA	Joint Appendix
LNB/SOFA	Low- NO_x Burners with Separated Overfire Air
NO_x	Nitrogen Oxide

OFA	Overfire Air (very comparable to, and often used as a substitute for, SOFA)
PM	Particulate Matter
RH Program	Regional haze statute, regulations, and guidelines (42. U.S.C. § 7491, 40 C.F.R. §§ 51.300-309, and 40 C.F.R. pt. 51, app. Y)
RTC	EPA's "Response to Comments" filed regarding the Final Rule
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SO_2	Sulphur Dioxide
Utah BART Alternative, or the Alternative	Utah's proposed SIP adopting a BART alternative which relies on NO_x combustion controls installed at all BART units and at a non-BART unit, and the closure of a non-BART power plant. When referring to the Utah-specific alternative measure that is the subject of the Final Rule and this appeal, a capital "A" is used to distinguish from general BART alternative measures or BART alternatives of other states. *C.f.* **BART alternative** in this glossary.

CERTIFICATE REGARDING NECESSITY OF SEPARATE BRIEFS

Pursuant to 10th Cir. Rule 31.3(B), Petitioner PacifiCorp hereby states that separate briefs for the Petitioners are necessary pursuant to 10th Cir. Rule 31.3(A). On October 5, 2016, Petitioners and Respondents filed a joint status report addressing the necessity of separate briefing. Joint Status Report, *Utah v. EPA*, No. 16-9541, (10th Cir. Oct. 5, 2016). On October 6, 2016, the Clerk of Court entered an order approving a briefing schedule that included the filing of up to four separate opening and reply briefs for PacifiCorp and the other non-state Petitioners and supporting Intervenors. Order, *Utah v. EPA*, No. 16-9541 (10th Cir. Oct. 6, 2016). Although on October 21, 2016, the Clerk of Court entered an order allowing the Utah Municipal Power Agency to file a separate brief, Order, *Utah v. EPA*, No. 16-9541 (10th Cir. Oct. 21, 2016), the Utah Municipal Power Agency has reviewed PacifiCorp's brief, concurs with PacifiCorp's arguments and positions, and will not be filing a separate brief.

JURISDICTIONAL STATEMENT

PacifiCorp petitions for review of those portions of the United States Environmental Protection Agency's ("EPA") Final Rule[1] that disapprove Utah's regional haze state implementation plan ("SIP") related to nitrogen oxide ("NO_x") emissions controls and imposes additional NO_x pollution control requirements on the Hunter and Huntington power plants in Utah. This Court has jurisdiction over PacifiCorp's petition pursuant to the Clean Air Act ("CAA"), 42 U.S.C. § 7607(b)(1). PacifiCorp's petition was filed in accordance with Rule 15(a) of the Federal Rules of Appellate Procedure. The Final Rule is a "locally or regionally applicable" regulation because it applies only to Utah; therefore, this Court has jurisdiction as "the United States Court of Appeals for the appropriate circuit." 42 U.S.C. § 7607(b)(1).

The CAA requires a petition for review to be filed within 60 days of publication in the Federal Register. *Id.* PacifiCorp timely filed its Petition for Review on September 2, 2016, which is within 60 days of publication of the Final Rule on July 5, 2016.

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[1] The Final Rule was published on July 5, 2016, and is titled "Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze," 81 Fed. Reg. 43,894 (July 5, 2016) ("Final Rule") [JA__] . References to the Final Rule include both EPA's disapproval of the SIP and issuance of its FIP.

PacifiCorp has standing to pursue its petition. EPA's Final Rule requires unwarranted NO_x pollution control devices, imposing costs of over $700 million. This constitutes a concrete and particularized injury, fairly traceable to the Final Rule, for which there is a substantial probability of redress by a decision holding the Final Rule invalid. *See, e.g.*, *Lujan v. Defenders of Wildlife*, 504 U.S. 555, 561–62 (1992) .

STATEMENT OF ISSUES

1. Whether EPA's disapproval of Utah's NO_x Best Available Retrofit Technology Alternative ("Utah BART Alternative," or "Alternative") was arbitrary, capricious, or otherwise contrary to the law when Utah developed and submitted the Alternative pursuant to the applicable CAA provisions and in compliance with EPA regulations.

2. Whether EPA's failure to consider and analyze key information relating to the contested Utah BART Alternative was arbitrary and capricious.

3. Whether EPA's adoption of a federal implementation plan ("FIP"), promulgated to replace the Utah BART Alternative, was arbitrary, capricious, or otherwise contrary to the law because the FIP failed to meet the requirements of the CAA and applicable regulations.

4. Whether EPA's failure to consider and analyze key information relating to the FIP was arbitrary and capricious.

STATEMENT OF THE CASE

EPA's Final Rule illegally rejected a part of Utah's SIP addressing NO_x emissions from certain facilities owned by PacifiCorp, an electric utility. Utah's SIP included an effective and efficient approach, known as a "BART alternative," that included not only NO_x emissions reductions from PacifiCorp's Hunter and Huntington power plants, but also emissions reductions of other visibility-related pollutants resulting from the closure of the Carbon power plant. In formulating the BART Alternative, Utah followed all applicable statutes, regulations, and guidelines, and acted within the power granted it by Congress.

EPA, however, illegally disapproved Utah's BART Alternative, replacing it with a FIP that covers fewer facilities than the SIP, costs hundreds of millions more than the SIP, results in fewer days of visibility improvement as compared to the SIP, ignores SIP emissions reductions that occur much earlier than the FIP, and produces—at best—an imperceptible and dubious computer-modeled visibility benefit over that produced by the SIP. Moreover, EPA's Final Rule is an improper attempt both to capture the benefits of the SIP while requiring even more emissions reductions through the burdensome and unjustified FIP. Because EPA overstepped

its authority, this Court should grant the Petitions by PacifiCorp, Utah,[2] and the other petitioners.[3]

The remainder of this section provides the relevant facts, procedural history, and context for application of the important regulations and statutes.

I. REGIONAL HAZE BACKGROUND

Regional haze is caused when sunlight encounters small particles in the air. Some light is absorbed by particles; other light is scattered. Haze reduces visibility in national parks and wilderness areas. These areas (called "Class I areas") are the subjects of the CAA's regional haze program ("RH Program"). *See, e.g.*, 42 U.S.C. § 7491(a). Haze-causing particles in Utah come from numerous natural and human-made sources. Natural sources include dust and wildfire smoke, which are significant causes of haze on the worst days. *See* Utah Div. of Air Quality, Staff Review 2008 PM BART Determination and Recommended Alternative to BART for NO_x at 25–26 (May 13, 2015) [Joint Appendix ("JA")__] ("Staff Review").

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[2] PacifiCorp adopts all of the arguments and information from the State of Utah's preliminary opening brief ("Utah's Brief" or "Utah Br."). As directed by the Court, Utah and PacifiCorp worked to provide complementary, non-repetitive information and argument as much as possible.

[3] The other electrical utility petitioners and the county-intervenors join the arguments in this brief. Where the other electrical utility petitioners and county-intervenors have arguments specific to them, or that required their particular point of view, they have been included in separate briefs by those entities. Otherwise, this brief represents the common arguments of the electrical utility petitioners and the county-intervenors.

Human-made sources include emissions from motor vehicles, oil and gas operations, small businesses, electric utility and industrial fuel burning, and manufacturing operations. Local, regional, and even global sources contribute to regional haze in a given Class I area. *See* 77 Fed. Reg. 28,825, 28,827 (proposed Utah disapproval, May 16, 2012).

The RH Program, created by Congress, established as a national goal the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas [i.e., national parks and wilderness areas,] which impairment results from manmade air pollution." 42 U.S.C. § 7491(a)(1). The ultimate goal of the RH Program is to restore (and preserve) natural background visibility conditions by the year 2064. *Id.*; 40 C.F.R. § 51.308(d)(1)(i)(B). The RH Program is not a health-based CAA program; its goals are purely aesthetic.

Congress delegated most of the required work for the RH Program to the states, which must prepare SIPs containing emission limits, compliance schedules, and other measures necessary to make "reasonable progress" toward meeting the 2064 goal. 42 U.S.C. § 7491(a)(4), (b)(2); 40 C.F.R. § 51.309(d). EPA promulgated regulations for the states to develop regional haze SIPs, now codified at 40 C.F.R. §§ 51.300–09. EPA also issued binding guidelines (which were subject to notice and comment rulemaking) for states to use in developing their

SIPs. These guidelines are obligatory for states when making Best Available Retrofit Technology ("BART") determinations for certain large power plants, including the Utah units at issue here. *See* 40 C.F.R. pt. 51, app. Y (hereinafter "BART Guidelines").

In developing a SIP, states are required to complete an extensive state rule-making process by applying the appropriate CAA statutes, regulations and BART Guidelines (where applicable). EPA is required to review each SIP to ensure that the state properly considered and applied the regional haze statutes, regulations, and BART Guidelines (where applicable), but otherwise EPA must grant deference to the state's regional haze actions. *See* 42 U.S.C. §§ 7491(b)(2), 7410(k)(3).[4]

EPA documents show that the Class I areas in Utah and surrounding states enjoy some of the best visibility in the country.[5]

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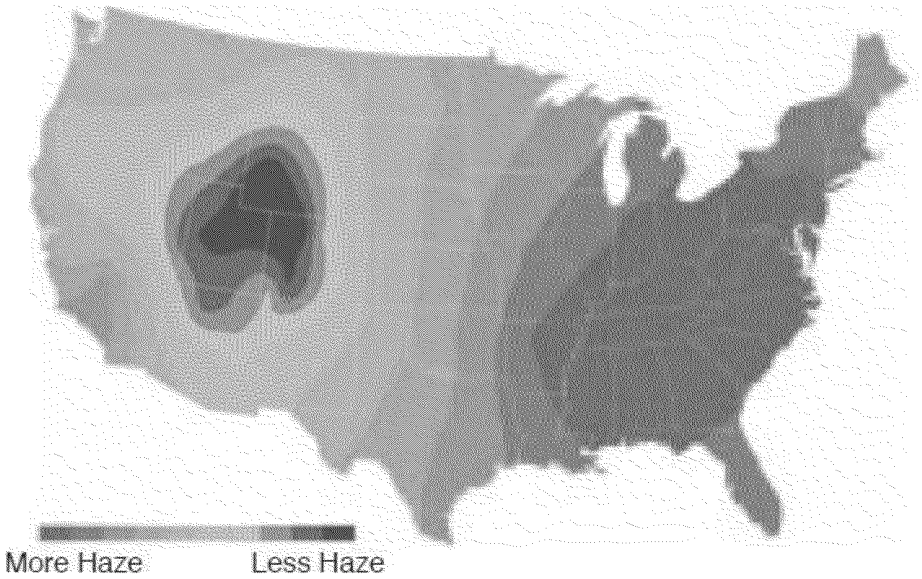
[4] EPA acknowledges that, in making BART determinations, "**States are free to determine the weight and significance** to be assigned to each factor." 70 Fed. Reg. 39,104, 39,123 (July 6, 2005) (emphasis added) (BART Guidelines).

[5] *See* EPA, "How Air Pollution Affects the View," *available at* https://www.epa.gov/sites/production/files/2015 -05/documents/haze_brochure_200 60426.pdf (last accessed Mar. 16, 2017).



Haze conditions vary across the country. Eastern U.S. areas have more haze due to higher pollutant and humidity levels.

a. The RH Program Is a Decades-Long Program with Many Phases

Utah's SIP was not a one-time event, but reflects one stage in a long-term program intended by Congress to be phased-in over many decades. States must set reasonable progress goals for 10-year periods that establish the "uniform rate of visibility improvement" necessary to attain the 2064 goal. 40 C.F.R. § 51.308(d)(1)(i)(B). States must evaluate and report progress toward their goals every five years, *id.* § 51.309(d)(10), and reevaluate all elements of their SIPs and reasonable progress analyses every 10-years, including consideration of potential additional controls on affected sources, *id.* §§ 51.309(d)(1); 51.308(f). Between both the comprehensive SIP revisions and the progress reports, states and EPA will conduct many reevaluations and revisions to ensure the uniform rate of

improvement is achieved by 2064, as Congress intended. EPA's use of the Final Rule to front-load as many retrofits and pollution controls as possible in the first planning period is inconsistent with the RH Program. Such efforts undermine the RH Program's stated intent to achieve better visibility through future advances in new technology and the periodic phase-out of older sources over time.[6] *See* Regional Haze Regulations, 64 Fed. Reg. 35,714, 35,732 (July 1, 1999).

b. BART and BART Alternatives

Under 40 C.F.R. § 51.308, each state must submit a SIP during the first planning period "containing emission limitations representing BART" for each BART-eligible source. *Id.* § 51.308(e). The CAA requires states to consider five statutory "BART" factors when determining what emissions controls constitute BART: (1) "[T]he costs of compliance," (2) "the energy and nonair quality environmental impacts of compliance," (3) "any existing pollution control technology in use at the source," (4) "the remaining useful life of the source," and

[6] Other CAA programs address the need to impose near-term emission reductions and/or installation of state-of-the-art emission control technology in certain circumstances. For example, every "major modification" at an existing power plant that will cause a significant net emissions increase requires a Best Available Control Technology ("BACT") review. 40 C.F.R. § 52.21. If the BACT requirement is triggered, which by definition is more stringent than a BART requirement, it can compel a source to make significant upgrades to emission controls.

(5) "the degree of improvement in visibility[7] which may reasonably be anticipated to result from the use of such technology." 42 U.S.C. § 7491(g)(2). Congress requires states to consider and weigh these five BART factors because states are better positioned to balance the improvement of scenic views over time against the cost of emission controls, the remaining life of a source, energy and environmental factors, etc.

Alternatively, a state "may opt to implement . . . an emissions trading program or other alternative measure" in lieu of establishing BART if it can demonstrate that the alternative would result in "greater reasonable progress than would be achieved through the installation and operation of BART." 40 C.F.R. § 51.308(e)(2).[8] This is typically called a "BART alternative." Section 308(e)(2)(i)(E) provides that a state may demonstrate "greater reasonable progress" for a BART alternative *either* "under paragraph (e)(3) of this section," which provides two quantitative tests (emissions reductions or 98th percentile visibility modeling), or using a qualitative test that is "**based on the clear weight of**

[7] The CAA and related regulations establish the "deciview" ("dv") as the unit by which visibility improvement is determined. One dv is intended to reflect actual human perception of visibility. 64 Fed. Reg. at 35,725–26.

[8] The use of BART alternatives has been upheld as a permissible interpretation of the CAA's purpose and requirements. *See Util. Air Regulatory Grp. v. EPA*, 471 F.3d 1333, 1340 (D.C. Cir. 2006) (considering the Clean Air Interstate Rule cap-and-trade program as a BART alternative).

evidence that the trading program or other alternative measure achieves greater reasonable progress [than BART]." *Id.* § 51.308(e)(2)(i)(E) (emphasis added). EPA's regulations allow states full discretion to choose any one of these three options, and EPA has made clear that the "clear weight of evidence" ("CWE") qualitative test is an **alternative** to the quantitative (e)(3) tests, and not a replication. *See* 71 Fed. Reg. 60,612, 60,622 (BART regulation revisions, Oct. 13, 2006); *see also WildEarth Guardians v. EPA*, 770 F.3d 919, 934 (10th Cir. 2014).

The EPA's regulations do not specify how to conduct the CWE test, but EPA has explained that states may "use of all available information and data which can inform a decision while recognizing the relative strengths and weaknesses of that information in arriving at the soundest decision possible." 71 Fed. Reg. at 60,622. "All available information and data" has been interpreted in other rulemakings, court decisions, and guidance documents to include policy considerations, qualitative considerations, and cost and timing considerations. *See, e.g.*, *WildEarth*, 770 F.3d at 934–35; 70 Fed. Reg. 44,154, 44,158 (proposed BART regulation revisions, Aug. 1, 2005) (presenting the CWE purpose "to evaluate both air quality modeling results and **other policy considerations**") (emphasis added). BART alternatives were designed to promote flexibility, long-term planning, innovation, and lower compliance costs. *See, e.g.*, 71 Fed. Reg. at

60,614 (explaining that alternatives will promote "flexibility" to achieve "greater progress" "in the most cost-effective manner practicable").

c. EPA Found Utah's BART Alternative Approvable

As explained above, a state may implement BART or a BART alternative. Either satisfies the CAA. Utah chose to implement a BART alternative. In doing so, it followed the applicable CAA statutes and regulations. In the proposed rule, EPA admitted Utah's BART Alternative contained the requirements "necessary" for EPA approval. 81 Fed. Reg. 2,004, 2,021 (proposed Jan. 14, 2016) [JA__] ("Proposed Rule") (proposing to approve Utah's SIP based on an evaluation of "[a]ll general SIP requirements contained in CAA section 110, other provisions of the CAA, and our regulations applicable to this action"). In fact, EPA proposed approval of the Utah BART Alternative "based on an evaluation of Utah's regional haze SIP submittals against the regional haze requirements at 40 CFR §§ 51.300–09 and CAA sections 169A and 169B." *Id.* EPA admitted in the Proposed Rule that the Utah BART Alternative was approvable based on nine different metrics that Utah analyzed under the regional haze regulations. The nine metrics included several metrics measuring visibility, including CALPUFF modeling of the 98th percentile days of highest visibility impact ("98% Metric"), as well as metrics encompassing monitoring data, costs, energy, and environmental considerations. EPA's finding that Utah's evaluation of these metrics satisfied the CAA's

"applicable requirements" stands in sharp contrast to EPA's subsequent, illegal rejection of the Utah BART Alternative.

II. PACIFICORP'S FACILITIES AND THE REGIONAL HAZE PROGRAM

PacifiCorp is the majority owner and operator of Hunter Units 1 and 2, and the owner and operator of Huntington Units 1 and 2, which constitute the four coal-fired electrical generating units in Utah that are subject to BART under the RH Program ("BART Units"). PacifiCorp is also owner/operator of Hunter Unit 3 and the now-closed Carbon Units 1 and 2 (collectively "non-BART Units"), which are included in the Utah BART Alternative. The electrical capacity and energy produced by the BART Units and Hunter Unit 3 help serve the needs of PacifiCorp's 1.8 million customers in six western states. The BART Units and Hunter Unit 3 are an integral and essential power generation resource for the customers of PacifiCorp. Hunter Unit 2 similarly serves the customers of Deseret Generation & Transmission Cooperative ("DG&T")[9] and Utah Associated Municipal Power Systems.[10] Hunter Unit 1 also serves the customers of Utah Municipal Power Agency.[11] The BART Units and Hunter Unit 3 directly employ

[9] DG&T owns an undivided 25.1% interest in Hunter Unit 2.

[10] UAMPS owns an undivided 14.582% interest in Hunter Unit 2.

[11] UMPA owns an undivided 6.25% interest in Hunter Unit 1.

approximately 370 people, and contribute approximately $7.9 million annually in property taxes to the state of Utah. PacifiCorp's Motion for Stay, *PacifiCorp v. EPA*, No. 16-9542, Ex. D ¶10 (10th Cir. Oct. 28, 2016) (Declaration of Chad Teply) (hereinafter "Teply Decl.").

The BART Units have been regulated by the RH Program for years. Utah submitted a SIP revision to EPA in September of 2008 with NO_x BART determinations for the BART Units ("2008 SIP"). *See* 77 Fed. Reg. 74,355, 74,355 –56 (Dec. 14, 2012) (referencing and partially disapproving Utah's 2008 SIP revision). Utah rejected the installation of selective catalytic reduction ("SCR")[12] as NO_x BART for the BART Units because the excessive cost and environmental impacts of SCR were not justified by the presumed visibility benefits. Instead, Utah found that low NO_x burners with separated overfire air ("LNB/SOFA")[13] were the appropriate BART controls. *See* 77 Fed. Reg. at 28,841.

Because the 2008 SIP became Utah law, PacifiCorp was legally required to install the state's determination for NO_x BART of LNB/SOFA at the BART Units. Through proactive planning, PacifiCorp began these installations in 2006 and

[12] SCR is a NO_x emissions control technology added to the power plants downstream from the combustion process.

[13] LNB/OFA/SOFA are NO_x emissions control devices built into the combustion process.

completed them in 2014, as required by the 2008 SIP.[14] The installation of LNB/SOFA at the BART Units between 2006 and 2014 reduced total NO_x emissions by approximately 11,000 tons annually. Teply Decl. ¶13 [JA__].

In 2012, responding to a consent decree with WildEarth Guardians compelling action on Utah's 2008 SIP, and over the objections of Utah and PacifiCorp, EPA disapproved the State's 2008 BART determinations for NO_x and PM_{10}. *See* 77 Fed. Reg. at 74,355. EPA did not issue a FIP at that time. Instead, Utah worked closely with EPA to develop a solution that would meet the applicable requirements of the CAA and satisfy EPA demands for NO_x BART.

In 2015, Utah submitted the revised SIP—at EPA's request—including the Utah BART Alternative for NO_x. In addition to the same NO_x controls already installed pursuant to the 2008 SIP, the Utah BART Alternative required additional NO_x emission reductions at the three Utah non-BART Units: (i) Hunter Unit 3 (installation of LNB/SOFA); (ii) Carbon Unit 1 (closure); and (iii) Carbon Unit 2 (closure). The required closure of the Carbon power plant resulted in further emission reductions for PM and SO_2. Teply Decl. ¶¶16–17 [JA__]. The additional, annual emission reductions from these three Utah non-BART Units totaled approximately 4,900 additional tons of NO_x, as well as approximately 8,000

[14] The total cost of the LNB/SOFA installations for all BART Units was approximately $40 million. Teply Decl. ¶13 [JA__].

additional tons of SO_2, and 570 additional tons of PM. These non-BART Units emissions reductions are in addition to the NO_x reductions from the 2008 SIP, all of which will continue in the future. *Id.* ¶17 [JA__]. Absent the Utah BART Alternative, there would have been no regional haze requirement to achieve these added, non-BART Units emissions reductions and resulting visibility improvements.

However, EPA rejected Utah's BART Alternative and imposed a FIP that requires installation of SCRs at the BART Units. PacifiCorp has projected that installation of the FIP's BART requirements will cost in excess of $700 million, with an additional increase in annual operating and maintenance costs of approximately $6 million per year (which does not include the millions needed every four years for SCR catalyst replacement). PacifiCorp has invested heavily in pollution control equipment at the BART Units since 2006, spending approximately $500 million to install NO_x, PM, and SO_2 emissions control equipment. *Id.* ¶21 [JA__].

STANDARD OF REVIEW

Under the Administrative Procedure Act ("APA"), final agency action must be set aside if it is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. § 706(2)(A). The APA also provides "[t]o the extent necessary to decision and when presented, **the reviewing court shall decide**

all relevant questions of law, interpret constitutional and statutory provisions, and determine the meaning or applicability of the terms of an agency action." *Id.* § 706 (emphasis added). The "arbitrary and capricious" standard is the standard of review for EPA action under the CAA. *See Oklahoma v. EPA*, 723 F.3d 1201, 1211 (10th Cir. 2013). This standard cannot, however, be applied in a vacuum. *See, e.g.*, *Barnum Timber Co. v. EPA*, 835 F. Supp. 2d 773, 778–79 (N.D. Ca. 2011) (holding "[t]he context of the Clean Water Act and the EPA's involvement in its implementation provides greater clarity" to the arbitrary and capricious standard of review). Thus, this Court must consider the context of the CAA in which EPA has acted.

The governing statute for SIP review in the CAA mandates that "[EPA] **shall approve** such [SIP] submittal as a whole if it meets all of the **applicable requirements** of this chapter." 42 U.S.C. § 7410(k)(3) (emphasis added). Here, the "applicable requirements" relevant to Utah's BART Alternative and FIP are found in the regional haze statutes and regulations. *See, e.g.*, 42 U.S.C. § 7491(b)(2) (requiring states to adopt a SIP that contains "such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal"); *id.* § 7491(g)(1) (defining "reasonable progress" by reference to certain factors); *id.* § 7491(g)(2) (requiring that BART be determined by weighing and considering the five BART factors); 40

C.F.R. § 51.308(e) (detailed BART and BART alternative section of the regional haze regulations).

Therefore, it is arbitrary and capricious for EPA to disapprove a SIP that meets the CAA's "applicable requirements," as EPA did here.

I. EPA MUST RESPECT THE BROAD DISCRETION CONGRESS GRANTED STATES TO MAKE BART DETERMINATIONS

Congress made clear that states have considerable discretion in determining BART. Congress twice stated in the CAA that BART is "determined by the State." 42 U.S.C. § 7491(b)(2)(A). The CAA also declares the "State . . . shall take into consideration" the five BART factors. *Id.* § 7491(g)(2). Likewise, EPA's BART Guidelines explain, "**States** identify the level of control representing BART after considering the factors." 40 C.F.R. pt. 51, app. Y § I(E)(2) (emphasis added). Additionally, EPA recognized the states' broad discretion in the Preamble to the BART Guidelines, stating that "how **states** make BART determinations or how they determine which sources are subject to BART" are among the issues "where the Act and legislative history indicate that **Congress evinced a special concern with [e]nsuring that States would be the decision makers**." 70 Fed. Reg. at 39,137 (emphasis added). Importantly, EPA regulations also acknowledge that, in making BART determinations, "**States are free to determine the weight and significance** to be assigned to each factor." *Id.* at 39,123 (emphasis added); *see also* 40 C.F.R. pt. 51, app. Y § IV(D)(5).

In contrast, EPA's role is to provide "guidelines" for the states to use when creating SIPs. 42 U.S.C. § 7491(b)(1). EPA also reviews SIPs to determine whether a SIP contains "such emission limits, schedules of compliance and other measures as may be **necessary to make reasonable progress** toward meeting the national goal." 42 U.S.C. § 7491(b)(2) (emphasis added); *see also Oklahoma*, 723 F.3d at 1207–08 (confirming EPA's authority to review SIPs for compliance with regional haze statutes, regulations, and guidelines).

Thus, EPA may only reject a state's determination when the "determination is 'not based on a reasoned analysis'" that ensures "statutory requirements are honored." *Alaska Dep't of Envtl. Conservation v. EPA*, 540 U.S. 461, 489–91 (2004) (hereinafter "*ADEC*"). This means that EPA must approve a SIP when its only disagreement with the SIP is how the state balanced the various elements required by the statutes and regulations. *See Oklahoma*, 723 F.3d at 1209 (upholding EPA's decision, in part, because "EPA did not reject the petitioners' BART determination because it disagreed with the way it balanced the five factors"); *Texas v. EPA*, 829 F.3d 405, 427–28 (5th Cir. 2016).

Here, if this Court finds that Utah's SIP meets the requirements of the applicable statutes and regulations, and is supported by the record, then this Court must reverse EPA's disapproval of Utah's SIP.

II. THIS COURT SHOULD AFFORD EPA LESS DISCRETION IN ITS REVIEW OF EPA'S REJECTION OF THE UTAH SIP

This Court has recognized that "EPA has less discretion when it takes actions to reject a SIP than it does when it promulgates a FIP." *Oklahoma*, 723 F.3d at 1213, n.7. This higher standard aligns with the Supreme Court's direction that when reviewing EPA's rejection of a determination entrusted to a state, "the production and persuasion burdens remain with EPA" to show "[w]hether the state agency's . . . determination was reasonable, in light of the statutory guides and the state administrative record." *ADEC*, 540 U.S. at 494. As the Supreme Court emphasized, EPA should act only in the "unusual case" in which a state has acted arbitrarily. *Id.* at 491. Congress left no doubt that BART decision-making authority lies with the states. *See, e.g.*, *Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1, 8–9 (D.C. Cir. 2002). Thus, EPA carries the burden to convince this Court through record review that Utah's SIP *did not* meet the statutory requirements.

III. THIS COURT SHOULD APPLY THE ARBITRARY AND CAPRICIOUS STANDARD IN ITS REVIEW OF EPA'S FIP

EPA's disputed actions in the Final Rule are subject to "arbitrary and capricious" review under the APA. *See Oklahoma*, 723 F.3d at 1213, n.7; 5 U.S.C. § 706(2)(A). Agency action is arbitrary and capricious if "the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs

counter to the evidence before the agency, or if the agency action is so implausible that it could not be ascribed to a difference in view or the product of agency expertise." *Wyoming v. U.S. Dep't of Agric.*, 661 F.3d 1209, 1227 (10th Cir. 2011) (internal quotation marks omitted). Agencies like EPA have an obligation "to follow their own regulations, procedures, and precedents, or provide a rational explanation for their departures." *City of Colorado Springs v. Solis*, 589 F.3d 1121, 1132 (10th Cir. 2009) (citation omitted). At a minimum, the Court "must determine whether the agency considered the relevant data and rationally explained its decision." *Ariz. Pub. Serv. Co. v. EPA*, 562 F.3d 1116, 1122 (10th Cir. 2009).

IV. *CHEVRON* DEFERENCE HAS LIMITED APPLICATION IN THIS APPEAL

This Court must determine whether EPA's interpretations of the CAA in the Final Rule are subject to the standard in *Chevron, U.S.A., Inc. v. Natural Res. Def. Council Inc.*, 467 U.S. 837 (1984). Under that standard, "'[i]f the statute is clear, we apply its plain meaning' and the inquiry ends." *Ariz. Pub. Serv. Co.*, 562 F.3d at 1123 (quoting *Qwest Corp. v. FCC*, 258 F.3d 1191, 1199 (10th Cir. 2001)). As explained above, the CAA Regional Haze provisions at issue are "clear," both in spelling out required considerations for BART determinations and in giving states tremendous discretion in adopting BART alternatives. *See ADEC*, 540 U.S. at 489–91; *North Dakota v. EPA*, 730 F.3d 750, 764 (8th Cir. 2013). Therefore, this

Court should not defer to EPA's interpretations of the CAA, but instead should apply the plain meaning of the CAA provisions at issue.

SUMMARY OF ARGUMENT

EPA took two distinct actions here that are arbitrary and capricious. First, EPA illegally disapproved Utah's BART Alternative, even though it met all applicable CAA requirements, was reasoned and supported, and fell within Utah's discretionary regional haze responsibilities. EPA's disapproval resulted from EPA unlawfully requiring Utah's BART Alternative to comply with EPA's preferences, including applying an incorrect CWE test and disregarding Utah's evidentiary support and sound reasoning.

Second, EPA issued a replacement FIP for the BART Units that did not meet the applicable CAA requirements, including the five-factor BART analysis required by statute. EPA's replacement of NO_x BART determinations is also contrary to EPA's earlier stated positions and evidence in the record.

ARGUMENT

I. EPA ILLEGALLY REJECTED UTAH'S BART ALTERNATIVE

As described *supra*, the RH Program requires each state to develop a SIP to make reasonable progress towards the national goal of natural visibility at Class I areas. 42 U.S.C. § 7691(b)(2). Part of a state's first regional haze SIP must include emission controls representing BART for eligible sources that contribute to

visibility impairment at affected Class I areas. 40 C.F.R. § 51.308(e). However, a state may select an alternative measure in place of the BART controls if it can demonstrate that the alternative would result in "greater reasonable progress" than BART. *Id.* § 51.308(e)(2).

States may make the "greater reasonable progress" demonstration through one of three ways: (i) a quantitative emissions reduction test; (ii) a quantitative visibility modeling test; *or* (iii) a qualitative test "**based on the clear weight of evidence** that the trading program or other alternative measure achieves greater reasonable progress [than BART]." *Id.* § 51.308(e)(2)(i)(E) (emphasis added). EPA and this Court have made clear that the CWE test differs from—and is a **qualitative alternative** to—the two quantitative tests, and that it provides a lawful way for states to meet the applicable requirements of the RH Program. 71 Fed. Reg. at 60,622; *WildEarth*, 770 F.3d at 934. However, for the Utah SIP, EPA departed from these established requirements and rejected Utah's legally- and factually-supported BART Alternative.

a. EPA Illegally Revised the CWE Test, Materially Biasing Its Disapproval of the Utah BART Alternative.

EPA acknowledges that the CWE test is flexible. Indeed, EPA has found that data and information such as quantitative modeling and monitoring, capital costs, policy, and timing of emission reductions to be reasonable considerations under the CWE test. *See, e.g.*, 79 Fed. Reg. 33,438, 33,439 (Washington, Jun. 11,

2014) (EPA conducted an affordability analysis for a Washington BART alternative); *WildEarth*, 770 F.3d at 933–35 (approving use of qualitative considerations in CWE tests for BART alternatives in Utah, Wyoming, and New Mexico).

Yet in evaluating Utah's BART Alternative, EPA applies the CWE test in an inflexible, narrow, and never-before-introduced manner—"clearly demonstrated . . . greater visibility benefits" (hereinafter referred to as the "Visibility-Only Test"). 81 Fed. Reg. at 43,897 [JA__]. Such terminology is not found anywhere in the BART alternative rule. *See* 40 C.F.R. § 51.308(e)(2)(i)(E) (referring to "greater **reasonable progress** than would be achieved through the installation and operation of BART," not "greater visibility benefits") (emphasis added).

EPA's illegally-revised Visibility-Only Test ("clearly demonstrated . . . greater visibility benefits") conflicts with the regional haze statute, regulations, EPA guidance, and a binding decision by this Court, which held that the CWE test should use "all available information" to demonstrate "reasonable progress," including "consideration of qualitative evidence." *See WildEarth*, 770 F.3d at 934–35. The Supreme Court has explained that, when introducing a new test or policy, such as the Visibility-Only Test, "the agency must at least display awareness that it is changing position . . . [and] a reasoned explanation is needed for disregarding facts and circumstances that underlay or were engendered by the

prior policy." *See Encino Motorcars, LLC v. Navarro*, 136 S. Ct. 2117, 2126 (2016) (internal quotation marks omitted). EPA does not even attempt to fulfill these requirements in the Final Rule.

i. EPA's Visibility-Only Test violates the regional haze statute by narrowing the statutory definition of "reasonable progress."

The regional haze regulations clearly explain a CWE analysis must consider whether the alternative results in "greater **reasonable progress** than . . . BART." 40 C.F.R. § 51.308(e)(2)(i)(E) (emphasis added). And Congress clearly defined how "reasonable progress" must be determined, instructing EPA that:

> in determining **reasonable progress** there shall be taken into consideration the **costs of compliance, the time necessary for compliance**, and the **energy and nonair quality environmental impacts** of compliance, and the remaining useful life of any existing source subject to such requirements.

42 U.S.C. § 7491(g)(1) (emphasis added).

In the Final Rule, EPA departed from this Congressional definition of "reasonable progress" and replaced it with the narrow Visibility-Only Test, as expressed in EPA's Response to Comments: "The weight-of-evidence analysis answers just this question—whether the Alternative will **clearly result in greater visibility benefits**." EPA Response to Comments ("RTC") at 39 [JA__] (emphasis added). This departure from the CWE test, as it is described in the regulations, flouts the statutory definition of "reasonable progress" by excluding consideration

of, among other data, "the costs of compliance" and "the energy and nonair quality environmental impacts of compliance." *See* 42 U.S.C. § 7491(g)(1). By statute, a "reasonable progress" analysis, and by extension a "**greater** reasonable progress" analysis, must allow a state to consider both the cost and environmental impact factors consistent with the statutory definition. EPA cannot prohibit a state from doing that by implicitly redefining "reasonable progress." *See also infra* Argument § I.b and c.

ii. The Visibility-Only Test contradicts the regional haze regulations.

In addition to contradicting the regional haze statute, EPA's application of the new Visibility-Only Test departs from existing regulations. EPA conducted rulemaking that established the CWE test as "an alternative to the [quantitative] methodology of section 51.308(e)(3)." 71 Fed. Reg. at 60,622. The (e)(3) methodology allows states to demonstrate an alternative is allowable by either: (1) showing the alternative would produce "greater emission reductions" than BART; or (2) using dispersion modeling to show average overall "improvement in visibility" over BART. 40 C.F.R. § 51.308(e)(3).

EPA introduced the CWE test as a third alternative methodology that differed from the (e)(3) options by "mak[ing] use of **all available information and data** which can inform a decision while recognizing the relative strengths and weaknesses of that information in arriving at the soundest decision possible." 71

Fed. Reg. at 60,622 (emphasis added). EPA created BART alternatives because they "have the potential to achieve greater progress towards the national visibility goals than more traditional approaches to regulation, and **to do so in the most cost-effective manner practicable**." *Id.* at 60,614 (emphasis added). While visibility benefits are certainly the over-arching goal of an alternative, the regional haze regulations do not support EPA's new, cramped Visibility-Only Test that reduces the CWE test to a clone of the quantitative (e)(3) modeling requirement.

iii. EPA's application of the Visibility-Only Test contradicts past practice and evidence before the agency.

EPA's previous rulemakings have not applied the Visibility-Only Test, instead relying on the much broader and inclusive CWE test that considers "all available information." Several states have used the CWE test to gain EPA's approval for BART alternatives. An example familiar to this Court is the SO_2 BART alternative that EPA approved for Utah, Wyoming, and New Mexico, and which this Court reviewed and upheld in the *WildEarth* case. *See WildEarth*, 770 F.3d at 933–34 (finding qualitative factors appropriate as CWE evidence, such as the inclusion of non-BART and new sources of emissions, creating a "mass-based" cap for aggregate emissions, and encouraging early reductions in emissions).

In the *WildEarth* case, EPA successfully argued before this Court that, "[BART alternatives, such as cap-and-trade] programs promote flexibility, long-term planning, innovation, and **lower compliance costs—'policy considerations'**

which EPA may properly assess under the 'clear weight of the evidence' standard when comparing BART to a BART-alternative." Brief of Respondent EPA, *WildEarth*, No. 13-9510, at 42 (10th Cir. Dec. 6, 2013)(emphasis added) (hereinafter "EPA WildEarth Br."). And yet EPA rejects Utah's consideration of these same metrics now. This Court should not allow EPA to apply the CWE test to approve Utah's SO_2 BART alternative, and then apply a different, Visibility-Only Test to disapprove Utah's NO_x BART Alternative. Such action is a prime example of an arbitrary and capricious decision.

EPA has approved other states' CWE analyses without applying a Visibility-Only Test. For Connecticut, EPA approved the state's CWE analysis even though Connecticut had "difficulty directly showing that their alternative program would necessarily result in greater reasonable progress." 77 Fed. Reg. 17,367, 17,378 (proposed Mar. 26, 2012). Connecticut's CWE test did not require (e)(3) (i.e. 98th percentile) modeling, *id.*, but relied instead on early emissions from an existing state NO_x program in place since 1994, as well as the sources' minimal projected impacts on Class I areas, and an existing statewide seasonal emission cap, *id.* at 17,378–79. *See also* 79 Fed. Reg. 39,322 (July 10, 2014) (final rule).

For North Carolina, EPA found several of the state's CWE factors weighed in favor of approval, including application of the alternative to non-BART units; recognizing early emission reductions; lower projected SO_2 and NO_x emissions; no

emissions shifting; and incorporating benefits from an existing state program that had required SCR for many, but not all, units. 81 Fed. Reg. 19,519, 19,524 (proposed Apr. 5, 2016). EPA also accepted North Carolina's consideration of the costs of compliance for those units where North Carolina determined that SCR should not be required. *Id.* Like Connecticut, North Carolina was not required to provide (e)(3) modeling. *Id.*; *see also* 81 Fed. Reg. 32,652 (May 24, 2016) (final rule approving North Carolina's CWE evaluation of the alternative). In none of these CWE evaluations did EPA discuss or impose a Visibility-Only Test.

Yet EPA's application of the Visibility-Only Test to Utah's BART Alternative resulted in the opposite conclusion from Utah's application of the CWE test. *See* Utah Preliminary Brief at 23–42 (hereinafter "Utah Br.") (describing Utah's analysis of the nine metrics and application of the CWE test to determine that the Alternative achieved greater reasonable progress than BART). In rejecting Utah's BART Alternative, EPA relied on the Visibility-Only Test to ignore or distort the evidence from several of Utah's metrics, and to ultimately determine that the $700 million SCR system that Utah had now twice rejected as BART somehow provided greater reasonable progress than Utah's BART Alternative. *See* 77 Fed. Reg. at 74,369 (Utah's first finding rejecting SCR as BART).

Courts have found procedural error where, as here, "vital assumptions" regarding the basis for EPA's new test (Visibility-Only Test) do not conform to the governing statute and EPA's own regulations, and the agency's subsequent justification has not been subject to notice-and-comment rulemaking. *See New Jersey v. EPA*, 517 F.3d 574, 583–84 (D.C. Cir. 2008) (vacating EPA rulemaking that "nullifie[d]" provisions of the CAA). In addition, EPA has an obligation to rationally consider all relevant data. *See Ariz. Pub. Serv. Co.*, 562 F.3d at 1122. EPA's application of its Visibility-Only Test to Utah's BART Alternative excluded consideration of all the relevant data, and therefore is arbitrary and capricious.

b. EPA's Rebuff of Utah's Consideration of Statutory Cost Issues Is Fatal to Its Rejection of Utah's BART Alternative.

EPA's refusal[15] to consider Utah's evidence of significant comparative cost savings from the Utah BART Alternative is "not in accordance with law." 5 U.S.C. § 706(2). When EPA compared the "reasonable progress" from Utah's BART Alternative to the SCR BART Benchmark (EPA's preferred option), EPA purposely ignored the hundreds of millions of dollars difference in capital and

[15] EPA claims the cost difference of at least $500 million (PacifiCorp's estimates are over $700 million) had no "direct bearing on whether the BART Alternative achieves greater reasonable progress" and was not "material." 81 Fed. Reg. at 43,901 [JA__]. Nowhere in its Final Rule does EPA assert that cost information was not available or was not a part of "all available information and data."

operating costs that Utah had considered.[16] As discussed above, the Utah BART Alternative standard requires "greater reasonable progress than . . . BART," 40 C.F.R. § 51.308(e)(2)(i)(E), and the CAA instructs that "determining reasonable progress"[17] for any regional haze action requires consideration of "the costs of compliance," 42 U.S.C. § 7491(g)(1). EPA has also "sanctioned consideration of 'all available information'" when using the CWE standard. *WildEarth*, 770 F.3d at 934 (citing 71 Fed. Reg. at 60,622). Thus EPA violated the clear language of the regional haze statute and rules by refusing to consider the enormous cost difference that Utah concluded was significant.

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[16] After refusing to consider comparative costs as part of the CWE test, EPA takes a protective position by claiming that it nevertheless did consider costs. RTC at 38 [JA__]. To be clear, EPA refused to consider an over $500/$700 million difference between Utah's BART Alternative and the BART Benchmark/EPA FIP. "[S]tating that a factor was considered . . . is not a substitute for considering it." *WildEarth Guardians v. EPA*, 759 F.3d 1064, 1073 (9th Cir. 2014) (internal quotation marks omitted). Any argument that EPA meaningfully considered costs is unsupported. Moreover, having conceded that the consideration of cost in some fashion for a Utah BART Alternative is "consistent with the CAA and RHR," and that "cost effectiveness is an important justification for allowing States to propose alternatives," RTC at 38–39 [JA__], EPA never rationally explains why Utah's consideration of the comparative costs between the Utah BART Alternative and the BART Benchmark, totaling hundreds of millions of dollars, is not also "consistent with the CAA and RHR."

[17] The regional haze statute requires each SIP (regardless of whether it includes BART, a BART Alternative, etc.) to "contain such emission limits, schedules of compliance and other measures as may be necessary **to make reasonable progress**." 42 U.S.C. § 7491(b)(2) (emphasis added).

Instead, EPA improperly narrowed the statutory "reasonable progress" language to "greater visibility improvement," and used this faulty construction to claim a cost difference of over $500/$700 million, "is not material to our action." 81 Fed. Reg. at 43,901 [JA__]. Utah's evaluation of whether the Utah BART Alternative makes "greater reasonable progress" than BART allows Utah to compare the two options and, by statute, their comparative costs. By rejecting Utah's analysis of these statutory "reasonable progress" factors, EPA effectively wrote "reasonable" out of the "reasonable progress" statute and the CWE regulation.

This Court implicitly confirmed that it is within Utah's discretion and authority to consider costs of a BART alternative to determine reasonable progress: "'Reasonable progress' is measured by comparing '**the costs of compliance**, the time necessary for compliance, . . . the **energy and nonair quality environmental impacts** of compliance, and the remaining useful life of any existing [regulated] source' (known as the 'four factors')." *WildEarth*, 770 F.3d at 924 n.3 (emphasis added) (quoting 42 U.S.C. § 7491(g)(1); 40 C.F.R. § 51.308(d)(1)(i)(A)).

Moreover, in the *WildEarth* appeal, EPA represented to this Court that comparing costs between BART and a BART alternative is an appropriate policy

consideration under the CWE test.[18] EPA specifically stated that "**lower compliance costs"** are "**policy considerations' which EPA may properly assess under the 'clear weight of the evidence' standard when comparing BART to a BART-alternative.**" EPA WildEarth Br. at 42 (emphasis added). Thus Utah's assessment of "lower compliance costs" for the Utah BART Alternative over BART complied with the regional haze statutes and regulations, as well as EPA's past representations to this Court. *See, e.g.*, Staff Review at 27 [JA__]. But, EPA reversed its position (from the one expressed supporting Utah's SO_2 BART alternative in *WildEarth*), and rejected the Utah NO_x BART Alternative, falsely claiming: "EPA has **always** interpreted this [weight-of-evidence] provision as evaluating the ***visibility benefits*** to be gained by the BART alternative **only**, an evaluation in which **consideration of costs . . . has no role**." Respondents' Opp'n to the Motions to Stay the Final Rule, *Utah v. EPA*, No. 16-9541, at 40 (10th Cir. Dec. 16, 2016) (emphasis added). This Court should reject EPA's newly-minted,

[18] In a recent CAA case, the Supreme Court rejected similar attempts by EPA to ignore cost through a skewed statutory reading. Even in a statute where the cost consideration requirement was not clearly articulated, the Court found "EPA strayed far beyond those bounds when it read § 7412(n)(1) to mean that it could ignore cost when deciding whether to regulate power plants." *Michigan v. EPA*, 135 S. Ct. 2699, 2707 (2015). The principle of *Michigan* that costs cannot be ignored applies with even more force here. *See* UAMPS Brief.

inconsistent position on costs,[19] which is another clear example of EPA's arbitrary and capricious conduct related to the Final Rule.

Because the language of the regional haze statute is clear, this Court should give no weight to EPA's recently-revised interpretations of that statute. "If a statute is clear and unambiguous, the court must interpret the statute to effect the unambiguous intent of Congress, regardless of the interpretation given to the statute by an administrative agency with responsibility for enforcement." *Mt. Emmons Min. Co. v. Babbitt*, 117 F.3d 1167, 1170 (10th Cir. 1997). EPA's failure to consider the comparative costs as required by the statute is fatal to its rejection of Utah's BART Alternative.

c. **EPA's Rejection of Utah's Consideration of Statutory Energy/Environmental Impacts Is Fatal to Its Denial of Utah's BART Alternative.**

As with costs, EPA's refusal to consider energy/environmental impacts as part of its evaluation of the Utah BART Alternative is similarly fatal to EPA's ultimate determinations in the Final Rule. *See, e.g.*, *WildEarth*, 770 F.3d at 924 n.3. Energy and non-air environmental impacts are also statutory factors identified in the statutory "reasonable progress" definition. 42 U.S.C. § 7491(g)(1). EPA

[19] This Court should estop EPA from assuming the contrary position here. "[W]here a party assumes a certain position in a legal proceeding, and succeeds in maintaining that position, he may not thereafter, simply because his interests have changed, assume a contrary position . . . ." *New Hampshire v. Maine*, 532 U.S. 742, 749 (2001).

recognized "the Utah BART Alternative would avoid an annual energy penalty of approximately $2 million [from SCR]." 81 Fed. Reg. at 2,024 [JA__]. Additionally, Utah provided information that the Utah BART Alternative would avoid environmental impacts from certain solid waste, liquid, and gaseous discharges.[20] *See* Staff Review at 26–27 [JA__]. Nevertheless, EPA incorrectly found that the comparative energy and non-air quality environmental benefits of the Utah BART Alternative "do not have direct bearing on whether the BART Alternative achieves greater reasonable progress" and are "not material." 81 Fed. Reg. at 43,900 [JA__]. EPA's rejection of Utah's consideration of these statutory "reasonable progress" factors is arbitrary and capricious.

d. EPA Improperly Ignored Relevant SO_2 Emission Reductions That Support the Utah BART Alternative (Annual Emissions Metric).

Although Utah found the "annual emissions" metric supported the Utah BART Alternative, EPA refused to consider it in its Visibility-Only Test. 81 Fed. Reg. at 43,898 [JA__]. The "annual emissions" metric compares the Utah BART Alternative's and the BART Benchmark's aggregate reductions of three visibility-impairing pollutants (by tons). Utah determined that the Alternative would remove 2,856 tons per year more of combined visibility-impairing pollutants (NO_x, SO_2,

[20] Utah introduced evidence that permanent closure of the Carbon plant under the Utah BART Alternative would considerably reduce environmental impacts from produced fly ash and waste water. Staff Review at 26–27 [JA__].

and PM) than the BART Benchmark, including 8,005 tons per year more of SO_2 (which all evidence indicates has the greatest year-round impact on visibility). 81 Fed. Reg. at 2,022 [JA__]. Utah determined that the Alternative's relatively smaller comparative NO_x emissions increase would be offset by the much greater SO_2 and PM emissions reductions. 81 Fed. Reg. at 43,898 [JA__].

In the Final Rule, EPA admitted that the "annual emissions" metric "is a relevant concept because it relates to visibility impacts," but nonetheless rejected Utah's reliance on the metric because of alleged "differences in visibility impacts and complex interactions between pollutants [SO_2 and NO_x]." *Id.* EPA claimed it could not "discern the overall visibility impacts of the aggregate emission reductions in this case without modeling." *Id.*

EPA's rejection of the "annual emissions" metric is contrary to EPA's own evidence. *See* Utah Br. at 41–43. Numerous studies and government reports in the record show SO_2 emissions have a significantly greater visibility impact than NO_x emissions at the relevant Class I areas. This means that a reduction in SO_2 emissions results in a greater visibility improvement than a similar reduction in NO_x emissions. *See, e.g.*, Western Regional Air Partnership, Regional Haze Rule Reasonable Progress Report Support Document, State and Class I Area Summaries, at 6-11–6-16 (compare "aerosol extinction" numbers for ammonium sulfate and ammonium nitrate) [JA__]; Utah Div. of Air Quality, Progress Report

for Utah's State Implementation Plan for Regional Haze at 6 (Sep. 23, 2014 [JA__].

Moreover, as Utah demonstrates in its brief, EPA agrees with the findings from these reports and Utah's analysis that "sulfate is the largest contributor to visibility impairment at the affected Class I areas," 81 Fed. Reg. at 43,900 [JA__], and has allowed the use of SO_2 emissions reductions as surrogates for NO_x reductions for other BART alternatives. Utah Br. at 13–15, 37–39. Despite these admissions, EPA claims "it is not possible to discern the overall visibility impacts of the aggregate [annual] emission reductions in this case without modeling." 81 Fed. Reg. at 43,898 [JA__]. Ironically, in asserting that additional modeling is needed to determine the visibility impacts from SO_2 and NO_x emissions, EPA actually ignored Utah's analysis of its own modeling that showed SO_2 produced more reliable visibility improvements. Staff Review at 13–17 [JA__].

And perhaps more importantly, if EPA believed additional modeling was necessary to adequately evaluate this metric, then it should have performed that modeling. EPA performed other modeling to address less important issues raised in public comments. 81 Fed. Reg. at 43,919 [JA__] ("In response to comments, EPA performed additional modeling analysis to assess the combined benefit of SCR when applied to each of the two BART units at the Hunter facility. We did the same for the Huntington facility."). Moreover, when faced with a lack of

modeling information regarding PacifiCorp's BART units in Wyoming, EPA performed the needed modeling to resolve the issue. 79 Fed. Reg. 5,032, 5,091 (Jan. 30, 2014) (After "EPA was unable to ascertain the visibility benefits of individual NO_x controls for the PacifiCorp units from the State's modeling . . . [EPA] developed additional modeling."). It is arbitrary and capricious for EPA to perform additional modeling to support its FIP, but not perform important, additional modeling that would support the BART Alternative. Rather, EPA idly declared "this metric is inconclusive," ignored Utah's modeling data, refused to do its own modeling, and moved on to its preferred outcome. 81 Fed. Reg. at 43,898 [JA__].

EPA's position on SO_2 emissions and the aggregate annual emissions metric is contrary to the evidence and EPA's admissions. If SO_2 emissions are the largest contributor to visibility impairment, as EPA admits, *id.* at 43,900 [JA__], then reductions of those SO_2 emissions will have a greater impact than NO_x emissions, and this key metric (which EPA ignored) supports Utah's BART Alternative.

e. EPA's Devaluation of the "Timing of Emission Reductions" Metric Was Arbitrary and Outcome-Determinative.

EPA's position regarding the "early emissions reductions" metric supporting the Utah BART Alternative is confusing, inconsistent, and ignores available information. EPA and this Court have recognized that "early emission reductions" is an important factor to consider when analyzing whether a BART alternative

provides "greater reasonable progress." *See WildEarth*, 770 F.3d at 937; 77 Fed. Reg. at 74,360 (finding even though emissions under the BART alternative and benchmark were equal, the alternative's incentives for earlier reductions promoted "greater reasonable progress than BART").

Yet, despite EPA's acknowledgement that the "early and ongoing emissions reduction" metric relates to "assessing visibility impacts," EPA ignored all "ongoing" emissions reductions (as of the Final Rule)[21] and only considered some of the "early" NO_x emissions reductions from the Utah BART Alternative that occurred between 2006 and 2011. 81 Fed. Reg. at 43,900–01 [JA__] (ignoring any emissions reductions from LNB/SOFA installed in 2014 and the large emissions reductions from the closure of the Carbon power plant, admitting that "the emission reductions at issue are only a portion of the overall emission reductions claimed under the Alternative"); RTC at 34 [JA__] (limiting the "early" emissions reductions considered to the "emissions reductions from Hunter and Huntington that occurred between 2006 and 2011").

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[21] EPA admitted:

> [R]eductions under the Utah BART Alternative will occur earlier than the BART Benchmark. The reductions under the Utah BART Alternative are required under the State SIP by August 2015 . . . and would provide an **early and on-going visibility benefit** as compared to BART. . . . BART likely would be fully implemented sometime between 2019 and 2021. Therefore, we recognize that the reductions from the BART Alternative would occur before the BART Benchmark.

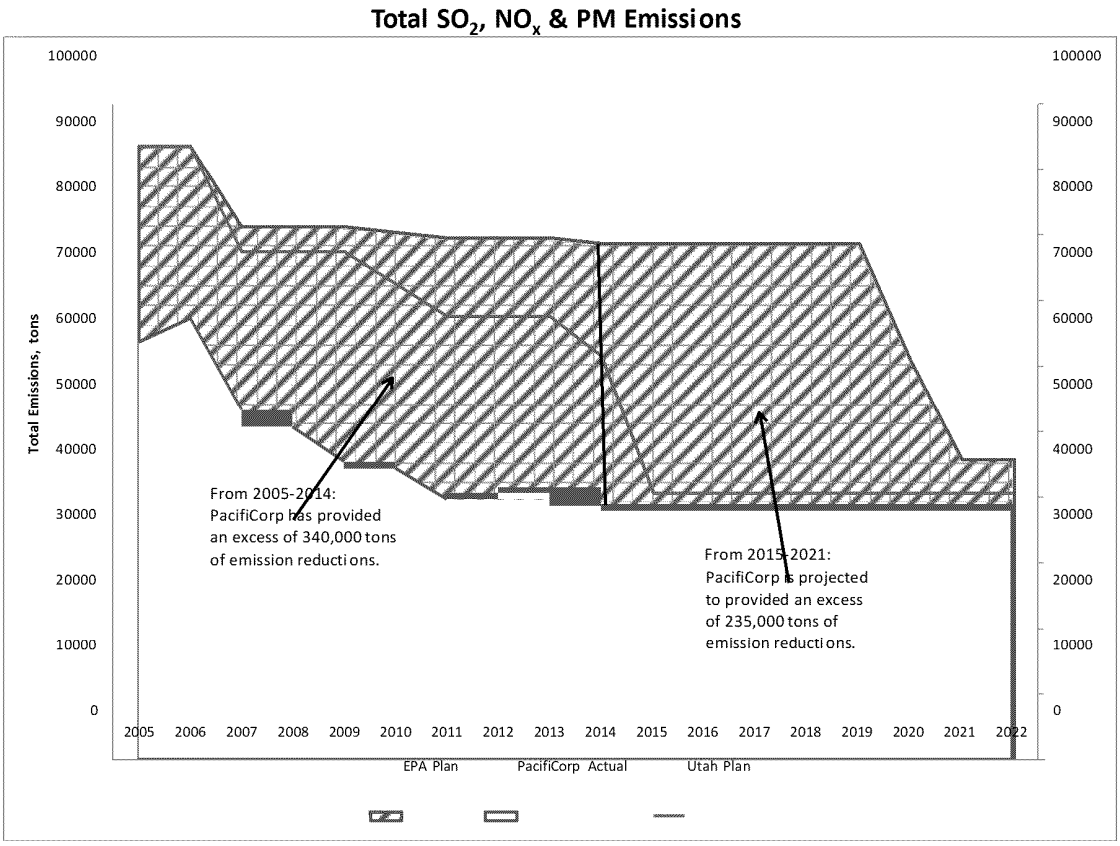
81 Fed. Reg. at 2,030 (emphasis added) [JA__].

EPA's actions here are contrary to its past practice. EPA has relied on "early and on-going emission reductions," in part, to approve several other BART alternatives, including the Utah and Wyoming SO_2 BART alternatives. *See* 77 Fed. Reg. 73,926, 73,930 (Dec. 12, 2012) (Wyoming); 77 Fed. Reg. at 74,360 (Utah); 79 Fed. Reg. 46,514, 46,517 (Aug. 8, 2014) (Navajo Nation); 77 Fed. Reg. 34,801, 34,804 (June 12, 2012) (Minnesota); 81 Fed. Reg. at 19,525 (North Carolina, proposed rule). Yet, for Utah's NO_x BART Alternative, EPA arbitrarily refused to credit much of the hundreds of thousands of tons of "early and on-going" emission reductions from the Alternative. *See, e.g.*, RTC at 136–37 [JA__] (illustrated in the figure at 137); 81 Fed. Reg. at 43,900 [JA__].

EPA's refusal to credit "early and ongoing emission reductions" after 2011 is allegedly based on an incorrect view of the state of Utah's analysis, where EPA claims "Utah relied only on the NO_x reductions . . . that occurred between 2006 and 2011 in arguing that the BART Alternative provides for early and ongoing visibility improvement. . . . [W]e have decided to consider only those emission reductions that occurred between 2006 and 2011 . . . ." RTC at 138 [JA__].

Contrary to EPA's unfounded claims, Utah considered "early and ongoing emissions reductions" from the Utah BART Alternative after 2011. Utah Br. at 39–41. And EPA knows Utah considered a broad range of "early and ongoing emissions reductions." In the proposed rule, EPA admitted the State considered

"early and on-going" emissions reductions after 2011. 81 Fed. Reg. at 2,012 [JA__] (citing Utah's reliance on on-going "reductions from the August 2015 retirement of PacifiCorp's nearby Carbon power plant"); *id.* at 2,018, Table 9 [JA__] (admitting Utah relied on reductions from controls installed from 2006–2014 and recognizing those reductions as "on-going"). PacifiCorp also submitted evidence in its public comments regarding the "early and on-going" emissions reductions (post-2014) that EPA ignored, including the hundreds of thousands of tons of emissions that have been, and will be, eliminated by the Utah BART Alternative. *See* PacifiCorp Comments at 16–18 [JA__] and the chart below from PacifiCorp's comments. EPA never provides any explanation why it ignored PacifiCorp's evidence of "early and ongoing emissions reductions," and EPA's failure to consider that critical information is arbitrary and capricious.



EPA also erroneously claims that any emissions reductions after 2014 are ineligible to be considered because they occur after an incorrect and unmet 2014 BART implementation deadline.[22] RTC at 138 [JA__]. As explained in Utah's Brief, EPA's assertion of a 2014 BART deadline is not only unsupported, but directly contrary to EPA's statements in the Final Rule that the BART deadline is 2021. Utah Br. at 50–54. EPA cannot have it both ways. EPA cannot refuse to

[22] EPA never explains why its claimed 2014 BART installation date is even relevant, given EPA's claim that it only considered NO_x emissions reductions between 2006 and 2011. RTC at 138 [JA__].

consider the Utah BART Alternative's "early" emission reductions after 2014 because BART must be implemented by then, and then argue that BART need not be implemented under EPA's FIP until 2021.[23] Such internal inconsistencies are "the hallmark of arbitrary action." *Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1145 (9th Cir. 2015). Additionally, EPA's refusal to consider all evidence of "early and ongoing" emissions reductions, including the undisputed evidence by PacifiCorp, is arbitrary and capricious because it failed to consider an "important aspect of the problem," and because its decision "runs counter to the evidence before the agency." *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto Ins. Co.*, 463 U.S. 29, 43 (1983). Because the decision to disapprove the Utah BART Alternative was such a "close call," 81 Fed. Reg. at 43,895, any additional piece of favorable evidence should tip the balance towards approval of the Alternative.

f. EPA's Exclusive Reliance on the 98th Percentile Test Is Unfounded.

EPA illegally relied exclusively on the 98th percentile computer-modeling metric ("98% Metric") when it found the BART Benchmark preferable to the Utah BART Alternative. *See* 81 Fed. Reg. at 43,899 [JA__]. Utah's Brief comprehensively addresses this issue, including EPA's improper application of the

[23] The proper BART installation date that EPA has repeatedly recognized is 2018. *See* Utah Br. at 52.

CWE test and EPA's incorrect rejection of actual visibility monitoring data which undermines absolute reliance on the 98% Metric. Utah Br. at 29–32, 37–39.

Additionally, the 98% Metric must be cautiously applied and weighed due to the CALPUFF model's margin of error. *See, e.g.*, *Nat'l Parks Conservation Ass'n*, 788 F.3d at 1146 (reversing EPA's decision where "the results the [98% Metric] model predicts . . . are too insignificant for the model to measure, and therefore cannot be reasonably anticipated as the Act requires"); EPA, Revisions to the Guideline on Air Quality Models, 82 Fed. Reg. 5,182, 5,195 (Jan. 17, 2017) (explaining that "concerns, including the well-documented scientific and technical issues with the [CALPUFF] modeling system, support the EPA's decision to remove it as a preferred model"). As explained in Argument Section II.d, the CALPUFF model (which generates the visibility improvement data for the 98% Metric) as used by EPA in the Final Rule has certain limitations and the data it generated should have been cautiously considered. Rather than cautiously consider the 98% Metric data, EPA capriciously adopted it as superior to all other information and data. 81 Fed. Reg. at 43,899; Utah Br. at 29–32.

g. EPA Improperly Discounted Other Evidence That the Utah BART Alternative Should Be Approved.

i. Improvement in number of days with significant visibility improvement

EPA found the "number of days" metric persuasive in its proposal to approve the Utah BART Alternative, 81 Fed. Reg. at 2,022 [JA__], but EPA discounted or ignored the same information in the Final Rule, 81 Fed. Reg. at 43,898 [JA__]. Thus EPA overlooked important evidence in its FIP analyses. For example, EPA ignored Utah's information concerning days of visibility improvement over 1.0 dv (the limit at which the human eye can discern a difference) because "seven of the nine Class I areas had the same result or were within one day of having the same result under both the Utah BART Alternative and Benchmark." *Id.*

While this statement is true, EPA fails to examine or explain the number of days of improvements at the other two Class I areas. In fact, Utah's analysis demonstrated that at Arches National Park—one of the most impacted areas—the Utah BART Alternative would result in nine more days of visibility improvement over 1.0 dv than the Benchmark. RTC at 113, Table 4 [JA__]. Although EPA's Final Rule claims the "impacts over the 1.0 dv threshold do not show that the BART Alternative is better," EPA only reaches this conclusion by ignoring this

important visibility data regarding Arches that supports the Utah BART Alternative. 81 Fed. Reg. at 43,898 [JA__].

Moreover, EPA admits that the Alternative would result in "58 fewer days per year with a visibility impact greater than 0.5 dv." *Id.* Despite the fact the Utah BART Alternative results in almost two months fewer days with a visibility impact greater than 0.5 dv, EPA claims it is only "marginally better" than the Benchmark because most of these days are concentrated in four of the nine Class I areas. *Id.* EPA never explains (because it cannot) why it was improper for Utah to consider two months of visibility improvement in four Class I areas as significant. EPA should have given sufficient weight to this metric, and EPA's failure to adequately analyze, examine, and consider this important visibility data is arbitrary and capricious.

ii. IMPROVE monitoring data

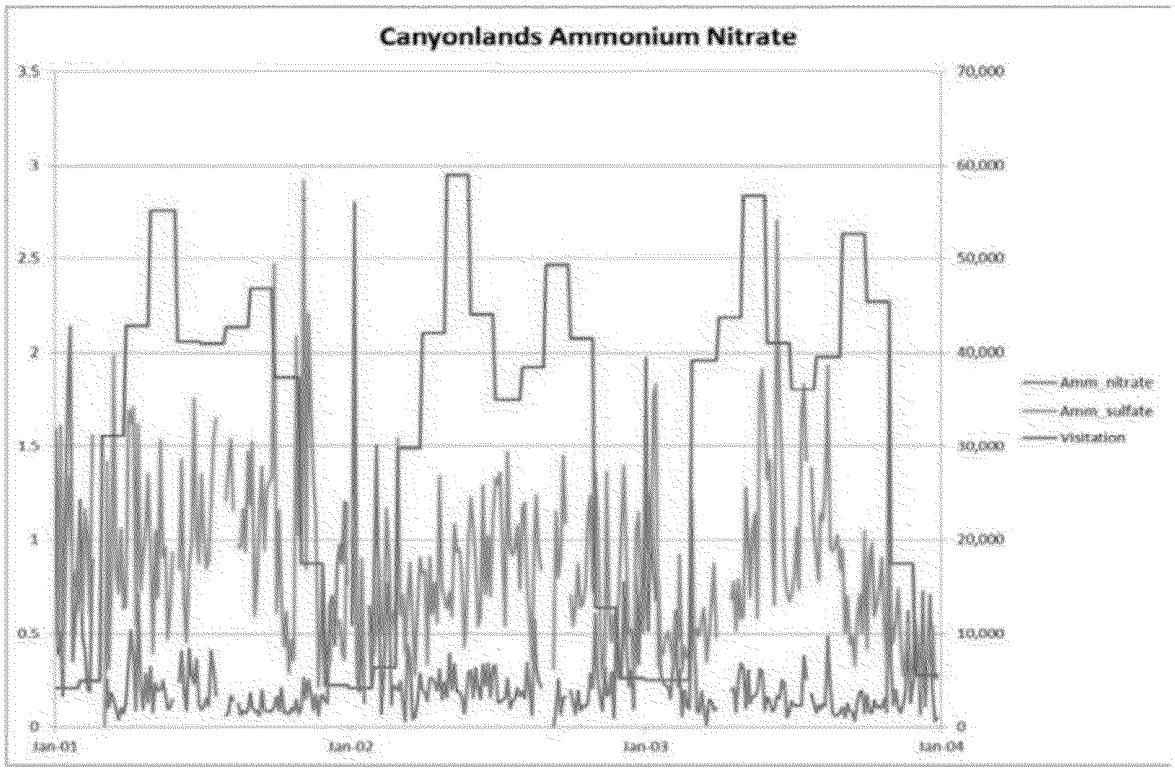
In Utah's thorough review of the Utah BART Alternative, it reviewed past monitoring data (from Canyonlands National Park) to determine visibility impacts from the various pollutants (referred to as the IMPROVE monitoring data), and compared the monitoring data to NO_x and SO_2 emission trends. *See* Utah Br. at 37–39. Utah analyzed this data to determine if there was a correlation between (1) NO_x and SO_2 emissions from the BART Units, (2) reductions of the same

emissions due to controls installed at the BART Units over time, and (3) the visibility impacts from those same pollutants in Canyonlands. Utah found:

> DAQ has confidence that SO_2 reductions will achieve meaningful visibility improvement. The visibility improvement during the winter months due to NO_x reductions is much more uncertain. Figure 5 shows the significant emission reductions of both SO_2 and NO_x that have occurred from the four subject to BART EGUs over the last 15 years. Figure 6 shows corresponding improvements in ammonium sulfate values at Canyonlands throughout the year. However, ammonium nitrate values do not show similar improvement in the winter months, despite a 50% reduction in NO_x over this time period.
> . . . .
> For this reason, DAQ has greater confidence that modeled improvements due to reductions in SO_2 will be reflected in improved visibility for visitors to the Class I areas over the next decade, while modeled improvements due to reductions in NO_x will have a more uncertain benefit.

Staff Review 13, 17 [JA__]. In other words, Utah was able to correlate decreasing SO_2 emissions from SO_2 controls installed at the BART Units with decreasing SO_2-related visibility impacts. However, despite decreasing NO_x emissions from NO_x controls installed at the BART Units, NO_x-related visibility impacts actually increased in the wintertime. *Id.* at 13 [JA__]. Moreover, when Utah analyzed visitation data from Canyonlands, Utah found relatively few visitors were present when the NO_x-related visibility impacts occurred in the wintertime. It also found that Canyonlands had much higher visitation during the spring, summer, and fall months, resulting in more people benefiting from the BART Alternative and enjoying the decreasing SO_2-related visibility impacts. *Id.* at 13, Figure 4 [JA__].

The chart below from Utah's BART Alternative analysis shows the relative contributions of SO_2 and NO_x at Canyonlands, and compares that to visitation numbers. *Id.* In sum, the chart shows SO_2-related visibility impairment (green line) is higher (often much higher) than NO_x-related visibility impairment (blue line) during a large part of the year, confirming Utah's analysis that SO_2 is a larger concern for visibility impairment. The chart and data also show that SO_2-related visibility impairment (green line) is greater during the seasons Canyonlands has the most visitors (*see* red line), while NO_x-related visibility impairment (blue line) is greatest when Canyonlands has the fewest visitors.



This data and analysis supports Utah's BART Alternative, and calls into question EPA's decision in the FIP to install additional, expensive NO_x controls to address wintertime NO_x-related visibility issues (when SO_2-related visibility was more of an issue). This data and analysis also cast doubt on the reliability of CALPUFF computer-modeling results (SIP 98% Metric and FIP modeling) that indicate NO_x-related visibility would improve with SCRs. Utah Br. at 29–32, 37–39.

In sum, EPA's disapproval of Utah's BART Alternative is arbitrary and capricious because the Alternative met the applicable requirements of the regional haze program and the CAA. Relying on the Visibility-Only Test, EPA contravened the regional haze statute, its own regulations, and relevant case law, and ignored the compelling record evidence before it. Because EPA failed to present "[a] rational connection . . . between the facts before the agency and the rule-making choice made," this Court should reverse EPA's action on Utah's SIP. *See Humana of Aurora, Inc. v. Heckler*, 753 F.2d 1579, 1582 (10th Cir. 1985) (citation omitted).

II. EPA'S FIP DOES NOT COMPLY WITH THE CAA

The CAA requires EPA to analyze all five BART factors when adopting a BART determination through a FIP. EPA's failure to do so is illegal. 42 U.S.C.

§7491(g)(2); *WildEarth Guardians v. EPA*, 759 F.3d 1064, 1068–69 (9th Cir. 2014). Here, EPA incorrectly analyzed four of the five statutory BART factors.

a. EPA Failed to Consider "Existing Controls in Use" at a Source as Required by One BART Factor and Critical to the Analysis of Two Other Factors.

When EPA conducted its 2016 BART cost and visibility analyses for its FIP, it did not correctly consider the statutory "existing controls" BART factor.[24] EPA openly acknowledges that "existing controls" were in use at the BART Units for NO_x emissions (LNB/SOFA) between 2006 and 2014. *See, e.g.*, 81 Fed. Reg. at 2,023 [JA__].[25] However, EPA intentionally ignored the existing LNB/SOFA when establishing the important baseline emissions for the required BART cost effectiveness and visibility improvement analyses. As a result, EPA's projected visibility improvements resulting from SCR are inflated, and the average cost-

[24] EPA admitted that its "baseline emissions," a key component of the BART cost and visibility analyses, "predates the installation of the LNB/SOFA at the four BART Units." 81 Fed. Reg. at 43,904 [JA__].

[25] These LNB/SOFA controls have been reducing NOx emissions since installation, (with the first controls installed in 2006), and EPA's BART analysis was not proposed for public comment until January of 2016. By that time, all of the LNB/SOFA controls had been installed and were operating from one to ten years, and the reduced emissions from the controlled sources were available for use as the baseline. Thus EPA's 2001–2003 baseline NOx emissions rate of 0.40 lb/MMBtu was no longer realistic in 2016; NOx emissions rates at the BART Units had decreased by 48.4% to 0.21 lb/MMBtu. 81 Fed. Reg. at 2,034 [JA__].

effectiveness of SCR is artificially enhanced. *See, e.g.* 81 Fed. Reg. at 43,903–07, Tables 1–7 [JA__].

By refusing to include "existing controls" in the BART baseline emissions, EPA violated the BART statute and acted contrary to EPA's BART Guidelines. EPA's arbitrary and capricious act materially impacted the FIP's BART determinations, which should be vacated. *See City of Colorado Springs*, 589 F.3d at 1132.

i. The regional haze statute and BART Guidelines require EPA to consider "Any Existing Controls in Use" in its BART determination.

When conducting a BART determination, the statute requires "the Administrator . . . shall take into consideration . . . **any existing pollution control technology in use at the source**." 42 U.S.C. § 7491(g)(2) (emphasis added). EPA has recognized this requirement, explaining that it is "reflected in the BART analysis in two ways: First, in the consideration of available control technologies . . . and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. . . ." 77 Fed. Reg. 42,834, 42,841 (July 20, 2012) (Arizona); *see also* 80 Fed. Reg. 18,944, 18,967 (April 8, 2015) (Arkansas). For Utah, EPA admits that it considered existing controls for the first "step" (considering available technologies), but intentionally refused to consider

existing controls for the second "step" (establishing baseline emissions). 81 Fed. Reg. at 43,904 [JA__].

Establishing baseline emissions is a fundamental step in any BART determination because two key BART factors—the cost and visibility improvement analyses—build off of the baseline emissions for comparative purposes.[26] If the baseline emissions are incorrect (such as the 48.4% mistake EPA made in baseline emissions rates here), then all comparisons and determinations of relative cost and visibility improvement will be incorrect. For this reason, EPA's regulations require baseline emissions calculations to represent a "**realistic** depiction of anticipated annual emissions for the source." 40 C.F.R. pt. 51, app. Y § IV(D)(4)(d)(1) (emphasis added). Contrary to this requirement, EPA refused to include "existing controls" in the baseline emissions, which resulted in "unrealistic" emissions estimates.

EPA uses emissions estimates for 2001–2003 for its FIP baseline. *See* 81 Fed. Reg. at 43,904 [JA__]. But these emission estimates are unrealistically high.

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[26] The BART Guidelines require that existing controls in place before the BART determination be included in the baseline to correctly evaluate the cost and visibility impacts of the proposed controls. Specifically, the BART Guidelines require: (1) the average cost effectiveness of BART to be determined based on "the difference between **baseline** annual emissions and the estimate of emissions after [the BART] controls," 40 C.F.R. pt. 51, app. Y. § IV(D)(4)(c) (emphasis added); and (2) visibility improvement to be determined based on "**pre-[BART]control** and post-control **emission rates**," *id.* § IV(D)(5) (emphasis added).

This is because they assume operating parameters at the BART Units that are not correct today, and haven't been correct for years. In fact, compared with 2001–2003 levels, the NO_x emissions rate in 2016 is nearly 50% lower due to the installation and operation of the LNB/SOFA. *See* 81 Fed. Reg. at 2,034, Table 13 [JA__] (compare LNB/SOFA with LNB/SOFA SCR emissions reductions). EPA was statutorily required to consider "any existing pollution control technology in use" in its BART baseline emissions, and EPA's failure to do so resulted in incorrect BART analyses that are arbitrary and capricious.

ii. A Circuit Court has ruled EPA may not exclude existing controls from the baseline.

The Utah FIP is not the first time EPA has confronted the "existing controls" issue. The Eighth Circuit Court of Appeals found that EPA acted contrary to the plain language of the CAA by refusing to include existing controls in the BART baseline emissions analysis. *North Dakota*, 730 F.3d at 762–64. In the North Dakota rulemaking, EPA had said it was "not reasonable to consider controls installed after the baseline period in determining BART," claiming that sources would install controls early "to **avoid installing more effective BART controls** later." 77 Fed. Reg. 20,894, 20,927 (April 6, 2012) (emphasis added). The Eighth Circuit rejected EPA's excuse, and explained that the plain language of the CAA requires EPA to consider "any" existing controls, including "controls **installed**

after the baseline period" when making cost estimates. *North Dakota,* 730 F.3d at 761–62 (emphasis added).

Here, EPA's rulemaking uses very similar, but still faulty, language to avoid including the existing controls in the baseline for the Utah BART Units: "[I]f it appeared that controls had been installed early in order to **avoid a more stringent BART determination**,[27] it would presumably not be appropriate to use a baseline representing these new controls." RTC at 354 [JA__] (emphasis added). This Court should follow the *North Dakota* decision, which clearly held that EPA must consider "**any**" existing controls under the statute. *North Dakota*, 730 F.3d at 764. EPA's refusal to consider PacifiCorp's "existing controls" in the FIP's baseline emissions analyses for the BART Units based on unsupported assumptions about the reasons those controls were installed is contrary to the "any" existing controls "in use" language in the BART statute. 42 U.S.C. § 7491(g)(2); *see also* Utah Br. at 45–50.

[27] EPA never offers any proof that the LNB/SOFA controls for the BART Units were installed to avoid a more stringent BART determination; rather, EPA baldly asserts the proposition and ignores PacifiCorp's legal obligation to install the controls as a result of the 2008 SIP.

iii. Contrary to its analyses for the BART Units, EPA has recognized in other rulemakings that "existing controls" should be considered in a BART baseline emissions analysis.

In other rulemakings, EPA has explained that including "existing controls" in the baseline "is consistent with the statutory requirement that each BART determination take into consideration 'any existing pollution control technology at the source'" and that "in order to 'represent a realistic depiction of anticipated annual emissions for the source' the baseline can account for controls already installed on the source." 77 Fed. Reg. 72,512, 72,526 (Dec. 5, 2012) (Arizona)[28]; *see also* 77 Fed. Reg. 57,864, 57,873 (Sept. 18, 2012) (Montana FIP) (noting that "for each Montana source subject to BART . . . [e]xisting pollution control technology was considered . . . when establishing a baseline for determining visibility impacts"). EPA not only accepted and defended the use of "existing

[28] When reviewing the Arizona regional haze SIP, EPA rejected the same approach it now uses for Utah. Citing the same BART Guidelines, EPA objected to a National Park Service cost analysis that did not include existing equipment (wet lime FGD) in the baseline, resulting in a cost-effectiveness of $1,320 per ton: "This approach is inconsistent with the BART Guidelines, which provide that, for purposes of calculating the costs of compliance: 'The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source' . . . . Accordingly, the baseline emissions rate for Cholla Unit 1 should reflect use of the existing wet lime FGD, which is more than 30 years old, but continues to operate effectively. Based on this more accurate baseline, we estimate that the cost-effectiveness of a new scrubber would be over $20,000/ton." 78 Fed. Reg. at 46,162. This example not only shows EPA's requirement that existing equipment be included in the baseline, but demonstrates the dramatic difference in cost-effectiveness that can occur when existing equipment is excluded.

controls" in these baseline emissions analyses, it found such an approach "to be reasonable and generally consistent with the [Regional Haze Rule] and the BART Guidelines." 77 Fed. Reg. at 42,841.

As can be seen in the table below, EPA regularly includes "existing controls" in the baseline emissions for BART analyses.

BART Determinations that Include Existing Equipment in Baseline	**BART Determinations that DO NOT Include Existing Equipment in Baseline**
Arizona (Cholla – cited in Final Rule) 78 Fed. Reg. 46,142, 46,162 (July 30, 2013).	Utah (currently in litigation), 81 Fed. Reg. at 43,904 [JA__].
Arkansas 80 Fed. Reg. at 18,974	Wyoming (currently in litigation), 79 Fed. Reg. 5,032
Colorado (Hayden – cited in Final Rule) 77 Fed. Reg. 76,871, 76,875 (Dec. 31, 2012); 77 Fed. Reg. 18,052 (March 26, 2012)	
Montana (Colstrip Units 1 and 2) 77 Fed. Reg. at 57,885	
New Mexico 76 Fed. Reg. 52,388, 52,421 (Aug. 22, 2011)[29]	
Navajo Nation (including LNB/SOFA in the baseline for BART benchmark, leading to approval of BART alternative to SCR) 79 Fed. Reg. 46,514, 46,517 (Aug. 8, 2014)	

[29] "We agree with the commenters that a consistent method of analysis should apply for all BART evaluations, and we believe the use of the BART Guidelines ensures that occurs. . . . We note that the differences the first commenter mentions, such as existing pollution control equipment and site congestion, were factored into our SJGS NOx BART visibility modeling (baseline emissions) and cost evaluation, respectively."

Excluding "existing controls" from the baseline emissions for Utah's BART Units goes against EPA's past practice, and is thus arbitrary and capricious. *See City of Colorado Springs*, 589 F.3d at 1132 ("[A]gencies are under an obligation to follow their own regulations, procedures, and precedents, or provide a rational explanation for their departures") (citations omitted).

In summary, EPA failed to consider "any existing controls in use" at the BART Units when formulating the NO_x BART baseline emissions, in violation of the BART statute and the BART Guidelines. EPA has admitted in other rulemakings that it should consider the "existing controls" as part of the BART baseline emissions, and the Eighth Circuit reached the same conclusion. But EPA still refused to do so here. Although EPA offers numerous unpersuasive excuses (*see, e.g.,* 81 Fed. Reg. at 43,919–20 [JA__]), EPA's failure to adequately consider "**any**" existing controls "**in use** at the source" is contrary to the statute, and EPA's creation of an "unrealistic" baseline is contrary to the regulation. None of EPA's excuses justify its failure to abide by the applicable statute and regulation. Like the Eighth Circuit, this Court should remand this matter to EPA for adequate consideration of "existing controls" in EPA's BART determinations.

b. EPA's Cost Analysis for the FIP Is Fatally Flawed.

i. The regional haze statute and regulations require EPA to consider costs when determining BART.

Another statutory BART factor requires consideration of the costs of compliance. 42 U.S.C. § 7491(g)(2). In promulgating the FIP, EPA stands in the shoes of a state and must analyze the same BART factors. *See* 77 Fed. Reg. 40,150, 40,164 (July 6, 2012). According to EPA's BART Guidelines, the analysis of cost must include calculating the "average cost effectiveness" and "incremental cost effectiveness" of the proposed BART control, "to assess the potential for achieving" the visibility objective "in the most economical way." 40 C.F.R. pt. 51, app. Y § IV(D)(4)(b). The cost analysis may be outcome-determinative because "[i]n the course of the BART review, one or more of the available control options may be eliminated from consideration because they are demonstrated . . . to have unacceptable . . . cost . . . impacts on a case-by-case (or site-specific) basis." *Id.* § IV(D)(1)(4).

ii. EPA's failure to apply a reasonable standard for cost comparison in the FIP makes its BART determination arbitrary and capricious.

This Court should not defer to EPA's BART cost calculations because EPA failed to establish any reasonable standard against which to measure cost effectiveness. The "lack of reasoned explication for a regulation that is inconsistent" with an agency's prior positions "cannot carry the force of law [and]

does not receive Chevron deference . . . ." *Encino Motorcars*, 136 S. Ct. at 2127. Courts have rejected EPA FIPs that do not establish reasonable standards for costs in a regional haze SIP. *See*, *Nat'l Parks Conservation Ass'n*, 788 F.3d at 1144 ("EPA . . . still failed to explain what makes a cost reasonable in light of potential visibility benefits.").

In the FIP, EPA attempted to establish a cost-effectiveness standard by comparing the cost and visibility impacts with other "cherry-picked" BART determinations. For example, EPA compared the average and incremental cost effectiveness of SCR for Hunter Unit 1 to average and incremental cost effectiveness numbers for SCR at four other, hand-picked facilities: Laramie River Station (Wyoming); Dave Johnston Units 3 and 4 (Wyoming); Hayden Units 1 and 2 (Colorado); and Cholla Units 2, 3, and 4 (Arizona). 81 Fed. Reg. at 43,904–06 [JA__]. But by using only these four facilities and ignoring data from other facilities and previous regulatory cost determinations, EPA created a faulty standard.

The FIP's costs are not consistent with EPA regulations. EPA established general standards for BART NO_x controls in the BART Guidelines, including "presumptive" BART emission limits[30] which are used to set BART

[30] The ultra-stringent NOx limits required by EPA's FIP are four times more stringent than the NOx "presumptive BART" limits set by EPA for units like the BART Units.

benchmarks for a "better-than-BART" analysis. 40 C.F.R. pt. 51, app. Y § IV(E)(5), Table 1. In the Preamble to the BART Guidelines, EPA determined that approximately 75% of BART-eligible power plants would have BART NO_x costs between $100 and $1,000 per ton, with almost all of the remaining units able to sufficiently control NO_x by installing BART for less than $1,500 per ton. *See* 70 Fed. Reg. at 39,135 (BART Guidelines). EPA specifically recognized in the Preamble that SCR was generally not cost effective for power plants like the BART Units. 70 Fed. Reg. at 39,135–36 ("For [such non-cyclone] units, we are not establishing presumptive limits based on the installation of SCR. Although States may in specific cases find that the use of SCR is appropriate, **we have not determined that SCR is generally cost-effective for BART across unit types**.") (emphasis added). Based upon EPA's BART Guidelines and EPA's related analyses, a reasonable standard for "average cost-effectiveness" BART NO_x control technology costs is $1,500 per ton, and SCR should be presumed unreasonable. Without any rulemaking or notice, EPA abandoned this approach in favor of an ad hoc, outcome-determinative approach.

For the BART Units in Utah, EPA found SCR controls to be "cost effective," even when the true costs (as represented by "incremental cost

effectiveness" due to the "existing controls" error)[31] are several multiples of the EPA's suggested standard of $1,500 per ton of NO_x. *See, e.g.*, 81 Fed. Reg. at 43,903, Table 2 [JA__] (putting the "incremental cost" for SCR at $5,561/ton for Hunter Unit 1). EPA simply ignores its own Guidelines and previous statements when declaring that SCR is reasonable and cost-effective. EPA's failure to follow its past interpretation of "cost effectiveness" is arbitrary and capricious. "Based on its explanation, the Rule's reader is left to wonder what rationale EPA used to determine cost-effectiveness. Again, the law requires a reasoned answer to that question." *Nat'l Parks Conservation Ass'n*, 788 F.3d at 1144.

Costs are not consistent with other EPA BART determinations. Second, EPA cherry-picks BART determinations that appear to support its position. As mentioned above, EPA cites four examples where it claims that costs for NO_x BART are comparable with Utah. EPA attempts to use these NO_x BART determinations to establish a cost-effectiveness standard. However, EPA neglects to include numerous additional examples where it has found similar, and even lower, costs for BART NO_x ***not*** to be cost-effective. For example, EPA approved

[31] EPA calculated the baseline emissions differently for the Utah BART Units than it did for units used for comparison (*e.g.*, Cholla and Hayden). EPA tries to compensate by instructing that only the Utah units' **incremental costs** should be compared with the other units' **average costs**. 81 Fed. Reg. at 2,037 [JA__]. This type of incremental to average cost comparison is neither contemplated nor allowed by the BART Guidelines. *See* 40 C.F.R. pt. 51, app. Y § IV(D)(4)(c), (d), and (e).

Florida's rejection of SCR because costs of $3,776/ton were not cost effective. *See* 77 Fed. Reg. 73,369, 73,377. Additionally, EPA rejected both SNCR (a less expensive and less stringent technology) and SCR based on unreasonable costs of $3,195/ton (with incremental costs of $5,770/ton). *See* 77 Fed. Reg. at 57,889 (Montana). Also, EPA proposed to agree with Nebraska's rejection of SCR based on costs of $2,297/ton ($5,445/ton incremental). *See* 77 Fed. Reg. at 12,770, 12,779.

If EPA had selected these comparisons, or others,[32] SCR as NO_x BART would not be reasonably cost-effective at $5,206–$5,561/ton for the BART Units. By "cherry-picking" favorable comparisons while ignoring unfavorable comparisons, EPA's attempt to create a cost-effectiveness standard for NO_x BART loses legitimacy.[33] In fact, as compared to EPA's previous NO_x BART determinations and statements, it is clear EPA cannot establish a reliable "cost effectiveness" metric in the FIP—because EPA's approach in similar

[32] EPA approved an earlier Colorado SIP that set an explicit limit of $5,000/ton beyond which SCR was not cost effective. 77 Fed. Reg. at 18,061. Though EPA noted some concerns with Colorado's reasoning, it ultimately approved this $5,000/ton standard.

[33] Moreover, comparisons with SCR BART determinations for Cholla and Laramie River are suspect for another reason. In both cases, EPA's SCR BART determinations have been challenged in court and are subject to judicial review.

circumstances has been too inconsistent. *See Nat'l Parks Conservation Ass'n*, 788 F.3d at 1141 ("inconsistent analysis is arbitrary and capricious").

EPA's FIP cost comparisons are improper. EPA's attempted cost comparisons between the BART Units and the four cherry-picked sites (Cholla, Hayden, Dave Johnston, and Laramie River) do not withstand close scrutiny. EPA has counseled that only facilities where cost estimates (which would include related baseline emissions analyses) were estimated using similar methods should be compared. *See, e.g.*, 79 Fed. Reg. at 5,156 ("In order for . . . comparison to be meaningful, the cost estimates for these facilities must be performed in a consistent manner. Without an 'apples-to-apples' comparison of costs, **it is impossible to draw rational conclusions about the reasonableness of the costs** of compliance for particular control options.") (emphasis added). However, EPA's cost analyses of the BART Units in Utah were based on improper "apples-to-oranges" comparisons. As explained in Argument § II.a.iii *infra*, the baseline emissions for Cholla and Hayden were calculated differently, and EPA itself admitted that only Utah's incremental costs should be compared with both BART Units' average costs. 81 Fed. Reg. at 2,037 [JA__]. Because EPA ignored its previous NO_x BART cost analyses, "cherry-picked" favorable cost comparisons and ignored unfavorable comparisons, and failed to establish that any of the cost estimates at the "cherry-picked" power plants were "performed in a consistent manner" with

the cost estimates for the BART Units, EPA's cost comparisons are improper and unreliable.

iii. EPA's lack of a reasonable cost standard is reflected in the lack of impact from EPA's admitted $82 million cost error.

EPA presented the cost analysis for its preferred SCR BART control in the Proposed Rule, which was adopted from a report it commissioned from ATP (an EPA contractor) that drew from PacifiCorp's cost estimates. 81 Fed. Reg. at 2,034–35 [JA__]. Based on this analysis, EPA initially estimated total costs for SCR at $107.8 to $110.3 million per unit in the Proposed Rule, for a total cost of $435.6 million. *Id.* at 2,035–48, Tables 14, 20, 26, 32 [JA__]. However, as admitted in the Final Rule, EPA's original cost analyses were in error because "[ATP] incorrectly re-designed the SCR reactors." 81 Fed. Reg. at 43,902 [JA__]. This re-design error resulted in EPA increasing the total SCR cost by nearly $82 million in capital costs, plus $7.1 million in additional annual costs for the four SCR systems. Correcting ATP's cost error not only increased the average capital costs for SCR, but significantly increased the more important incremental cost-effectiveness for each unit. *See* Argument § II.b.ii (n.31) *supra* discussing EPA's admission that incremental cost/ton represents the real costs of installing SCR. EPA's SCR cost changes (from the Proposed Rule to the Final Rule) are summarized in the table below. It is important to remember that the cost increases

expressed in dollars per ton represent millions of dollars in increased capital costs for pollution control every year.

Unit	**Proposed Rule**[34]			**Final Rule**[35]		
	Capital Costs	**Increm. Cost/Ton**	**Annual Costs**	**Capital Costs**	**Increm. Cost/Ton**	**Annual Costs**
Hunter U1	$110.3M	$4,853	$13.1M	$130.6M	$5,561	$14.8M
Hunter U2	$108.1M	$5,092	$12.7M	$128.5M	$5,861	$14.5M
Huntington U1	$107.8M	$4,522	$12.8M	$128.3M	$5,206	$14.6M
Huntington U2	$109.4M	$5,326	$12.9M	$130.0M	$5,626	$14.7M
Total	$435.6M	$4,948 (four unit average)	$51.5	$517.4M (+81.8M)	$5,564 (four unit average)	$58.6M (+7.1M)

Thus EPA's error correction increased estimated capital costs for SCR by nearly 19% between the Proposed and Final Rule and annual costs increased by almost 10%. This caused the cost data point primarily relied on by EPA, the "cost effectiveness" number, to increase by more than $600 per ton. Ultimately, EPA "shrugged off" this significant cost increase and simply changed the reported numbers in its tables. 81 Fed. Reg. at 43,902 [JA__].

EPA's decision to forego analysis of whether these additional tens of millions of dollars of corrected costs would impact the cost-effectiveness of SCR as BART illustrates the lack of any meaningful standard for measuring cost

[34] 81 Fed. Reg. at 2,035-2,048, Tables 14, 20, 26, 32 [JA__].

[35] 81 Fed. Reg. at 43,903 – 43,904, Tables 1-5 [JA__].

effectiveness. If $82 million in additional costs—reflected in the $600/ton increase in cost-effectiveness—have absolutely no impact on whether controls achieve visibility improvement "in the most economical way," 40 C.F.R. pt. 51, app. Y § IV(D)(4)(b), then it appears there is no recognizable cost standard. While courts give EPA deference in matters subject to its expertise, they have also explained that "[w]e are hesitant to rubber-stamp EPA's invocation of statistics without some explanation of the underlying principles or reasons why its formulas would produce an accurate result, particularly when the 'facts found' . . . demonstrate flaws in the formula." *Nat'l Ass'n of Clean Water Agencies v. EPA*, 734 F.3d 1115, 1145 (D.C. Cir. 2013); *Texas*, 829 F.3d at 432 (finding deference diminished when EPA must rely on contractors).

In summary, EPA's evaluation of the costs for SCR is unmoored to any reasonable standard, EPA's comparisons with other rulemakings are "selective" and not based on comparable methods, and the Final Rule's readers are "left to wonder what rationale EPA used to determine cost-effectiveness. Again, the law requires a reasoned answer to that question." *Nat'l Parks Conservation Ass'n*, 788 F.3d at 1144.

c. EPA's Failure to Provide the Statutorily Required Analysis of the Energy and Nonair Quality Environmental Impacts of SCR Is Arbitrary and Capricious.

Congress required states to analyze energy and non-air quality environmental impacts when determining BART. 42 U.S.C. § 7491(g)(2). The BART Guidelines set forth specific requirements for how such analysis should be completed. 40 C.F.R. pt. 51, app. Y §§ IV(D)(4)(h), (i) and IV(E). However, EPA's FIP failed to meet these specific requirements for both energy and non-air quality impacts. EPA has rejected BART determinations for several states based on the same failure to adequately address all of the BART factors, including Utah's 2008 SIP. *See, e.g.*, 77 Fed. Reg. at 74,356-57; *Oklahoma*, 723 F.3d at 1206 ("Oklahoma failed to follow the promulgated regulations in determining BART").

Under the BART Guidelines, energy impacts must be "quantified to the extent practicable" to determine whether the technology results in energy penalties or benefits. 40 C.F.R. pt. 51, app. Y § IV(D)(4)(h). EPA also has a duty to determine "whether a given alternative would result in significant economic disruption or unemployment." *Id.* § IV(D)(4)(h)(5). Although EPA did include the cost of electricity needed to run the SCR in its cost-effectiveness calculations, it should have considered other types of energy and economic impacts. The Emery and Carbon Counties' Brief addresses in detail the energy and economic impacts EPA failed to consider as part of its BART determinations, and PacifiCorp

incorporates those arguments. *See* Emery County and Carbon County's Preliminary Brief in Support of Petition for Review.

For the non-air quality environmental impacts, the BART Guidelines require analysis "based on a consideration of site-specific circumstances." 40 C.F.R. pt. 51, app. Y § IV(D)(4)(i)(3). The analysis should include "identification and quantification of the solid, liquid, and gaseous discharges from the control device," as well as assessment of "the mass and composition of any such discharges," and "pertinent information about the public or environmental consequences of releasing these materials." *Id.* § IV(D)(4)(i)(4).

EPA departed even further from the regulations in its analysis of the non-air quality environmental impacts. Despite the list of required analyses from the BART Guidelines, EPA presented only the following conclusory analysis:

> SCR will slightly increase the quantity of ash that will need to be disposed. In addition, transportation and storage of chemical reagents may result in spills or releases. However, these non-air quality environmental impacts do not warrant elimination of either SNCR or SCR as BART. There are no additional energy requirements associated with the new LNB and SOFA, and no significant non-air quality environmental impacts.

81 Fed. Reg. at 2,035 [JA__] (this language is repeated practically verbatim for each of the four BART Units). This analysis does not meet the BART Guideline requirements for site-specific analysis, nor does it identify and quantify "the solid, liquid, and gaseous discharges from the control device," "the mass and

composition of any such discharges," or "pertinent information about the public or environmental consequences of releasing these materials." 40 C.F.R. pt. 51, app. Y § IV(i)(4). PacifiCorp and the State provided substantial information about the environmental impacts of installing SCR that EPA ignored. *See, e.g.*, PacifiCorp Comments at 40–42 [JA__]; Staff Review at 26 [JA__].

EPA's minimal and insufficient analysis is more egregious because Utah had previously found the energy and non-air quality environmental factors weighed *against* selecting SCR as BART. *See* Staff Review at 26 [JA__]; 77 Fed. Reg. at 74,369 (discussing Utah's SIP submittals rejecting SCR as BART). If EPA wanted to overrule Utah's analysis of this BART factor, then, at a minimum, EPA needed to comply with the requirements of the BART Guidelines. EPA failed to do so. EPA's analysis of the energy and non-air quality impacts was contrary to the statute and BART Guidelines, and should be overturned. *See Ariz. Pub. Serv.*, 562 F.3d at 1123.

d. EPA's FIP Did Not Adequately Consider the "Reasonably Anticipated" Visibility Improvement BART Factor.

Every BART determination requires an analysis of the reasonably anticipated visibility improvements from installation of the BART controls. 42 U.S.C. § 7491(g)(2). When EPA conducted its "reasonably anticipated" visibility improvement analyses for its NO_x BART determinations of the BART Units, and when EPA analyzed the 90% and 98% Metrics for the Utah BART Alternative,

EPA relied exclusively on computerized modeling results, using the CALPUFF model. *See* 81 Fed. Reg. at 2,033 [JA__]. Although EPA is allowed to use the CALPUFF model and its outputs, it also must consider the limitations inherent in such modeling and information. EPA did not. In both its FIP BART visibility analyses, as well as the 98% Metric analyses for the Utah BART Alternative, EPA presumed an accuracy and infallibility of the CALPUFF model's projected results that are not realistic, thereby muddling EPA's FIP decision-making.[36]

i. EPA failed to account for margin of error.

In PacifiCorp's public comments, and through the submittal of a report by renowned modeling expert Gayle Hoffnagle, PacifiCorp cautioned EPA about the CALPUFF model's "margin of error," asked EPA to consider the impacts of this "margin of error" on EPA's Utah BART Alternative analysis (98% Metric) and the FIP's CALPUFF model-based visibility analyses, and requested EPA to reconsider the weight it placed on CALPUFF model results. PacifiCorp Comments at 13–14, 27, 42–51 [JA__]. EPA refused.

In fact, in the Final Rule, EPA incorrectly stated: "The notion of a calculated 'margin of error' is not part of any modeling guidance and has no regulatory basis

[36] EPA has admitted that CALPUFF modeling results do not reflect "actual" visibility improvement expected from the installation of pollution controls. "[I]t is important to note that CALPUFF modeling performed in accordance with the BART Guidelines is not intended to predict the amount of visibility improvement that will occur under existing conditions." RTC at 145 [JA__].

or applicability here." 81 Fed. Reg. at 43,919 [JA__]. EPA's statement is not only wrong, but shocking given that EPA's own modeling guidance specifically references a "margin of error." In its Response to Comments, EPA cited to its modeling guidance, Appendix W of 40 C.F.R. part 51, and admitted that "even given a 'perfect model,' uncertainty can be as much as +/- 50 percent." RTC at 302 [JA__]. Appendix W acknowledges that modeled "estimates of concentrations that occur at a specific time and site, are poorly correlated with actually observed concentrations and are much less reliable." 40 C.F.R. pt. 51, app. W § 9.1.2. PacifiCorp's public comments, summarizing Mr. Hoffnagle's expert report, confirmed the CALPUFF model "uncertainty," or "margin of error," discussed in Appendix W. PacifiCorp Comments at 44 [JA__]. In fact, as part of his expert report, Mr. Hoffnagle reviewed EPA's past "uncertainty" studies, and found those studies showed that the CALPUFF model results at 100 km were "35%, 5%, or 250% too high," and on average were "96% too high." Hoffnagle Report at 6 [JA__].

In the past, EPA has recognized that model "uncertainty" or "margin of error" should be considered when making decisions. In EPA's guidance governing modeling, specifically in the subsection entitled "Use of Uncertainty in Decision Making," EPA cautions "it is desirable to quantify the accuracy or uncertainty associated with concentration estimates used in decision making." 40 C.F.R. pt.

51, app. W § 9.1.3. The guidance reminds EPA decision-makers "to identify the reliability of the model estimates for that particular area and to determine the magnitude and sources of error associated with the use of the model." *Id.* § 9.1.3.b. This is exactly what PacifiCorp requested that EPA do, and what PacifiCorp's public comments suggest is required in this case; EPA must quantify the "accuracy or uncertainty" of EPA's CALPUFF modeling results, "determine the magnitude and sources of error associated with the model," and then use that information in its BART decision making.

But that is what EPA refused to do, contrary to its own modeling guidance. Rather, in addition to incorrectly stating that a "margin of error" was not a valid concept, EPA incorrectly claimed that all of the limitations of CALPUFF are already accounted for in the 98th percentile analysis. 81 Fed. Reg. at 43,918–19 [JA__]. EPA also attempted to divert attention from its actions, claiming that PacifiCorp is attacking the use of the model and the regulatory method of doing a BART visibility analysis. *Id.* Such claims are baseless. In its public comments, PacifiCorp simply asked that, as required by EPA's own modeling guidance, EPA consider the uncertainty of the CALPUFF modeling results, and then factor that uncertainty into its decisions related to the Utah BART Alternative, BART Benchmark, and EPA's FIP. PacifiCorp Comments at 43–44 [JA__]. EPA refused.

The Ninth Circuit Court of Appeals rejected certain EPA BART decisions due to EPA's failure to properly consider the limitations of the CALPUFF model. In fact, PacifiCorp's position is the same as the petitioner, PPL Montana, in that Ninth Circuit decision. *Nat'l Parks Conservation Ass'n*, 788 F.3d 1134. In *National Parks*, PPL Montana objected to EPA's use of the CALPUFF model's results to show the visibility benefit from a pollution control because the result was "below the range of perceptibility and [fell] within the [CALPUFF] model's margin of error, meaning such improvement cannot be 'reasonably . . . anticipated' as required by the Act." *Id.* at 1146. EPA responded, just as it has here, that EPA need not defend the model's application because "the CALPUFF model was approved in the Guidelines." *Id.* The *National Parks* court rejected EPA's arguments, stating,

> [It is] no answer to respond, as EPA did, that low levels of visibility impairment must be addressed even though they are not perceptible to the human eye, or that measures have been taken to minimize the margin of error. The issue is . . . the model's ability to anticipate improvements at a level allegedly within its margin of error, whether perceptible or not to the human eye. EPA simply offered no response to this objection.

Id. at 1147. Likewise, EPA never properly responded to PacifiCorp's objection that EPA needed to consider the "margin of error" when weighing the CALPUFF model results.

EPA's refusal to consider the limitations of the CALPUFF model has material consequences. The *National Parks* decision explained the importance of this issue.

> The predictability concern is important because the Act requires that any visibility improvement be "reasonably ... anticipated" as a result of BART installation. 42 U.S.C. § 7491(g)(2). As the D.C. Circuit explained in vacating a portion of the Regional Haze Rule itself, it is arbitrary and capricious for EPA to force an emissions source "to spend millions of dollars for new technology that will have no appreciable effect on the haze in any Class I area."

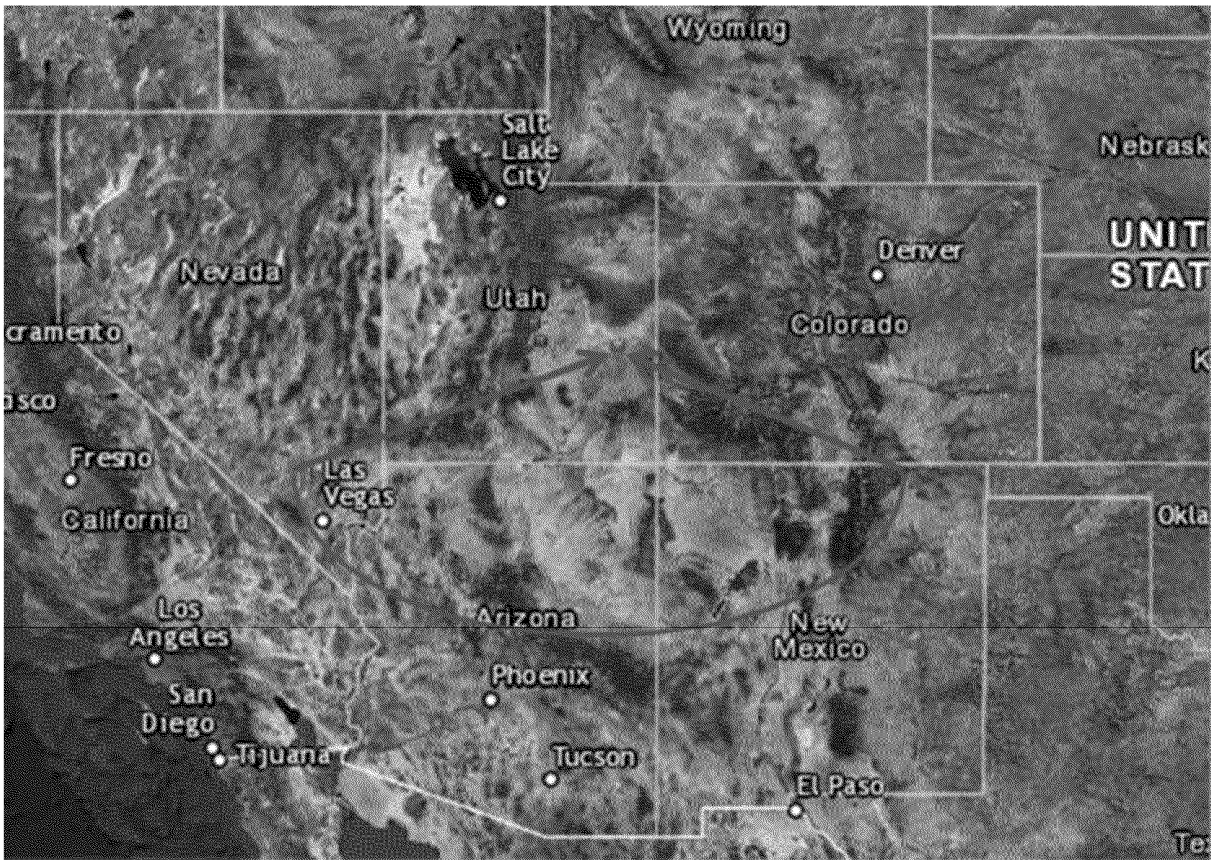
Id. (quoting *Am. Corn Growers Ass'n*, 291 F.3d at 7). As the Ninth Circuit did in *National Parks*, this Court should reject EPA's excuses for its failure to consider the CALPUFF model's limitations when conducting its visibility analyses. Such action was arbitrary and capricious.

ii. EPA failed to consider PacifiCorp's wind trajectory evidence.

PacifiCorp also asked EPA to consider other problems with its CALPUFF modeling results, which EPA again refused to do. In its public comments, PacifiCorp explained:

> The wind direction for these 20% worst days ranged from 115 degrees to 249 degrees. As can be seen [in the figure provided], the prevailing winds do not come from the direction of the BART Units. Therefore, EPA cannot 'reasonably anticipate' visibility improvement on the 20% worst days resulting from the installation of the BART Benchmark at the Utah BART Units. This failure alone invalidates the FIP Proposal.

PacifiCorp Comments at 51–52 and Attachment 10 [JA__] (graphic reproduced below; blue dots represent BART Units and non-BART Units; red dot represents Canyonlands Class I area; red arrows represent the wind direction on 20% worst days).



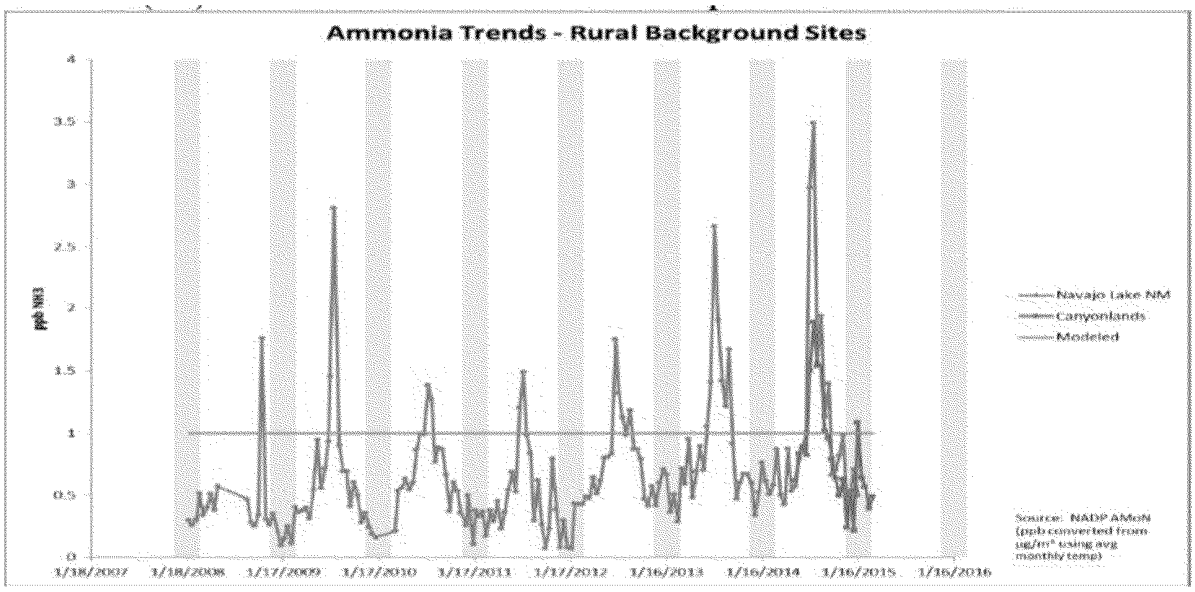
In other words, regardless of what the CALPUFF computer modeling results state, the actual EPA wind data shows that the BART Units (which are west-northwest of the particular Class I area) could not be responsible for the NO_x-related visibility impairment on the winter days, as the CALPUFF model results predict, because the prevailing wind on those days was blowing into the Class I

areas from areas other than where the BART Units are located (the southeast-south-southwest).

In response, EPA vaguely claimed the CALPUFF model accounted for wind direction, but never explained why EPA relied solely on CALPUFF model results when EPA's actual wind data showed the prevailing winds were blowing from a different direction. This wind data demonstrates that the CALPUFF computer model's predicted results could not be correct on those days. *See* RTC at 311 [JA__]. EPA's nonresponse is arbitrary and capricious. EPA's rulemaking obligations require not only that EPA's decision be well reasoned, but that EPA "examine key assumptions as part of its affirmative burden of promulgating and explaining a non-arbitrary, non-capricious" decision. *Columbia Falls Aluminum Co. v. EPA*, 139 F.3d 914, 923 (D.C. Cir. 1998) (internal quotation omitted); *see also Brower v. Evans*, 257 F.3d 1058, 1067 (9th Cir. 2001) ("The presumption of agency expertise can be rebutted when its decisions, while relying on scientific expertise, are not reasoned."). EPA's failure to provide a reasoned response to significant public comments also renders its action arbitrary and capricious. *Int'l Fabricare Inst. v. EPA*, 972 F.2d 384, 389 (D.C. Cir. 1992) ("EPA is required to give reasoned responses to all significant comments in a rulemaking proceeding.") (internal quotation omitted).

iii. EPA failed to consider background ammonia.

Relying on Mr. Hoffnagle's expert analysis, PacifiCorp also explained to EPA that CALPUFF modeling is "greatly influenced by the background ammonia number used in the model," "EPA improperly used a constant 1ppb" number, and this mistake "greatly overestimated the 'reasonably anticipated' visibility improvements from SCR." PacifiCorp Comments at 47 [JA__]. "EPA should have used available ammonia monitoring data," which demonstrated that background ammonia was much lower than 1 ppb in winter months. *Id.* PacifiCorp asked that EPA use a more realistic "variable" ammonia number, with lower background values in the winter months, as EPA had done in the Wyoming and Montana regional haze modeling exercises. *Id.* at 48. PacifiCorp provided the chart below, and related information, regarding background ammonia studies in New Mexico and at Canyonlands (one of the Class I areas at issue) that strongly suggested background ammonia levels are extremely low in the wintertime, much lower than 1 ppb, and that background ammonia changes markedly throughout the year. Hoffnagle Report at 12-13 [JA__].



EPA acknowledged that "it would be preferable to use actual monitoring data to determine background ammonia concentrations," but claimed the data provided by PacifiCorp was "too sparse." As a result, EPA used the constant (year-round) and flawed 1ppb background ammonia number lifted from outdated regulatory guidance. RTC at 325 [JA__]. However, knowing that the 1 ppb background ammonia number was likely incorrect in winter months (based on the data presented by PacifiCorp), at a minimum EPA should have studied the issue and determined the proper winter-time ammonia level.[37] In Wyoming, after

[37] In the Montana rulemaking, EPA recognized the "seasonal variability in ambient ammonia concentrations," and admitted "it is preferable to use ambient ammonia measurement when such data are available." 77 Fed. Reg. at 57,867. After recognizing that no background ammonia data for Montana existed, EPA applied data from North Dakota because EPA determined "it would be more appropriate to use the North Dakota ammonia monitoring data instead of using CALPUFF default ammonia concentrations." *Id.* Here, EPA refused to use ammonia background data from Utah or surrounding states.

receiving similar criticism about the use of constant background ammonia based on the same guidance document, EPA conducted new modeling using monitored, variable ammonia background numbers. 79 Fed. Reg. at 5,111 ("After evaluating comments on the re-proposal, EPA determined that is was necessary to remodel all of the baseline and control technology scenarios using different background ammonia concentrations."). EPA's reliance in its BART visibility analyses on an incorrect background ammonia number, and its refusal to accept the ammonia background data provided by PacifiCorp or to gather its own, were incorrect, arbitrary and capricious.

EPA is very aware that the use of monitored, variable ammonia background data can change the CALPUFF model's results (which can make SCR look less favorable). In the Wyoming rulemaking, EPA said: "We agree . . . the background ammonia concentration has a significant effect on model predicted visibility impacts." *Id.* at 5,117. Additionally, after the monitored, variable background ammonia numbers were used for some of the Wyoming BART sources, the CALPUFF model showed a smaller visibility improvement associated with most of the subject BART controls in Wyoming. *Id.* at 5,040, Tables 5 and 6; at 5041 Tables 7 and 8; at 5043 Tables 12 and 13. This Court should remand this matter to EPA and require it to run the computer models with representative ammonia background numbers, consider the contradiction between actual wind data and the

CALPUFF results, and factor in the "margin of error" when reviewing CALPUFF modeling results.

CONCLUSION

This Court should invalidate the Final Rule, and remand it back to EPA for correct analysis of the Utah BART Alternative.

DATED this 17th day of March, 2017.

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STATEMENT REGARDING ORAL ARGUMENT

PacifiCorp requests oral argument because both the Utah BART Alternative and the FIP involve technical issues that will benefit from oral presentation to the Court and the opportunity for the Court to pose clarifying questions. The outcome of this case involves precedent-setting standards for protecting state discretion and enforcing statutory requirements for reasonableness under the regional haze program and CAA. Oral argument will enable the Court to ensure a more thorough review of these important issues, which will determine whether PacifiCorp may be mandated by the federal government to invest hundreds of millions of dollars in controls with highly questionable visibility benefits against the recommendations of the State of Utah.

CERTIFICATE OF SERVICE

I hereby certify that on this 17th day of March, 2017, the foregoing **PRELIMINARY BRIEF OF PETITIONER PACIFICORP** was served electronically on all active registered counsel of record through the Court's CM/ECF system.

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CERTIFICATE OF DIGITAL SUBMISSION

I hereby certify that with respect to the foregoing:

(1) all required privacy redactions have been made per 10th Cir. R. 25.5;

(2) if required to file additional hard copies, that the ECF submission is an exact copy of those documents;

(3) the digital submissions have been scanned for viruses with the most recent version of a commercial virus scanning program, Symantec Endpoint Protection (Version 12.1.6), and according to the program are free of viruses.

DATED this 17th day of March, 2017.

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CERTIFICATE OF COMPLIANCE WITH RULE 32(a) AND OCTOBER 6, 2016 ORDER

Certificate of Compliance With Type-Volume Limitation, Typeface Requirements, and Type Style Requirements

1. In accordance with this Court's Order dated October 6, 2016, which allows a combined limitation of 30,000 words for the non-State Petitioners' (and County-Intervenors') Opening Merits Briefs imposed by said Order:

   [X] this brief contains 17,402 words, excluding the parts of the brief exempted by Fed. R. App. P. 32(a)(7)(f), or

   [ ] this brief uses a monospaced typeface and contains <state the number of> lines of text, excluding the parts of the brief exempted by Fed. R. App. P. 32(a)(7)(B)(iii).

2. This brief complies with the typeface requirements of Fed. R. App. P. 32(a)(5) and the type style requirements of Fed. R. App. P. 32(a)(6) because:

   [X] this brief has been prepared in a proportionally spaced typeface using MS Word 2010 in 14 point Times New Roman, or

   [ ] this brief has been prepared in a monospaced typeface using <state name and version of word processing program> with <state number of characters per inch and name of type style>.

DATED this 17th day of March, 2017.

/s/ E. Blaine Rawson
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UNITED STATES COURT OF APPEALS
FOR THE TENTH CIRCUIT

STATE OF UTAH, on behalf of the Utah Department of Environmental Quality, Division of Air Quality, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, and GINA MCCARTHY, Administrator of the United States Environmental Protection Agency, Respondents.	***Case No. 16-9541***
PACIFICORP, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, and GINA MCCARTHY, Administrator of the United States Environmental Protection Agency, Respondents.	***Case No. 16-9542***
UTAH ASSOCIATED MUNICIPAL POWER SYSTEM, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, and GINA MCCARTHY, Administrator of the United States Environmental Protection Agency, Respondents.	***Case No. 16-9543***

DESERET GENERATION & TRANSMISSION CO-OPERATIVE, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, and GINA MCCARTHY, Administrator of the United States Environmental Protection Agency, Respondents. HEAL UTAH, NATIONAL PARKS CONSERVATION ASSOCIATION, SIERRA CLUB, and UTAH PHYSICIANS FOR A HEALTHY ENVIRONMENT Respondent-Intervenors. EMERY COUNTY, UTAH, and CARBON COUNTY, UTAH Petitioners-Intervenors.	***Case No. 16-9545***

EMERY COUNTY AND CARBON COUNTY'S PRELIMINARY BRIEF IN SUPPORT OF PETITION FOR REVIEW
(Deferred Appendix Appeal)

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STATEMENT OF RELATED CASES

As required by 10th Cir. R. 28.2(C)(1), the following cases are related to this appeal:

1. *State of Utah v. EPA et al.*, No. 16-9541 (10th Cir. Sept. 1, 2016), and *PacifiCorp v. EPA et al.*, No. 16-9542 (10th Cir. Sept. 2, 2016). Emery County and Carbon County are intervenors in the State of Utah and the PacifiCorp appeals. *Utah Associated Mun. Power Sys. v. EPA et al.*, No. 16-9543 (10th Cir. Sept. 6, 2016) and *Deseret Generation & Transmission Coop. v. EPA et al.*, No. 16-9545 (10th Cir. Sept. 6, 2016) are petitions for review of the same Final Rule[1] challenged in the State of Utah and PacifiCorp appeals. These appeals have been consolidated with this case number 16-9541.

2. *WildEarth Guardians v. EPA*, 770 F.3d 919 (10th Cir. 2014), where this Court denied a challenge by environmental petitioners to Environmental Protection Agency's (EPA) approval of the State of Utah's (Utah) proposed cap-and-trade program for sulphur dioxide (SO_2) emissions in lieu of BART.

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[1] The Final Rule is titled "Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze," 81 Fed. Reg. 43894 (July 5, 2016) ("Final Rule") [JA ___].

3. Utah v. EPA, 750 F.3d 1182 (10th Cir. 2014), *reh'g denied*, 765 F.3d 1257 (10th Cir. 2014), where Utah and PacifiCorp challenged EPA's disapproval of Utah's proposed State Implementation Plan (SIP) for nitrogen oxide (NOx) BART. The Court did not reach the merits of the appeal due to jurisdictional issues.

GLOSSARY OF ACRONYMS

BART ..... Best Available Retrofit Technology

CAA ..... Clean Air Act

EPA ..... Environmental Protection Agency

FIP ..... Federal Implementation Plan

JA ..... Joint Appendix

RHR ..... Regional Haze Rule

RTC..... EPA's Response to Comments

SCR ..... Selective Catalytic Reduction

SIP ..... State Implementation Plan

Pursuant to Rule 18 of the Federal Rules of Appellate Procedure, Petitioners-Intervenors Emery County and Carbon County (the "Counties") submit this Brief in Support of the State of Utah's and PacifiCorp's Petitions for Review of EPA's July 5, 2016 Final Rule ("Final Rule"). The Counties also join in the State of Utah's and PacifiCorp's Briefs, and adopt and incorporate by reference herein their respective Briefs.

STATEMENT OF JURISDICTION

On July 5, 2016, EPA published its Final Rule. On September 1, 2016, and September 2, 2016, the State of Utah and PacifiCorp filed their respective timely Petitions for Review of that Final Rule. By its Order of October 4, 2016, this Court granted leave to the Counties to intervene in this matter. This Court has jurisdiction to review EPA's Final Rule under 42 U.S.C. § 7607(b)(1) and Rule 15(a) of the Federal Rules of Appellate Procedure.

STATEMENT OF ISSUES

1. Whether EPA was required to consider all of the BART factors required under the CAA and the BART Guidelines, and thereby improperly promulgated its FIP in place of Utah's Alternative; and

2. Whether EPA was required to conduct an evaluation of the potential loss or shifts of employment under the CAA.

STANDARD OF REVIEW

In reviewing EPA's decision on the disapproval of the SIP and the promulgation of the FIP, this Court should reverse EPA's decision if it is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. § 706(2)(A) (West 2016); 42 U.S.C. § 7607(d)(1)(B),(9)(A).

STATEMENT OF CASE

The EPA's Final Rule threatens the Counties' coal-mining and utility-related industries. These industries provide hundreds of jobs, support dozens of businesses, and provide a significant portion of the otherwise limited tax base for the Counties. The EPA was required to consider these economic disruption and unemployment impacts in developing its Final Rule, but failed to do so.

The subject Hunter and Huntington power plants (the "Plants") are located in Emery County, Utah, and the Skyline and Dugout coal mines which provide coal to the Plants are located in Carbon County, Utah. The Counties have both been designated as "Mining Dependent" by the U.S. Department of Agriculture.[2] The Counties are home to six of the State's seven coal mines.[3] Not surprisingly, coal mining and related coal-fired utility jobs represent a significant percentage of

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[2] USDA, Economic Research Service, County Typology Codes (2015), http://www.ers.usda.gov/data-products/county-typology-codes.aspx.

[3] South Eastern Utah Economic Development District, Workforce Study ("SEUEDD Workforce Study") at 6 (Mar. 2016) (Exhibit A) [JA ___].

the jobs in the Counties.[4] The Counties have already been impacted by the recent decline in the coal industry, including the recent closure of the Deer Creek mine in Emery County and the Horizon mine in Carbon County. Over the past three years, employment in coal mining in Carbon County has decreased by 21%, and in Emery County by a staggering 36%.[5] In addition, the closure of the Carbon power plant (in Carbon County) in 2015 resulted in a direct loss of 70 jobs and an indirect loss of up to 300 jobs.[6] These past job losses have been injurious to the Counties; any additional significant job losses could be crippling.

In the likely event that the Plants will be pushed into early closure or conversion from coal to natural gas as a result of the costly FIP requirements, the Counties would be severely harmed. Job losses at the two Plants alone would exceed 370 employees or approximately $35 million in wages.[7] Additional indirect job losses would also be expected in the many sub-industries that supply,

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[4] Coal mining and related coal-fired utility jobs represent approximately 30% of the jobs in Emery County. *Id.* at 17 [JA ___].

[5] *Id.* at 4 [JA ___].

[6] Amy Joi O'Donoghue, *End of an era: Mercury rule shutters Utah's oldest power plant*, Deseret News (Apr. 14, 2015), http://www.deseretnews.com/article/865626442/End-of-an-era-Mercury-rule-shutters-Utahs-oldest-power-plant.html?pg=all; EPA Response to Comments ("RTC") at 377 (Exhibit B) [JA ___].

[7] Estimate based on PacifiCorp projections and average monthly wage in utilities sector for Emery County for third quarter 2015. SEUEDD Workforce Study at 24-25 [JA ___].

service, and support the Plants, including local equipment vendors, transportation providers, engineers, contractors, consultants, etc., estimated at another 300+ jobs or another $25 million in wages.[8] One Emery County commissioner estimates the economic impact could be double this—800+ jobs in Emery County alone.[9] Additional job losses would also be likely in the local coal mining industry, as the coal for the closed or converted Plants would no longer be needed.

The loss of more than $60 million of employment income for the Counties' residents would also have a significant and incremental trickle-down impact on all sectors of the Counties' economies, and notably a significant impact on the Counties' own property, sales, and other tax, fee, and license revenues.[10] In addition, the continued job losses and the uncertainty created by the FIP are

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[8] Estimate based on PacifiCorp projections and the mean of the average monthly wage for mining and utilities jobs for the Counties for third quarter 2015. *Id* [JA ___] .

[9] Patsy Stoddard, *Part I: Commissioner Brady speaks at EPA hearing on regional haze*, Emery County Progress (Feb. 2, 2016), http://ecprogress.com/index.php?tier=1&article_id=18488 ("The economic impact of the Hunter and Huntington Power Plants is a large portion of our economy in Emery County. The economic impact Rocky Mountain Power has had to Emery County in direct and indirect is 800+ jobs.") *See* RTC at 378 [JA ___].

[10] The plants provide a significant portion of the tax base for Emery County, contributing approximately $7.9 million annually in property taxes. *See* Chad Teply Decl. at 4 [JA ___].

detrimentally impacting the Counties by making it difficult to expand or attract businesses, in particular businesses in the mining or utility industries.[11]

Even if the plants were able to avoid early closure, the estimated $700 million to implement the FIP would likely be passed along to utility customers, including the Counties' residents. By EPA's own estimates, implementation of the FIP will result in 5-10% rate increases.[12] While mining and utility jobs pay higher than average wages, the remaining residents of the Counties are not so fortunate. Excluding mining and utility jobs, the remaining 70% of Emery County residents' average monthly wage is $2,413, and the remaining 86% of Carbon County residents' average monthly wage is $2,374[13]—both over $1,000 less than the statewide average wage of $3,539.[14] Of these non-mining and non-utility workers, many earn less than minimum wage ($1,256 per month).[15] These wage statistics

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[11] SEUEDD Workforce Study at 31-35 ("mines have closed and a moratorium has been placed on renewing coal leases, resulting in significant decreases in employment… companies wishing to expand are presently required to postpone any plans of growth….") [JA ___].

[12] *See* RTC at 370 [JA ___] .

[13] SEUEDD Workforce Study at 17-18, 24-25 [JA ___].

[14] Department of Workforce Services, Employment and Wage Statistics, Utah Statewide, 3rd Quarter 2015, https://jobs.utah.gov/jsp/wi/utalmis/industrydetail.do (last visited Nov. 1, 2016) [JA ___].

[15] In Emery County 19% of the non-mining and non-utility industry wage earners earn less than minimum wage, and in Carbon County, it is 15.5%. SEUEDD Workforce Study at 17-18, 24-25 [JA ___].

show that the anticipated rate increases will cause significant harm to the already burdened residents. Business utility customers will be similarly disrupted, unless they can pass those increases along to consumers—many of whom are residents of the Counties, creating even further economic disruption. Such rate increase caused by EPA-mandated controls was one of several factors justifying the recent stay of a Regional Haze FIP in Texas. *Texas v. EPA*, 829 F.3d 405, 433 (2016).

In short, the EPA was required under the CAA to consider these significant economic disruption and unemployment impacts the Counties will suffer as a result of the Final Rule, but failed to do so.

SUMMARY OF ARGUMENT

EPA disapproved Utah's SIP, and in its place imposed its own FIP. In developing its FIP, EPA made a BART determination of SCR, and mandated SCR in the FIP. In making its BART determination, EPA failed to consider all of the BART factors, and to conduct the required evaluation of potential loss or shifts of employment, required under the CAA. EPA's failure was arbitrary, capricious, an abuse of discretion, and otherwise not in accordance with law.

ARGUMENT

The CAA's regional haze program requires steady incremental progress towards natural visibility in Class I areas by 2064. *See* 42 U.S.C. § 7491(b)(2); 40 C.F.R. § 51.308(d)(1)(i)(B). To ensure reasonable progress, EPA's regulations

require the states to develop SIPs to implement a long-term strategy to reduce haze. *See* 40 C.F.R. § 51.308(d)(3)(iv). A core component of the long-term strategy is regulation of certain major stationary sources through the determination and installation of BART or, in the alternative, implementation of measures that achieve greater reasonable progress than BART. *See* id. § 51.308(e),(e)(2). In September of 2008, Utah implemented such alternative measures (Utah's BART "Alternative") for NOx because the review of "all available information and data," showed that the Alternative would achieve greater reasonable progress than the most stringent BART controls. 71 Fed. Reg. 60,612-01, 60,622 (Oct. 13, 2006). The Alternative also was significantly more cost-effective (by hundreds of millions of dollars).

Notwithstanding those clear advantages, and EPA's acknowledgment that Utah's Alternative satisfied the CAA's applicable requirements, EPA later disapproved the Alternative. In its place EPA made a BART determination of the very expensive selective catalytic reduction ("SCR") control technology, and imposed its own FIP mandating SCR. *See* 81 Fed. Reg. at 43,907 [JA ___]. In making its BART determination, EPA failed to consider all of the required BART factors and conduct the required evaluations of potential employment loss. EPA's failure was arbitrary, capricious, an abuse of discretion, and otherwise not in accordance with law.

I. EPA FAILED TO CONSIDER ALL OF THE BART FACTORS REQUIRED UNDER SECTION 7491 AND THE BART GUIDELINES, AND THEREBY IMPROPERLY PROMULGATED ITS OWN FIP IN PLACE OF UTAH'S ALTERNATIVE

A. EPA is Required to Consider the Energy Impacts Factor, and the Associated Economic Disruption and Unemployment, but Failed to do so

In making a BART determination, the CAA requires that the agency "shall take into consideration" five specified factors: "the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. . . ." 42 U.S.C. § 7491(g)(2); *see also WildEarth Guardians v. EPA*, 770 F.3d 919, 924 (10th Cir. 2014) (requiring that agencies "must consider five factors…."). One of those expressly required factors is the "energy . . . impacts of compliance …." 42 U.S.C. § 7491(g)(2).

EPA has issued BART Guidelines to assist states in implementing their BART determinations. *See* 40 C.F.R. pt. 51, App'x Y. The Guidelines are mandatory for BART-eligible 750-megawatt units, such as the Plants here. *Id.*, I.F.1 ("States must follow the guidelines in making BART determinations on a source-by-source basis for 750 megawatt (MW) power plants …"). In considering the required factor of "energy impacts," EPA's BART Guidelines provide specific

direction and instruct that consideration be given to any "economic disruption or unemployment." 40 C.F.R. pt. 51, app. Y, § IV.D.4.h.5.[16]

When promulgating a FIP, EPA stands in the shoes of the State, and must meet the same requirements. *See* 77 Fed. Reg. 40,150, 40,164 (July 6, 2012). "Just as the State was required to properly consider each statutory factor in the BART analysis in the implementation of its SIP, so too was EPA in the promulgation of its FIP." *North Dakota v. EPA*, 730 F.3d 750, 764 (8th Cir. 2013).

Despite the statutory requirement to consider the energy factor and the associated economic disruption and unemployment, EPA failed to do so. In its Proposed Rule to disapprove the Alternative and promulgate the FIP, EPA cavalierly dismissed this economic information as immaterial. *See* 81 Fed. Reg. 2,004, 2,024 (Jan. 14, 2016) ("Because such benefits do not have direct bearing on whether the BART Alternative achieves greater reasonable progress, it is not material to our action . . . .") [JA ___] . In its Final Rule, EPA similarly dismissed this factor as irrelevant and assigned it no weight in the BART Alternative analysis. *See* 81 Fed. Reg. at 43,900-01 ("Energy and non-air quality impacts do not provide relevant information on the relative visibility benefit of a BART

[16] The Guidelines also contemplate in these circumstances the conduct of "an economic analysis that demonstrates, in sufficient detail for public review, the specific economic effects, parameters, and reasoning" for a BART selection. 40 C.F.R. pt. 51, app. Y, § IV.E.3.2.

Alternative as compared to BART. We, therefore, did not assign this metric any weight in our evaluation of the State's weight-of-evidence conclusion.") [JA ___]. Likewise, EPA refused to consider the information as part of its FIP BART determinations.[17]

EPA was repeatedly made aware of its failure to consider this factor by the Counties and their residents during the public comment period.[18] In response to comments requesting that EPA consider the economic disruption and

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[17] *See* EPA RTC at 364 364 ("However, neither the CAA nor the RHR provide for consideration of the affordability of controls, ratepayer impacts or potential job losses as part of a BART determination analysis.") [JA ___] .

[18] *See, e.g.*, County Commissioner Comments, EPA-R08-OAR-2015-0463-0063 ("The economic impact of the Hunter and Huntington Power Plants is a large portion of our economy in Emery County. The economic impact Rocky Mountain Power has had to Emery County in direct and indirect is 800+ jobs.")[JA ___]; Carbon County Board of Commissioners Comment, Mar. 10, 2016 ("Carbon County is most concerned that, based on testimony from the Navajo tribe with a population of 166,826 how the loss of nearly 1,000 jobs between the plant and the mine would be too great of an impact to the tribe. Yet the loss of 1,260 direct and 1,850 indirect jobs between the mines and power plants and our supporting businesses in the Carbon/Emery County area with a combined population of 31,737 somehow does not measure up to the a major economic impact to the area and our citizens? Why has no testimony been taken on the impacts to our area?") [JA ___.]; Public Lands Administrator Comment, Jan. 26, 2016 ("PacifiCorp and its predecessors have been good neighbors and is an extremely important economic asset to Emery County.") [JA ___]; PacifiCorp Comments, EPA-R08-OAR-2015-0463-0169, at 41, Mar. 3, 2016 ("When considering the FIP Proposal, EPA must include in its evaluation of energy impacts and their associated costs the impacts to local jobs and state and local economies surrounding the affected facilities. With retirement, replacement, or natural gas conversion of individual units a potential outcome due to EPA's FIP Proposal, EPA's assessment must include coordination with state regulators, environmental agencies and elected officials.")[JA ___].

unemployment impacts, EPA attempted to excuse its omission by erroneously stating that "[n]either the CAA nor the RHR provide for consideration of . . . potential job losses as part of a BART determination analysis."[19]

EPA further attempted to excuse its failure by suggesting that such impacts should be considered "only in 'unusual circumstances.'"[20] This attempted "unusual circumstances" excuse derives from an altogether different section of the BART Guidelines and is irrelevant here. *Compare* 40 C.F.R. pt. 51, app. Y, § IV.D.4.h.5 (consideration of economic and employment impacts as part of the *energy impacts analysis*) *with* 40 C.F.R. pt. 51, app. Y, § IV.E.3.2 (identifying the "unusual circumstances" when the *affordability of the controls* should be considered in *selecting a best alternative*). In any event, this case does present such "unusual circumstances" given the dependency of the Counties' on the mining and utility industries. *See* Statement of Case above.

In summary, EPA was *required* to consider these "energy" and "economic disruption and unemployment" impacts in its BART analysis, 42 U.S.C. § 7491(g)(2); 40 C.F.R. pt. 51, app. Y, § IV.D.4.h.5, but failed to do so. EPA has rejected BART determinations for several states based on this same failure to address all of the required BART factors, including Utah's 2008 SIP. *See, e.g.*, 77

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[19] RTC at 364−65 [JA ___].

[20] RTC at 364−65 [JA ___].

Fed. Reg. 74,355 (Dec. 14, 2012) [JA ___]; *Oklahoma v. EPA*, 723 F.3d 1201, 1206 (10th Cir. 2013).

B. Economic Disruption and Unemployment Impacts in Emery and Carbon Counties Would Irrefutably Result from the Final Rule

The SCR requirements of EPA's Final Rule would result in significant economic disruption and unemployment. *See* Statement of the Case above. If the Final Rule is not rescinded, the cost-prohibitive FIP will likely force the owners to consider shutting down the Plants, as EPA has seen on several occasions,[21] or possibly convert them to natural gas plants. Under either scenario, the result would be economic disruption and unemployment. EPA's failure to consider these impacts is arbitrary, capricious, an abuse of discretion, and otherwise not in accordance with law.

II. EPA FAILED TO CONDUCT THE EVALUATION OF POTENTIAL LOSS OR SHIFTS OF EMPLOYMENT AS REQUIRED UNDER SECTION 7621

In addition to the CAA provision (42 U.S.C. §7491) requiring EPA to consider the energy impacts and economic disruption and unemployment in its BART analyses, the CAA has a related provision requiring EPA to conduct

[21] For example, units at the Apache and Cholla plants in Arizona, San Juan plant in New Mexico, Boardman plant in Oregon, and Craig plant in Colorado, have been shut down or converted rather than retrofitted with prohibitively expensive SCR. *See*, Apache Plant, 80 Fed. Reg. 19,220 (Feb. 27, 2015); Cholla Plant, 81 Fed. Reg. 46,852 (July 19, 2016) [JA ___]; Boardman Plant, 76 Fed. Reg. 38,997 (July 5, 2011) [JA ___].

evaluation of potential loss or shifts of employment related to its administration of the CAA and "applicable implementation plans." Section 7621 of the CAA provides:

> The administrator shall conduct continuing evaluations of potential loss or shifts of employment which may result from the administration or enforcement of the provision of [the CAA] and applicable implementation plans, including where appropriate , investigating threatened plant closures or reductions in employment allegedly resulting from such administration or enforcement.

42 U.S.C. § 7621(a) (emphasis added).

EPA argues that Section 7621(a) does not impose a mandatory duty. *See* EPA's Opposition to the Motions to Stay the Final Rule at 56-57. That argument has been flatly rejected in a very recent and similar case. *Murray Energy Corp. v. McCarthy*, No. 5:14-CV-39, 2017 WL 150511, at *1 (N.D.W.Va. Jan. 11, 2017).

> Congress intended to impose a mandatory duty upon the EPA. With specific statutory provisions like Section [7621(a)], Congress unmistakably intended to track and monitor the effects of the Clean Air Act and its implementing regulations on employment processes… the legislative record for these statutory provisions, as well as Supreme Court precedent, confirm this purpose.

Id. (citation to several pages of legislative record omitted). The court also noted that "[w]hile EPA is elsewhere required to research national, regional, and sector-wide economic impacts, § [7621] requires EPA to answer the particular question of whether the EPA is contributing to specific worker dislocations and plant and mine

closures… No other provision requires this type of 'Facility-and-community-specific at-risk assessment of jobs.'" *Id.* at 4.

The evaluation mandated by Section 7621 requires not just an after-the-fact evaluation, but a before-the-fact evaluation of "potential loss or shifts of employment" which "may" result from the "administration or enforcement of … applicable implementation plans . . . ." 42 U.S.C. § 7621(a). In *Murray Energy Corp.*, the Court emphasized that, consistent with the language of Section 7621(a), EPA should not only be "retrospectively evaluating 'any actual closures or reductions which are alleged to have occurred because of such requirements,'" but "prospectively 'investigat[ing] … threatened plant closures or reductions in employment allegedly due to requirements of the act….'" *Id.* at *4. This prospective application of the Section 7621(a) "was specifically 'intended to bring into play any government programs available to provide financial assistance which would prevent plant closings or production curtailments or to assist workers and communities impacted by closings and curtailments.'" *Id.,* at *5 (citations omitted).[22]

[22] Section 7721(a) became effective in 1972. In the initial years of its implementation, EPA identified numerous plant closures and curtailments, and associated actual and threatened dislocation of workers. *See Murray Energy Corp.*, at *5. At some point, however, "EPA discontinued these evaluations of losses and shifts in employment resulting from its actions." *Id.* In more recent years, EPA has taken the position that it does "'not interpret[] section [7621(a)] to

EPA is now taking the position that it does not interpret section 7621(a) to require it to conduct evaluations of potential loss or shifts of employment in administering implementation plans,[23] that such evaluations "are untethered to any particular action," and that section 7621(a) merely "creates a mechanism for individual employees to alert EPA if his or her job has been threatened…." EPA's Opposition to Stay at 56.

In a flat rejection of those arguments, the court in *Murray Energy Corp.* sharply reprimanded EPA's disregard of its mandatory obligation.

> EPA cannot redefine statutes to avoid complying with them. Nor can EPA render them superfluous or contrary to their original purpose by simply defining them to be. The record in this case demonstrates hostility on the part of the EPA to doing what is ordered by § [7621(a)]. . . EPA does not get to decide whether compliance with § [7621(a)] is good policy… It is time for the EPA to recognize that Congress makes the law, and EPA must not only enforce the law, it must obey it.

Id., at *9.

EPA has repeatedly been made aware of its failure to evaluate potential loss of employment by the Counties and their residents during the public comment

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(. . . continued)
require the agency to conduct employment investigations in taking regulatory actions.'" *Id.*

[23] EPA is acutely aware that its BART FIPs have resulted in the shutting down of several coal-fired units, and the unemployment resulting therefrom. *See* footnote 26 above.

period,[24] but EPA has attempted to excuse its failure by shifting the responsibility for performing such evaluations away from itself. "[W]e lack evidence to support the assertions that our proposed FIP would result in significant rate increases, jeopardize the plant's operations, or result in any other economic effects. In the absence of such evidence, commenter's assertions regarding job losses are speculative, and we cannot consider them as part of our BART determination."[25] But EPA had a statutory duty (under Section 7621) to conduct the very evaluation of potential job losses that would have confirmed the potential job losses information EPA claims it lacked. EPA cannot claim it "lacked evidence" when it had the statutory duty to collect the evidence in the first instance and yet failed to do so. Further, because EPA has seized the prerogative to propose the FIP, it has the duty to obtain and consider the required information—not the State or the petitioners. *See* 77 Fed. Reg. at 40,164 [JA ___]; *North Dakota v. EPA*, 730 F.3d at 764.

As addressed in detail in the Statement of Claims above, the Final Rule would have very important and widespread employment effects on the coal industry and the Counties. In very similar circumstances, the court in *Murray Energy Corp.* held that, "due to the importance, widespread effects, and the claims

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[24] *See* footnote 22 above.

[25] RTC at 365 [JA ___].

of the coal industry, it would be an abuse of discretion for the EPA to refuse to conduct a § [7621(a)] evaluation on the effects of its regulations . . . ." *Id.* at *11. Likewise, EPA's failure here to conduct the required evaluation of potential loss or shifts of employment is arbitrary, capricious, an abuse of discretion, and otherwise not accordance with law.

CONCLUSION

Based on the foregoing, and on the reasons set forth by Utah and PacifiCorp in their briefs, this Court should invalidate that portion of the Final Rule disapproving the Alternative and imposing the FIP, and remand it to EPA for a full analysis of the Alternative.

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CERTIFICATE OF DIGITAL SUBMISSION

I hereby certify with respect to the foregoing:

1) all required privacy redactions have been made pursuant to Rule 25.5 of the Tenth Circuit Local Rules;

2) if required to file additional hard copies, that the ECF submission is an exact copy of those documents; and,

3) the digital submission has been scanned for viruses with the most recent version of a commercial virus scanning program, Endpoint Protection (Product version 4.7.214.0) most recently updated on November 2, 2016, and according to the program, the submission is free of viruses.

Respectfully submitted this 17th day of March, 2017.

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CERTIFICATE OF REASONS FOR SEPARATE BRIEF

In accordance with the requirement of Rule 31.3(B) of the Rules of the Tenth Circuit, Petitioners/Intervenors Emery County and Carbon County (the "Counties") submit this separate brief in accordance with the direction provided in this Court's Order of October 6, 2016. That Order provided that, as to the "[i]ndustry petitioners' PacifiCorp, UAMPS, and DG&T . . . and intervenors supporting petitioners . . . opening briefs," "[u]p to four separate briefs allowed, sharing 30,000 total words among all briefs in this category." Because on their different, albeit aligned, interests, those industry petitioners and supporting intervenors thought it necessary that four separate briefs be submitted, including this the Counties' brief.

Respectfully submitted this 17th day of March, 2017.

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CERTIFICATE OF COMPLIANCE WITH TYPE-VOLUME LIMITATION AND TYPE-FACE REQUIREMENTS

In accordance with this Court's Order of October 6, 2016, which allows the Counties to share in the petitioners' combined limitation of 30,000, this brief contains 4,000 words, exclusive of the items listed in Fed. R. App. P. 32(a)(7)(B)(iii).

This brief complies with the typeface requirements of Fed. R. App. P. 32(a)(5) and the type style requirements of Fed. R. App. P. 32(a)(6) because this brief has been prepared in a proportionally spaced typeface using MS Word 2010 in 14 point Times New Roman.

Respectfully submitted this 17th day of March, 2017.

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CERTIFICATE OF SERVICE

I hereby certify that on this 17th day of March, 2017, the foregoing **EMERY COUNTY AND CARBON COUNTY'S PRELIMINARY BRIEF IN SUPPORT OF PETITION FOR REVIEW** was filed electronically with the Clerk of the Court for the United States Court of Appeals for the Tenth Circuit by using the appellate CM/ECF system, which will send notification of this filing to all counsel of record:

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IN THE UNITED STATES COURT OF APPEALS
FOR THE TENTH CIRCUIT

DESERET GENERATION & TRANSMISSION CO-OPERATIVE, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and GINA McCARTHY, Administrator, United States Environmental Protection Agency, Respondents.	Case No. 16-9545
STATE OF UTAH, on behalf of the Utah Department of Environmental Quality, Division of Air Quality, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and GINA McCARTHY, Administrator, United States Environmental Protection Agency, Respondents.	Case No. 16-9541

PACIFICORP, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY et al., Respondents.	Case No. 16-9542
UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY et al., Respondents.	Case No. 16-9543

CARBON COUNTY, UTAH et al.,

Petitioners-Intervenors,

and

HEAL UTAH et al.,

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STATEMENT OF RELATED CASES

As required by 10th Cir. R. 28.2(C)(1), the following cases are related to this appeal:

1. *PacifiCorp v. EPA et al.*, Case No. 16-9542 (10th Cir. Sept. 2, 2016), *Utah Associated Mun. Power Sys. v. EPA et al.*, Case No. 16-9543 (10th Cir. Sept. 6, 2016), and *State of Utah v. EPA,* Case No. 16-9541 (10th Cir. Sept. 6, 2016), are petitions for review of the same Final Rule challenged in this appeal. These appeals have been consolidated with this case number 16-9545.

2. *WildEarth Guardians v. EPA*, 770 F.3d 919 (10th Cir. 2014), where this Court denied a challenge by environmental petitioners to Environmental Protection Agency's (EPA) approval of the state of Utah's (Utah) proposed cap-and-trade program for sulphur dioxide (SO_2) emissions in lieu of Best Available Retrofit Technology (BART).

3. *Utah v. EPA*, 750 F.3d 1182 (10th Cir. 2014), where Utah and PacifiCorp challenged EPA's disapproval of Utah's proposed State Implementation Plan (SIP) for nitrogen oxide (NO_x) BART. The Court did not reach the merits of the appeal due to jurisdictional issues.

GLOSSARY OF TERMS

BART ..... Best Available Retrofit Technology

CAA ..... Clean Air Act

dv ..... deciview

EPA ..... Environmental Protection Agency

FIP ..... Federal Implementation Plan

JA ..... Joint Appendix

NO_x ..... Nitrogen Oxide

RTC ..... EPA's Response to Comments

SCR ..... Selective Catalytic Reduction

SNCR ..... Selective Non-Catalytic Reduction

SIP ..... State Implementation Plan

INTRODUCTION

Deseret Generation & Transmission Co-operative ("Deseret"), owns an undivided 25.108% interest in the Hunter 2 Unit ("Hunter 2"), one of four units identified as BART eligible for implementation of Best Available Control Technology ("BART") in the state of Utah. The Respondent, Environmental Protection Agency ("EPA"), has illegally rejected an implementation plan developed by the state of Utah under authority of the Clean Air Act ("CAA") regional haze program ("Final Rule")[1] as it pertains to control of nitrogen oxide ("NO_x") emissions (the "BART Alternative"). Instead, EPA imposed a Federal Implementation Plan ("FIP") requiring the most stringent and costly form of pollution controls to be installed at Hunter 2 rather than the BART Alternative appropriately developed and selected by the State.[2]

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[1] The final rule was published on July 5, 2016, and is titled "Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze," published at 81 Fed. Reg. 43,894 (July 5, 2016) ("Final Rule"), attached hereto as Attachment A [Joint Appendix ("JA") ___.]

[2] The controls mandated by the EPA FIP include installation of Selective Catalytic Reduction, in combination with Low NOx Burners and Overfire Air (referred to collectively as "SCR").

EPA's Final Rule was promulgated in the face of significant data and information from the state of Utah that the NO_x BART Alternative proposed in Utah's State Implementation Plan ("SIP") would reduce haze more significantly than the installation of much more expensive controls—thereby satisfying both the main goal as well as the technical requirements of the regional haze program under the CAA. Deseret submitted to the EPA a Petition for Reconsideration and Request for Administrative stay of the FIP in September of 2016. Deseret has received no response from the EPA despite the fatal flaws in EPA's Final Rule.

JURISDICTION

On September 6, 2016, Deseret timely petitioned this court for a review of EPA's determination to illegally reject the SIP and implement a FIP. EPA had jurisdiction to review Utah's SIP, and its component NO_x BART Alternative, and to issue the Final Rule (including the FIP), under 42 U.S.C. § 7410. This Court has jurisdiction to review EPA's decision on the Final Rule under 42 U.S.C. § 7607(b)(1). The review of the Final Rule, which applies "locally or regionally" to Utah only, is appropriate in this Court as it is "the United States Court of Appeals for the appropriate circuit." 42 U.S.C. § 7607(b)(1).

ISSUES PRESENTED FOR REVIEW

In addition to the issues presented by the state of Utah in its preliminary brief and those presented by PacifiCorp in its preliminary brief, the following issues are specifically presented for review:

1. Whether EPA acted arbitrarily, capriciously, abused its discretion, or acted contrary to law when it ignored the principles of cooperative federalism in rejecting the state of Utah's SIP, including the NO_x BART Alternative and imposing a FIP?

2. Should the Court refuse to grant any deference to EPA in this case where EPA acted beyond the scope of the Clean Air Act in imposing a FIP?

3. Did EPA act arbitrarily, capriciously, abuse its discretion, or act contrary to law when it imposed significant costs for SCR as BART without any measurable visibility improvement?

STATEMENT OF THE CASE

This appeal is the result of classic federal overreach, whereby the EPA disrupted the Congressionally-required balance between the states and the federal government in the implementation of plans to address regional haze. In Section 169A of the CAA, Congress created a program to protect visibility in national parks and wilderness areas from the effects of regional haze. In doing so, it

specifically delegated to the States—not EPA— the task of determining the appropriate level of "emissions limits, schedules of compliance and other measures" to regulate regional haze. 42 U.S.C. § 7491(b)(2).

EPA's role is limited to reviewing the State's BART determinations, or in this case, the state of Utah's BART Alternative SIP, and ensuring the SIP meets all "applicable requirements" of the Clean Air Act. 42 U.S.C. § 7410(k)(3). In making BART and presumably BART Alternative determinations, "*States* are *free to determine the weight and significance* to be assigned to each factor." 70 Fed. Reg. 39,104, 39,123 (July 6, 2005) (emphasis added). In determining whether a BART Alternative may achieve greater reasonable progress toward visibility improvement than a traditional BART Benchmark, states may consider some or all of the following factors: "the costs of compliance, the time necessary for compliance, [] the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements." 42 U.S.C. § 7491(g)(1). The EPA may not, as it did in this case, reject a SIP on the basis that it disagrees with Utah's discretionary consideration of, or the weight assigned to the factors. *See e.g., Train v. Natural Res. Def. Council*, 421 U.S. 60, 79 (1975) (the EPA "has no authority to question the wisdom of a State's choice of emission limitations if they are part of a plan which satisfies [the] standards").

Rather than heed Utah's BART Alternative, made on the basis of specific scientific investigation and intimate knowledge of the state's regional haze causing sources in accordance with the applicable BART Alternative requirements, EPA has taken the extraordinary step in imposing a FIP that will cost BART-eligible sources in the state of Utah hundreds of millions of dollars more than the State BART Alternative would have cost. Such extraordinary costs yield minimum visibility benefits and will place unbearable, unjustified burdens on sources like Deseret Power.

STATEMENT OF FACTS

In an effort to prevent duplicative briefing as requested by this Court in its scheduling order dated October 6, 2016 Deseret hereby adopts the Statement of Facts included in the Preliminary Brief of the state of Utah filed on March 10, 2017, *Utah v. EPA*, No 16-9541, at 7-20, hereinafter "Utah Brief".]

STANDARD OF REVIEW

Final agency action must be set aside if it is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. § 706(2)(A). This arbitrary and capricious standard is applicable in CAA cases where EPA's actions are under review. *Oklahoma v. EPA*, 723 F.3d 1201, 1211 (10th Cir. 2013). Specifically, here, where the review is focused on EPA's rejection of the

state of Utah's SIP, the court must evaluate whether EPA was arbitrary in denying Utah's BART Alternative SIP even though the SIP met all applicable requirements of the SIP review provisions of the CAA. *See* 42 U.S.C. § 7410(k)(3). As discussed below, EPA arbitrarily refused to allow the state of Utah to consider certain statutory factors in evaluating the reasonable progress achieved by the BART Alternative.

Deseret also agrees with the standard of review articulated by the state of Utah and PacifiCorp in their merits briefs that this court should employ in its review of EPA's illegal actions.

SUMMARY OF THE ARGUMENT

EPA acted with blind allegiance to its pre-conceived agenda to force BART eligible sources in the state of Utah to install the most costly controls including SCR without attendant visibility benefits, regardless of other statutory considerations. This singular focus was arbitrary and capricious for a number of reasons. First, in rejecting the state of Utah's BART Alternative, EPA refused to acknowledge the cost difference between the BART Benchmark and the BART Alternative as properly considered by the State in its reasonable progress analysis. This unfairly tipped the scale in favor of the BART Benchmark—or SCR—and resulted in a breach of the federalism balance required by the CAA. Second,

EPA's FIP determination unfairly refused to take account of the impact of existing controls on BART eligible sources. EPA's actions cannot be justified under the CAA, and the portion of the final rule disapproving the BART Alternative SIP and imposing the FIP should be vacated.

ARGUMENT

Deseret hereby adopts and incorporates into its brief the arguments advanced by the state of Utah, PacifiCorp, UAMPS, and the Counties. The remainder of this brief addresses EPA's significant breach of federalism principles set forth in statute by: (i) arbitrarily rejecting the state of Utah's BART Alternative SIP and imposing a FIP which will yield little to no comparative improvement in visibility despite an enormous disparity in compliance costs' and (ii) failing to give due consideration of the "costs of compliance" in developing the FIP.

I. EPA Undermined the Core Tenants of Federalism by Imposing its FIP in the Place of Utah's BART Alternative SIP.

Section 169A of the CAA sets forth a system whereby the states, being the most familiar with the sources that may contribute to regional haze, and being most familiar with the cost impacts to the sources in each state, are designated by statute as the governmental entities vested with authority to determine the "emissions limits, schedules of compliance, and other measures as may be necessary to make

reasonable progress." 42 U.S.C. § 7491(b)(2). In this case, Utah spent many years developing what ultimately became a BART Alternative that it determined, by the clear weight of the evidence, would provide greater "reasonable progress" toward visibility improvement across all Class I areas. [Utah Brief at 11-19.]

The EPA's role in reviewing a state's SIP is limited in scope; it may only disapprove the SIP in instances where a state fails to meet applicable CAA requirements. *See* 42 U.S.C. § 7410(k)(3); *see e.g., Texas v. EPA,* 829 F.3d 405 (5th Cir. 2016) (court granted stay motion in favor of Texas finding likelihood of success on the merits of state's challenge to EPA FIP). EPA may not, as it did in this case, disapprove a SIP because it disagrees with the state's weighing of certain statutory factors as part of its "greater reasonable progress" analysis for the BART Alternative. *Id.* Indeed, the Supreme Court has stated that EPA has "no authority to question the wisdom of a State's choice of emission limitations if they are part of a plan which satisfies [the] standards of [the CAA] and the Agency may devise and promulgate a specific plan of its own only if a State fails to submit an implementation plan which satisfies those standards." *Train v. Natural Res. Def. Council*, 421 U.S. 60, 79 (1975).

The CAA's legislative history also confirms this division of responsibility between the states and EPA. During the floor debate preceding adoption of the

Conference Agreement supporting Section 169A of the CAA, Senators McClure (R-Idaho) and Muskie (D-Maine) engaged in the following dialogue:

> Senator McClure: Under the conference agreement, does the State retain the sole authority for identification of sources for the purpose of visibility issues under this section?
>
> Senator Muskie: Yes; the State, not the Administrator, identifies a source that may impair visibility and thereby falls within the requirement of section 128.
>
> Senator McClure: And does this also hold true for determination of "Best Available Retrofit Technology"?
>
> Senator Muskie: Yes; here again it is the State which determines what constitutes "Best Available Retrofit Technology," as defined in section 128…

123 Cong. Rec. S13709 (daily ed. Aug. 4, 1977).

Even EPA itself has explained that "[t]he State must determine the appropriate level of BART control for each source subject to BART." RHR, 70 Fed. Reg. at 39,107. Moreover, EPA acknowledges that, in making BART determinations, "*States* are *free to determine the weight and significance* to be assigned to each factor." 70 Fed. Reg. 39,104, 39,123 (July 6, 2005) (emphasis added). Clearly, if Congress (and EPA according to prior positions) intended for States to determine BART, then Congress (and EPA at least in the past) intended States to determine BART alternatives, including the flexibility to compare multiple BART factors in determining reasonable progress. And yet, in this case,

EPA ignored Utah's consideration of certain statutory factors in determining that Utah's BART Alternative created greater reasonable progress toward visibility improvement. [Utah Brief at 19-20, 43-44.]

EPA's legal authority under section 169A of the CAA may not be expanded to give it the ability to impose its agenda of forcing all BART-eligible sources in the state of Utah to install a particular technology, namely SCR, at an unreasonable cost, and at the expense of a reasonable BART Alternative. Neither the plain language of the CAA, the legislative history underlying the adoption of the regional haze provisions, court decisions interpreting the CAA's language, nor EPA's own RHR supports EPA's actions in this case. For these reasons, the EPA's FIP must be rejected and the state of Utah should be allowed to continue implementation of its legally justifiable BART Alternative NOx strategy.

II. EPA's Decision to Reject Utah's Alternative BART and Impose a FIP Was Arbitrary and Capricious and Should be Afforded No Deference.

Courts generally review agency interpretations of the statutes they are charged to administer under the deferential standard articulated in *Chevron U.S.A., Inc. v. Natural Resources Defense Council*, 467 U.S. 837 (1984). However, "'[i]f the statute is clear, [courts] apply its plain meaning' and the inquiry ends." *Ariz. Pub. Serv. Co. v. EPA*, 562 F.3d 1116, 1123 (*quoting Qwest Corp. v. FCC*, 258

F.3d 1191 (10th Cir. 2001)). In this case, as explained in Section I infra, the CAA plainly and clearly articulates that it is the States that have the authority and discretion to consider and weigh the reasonable progress factors when choosing a BART alternative to meet the applicable reasonable progress goals.

EPA's failure to accept the state of Utah's proper weighing of the metrics supporting the BART Alternative, which achieves "greater reasonable progress" toward visibility improvement is a decision that should not be afforded any deference. Instead, EPA's actions must be evaluated based solely on the APA arbitrary and capricious standard. Under the APA, final agency action must be set aside if it is "arbitrary and capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. § 706(2). An agency's action is arbitrary and capricious if "the agency 'has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or if the agency action is so implausible that it could not be ascribed to a difference in view or the product of agency expertise." *Wyo. v. U.S. Dep't of Agric.*, 661 F.3d 1209, 1227 (10th Cir. 2011) (internal quotation marks omitted).

As set out in detail in the state of Utah's Preliminary Brief, Utah's Division of Air Quality went to great lengths to review all of the scientific evidence and cost

impacts that both the BART Benchmark and the BART Alternative would have with respect to the individual BART–eligible and non-BART sources and the improvement in visibility. [Utah Brief at 23-44.] Instead of accepting the work done by the state of Utah, EPA focused primarily on one metric, the 98th percentile metric, that showed a slightly higher degree of visibility improvement with the BART Benchmark, and completely ignored the rest of Utah's analysis of other visibility information, costs, energy impacts, and non-air environmental impacts. *Id.*; 81 Fed. Reg. at 43,899 [JA ___.] In other words, EPA "entirely failed to consider an important aspect of the problem" by ignoring the State's weighting of the permissible factors that Congress expressly authorized for state determination. Specifically, EPA ignored the severe and devastating cost impacts the BART Benchmark/FIP would cause.

The CAA and the relevant regulations require the states and EPA to consider cost impacts when determining reasonable progress. 42 U.S.C. § 7491(g)(1) ("[I]n determining reasonable progress there *shall* be taken into consideration the costs of compliance . . . and the energy and nonair quality environmental impacts of compliance . . .") (emphasis added); 40 C.F.R. § 51.308(d)(1)(i)(A) (In establishing a reasonable progress goal . . . the State must . . . [c]onsider the costs of compliance . . . the energy and non-air quality environmental impacts of

compliance . . . ."). The state of Utah properly rejected the BART Benchmark, in part because the nearly $700 million price tag to install SCR on the BART-eligible sources, including the Hunter I and II facilities, did not produce meaningful visibility improvements.

EPA's exclusive focus on the 98th percentile metric, and complete disregard for cost impacts, meets the very definition of arbitrary and capricious. Not only does the CAA plainly and clearly require considerations of costs impacts, especially where Section 169A imposes visibility standards and not health based standards, it certainly does not allow the EPA to focus only on one factor (the 98th percentile metric) to the exclusion of cost impacts to justify EPA's endgame—installation of SCR. This court should not allow the EPA to rewrite the CAA by giving any deference to its illegal actions here.

III. The Cost Impacts to Deseret of EPA's FIP are Severe, Unreasonable, and were not Properly Considered.

Even were EPA allowed to reject Utah's BART Alternative and impose a FIP by refusing to consider costs and focusing on the 98th percentile metric (which it is not), EPA's actions are still arbitrary and capricious because it failed to justify the nearly $700 million price tag of SCR required in the FIP that would threaten Deseret's ability to continue to operate within the constraints of its status as a

financially distressed utility.[3] Indeed, nowhere in the record of EPA's analysis is there any hint that EPA attempted to investigate, educate itself, or understand even rudimentarily the impact to Deseret of the dramatically increased price tag of the FIP mandated controls – even though Deseret is the second largest utility operating within the State of Utah, with more than twice the exposure to the cost of this action than the next largest stakeholder other than PacifiCorp.

Deseret articulated the specific and immediate harm that would result from EPA's FIP in its Motion for Stay filed with this Court on October 28, 2016, and detailed in the declaration of Robert Dalley attached to the motion. ["Stay Brief" attached hereto as Attachment B.] Despite the severe nature of these impacts, EPA failed to fairly evaluate costs in its decision to issue the FIP, instead relying completely on its own visibility improvement measurements, which were flawed. *See* 81 Fed. Reg. at 43,903-4, Tables 2-5 [JA ___]; *see also* 81 Fed. Reg. at 43,897 [JA ___] (Refusing to give any "weight" to cost considerations of the BART

[3] The EPA acknowledged that the BART Alternative would be less costly by a significant margin when it stated that "[w]e do agree…[with] Utah's conclusion that the BART Alternative would have a lower cost impact to PacifiCorp than the BART Benchmark…" *See* 81 Fed. Reg at 2024 [JA ___.] EPA, as a federal agency based outside the state, exhibited no apparent understanding of Deseret's financial condition and took no effort to understand or weigh the financial impact of the FIP to Deseret, as the second largest utility operating within Utah.

Benchmark "because the metric[] does not evaluate visibility benefits at the nine class I areas impacted by the State's sources."); Response to Comments at 37 ("EPA disagrees that the difference in total capital cost between the BART Alternative and BART Benchmark is relevant in the context of a weight-of-evidence analysis. EPA further disagrees that considering the difference in total capital cost between the BART Alternative and BART FIP is relevant or consistent with the CAA and RHR.").

Such a position by EPA is directly contrary to the requirements of the CAA, as articulated at least three separate times by Federal Courts. *See, e.g., Michigan vs. EPA,* 576 U.S. ___; 135 S. Ct. 2699 (2015) (EPA interpreted Clean Air Act § 112(n) unreasonably when it deemed cost irrelevant to the decision to regulate power plants); *National Parks Conservation Association, v. EPA,* 788 F.3d 1134, 1144 (9th Cir. 2015) ("Based on its explanation, the [FIP]'s reader is left to wonder what rationale EPA used to determine cost-effectiveness. Again, the law requires a reasoned answer to that question."); *Wildearth Guardians v. EPA,* 770 F.3d 919, 924, n. 3 (10th Cir. 2014) ("reasonable progress is measured by comparing the cost of compliance…the energy and nonair quality environmental impacts…and the remaining useful life of any existing [regulated] source" (quotation marks omitted)). Even EPA itself has recognized that in considering a BART

Alternative, "[t]he EPA continues to support State efforts to develop trading programs and other alternative strategies to fulfill the goals of the CAA. We believe such strategies have the potential to achieve greater progress towards the national visibility goals than more traditional approaches to regulation, and to do so in the most cost-effective manner practicable." 71 Fed. Reg. 60,612, 60,614 (October 13, 2006).

EPA's remarkable decision to disregard the cost impacts of its FIP, and refusal to acknowledge the tremendous cost impacts found by the State as part of its BART Alternative analysis will have severe impacts to Deseret. Currently, Deseret is operating under the terms of a long-term debt forbearance arrangement with its creditors, which was necessitated by market forces in the late 1980's and early 1990's, and by acquisition of its interest in the Hunter 2 Unit. [Stay Brief at 5.] Deseret's creditors have agreed to forebear its debt repayment but only on the condition that Deseret avoids incurring capital costs beyond current operating costs and cash reserves. [*Id.*] Ironically, the $165 million price tag (of which Deseret would be responsible for contributing $41 million) for installation of SCR at Hunter 2, the unit partially responsible for Deseret's current debt situation, would threaten this debt restructuring arrangement, which, were it to occur, could result in a requirement to make full, immediate repayment of the unrestructured balance of

Deseret's debts. [Stay Brief at 8.] This would force Deseret into bankruptcy. [*Id.* at 7.]

The enormous cost to install FIP mandated controls exceeds Deseret's available financial resources. [*Id.* at 7.] To secure financing for such costs, Deseret must seek approval from its lender under the long-term debt restructure. [*Id.* at 7-8.] Even if such approval could be negotiated, the debt service on the new financing alone would cause an immediate 11.2% price increase to Deseret's customers in rural and tribal service areas, risking disruption of service to many in these economically disadvantaged communities. [*Id.* at 13.] Individuals in these rural communities and tribal areas include economically at-risk communities that are not able to afford such dramatic cost increases—another factor known to the State of Utah and taken into account by the SIP which was unknown to and ignored by EPA. These communities should not be the victims of EPA's SCR agenda, which profoundly lacks support in either visibility reduction, reasonable progress metrics, or reasonable cost consideration factors.

The state of Utah properly evaluated the foregoing factors impacting Deseret and its rural/tribal service communities in developing its BART Alternative SIP. [Utah Brief at 44.] Not only did the BART Alternative achieve greater reasonable progress than the BART Benchmark, but it avoided the severe cost impacts of SCR

installation. EPA not only refused to consider the cost impacts in rejecting the BART Alternative, but in preparing its FIP, EPA underestimated the cost impacts of SCR installation by refusing to factor in existing controls at the facilities. *See* 81 Fed. Reg. at 43,903-4, Tables 2-5 [JA ___]; *see also* [Utah Brief at 45-50.] The CAA does not allow the EPA to ignore significant cost impacts in this way—especially for visibility improvement standards that result in less than 1 dv of visibility improvement, imperceptible to the human eye.

EPA's illegal actions have severe consequences for the businesses and electric consumers in the state of Utah. The refusal by EPA to truly evaluate the cost impacts of SCR is yet another in the long list of reasons why EPA's rejection of Utah's Alternative BART SIP and imposition of the FIP on the Hunter 2 unit was arbitrary and capricious and should rejected by this Court.

CONCLUSION

For the foregoing reasons, this court should reject EPA's actions contrary to the federalism principles dictated by the CAA and vacate the portion of the Final Rule disapproving the BART Alternative and imposing the FIP.

DATED this 17th day of March, 2017.

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CERTIFICATE OF SERVICE

I hereby certify that on the 17th day of March 2017, the foregoing **PRELIMINARY BRIEF OF DESERET GENERATION & TRANSMISSION CO-OPERATIVE** was served electronically on all counsel of record through the Court's CM/ECF system.

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CERTIFICATE OF DIGITAL SUBMISSION

I hereby certify that with respect to the foregoing:

(1) all required privacy redactions have been made per 10th Cir. R. 25.5;

(2) if required to file additional hard copies, that the ECF submission is an exact copy of those documents;

(3) the digital submissions have been scanned for viruses with the most recent version of a commercial virus scanning program, Symantec Endpoint Protection (Version 12.1.6), and according to the program are free of viruses.

DATED this 17th day of March, 2017.

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CERTIFICATE OF COMPLIANCE WITH RULE 32(a)

Certificate of Compliance With Type-Volume Limitation,
Typeface Requirements, and Type Style Requirements

1. This brief complies with the type-volume limitation of Fed. R. App. P. 32(a)(7)(B) because:

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DATED this 17th day of March, 2017.

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CERTIFICATE OF COUNSEL
RE COMPLIANCE WITH RULE 31.3.B

Pursuant to Rule 31.3(B), Counsel for Deseret Generation & Transmission Co-operative ("Deseret") hereby certifies that it submits this separate brief pursuant to this Court's Scheduling Order dated October 6, 2016, in which the Industry petitioners, PacifiCorp, UAMPS, Deseret, and the Intervenors, were specifically allowed to submit up to four separate merits briefs sharing 30,000 total words among all the Industry petitioners. It is therefore necessary and appropriate for Deseret to submit this separate merits brief to the Court. The separate brief contains arguments specific to Deseret, not shared by the other Industry petitioners.

DATED this 17th day of March, 2017.

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ATTACHMENT A

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Part IV

Environmental Protection Agency

40 CFR Part 52
Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; Utah; Revisions To Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Final Rule

EPA-HQ-2017-010177 Production Set #2

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R08–OAR–2015–0463; FRL–9947–42–Region 8]

Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is partially approving and partially disapproving a State Implementation Plan (SIP) revision submitted by the State of Utah on June 4, 2015 to implement the regional haze program pursuant to section 169A of the Clean Air Act (CAA or Act). The State's SIP revisions would establish an alternative to best available retrofit technology (BART) controls that would otherwise be required to control nitrogen oxides (NO_X) at PacifiCorp's Hunter and Huntington power plants. The June 2015 SIP revision also includes BART determinations for particulate matter with an aerodynamic diameter of less than 10 micrometers (PM_{10}) at these power plants and provisions for making the NO_X and PM_{10} BART emission limits federally enforceable. The CAA requires states to prevent any future and remedy any existing man-made impairment of visibility in national parks and wilderness areas designated as Class I areas. Air emissions from the four electric generating units (EGUs) at the two plants affected by this action cause or contribute to visibility impairment at nine Class I areas including Grand Canyon, Arches, Black Canyon, Bryce Canyon, Canyonlands, Capitol Reef, Mesa Verde and Zion National Parks and Flat Tops Wilderness Area. The EPA is finalizing the option in our January 14, 2016 co-proposal to partially approve and partially disapprove the June 2015 SIP revision and is promulgating a Federal Implementation Plan (FIP) to address the deficiencies identified in our proposed partial disapproval of Utah's regional haze SIP. The EPA is not taking any final action on a related October 20, 2015 SIP revision. The State retains its authority to submit a revised state plan consistent with CAA and Regional Haze Rule (RHR) requirements. An approvable SIP submission will result in the modification or withdrawal of the FIP.

DATES: This final rule is effective August 4, 2016.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–R08–OAR–2015–0463. All documents in the docket are listed on the *www.regulations.gov* Web site. Publicly available docket materials are available either electronically through *www.regulations.gov*, or in hard copy at the Air Program, Environmental Protection Agency (EPA), Region 8, 1595 Wynkoop Street, Denver, Colorado 80202–1129. EPA requests that if, at all possible, you contact the individual listed in the **FOR FURTHER INFORMATION CONTACT** section to view the hard copy of the docket. You may view the hard copy of the docket Monday through Friday, 8 a.m. to 4 p.m., excluding federal holidays.

FOR FURTHER INFORMATION CONTACT: Gail Fallon, Air Program, EPA, Region 8, Mailcode 8P–AR, 1595 Wynkoop Street, Denver, Colorado, 80202–1129, (303) 312–6281, *Fallon.Gail@epa.gov.*

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I. Introduction

The purpose of federal and state regional haze plans is to achieve the national goal, declared by Congress, of restoring and protecting visibility at 156 federal Class I areas across the United States, most of which are national parks and wilderness areas with scenic vistas enjoyed by the American public. The national goal, as described in CAA section 169A, is the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I federal areas where such impairment results from man-made air pollution. States are required to submit SIPs that, among other things, ensure reasonable progress toward the national goal of remedying anthropogenic visibility impairment in federal Class I areas. Arizona, Colorado, and Utah have a wealth of such areas that are impacted by the Hunter and Huntington power plants, including Grand Canyon, Arches, Black Canyon,

Bryce Canyon, Canyonlands, Capitol Reef, Mesa Verde and Zion National Parks and Flat Tops Wilderness Area. The four units at the two power plants that are subject to the CAA BART requirements are large sources of NO_X,[1] and the NO_X emissions from these plants affect visibility[2] at some of the countries' most beloved Class I areas that are visited by millions of Americans. The CAA requires that such sources install and operate controls to limit visibility impairing pollutants; in this instance there are very cost-effective controls available for these units, which will operate for many years into the future.

We proposed action on Utah's June 4, 2015 and October 20, 2015 regional haze SIP submittals addressing NO_X and PM_{10} BART requirements on January 14, 2016.[3] The EPA conducted a public hearing for our proposed action in Salt Lake City, Utah on January 26, 2016. Our public comment period closed on March 14, 2016.

In this action, we are partially approving and partially disapproving the SIP submittal submitted by Utah on June 4, 2015, and taking no action on the State's October 20, 2015 SIP submittal. These submittals include actions intended to satisfy the State's obligations for the regional haze program's first planning period, including the obligation to submit a SIP containing emission limitations representing BART for NO_X and PM for each of the four subject-to-BART sources of visibility-impairing emissions. We are also promulgating a FIP to address the deficiencies we have identified in the portions of the SIP submittal that we are disapproving.

Utah's SIP submittal was to address the BART requirements for NO_X in part through reliance on a BART alternative program under 40 CFR 51.308(e)(2), which allows a state to implement such a BART alternative when the clear weight of the evidence demonstrates that it achieves greater reasonable progress than BART.[4] Specifically, rather than installing and operating BART controls for its four subject-to-BART electric generating units (EGUs), Utah's SIP submittal relied on an alternative program, which included the following: (1) The installation of upgraded combustion controls between 2006 and 2014 at the four BART units plus an additional EGU at PacifiCorp's Hunter plant; and (2) the shutdown of the Carbon plant, a non-BART source, to meet the BART requirements for emissions of NO_X. To meet its PM BART requirements, Utah's SIP submittal included the most stringent control technology at each of the four subject-to-BART EGUs. We provided a detailed explanation of the contents of Utah's June and October 2015 submittals along with an overview of earlier Utah regional haze submittals and EPA's actions on these earlier submittals in sections IV and III.E, respectively, of our proposed rule.[5]

EPA takes very seriously a decision to disapprove any state plan. Our intention is to approve a state's exercise of discretion if it can be supported. However, to approve a state plan EPA must be able to find that the plan is consistent with the requirements of the CAA and EPA's regulations. Although these are largely fact-based decisions, we focus strongly on consistently applying the regional haze requirements across this national program. After carefully considering the comments on our proposal, we determined that there is only one permissible outcome. Therefore, for the reasons described in our proposal and in this action, we find that the State's NO_X BART Alternative for the power plants is not consistent with the applicable statutory and regulatory requirements. As a result, EPA has determined that final disapproval is the only path that is consistent with the Act.

Although we are promulgating a federal plan, the State retains its authority to submit a revised state plan consistent with CAA and Regional Haze Rule requirements. If we determine that the SIP revision is approvable, regardless of whether or not its terms match those of our final FIP, we would propose to approve such a SIP revision. An approvable SIP submission will result in the modification or withdrawal of the FIP.[6]

A. Our Co-Proposals

When we reviewed the Utah regional haze SIP, we noted that some of the metrics the State included in its weight-of-evidence analysis presented to support the NO_X BART Alternative appear to support a conclusion that the BART Alternative achieves greater reasonable progress than BART (*i.e.,* selective catalytic reduction (SCR) technology at the four BART units at Hunter and Huntington). However, we also noted that several other metrics in the State's analyses did not appear to support a conclusion that the BART Alternative achieves greater reasonable progress. The collection of information before EPA at the time of proposal presented a close call for us to decide whether to approve or disapprove the State's BART Alternative. Therefore, to allow all interested parties an opportunity to comment on either approach, we proposed and solicited comment on two possible conclusions and courses of action: (1) The State's submittal for NO_X BART meets the test under 40 CFR 51.308(e)(2)(i)(E) and we approve the BART Alternative; or (2) the State's submittal falls short of meeting this test and we disapprove the BART Alternative and promulgate a FIP for NO_X BART. We requested comment on all aspects of each proposal.

1. Summary of Proposed Full Approval of the SIP

In one option of our co-proposal, we proposed to approve the following aspects of the State's June 4, 2015 SIP submittal:

- NO_X BART Alternative, including: NO_X emission reductions from Hunter Units 1, 2, and 3; Huntington Units 1 and 2; and Carbon Units 1 and 2; and sulfur dioxide (SO_2) and PM_{10} emission reductions from Carbon Units 1 and 2.
- BART determinations and emission limits for PM_{10} at Hunter Units 1 and 2 and Huntington Units 1 and 2.
- Monitoring, recordkeeping, and reporting requirements for units subject to the BART Alternative and the PM_{10} emission limits.

We also proposed to approve these elements of the State's October 20, 2015 SIP submittal:

- Enforceable commitments to revise SIP Section XX.D.3.c and State rule R307–150 by March 2018 to clarify emission inventory requirements for tracking compliance with the SO_2 milestone and properly accounting for the SO_2 emission reductions due to the closure of the Carbon plant.

2. Summary of Proposed Partial Approval and Partial Disapproval of the SIP and Proposal of a FIP

In the other option of our co-proposal, we proposed to approve these elements of the State's June 4, 2015 SIP submittal:

- BART determinations and emission limits for PM_{10} at Hunter Units 1 and 2 and Huntington Units 1 and 2.

[1] Annual average NO_X emissions in tons per year for each of the four BART units for the period 2001–2003 were as follows: Hunter Unit 1 [6,380 tons/yr], Hunter Unit 2 [6,092 tons/yr], Huntington Unit 1 [5,944 tons/yr], Huntington Unit 2 [5,816 tons/yr].

[2] Refer to Tables 6 and 7 for visibility impacts.

[3] 81 FR 2004 (Jan. 14, 2016).

[4] For purposes of comparing the proposed BART Alternative to BART, Utah used most stringent NO_X control technology to represent BART, which is referred to as the BART Benchmark.

[5] 81 FR 2004, 2012–2020 (Jan. 14, 2016).

[6] Additionally, as discussed later in section I.B.3, at this time we not taking action on the State's October 20, 2015 enforceable commitment SIP submittal.

• Monitoring, recordkeeping, and reporting requirements for units subject to the PM_{10} emission limits.

We proposed to disapprove these aspects of the State's June 4, 2015 SIP submittal:

• NO_X BART Alternative, including NO_X emission reductions from Hunter Units 1, 2, and 3; Huntington Units 1 and 2; and Carbon Units 1 and 2; and SO_2 and PM_{10} emission reductions from Carbon Units 1 and 2.

We proposed to disapprove the State's October 20, 2015 SIP submittal.

We proposed promulgation of a FIP to address the deficiencies in the Utah regional haze SIPs that were identified in the proposed action. The proposed FIP included the following elements:

• NO_X BART determinations and emission limits for Hunter Units 1 and 2 and Huntington Units 1 and 2.

• Monitoring, recordkeeping, and reporting requirements for NO_X at Hunter Units 1 and 2, and Huntington Units 1 and 2.

B. Summary of the Basis for Our Final Decision

Based upon comments we received on our proposed action and our evaluation of both the State's submittals and those comments, in this final action we are partially approving and partially disapproving Utah's regional haze SIP submitted on June 4, 2015, and we are taking no action on Utah's regional haze SIP submitted on October 20, 2015. We are promulgating a FIP to address the deficiencies we have identified in the portions of the SIP that we are disapproving. Later we present a summary of the major points of our final decision regarding the Utah regional haze SIP submittal that we are acting on today in which we summarize which parts of the Utah regional haze SIP submittal we are approving and disapproving and which parts are cured by our FIP.

1. NO_X BART

As discussed in depth elsewhere in this document and in our separate Response to Comment (RTC) document, we considered the record before us and comments on both of our co-proposals, and have determined that the evidence does not clearly demonstrate that Utah's BART Alternative makes greater reasonable progress than BART; that is, we have determined that the State's Alternative is not clearly better than BART. Therefore, we are disapproving the BART Alternative contained in Utah's June 4, 2015 submittal and promulgating a FIP to satisfy the regional haze program's NO_X BART requirements.

In our co-proposal, to ensure our final decision was based on the best and most currently available data and information, we asked if interested parties had additional information in a number of areas, including: (1) Analysis related to the modeled visibility benefits of the BART Alternative compared to BART; and (2) other BART alternatives or BART control technology options related to what we proposed and that could be finalized as our FIP. We also asked if interested parties had additional information or comments on the proposed timeline of compliance.[7] We explained that any supplemental information we received could lead us to adopt final SIP and/or FIP regulations that differ somewhat from the co-proposals presented in our proposed rule regarding the BART Alternative, BART control technology option or emission limits, or impact other proposed regulatory provisions.[8] We did not receive any modeling analysis related to the benefits of the BART Alternative compared to BART or any suggestions for consideration of other BART alternatives or BART control technology options. However, we did receive extensive comments on our two possible evaluations of Utah's BART Alternative. As a result of these comments, we have revised some of the aspects of our evaluations of the State's BART Alternative metrics. Based on the revisions to our evaluations of the State's metrics, we have reassessed our co-proposed actions on the State's BART Alternative and determined that it does not demonstrate greater reasonable progress than BART. We provide our reassessment of the State's weight-of-evidence metrics in this section, and provide additional detail in our RTC document.

a. Regulatory Framework for BART Alternatives

To demonstrate that a BART alternative measure achieves greater reasonable progress than the BART requirements, EPA evaluates a SIP submittal to determine whether it demonstrates that the alternative will achieve greater reasonable progress toward natural visibility conditions than BART under 40 CFR 51.308(e)(3) or otherwise based on the *clear* weight of evidence.[9] The BART Alternative rule requires that the alternative program must "clearly" be better than BART, which we have explained is "when there is confidence that the difference in visibility impacts between BART and the alternative scenarios are expected *to be large enough*" [10] to ensure that that the alternative is, in fact, better. Therefore, as part of our evaluation of Utah's SIP we evaluated whether the differences in visibility impacts between BART and the State's BART Alternative are "large enough" to satisfy the *clear* weight-of-evidence requirement. The State of Utah opted to develop its SIP under the clear weight-of-evidence standard, and provided its analysis in the "Greater Reasonable Progress than BART" section of the SIP submittal.[11] As explained in our BART Alternative rule, the clear weight-of-evidence test follows these steps:[12]

(1) *Use information and data that can inform the decision.* Collect information that can be used to assess whether the proposed alternative measure will achieve greater reasonable progress than BART. The information is used to

[7] 81 FR 2004, 2007, Jan. 14, 2016.

[8] *Id.*

[9] 40 CFR 51.308(e)(2)(i)(E).

[10] 71 FR 60622 ("In showing that an alternative program is better than BART and when there is confidence that the difference in visibility impacts between BART and the alternative scenarios are expected *to be large enough,* a weight of evidence comparison may be warranted in making the comparison." (emphasis added)).

[11] This section of the State's SIP submittal presents the BART Alternative rule regulatory requirements, including EPA's description that the clear weight of evidence standard uses information to inform a decision while recognizing the relative strengths and weaknesses of that information. The Utah SIP Section XX that was submitted to EPA, was adopted by the Air Quality Board on June 3, 2015, and included the proposed provisions to address the NO_X BART requirements. Footnote 4 in that Section of the SIP referenced the State's greater reasonable progress demonstration. The document referenced in the footnote was titled "Staff Review 2008 PM BART Determination and Recommended Alternative to BART for NO_X, Utah Division of Air Quality, May 13, 2015" ("Utah Staff Review Report" at 11).

[12] 71 FR 60612, 60622 (Oct. 13, 2006). As we explained in adding to our final RHR the "clear weight of the evidence" standard, "'[w]eight of evidence' demonstrations attempt to make use of all available information and data which can inform a decision while recognizing the relative strengths and weaknesses of that information in arriving at the soundest decision possible. Factors which can be used in a weight of evidence determination in this context may include, but not be limited to, future projected emissions levels under the program as compared to under BART, future projected visibility conditions under the two scenarios, the geographic distribution of sources likely to reduce or increase emissions under the program as compared to BART sources, monitoring data and emissions inventories, and sensitivity analyses of any models used. This array of information and other relevant data may be of sufficient quality to inform the comparison of visibility impacts between BART and the alternative program. In showing that an alternative program is better than BART and when there is confidence that the difference in visibility impacts between BART and the alternative scenarios are expected to be large enough, a weight of evidence comparison may be warranted in making the comparison. The EPA will carefully consider the evidence before us in evaluating any [state implementation plans] submitted by States employing such an approach." *Id.*

evaluate whether the *visibility* improvements at the Class I areas will be better under the alternative than under BART. Such information may include, but is not limited to, future projected emissions levels under the BART alternative as compared to under the BART benchmark; future projected visibility conditions under the two scenarios; the geographic distribution of sources likely to reduce or increase emissions under the program as compared to BART sources; monitoring data and emissions inventories; and sensitivity analyses of any models used.

(2) *Recognize the relative strengths and weaknesses of the information.* Evaluate the information and recognize the relative strengths and weaknesses of the metrics used. This process involves assigning weights to each piece of information that indicate the degree to which it supports a finding that the alternative program will achieve greater visibility benefits. Such a weighing system might find that: (i) The information *clearly* shows the alternative will achieve greater reasonable progress than BART; (ii) the information supports the alternative in some way, but not clearly; or (iii) the information does not support the alternative.

(3) *Carefully consider all the information to reach a conclusion.* Collectively consider the weights assigned to the individual pieces of information and consider the total weight of all the information to determine whether the proposed BART alternative will *clearly* provide for greater reasonable progress than BART at the impacted Class I areas.

Additionally, in this document, we occasionally point to the BART Guidelines for authority on the analysis of BART alternatives (*e.g.,* consideration of 98th percentile CALPUFF modeling).[13] We acknowledge that the BART Guidelines are not mandatory for the evaluation of BART alternatives and the Guidelines do not directly address this subject.[14] However, our rules at 40 CFR 51.309 and the preamble for the provisions governing alternatives to source-specific BART determinations[15] do not provide guidance on visibility modeling. We rely on the BART Guidelines here and in other actions involving BART alternatives because they provide a reasonable and consistent approach regarding visibility modeling, as well as other aspects of a BART alternative, conducted as part of a weight-of-evidence analysis.

b. Utah's "Greater Reasonable Progress Than BART" Metrics

The State collected and evaluated information "from a number of different metrics . . . to compare the two scenarios."[16] These nine metrics included: (1) Annual emissions of visibility-impairing pollutants; (2) improvement in the number of days with significant visibility impairment derived from CALPUFF modeling results; (3) 98th percentile modeling impact (deciview [dv]) results derived from CALPUFF modeling; (4) annual average impact (dv) derived from CALPUFF modeling results; (5) 90th percentile impact (dv) results derived from CALPUFF modeling; (6) timing of emissions reductions; (7) results from IMPROVE monitoring data; (8) energy and non-air quality benefits; and (9) costs. The State considered the information from these metrics and concluded that the weight-of-evidence shows that its alternative program will provide greater reasonable progress than BART.[17]

c. EPA's Evaluation of Utah's "Greater Reasonable Progress Than BART" Analysis

We evaluated the information for each of the nine metrics in the State's SIP submittal,[18] as well as additional information submitted by commenters. As part of this evaluation, we assessed the relevance and strength of each metric, that is, we assigned each metric a weight.[19] After determining if, and the extent to which, the information the State relied upon was "of sufficient quality to inform the comparison of visibility impacts between BART and the alternative program,"[20] we assessed the metrics collectively to determine whether the relevant evidence, considered as a whole, clearly demonstrated that the alternative program achieves greater visibility benefits.

Our initial review considered whether each of the nine metrics met the threshold regulatory requirement that information considered in a weight-of-evidence analysis be relevant to an assessment of visibility impacts. We find the State included two metrics, (1) energy and non-air quality impacts and (2) cost, that are inconsistent with the greater reasonable progress analysis in the RHR because the metrics do not evaluate *visibility* benefits at the nine Class I areas impacted by the State's sources. Therefore, as discussed in detail later in sections I.B.1.c.viii and I.B.1.c.ix, we did not give this information any weight in our evaluation of whether the State has demonstrated that its BART Alternative achieves greater reasonable progress than BART.

Additionally, the State included information on the aggregate annual emissions of all three visibility-impairing pollutants emitted by the sources. However, in this particular instance the aggregate emissions data do not provide information on the likely visibility impacts of the State's alternative program as compared to BART. Therefore, as discussed in detail later in section I.B.1.c.i, we found that this information was inconclusive and does not weigh either in favor of or against the BART Alternative.

Next, we evaluated how the State recognized the strengths and weakness of the remaining six metrics. The State placed each metric in one of two categories: The information from the metric supported the BART Alternative, or it did not. The State determined that five of the metrics supported the BART Alternative[21] and one metric, the 98th percentile CALPUFF modeling results, did not support the BART Alternative.[22] However, contrary to the requirement to *weigh* the evidence,[23] which Utah's SIP acknowledged is part of the weight-of-evidence standard,[24] the SIP submittal did not assess the relative strengths and weaknesses of the metrics; that is, it did not explain the *weight* that the State assigned to each of the metrics it found supported the BART Alternative. In evaluating the SIP submittal, we assessed the relative strengths and weakness of each of the State's metrics to determine whether it was reasonable for the State simply to categorize the metrics into the two categories (the metric supported the BART Alternative or did not support the Alternative). In

[13] We also referred to the BART Guidelines as authority in our proposal.

[14] The BART Guidelines are mandatory in this action regarding both the State's determinations of the BART Benchmark pursuant to 40 CFR 51.308(e)(2)(i)(C) and EPA's BART determinations in the FIP pursuant to 40 CFR 51.308(e)(1)(ii)(B).

[15] 71 FR 60612, October 13, 2006.

[16] Utah Staff Review Report at 12.

[17] *Id.* at 27 and Utah's SIP, Section XX, Regional Haze (June 3, 2015) ("2015 SIP").

[18] Utah Staff Review Report at pp. 13–29.

[19] As discussed in this section, Utah did not assign a weight to each metric.

[20] 71 FR 60612, 60622.

[21] See Utah Staff Review Report at p. 27 (listing factors the State suggested to support the BART Alternative in the "Summary of Weight of Evidence" section).

[22] As discussed elsewhere, EPA disagrees with the State's evaluation of the 98th percentile metric.

[23] 40 CFR 51.308(e)(2)(i)(E).

[24] Utah Staff Review Report at 11 (the BART alternative regulatory provisions and EPA's description of the weight-of-evidence standard, including that a demonstration recognize the strengths and weaknesses of the information in arriving at the soundest decision possible, citing 71 FR 60612, 60622).

addition to information in the submittal, we considered suggestions on the amount of ''weight'' that should be given to each of the metrics that were provided by commenters on our proposal, including the State.[25] As a result of our evaluation, we find that the State's assessment of the metrics was inadequate because it did not recognize the relative strengths and weaknesses of the metrics on an individual basis. We also find that a proper recognition of the relative strengths and weaknesses, including the consideration that some metrics are more meaningful than others, shows that the BART Alternative does not achieve greater reasonable progress than BART.

We evaluated each of the State's nine metrics and included: (1) An assessment of whether we agree as a factual matter with the State's conclusion; and (2) the weight we would give to each metric. Our evaluation below includes the two metrics that we find contain information that is not relevant, and the one to which we did not assign any weight.

i. Annual Emissions Comparison of All Visibility-Impairing Pollutants

The State's regional haze SIP submittal determined that the combined emissions of three key visibility-impairing pollutants will be lower under the BART Alternative scenario and that this supported the weight-of-evidence determination that the BART Alternative will provide greater reasonable progress than BART.[26] [27] We proposed to find that, since Utah's BART Alternative provides greater emission reductions for two pollutants (SO_2 and PM_{10}), but that NOX emissions would be greater under the BART Alternative, it is not appropriate to combine all three pollutants in the annual emissions comparison test to support the BART Alternative. Therefore, we further proposed to find that the annual emissions comparison of all three pollutants does not show that the BART Alternative is better than the BART Benchmark.[28]

As a result of the comments received on our co-proposal, we have further assessed the State's evidence for this metric and while we have clarified our assessment, we have not changed our overall proposed findings. Although emissions of two visibility-impairing pollutants are less under the BART Alternative, emissions of one of the pollutants would be greater. Due to differences in visibility impacts and complex interactions between pollutants, it is not possible to discern the overall visibility impacts of the aggregate emission reductions in this case without modeling; as discussed elsewhere, we disagree with comments to the contrary. Therefore, while we consider that aggregate emission reductions is a relevant concept because it relates to visibility impacts, in this particular case we continue to find that it is not appropriate to combine all three pollutants in the annual emission comparison test. We thus find that this metric is inconclusive and does not weigh either in favor of or against the BART Alternative.

ii. Improvement in Number of Days With Significant Visibility Impairment

In its regional haze SIP submittal, Utah provided modeling results comparing the number of days with significant visibility *impairment* relative to natural visibility under the BART Alternative scenario to the number of days under the BART Benchmark. The State presented this information for two different thresholds of visibility impairment: 1.0 dv of impairment compared to natural visibility, and 0.5 dv of impairment. The State determined that the BART Alternative leads to an average of six fewer days per year with a visibility impact greater than 1.0 dv per year and 58 fewer days per year with a visibility impact greater than 0.5 dv at the nine Class I areas.[29] Utah also provided information in its submittal regarding the number of days with visibility *improvement* relative to baseline visibility (visibility conditions in 2001–2003) using a range of deciview thresholds (0.5 to 5.0 dv improvement compared to baseline visibility conditions).[30]

In EPA's review, we considered this metric in our evaluation of the State's weight-of-evidence analysis because the improvement in the number of days with significant visibility impairment relates to assessing the frequency and duration of visibility impacts. It is relevant to look at the results for the Class I areas individually because visibility impacts are location specific. The results for the average number of days with impacts over 1.0 dv show that seven of the nine Class I areas had the same result or were within one day of having the same result under both the BART Alternative and Benchmark. In the context of an entire year, a difference of one day is not particularly significant. Therefore, we find that the results from the average number of days with visibility impacts over the 1.0 dv threshold do not show the BART Alternative is better. We observe that the results for the average number of days with impacts over 0.5 dv show that the BART Alternative is better at five of nine Class I areas, and at four Class I areas the Alternative results in the same number of days with impacts greater than 0.5 dv as the Benchmark or is within two days of the same result (favoring the BART Alternative at each of the four where there is a two-day difference). Therefore, we find that the results from the 0.5 dv threshold show that the BART Alternative is marginally better.

iii. 98th Percentile Modeling Impact (dv)

In its regional haze SIP, the State determined that while the 98th percentile modeling impact showed greater reasonable progress under the BART Benchmark,[31] several considerations led to the State's conclusion that this metric does not give a complete picture of the visibility improvements that will be seen by visitors to Class I areas.[32] Therefore, the State's summary of the weight-of-evidence did not include the results from the 98th percentile modeling impact.[33] We assessed the State's evidence for this metric and proposed to find that on the whole, when using this method, the results from the BART Benchmark are slightly better on average across all years and nine Class I areas

[25] The State's Comment letter suggested the ''weight'' for several of the metrics.

[26] 2015 SIP at 25, and Utah Staff Review Report at 27.

[27] EPA derived the following emissions reductions for the BART Alternative from the Utah Staff Review Report at 10, by subtracting the total annual emissions for the BART Alternative from the total annual emissions for the BART Benchmark for each of the visibility-pairing pollutants: SO_2 8,005 tpy, PM_{10} 573 tpy, and NO_X ¥5,721 tpy (NO_X is negative because NO_X emissions increase under the BART Alternative). This information is also provided in Table 4 of our proposed rule. (81 FR 2004, 2016.)

[28] 81 FR 2004, 2029.

[29] EPA unintentionally created some confusion with regard to this metric in our proposed rule by expressing this information as the *total* number of days with visibility impairment greater than 1.0 and 0.5 dv in Tables 7 and 8, 81 FR 2004, 2017, based on modeling results presented in SIP TSD Ch. 6, Summary of Visibility Modeling. The State did not highlight these particular modeling results in this manner in its Utah Staff Review Report; rather, the State expressed this metric only as the average number of days per year over the three years modeled. We considered these modeling results, and as discussed in our RTC document, find that the results marginally support the Alternative.

[30] See Utah Staff Review Report, pp. 19–22, and Ch. 6, Summary of Visibility Modeling, and 2015 SIP at 25.

[31] Utah Staff Review Report at 24.

[32] *Id.* at 25.

[33] *See id.* at 27 (''Summary of Weight of Evidence'' section does not include 98th percentile modeling impact results).

(0.14 dv average difference). Also, this metric shows greater visibility improvement at five of nine Class I areas for the BART Benchmark. We proposed to find, consistent with the State's evaluation, that this metric favors the BART Benchmark and does not show that the BART Alternative is better.[34]

As a result of the comments received on our co-proposal, we have further assessed the State's evidence for this metric and while we have clarified our assessment, we have not changed our overall proposed finding. We considered this metric in our evaluation of the State's weight-of-evidence analysis because the 98th percentile modeling results relate to assessing visibility impacts. We have considered all information, and consistent with the Agency's approach to assessing visibility benefits in both BART determinations and other determinations of ''greater reasonable progress'' using the CALPUFF model, have given most weight to the visibility impacts based on the 98th percentile air quality modeling results.[35]

iv. Annual Average Modeling Impact (dv)

The State's regional haze SIP submittal stated that the average deciview impact metric shows the benefit from the BART Alternative will be achieved day in and day out in the Class I areas.[36] This metric shows greater average visibility improvement at five of nine Class I areas for the BART Alternative.

We assessed the State's evidence for this metric and proposed to find that the BART Alternative is only marginally better than the BART Benchmark based on the difference in overall averages between the two scenarios of 0.009 dv and that it shows less or equal visibility improvement than BART at four of the nine Class I areas. Therefore, we proposed to find that the information from the annual average metric does not support a conclusion that the BART Alternative achieves greater reasonable progress than the BART Benchmark.[37]

As a result of the comments received on our co-proposal, we have further assessed the State's evidence for this metric and we have clarified our assessment and finding about the State's evaluation. We considered this metric in our evaluation of the State's weight-of-evidence analysis because the annual average modeling results relate to assessing visibility impacts. Importantly, we find that the annual average metric is less relevant than the 98th percentile because it does not provide information on visibility benefits on the days most impacted by the sources, which has been the focus of prior BART determinations[38] and other determinations of ''greater reasonable progress'' that relied on CALPUFF modeling.[39] Averaging the modeling results over an entire year dilutes the emission controls' (and BART Alternative emission reductions) potential visibility benefits and is inconsistent with the basis of the CALPUFF modeling approach used by the State. Additionally, the annual average visibility impact metric does not show greater visibility improvements than the Alternative at four of the nine affected Class I areas, and the average difference between BART and the Alternative across all nine of these areas is relatively small (0.009 dv). For these reasons, we find that the annual average impact metric in Utah's weight-of-evidence analysis only marginally supports the BART Alternative.

v. 90th Percentile Modeling Impact (dv)

The State's regional haze SIP submittal determined that the CALPUFF modeling results from the 90th percentile deciview impact show that the BART Alternative will provide greater improvement.[40] We assessed the State's evidence for this metric and proposed to find that although there was greater visibility improvement at seven of nine Class I areas for the BART Alternative, it was questionable if the BART Alternative was better based on the difference in the two scenarios of 0.006 dv. We therefore proposed to find that it is questionable whether the 90th percentile supports a conclusion that the BART Alternative achieves greater reasonable progress.[41]

As the result of the comments received on our co-proposal, we have further assessed the State's evidence for this metric and have clarified our assessment and finding. EPA has never used the CALPUFF 90th percentile results in other RH decisions, and we disapproved the use of the 90th percentile results for subject-to-BART modeling.[42] Here, though, we find it is appropriate to consider the CALPUFF 90th percentile results in evaluating the State's weight-of-evidence analysis because this metric provides some additional information about visibility benefits. However, we note that the 90th percentile metric excludes more than a month's worth of visibility data, which significantly dilutes the overall visibility results achieved from potential control options, and is therefore less relevant than the 98th percentile. Furthermore, while the 98th percentile day reflects visibility benefits on the days on which the sources have the largest impacts, the State has not indicated that the 90th percentile day has any particular significance other than to provide an additional metric to consider. We also acknowledge that the difference between BART and the BART Alternative using the 90th percentile is relatively small (0.006 dv). Additionally, we disagree with commenters that suggested the 90th percentile metric is similar to the 20% worst day metric; the 90th percentile relates to a single value, the 110th highest impact day across three years for the scenario considered (*i.e.*, BART Alternative or BART Benchmark), whereas the 20% worst days metric describes visibility impacts from all sources on the average of the 20% worst visibility days. Therefore, while we considered the results from the 90th percentile to evaluate the State's weight-of-evidence analysis, we placed a very small amount of weight on this metric, and therefore find that this metric only marginally supports the BART Alternative.

vi. Timing of the Emissions Reductions

The State's regional haze SIP submittal included statements in the greater reasonable progress than BART analysis that the NO_X reductions from Huntington Units 1 and 2 and Hunter

[34] 81 FR 2004, 2030.

[35] *See* 81 FR 2004, 2021; 40 CFR part 51, appendix Y, section IV.D.5; 70 FR 39104, 39129 (July 6, 2005). *See, e.g.,* 78 FR 79344 (Dec. 30, 2012) (proposed rule, FIP for Tesoro Refining and Intalco Refinery BART Alternatives); 79 FR 33438 (June 11, 2014) (final rule, FIP for Tesoro Refining and Intalco Refinery BART Alternatives); 79 FR 56322, 56328 (Sept. 19, 2014) (proposed approval of Arizona Apache BART Alternative); 80 FR 19220 (Apr. 10, 2015) (final approval of Arizona Apache BART Alternative). We provide examples of use of the 98th modeling results for BART determinations in the RTC.

[36] Utah Staff Review Report at 23.

[37] 81 FR 2004, 2030.

[38] 40 CFR part 51, appendix Y, section IV.D.5; 70 FR 39104, 39129 (July 6, 2005). We provide examples of use of this information for BART determinations in the RTC.

[39] See, *e.g.,* 78 FR 79344, 79355 (Dec. 30, 2013) (proposed rule, FIP for Tesoro Refining and Intalco Refinery BART Alternatives in Washington), 79 FR 56322, 56328 (Sept. 19, 2014) (proposed approval of Arizona Apache BART Alternative).

[40] Utah Staff Review Report at 23–24, and 2015 SIP at 25.

[41] 81 FR 2004, 2030.

[42] In our North Dakota final action we explained that EPA addressed the appropriate interpretation of CALPUFF modeling results in the BART Guidelines within the context of subject-to-BART modeling and we rejected the use of the 90th percentile because it would be inconsistent with the Act. We explained that the use of the 90th percentile value would effectively allow visibility effects that are predicted to occur at the level of the threshold (or higher) on 36 or 37 days a year. 70 FR 39121.

Units 2 and 3 occurred earlier than was required by the rule, providing corresponding early and ongoing visibility improvement under the Alternative as compared to the BART Benchmark, citing to *WildEarth Guardians* v. *EPA*. 770 F.3d 919, 938 (10th Cir. 2014).[43]

The State further asserted that the timing of emission reductions provided support for the weight-of-evidence determination that the BART Alternative will provide greater reasonable progress than BART. We assessed the State's evidence for this metric and recognized that the reductions from the BART Alternative would occur before the BART Benchmark because the controls at the Hunter and Huntington facilities have been achieving significant NO_X reductions since the time of their installation between 2006 and 2014.[44]

As a result of the comments received on our co-proposal, we have further assessed the State's evidence for this metric. We considered the State's early emission reduction statement in our evaluation of the State's weight-of-evidence analysis because the reductions relate to assessing visibility impacts. We note that the State's weight-of-evidence analysis presents and considers only the early timing of emission reductions from the Hunter and Huntington units at which controls were installed before 2014.[45]

We find that the timing of emissions reductions metric, which considers the early reductions from Hunter Units 2 and 3 and Huntington Units 1 and 2, supports a finding that the BART Alternative is better than BART.

vii. Monitoring Data at the Class I Areas (IMPROVE Network)

The State's regional haze SIP submittal determined that the BART Alternative provides greater reductions of SO_2[46] and that SO_2 is the most significant anthropogenic pollutant affecting Class I Areas that impacts visibility year-round, including throughout the high visitation seasons at the National Parks in spring, summer, and fall.[47] The State thus concluded, working from assumptions regarding sulfate and nitrate formation based on historical trend data,[48] that the BART Alternative will provide greater reasonable progress than BART.

We assessed the State's evidence for this metric and proposed to concur with one of the State's findings. We proposed to find that visibility benefits associated with NO_X reductions are much more likely to occur in the winter months because this is when aerosol thermodynamics favors nitrate formation, while SO_2 emissions reductions should provide visibility benefits in all seasons. We also proposed to find that, as concluded by the Grand Canyon Visibility Transport Commission (GCVTC), and supported by the IMPROVE monitoring data presented by Utah, anthropogenic visibility impairment on the Colorado Plateau is dominated by sulfates. Therefore, we proposed to concur with Utah's statement that sulfate is the largest contributor to visibility impairment at the affected Class I areas.

We proposed to disagree with the State's findings related to park visitation. While we explained that the BART Guidelines do mention visitation as something that can inform a control decision, EPA proposed to place little weight on the State's correlation of emissions reductions and park visitation because nothing in the CAA suggests that visitors during busy time periods are entitled to experience better visibility than visitors during off-peak periods.

As the result of the comments received on our co-proposal, we have further assessed the State's evidence for this metric and while we have clarified our assessment, our overall findings remain the same. We considered this metric in our evaluation of the State's weight-of-evidence analysis because the monitoring data relate to assessing visibility impacts. We conducted an analysis of 2013 and 2014 IMPROVE monitoring data for Canyonlands, the most impacted Class I area,[49] considering seasonal averages and the 20% best and worst days.[50] Our analysis confirms that sulfate is a large contributor to light extinction year round and that nitrate contributions are highest in the winter season. Nonetheless, overall nitrate extinction at the affected areas is significant, particularly on the 20% worst days. We have taken the strength of the modeling results for winter months into consideration; however, contrary to the State's and other's suggestions that visibility improvements during seasons of peak Class I area visitation should carry more weight, we evaluate the visibility impacts for an entire year, regardless of the season. Therefore, we decided to place little weight on this metric and find that the monitoring data analysis metric in Utah's weight-of-evidence analysis only marginally shows the BART Alternative is better than the BART Benchmark.

viii. Energy and Non-Air Quality Benefits

The State's regional haze SIP submittal indicated in its weight-of-evidence assessment that the BART Alternative would avoid the energy penalty associated with operating the SCR units, *i.e.*, the controls assumed under the BART Benchmark. The State also cited non-air quality benefits of its Alternative, including lower fly ash production and reduced water usage associated with the shutdown of Carbon. However, the State's "Summary of the Weight of Evidence," which presented a summary and short evaluation of each of the metrics, did not reference this assessment.[51]

We assessed the State's evidence for this metric and proposed to find that because the benefits do not have direct bearing on whether the BART Alternative achieves greater reasonable progress, it is not material to our action whether we agree or disagree with Utah's assessment that the Alternative would reduce energy and non-air quality impacts relative to BART.

As a result of the comments received on our co-proposal, we have further assessed the State's evidence for this metric; however, we have decided not to alter our proposed finding. The purpose of a weight-of-evidence analysis is to determine whether a BART Alternative would achieve greater reasonable progress, which is measured in terms of visibility improvement.[52] Thus, only metrics that are indicative of improvements in visibility are relevant in a weight-of-evidence analysis. Energy

[43] Utah Staff Review Report at 11, 27 ("The NO_X reductions at Huntington 1 and 2 and Hunter 2 and 3 occurred between 2006 and 2011, earlier than was required by the rule, providing an early and on-going visibility improvement" and offering in footnote 14 that "[the] U.S. Circuit Court of Appeals for the 10th Circuit explicitly acknowledged that the consideration of early reductions was proper as part of a qualitative or clear weight of evidence approach to determining greater reasonable progress." (citing *WildEarth Guardians* v. *EPA*, 770 F.3d 919, 938 (10th Cir. 2014)). EPA agrees that it is appropriate to consider the timing of emission reductions for the Utah BART Alternative.

[44] 81 FR 2004, 2030.

[45] Utah Staff Review Report at 11.

[46] *Id.* at 27.

[47] *Id.* at 27.

[48] *Id.* at 12–19.

[49] Canyonlands was the most impacted Class I area in the State's BART Alternative modeling that assessed the visibility impacts from all three power plants (*i.e.*, Hunter, Huntington, and Carbon), as well as most impacted in EPA's modeling assessing the visibility impacts for the BART Benchmark for Hunter and Huntington.

[50] See spreadsheet entitled, EPA Analysis of 2013 and 2014 IMPROVE Monitoring Data for Canyonlands, in the docket. More detailed information regarding this analysis is available in section II.E of this document and in our RTC document.

[51] Utah Staff Review Report at 27.

[52] 40 CFR 51.308(d)(1), (e)(2)(i)(E).

and non-air quality impacts do not provide relevant information on the relative visibility benefit of a BART Alternative as compared to BART. We, therefore, did not assign this metric any weight in our evaluation of the State's weight-of-evidence conclusion.

ix. Cost

The State's regional haze SIP indicated in its weight-of-evidence assessment that, although the State had not officially determined the cost of BART, it is clear that the BART Alternative would have significant capital cost savings to PacifiCorp and its customers. The submittal noted that the Carbon Plant has already been closed and the cost to ratepayers of replacing the power generated by that facility have already occurred. However, the State's ''Summary of the Weight of Evidence,'' which presented a summary and short evaluation of each of the metrics, did not reference the cost comparison.[53]

We assessed the State's evidence for this metric and proposed to find that because the described cost difference does not have a direct bearing on whether the BART Alternative achieves greater reasonable progress, it is not material to our action whether we agree or disagree with Utah's conclusion that the BART Alternative would have a lower cost impact to PacifiCorp than the BART Benchmark (*i.e.*, costs provided by PacifiCorp in its BART analyses of August 5, 2014, SIP TSD Chapter 2).

As a result of the comments received on our co-proposal, we have further assessed the State's evidence for this metric; however, we have decided not to alter our proposed finding. The purpose of a weight-of-evidence analysis is to determine whether a BART Alternative would achieve greater reasonable progress, which is measured in terms of visibility improvement.[54] The difference in the capital costs between BART and the BART Alternative does not provide information relevant to the scenarios' relative visibility benefits.[55] We therefore did not assign this metric any weight in our evaluation of the State's weight-of-evidence conclusion.

x. EPA's Evaluation of the State's Conclusions

The State's regional haze SIP submittal suggested that eight of the nine metrics considered by Utah support the BART Alternative, finding that one metric, the 98th percentile CALPUFF modeling metric did not support its BART Alternative. As explained earlier in this section, evidence in the SIP and from commenters demonstrates that four of these metrics have documented weaknesses and only marginally support the BART Alternative: Improvement in the number of days with significant visibility impairment predicted by modeling (analyzed using different thresholds); the annual average visibility impacts predicted by modeling; monitoring data trends collected at the Class I areas; and the 90th percentile impacts predicted by modeling. Additionally, while the timing of emission reductions metric does favor the State's BART Alternative, the emission reductions at issue are only a portion of the overall emission reductions claimed under the Alternative. The timing of these emission reductions does not alter our conclusion that, on balance, the Alternative has not been shown to result in greater visibility benefits than would BART. Finally, we did not assign any weight to three metrics in our evaluation of the State's weight-of-evidence analysis because we determined that the metrics for energy and non-air quality and cost considerations are not related to visibility and have no bearing on whether the BART Alternative achieves greater reasonable progress than the BART Benchmark, and that information from the annual emissions comparison of all visibility-impairing pollutants metric was inconclusive.

When we weighed the State's metrics (excluding the energy and non-air quality and cost metrics) that evaluate visibility collectively, considering the strengths and weaknesses of each metric and the magnitude of the differences in visibility benefit between BART and the Alternative, we find that it was not reasonable for the State to determine that the clear weight of the evidence favors the BART Alternative for the following reasons. We find that the State's characterization of the 98th percentile modeling results, the one metric that did not support its BART Alternative, was contrary to EPA's established interpretation of and reliance on that metric. The 98th percentile CALPUFF modeling metric takes into account peak visibility impacts and carries the most weight. The 98th percentile visibility impact is a key metric recommended by the BART Guidelines and EPA has relied on this metric in evaluating prior regional haze actions that have included BART alternatives.[56] Furthermore, two factors which marginally support the BART Alternative (annual average modeled impact and 90th percentile modeled impact) are given little weight because they are considered to be less relevant metrics and show very small differences between the BART Alternative and the BART Benchmark, while another factor which marginally supports the BART Alternative (results from IMPROVE monitoring data) is also given little weight because of the need to consider visibility impacts during all times of the year, not just during peak visitation periods. Another factor which marginally supports the BART Alternative (improvement in number of days with significant visibility impairment) is given little weight because even though the BART Alternative is favored using a 0.5 dv threshold, the 1.0 dv threshold does not show that the BART Alternative is better. In addition, although a portion of the emission reductions under the Alternative were achieved prior to 2014, this does not diminish our fundamental finding that the quantity of reductions available under the Alternative would not result in greater visibility improvements than the emission reductions under BART. Therefore, the visibility metrics that favor the BART Alternative neither individually nor collectively clearly demonstrate that the BART Alternative will achieve greater reasonable progress at the nine Class I areas when weighed against visibility benefits predicted by the 98th percentile modeling results under BART.

In summary, we have relied on the standards contained in the RHR and the authority that Congress granted us to review SIPs to determine whether the State's SIP submittal complies with the minimum statutory and regulatory requirements. In determining SIP adequacy, we must exercise our judgment and expertise regarding complex technical issues, and it is entirely appropriate that we do so. Courts have recognized this necessity and deferred to our exercise of

[53] Utah Staff Review Report at 27.

[54] 40 CFR 51.308(d)(1), (e)(2)(i)(E).

[55] We also note that, consistent with our statements in the BART Guidelines, the capital cost of controls would not be a relevant consideration because it does not take into account the degree of visibility improvement associated with those controls. 40 CFR part 51, appendix Y, section IV.D.4.g. Therefore, even if we did consider cost as relevant in a weight-of-evidence analysis, which we do not, the capital cost of controls would not be the appropriate metric.

[56] *See, e.g.*, 78 FR 79344 (Dec. 30, 2012) (proposed rule, FIP for Tesoro Refining and Intalco Refinery BART Alternatives); 79 FR 33438 (June 11, 2014) (final rule, FIP for Tesoro Refining and Intalco Refinery BART Alternatives); 79 FR 56322, 56328 (Sept. 19, 2014) (proposed approval of Arizona Apache BART Alternative); 80 FR 19220 (Apr. 10, 2015) (final approval of Arizona Apache BART Alternative).

discretion when reviewing SIPs.[57] We thus review a state's SIP submittal with the understanding that the state's discretion in developing an alternative measure "is subject to the condition that it must be reasonably exercised and that its decision is supported by adequate documents of its analysis."[58] In the present circumstance—as discussed in more detail in the proposed action and this final action—EPA was not able to find that the weight-of-evidence analysis satisfied the relevant regulatory requirements. Specifically, we find:

(1) The State's assessment of the metrics it found to support its BART Alternative was inadequate because it did not evaluate the relative strengths and weaknesses of the visibility metrics on an individual basis;

(2) The State did not consider the 98th percentile CALPUFF modeling metric, which did not support its BART Alternative, in a manner consistent with EPA's established interpretation of and reliance on that metric;

(3) The State's assessment of the metric that considered aggregate annual emissions of visibility-impairing pollutants was contrary to EPA's established interpretation of and reliance on that metric;

(4) The State's assessment relied on two metrics that are not consistent with the "greater reasonable progress" analysis because they are not related to visibility (energy and non-air quality and cost considerations);

(5) The State did not satisfy the requirement that it assess the collective weight of its evidence in a reasonable and adequately supported manner; and

(6) The SIP submittal lacked an explanation of why the information from all the metrics demonstrated that the difference in visibility impacts between BART and the Alternative was large enough to "clearly" demonstrate that the BART Alternative would achieve greater reasonable progress than BART.[59]

Based on this evaluation, we find that, on balance, the evidence does not show that the Alternative clearly achieves greater visibility benefits than BART. Thus, the State has not satisfied the regulatory requirement in 40 CFR 51.308(e)(2) that a state's submittal of a BART alternative include a "determination . . . based on the clear weight of evidence that the . . . alternative measure achieve greater reasonable progress than would be achieved through the installation and operation of BART at the covered sources." Therefore, we are disapproving the State's NO_X BART Alternative contained in its June 4, 2015 SIP submittal, including the NO_X emission limits for Hunter Units 1, 2, and 3; and the NO_X emission limits for Huntington Units 1 and 2; and the requirements for permanent closure of Carbon Units 1 and 2.[60]

d. Remaining BART Alternative Criteria

The RHR establishes a number of additional regulatory criteria to be included in any demonstration that an alternative will provide for greater reasonable progress than BART. These criteria are set out at 40 CFR 51.308(e)(2)(i)(A)–(D) and (e)(2)(iii)–(v). In both co-proposals, we proposed to find that Utah's SIP submittal addressing the BART Alternative met these requirements.[61] We received adverse and supportive comments on our proposed finding that the State had met these remaining requirements. We respond to these comments in our RTC document.

Having carefully considered the comments received, we have concluded that the State's SIP submittal generally met most of these requirements, as explained in our RTC document. As a result, our partial disapproval of the State's SIP submittal is based on our assessment that Utah failed to demonstrate based on the weight of evidence that the BART Alternative would provide for greater reasonable progress and not on any deficiencies in the state's demonstration that it had met the additional regulatory criteria in 40 CFR 51.308(e)(2).

e. Monitoring, Recordkeeping and Reporting for Utah's BART Alternative

Section IV.B.3 of Utah's June 2015 regional haze SIP included enforceable measures and monitoring, recordkeeping and reporting requirements for the Utah BART Alternative and the State's PM_{10} BART determinations. In our co-proposal we proposed to disapprove (in other words, to not make federally enforceable as part of the SIP) the monitoring, recordkeeping and reporting requirements located in SIP Sections IX.H.22 associated with the BART Alternative. This includes SIP Section IX.H.22, subsections a.ii, a.iii, b.ii, and c.i.[62]

While we did not receive any comments on this element of Utah's regional haze SIP submittal in our co-proposal, the monitoring, recordkeeping, and reporting provisions in the submittal are linked directly to the emission limitations under the Alternative, which we are disapproving.[63] Our partial disapproval of the State's SIP submittal is based on our assessment that Utah failed to demonstrate based on the weight of evidence that the BART Alternative would provide for greater reasonable progress and not on any deficiencies in the State's demonstration that it had met the monitoring, recordkeeping, and reporting requirements under the RHR.

f. Basis for Our NO_X BART Determinations and FIP

Based upon comments we received on our proposed FIP, we revised our analysis of the cost of installing and operating NO_X BART controls at the four subject-to-BART EGUs. In particular, and as discussed at length in our RTC document, we revised the costs in response to comments from PacifiCorp that we incorrectly re-designed the SCR reactors. Having carefully considered the comments received, we concluded it was unnecessary to revise our analysis of visibility improvement or the other statutory BART factors. Our proposed action contains a full description of the five step BART analysis, the five BART factors, and our proposed BART determination. Because we have revised

[57] See, e.g., Connecticut Fund for the *Env't., Inc.* v. *EPA*, 696 F.2d 169 (2d Cir. 1982); *Michigan Dep't. of Envtl. Quality* v. *Browner*, 230 F.3d 181 (6th Cir. 2000); *Montana Sulphur & Chem. Co.* v. *EPA*, 2012 U.S. App. LEXIS 1056 (9th Cir. Jan. 19, 2012).

[58] 71 FR 60612, 60621 (Oct. 13, 2006).

[59] The State's assessment of the overall weight of evidence states only that "[t]he weight of evidence shows that the alternative will provide greater reasonable progress than BART." Utah Staff Review Report at 27.

[60] We are disapproving SIP Sections IX.H.21, subsection (c), IX.H.22, subsections:.a.iii–iii., b.ii. and c. We are also disapproving SIP Section XX,D subsections: 6.a. (the provisions in the "Regional Haze Rule BART Requirements" that cover the NO_X alternative measure); 6.c. ("BART for NO_X, " including footnote 4 that references the State's Analysis in a separate document); 6.d. (the provisions in the "BART Summary" that cover NO_X and SO_2 emissions, including the references to use of approval orders and permitted limits to establish the emission limits, the statement that "the four EGUs also met the presumptive emission rates for both NO_X and SO_2 established in Appendix Y independently of the alternative programs", and references in Table 5 to "Permitted" (and the NO_X and SO_2 limits in that column), "Hunter 3", all provisions in the "Presumptive BART Rates" column NO_X and SO_2 emissions); 6.e. (the provisions in "Schedule for Installation of Controls" as the dates refer to emissions for sources that are in the proposed BART Alternative; and the discussion immediately following Table 6 that presents information about the emission limits also appearing in State-issued permits). Additional discussion appears in our RTC document.

[61] 81 FR at 2021, 2025–26, 2027–28, 2032

[62] As explained later, our co-proposal proposed to approve or conditionally approve the remainder of the monitoring, recordkeeping and reporting requirements associated with Utah's PM_{10} BART determinations.

[63] However, we note that we are proposing conditional approval of the following regulations in Section IX.H.21(e), as discussed in section I.B.2.

our cost analysis, we provide updated tables containing the results of the cost analyses, including the summary tables that also show the visibility improvements associated with the controls under consideration (which we did not revise). Following these tables, we provide our final BART determination. Because the Hunter and Huntington BART units are similar, our reasoning for the final BART determination applies to all four units. Table 1 shows the NO_X BART control technologies, associated cost, emission reductions, and the BART emission limitation for each source that is subject to the FIP. The costs in Table 1 reflect EPA's revised cost analysis. Please note that the cost-effectiveness values for SCR with low-NO_X burners and separated overfire air (SCR + LNB/SOFA) were computed using an assumed emission rate of 0.05 lb/MMBtu on an annual basis, but for compliance purposes the NO_X emission limit for each unit is 0.07 lb/MMBtu, 30-day rolling average.

TABLE 1—EMISSION LIMITS, COSTS, AND COST EFFECTIVENESS FOR LNBS/SOFA WITH SCR FOR THE SOURCES SUBJECT TO THE FIP

Source	Technology*	NO_X Emission limit—lb/MMBtu (30-day rolling average)	Total capital cost ($)	Total annualized cost ($)	Average cost-effectiveness ($/ton)
Hunter Unit 1	SCR + LNB/SOFA	0.07	$130.6M	$14.8M	$2,697
Hunter Unit 2	SCR + LNB/SOFA	0.07	128.5M	14.5M	2,774
Huntington Unit 1	SCR + LNB/SOFA	0.07	128.3M	14.6M	2,871
Huntington Unit 2	SCR + LNB/SOFA	0.07	130.0M	14.7M	2,928

*The technology listed is the technology evaluated as BART, but sources can choose to use another technology or combination of technologies to meet established limits.

Tables 2 and 3 provide summaries of EPA's NO_X BART analysis of all feasible control options for Hunter Units 1 and 2, including the costs of compliance and visibility impacts. Please refer to our discussion in section I.B.1.f in regard to how we selected BART from among these control options.

TABLE 2—SUMMARY OF EPA'S HUNTER UNIT 1 NO_X BART IMPACTS ANALYSIS

Control option	Annual emission rate (lb/MMBtu)	Emission reduction (tpy)	Total annual costs (million$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts*		
						Improvement (dv)	Days > 0.5 dv	Days > 1.0 dv
LNB with SOFA	0.21	3,042	$1.2M	$382		0.846	330 (29)	218 (22)
LNB with SOFA and SNCR	0.16	3,735	3.8M	1,016	3,796	1.041	322 (37)	202 (38)
LNB with SOFA and SCR	0.05	5,500	14.8M	2,697	6,255 (compared to LNB with SOFA and SNCR) 5,561 (compared to LNB with SOFA).	1.545	311 (48)	188 (52)

*At the most impacted Class I area, Canyonlands National Park. The improvement in days over 0.5 and 1.0 dv provided by the control option relative to the baseline is presented in parentheses. See Table H.9. Air Quality Modeling Protocol: Utah Regional Haze Federal Implementation Plan, US EPA Region 8 (Nov. 2015); Docket Id. EPA–R08–OAR–2015–0463–0012.

TABLE 3—SUMMARY OF EPA'S HUNTER UNIT 2 NO_X BART IMPACTS ANALYSIS

Control option	Annual emission rate (lb/MMBtu)	Emission reduction (tpy)	Total annual costs (million$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts*		
						Improvement (dv)	Days > 0.5 dv	Days > 1.0 dv
LNB with SOFA	0.20	2,902	$0.9M	$298		0.658	336 (23)	221 (19)
LNB with SOFA and SNCR	0.16	3,562	3.5M	968	3,913	0.822	331 (28)	218 (22)
LNB with SOFA and SCR	0.05	5,230	14.5M	2,774	6,632 (compared to LNB with SOFA and SNCR) 5,861 (compared to LNB with SOFA).	1.250	317 (42)	198 (42)

*At the most impacted Class I area, Canyonlands National Park. The improvement in days over 0.5 and 1.0 dv provided by the control option relative to the baseline is presented in parentheses. See Table H.10. Air Quality Modeling Protocol: Utah Regional Haze Federal Implementation Plan, US EPA Region 8 (Nov. 2015); Docket Id. EPA–R08–OAR–2015–0463–0012.

Tables 4 and 5 provide summaries of EPA's NO_X BART analysis of all feasible control options for Huntington Units 1 and 2, including the costs of compliance and visibility impacts.

TABLE 4—SUMMARY OF EPA'S HUNTINGTON UNIT 1 NO_X BART IMPACTS ANALYSIS

Control option	Annual emission rate (lb/MMBtu)	Emission reduction (tpy)	Total annual costs (million$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts*		
						Improvement (dv)	Days > 0.5 dv	Days > 1.0 dv
LNB with SOFA	0.22	2,440	$0.8M	$332		0.851	249 (28)	153 (22)
LNB with SOFA and SNCR	0.17	3,185	3.5M	1098	3,609	1.113	244 (33)	143 (32)
LNB with SOFA and SCR	0.05	5,092	14.6M	2,871	5,830 (compared to LNB with SOFA and SNCR) 5,206 (compared to LNB with SOFA).	1.881	210 (67)	117 (58)

*At the most impacted Class I area, Canyonlands National Park. The improvement in days over 0.5 and 1.0 dv provided by the control option relative to the baseline is presented in parentheses. See Table H.11. Air Quality Modeling Protocol: Utah Regional Haze Federal Implementation Plan, US EPA Region 8 (Nov. 2015); Docket Id. EPA–R08–OAR–2015–0463–0012.

TABLE 5—SUMMARY OF EPA'S HUNTINGTON UNIT 2 NO_X BART IMPACTS ANALYSIS

Control option	Annual emission rate (lb/MMBtu)	Emission reduction (tpy)	Total annual costs (million$)	Average cost effectiveness ($/ton)	Incremental cost effectiveness ($/ton)	Visibility impacts*		
						Improvement (dv)	Days > 0.5 dv	Days > 1.0 dv
LNB with SOFA	0.21	2,576	$0.9M	$365		0.776	254 (23)	153 (22)
LNB with SOFA and SNCR	0.17	3,264	3.5M	1,075	3,730	1.016	244 (33)	149 (26)
LNB with SOFA and SCR	0.05	5,023	14.7M	2,928	6,368 (compared to LNB with SOFA and SNCR) 5,626 (compared to LNB with SOFA).	1.657	220 (57)	126 (49)

*At the most impacted Class I area, Canyonlands National Park. The improvement in days over 0.5 and 1.0 dv provided by the control option relative to the baseline is presented in parentheses. See Table H.12. Air Quality Modeling Protocol: Utah Regional Haze Federal Implementation Plan, US EPA Region 8 (Nov. 2015); Docket Id. EPA–R08–OAR–2015–0463–0012.

In our final BART determinations, we have taken into consideration all five of the statutory factors required by the CAA: Costs of compliance, energy and non-air quality environmental impacts of compliance, any existing pollution control technology in use at the source, remaining useful life of the source, and degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

We received some comments on our proposed consideration of remaining useful life and energy and non-air quality environmental impacts. However, we have not changed our evaluation from the proposal of the energy and non-air quality environmental impacts of compliance and the remaining useful lives of the sources. We find that the remaining useful life of the Hunter and Huntington units of at least twenty years is considerable and does not require us to revise our amortization period for the costs of controls. We also find that the energy and non-air quality environmental impacts of the various control options do not significantly favor one option over another. Please see the proposal action and our RTC document for details.

We also received comments on our proposed consideration of existing pollution control technology in use at the source, in this case LNB/SOFA at all four BART units. For reasons explained later in the preamble and in our RTC document, we continue to use a baseline period for emissions (2001–2003) that predates the installation of LNB/SOFA at the four BART units. We have considered the existing LNB/SOFA in several other ways. First, we considered them in selecting the control options to analyze for BART. Second, we considered them in determining the impacts of the control options, both by taking the LNB/SOFA into account in determining the proper NO_X rates for the post-combustion control options (selective non-catalytic reduction (SNCR) and SCR), and in computing the incremental cost-effectiveness values in the tables earlier. We also consider the existing LNB/SOFA in our discussion of incremental visibility benefits later. As explained later in the preamble and in our RTC document, this is a reasonable approach and consistent with other actions.

We now discuss the remaining factors, the costs of compliance and the degree of visibility improvement, and how we are weighing them in determining BART. At this point in time, EPA and the states have made a number of BART determinations for large coal-fired EGUs. EPA is taking into account the BART decisions made in other states to help frame our assessment of the cost and visibility benefits of control options in this action.[64] Specifically, we have compared the average cost-effectiveness, incremental cost-effectiveness, visibility improvement, and incremental visibility improvement for the selected BART controls, SCR + LNB/SOFA, with BART determinations for coal-fired EGUs where the EPA and states have based those determinations on the same or similar metrics.

The most comparable determination is in EPA's final action on Wyoming's regional haze SIP, in which EPA promulgated a FIP for three units at Laramie River Station and determined NO_X BART to be SCR + LNB/SOFA for the three units.[65] On a per-unit basis, the visibility improvement at the most impacted Class I area from this control option ranged from 0.52 to 0.57 dv, and across all three units the sum of the improvement was 1.62 dv.[66] Thus, applying this control option to all three units of Laramie River Station was estimated to have a visibility benefit

[64] As discussed in our proposal action, in the context of reasonable progress determinations, a comparison with another reasonable progress determination has been upheld by the Ninth Circuit Court of Appeals as a rational explanation for that determination. Nat'l Parks Conserv. Ass'n v. U.S. EPA, 788 F.3d 1134, 1148–49 (9th Cir. 2014).

[65] 79 FR 5032, 5047 (Jan. 30, 2014).

[66] As explained in our proposal, the BART Guidelines require consideration of the visibility improvement from the use of BART controls applied to the collection of emissions units that make up the BART source. Although this requires consideration of the visibility improvement from BART applied to the subject-to-BART source as a whole, states (and EPA) may also include the visibility benefits on a per unit basis as well in their evaluation of the BART factors. In this action we have considered both the per-unit visibility benefits as well as the source-wide visibility benefits. The source-wide visibility benefits of our selected BART control, SCR + LNB/SOFA, at all nine impacted Class I areas are presented and discussed later.

about the same as applying the same control option to just one of the Hunter and Huntington BART units (the visibility benefits in today's action at the most impacted Class I area range from 1.25 dv at Hunter Unit 2 to 1.881 dv at Huntington Unit 1). The visibility benefits of SCR + LNB/SOFA at Hunter or Huntington as a whole (2.948 dv for Hunter, 3.848 dv for Huntington) are significantly greater than at Laramie River Station.

The average cost-effectiveness for SCR + LNB/SOFA at Laramie River Station ranged from $4,375/ton to $4,461/ton, considerably higher than the corresponding values of $2,697/ton to $2,928/ton for the Hunter and Huntington BART units. The incremental cost-effectiveness for SCR + LNB/SOFA at Laramie River Station as compared to SNCR + LNB/SOFA ranged from $5,449 to $5,871/ton, which is generally in line with the corresponding values for the Hunter and Huntington BART units, $5,830/ton to $6,632/ton. Finally, the incremental visibility improvement for SCR + LNB/SOFA at the most impacted Class I area as compared to SNCR + LNB/SOFA for Laramie River Station was significant (0.25 dv to 0.29 dv), but is even more so for the Hunter and Huntington BART units (0.428 dv at Hunter Unit 2 to 0.748 dv at Huntington Unit 1). Thus, the selection of SCR + LNB/SOFA at the Hunter and Huntington BART units is very much in line with the selection of SCR + LNB/SOFA at Laramie River Station. This is particularly true given that Laramie River Station impacts four Class I areas, while the Hunter and Huntington BART units impact nine Class I areas.

In the same Wyoming action, our BART determinations for Dave Johnston Units 3 and 4 also provide a useful comparison. At Unit 3, we selected SCR + LNB/OFA as BART based on an assumed 20-year remaining useful life. Under that assumption, the average cost-effectiveness and incremental cost-effectiveness (as compared to SNCR + LNB/OFA) were $2,635/ton and $7,583/ton, respectively. We found these costs reasonable in light of a 0.51 dv improvement and a 0.12 dv incremental improvement at the most impacted Class I area. The average cost-effectiveness of SCR + LNB/SOFA at the Hunter and Huntington BART units, $2,697/ton to $2,928/ton, is comparable, while the incremental cost-effectiveness of SCR + LNB/SOFA at the Hunter and Huntington BART units, $5,830/ton to $6,830/ton, is less than at Dave Johnston Unit 3. On the other hand, the visibility benefit and incremental visibility benefit of SCR + LNB/SOFA at the Hunter and Huntington BART units is considerably higher than that at Dave Johnston Unit 3, and the Hunter and Huntington BART units impact nine Class I areas as compared to five for Dave Johnston Unit 3. Thus, the selection of SCR + LNB/SOFA for the Hunter and Huntington BART units is very much in line with our BART determination for Dave Johnston Unit 3 (assuming a remaining useful life of 20 years).

In the Wyoming action, at the request of PacifiCorp we also analyzed an alternative compliance scenario for Dave Johnston Unit 3 that assumed a shutdown in 2027 and correspondingly a 9-year remaining useful life. As explained in the BART Guidelines, for BART units with a relatively short remaining useful life—in other words, less than the time period used for amortizing costs, which in this case was 20 years—the shorter time period can be used to amortize costs instead. Effectively, this increases the cost-effectiveness values; in the case of Dave Johnston Unit 3, the average and incremental cost-effectiveness of SCR + LNB/OFA increased to $3,742/ton and $11,781/ton, respectively. Considering these values against the visibility benefits, we found that the incremental cost-effectiveness of SCR + LNB/OFA in this instance was not reasonable. Of course, for the Hunter and Huntington BART units the incremental cost-effectiveness is much lower than this scenario and in line with the previous scenario assuming a 20-year remaining useful life, for which we selected SCR + LNB/OFA as BART. Similarly, for Dave Johnston Unit 4, as for the 9-year remaining useful life scenario for Unit 3, we rejected SCR + LNB/OFA due to a high incremental cost-effectiveness of $13,312. This is again consistent with our determination here, given the much lower incremental cost-effectiveness numbers for SCR + LNB/SOFA at the Hunter and Huntington BART units.

There are other BART determinations in which SCR has been selected as BART (either alone or in conjunction with LNB and SOFA) based on similar metrics, although those determinations may not have explicitly discussed incremental cost-effectiveness and incremental visibility benefits on a per-unit basis. First, the State of Colorado selected, and the EPA approved, SCR as NO_X BART for Public Service Company's Hayden Station, Units 1 and 2.[67] Hayden Units 1 and 2 were equipped with first generation LNB and over-fire air (OFA) installed in 1999 as the result of a consent decree to address other CAA requirements.[68] In its BART determination, Colorado considered these existing controls as given and included them in the baseline emissions, which is consistent with our approach here: Colorado included the Hayden combustion controls in the baseline because they were not installed for a proposed BART determination but for other CAA purposes. In contrast, we do *not* include the combustion controls at Hunter and Huntington because they *were* installed pursuant to a proposed BART determination.[69]

Colorado analyzed as feasible controls upgraded LNB, SNCR, and SCR. Based on an average cost-effectiveness of $3,385/ton and $4,064/ton, incremental cost-effectiveness (as compared with SNCR + the existing LNB/OFA) of $5,326/ton and $7,331/ton, and visibility improvement of 1.12 dv and 0.85 dv at the most impacted Class I area, respectively, Colorado selected SCR (added to the existing LNB/OFA) as BART for Units 1 and 2. The average cost-effectiveness of SCR + LNB/SOFA at the Hunter and Huntington BART units, $2,697/ton to $2,928/ton, compares favorably with the average cost-effectiveness of SCR at the Hayden units, and the incremental cost-effectiveness of SCR + LNB/SOFA at the Hunter and Huntington BART units, $5,830/ton to $6,632/ton, is generally in line with the incremental cost-effectiveness of SCR at the Hayden units. The visibility improvement from SCR + LNB/SOFA at the most impacted Class I area for the Hunter and Huntington BART units, from 1.25 dv to 1.881 dv, compares favorably with the Hayden units. While Colorado appears to have not considered the incremental visibility benefits, these are also favorable for our selection of SCR + LNB/SOFA: 0.428 dv to 0.768 at the Hunter and Huntington units, as compared to 0.37 dv and 0.43 dv at Hayden Units 1 and 2, respectively. We also note that Hayden Station impacts eleven Class I areas, slightly more than Hunter and Huntington; however for six of those areas the impacts from Hayden Station are less than the impacts from Hunter and Huntington at the least

[67] 77 FR 18069 (Mar. 26, 2012) (proposal); 77 FR 76871 (Dec. 31, 2012) (final).

[68] Colorado Department of Health and Environment, Air Pollution Control Division, Technical Review Document, Renewal/Modification of Operating Permit 96OPRO132, Public Service Company—Hayden Station, Colorado, at 2 (2007–2008).

[69] We respond later in this action and in our RTC document about comments that this comparison should not be used because the baseline for Hayden included the existing controls.

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impacted Class I area, Zion National Park.[70]

Another comparable determination can be found in EPA's FIP for Arizona Public Service's Cholla Power Plant, Units 2, 3, and 4, in which EPA determined that NO_X BART was SCR for all three units.[71] Similar to Colorado's determination for Hayden, EPA included the existing controls, LNB and OFA, in the baseline for the three units.[72] EPA estimated average cost-effectiveness values for SCR (as added to the existing LNB/OFA) of $3,114/ton, $3,472/ton, and $3,395/ton; and incremental cost-effectiveness values (as compared to SNCR + LNB/OFA) of $3,257/ton, $3,811/ton, and $3,661/ton, respectively, for Units 2, 3, and 4. EPA's modeling showed a source-wide visibility improvement for SCR of 1.34 dv at the most impacted Class I area. In comparison, the source-wide visibility improvements at the most impacted Class I area for Hunter and Huntington from SCR + LNB/SOFA are much larger: 2.948 dv and 3.848 dv, respectively. While the average cost-effectiveness values at Cholla are somewhat higher than those for the Hunter and Huntington BART units, the incremental cost-effectiveness of SCR at the Hunter and Huntington BART units is considerably higher, at $5,830/ton to $6,632/ton. Despite that disparity in incremental cost-effectiveness, this comparison still supports selection of SCR + LNB/SOFA for the Hunter and Huntington BART units, given the much greater magnitude of the visibility benefits and the fact that our other comparisons show the incremental cost-effectiveness of SCR + LNB/SOFA is still reasonable. Finally, Cholla Power Plant does impact somewhat more Class I areas, thirteen as opposed to nine for Hunter and Huntington; however, were we to sum the baseline impacts of Hunter and Huntington, they would be greater than those for Cholla.

Based on these comparisons to Laramie River Station, Hayden Station, Dave Johnston Units 3 and 4, and Cholla Power Plant Units 2, 3, and 4, the selection of LNB and SOFA with SCR as BART for the Hunter and Huntington BART units is fully justified.[73] For these four units, LNB and SOFA with SCR is very cost-effective, at $2,697/ton to $2,928/ton on an average basis (counting the costs and emission reductions from the combination of the three control technology elements), and at $5,830/ton to $6,632/ton on an incremental basis compared to LNB with SOFA and SNCR. Compared to LNB with SOFA, the incremental cost effectiveness of LNB and SOFA with SCR ranges from $5,206/ton to $5,861/ton, which is in line with the incremental cost effectiveness that supported the selection of LNB with SOFA and SCR for Laramie River Station. For the Hunter and Huntington BART units, LNB and SOFA with SCR provides substantial visibility benefits at several Class I areas that are similar in magnitude to those from Laramie River Station. For example, the visibility improvement from that control option installed on a single unit is 1.342 dv at Arches National Park, 1.545 dv at Canyonlands National Park, and 1.113 at Capitol Reef National Park. These comparisons show that costs are justified in light of the substantial visibility benefits, both total and incremental. In addition, for each unit, SCR + LNB/SOFA provides a significant improvement in the number of days over 0.5 dv as compared to the baseline (ranging from 42 days improvement at Hunter Unit 2 to 67 days improvement at Huntington Unit 1).

As mentioned earlier, the BART Guidelines require consideration of the visibility improvement from the use of BART controls applied to the collection of emissions units that make up the BART source. Tables 6 and 7 summarize the source-wide visibility improvements from the installation of SCR + LNB/SOFA at both BART units at Hunter and both BART units at Huntington, as well as the visibility improvements from the installation of SCR + LNB/SOFA at the other impacted Class I areas.

TABLE 6—SUMMARY OF SOURCE-WIDE VISIBILITY IMPACTS AND IMPROVEMENTS FOR HUNTER

Class I area	Baseline visibility impacts			BART (SCR + LNB/SOFA) Impacts (Improvements over baseline shown in parentheses)		
	Impacts (dv)	Days > 0.5 dv	Days > 1.0 dv	Impacts (dv)	Days > 0.5 dv	Days > 1.0 dv
Arches National Park (NP)	4.601	293	170	1.981 (2.62)	158 (135)	71 (99)
Black Canyon NP	1.097	68	22	0.481 (0.616)	14 (54)	1 (21)
Bryce Canyon NP	1.833	42	22	0.811 (1.022)	20 (22)	6 (16)
Canyonlands NP	5.356	359	240	2.408 (2.948)	223 (136)	111 (129)
Capitol Reef NP	4.606	175	118	2.171 (2.435)	114 (61)	55 (63)
Flat Tops Wilderness	1.281	77	31	0.537 (0.744)	22 (55)	1 (30)
Grand Canyon NP	1.891	49	32	0.730 (1.161)	25 (24)	9 (23)
Mesa Verde NP	1.327	82	32	0.514 (0.813)	21 (61)	4 (28)
Zion NP	0.963	29	14	0.369 (0.594)	10 (19)	4 (10)

Note: The baseline impacts are the combined impacts from all three units at Hunter, while the BART source is comprised of only units 1 and 2. EPA's evaluation of visibility under BART relies only on the visibility benefits associated with controls on the two BART units.

[70] See BART CALPUFF Class I Federal Area Individual Source Attribution Visibility Impairment Modeling Analysis for Public Service Company of Colorado Hayden Station Units 1 and 2, Colorado Department of Public Health, at 48 (Nov. 1, 2005).

[71] 77 FR 42834 (July 20, 2012) (proposal); 77 FR 72512, 72514–15 (Dec. 5, 2012) (final).

[72] In response to a comment about the use of this baseline, EPA explained that the three Cholla units had installed LNB/OFA and switched to a new source of coal with a much higher potential for NO_X emissions. Thus, the LNB/OFA had not been installed pursuant to a proposed state BART determination; instead they appear to have been installed to accommodate the use of the new coal. This is again distinguishable from the situation for Hunter and Huntington.

[73] As explained later and in our RTC document, we reject the comparisons to BART determinations in Montana, Florida, and Nebraska.

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TABLE 7—SUMMARY OF SOURCE-WIDE VISIBILITY IMPACTS AND IMPROVEMENTS FOR HUNTINGTON

Class I area	Baseline visibility impacts			BART (SCR + LNB/SOFA) impacts (improvements shown in parentheses)		
	Impacts (dv)	Days > 0.5 dv	Days > 1.0 dv	Impacts (dv)	Days > 0.5 dv	Days > 1.0 dv
Arches NP	3.887	237	146	0.848 (3.039)	67 (170)	18 (128)
Black Canyon NP	0.773	45	16	0.196 (0.577)	1 (44)	0 (16)
Bryce Canyon NP	1.221	36	19	0.326 (0.895)	4 (32)	0 (19)
Canyonlands NP	5.130	277	175	1.282 (3.848)	89 (188)	31 (144)
Capitol Reef NP	3.389	131	91	0.986 (2.403)	42 (89)	9 (82)
Flat Tops Wilderness	0.926	64	17	0.216 (0.710)	2 (62)	0 (17)
Grand Canyon NP	1.107	40	19	0.190 (0.806)	4 (36)	0 (19)
Mesa Verde NP	1.115	63	22	0.261 (0.854)	0 (63)	0 (22)
Zion NP	0.820	21	11	0.211 (0.609)	3 (18)	0 (11)

As can be seen from these tables, the baseline visibility impacts in dv at all nine Class I areas are large: Even at the least impacted Class I area, Zion National Park, Hunter and Huntington are each above the 0.5 dv threshold for contributing to visibility impairment. For Hunter, at the three most impacted Class I national park areas, Arches, Canyonlands and Capitol Reef, the baseline visibility impacts range from 4.601 dv to 5.356 dv. At these three Class I areas, the number of days with impacts over 0.5 dv and 1.0 dv range from 175 to 359, and from 118 to 240, respectively. The visibility benefits of BART (SCR + LNB/SOFA) at the three Class I areas are correspondingly large, ranging from 2.435 dv to 2.948 dv. The improvement in the number of days over 0.5 dv and 1.0 dv at these three Class I areas are large as well, ranging from an improvement of 61 to 136 days in the number of days over 0.5 dv and 63 to 129 days in the number of days over 1.0 dv. Even at the least impacted Class I area, Zion National Park, the visibility benefits of BART are significant, 0.594 dv, and 19 and 10 days in the number of days over 0.5 dv and 1.0 dv, respectively. Consideration of these source-wide visibility benefits confirms that SCR + LNB/SOFA at Hunter is fully justified in light of its reasonable costs.

For Huntington, at the three most impacted Class I national park areas, Arches, Canyonlands and Capitol Reef, the baseline visibility impacts range from 3.389 dv to 5.130 dv. At these three Class I areas, the number of days with impacts over 0.5 dv and 1.0 dv range from 131 to 271, and from 91 to 175, respectively. The visibility benefits of BART (SCR + LNB/SOFA) at the three Class I areas are correspondingly large, ranging from 2.063 dv to 3.538 dv. The improvement in the number of days with impacts from Huntington over 0.5 dv and 1.0 dv at these three Class I areas are similar to those of Hunter. Huntington has 89 fewer days with impacts over 0.5 dv at Capitol Reef, 170 fewer days with such impacts at Archers, and 188 fewer days at Canyonlands. The number of days Huntington has impacts over 1.0 dv at these areas falls by 82 to 144 days. Even at the least impacted Class I area, Zion National Park, the visibility benefits of BART are significant. BART is projected to result in a 0.609 dv improvement at Zion the number of days with impacts over 0.5 dv and 1.0 dv fall by 18 and 11 days, respectively. Consideration of these source-wide visibility benefits confirms that SCR + LNB/SOFA at Huntington, as at Hunter, is fully justified in light of its reasonable costs.

Accordingly, for the Hunter and Huntington BART units, we find that BART for NO_X is SCR + LNB/SOFA, represented by an emission limitation of 0.07 lb/MMBtu (30-day rolling average). The BART emission limitation of 0.07 lb/MMBtu allows for a sufficient margin of compliance for a 30-day rolling average limit that would apply at all times, including startup, shutdown, and malfunction.[74] We are also finalizing our proposed monitoring, recordkeeping, and reporting requirements in our regulatory text for 40 CFR 52.2336; these requirements will ensure that the BART emission limitation is enforceable.

Under 40 CFR 51.308(e)(1)(iv), "each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but in no event later than five years after approval of the implementation plan revision." In light of the considerable effort involved to retrofit SCR, we determine that five years is as expeditiously as practicable. Therefore, the compliance deadline for the BART requirements will be five years from the date our final FIP becomes effective.

2. PM_{10} BART

We are finalizing our proposed approval of Utah's PM_{10} BART determinations for Hunter Units 1 and 2 and Huntington Units 1 and 2. We have determined that Utah's PM_{10} BART determinations, emission limitations, and associated monitoring, recordkeeping and reporting for Hunter Units 1 and 2 and Huntington Units 1 and 2 meet the requirements of 40 CFR 51.309(d)(4)(vii) and the linked BART requirements in 40 CFR 51.308(e)(1).[75] We are approving SIP Section IX, Part H.21 subsections a through d and f (related to applicability, definitions, recordkeeping, and stack testing), and conditionally approving Subsection e (emission limitations shall apply at all times). We are approving SIP Section IX, Part H.22 subsections a.i and b.i. We considered and rejected comments on the validity of the State's BART analyses for PM_{10} and the State's emission limitation of 0.015 lb/MMBtu on a 30-day rolling basis for the Hunter and Huntington BART units. For PM_{10} reporting, we are finalizing our proposed conditional approval of this element in accordance with CAA section 110(k)(4), based on Utah's commitment to submit specific measures to address the reporting requirement.[76] Utah's letter commits to adopt and submit rule language that would require sources to report any deviation from the requirements of the regional haze SIP provisions, which would include the PM_{10} emission limitations. The specific language is

[74] Emission limits such as BART are required to be met on a continuous basis. *See* 70 FR 39104, 39172 (July 6, 2005) (stating that emissions limits including BART are to be met on a "continuous basis" in the BART Guidelines, section V); 42 U.S.C. 7602(k) (noting that emission limits are to be on "a continuous basis").

[75] As discussed elsewhere, while we are approving the PM_{10} emission limits in SIP Section IX, Part H.21, we are not approving into the SIP the "approval orders" (*i.e.*, State-issued permits) that are referenced in SIP Section XX.D.6.d at 25 and 29).

[76] Letter from Department of Environmental Quality, State of Utah to EPA, DAQP–120–15 (Dec. 10, 2015).

detailed in Utah's commitment letter. We did not receive any adverse comments on our conditional approval of the recordkeeping requirements for the PM_{10} emission limitations.

Pursuant to CAA section 110(k)(4), the State has one year from the date of this action to adopt and submit the necessary SIP revisions for SIP Section IX.H.21.e. If the State does not meet its commitment within the one year period, the conditional approval is treated as a disapproval. EPA finds that the necessary SIP revisions meet EPA's criteria for conditional approvals,[77] as the revisions appear to involve a limited amount of technical work, are anticipated to be non-controversial, and can reasonably be accomplished within the length of time for the State's adoption process.

3. Enforceable Commitment SIP

We are taking no action on Utah's enforceable commitment SIP, submitted on October 20, 2015. In its enforceable commitment SIP submittal, the State resolved to address double counting certain emissions reductions from the Carbon power plant closure under both the Utah BART Alternative and the SO_2 backstop trading program under 40 CFR 51.309. As we explained in our proposal, we interpret our authority to enable us to approve enforceable commitment SIPs under section 110(a)(2)(A) of the Act and other applicable sections as relevant (for our NO_X BART action, this is section 169A). However, since we are not approving the State's NO_X BART Alternative SIP submittal, which included emissions reductions from the Carbon power plant, there is no need for the elements of the enforceable commitment SIP. Additionally, because we are not taking action on the enforceable commitment SIP package submitted on October 20, 2015 we are not responding to comments on that SIP in this action.

II. Summary and Analysis of Major Issues Raised by Commenters

We received both written and oral comments at the public hearings we held in Salt Lake City. We also received comments by the Internet and mail. The full text of comments received from these commenters is included in the publicly posted docket associated with this action at *www.regulations.gov*. Our RTC document, which is also included in the docket associated with this action, provides detailed responses to all significant comments received. In total, we received approximately 4,900 pages of significant comments. Later we provide a summary of the more significant comments received and a summary of our responses to them. Our RTC document is organized similarly to the structure presented in this section (*e.g.,* Cost of Controls, BART Alternative CALPUFF Modeling, etc.). Therefore, if additional information is desired concerning how we addressed a particular comment, the reader should refer to the appropriate section in our RTC document.

PacifiCorp, conservation organizations (HEAL Utah, National Parks Conservation Association, and Sierra Club) and the National Parks Service (NPS) submitted detailed comments that include new cost and visibility modeling information.[78] Several government, tourism and industry organizations also submitted comments. Many general comments were made at the public hearing. We received approximately 400 comments through email and the *www.regulations.gov* Web site. We also received approximately 70,000 mass mailer comments from private citizens.

A. General Comments

Comment: Several commenters expressed concern over the accommodations provided at the public hearing. Several commented on the large number of attendees, and how this made it difficult for them to make their comments as well as hear those who were speaking. Commenters noted that many attendees were intimidated by the size of the hearing and by some of the other attendees, and suggested that many attendees left the hearing without commenting on the issues. There was concern that these departures may have led to an imbalance in opinions presented. Some commenters noted that some of the attendees at the hearing were not being cordial with the others and were unkind to those who expressed different opinions. Several commenters made requests for additional hearings, suggesting that additional hearings be located closer to the affected Class I areas and at locations that could accommodate a larger number of attendees.

Response: Several commenters expressed their dissatisfaction with EPA's public hearing arrangements. As required by section 307(d)(5) of the CAA the EPA provided an opportunity for the public to submit written comments and voice concerns at the public hearing. In arranging the logistics for the public hearing, EPA's intent was to provide an opportunity for all members of the public to voice their opinions about the proposed rulemaking. The Salt Lake City library was chosen as the public hearing site because: (1) The library had reasonable accommodations to hold approximately 100 attendees; (2) the library was centrally located, and would be convenient for many members of the public to access; and (3) the library did not require a fee. The size of the venue was consistent with other hearings the EPA has conducted across the country.[79] Based on these considerations, the EPA had no reason to believe the venue could not accommodate the anticipated level of public participation or that it would not fulfill the purposes of and the Act's requirements for the hearing.

While the number of individuals attending the public hearing exceeded what we anticipated, we made adjustments throughout the day to accommodate the large numbers. For example, the library staff worked with us and set up broadcast speakers in the hallway so that those in the hallway could hear what was said during the hearing. The EPA could not allow the meeting room used for the public hearing to exceed its capacity limit in order to comply with the library's policies to comply with the fire code occupancy requirements. In response to the unkind statements made by some participants, the Hearing Officer reminded the crowd that the purpose of the meeting was to allow people to testify comfortably without being intimidated, and that people causing distractions would be asked to leave. In fact, some attendees who were causing distractions were asked to leave. Additionally, even though the turnout was larger than expected, EPA scheduled the opportunity for the public to speak based on their arrival time (with those arriving first, first allowed to speak); and the EPA accommodated all the potential speakers at the end of the scheduled hearing time, by extending the hearing until everyone who was present at that time and wanted to speak had done so. As a result the hearing was extended by approximately 20 minutes.

[77] *See* Memorandum from John Calcagni to EPA Regional Directors. ''Processing of State Implementation Plan (SIP) Submittals'' (July 1992), available at *http://www3.epa.gov/ttn/oarpg/t1/memoranda/siproc.pdf.*

[78] On May 19, 2015, PacifiCorp submitted late comments. These comments are included in the docket for this action and we address them in our RTC document.

[79] Examples include: (1) The public hearing on FIP proposal on May 1, 2012 at the Lewis and Clark Library in Helena, MT; (2) the public hearing on FIP proposal on July 27, 2013 at the Laramie County Library in Cheyenne, WY; and (3) the public hearing on FIP proposal on October 13–14, 2011 at the North Dakota Department of Health Training Center in Bismarck, ND.

The EPA determined that additional hearings were unnecessary, because the written comment period continued for approximately seven weeks after the public hearing, allowing for additional comments to be submitted. As explained in the proposed rule,[80] in addition to the public hearing, the EPA accepted written comments provided those comments were received on or before March 14, 2016. Therefore, while some of the members of the public may have left before they had an opportunity to speak at the hearing, they still had the opportunity to submit their comments either online or via mail to EPA for approximately seven weeks after the public hearing, as demonstrated in 81 FR 2004. The EPA gives just as much consideration to comments we receive in writing as we do to those we receive at public hearings.

B. EPA Authority and State Discretion

Comment: The State of Utah commented that EPA should approve its BART Alternative because it meets all of the current requirements of the CAA and the RHR found at 40 CFR 51.300 through 51.309. EPA is obligated to approve a SIP that meets all of the applicable requirements of the CAA. See 42 U.S.C. 7410(k)(3) (''In the case of any submittal on which the Administrator is required to act under paragraph (2), the Administrator shall approve such submittal as a whole if it meets all of the applicable requirements of this chapter.''). The Section 308 regulation grants states full discretion as to whether to adopt the BART Alternative. In the current proposed rule, EPA also acknowledges a state's discretion in approving alternative measures: Finally, in . . . responding to concerns regarding ''impermissibly vague'' language in §51.308(e)(3) that would allow a State to ''approve alternative measure that are less protective than BART,'' we explained that ''[t]he State's discretion in this area is subject to the condition that it must be reasonably exercised and that its decision be supported by adequate documentation of its analyses.'' 81 FR 2004, 2012 (quoting 71 FR 60612, 60621 (Oct. 13, 2006)). Therefore, the alternative measure is within the state's discretion, as long as it is adequately supported.

Response: We agree that states have discretion to adopt BART alternatives; however, as the commenter explains, the state's discretion is subject to a number of requirements, including that it be reasonably exercised and adequately supported and that the state's Alternative clearly provides greater reasonable progress than BART. The CAA requires that states submit SIPs that contain such measures as may be necessary to make reasonable progress toward achieving natural visibility conditions, including the BART requirements. As EPA explained when promulgating the regional haze regulations, ''[t]he overarching requirement of the visibility protection provisions of section 169A is to make reasonable progress toward the national goal of eliminating visibility impairment. If greater reasonable progress can be made through an approach that does not require source specific application of BART, EPA believes that approach would comport with this statutory goal.''[81] States have the opportunity to adopt alternative measures in lieu of BART where the agency *reasonably concludes* that more reasonable progress will thereby be attained toward the national visibility goal.[82] We explained these requirements in our co-proposal as follows: ''[a]s described in our 2006 revisions to the RHR, concerning BART alternatives, '[t]he State's discretion in this area is subject to the condition that it must be reasonably exercised and that its decisions be supported by adequate documentation of its analyses.'''[83]

While states have discretion to decide whether to adopt a BART alternative in a SIP, such discretion does not extend to the authority to adopt SIPs that will not ensure reasonable progress toward the national visibility goal of preventing any future and remedying of any existing visibility impairment in Class I areas. Such an interpretation is also inconsistent with the legislative history, which stresses the importance of the ''national goal''[84] of clear air quality in Class I areas and ''preventing impairment of visibility,'' noting that ''the millions of Americans who travel thousands of miles each year to visit Yosemite or the Grand Canyon or the North Cascades will find little enjoyment if . . . upon reaching the Grand Canyon it is difficult if not impossible to see across the great chasm.''[85]

Thus, we do not agree that Congress assigned states full discretion in developing SIPs, because it is not clear how EPA's limited role under such a scenario would assure attainment of the national goal or imposition of the [better than] BART requirements where a state's BART alternative demonstration does not demonstrate that the alternative achieves greater reasonable progress. In view of the statutory requirements, it is logical that EPA would evaluate the reasonableness of the State's BART Alternative analysis in light of the purpose of the regional haze program.

As detailed in the sections in our co-proposal and based on our evaluation and findings as detailed in Section I.B.1 of this document and in our RTC document, we determined that, on balance, the evidence does not show that the Alternative clearly achieves greater visibility benefits than BART. Because the State's BART Alternative is not approvable, we are obligated to disapprove it, develop BART analyses, and then arrive at our own BART determinations for the four EGUs that are subject-to-BART.

Furthermore, this is a SIP review action, and we believe that EPA is not only authorized, but required to exercise independent technical judgment in evaluating the adequacy of the State's regional haze SIP, including its BART Alternative analyses, just as EPA must exercise such judgment in evaluating other SIPs. In evaluating other SIPs, EPA is constantly exercising judgment about SIP adequacy, not just to meet and maintain the NAAQS, but also to meet other requirements that do not have a numeric value. In this case, Congress did not establish a specific numeric value by which to measure visibility improvement; instead, it established a reasonable progress standard and required that EPA assure that such progress be achieved via implementation, *inter alia,* of the Act's BART requirement. Here, we are exercising judgment within the parameters laid out in the CAA and our regulations.

Our evaluation of the State's BART Alternative is presented in section I.B.1 and in our RTC document.

Comment: The State commented that EPA mistakenly imposes additional inapplicable requirements in its evaluation of Utah's regional haze SIP. Greater reasonable progress under Section 308(e)(2) can be demonstrated using either one of two methods: (1) Greater emission reductions than under BART (Section 308(e)(3)); or (2) the weight-of-evidence test, consisting of a number of requirements that the state weighs to conclude which option achieves greater reasonable progress (section 308(e)(2)). *See* 40 CFR 51.308(e)(2) and (3). The state has discretion to choose one method over the other. *See WildEarth Guardians* v. *E.P.A.,* 770 F.3d 919, 935–37 (10th Cir.

[80] 81 FR 2004 (Jan. 14, 2016).

[81] 64 FR 35714, 35739 (July 1, 1999).

[82] *Id.* (emphasis added).

[83] 81 FR 2004, 2006 (Jan. 6, 2016) (citing 71 FR 60612, 60621 (Oct. 13, 2006)).

[84] 42 U.S.C. 7491(a)(1).

[85] H.R. Rep. No. 95–294, at 137 (1977).

2014). The Tenth Circuit characterized the former approach as ''quantitative'' and the latter as ''qualitative,'' ultimately ruling that EPA can properly rely on qualitative factors in applying the ''weight-of-evidence test.'' *See id.* at 934–35 (EPA's choice of qualitative standard was ''permissible under the EPA's interpretation of its regulations.'').

Utah submitted its BART Alternative under Section 308(e)(2), purposefully electing to make its determination that the alternative program achieves greater reasonable progress under the ''weight-of-evidence'' test. EPA analyzed Utah's BART Alternative in both co-proposals under the section 308(e)(3) ''greater emissions reductions test'' in addition to the ''weight-of-evidence'' analysis. See 81 FR 2004, 2021, 2028. EPA proposed that Utah's BART Alternative does not result in greater emission reductions because ''the total NO_X emissions are greater under the BART Alternative than the BART Benchmark,'' even though ''in the aggregate there are fewer SO_2 and PM_{10} emissions for the BART Alternative . . . .'' *Id.* at 2028. EPA erroneously imposed Section 308(e)(3) requirements on Utah's BART Alternative in addition to the Section 308(e)(2) weight-of-evidence test. EPA must withdraw its analysis of Utah's BART Alternative under the greater emissions reductions test because, as Utah clearly explained, the State never intended its data to satisfy this test.

Response: We agree in part and disagree in part with this comment. In developing a BART Alternative SIP, we agree that a state has the discretion to choose between the ''greater emission reduction'' test (section 308(e)(3)) and the ''weight-of-evidence'' test (section 308(e)(2)). Utah's comments clarify that they elected the weight-of-evidence test, and so we clarify and modify our evaluation of the State's SIP submittal. We therefore clarify that we are not disapproving the SIP under the elements of the section 308(e)(3) test as we had proposed.[86]

The State's submittal, however, asserted that the BART Alternative is better than BART based in part on the metric that compared annual emissions of the three visibility impairing pollutants in the aggregate. There is no requirement in section 308(e)(2) for the State to compare annual emissions of visibility pollutants in the aggregate. Rather, as we explained in our proposal, we have addressed this issue under section 308(e)(3); our interpretation under that provision also applies under section 308(e)(2). Specifically, if under section 308(e)(2) a state compares annual emissions of visibility in the aggregate to determine whether a BART alternative ''results in greater emission reductions,'' we examine whether each of the visibility causing pollutants is less under the alternative. For the reasons explained in our proposal and in section I.B.1.c.i of this document, we have not approved a BART alternative where one or more of the specific pollutants under the BART alternative is greater than it would be under the BART benchmark.[87]

Therefore, as we did in our proposal, it is reasonable to apply our interpretation of the section 308(e)(3) ''greater emission reductions'' element under section 308(e)(2) as well, because the same concerns regarding the relationship between reductions of multiple pollutants and visibility improvements are also relevant in the weight-of-evidence context.

Comment: PacifiCorp asserted that EPA is not empowered under the CAA to require compliance with both the SIP proposal and the FIP proposal. As a practical matter, that is precisely what EPA proposes to do to the extent it approves the FIP proposal. This is because PacifiCorp already has implemented the SIP proposal as required by Utah law. If EPA were to select the FIP proposal, it would do so knowing[88] that PacifiCorp would be required to implement both the SIP proposal and the FIP proposal. Nothing in CAA or regional haze rules allows EPA to require such a result when the proposed action itself states that EPA ''intends to finalize only one proposal.'' See 81 FR 2004, 2006.

For all of the reasons stated earlier, EPA should approve the Utah SIP as stated in the SIP proposal, and should reject the FIP proposal. What EPA cannot do, and indeed is not empowered under the CAA to require, is compliance with both the SIP proposal and the FIP proposal.

Response: We disagree with this comment. As explained elsewhere, the CAA requires that states submit SIPs that contain such measures as may be necessary to make reasonable progress toward achieving natural visibility conditions, including the BART requirements. EPA is acting under its authority pursuant to the CAA in disapproving portions of the SIP submittal and promulgating the FIP. We have the duty to ensure that regional haze SIP submittals meet the requirements of the Act and the RHR.[89] While states have the opportunity to adopt alternative measures in lieu of

[86] 81 FR 2004, 2028 (''Therefore, we propose to disapprove Section XX.D.6.c. of the Utah SIP under the test in 40 CFR 51.308(e)(3).'').

[87] EPA's interpretation of the requirement under 40 CFR 51.308(e)(3) that the alternative measure ''results in greater emission reductions'' has been that the emission reduction comparisons are pollutant specific. We have applied this interpretation in evaluating BART alternatives and we have not looked at a total emissions profile that combines emissions of multiple pollutants to determine whether a BART benchmark or a BART alternative is ''better,'' except where every visibility impairing pollutant is reduced by a greater amount under the BART alternative. See 79 FR 9318, 9335 (Feb. 18, 2014) (proposed approval of Arizona BART Alternative for Sundt Unit 4); 79 FR 52420 (Sept. 3, 2014) (final approval of Arizona BART Alternative for Sundt Unit 4); 77 FR 18052, 18073–75 (Mar. 26, 2012) (proposed approval of Colorado BART Alternative, no modeling required where the 40 CFR 51.308(e)(3) test was met); 77 FR 76871 (Dec. 31, 2012) (final approval of Colorado BART Alternative). EPA has not relied on a total emissions profile that combines emissions of multiple pollutants together to determine that either BART or a BART alternative is ''better,'' because visibility modeling is the most appropriate method to assess the overall improvements in visibility impacts from control scenarios where reductions of multiple pollutants are considered, except where every visibility impairing pollutant is reduced by a greater amount under the alternative. As we have explained, ''[e]ach of the five pollutants which cause or contribute to visibility impairment has a different impact on light extinction for a given particle mass, making it therefore extremely difficult to judge the equivalence of interpollutant trades in a manner that would be technically credible, yet convenient to implement in the timeframe needed for transactions to be efficient. This analysis is further complicated by the fact that the visibility impact that each pollutant can have varies with humidity, so that control of different pollutants can have markedly different effects on visibility in different geographic areas and at different times of the year.'' See 64 FR 35714, 35743(July 1, 1999). As other Agency actions on BART alternatives have explained, modeling assesses ''both pollutants' chemical aerosol formation mechanisms and impacts on visibility,'' (see 78 FR 79344, 79355; Dec. 30, 2013) which allows evaluation of the ''relative visibility impacts from the atmospheric formation of visibility impairing aerosols of sulfate and nitrate.'' See 79 FR 33438, 33440 (June 11, 2014).

[88] EPA is well aware that the Utah SIP, as it has been implemented over time, became binding state law in regard to the Utah BART Units and ultimately the other units covered by the BART Alternative. This makes it particularly egregious that, even though EPA knew that PacifiCorp was required to expend hundreds of millions of dollars to fully implement the BART Alternative under state law, EPA said nothing about its intention to issue a competing co-proposal until after PacifiCorp had completed all of the emission reductions required under the Utah SIP. *See* Letter from Carl Daly to Bryce Bird, Re. EPA Region 8 Comments on Utah's February 2015 Draft Regional Haze SIP Revision, at 1 (May 1, 2015) (commenting on the then-proposed Utah SIP including the BART Alternative). This secretive approach by EPA also caught the Utah Division of Air Quality off guard as explained in their oral comments during the January 26, 2016 hearing: ''Throughout the SIP development process, we worked as regulatory partners, closely and extensively with EPA staff to ensure that Utah's Alternative to BART SIP revision met all the requirements of the Clean Air Act and was approvable by EPA. The EPA should approve the option that Utah developed while in close consultation with EPA and not the option that Utah was not even aware was being prepared or under consideration until it was proposed in the **Federal Register**.''

[89] *See* CAA sections 169A and 110(k)(3).

BART, their discretion in this area is subject to the condition that it must be reasonably exercised and that their decisions be supported by adequate documentation of its analyses.

Therefore, we do not agree that we are prohibited from identifying deficiencies in the Utah SIP submittal after the State rulemaking process is complete, and the commenter cites nothing in the Act to the contrary. While a state may adopt regulations that are effective as a matter of state law before EPA goes through its rulemaking process to evaluate the proposed SIP elements, those state rules are not federally enforceable because any SIP submittal "shall not be treated as meeting the requirements of this chapter until the Administrator approves the entire plan revision as complying with the applicable requirements." 42 U.S.C. 7410(k)(3). The State's and EPA's roles in this process were understood in PacifiCorp statements. For example, in response to a question provided during rebuttal testimony that asked whether the regional haze rules are final, the Company explained that the 2011 Utah and Wyoming SIP submittals "are final insofar as state action is considered" and recognized that "these submittals have not yet been approved by the Environmental Protection Agency." [90]

The commenter suggests that measures in Utah's SIP submittal became "binding state law in regard to the Utah BART Units" and "the other units covered by the BART Alternative" prior to EPA's final action. The commenter merely suggests there are state law provisions but does not provide citations to any state law specific provisions.[91] It appears, however, that the commenter may be referring to measures established pursuant to the State's permit process. If this is, indeed, what the commenter is referring to, both the CAA and our regulations require that emission limits be established pursuant to a BART or BART alternative determination, and be contained in an EPA-approved SIP.[92] The fact that Utah chose to use its permit process to establish emission limits for its BART sources before EPA completed its review of the State's SIP submittal has no bearing on EPA's authority and obligation to conduct this review and to approve or, if necessary, disapprove the State's submittal.

Finally, EPA's comment letter on the State's proposed SIP clearly explained that "we will only come to a final conclusion regarding the regional haze program for Utah when we take action on the program through our own public notice-and-comment rulemaking." [93] Our letter further explained to the State that, "we are working towards meeting our legal obligations that have resulted from our January 2013 partial disapproval action for Utah's May 2011 regional haze SIP." EPA comment letters are intended to help improve any SIP revision that is under development, but they do not constitute agency action on that SIP revision or constitute any assurance of positive action on that revision upon submission and review. Instead and always, EPA has to formally discharge its responsibilities to review any SIP submittal. Moreover, the CAA does not require EPA to participate in state proceedings related to a state's SIP submission, nor does it preclude EPA from carrying out its statutory duty to disapprove an inadequate SIP if EPA does not voice concerns during state proceedings. The CAA requires EPA to issue a FIP when states have not met their obligations under the CAA. Therefore, EPA is promulgating this FIP to fill the regulatory gap created by the partial disapproval of Utah's SIP submittals. Despite the existence of a FIP, the State retains its authority to submit future regional haze SIPs consistent with CAA and RHR requirements; we do not discount the possibility of a future, approvable SIP submission that results in the modification or withdrawal of the FIP.

C. Reasonableness Standard

Comment: One commenter asserted that EPA arbitrarily and capriciously applies two inappropriate standards to the Utah SIP proposal. The commenter stated that, in an attempt to replace Utah's determination with its own, EPA imposes a "Reasonableness Standard" without concluding the Utah SIP contains data or methodological flaws—the limited circumstances under which courts have upheld use of this standard—and also imposes a "Complexity of Evaluation" standard which finds no support in the CAA or applicable regulations.

The commenter also asserted that EPA is prohibited from imposing additional requirements upon its approval/disapproval of a SIP that do not qualify as "applicable requirements." EPA is not correct in its attempt in the proposed action to impose additional requirements on its evaluation of the BART Alternative and Utah SIP that are different than the applicable BART alternative requirements.

1. Reasonableness Standard –EPA asserts that Utah "has several options for making the greater reasonable progress determination [and it] elected to use two separate approaches." [94] See 81 FR at 2006. EPA further states that it will evaluate both of those approaches in deciding whether to approve the Utah SIP. EPA then makes the blanket assertion that "the State's discretion in this area is subject to the condition that it must be reasonably exercised and that its decisions be supported by adequate documentation of its analysis." ("Reasonableness Standard.") See 81 FR at 2006. Although the use of words like "reasonable" and "adequate" have common sense appeal in the abstract, EPA may not apply this standard in a way that allows EPA to discard the state's discretion and instead impose EPA's own will.

In addition, the present circumstances regarding the SIP proposal are far different than those circumstances in

[90] Rebuttal Testimony of Cathy S. Woolums, at 26. (June 30, 2011). (Available in the docket at *https://www.regulations.gov/#!documentDetail;D=EPA-R08-OAR-2015-0463-0167*).

[91] Utah's Effective rule explains that "[w]hile Utah has chosen to meet the NO_X BART requirement through alternative measures . . . the enforceable emission limits for both NO_X and SO_2 established in the approval orders and in the SIP for the four EGUs also met the presumptive emission rates for both NO_X and SO_2 established in Appendix Y independently of the alternative program." Effective Rule at page E–12, Section XX, p. 168 (adopted by the Board on June 3, 2015), available in the docket at *https://www.regulations.gov/#!documentDetail;D=EPA-R08-OAR-2015-0463-0002.* The presumptive emission limits in the BART Guidelines are rebuttable. The presumptive emission limits apply to power plants with a total generating capacity of 750 MW or greater insofar as these sources are required to adopt emission limits at least as stringent as the presumptive limits, unless after considering the five statutory factors, the State determines that the presumptive emission limits are not appropriate.

[92] Congress required EPA to promulgate regulations to assure "reasonable progress" toward meeting the national goal and compliance with section 169A. The regulations require the submission of regional haze SIPs for states with Class I areas within their borders and states whose emissions "may reasonably be anticipated to cause or contribute to any impairment of visibility" in a Class I area outside their borders. 42 U.S.C. 7491(b)(2), 7491(e)(2). All SIPs must include "enforceable emission limitations and other control measures, means, or techniques . . . as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of [the Act]." CAA section 110(a)(2)(A). Regional haze SIPs must include emission limits, compliance schedules, and other measures "as may be necessary to make reasonable progress toward meeting the national goal." 42 U.S.C. 7491(b)(2).

[93] Letter from Carl Daly to Bryce Bird, Re. EPA Region 8 Comments on Utah's February 2015 Draft Regional Haze SIP Revision, at 1 (May 1, 2015). (Available in the docket at *https://www.regulations.gov/#!documentDetail;D=EPA-R08-OAR-2015-0463-0160*).

[94] As explained below [referring to PacifiCorp's comment document], EPA is simply wrong in concluding that Utah used two separate approaches to demonstrate greater reasonable progress. Therefore, EPA's stated basis for imposing the Reasonableness Standard does not support EPA's effort to do so.

which courts have upheld EPA's use of a similar Reasonableness Standard in other regional haze settings. For example, in *North Dakota* v. *EPA*, 730 F.3d 750, 760 (8th Cir. 2013), the court allowed EPA's use of the Reasonableness Standard under those circumstances where the state's BART determination contained "data flaws that led to an overestimated costs of compliance." Also, *Oklahoma* v. *EPA*, 723 F. 3d 1201, 1212 (10th Cir. 2013) reached a similar conclusion based on "methodological flaws."

In the case of the SIP proposal, however, EPA proposes to approve the BART Alternative based on compliance with the applicable BART alternative requirements[95] and without also concluding that the BART Alternative contains "data flaws" or "methodological flaws." Therefore, the factual bases for allowing EPA to apply a Reasonableness Standard do not exist in regard to the BART Alternative and EPA should not attempt to apply such a standard here—particularly as a basis for rejecting the BART Alternative.[96]

2. Complexity of Evaluation Standard—EPA also is wrong in its attempt to count among applicable requirements the unsupported conclusion that the "complexity of our evaluation" somehow necessitates EPA soliciting comments not only on the SIP proposal, but also on the competing FIP proposal. See 81 FR 2006.[97] Even taking at face value the assertion that analyzing the Utah SIP is "complicated," that alone does not require EPA to evaluate the Utah SIP differently than any other regional haze SIP, nor does it justify EPA in presenting dueling co-proposals.[98] In other words, EPA has simply conjured up this new "complexity" requirement[99] out of thin air in an attempt to support its offering of the competing FIP proposal. EPA is acting arbitrarily and without legal authority by seeking comment on the FIP proposal based on what EPA calls the "complexity of our evaluation" and for this reason EPA should withdraw the FIP proposal and approve the SIP proposal as proposed.

Response: We disagree with most of these comments. First, we disagree that we have used a "reasonableness standard" in a manner that is inconsistent with our prior actions or as a way to limit the State's discretion. As discussed elsewhere, EPA has a duty to review Utah's regional haze SIP, including its BART Alternative, for compliance with the applicable requirements of the CAA and the RHR. Based on our review of the SIP, we proposed to determine that certain elements of Utah's regional haze SIP met the applicable requirements, and we proposed to approve those elements. However, for the reasons explained in detail in our proposed action and elsewhere in this document, we have concluded that, with regard to other elements, the State did not exercise its discretion in a reasonable manner, *i.e.*, in a manner consistent with the requirements and goals of the CAA and RHR. Based on these findings, we are required to partially disapprove Utah's regional haze SIP submittal.

As discussed in detail elsewhere, the CAA provides EPA with the authority to review and reject an inadequate regional haze SIP submittal. *Oklahoma* v. *EPA*, 723 F.3d 1201, 1207–08 (10th Cir. 2013) (EPA may not approve a submittal that does not adhere to applicable statutory and regulatory requirements). Contrary to the commenter's assertions, our analysis and decision here is entirely consistent with the *North Dakota* and *Oklahoma* decisions. The RHR requires a state to demonstrate that its BART alternative achieves greater reasonable progress than BART, 40 CFR 51.308(e)(2), and Utah chose to make this demonstration using a weight-of-evidence analysis. In our review, EPA found a number of flaws in this analysis. Based on this evaluation and findings as detailed in Section I.B.1 of this document and in our RTC document, we determined that, on balance, the evidence does not show that the Alternative clearly achieves greater visibility benefits than BART.

Second, we disagree with the assertions regarding creation of a new complexity standard. The commenter misunderstands and misconstrues our proposed action. We did not create a new complexity standard, rather we explained that we were considering complex information and that it was a close call for EPA to decide whether the evidence presented by the State clearly demonstrated that the BART Alternative would achieve greater reasonable progress than BART (the complexity of our evaluation leads us to propose and solicit comment on two conclusions and courses of action because several of the metrics *appear to* support the State's analyses, while others do not appear to support the Alternative).[100] Contrary to the commenter's assertions, we merely explained that the information in the State's SIP submittal was complex; we did not create a new standard by which to evaluate SIP submittals. Our proposed action clearly explained that some metrics appeared to support approval, while others metrics appeared to support a disapproval.

Therefore, given that EPA's evaluation of the information before us presented a close call, and in order to provide a fair and meaningful process for *all* members of the public, we used the co-proposal approach. This approach provided an opportunity for the public to comment on both potential courses of action, *i.e.*, approval or disapproval of the State's BART Alternative. Recognizing the

[95] *See* generally 81 FR 2004, 2021–26.

[96] This is not to say that EPA lacks any role in reviewing and approving the Utah SIP. Indeed, the latest court to weigh in on EPA's review authority makes clear that "Congress intended that EPA, not the states alone, ultimately ensure that state determinations as to regional haze comply with the [Clean Air] Act. . ..." Arizona ex rel. Darwin v. EPA, Nos. 13–70366, 13–70410, 2016 U.S. App. LEXIS 3196, at *19–20 (9th Cir. Feb. 24, 2016). Although PacifiCorp agrees that EPA has a role to play in making sure the Utah SIP complies with the CAA and applicable requirements, it also notes that EPA must do so in a way that does not undermine the role of states like Utah to which "Section 169A [of the CAA] gives. . .substantial responsibility in determining appropriate BART [and BART Alternative] controls." The court goes on to make clear that "EPA may not disapprove reasonable state determinations that comply with the relevant statutory and regulatory requirements." *Id.* at *22. Such is the case with the Utah SIP.

[97] EPA attempts to further support this contrived "complexity" requirement by repeatedly stating that such a requirement exists, as if repetition alone somehow can bring an imaginary requirement into existence (*i.e.*, "In light of the variety of metrics Utah used, this is a complicated analysis. . . ;" "The complexity of our evaluation leads us to propose and solicit comments on two conclusions and two courses of action . . . ;" "Given the complexities in evaluating these co-proposals, EPA wants to ensure that our final decision is based on the best and most currently available data and information, and is taken with the fullest possible consideration of public input.") See 81 FR 2004, 2006.

[98] The Tenth Circuit Court of Appeals, which considered whether EPA's approval of a BART Alternative for SO_2 emissions was appropriate, did not conclude that EPA's analysis of the alternative program was, by its nature, more complicated than a BART analysis. See generally WildEarth Guardians v. EPA, 770 F.3d 919 (10th Cir. 2014).

[99] EPA further attempts to justify its rationale for considering the FIP proposal by asserting, as explained in footnote 3, the need to "ensure that our final decision is based on the best and most currently available data and information, and is taken with the fullest possible consideration of public input." EPA already is charged with ensuring that any final decision is based on the best current data and information available. See 71 FR 60612, 60622 (Oct. 13, 2006) (final rule on revisions to provisions governing alternative source-specific BART determinations); see also 5 U.S.C. 706(2). EPA already is required to make a decision based on the fullest possible consideration of public input. See 5 U.S.C. 553(c). Re-stating these fundamental principles does not allow EPA to bootstrap itself into also considering a competing coproposal (the FIP proposal) when the SIP proposal already meets all Applicable BART Alternative Requirements as EPA itself has proposed to conclude. Arizona ex rel. Darwin at *22 (stating that "EPA may not second-guess reasoned, legally compliant state decisions") (internal citations and quotations omitted).

[100] 81 FR 2004, 2006 (Jan. 14, 2016) (emphasis added).

information before the Agency was possibly susceptible to both interpretations, our two proposed conclusions and courses of action were as follows: ''(1) The State's submittal meets the test above and we approve the BART Alternative; or (2) the State's submittal falls short of meeting this test and we disapprove the BART Alternative and promulgate a FIP for NO_X BART.''

We exercised our rulemaking discretion and structured the action using the co-proposal approach so that our action would enable all interested parties to have the opportunity to provide meaningful and timely comment on either or both approaches. In structuring the action in this way, the interested public had notice of the proposals under consideration and whether they had interests at stake. This balanced approach was fair in that it provided all interested parties with the options EPA contemplated in taking final action, as well as providing an opportunity to comment on the full range of potential actions. The commenter cites to no CAA provision that restricts EPA's authority to present co-proposals. EPA often provides alternative approaches for final Agency action in our SIP rulemaking proposals, as we did here. Additionally, even assuming that EPA's proposed action on the Utah regional haze SIPs articulated new ''complexity'' grounds for evaluating a regional haze SIP, the proposed action provided the public with the opportunity to comment. As evidenced by the commenter's submission, the commenter had the opportunity to provide input on this purported new standard to evaluating the Utah regional haze SIP and to identify any concerns associated with the statements at issue. Therefore, even if we had created a new complexity standard, which we did not, it would have been properly proposed and applied in this instance.

As explained above, the EPA proposal identified several weaknesses and flaws in the State's SIP submittal in the proposed rulemaking,[101] and as explained in this final action, other commenters have made us aware of additional weaknesses and uncertainties in the SIP submittal.[102] Therefore, EPA is finalizing our co-proposal to disapprove the BART Alternative and promulgate a FIP for NO_X BART, which this commenter recognizes EPA has a role and authority to do.

Furthermore, as explained elsewhere, we appreciate and clarify in this final action that the State did not intend to have its BART Alternative evaluated under both the 40 CFR 51.308(e)(2) and section 308(e)(3) tests. We, therefore, based our final action on our evaluation of the State's submittal under §51.308(e)(2)'s weight-of-evidence test.

Finally, regarding the commenter's cross-reference to comments dated August 26, 2013, we explained in our final action in the Wyoming regional haze rulemaking that we disagreed with the comments in that context and we continue to disagree here.[103]

D. Compliance With 40 CFR 51.308

Comment: Two commenters noted that EPA's FIP proposal is unnecessary because EPA already found Utah is making the required ''reasonable progress.'' The goal of the RH program is to make ''reasonable progress'' towards the statute's national visibility goal. Accordingly, EPA promulgated regulations ''to assure . . . reasonable progress toward meeting'' the national visibility goal, section 7491(b)(2), and mandated that EPA's regulations contain ''such emission limits, schedules of compliance and other measures as may be necessary'' to assure such progress towards meeting that goal, ''including'' a requirement that states make BART determinations. Id. As EPA has stated, ''BART is one component of long term strategies to make reasonable progress.'' Regional Haze Regulations and Guidelines, 70 FR 39137.

Because BART's purpose is to make reasonable progress, EPA adopted regulations exempting states from making BART determinations if they can show that other measures for large stationary sources will achieve greater reasonable progress. 40 CFR 51.308(e)(2) (2012). EPA defended those regulations in court by arguing that BART is one of a number of ''emission limits, schedules of compliance and other measures'' that ''must'' be included in a SIP '''as may be necessary to make reasonable progress toward national visibility goals.''' *Ctr. for Energy and Econ. Dev.* v. *EPA*, 398 F.3d 653, 659–60 (D.C. Cir. 2005) (confirming BART is but one measure for achieving ''reasonable progress''); *Cent. Arizona Water Conservation Dist.* v. *EPA*, 990 F.2d 1531, 1534 (9th Cir. 1993) (same). If an alternative can better achieve those

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[101] Our proposal evaluated the State's use of the information from the metrics and identified weaknesses and flaws, for example: (1) The State's characterization of the 98th percentile modeling results that did not support its BART Alternative, was inconsistent with EPA's interpretation of and reliance on that metric; (2) the comparison of the results from the total annual emissions reductions was inconsistent with how we have interpreted our regulations; (3) the results from the modeling for the number of days the Alternative provided significant visibility impairment showed mixed results, with some results favoring the Alternative, while other results did not support the Alternative; (4) the annual average metric only marginally supported the Alternative, and showed less or equal visibility at four of nine Class I areas; and (5) the energy and non-air quality and cost metrics do not have a direct bearing on whether the Alternative achieves greater reasonable progress.

[102] Our RTC document provides details on the additional weaknesses and uncertainties that commenters brought to our attention.

[103] ''As explained in our proposed rulemaking for section 51.309(d)(4)(viii), we explained that the provision 'is intended to clarify that if EPA determines that the SO_2 emission reductions milestones and backstop trading program submitted in the section 51.309 SIP makes greater reasonable progress than BART for SO_2, this will *not* constitute a determination that BART for PM or NO_X is satisfied for any sources which would otherwise be subject to BART for those pollutants' (emphasis added). 70 FR 44169 (Aug. 1, 2005). EPA does not interpret this rule to mean that there are different BART requirements for section 308 and 309 regional haze SIPs. EPA's rulemaking made no finding that BART determinations conducted for a state submitting a SIP under section 51.309 should be conducted any differently than a state submitting a FIP under only section 308. The use of the word 'necessary' in section 51.309(d)(4)(viii) was to explain that some states may have BART NO_X emission limitations, while others may not. As already explained elsewhere in proposal and our response to other comments, Wyoming did not conduct a proper evaluation of the five statutory factors, as required by 40 CFR 51.308(e)(1)(ii)(A) and section 169A(g) of the CAA.

EPA also disagrees with the commenter's assertion that a BART submission is discretionary. 40 CFR 51.309(d)(4)(viii) is clear in that the implementation plan 'must' contain BART requirements. The proposed rulemaking explained that the provision that provides that '[a]ny such BART provisions may be submitted pursuant to either Section 51.308(e)(1) or 51.308(e)(2),' was included to 'allow States the flexibility to address these BART provisions either on a source-by-source basis under Section 51.308(e)(1), or through an alternative strategy under Section 51.308(e)(2).' 70 FR 44169 (Aug. 1, 2005).

Moreover, EPA's proposal made clear that '[i]n limited circumstances, it may be possible for a State to demonstrate that an alternative program which controls only emissions from SO_2 could achieve greater visibility improvement than application of source-specific BART controls on emissions of SO_2, NO_X and/or PM. We nevertheless believe that such a showing will be quite difficult to make in most geographic areas, given that controls on SO_2 emissions alone in most cases will result in increased formation of ammonium nitrate particles.' 70 FR 44169 (Aug. 1, 2005). Wyoming's RH SIP does *not* include a demonstration that the backstop SO[2] trading program under Section 51.309 achieves greater visibility improvement than application of source-specific PM BART controls. Therefore, Wyoming's Section 51.309 SIP does not provide the adequate level of visibility improvement to meet the BART requirements

With respect to the relationship of BART and requirements for reasonable progress under *40 CFR 51.308*, EPA interprets the reasonable progress requirements to apply to BART sources. As explained in our guidance, due to the similarity of the BART and reasonable progress factors, states may reasonably rely on their BART determinations to show reasonable progress for those sources for the first planning period. However, BART is an independent requirement of the statute and the RHR. We have disapproved certain BART determinations by Wyoming not due to a failure to make reasonable progress, but due to a failure to consider the BART factors appropriately.'' 79 FR 5032, 5098, 5099 (Jan. 30, 2014).

goals, EPA has stated that BART would not be "necessary to make reasonable progress." *Id.* The court agreed with EPA's analysis, although it overturned EPA on other grounds. *Id.* As the court said, "the focus of the Clean Air Act was to achieve 'actual progress and improvement in visibility,' 42 U.S.C. 7492(b), not to anoint BART the mandatory vehicle of choice." *Id.* at 660.

As EPA recognizes, in some circumstances no BART controls may be necessary to make reasonable progress. It follows that in other circumstances, depending on a state's reasonable-progress goals and expected non-BART emission reductions, BART controls of varying stringency may be necessary. Consistent with this goal, EPA has approved Utah's "reasonable progress" determination for its RH SIP in its entirety. *See* "Approval, Disapproval and Promulgation of State Implementation Plans; State of Utah; Regional Haze Rule Requirements for Mandatory Class I Areas Under 40 CFR 51.309," published at 77 FR 74355, 74367–68 (Dec. 14, 2012). EPA found that "the State met all reasonable progress requirements for the Class I areas," including by implication any required NO_X BART limits. In fact, EPA stated that Utah's 2008 RH SIP, including BART controls identified in that 2008 RH SIP, would result in "a significant decrease in stationary source NO_X and SO_2 emissions." *Id.* EPA further found that the NO_X BART controls adopted by Utah for the Hunter and Huntington EGUs at issue would decrease NO_X emissions by "6,200 tons [annually] between 2002 and 2018." *Id.* Therefore, EPA acknowledged that Utah's NO_X BART limits and controls are all that are required to achieve "reasonable progress," and no further NO_X BART requirements should be imposed by EPA through its FIP proposal.

Thus, EPA cannot validly judge a state's BART determination outside of its reasonable progress context. *Owasso Indep. Sch. Dist. No. I–011* v. *Falvo*, 534 U.S. 426, 434 (2002) ("the words of a statute must be read in their context and with a view to their place in the overall statutory scheme.").

Response: EPA disagrees with these comments. The commenters appear to be asserting that, since EPA approved Utah's 2011 SIP submission as meeting the reasonable progress requirements of 40 CFR 51.309 with regard to SO_2, no further controls are necessary to meet the RHR's requirements for NO_X and PM. However, this assertion ignores our statements in the BART Alternatives rulemaking that an EPA determination that a backstop trading program satisfies a state's reasonable progress obligations for SO_2 under 40 CFR 51.309 does not satisfy that state's obligation to address NO_X and PM requirements under 40 CFR 51.308(e)(1) or (2). In this rulemaking, EPA proposed amendments to the stationary source NO_X and PM provisions within §51.309 precisely in order to "clarify that if EPA determines that the SO_2 emission reductions milestones and backstop trading program in the §51.309 SIPs makes greater reasonable progress than BART for SO_2, this will *not* constitute a determination that BART for PM or NO_X is satisfied for any sources which would otherwise be subject to BART for those pollutants." [104] The final rulemaking reinforced that a reasonable progress determination for SO_2 under §51.309's backstop trading program does not satisfy the emission reductions requirements for non-SO_2 pollutants.[105]

We also took this position in another recent regional haze action, in which we found that the state's approved SO_2 alternative under §51.309 did "not provide the adequate level of visibility improvement to meet the [non-SO_2] BART requirements." [106] We then reiterated that "BART is an independent requirement of the statute and the RHR." [107] Our statements in both the national and regional contexts make it clear that a reasonable progress determination for an SO_2 backstop trading program under §51.309 does not relieve a state of its obligation to satisfy NO_X and PM BART. EPA thus *can* judge a state's BART determination outside the reasonable progress context, as they are independent requirements.

The commenters' claim that EPA's approval of Utah's §51.309 program in our December 2012 final action means that the State met its reasonable progress requirements "in its entirety" is thus clearly incorrect. In that action we determined that the State met the requirements of §51.309 and therefore satisfied its reasonable progress obligation *with regard to the particular pollutants covered in the State's alternative, i.e.,* SO_2. This determination has no bearing on the State's independent NO_X and PM obligations. To comply with the RHR, the state must still address any BART obligations for pollutants not included in the BART alternative analysis and therefore not covered by the "better than BART" determination.

EPA similarly disagrees that it acknowledged that the NO_X controls in Utah's 2011 SIP submission are all that are required to achieve reasonable progress and that EPA should therefore not require further NO_X BART requirements. As explained earlier, EPA's determination that Utah's 2011 submission satisfied reasonable progress requirements does not constitute implicit evaluation and action on Utah's NO_X and PM SIP submittal as meeting the BART requirements. Furthermore, the commenter overlooks EPA's explicit disapproval of Utah's NO_X and PM BART determinations in our December 2012 partial approval/disapproval.[108] EPA's disapproval of Utah's NO_X and PM control determinations necessarily precludes finding that these same controls are all that are required to satisfy the RHR's requirements. EPA is thus required to promulgate a NO_X BART FIP, which we are now doing. Commenters also take EPA's statements regarding the quantity of anticipated NO_X reductions from Utah's rejected BART determination out of context. These statements were offered as reasons why Utah satisfied the RHR's requirement to address impacts on Class I areas in other states by achieving previously agreed upon emission reductions, which is a separate consideration from whether the State has satisfied its independent NO_X and PM BART obligations.

EPA also disagrees that the statements in the cited cases have any bearing on this action. In *Center for Energy and Economic Development* v. *EPA* (*CEED*),[109] the issue was whether EPA's BART alternative provisions in §51.309 were consistent with CAA section 169A(b)(2) given that they used a methodology for establishing the BART benchmark that the D.C. Circuit had previously vacated in *American Corn Growers Ass'n* v. *EPA*.[110] As part of its challenge to EPA's BART alternative provisions, CEED argued that section 169A(b)(2) requires all states' SIPs to include BART, meaning EPA could not allow BART alternatives in place of source-specific BART. EPA argued that section 169A(b)(2) allows either BART or an alternative to BART submitted pursuant to §51.309 if that alternative would achieve greater reasonable progress than BART, *i.e.,* if the alternative is "better than BART." The statements the commenter cites express EPA's view on the narrow issue of whether and when we may allow states to substitute an SO_2 trading program for

[104] 70 FR 44154, 44169 (Aug. 1, 2005) (emphasis added).

[105] 71 FR 60612, 60626 (Oct. 13, 2006).

[106] 79 FR 5032, 5099 (Jan. 30, 2014) (final partial approval/partial disapproval of Wyoming regional haze SIP submission).

[107] *Id.*

[108] 77 FR 74355, 74357 (Dec. 14, 2012).

[109] 398 F.3d 653 (D.C. Cir. 2005).

[110] 291 F.3d 1 (D.C. Cir. 2002).

source-specific BART under §51.309. Because these statements address only the relationship between BART and BART alternatives for SO_2 under §51.309; they have no bearing on whether we believe a state's submission of an SO_2 trading program satisfies its independent obligation to address NO_X and PM, as these obligations were not at issue in this case.

In our December 14, 2012 action we approved Utah's BART Alternative for SO_2 under 40 CFR 51.309, finding that it achieved greater reasonable progress than SO_2 BART. As explained earlier, this determination has no bearing on Utah's outstanding NO_X and PM BART obligations. We, therefore, disagree that today's action to address these obligations is unnecessary.

Comment: Several commenters asserted that Utah's BART Alternative does not achieve greater reasonable progress based on the "clear weight-of-evidence." Utah's Regional Haze SIP also must be rejected under 40 CFR 51.308(e)(2)(i)(E) because it does not achieve "greater reasonable progress" based on the "clear weight-of-evidence." [111]

At the outset, Utah's proposed reliance on the "clear weight-of-evidence" test is improper. In promulgating regulations allowing for the test, 40 CFR 51.308(e)(2)(i)(E), offered the following example of when the test might be appropriate: "(1) The alternative program achieves emissions reductions that are within the range believed achievable from source-by-source BART at affected sources, (2) the program imposes a firm cap on emissions that represents meaningful reductions from current levels and, in contrast to BART, would prevent emissions growth from new sources, and (3) the State is unable to perform a sufficiently robust assessment of the programs using the two pronged visibility test due to technical or data limitations." [112] None of those conditions are met here. Most importantly, Utah's BART Alternative does not drive any meaningful reductions from "current levels" and does not prevent emissions growth from new sources, and Utah is not hindered by any technical or data limitations preventing a sufficiently robust visibility assessment. EPA further noted that "a weight-of-evidence comparison may be warranted" "when there is confidence that the difference in visibility impacts between BART and the alternative scenarios are expected to be large enough." [113] Here, as EPA correctly observed, even Utah's flawed modeling demonstrated the superiority of BART using the most relevant visibility metric and only minimal benefits of the BART Alternative compared with BART using other metrics.

Several commenters also raised concerns regarding emission shifting from the power plants covered by the SIP to existing sources that are not included in this SIP. They suggested that due to the nature of the electrical generation market, with the adjustments to the overall system to add capacity elsewhere to accommodate the Carbon power plant shutdown (and perhaps also to accommodate the emission limit reductions at the Hunter and Huntington power plants), those shifts in capacity could result in increases in emissions at power plants outside the BART Alternative. The commenters further suggested that if those emission increases had been considered in the State's weight-of-evidence analysis, the BART Alternative may not provide greater reasonable progress than BART if the emission reductions assessment under the Alternative are not permanent and were to shift to other power plants. As an example, one of the commenters provided an analysis for a Utah power plant (not covered by the BART Alternative) that based on its proximity to the nine Class I areas analyzed under the BART Alternative, if emission increases were to occur at that plant the increases could impact visibility impairment at the Class I areas. Other commenters expressed concern that the lost capacity from the BART Alternative sources could shift to new sources, and explained that the emissions from new sources are not evaluated in the State's weight-of-evidence analysis. One commenter suggested that this Alternative appears to be more like a "trading" program and that other regulations apply. One commenter expressed concern that a non-BART source is included in the BART Alternative, and further, that not all the sources in the State that are part of this source category are included.

Response: We agree in part and disagree in part with these comments. First, as explained elsewhere, we agree with the commenter that the State's analysis for the BART Alternative does not show that the Alternative clearly achieves greater visibility benefits than BART. Second, the four examples cited by the commenter from our RHR preamble were *examples,* rather than an exclusive list of circumstances under which a state may use a weight-of-evidence analysis. Therefore, the State was not required to fall into one of these categories in order to select the weight-of-evidence approach to support its BART Alternative. Third, we disagree that emission reductions must occur from current levels, because, consistent with the RHR, the baseline date for regional haze SIPs is 2002.[114]

Next we respond to the commenters' concerns about potential shifting of production and emissions from the sources in the BART Alternative to sources outside the BART Alternative. We acknowledge that the State's BART Alternative has the following characteristics: (1) It includes all the BART sources in the State; (2) it accounts for emission reductions from a non-BART source; and (3) it includes some, but not all, sources in the source category within the State. The RHR provides that BART alternative programs may include non-BART sources.[115] We disagree with commenters that suggested the RHR trading requirements apply to the Utah BART Alternative.[116] The RHR trading provisions apply to SIPs that establish a cap on total emissions from sources that are subject to the BART program, and further require the owners and operators of the sources to hold allowances to purchase, sell, and transfer allowances. Utah's SIP contains rate-based emission limits on the sources that are subject to the BART Alternative and therefore does not include a cap on emissions or trading provisions. Therefore, the Utah SIP does not contain the elements of a trading program as described in the RHR, which include provisions to prevent significant emission shifting.[117]

Although the State's SIP explained that the Carbon power plant had already closed and electricity generated from the Carbon power plant has been replaced (and the associated costs already have been absorbed by Utah rate payers and those in other states served by PacifiCorp),[118] the SIP submittal neither identified what electrical generating facilities increased capacity

[111] 40 CFR 51.308(e)(2)(i)(E).

[112] 71 FR 60612, 60621 (Oct. 13, 2006).

[113] *Id.* at 60622.

[114] *See* Memorandum from Lydia Wegman and Peter Tsirigotis, 2002 Base Year Emission Inventory SIP Planning: 8-hr Ozone, $PM_{2.5}$, and Regional Haze Programs (November 18, 2002).

[115] The preamble to the RHR provides for inclusion of BART and non-BART sources in a BART alternative. 64 FR 35714, 35743 (July 1, 1999).

[116] 40 CFR 51.308(e)(2)(E)(v) (containing requirements for a state to demonstrate that a trading program prevent any significant, potential shifting within the state of production and emissions from the sources in the program to sources outside the program).

[117] *Id.*

[118] Utah Staff Review Report at 27.

to accommodate the Carbon shut down, nor did it provide an analysis of whether the capacity replacement resulted in increases in visibility impairing pollutants. Furthermore, in addition to seeking and receiving authorization to recover costs associated with retirement of the Carbon plant, the Company also received authorization from state utility commissions to recover additional costs, including "installation of equipment necessary to ensure voltage stability, along with various communications upgrades and protection and control equipment." [119] It is unclear whether the activities associated with these additional costs resulted in capacity and emissions shifting and increased visibility impairment at the affected Class I areas. Therefore, while the record before us indicates that capacity has shifted, it is unclear how the shift was accommodated, and whether there are any emission increases and associated visibility impairment.[120]

It is therefore unclear whether the shift in capacity as a result of the Carbon plant retirement results in increased emissions and visibility impairment at the affected Class I areas. Because the record lacks information on these questions, we agree with the commenters that there is additional uncertainty as to whether the BART Alternative is better than BART.

E. Overarching Comments on BART Alternative Demonstration

Comment: The State of Utah commented that EPA should approve the option that Utah developed in close consultation with EPA and not the option that Utah was not even aware was being prepared or under consideration until it was signed by the Regional Administrator. Utah worked closely and in good faith with the EPA and the FLMs to evaluate and implement the appropriate controls for improving visibility. Up to the point of the current proposal, the EPA has indicated to Utah that the alternative to BART approach and analysis were acceptable. During the RH SIP development process, Utah and EPA worked as regulatory partners—Utah working closely and extensively with EPA's staff to ensure that Utah's BART Alternative was approvable. EPA's concurrence with Utah's RH SIP proposal is also supported by EPA's comments submitted during the state rulemaking public comment period on the current revision of the Utah's RH SIP. EPA did not point to any substantive flaws in Utah's RH SIP, but only requested minor clarifications and revisions in its 3-page comment letter.

Response: While we agree that EPA worked in close consultation with Utah on the BART Alternative within the limitations of what the State and PacifiCorp were willing to offer in the plan, EPA is not required to approve the option developed by Utah. As stated elsewhere in this document, EPA's comment letter on the State's proposed SIP explicitly explained the following: "[p]lease note that we will only come to a final conclusion regarding the regional haze program for Utah when we take action on the program through our own public notice-and-comment rulemaking." [121] Our May 1, 2015 letter further explained to the State that, "[i]n addition, we wish to inform you that we are working towards meeting our legal obligations that have resulted from our January 2013 partial disapproval action for Utah's May 2011 regional haze SIP." [122] EPA's assistance to states and our comment letters are intended to be helpful to the improvement of any SIP revision that is under development, but they do not constitute agency action on that SIP revision or constitute any assurance of positive action on that revision upon submission and review.

Additionally, the State's efforts to involve the FLMs did not adequately meet the requirements for FLM consultation in developing plan revisions. The State could have satisfied the consultation requirements by providing more time for FLM review so that the FLMs would have received the full number of 60 days for their review. However, in developing the co-proposals, consulting with the FLMs, and by taking this final action, EPA has considered the FLMs' concerns.

Comment: Several commenters asserted that both Utah and EPA imply that nitrate formation in non-winter months is not significant,[123] or that NO_X reductions will not meaningfully reduce nitrates in non-winter months.[124] Both are untrue. Based on IMPROVE data, light extinction attributable to ammonium nitrate in non-winter months is roughly 20% of that attributable to ammonium sulfate. Despite the preferential formation of ammonium sulfate year round and higher ammonium nitrate formation in winter months, it is clear that significant levels of ammonium nitrate also form in non-winter months, and that these are likely to be lowered by reductions in NO_X emissions. Furthermore, while EPA notes that wintertime conditions favor nitrate formation (versus non-winter),[125] this is accounted for in modeling and cannot be used to discount those results.

Response: We partially agree with the comment. While EPA did not suggest that nitrate in non-winter months is not significant, IMPROVE monitoring data do show that nitrate light extinction is highest in winter and substantially smaller in the other seasons. For example, in 2014, the most recent year of IMPROVE data available at the Canyonlands monitor, nitrate contributed an average of 31% of total light extinction in December to February compared to an average of 5% of total light extinction from March to November. In 2013, nitrate contributed an average of 45% of total light extinction in December to February compared to an average of 7.5% of total light extinction from March to November. By contrast, sulfate light extinction is relatively constant across the four seasons.[126]

Nonetheless, overall nitrate extinction at the affected areas is significant, particularly on the 20% worst days. For example, at Canyonlands on the 20% worst days, nitrate contributed 33% and 17% of total extinction in 2013 and

[119] *The Application of Rocky Mountain Power for Approval of a General Rate Increase,* No. 20000–446–ER–14, Wyoming Public Service Commission, (Jan. 23, 2015) (Findings of Fact, Conclusions of Law, Decision and Order Nunc Pro Tunc) (Available in docket at *https://www.regulations.gov/#!documentDetail;D=EPA-R08-OAR-2015-0463-0167*). An order from the Idaho Public Commission also discussed the impacts from Carbon's retirement on the transmission system and noted that "[t]he Company states that retiring Carbon may pose a complication with potential transmission system impacts." *See The Application of PacifiCorp DBD DBA Rocky Mountain Power,* Case No. PAC–E–12–08, Order No. 32701, at 1, Idaho Public Utilities Commission (Dec. 27, 2012) (Available in the docket at *https://www.regulations.gov/#!documentDetail;D=EPA-R08-OAR-2015-0463-0167*).

[120] Utah's BART Alternative has the characteristics of an "open market" program where some, but not all, sources in a source category are covered by the SIP measure. EPA Guidance, "Improving Air Quality with Economic Incentive Programs," at 48, 96, 112–118, EPA–452/R–01–001 (Jan. 2001), available at *https://www3.epa.gov/ttn/caaa/t1/memoranda/eipfin.pdf*); 77 FR 11928 (Feb. 28, 2012); 77 FR 46952 (Aug. 7, 2012).

[121] Letter from Carl Daly to Bryce Bird, Re. EPA Region 8 Comments on Utah's February 2015 Draft Regional Haze SIP Revision, at 1 (May 1, 2015). (Available in the docket at *https://www.regulations.gov/#!documentDetail;D=EPA-R08-OAR-2015-0463-0160*).

[122] *Id.*

[123] Utah Staff Review Report at 17, Exhibit 15. Winter months in this context are December, January, and February.

[124] 81 FR 2004, 2023 (EPA says that based on a computational model, "We propose to find that visibility benefits associated with NO_X reductions are much more likely to occur in the winter months because this is when aerosol thermodynamics favors nitrate formation").

[125] *Id.*

[126] See EPA spreadsheet entitled, Canyonlands IMPROVE Monitoring Data for 2013 and 2014 (Available in the in the docket).

2014, respectively. Given the focus of the reasonable progress provisions of the RHR on the 20% worst days, we consider the monitoring data for these days to be more informative than seasonal trends in monitoring data.

We also agree with the commenter that the modeling performed by Utah and EPA accounts for the fact that wintertime conditions favor nitrate formation (versus non-winter). In particular, the CALPUFF modeling performed by Utah and EPA both show that, while there will be some benefits from NO_X controls outside of the winter season, the largest benefits in nitrate reductions occur in winter months.[127] We have taken the strength of the modeling results for winter months into consideration; however, contrary to suggestions that visibility improvements during seasons of peak Class I area visitation should carry more weight, we have evaluated the visibility impacts throughout the entire year, regardless of the season and have given the most weight to those times when the sources in question have the largest impacts. In particular, as explained elsewhere in this document and our RTC document, we have given greater weight to the 98th percentile CALPUFF metric, which captures these highest impact days.

F. Cost of Controls

Comment: Several commenters submitted comments regarding the costs to install SCR at the Hunter and Huntington BART EGUs. PacifiCorp submitted a technical report developed by its consultant, Sargent & Lundy, which criticized numerous aspects of EPA's cost analysis developed by our contractor, Andover Technology Partners (ATP), including catalyst volume, SCR design, project and process contingency costs, and others. The conservation organizations' consultant reviewed PacifiCorp's cost analyses from 2012 and 2014 and provided comments about the validity of PacifiCorp's analyses. The National Park Service supported EPA's cost estimates in the proposed rule and indicated the estimates show that both the combined cost of LNB and SOFA plus SCR (SCR + LNB/SOFA) and the incremental cost of adding SCR to LNB/SOFA are cost-effective and represent BART. The conservation organizations also supported EPA's cost estimates in the proposed rule.

Response: EPA has provided a revised cost analysis to support our final rulemaking. We again used Andover Technology Partners (ATP) for conducting the analysis. We have carefully reviewed the analysis and determined that it appropriately estimates the costs to install SCR at Hunter and Huntington. Of particular note is that in our revised cost analysis, EPA has accepted both the catalyst volume and SCR design suggested by Sargent & Lundy. However, we continue to reject process and project contingency costs and other costs that are double counted, not permissible under the CCM, or are otherwise not justified. The final Andover report and spreadsheet provide further details regarding how each of these costs was addressed in the revised analysis supporting this rulemaking.[128] Also, in our RTC document, we have addressed the specific comments concerning the capital costs that Sargent & Lundy alleges that Andover incorrectly excluded from its analysis, as well as all other comments regarding our cost estimates.

We concur with the National Park Service's and conservation organizations' supportive comments regarding the cost effectiveness of SNCR and SCR. In addition, the revised cost effectiveness estimates that we prepared to support this final rule, when considered along with the other five BART factors, continue to support selection of SCR + LNB/SOFA as BART.

The conservation organizations' comments pertain to the costs that PacifiCorp submitted to the Utah Department of Air Quality, and which Utah included in its SIP submittal to EPA. However, EPA developed separate costs to support our FIP, and has updated those costs in support of our final action. Our RTC document contains additional detail concerning our consideration of these comments.

G. Comparison With Other Regional Haze Actions

Comment: Two commenters agreed with the comparisons we provided in our proposed rule to other BART determinations that EPA used to support our proposed FIP. One commenter disagreed with the comparisons. These comparisons included Cholla,[129] Hayden,[130] and Laramie River Station.[131] The commenter who disagreed asserted that different methodologies were involved in all three cases and that EPA failed to provide comparisons to other actions that did not support the FIP. The commenter provided additional examples from EPA actions in Florida, Montana, and Nebraska that they asserted do not support EPA's Utah FIP decision.

Response: We continue to find that the Cholla, Hayden and Laramie River Station comparisons are among the best to use considering the specifics of our Utah action. The commenter who disagreed with these comparisons did not show that it would make a significant difference to use precisely the same methodology in each of the determinations that EPA chose to rely on. Furthermore, we disagree that the methodology involved in the BART analyses necessarily must be precisely the same for each BART determination in order to use the determinations for comparison purposes. For example, a state may choose to use a slightly different methodology to analyze the BART factors and select BART, which is acceptable so long as the methodology is reasonable and consistent with the statute, RHR, and BART Guidelines. For details, please see the RTC document.

We also disagree that the cited BART determinations in Montana, Florida, and Nebraska are useful comparisons or show that our BART determination here is unreasonable. First, with respect to the Florida action, the cited NO_X BART determination at FPL's Manatee Plant involved two 800 MW oil and natural-gas fired steam turbines. 77 FR 73369, 73377 (Dec. 10, 2012) (proposal). As the two units were equipped with FGR, overfire air systems, staged combustion, LNB, and reburn, SCR was the only available additional control option identified. The total annualized cost of SCR at the two units would be $31 million, from which the state computed a dollar-per-deciview cost of $66 million/dv. *Id.* at 73377. Using these figures, the total (*i.e.* source wide) visibility improvements at the most impacted Class I area, Chassahowitzka NWA, would be 0.47 dv, which is considerably below the source-wide visibility improvement for SCR + LNB/SOFA at Hunter and Huntington of 2.948 dv and 3.848 dv, respectively.[132]

[127] Both Utah and EPA CALPUFF modeling results can be viewed in or obtained from the EPA Region 8 offices by contacting the individual listed in the **FOR FURTHER INFORMATION CONTACT** section of this document.

[128] Andover Technology Partners, *Cost of NO_X BART Controls on Utah EGUs to: EC/R Inc.* (May 13, 2016). Andover Technology Partners is a subcontractor to EC/R Incorporated.

[129] 77 FR 42834 (July 20, 2012) (proposal); 77 FR 72512, 72514–15 (Dec. 5, 2012) (final).

[130] 77 FR 18069 (Mar. 26, 2012) (proposal); 77 FR 76871 (Dec. 31, 2012) (final).

[131] 79 FR 5032, 5099 (Jan. 30, 2014) (final partial approval/partial disapproval of Wyoming regional haze SIP submission).

[132] See also our response to comments on existing controls and the baseline, in which we look at the cost and visibility benefits at Hunter and Huntington of SCR apart from the LNB/SOFA, to

Continued

In addition, the Manatee Plant impacted only one other Class I area, Everglades NP, at nearly twice the distance of Chassahowitzka NWA. In comparison, Hunter and Huntington significantly impact nine Class I areas. Furthermore, the Manatee Plant received a permit to increase natural gas utilization from 5,670 MMBtu/hr to 8,650 MMBtu/hr, which would displace the use of oil and provide additional NO_X reductions. All of these must be considered when examining the state's conclusion that SCR would not be cost-effective for these units, which was primarily based on the dollar-per-deciview cost of $66 million/dv and not on the raw cost-effectiveness number of $3,776/ton. While we are not basing our BART determinations on the dollar-per-deciview metric, for purposes of comparison to Manatee, the dollar-per-deciview cost for Hunter and Huntington would be considerably less than at Manatee, about $23.7 million/dv and $15.8 million/dv, respectively, at the most impacted Class I area, and as mentioned earlier Hunter and Huntington impact many more Class I areas than Manatee.

With respect to the Montana action, EPA stated for PPL Colstrip Units 1 and 2, "we estimated the incremental cost effectiveness of SCR + SOFA (over SNCR + SOFA) to [be] $5,770/ton and $5,887/ton, respectively. Given these costs, we continue to find that SCR + SOFA is not justified *by the visibility improvement that would be provided.*" 77 FR 57864, 57889 (Sept. 18, 2012) (emphasis added). The commenter omits the emphasized language. The visibility improvements for the various NO_X control options for Colstrip Units 1 and 2 can be seen in our proposal action and in general are much lower than those for Hunter and Huntington. See 77 FR 23988, 24026–27, 24034–35 (Apr. 20, 2012). In particular, at Colstrip Unit 1, the visibility improvements from SCR + SOFA at the five impacted Class I areas (which is less than the nine impacted by Hunter and Huntington) ranged from 0.081 to 0.404 dv. At Colstrip Unit 2, the visibility improvements from SCR + SOFA at the same class I areas ranged from 0.091 dv to 0.423 dv. These values are all much less than for the Hunter and Huntington BART units. In any case, our NO_X BART determinations for Colstrip Units 1 and 2 were vacated by the Ninth Circuit Court of Appeals. *Nat'l Parks Conserv. Ass'n* v. *U.S. EPA,* 788 F.3d 1134 (9th Cir. 2014).[133] Finally, commenter's citation to the Nebraska proposal is fully addressed by our response to a similar comment on our Wyoming regional haze action. 79 FR 5032, 5178 (Jan. 30, 2014). Please refer to our RTC document for additional discussion of our comparisons to other BART determinations.

H. CALPUFF Modeling

Comment: We received many comments related to both EPA's modeling for the FIP and Utah's modeling for the BART Alternative. In particular, PacifiCorp and its consultant asserted that EPA failed to account for the margin of error in the CALPUFF model and other material limitations of CALPUFF. PacifiCorp also asserted that we should have used CALPUFF version 6.42 in our FIP analysis instead of version 5.8.4. We partially respond to these comments here. Our full responses are contained in our RTC document.

Response: We do not agree with the commenter's criticism of the use of CALPUFF. In promulgating the 2005 BART Guidelines, we responded to comments concerning the limitations and appropriateness of using CALPUFF. In 2005 we explained that CALPUFF is the only EPA-approved model for use in estimating single source pollutant concentrations resulting from the long range transport of primary pollutants. In addition, it can also be used for other purposes such as visibility assessments to account for the chemical transformations of SO_2 and NO_X. As explained earlier, simulating the effect of precursor pollutant emissions on $PM_{2.5}$ concentrations requires air quality modeling that not only addresses transport and diffusion, but also chemical transformations. CALPUFF incorporates algorithms for predicting both. At a minimum, CALPUFF can be used to estimate the relative impacts of BART-eligible sources. *We are confident that CALPUFF distinguishes, comparatively, the relative contributions from sources such that the differences in source configurations, sizes, emission rates, and visibility impacts are well-reflected in the model results.*[134]

EPA also recognized the uncertainty in the CALPUFF modeling results when EPA made the decision (in the final BART Guidelines) to recommend that states use the 98th percentile visibility impairment rather than the highest daily impact value. We made the decision to consider the 98th percentile primarily because the chemistry modules in the CALPUFF model are simplified and likely to provide conservative (higher) results for peak impacts. Since CALPUFF's simplified chemistry could lead to model over predictions, EPA recommended the use of the 98th percentile to avoid giving undue weight to the extreme tail of the distribution.[135] Therefore, in recognizing some of the limitations of the CALPUFF model, we determined that use of the maximum modeled impact may be overly conservative and recommended the use of the 98th percentile value. While recognizing the limitations of the CALPUFF model in the BART Guidelines preamble, EPA concluded that, for the specific purposes of the RHR's BART provisions, CALPUFF is sufficiently reliable to inform the decision making process.[136]

It is further worth noting that the CALPUFF model can both predict higher and lower visibility impacts compared to a photochemical grid model. For example, the 2012 ENVIRON report on *Comparison of Single-Source Air Quality Assessment Techniques for Ozone, $PM_{2.5}$, other criteria pollutants and AQRVs* found that CALPUFF's predictions of the highest 24-hr nitrate and sulfate concentrations were lower than those predicted by the CAMx photochemical grid model in some areas within the modeling domain.[137] Thus, while there is some uncertainty in the absolute visibility impacts and benefits due to the model and some of the simplifications and assumptions used in the BART Guidelines modeling approach, the relative level of impact has been a reliable assessment of the degree of visibility impacts and benefit from controls. Any uncertainties in meteorological conditions that govern the transport and diffusion of pollutants are less important in comparing impacts between two control scenarios, since the

show that even if we agreed with this commenter that the baseline should reflect the installation of LNB/SOFA—which we do not—the selection of SCR as BART would still be reasonable. The numbers used there also compare favorably with Manatee.

[133] The same commenter notes that the Wyoming and Arizona BART determinations we used for comparison purposes are currently under litigation; however the commenter fails to note that the Montana BART determination they propose for comparison was actually litigated and vacated. With respect to the pending litigation over the Wyoming and Arizona BART determinations, there are other BART determinations such as Colorado's Hayden Station that are comparable, support our selection of SCR + LNB/SOFA, and are not under litigation.

[134] 70 FR 39122 (Jul. 6, 2005) (emphasis added).

[135] "Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source. Because of these features and the uncertainties associated with the model, we believe it is appropriate to use the 98th percentile—a more robust approach that does not give undue weight to the extreme tail of the distribution." 70 FR 39104, 39121 (Jul. 6, 2005).

[136] 70 FR 39123 (Jul. 6, 2005).

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

same effects will be included in both the base and the control scenario model simulations.

We also do not agree with the commenter's calculation of a ''margin of error'' for CALPUFF. The notion of a calculated ''margin of error'' is not part of any modeling guidance and has no legal or regulatory basis or applicability here. In addition, the commenter's suggestion that a 2012 report titled ''Documentation of the Evaluation of CALPUFF and Other Long Range Transport Models Using Tracer Field Experiment Data'', EPA–454/R–12–003 (ENVIRON Report) establishes a standard ''margin of error'' for CALPUFF is unfounded. The ENVIRON Report illustrated how well various types of modeling systems are able to capture regional transport. It does not provide any information about the accuracy of any models for predicting secondary $PM_{2.5}$ or visibility, nor does it indicate that the quantitative performance results provided are a presumptive globally applicable ''margin of error.'' Rather, these results are simply a way to compare various modeling systems in terms of performance for skill in long range transport. Thus, we do not agree that the ENVIRON Report provides a presumptive margin of error that can be applied to the modeling results in Utah's SIP or EPA's FIP.

With regard to Utah's use of CALPUFF in its SIP revision specifically, we note that the State was not required to use CALPUFF for purposes of its BART Alternative Demonstration under 40 CFR 51.308(e)(2)(i). Utah or PacifiCorp could have used other EPA-approved models with more advanced chemistry and dispersion techniques to support the BART Alternative demonstration but chose not to do so.

With regard to our use of CALPUFF for purposes of the FIP modeling, as explained in more detail in our RTC document, the legal deadline for challenging EPA's recommendation to use CALPUFF in BART analyses has passed. Furthermore, although the EPA proposed revisions to 40 CFR part 51, appendix W, Guideline on Air Quality Models (''Guideline'') in 2015, these proposed changes to the Guideline do not affect our recommendation in the 2005 BART Guidelines to use CALPUFF in the BART determination process.[138] Rather, as explained in the preamble to the proposed Guideline revisions, we consider it appropriate to continue using CALPUFF for BART determinations, given that the vast majority of BART determinations have been made using CALPUFF.[139]

In particular, for our FIP modeling, we used the current EPA-approved version of CALPUFF (Version 5.8.4, Level 130731). We disagree with the commenters that a new CALPUFF version should be used for the BART determinations. We relied on version 5.8 of CALPUFF because it is the version approved by EPA through a public notice-and-comment rulemaking, in accordance with the Guidelines (40 CFR part 51, appendix W, section 6.2.1.e). Later versions of CALPUFF are not approved by EPA for regulatory purposes, and we do not agree that the changes made to this most recent version of CALPUFF were simple model updates to address bugs. A full evaluation of a new model such as CALPUFF version 6.4 is needed before it should be used for regulatory purposes as errors that are not immediately apparent can be introduced along with new model features.

In response to comments, EPA performed additional modeling analysis to assess the combined benefit of SCR when applied to each of the two BART units at the Hunter facility. We did the same for the Huntington facility. These modeling results are shown in Tables 6 and 7 earlier in this document. Otherwise, we did not receive any comments that convinced us to alter our CALPUFF modeling analysis, and the comments we received do not justify a change in our BART determinations or our evaluation of the State's BART Alternative. We discuss these and other modeling comments in detail in our RTC document.

I. Consideration of Existing Controls

Comment: Several commenters asserted that EPA did not properly take into account the existing pollution control technology in use at the Hunter and Huntington BART units, as required by CAA section 169A(g)(2) and the BART Guidelines. Two of these commenters alleged that EPA was required to consider updated combustion controls, which were installed to comply with Utah's regional haze SIP. The commenters said EPA improperly used 2001–2003 emissions data to establish the baseline emissions for the Utah BART Units and that this is neither realistic nor provides the anticipated emissions as required by the BART Guidelines. The commenters asserted that had EPA relied on more recent emissions data, which reflect the NO_X reductions achieved by some of these newly installed controls, the cost-effectiveness values for SCR would have been higher, while the visibility improvement associated with SCR would have been lower.

Commenters pointed to an 8th Circuit court decision on EPA's final action on the North Dakota regional haze SIP where the Court found that EPA had failed to properly consider the existing pollution control technology at the Coal Creek Station. Commenters also asserted that in other EPA regional haze actions, EPA had adjusted baseline emissions to account for recently installed controls, such as EPA's final actions on the Arizona and Colorado regional haze SIPs, and settlement agreement with EPA Region 8 for the Deseret Bonanza plant. This commenter argued that because EPA had adjusted baseline emissions for some Arizona and Colorado EGUs to account for controls recently installed to satisfy consent decrees obligations or CAA requirements unrelated to regional haze, EPA was required to do so for Utah's EGUs as well.

Two final commenters submitted supportive comments regarding the need for using a standard baseline period to provide for greater national consistency. One of these commenters noted examples where EPA has evaluated NO_X BART based on a baseline period from before the installation of the pollution controls, for the Navajo regional haze plan and the Wyoming regional haze plan.

Response: We disagree with comments that EPA failed to consider or unreasonably considered the existing pollution control technology at the Hunter and Huntington BART units. One of the statutory factors EPA is to consider for BART is ''any existing pollution control technology in use at the source.'' 42 U.S.C. 7491(g)(2). The CAA and the BART Guidelines do not specify how states or EPA must ''take into consideration'' this factor. Nor did the Eighth Circuit Court of Appeals specify how existing controls must be taken into account; instead it only examined the meaning of the word ''any,'' holding that EPA misinterpreted the term. *North Dakota* v. *U.S. EPA,* 730 F.3d 750, 762–64 (8th Cir. 2013). The Court did not examine the meaning of the phrase ''take into consideration.'' *See id.* As the statute is silent on how to take into consideration existing controls, under *Chevron U.S.A.* v. *NRDC,* 467 U.S. 837, 843–44 (1984), this silence creates a gap for EPA to fill. As next summarized and detailed in our RTC document, we are reasonably considering existing controls in several ways.

[138] 80 FR 45340, 45350 (July 29, 2015).

[139] *Id.*

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First, the BART Guidelines state that existing pollution control technology in use at the source affects the availability of control options and their impacts. 40 CFR part 51, appendix Y, at IV.A. The Guidelines go on to explain that ''[f]or emission units subject to a BART review, there will often be control measures or devices already in place. For such emission units, it is important to include control options that involve improvements to existing controls and not to limit the control options only to those measures that involve a complete replacement of control devices.'' 40 CFR part 51, appendix Y, at IV.D.1.6. We have followed this recommendation. We find that the existing combustion controls, LNB/SOFA, cannot be reasonably upgraded, and we are not considering a control option that involves their complete replacement. The post-combustion control options, SNCR and SCR, by their nature can operate independently of combustion controls and without changes to the combustion controls, another way in which we considered the existing controls when evaluating SNCR and SCR.

Consistent with the Guidelines' statement that existing pollution control equipment in use at the source affects the impacts of the control options, we used the sources' current NO_X emission rates when we evaluated the size, design, and reagent/catalyst cost of SNCR and SCR. For example, in the case of Hunter Unit 1, we did not use the baseline emission rate of 0.40 lb/MMBtu, but rather the current emission rate of 0.21 lb/MMBtu that appropriately reflects the installation of LNB/SOFA. Due to the lower NO_X emission rate, the size of the SNCR and SCR systems and the amount of reagent/catalyst necessary to operate them are lower than if we had simply assumed the baseline emission rate. This is a reasonable way in which to consider existing pollution control technology.

As discussed in our Wyoming action and in additional detail in our RTC document for this action, baseline emissions should be ''a realistic depiction of anticipated annual emissions'' *before* the installation of BART. 40 CFR part 51, appendix Y, at IV.D.4.d. Because the LNB/OFA were installed pursuant to Utah's proposed BART determination, we used the period 2001–2003, prior to the installation of LNB/OFA at the Hunter and Huntington BART units, for baseline emissions, which in turn we used to evaluate the cost-effectiveness and visibility of control options. As a result, the existing LNB/OFA were not included in the baseline. According to the commenter, this skewed EPA's analysis.

We disagree. Because we have also considered the existing controls in our final BART determination by examining the cost-effectiveness and visibility benefit of SNCR and SCR relative to the existing LNB/SOFA as well as in tandem with LNB/SOFA, we have avoided any possibility that exclusion of the LNB/OFA from the baseline could result in an unreasonable BART selection. The cost-effectiveness values of SCR and SNCR relative to the existing LNB/SOFA are presented in the per-unit tables for Hunter and Huntington (Tables 2–5) under ''Incremental cost-effectiveness.'' In other words, the cost-effectiveness value for SCR alone (assuming the existing LNB/SOFA) is essentially the same as the incremental cost-effectiveness of SCR + LNB/SOFA as compared to LNB/SOFA that is presented in the tables. As can be seen, the incremental cost-effectiveness values of SCR + LNB/SOFA relative to LNB/SOFA are, for all four units, somewhat lower than the incremental cost-effectiveness of SCR relative to SNCR. As explained in the section giving the rationale for our final action, we find the incremental cost-effectiveness of SCR to be reasonable relative to SNCR; therefore it is also reasonable relative to the existing LNB/SOFA.

Another way to make the same point is to, for the sake of argument, accept (which we do not) commenter's position that the baseline should reflect the LNB/SOFA. In that case, the values in the tables for the incremental cost-effectiveness of SCR + LNB/SOFA relative to LNB/SOFA can serve as a proxy for the average cost-effectiveness of SCR (assuming LNB/SOFA in the baseline). As shown by our comparisons, the incremental cost-effectiveness of SCR + LNB/SOFA is generally reasonable given the visibility benefits. This in turn shows that, even accepting for the sake of argument that LNB/SOFA should be reflected in the baseline, the average cost-effectiveness of SCR remains reasonable. Similar considerations apply to the incremental visibility benefits of SCR + LNB/SOFA relative to LNB/SOFA, which can be used as a proxy for the visibility benefits of SCR alone assuming that LNB/SOFA are reflected in the baseline. As shown by our comparisons, the incremental visibility benefits of SCR + LNB/SOFA relative to SNCR + LNB/SOFA are substantial and justify the costs of SCR. Since the incremental visibility benefits of SCR + LNB/SOFA relative to LNB/SOFA are necessarily larger than the incremental benefits relative to SNCR + LNB/SOFA, the incremental visibility benefits of SCR + LNB/SOFA relative to LNB/SOFA will also justify the costs of SCR. This in turn shows that even if we accepted the commenter's position—which we do not—the visibility benefits of SCR would justify its selection. For our detailed responses, please see our RTC document.

Finally, we acknowledge the supportive comments from two commenters on this issue and agree with many of the points that were made, for reasons explained elsewhere in this document and in our RTC document.

J. PM_{10} BART

Comment: We received several minor comments on Utah's PM_{10} BART determinations. One commenter in particular asserted that Utah underestimated the control effectiveness of baghouses, which should be able to achieve a limit of 0.010 lb/MMBtu or even lower.

Response: EPA agrees that baghouses have very high PM control efficiency capabilities. However, due to the low contribution of direct PM emissions from point sources such as Hunter Units 1 and 2 and Huntington Units 1 and 2[140] to visibility impairment and, consequently, the low anticipated visibility benefits from small PM reductions, lowering the emission limit to 0.010 is unlikely to result in any meaningful visibility improvement. We agree with Utah that the existing PM_{10} emission limit adopted for these sources in Section IX, Part H.22 of Utah's SIP satisfies BART for these units. We are finalizing our approval of Utah's PM_{10} BART determination at Hunter Units 1 and 2 and Huntington Units 1 and 2. We find that an emission limit of 0.015 lb/MMBtu represents what can be continuously achieved with a properly operated baghouse on these units. The fabric filters (*i.e.,* baghouses) at Hunter and Huntington are all new since they were installed after 2008. Recent PSD BACT limits for coal-fired EGUs with new baghouses have typically ranged from 0.01 to 0.015 lb/MMBtu using Method 5.

In addition, we note that the latest revision to the EGU New Source Performance Standards (NSPS) requires modified units to meet a PM limit of 0.015 lb/MMBtu.[141] Also, the EGU MATS rule set a PM emissions standard

[140] See Western Regional Air Partnership Regional Haze Rule Reasonable Progress Summary Report, Air Resource Specialist, Inc., State and Class I Area Summaries, Appendix p. 6–29, Table 6.13–19 (June 28, 2013). Available in the docket and at *http://www.wrapair2.org/RHRPR.aspx.*

[141] 77 FR 9450 (Feb. 16, 2012) (codified at 40 CFR 60.42Da).

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of 0.03 lb/MMBtu as MACT for existing EGUs, and the BART Guidelines provide that, ''unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, you may rely on the MACT standards for purposes of BART.'' [142] Therefore, we are finalizing our proposed approval of Utah's BART determination for PM_{10} at Hunter Units 1 and 2 and Huntington Units 1 and 2.

K. Environmental Justice

Comment: One commenter requested that EPA's FIP address any disproportionately high and adverse human health, economic, and environmental impacts on minority and low-income communities in Utah due to the regional haze plan. The commenter noted that this may be accomplished consistent with federal Executive Order 12898, which establishes environmental justice policy. The commenter also noted that societal costs such as general public health costs associated with poor air quality should be considered in the environmental justice analysis.

Response: In making a final determination in this case, EPA considered Executive Order 12898, which establishes federal executive policy on environmental justice. This Executive Order directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations. The installation of SCR at the two facilities will ensure greater emissions reductions of NO_X resulting in overall increases in the level of environmental protection for all affected populations.

EPA disagrees with the comment that societal costs such as general public health costs associated with poor air quality should be considered in the environmental justice analysis for this action. As addressed elsewhere in our RTC document, neither section 169A of the CAA, nor the BART Guidelines, require the BART analysis to include or quantify benefits to health, as health impacts are appropriately addressed under other CAA programs. Moreover, an analysis of societal costs is unlikely to alter the impact relating to environmental justice concerns because the final rule will result in greater protection for all affected populations as a result of the installation of the most stringent control technology available for NO_X.

III. Final Action

For the reasons discussed more fully in sections I and II and detailed in our proposal and its accompanying supporting materials, in this action, we are partially approving and partially disapproving revisions to the Utah SIP submitted by the State of Utah on June 4, 2015. We are taking no action on the Utah SIP submittal of October 20, 2015.

Section 110(k)(3) of the Act addresses the situation in which an entire submittal, or a separable portion of a submittal, meets all applicable requirements of the Act. In the case where a separable portion of the submittal meets all the applicable requirements, partial approval may be used to approve that part of the submittal and disapprove the remainder. Since the portions of the regional haze SIP submittal we are approving are separable from the portions we are disapproving as explained earlier, each approved PM_{10} BART determination for a particular pollutant for a given source will have an enforceable date of five years from the date of EPA's approval.

Under section 110(k)(4) of the Act, EPA may approve a submittal based on a commitment of the State to adopt specific enforceable measures no later than one year after the date of approval of the submittal. We are conditionally approving the State's recordkeeping requirements for the PM BART emission limitations based on Utah's commitment to adopt and submit certain measures to address the deficiencies in the recordkeeping requirements. If the State fails to adopt and submit these measures within one year of this action, our conditional approval will be treated as a disapproval.

Under section 110(c)(1)(B) of the Act, within two years of disapproving a required submittal in whole or in part, EPA must promulgate a FIP to address the deficiencies, unless the State corrects the deficiencies through a submittal and EPA approves the submittal before we promulgate a FIP. As a result of our prior disapproval of Utah's PM and NO_X BART submittals in 2012, there was a pending obligation for EPA to promulgate a FIP for PM and NO_X BART. In this action, we are promulgating a FIP for NO_X BART. Because we are approving Utah's revised PM BART submittal, which corrects the previous deficiencies in the original PM BART submittal, there is no longer an obligation for EPA to promulgate a FIP for PM BART. Thus, EPA has discharged its FIP obligations with respect to PM and NO_X BART for the State of Utah.

A. Final Partial Approval

1. We are approving these elements of the State's SIP submittals, which rely on elements from prior approvals: [143]

- BART determinations and emission limits for PM_{10} at Hunter Units 1 and 2 and Huntington Units 1 and 2.
- Monitoring, recordkeeping, and reporting requirements for units subject to the PM_{10} emission limits, including conditional approval of the recordkeeping requirements for the PM_{10} emission limits.

B. Final Partial Disapproval and Federal Implementation Plan

1. We are disapproving these aspects of the State's June 4, 2015 SIP submittal:

- NO_X BART Alternative that includes NO_X, and SO_2 emission reductions from Hunter Units 1 through 3, Huntington 1 and 2, and Carbon Units 1 and 2, and PM_{10} emission reductions from Carbon Units 1 and 2.
- Monitoring, recordkeeping and reporting requirements for units subject to the BART Alternative.

2. We are promulgating a FIP to address the deficiencies in the Utah regional haze SIP. The FIP includes the following elements:

- NO_X BART determinations and limits for Hunter Units 1 and 2, Huntington Units 1 and 2.
- Monitoring, recordkeeping, and reporting requirements applicable to Hunter Units 1 and 2, and Huntington Units 1 and 2.

C. No Action

1. We are taking no action on the State's October 20, 2015 SIP submittal which includes the following:

- The enforceable commitments to revise, at a minimum, SIP Section XX.D.3.c and State rule R307–150 by March 2018.

[142] 40 CFR part 51, appendix Y, section IV.C. While the Supreme Court reversed the D.C. Circuit's judgment on the MATS rule, the Supreme Court did so based on EPA's approach to the ''appropriate and necessary'' finding, not EPA's determination of MACT for EGUs. *Michigan* v. *EPA*, 135 S. Ct. 2699 (2015).

[143] As necessary for our approval, we are filling gaps in the 2015 Utah regional haze RH SIP submittals with the following already-approved sections from the 2011 Utah RH SIP: Section XX.B.8, Figures 1 and 2, Affected Class I Areas, pp. 8–9; Section XX.D.6.b, Table 3, BART-Eligible Sources in Utah, p. 21; Section. XX.D.6.c, Sources Subject to BART, pp. 21–23.

IV. Incorporation by Reference

In this rule, the EPA is finalizing regulatory text that includes incorporation by reference. In accordance with requirements of 1 CFR 51.5, the EPA is finalizing the incorporation by reference of the Utah Administrative Code discussed in section III, Final Action of this preamble. The EPA has made, and will continue to make, these documents generally available electronically through *www.regulations.gov* and/or in hard copy at the appropriate EPA office (see the **ADDRESSES** section of this preamble for more information).

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is exempt from review by the Office of Management and Budget (OMB) because this final rule applies to only two facilities containing four BART units. It is therefore not a rule of general applicability.

B. Paperwork Reduction Act

This action does not impose an information collection burden under the provisions of the Paperwork Reduction Act (PRA).[144] Because this final rule applies to just two facilities, the PRA does not apply.

C. Regulatory Flexibility Act

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities.

EPA is partially disapproving the State's SIP submittal and promulgating a FIP that consists of imposing federal controls to meet the BART requirement for emissions on four specific BART units at two facilities in Utah. The net result of this action is that EPA is requiring direct emission controls on selected units at only two sources, and those sources are large electric generating plants that are not owned by small entities, and therefore the owners are not a small entities under the RFA.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments.

[144] 44 U.S.C. 3501 *et seq.*

EPA has determined that Title II of the UMRA does not apply to this rule. In 2 U.S.C. 1502(1) all terms in Title II of UMRA have the meanings set forth in 2 U.S.C. 658, which further provides that the terms "regulation" and "rule" have the meanings set forth in 5 U.S.C. 601(2). Under 5 U.S.C. 601(2), "the term 'rule' does not include a rule of particular applicability relating to . . . facilities." Because this rule is a rule of particular applicability relating to all four BART units at the Hunter and Huntington plants, EPA has determined that it is not a "rule" for the purposes of Title II of the UMRA. The private sector expenditures that result from promulgating a FIP include BART controls for all four units at the Hunter and Huntington plants are $58.6 million[145] per year. Additionally, we do not foresee significant costs (if any) for state and local governments. Thus, because the annual expenditures associated with promulgating a FIP are less than the threshold of $100 million in any one year, this final rule is not subject to the requirements of sections 202 or 205 of UMRA. This final rule is also not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of "covered regulatory action" in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. Moreover, "regulation" or "rule," is defined in Executive Order 12866 as "an agency statement of general applicability and future effect." E.O. 12866 does not define "statement of general applicability," but this term commonly refers to statements that apply to groups or classes, as opposed to statements, which apply only to named entities. The FIP therefore is not a rule of general applicability because its requirements apply and are tailored to only the Hunter and Huntington plants, which are individually identified facilities. Thus, it is not a "rule" or "regulation" within the meaning of E.O. 12866. However, as this action will limit emissions of NO_X, it will have a beneficial effect on children's health by reducing air pollution.

[145] Andover Technology Partners, *Cost of NO_X BART Controls on Utah EGUs*, to EC/R, Inc. (May 13, 2016). Andover Technology Partners is a subcontractor to EC/R Incorporated.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples, as specified in Executive Order 12898 (59 FR 7629, February 16, 1994).

The documentation for this decision is contained within the docket in a document entitled "Environmental Justice Analysis, November 2015." This final rule will result in overall emission reductions for NO_X, and PM_{10} and therefore an increase in the level of environmental protection for all affected populations.

K. Congressional Review Act

This action is not subject to the CRA because this is a rule of particular applicability. Additionally, this action

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is not a ''major rule'' as defined by 5 U.S.C. 804(2).

L. Judicial Review

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by September 6, 2016. Pursuant to CAA section 307(d)(1)(B), this action is subject to the requirements of CAA section 307(d) as it promulgates a FIP under CAA section 110(c). Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. See CAA section 307(b)(2).

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

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Particulate matter, Sulfur oxides.

Dated: June 1, 2016.

Gina McCarthy,

Administrator.

40 CFR part 52 is amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

* 1. The authority citation for part 52 continues to read as follows:

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

Subpart TT—Utah

* 2. Section 52.2320 is amended by:

* a. In the table in paragraph (c), under the heading ''R307–110. General Requirements: State Implementation Plan'' revising the entry ''R307–110–17.''

* b. In the table in paragraph (e), under the heading ''XVII. Visibility Protection'' adding in numerical order the entry ''Section XX.D.6. Best Available Retrofit Technology (BART) Assessment for NO_X and PM''.

The revision and addition read as follows:

§52.2320 Identification of plan.

* * * * *

(c) * * *

Rule No.	Rule title	State effective date	Final rule citation, date	Comments
*	*	*	*	*
R307–110. General Requirements: State Implementation Plan				
*	*	*	*	*
R307–110–17.	Section IX. Control Measures for Area and Point Sources, Part H, Emissions Limits.	6/4/2015	[Insert **Federal Register** citation] 7/5/2016.	Except for Section IX.H.21.e. which is conditionally approved through one year from [Insert date of publication in the **Federal Register**], IX.H.21.g., Sections of IX.H.21 that reference and apply to the source specific emission limitations disapproved in Section IX.H.22, and Sections IX.H.22.a.ii-iii, IX.H.22.b.ii, and IX.H.22.c.
*	*	*	*	*

* * * * *

(e) * * *

Rule title	State effective date	Final rule citation, date	Comments
*	*	*	*
XVII. Visibility Protection			

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Rule title	State effective date	Final rule citation, date	Comments
* *	*	* *	* *
Section XX.D.6. Best Available Retrofit Technology (BART) Assessment for NO_X and PM.	6/4/2015	[Insert **Federal Register** citation] 7/5/2016.	Except for XX.D.6.a the phrase "and BART for NO_X through alternative measures under 40 CFR 51.308(e)(2)"; XX.D.6.c; XX.D.6.d the phrase "NO_X and" in the first sentence, the entire last sentence in the introductory paragraph, all SO_2 and NO_X provisions and the word "Permitted" in the "Utah Permitted Limits" column in Table 5, "Hunter 3" and the Hunter limits, and all provisions in the "Presumptive BART Rates" column in Table 5; XX.D.6.e the phrase ", and pursuant to 51.308(e)(2)(E)(3) all alternative measures must take place within the first planning period", the rows beginning with "Hunter 3", "Carbon 1" and "Carbon 2" in Table 6, and the entire paragraph immediately following Table 6.
* *	*	* *	* *

* 3. Section 52.2336 is added to read as follows:

§52.2336 Federal implementation plan for regional haze.

(a) *Applicability.* (1) This section applies to each owner and operator of the following emissions units in the State of Utah:

(i) PacifiCorp Hunter Plant Units 1 and 2; and

(ii) PacifiCorp Huntington Plant Units 1 and 2.

(2) [Reserved]

(b) *Definitions.* Terms not defined in this paragraph (b) shall have the meaning given them in the Clean Air Act or EPA's regulations implementing the Clean Air Act. For purposes of this section:

(1) *BART* means Best Available Retrofit Technology.

(2) *BART unit* means any unit subject to a Regional Haze emission limit in Table 1 of this section.

(3) *Continuous emission monitoring system* or *CEMS* means the equipment required by this section to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of NO_X emissions, diluent, or stack gas volumetric flow rate.

(4) *FIP* means Federal Implementation Plan.

(5) The term *lb/MMBtu* means pounds per million British thermal units of heat input to the fuel-burning unit.

(6) NO_X means nitrogen oxides.

(7) *Operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the BART unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

(8) The *owner/operator* means any person who owns or who operates, controls, or supervises a unit identified in paragraph (a) of this section.

(9) *Unit* means any of the units identified in paragraph (a) of this section.

(c) *Emission limitations.* (1) The owners/operators of emission units subject to this section shall not emit, or cause to be emitted, NO_X in excess of the following limitations:

TABLE 1 TO §52.2336—EMISSION LIMITATIONS FOR BART UNITS

Source name/BART unit	NO_X Emission limitation—lb/MMBtu (30-day rolling average)
PacifiCorp Hunter Plant/Unit 1 [1]	0.07
PacifiCorp Hunter Plant/Unit 2 [1]	0.07
PacifiCorp Huntington Plant/Unit 1 [1]	0.07
PacifiCorp Huntington Plant/Unit 2 [1]	0.07

[1] The owners and operators of PacifiCorp Hunter Units 1 and 2 and Huntington Units 1 and 2, shall comply with the NO_X emission limit for BART of 0.07 lb/MMBtu and other requirements of this section by August 4, 2021.

(2) These emission limitations shall apply at all times, including startups, shutdowns, emergencies, and malfunctions.

(d) *Compliance date.* (1) The owners and operators of PacifiCorp Hunter Units 1 and 2 shall comply with the NO_X emission limitation of 0.07 lb/MMBtu and other requirements of this section by August 4, 2021. The owners and operators of PacifiCorp Huntington Units 1 and 2 shall comply with the NO_X emission limitation of 0.07 lb/MMBtu and other requirements of this section by August 4, 2021.

(2) [Reserved]

(e) *Compliance determinations for* NO_X. (1) For all BART units:

(i) *CEMS.* At all times after the earliest compliance date specified in paragraph (d) of this section, the owner/operator of each unit shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR part 75, to accurately measure NO_X, diluent, and stack gas volumetric flow rate from each unit. The CEMS shall be used to determine compliance with the emission limitations in paragraph (c) of this section for each unit.

(ii) *Method.* (A) For any hour in which fuel is combusted in a unit, the owner/operator of each unit shall calculate the hourly average NO_X emission rate in lb/MMBtu at the CEMS in accordance with the requirements of 40 CFR part 75. At the end of each operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu from the arithmetic average of all valid hourly emission rates from the CEMS for the current operating day and the previous 29 successive operating days.

(B) An hourly average NO_X emission rate in lb/MMBtu is valid only if the minimum number of data points, as specified in 40 CFR part 75, is acquired by both the pollutant concentration

EPA-HQ-2017-010177 Production Set #2

monitor (NO_X) and the diluent monitor (O_2 or CO_2).

(C) Data reported to meet the requirements of this section shall not include data substituted using the missing data substitution procedures of subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75.

(2) [Reserved]

(f) *Recordkeeping.* The owner/operator shall maintain the following records for at least five years:

(1) All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results.

(2) Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR part 75.

(3) Records of all major maintenance activities conducted on emission units, air pollution control equipment, and CEMS.

(4) Any other CEMS records required by 40 CFR part 75.

(g) *Reporting.* All reports under this section shall be submitted to the Director, Office of Enforcement, Compliance and Environmental Justice, U.S. Environmental Protection Agency, Region 8, Mail Code 8ENF–AT, 1595 Wynkoop Street, Denver, Colorado 80202–1129.

(1) The owner/operator of each unit shall submit quarterly excess emissions reports for NO_X BART units no later than the 30th day following the end of each calendar quarter. Excess emissions means emissions that exceed the emissions limits specified in paragraph (c) of this section. The reports shall include the magnitude, date(s), and duration of each period of excess emissions, specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted.

(2) The owner/operator of each unit shall submit quarterly CEMS performance reports, to include dates and duration of each period during which the CEMS was inoperative (except for zero and span adjustments and calibration checks), reason(s) why the CEMS was inoperative and steps taken to prevent recurrence, and any CEMS repairs or adjustments. The owner/operator of each unit shall also submit results of any CEMS performance tests required by 40 CFR part 75.

(3) When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted during the reporting period, such information shall be stated in the quarterly reports required by paragraphs (g)(1) and (2) of this section.

(h) *Notifications.* (1) The owner/operator shall promptly submit notification of commencement of construction of any equipment which is being constructed to comply with the NO_X emission limits in paragraph (c) of this section.

(2) The owner/operator shall promptly submit semi-annual progress reports on construction of any such equipment.

(3) The owner/operator shall promptly submit notification of initial startup of any such equipment.

(i) *Equipment operation.* At all times, the owner/operator shall maintain each unit, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

(j) *Credible evidence.* Nothing in this section shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with requirements of this section if the appropriate performance or compliance test procedures or method had been performed.

[FR Doc. 2016–14645 Filed 7–1–16; 8:45 am]

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ATTACHMENT B

IN THE UNITED STATES COURT OF APPEALS
FOR THE TENTH CIRCUIT

DESERET GENERATION & TRANSMISSION CO-OPERATIVE, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and GINA McCARTHY, Administrator, United States Environmental Protection Agency, Respondents.	Case No. 16-9545
STATE OF UTAH, on behalf of the Utah Department of Environmental Quality, Division of Air Quality, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and GINA McCARTHY, Administrator, United States Environmental Protection Agency, Respondents.	Case No. 16-9541

PACIFICORP, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY et al., Respondents.	Case No. 16-9542
UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY et al., Respondents.	Case No. 16-9543

CARBON COUNTY, UTAH et al., Petitioners-Intervenors, and HEAL UTAH et al., Respondents-Intervenors.	

DESERET GENERATION & TRANSMISSION CO-OPERATIVE'S MOTION FOR STAY

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INTRODUCTION AND JURISDICTION

Deseret Generation & Transmission Co-operative ("Deseret"), owns an undivided 25.108% interest in the Hunter 2 Unit ("Hunter 2"), one of four units identified as BART eligible for implementation of Best Available Control Technology ("BART") in the State of Utah. The Respondent, Environmental Protection Agency ("EPA"), has illegally rejected an implementation plan developed by the State of Utah under authority of the Clean Air Act ("CAA") regional haze program ("Final Rule")[1] as it pertains to control of NOx emissions. Instead, EPA imposed a Federal Implementation Plan ("FIP") requiring the most stringent and costly form of pollution controls to be installed at Hunter 2 rather than the BART Alternative appropriately developed and selected by the State.[2]

EPA's determination was made in the face of significant data and information from the state of Utah that the NO_x BART alternative proposed in

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[1] The final rule was published on July 5, 2016, and is titled "Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze," published at 81 Fed. Reg. 43,894 (July 5, 2016) ("Final Rule"), attached as Exhibit A.

[2] The controls mandated by the EPA FIP include installation of Selective Catalitic Reduction, Low NOx Burners, with Overfire Air (referred to collectively as "SCR").

Utah's State Implementation Plan ("SIP") would reduce haze more significantly than the installation of much more expensive controls—thereby satisfying both the main goal as well as the technical requirements of the regional haze program under the CAA.

As a joint owner in Hunter 2, Deseret will be severely and irreparably damaged by the requirement to install SCR at Hunter 2—especially when such technology will do little, as compared to Utah's SIP and BART Alternatives, to reduce the impact of regional haze in the region. Accordingly, Deseret seeks a stay of EPA's Final Rule, pursuant to the Federal Rule of Appellate Procedure 18 and 5 U.S.C. § 705, for the period of time the rule is under review in this court.

EPA had jurisdiction to review Utah's SIP, and its component NO_x BART Alternative, and to issue the Final Rule (including the FIP), under 42 U.S.C. § 7410. This Court has jurisdiction to review EPA's decision on the Final Rule under 42 U.S.C. § 7607(b)(1), and this Court has authority to grant a stay of EPA's Final Rule under 5 U.S.C. § 705.

Each of the four stay factors a petitioner must meet as set forth in *Winter v. Natural Res. Def. Council*, 555 U.S. 7, 20 (2008), is satisfied here. In order to avoid duplication in briefing (as requested by the Court in its scheduling order), Deseret will address in this brief its specific immediate and irreparable harm

suffered as a result of the Final Rule and how this will impact the public interest—for which Deseret has no monetary recourse against the EPA if the Final Rule is reversed. PacifiCorp, the State of Utah, and Utah Associated Municipal Power System ("UAMP") have extensively briefed the stay factors including: (1) that petitioners are likely to be successful on the merits; (2) that the balance of harms tips in favor of the petitioners; and (3) a stay is in the public interest—especially given the impact the Final Rule could have on the availability of affordable electricity. Rather than reiterating those same arguments here, Deseret hereby incorporates all of those arguments into this brief and refers the court to the motions for stay filed by PacifiCorp, the State of Utah, and UAMP.

Deseret has also submitted to the EPA a Petition for Reconsideration and Request for Administrative stay of the FIP nearly two months prior to filing this motion.[3] Deseret has received no response from the EPA despite the fatal flaws in EPA's Final Rule.

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[3] *See* Request for Reconsideration and Request for Administrative Stay (Sept. 6, 2016), attached as Exhibit B. This submission is in compliance with Fed. R. App. P. 18(a)(1).

I. Deseret Will Suffer Unique and Immediate Irreparable Harm if the Final Rule is Not Stayed.

"A [petitioner] suffers irreparable injury when the court would be unable to grant an effective monetary remedy after a full trial because such damages would be inadequate or difficult to ascertain." *Planned Parenthood Association of Utah v. Herbert*, 828 F.3d 1245, 12636 (10th Cir. 2016). Deseret is uniquely situated among the petitioners in this case due to its status as a financially distressed, member-owned co-operative. [*See* Declaration of Robert Dalley ("Dalley Declaration") at ¶¶2, 6, 12, attached hereto as Exhibit C.] In its present condition, Deseret is not certain of being able to raise capital necessary to pay its portion of costs to install the FIP mandated controls at Hunter 2. If left in place, the requirements under the FIP threaten to force Deseret into a bankruptcy. [*See* Dalley Declaration at ¶10.] The loss of its business is an injury no monetary remedy could resolve.

As courts have recognized, a bankruptcy filing is one of the most severe forms of irreparable harm one can suffer—and the possibility of such an outcome due to the imposition of the Final Rule warrants a stay here. *See, e.g., Doran v. Salem Inn, Inc.*, 422 U.S. 922, 932 (1975) (Where a party "would suffer a substantial loss of business and perhaps even bankruptcy…[c]ertainly the latter type of injury sufficiently meets the standards for granting interim relief, for

otherwise a favorable final judgment might well be useless."). As explained in detail below, the imposition of the Final Rule will cause irreparable and immediate damage to Deseret.

I.A. The FIP Requirement for Hunter 2 Threatens Deseret's Financial Condition and Poses an Intolerable Risk of Bankruptcy and Forfeiture of Deseret's Rights Under the Terms of a Debt Forbearance Arrangement With Its Creditors.

Since the late 1990's, Deseret has operated under the terms of a long-term debt forbearance arrangement with its creditors—an agreement approved by Deseret's utility regulator before it became effective. [*See* Dalley Declaration at ¶11.] The forbearance arrangement was necessitated by market forces in the late 1980's and early 1990's which made it impossible for Deseret to recover fully its costs of constructing the utility plant and equipment it operates. [*Id.*] One major source of this financial distress was the long-term financing for Deseret's acquisition of the Hunter 2—debt that Deseret has not been able to service or pay. [*See* Dalley Declaration at ¶12.]

Deseret's creditors have agreed to forbear from collecting the full amount of unpaid indebtedness for the Hunter 2 mortgage, on the condition that Deseret fully comply with certain specified terms of the long-term debt restructuring and forbearance agreement. One key element of that agreement prohibits Deseret from incurring any new long-term indebtedness above and beyond its current working

capital and available loan facilities, so long as the existing creditors continue to forbear from exercising remedies to collect on the full unpaid Hunter 2 and other delinquent debt owed to them. [*See* Dalley Declaration at ¶13.]

Should the FIP be allowed to remain in place and on the current time schedule for the installation of controls at Hunter 2 unaltered, Deseret's share of capital costs for the required additions at the unit would surpass its available financing capacity and available cash reserves. [*See* Dalley Declaration at ¶14.] By contrast, the controls selected under Utah's State BART alternative in the SIP is comfortably within Deseret's ability to afford, while resulting in virtually identical improvements to visibility.

As currently projected, Deseret would not be able to pay for the capital improvement of SCR at Hunter 2 prior to 2026. After 2026, a significant portion of the pre-existing debt is scheduled to be forgiven—provided Deseret fully adheres to the particular terms spelled out in the forbearance arrangement through that date. Incurring such an amount of new debt prior to 2026, without a new consensual arrangement with its existing creditors, could virtually ensure a violation of the forbearance terms. Should such a violation result in the waiver or termination of creditors' forbearance obligations under the agreement, Deseret would find itself hopelessly unable to make payment on nearly $2 Billion in

unamortized, pre-existing debt—far in excess of its ability to satisfy.[4] The debt forgiveness Deseret has worked toward for twenty years would not occur as planned, and the obvious result would almost certainly lead to a bankruptcy of Deseret. [*See* Dalley Declaration at ¶¶15-17.]

Alternatively, Deseret could attempt, with only uncertain assurance of success, to seek a voluntary accommodation from its creditors effectively equating to a major restructuring of all of Deseret's long term indebtedness. In any such arrangement, Deseret would expect to be required to make significant, harsh, and irreparable concessions to the creditors. Either option, bankruptcy or restructuring, would result in irreparable harm to Deseret, which, as courts have recognized, warrants a stay of the Final Rule. [*See* Dalley Declaration at ¶¶18-20.]

I.B. Absent an Immediate Stay of the FIP, Deseret Risks Immediate Creditor Remedies Associated With a Potential Projected Future Cash Shortfall.

Even if Deseret could avoid an eventual bankruptcy triggered by the sizeable capital costs of the FIP-mandated controls at Hunter 2, the terms of the existing

[4] Deseret could not conceivably raise its rates to its customers in time, or in an amount sufficient to pay off the full amount of debt which would come due and payable should the existing creditors no longer be required to forbear from collecting unpaid pre-forbearance debt. [*See* Dalley Declaration at ¶ 20.]

forbearance will result in immediate restrictions on Deseret's rates and operations, unless the FIP is stayed. [*See* Dalley Declaration at ¶21.]

The SCR for Hunter 2 will cost approximately $165 million according to EPA's estimate. [*See* Table 5, Response to Comments, EPA-R08-OAR-2015-0463-0208 at p. 205 (hereafter referred to as "RTC").][5] Of that amount, Desert would be responsible for contributing approximately $41 million. Deseret cannot borrow or pay that amount from existing resources. Even short of a threatened bankruptcy filing, the very existence of the FIP, without immediate administrative or judicial stay, brings with it irreparable damage for Deseret. Under the forbearance arrangement, Deseret must provide annual revised forward projections to its creditors of anticipated cash flows (or deficits) through approximately 2025. Should the revised cash flow projection indicate a projected deficit in available cashflows to meet minimum scheduled debt payments for the coming year, *immediate restrictions on Deseret's use of available cash flow are triggered.* [*See* Dalley Declaration at ¶¶22-23.]

[5] In the Final Rule, page 43903, table 1, EPA estimates the SCR/LNB/OFA cost of Hunter 2 at $128.5 million. In the Sargent & Lundy report attached to PacifiCorp's public comments, the SCR/LNB/OFA costs for Hunter 2 are estimated at $177.5 million. These numbers constitute a range representing the significant cost of SCR for Hunter 2. In any event, the costs will be more than Deseret can reasonably finance.

Among the remedies Deseret's creditors will immediately acquire, upon such a projected cash flow shortfall, Deseret's annual operating budgets, rebate programs to its Members, capital rotation payments to member cooperatives, and other similar payments must immediately cease or be approved on a case-by-case basis by the unpaid creditors. These creditor remedies will become active *immediately* once Deseret delivers updated long term cash flow projections that show Deseret's inability to meet cash requirements for the coming period. [*See* Dalley Declaration at ¶¶ 24-25.]

Among the very immediate ramifications that could flow from Deseret delivering such a revised cash flow projection:

- Deseret relies on making cash rebates to its six rural electric cooperative members to equalize and stabilize rate effects among the six rural organizations. Should the creditors place these cash rebates on hold, the result will be to greatly increase all of the rates paid by these rural electric cooperatives and passed through to rates charged for electricity served to rural homes and communities. Some members in portions of Wyoming and elsewhere would see much more dramatic, unplanned, and sudden increases in rates than other

areas, because the FERC-approved rebates serve to levelize and equalize rates among the Deseret distribution members.

- Deseret would be precluded from funding Energy Efficiency Improvement programs.
- Deseret would be forced to re-evaluate labor costs and compensation levels, for its workforce.
- Deseret would be precluded from making cash payments to member distribution cooperatives to rotate capital margins (cash paid in excess of operating costs) accumulated during past years. Other major maintenance projects at Deseret's plants would be severely restricted or curtailed for the coming years through 2025.

[*See* Dalley Declaration at ¶28.]

Absent a judicial stay of the FIP, *even if the FIP is ultimately modified or judicially invalidated,* Deseret will have been damaged *beginning as soon as this year.* [*See* Dalley Declaration at ¶35.] Even if the FIP is eventually modified by EPA and/or invalidated by Court action, Deseret will suffer the damage of the foregoing effects for as long as the ongoing consideration of the FIP continues. Under the terms of the forbearance arrangement with its creditors, much of these

damages will never be recovered from the creditors, even if Deseret, PacifiCorp, and the State of Utah ultimately prevail on the merits.

But for a stay of the FIP, Deseret will be put to an intolerable Hobson's choice—it will be forced to undertake one or more of the following unfavorable courses of action:

(i) either report and project that it will need to incur additional long-term indebtedness in addition to its existing credit facilities to finance the Hunter 2 SCR installation costs (thereby likely triggering a negotiation with its existing creditor to accommodate such new additional debt); and/or

(ii) begin immediately to restructure its rates for electricity sold, its operational plans and levels of dispatch for its existing generation resources, as well as expenditures to reflect an "emergency" or "survival" budget, in order to truthfully project future net cash flows sufficient to pay the costs associated with SCR installation at Hunter 2 before the end of 2021 without the need for new indebtedness; and/or

(iii) approach the creditors immediately to seek permission to withhold net cashflows generated in the remainder of 2016 and subsequent

years in order to create a cash reserve for offsetting a sizeable portion of the capital costs associated with the mandated Hunter 2 improvements. In making such a request, Deseret will in likelihood be asked to make and commit *immediately* to significant additional concessions to the creditors such as deferring or delaying the debt forgiveness on pre-forbearance debt, increasing creditors' future share of net available cashflows, etc.; and/or

(iv) project a major future cash flow deficit to accommodate the unavoidable cash outlays that would accompany SCR installation.[6] The latter would seriously threaten to trigger immediate aggressive creditor rights which in turn would bear heavy negative impacts on

[6] Given the relatively short time period remaining before the 2021 compliance deadline for all BART eligible units under the FIP, attempting to devise a 5 year plan that could work around the projected cash flow shortfall from SCR installation at Hunter 2 would be painful, if it is even possible. It would require dramatic and immediate changes in Deseret's planned operations beginning immediately to take actions such as: dramatically reducing costs (with dramatic negative long term ramifications for the Company), raising member rates in anticipation of the coming cash deficit (raising negative consequences on small businesses and tribal interests throughout the economically disadvantaged areas served by Deseret's cooperative members and curtailing long-term revenue growth for Deseret and its member systems), adjust rebate programs and/or curtail investments planned in energy efficiency programs, etc. In addition, Deseret could conceivably be challenged before FERC in an attempt to successfully build a cash reserve in advance of the SCR installation through anticipatory rate adjustments. [*See* Dalley Declaration at ¶31.]

Deseret's ability to continue to conduct its business affairs in the manner it currently does.

[*See* Dalley Declaration at ¶30.]

Even should Deseret prevail in its petition for relief, it will begin immediately to incur irreparable harm unless the FIP is stayed pending this judicial appeal.

II. A Stay of the Final Rule is in the Public Interest Because it Will Allow Rural Communities to Continue to Receive Affordable Power from Deseret.

Deseret provides retail electric service in rural areas of Utah and neighboring states and also provides significant "baseload" electric energy to public utilities operating throughout the Western United States. [*See* Dalley Declaration at ¶ 2.] The significant capital costs of the FIP mandated pollution controls for Hunter 2 would necessarily all be financed or recovered (if such financing is even possible) through increases in rates charged for sales to serve residential, agricultural, and small commercial customers within Deseret's rural service areas. [*Id.* at ¶ 9.] This equates to $3.73 per MWh, an increase of about 11.2% from existing net-billed rates for Deseret customers. [*Id.* at ¶ 10.]

Similarly, In the rulemaking docket, EPA provides an estimate (utilizing its estimated costs, which are lower than expected by PacifiCorp) that installation of

SCR at the Utah BART Units will result in 5-10% higher electricity rates for PacifiCorp customers. RTC at 370. EPA admits these rate increases "are not trivial." *Id.*

Higher electricity rates could have an even broader adverse economic impact on the citizens of Utah and Wyoming, as businesses look to pass their higher costs through to their customers. Consideration of rate increases caused by EPA mandated control equipment was one of several factors found to support the recent stay of a Regional Haze FIP in Texas. *See Texas v. EPA*, No. 16-60118 at *18, notes 40-42 (5th Cir. July 15, 2016).

Given the need for such dramatic electricity cost increases to cover the capital improvement of installing SCR at Hunter 2, the public is directly and financially impacted by imposition of the FIP. The public interest in avoiding such electricity cost increases—especially when such costs will not result in more visibility improvement beyond the State's BART alternative—is significant. Indeed, Utah has reported to EPA that its SIP elements and strategies, already underway, are sufficient to meet all established reasonable progress goals for visibility improvement. *See, e.g.*, Utah Progress Report at F10-F11, F-62 ("Utah Progress Report"); *see also* 77 Fed. Reg. at 74367-68 (Dec. 14, 2012) (finding that Utah "met all reasonable progress requirements for the Class I areas in Utah" and

"satisfied the RHR's requirements and included controls in the SIP sufficient to address the relevant requirements of the RHR related to impacts on Class I areas in other states."). Individuals in these rural communities who are not able to afford such dramatic cost increases cannot and should not be required to suffer through the pendency of this litigation without a stay of the Final Rule. EPA cannot make a credible argument that its interest in purported visibility improvement (albeit limited) outweighs the interest of rural individuals to receive affordable power. Accordingly, a stay is appropriate and in the public interest here.

CONCLUSION

For all of the reasons stated herein and for all of the reasons articulated by PacifiCorp, the State of Utah, and UAMP in their motions for stay, the Court should grant Deseret's motion to stay the Final Rule.

DATED this 28th day of October, 2016.

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CERTIFICATE OF SERVICE

I hereby certify that on the 28th day of October 2016, the foregoing **DESERET GENERATION & TRANSMISSION CO-OPERATIVE'S MOTION FOR STAY** was served electronically on all counsel of record through the Court's CM/ECF system.

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CERTIFICATE OF DIGITAL SUBMISSION

I hereby certify that with respect to the foregoing:

(1) all required privacy redactions have been made per 10th Cir. R. 25.5;

(2) if required to file additional hard copies, that the ECF submission is an exact copy of those documents;

(3) the digital submissions have been scanned for viruses with the most recent version of a commercial virus scanning program, Symantec Endpoint Protection (Version 12.1.6), and according to the program are free of viruses.

DATED this 28th day of October, 2016.

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CERTIFICATE OF COMPLIANCE WITH RULE 32(a)

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1. This brief complies with the type-volume limitation of Fed. R. App. P. 32(a)(7)(B) because:

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DATED this 28th day of October, 2016.

EXHIBIT A

SLIP SHEET

FOR

Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Partial Approval and Partial Disapproval of Air Quality Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, 81 Fed. Reg. 43,894 (July 5, 2016) ("Final Rule"), [Joint Appendix ("JA") ___.]

EXHIBIT B

SLIP SHEET
FOR

Request for Reconsideration and Request for Administrative Stay of EPA's Final Rule: "Approval, Disapproval and Promulgation of Air Quality Implementation Plans;Partial Approval and Partial Disapproval of Air Quality Implementation Plans and Federal Implementation Plan; Utah; Revisions to Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Final Rule." Docket ID No. EPAR08-OAR-2015-0463 ("Deseret Petition for Reconsideration"), [Joint Appendix ("JA") ___.]

EXHIBIT C

IN THE UNITED STATES COURT OF APPEALS FOR THE TENTH CIRCUIT

DESERET GENERATION & TRANSMISSION CO-OPERATIVE, Petitioner, v. UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and GINA McCARTHY, Administrator, United States Environmental Protection Agency, Respondents.	Case No. 16-9542

DECLARATION OF ROBERT R. DALLEY FOR DESERET GENERATION & TRANSMISSION CO-OPERATIVE IN SUPPORT OF MOTION TO STAY

I, Robert R. Dalley declare as follows:

Introduction

1. I am the Vice President and Chief Financial Officer of Deseret Power ("Deseret") and have been employed in that capacity since 2008.

2. Deseret is a Utah non-profit corporation comprised of six members. Its members are rural electric cooperatives that provide retail electric service in rural areas of Utah and neighboring states. Deseret owns and operates electric generation and transmission facilities for the benefit of its members. Deseret also provides significant "baseload" (around-the-clock) electric energy to public utilities operating throughout the Western United States.

3. Deseret's sales are generally grouped into three categories: (i) sales to distribution cooperative members for energy needed to serve traditional retail customers at cost-based rates ("Cost Based Sales"); (ii) sales at market-based prices to members for requirements to serve large industrial customer loads ("Market Based Sales"); and (iii) sales to off-system wholesale purchasers at negotiated market-based prices ("Off System Opportunity Sales").

4. For Off System Opportunity Sales, Deseret has generally negotiated fixed price terms that will remain largely unchanged over the term of the sales agreement, many of which extend for years into the future. Deseret has limited ability to recover cost increases which will be incurred during the term of these agreements

to purchasers under these Off System Opportunity Sales. These sales generally are priced at a generalized market clearing price which Deseret cannot unilaterally influence.

5. For Market Based Sales to serve member requirements for large industrial class of services, Deseret has received market based ratemaking authority from the Federal Energy Regulatory Commission. These sales are negotiated to reflect generalized market price for electricity from all sources (or regardless of source) in the market(s) in which the delivery of energy will occur. Deseret does not have market power to influence, or to recover from the purchaser of the Market Based Sales any significant portion of additional costs associated with increased capital and/or operating expense at Deseret's own generating resources.

6. As a result, Deseret must recover the vast majority of future increased costs in its generating resources from the limited customers which are served through Cost Based Sales. These customers represent the residential, agricultural, and small commercial/municipal consumers located in the rural areas served by Deseret's rural electric cooperative distribution members. Throughout Deseret's history and for the foreseeable future, these cost based sales only cover ***less than half*** of the total sales revenue which Deseret makes each year.

7. Deseret owns a 25.108% undivided interest in the Hunter 2 generating unit. Deseret's Hunter 2 ownership share constitutes one fifth of Deseret's total generating resources. Placed in context of the portion of Deseret's sales to Cost-

Based consumers, the output generated by Deseret's ownership share in Hunter 2 accounts for sufficient electric energy to serve 40% to 60% of the total electric energy requirements (depending on required Hunter 2 maintenance) for these residential, agricultural, and small commercial customers.

The FIP Mandated Improvements at Hunter 2 Will Heavily Impact the Rates for Deseret's Small Residential and Agricultural/Commercial Consumers

8. EPA has estimated the total annual debt service and operating costs for the mandated improvements at Hunter 2 to be $21,703,997. *Table 5, Response to Comments, EPA-R08-OAR-2015-0463-0208 at p. 205.* Deseret's share of those annual costs would equate to $5,449,440.

9. Deseret's share of the annual cost to install the FIP mandated improvements would almost all be recovered through increases in rates charged for sales to serve residential, agricultural, and small commercial consumers within Deseret's rural service areas.

10. The rate increase that would have been required to fully recover the required annual cost of FIP mandated improvements at Hunter 2, based on 2015 Cost Based Sales to these small customer loads, would have been approximately $3.73 per MWh, an increase of about 11.2% from existing net-billed rates. This burdensome rate increase assumes Deseret could finance this regulatory imposition which is problematic at best. See the discussion below regarding Deseret's severely limited capital-financing access.

The FIP mandated Improvements at Hunter 2 Imperil Deseret's Current Planning and Access to Long-term Financing

11. Since the late 1990's, Deseret has operated under the terms of a long-term debt forbearance arrangement with its creditors. The forbearance arrangement was necessitated by market forces in the late 1980's and early 1990's which made it impossible for Deseret to recover fully its costs of constructing the utility plant and equipment it operates.

12. One major source of this financial distress was the long-term indebtedness for Deseret's purchase of its ownership share in the Hunter 2 Unit – debt that Deseret has not been able to fully pay.

13. Deseret's creditors have agreed to forbear from collecting the full amount of unpaid indebtedness for the Hunter 2 Unit mortgage, on the condition that Deseret fully comply with certain specified terms of the long-term debt restructuring and forbearance agreement. One key debt covenant prohibits Deseret from incurring any new long-term indebtedness while the existing creditors continue to forbear from collecting the full unpaid debt owed to them.

14. Should the FIP be allowed to remain in place and on the current time schedule, Deseret's share of capital costs for the required additions at Hunter 2 would surpass its available (unused) financing capacity and cash reserves. The SCR for Hunter 2 will cost approximately $165 million according to EPA's estimate (*Table 5,*

Response to Comments, EPA-R08-OAR-2015-0463-0208 at p. 205). Of that amount, Desert would be responsible for contributing approximately $41 million. At present, Deseret's total available credit under its working capital line of credit, combined with Deseret's available non-restricted cash reserves, is less than $30 million.

15. Deseret is unable to pay for its portion of FIP mandated improvements at Hunter 2 without seeking new, substantial long term debt, which in turn requires Deseret to negotiate for the consent of its current creditors under the forbearance arrangement.

16. Incurring such an amount of new debt without a new consensual arrangement with its existing creditors, could lead directly to a violation of the terms in the forbearance arrangement, in which case, creditors' forbearance obligations under the agreement could be suspended. If that were to occur, Deseret would find itself hopelessly unable to make payment on nearly $2 Billion in pre-existing unamortized debt – far in excess of its ability to satisfy.

17. The obvious result, should the creditors' forbearance agreement be impaired or terminated, and Deseret once again face the prospect of immediate acceleration of the full amount of its unamortized pre-existing debt, would lead to a bankruptcy of Deseret.

18. Alternatively, Deseret could attempt, with only uncertain assurance of success, to seek a voluntary accommodation from its creditors to permit new long-term financing for the Hunter 2 improvements under the FIP. Such an

accommodation would effectively equate to a major restructuring of all of Deseret's long term indebtedness.

19. In any such an arrangement, Deseret would expect to be required to make significant, harsh, and irreparable concessions to the creditors.

20. Deseret could not conceivably raise its rates to its tariff customers (those customers served under ordinary residential/commercial rate tariffs by Deseret's distribution cooperative members) in time, or in an amount sufficient to pay off the full amount of debt which would come due and payable should the existing creditors no longer be required to forbear from collecting unpaid pre-forbearance debt.

Absent Immediate Stay of the FIP, Deseret Will Begin to Trigger Immediate Creditor Remedies Under Its Forbearance Arrangement

21. Even if Deseret could avoid a likely bankruptcy triggered by the sizeable capital costs of SCR at Hunter 2 under the FIP, the terms of the existing forbearance will result in immediate restrictions on Deseret's rates and operations, unless the FIP is stayed.

22. Under the forbearance arrangement with Deseret's creditors, prior to November 15 of each year, Deseret must provide revised forward projections to its creditors of anticipated cash flows (or deficits) through approximately 2025 (the "Projected Cashflow").

23. The terms of the forbearance arrangement triggers immediate creditor rights, should the Projected Cashflow in a given year reflect a projected cash flow

deficit of sufficient magnitude that calls into question Deseret's ability to make scheduled minimum debt service payments from projected operating cash flows in the following year (a "Projected Cashflow Deficit").

24. Among the remedies Deseret's creditor will immediately acquire, upon such a Projected Cashflow Deficit, the creditors would immediately have the following rights:

- The right to approve Deseret's annual operating budgets;
- The right to end rebate programs to its members currently used to stabilize costs, incentivize efficiencies, and so forth at the end-consumer level;
- The right to suspend all capital rotation payments to member cooperatives;

25. These creditor remedies will become active *immediately* once Deseret delivers updated long-term cash flow projections that show a Projected Cashflow Deficit.

26. Deseret uses available "free" cash flow for a number of vital and important organizational purposes these payments are at immediate risk of creditor disapproval unless the FIP is stayed.

27. In addition, submitting Deseret's operating budgets to creditor approval places Deseret and its elected Governing Board in an untenable, irreparable position.

28. Among the immediate ramifications that could flow from Deseret projecting a Projected Cash Flow Deficit:

- Deseret relies on making cash rebates to its six rural electric cooperative members to equalize and stabilize rate effects. Should the creditors place these cash rebates on hold, the result will be to greatly increase all of the rates paid by these rural electric cooperatives and passed through to rates charged for electricity served to rural homes and communities; moreover, members in portions of Wyoming and elsewhere would see much more dramatic, unplanned, and sudden increases in rates than other areas, because the FERC-approved rebates serve to levelize and equalize rates among the Deseret distribution members.
- Deseret would be precluded from funding Energy Efficiency Improvement programs – investment programs designed to increase efficient use of electricity, thereby optimizing the amounts paid by ultimate electricity consumers.
- Deseret would be forced to re-evaluate labor costs and compensation levels, in order to satisfy creditor demands in seeking approval of annual operating budgets.
- Deseret would be precluded from making cash payments to member distribution cooperatives to rotate capital margins (cash paid in excess of operating costs) accumulated during past years. Deseret normally retires accrued patronage capital credits to its members on a regular basis. Creditors would most certainly prohibit such payments upon any Projected Cashflow Deficit.
- Other major maintenance projects at Deseret's plants (including approval for projects at the jointly owned Hunter 2 Unit), together with capital improvement funding for the coal mining operations of Deseret's wholly owned fuel supply subsidiary would be severely restricted or curtailed for the coming years

29. Even if the FIP is eventually modified by EPA and/or invalidated by Court action, Deseret will never recover from the forbearance creditors, payments made under restrictive budgets or rebates disallowed during the pendency of litigation, even if Deseret, PacifiCorp, and the State of Utah ultimately prevail on the merits.

30. But for a stay of the FIP, Deseret will be forced to undertake one or more of the following intolerable courses of action, effective immediately:

- Either report and project that Deseret will need to incur additional long-term indebtedness to finance the installation of FIP mandated improvements at Hunter 2 in potential contravention of the forbearance covenant against new indebtedness (thereby likely triggering a re-negotiation with its existing creditor to accommodate such new additional debt); and/or
- Begin immediately to restructure its rates for electricity sold, its operational plans and levels of dispatch for its existing generation resources, as well as budgeted operating expenditures to reflect an "emergency" or "survival" budget, to attempt to increased net operational cash flows, and (again) approach the forbearance creditors to re-negotiate for the ability to reserve (rather than to pay to the creditors on account of pre-existing unpaid indebtedness) and to accumulate increased operating cashflows in order to offset the future anticipated cost of such improvements; and/or
- Project a major future Projected Cashflow Deficit on account of the unavoidable cash outlays that would accompany anticipated installation of FIP mandated improvements at Hunter 2. The latter, if it results in a Projected Cashflow Deficit for the coming year, would seriously threaten to trigger immediate aggressive creditor rights which in turn would bear heavy negative impacts on Deseret's ability to continue to conduct its business affairs in the manner it currently does.

31. Given the relatively short time period remaining before the 2021 compliance deadline under the FIP mandate for all BART eligible in Utah, attempting to devise a cash flow plan that could accumulate sufficient cash reserves from Deseret's projected net operating cashflows by no later than 2021, to avoid the need for added long-term financing to pay for installation of mandated improvements at Hunter 2 would be painful, if it is even possible.

32. Devising a projected cashflow projection to derive and accumulate net cash flows to avoid financing the mandated Hunter 2 improvements would require

dramatic and immediate changes in Deseret's planned operations beginning immediately.

33. Deseret would have to immediately begin to take actions such as: dramatically reducing costs (with dramatic negative long term ramifications for the Company); raising member rates in anticipation of the coming cash requirements (raising negative consequences on small businesses and tribal interests throughout the economically disadvantaged areas served by Deseret's cooperative members and curtailing long-term revenue growth for Deseret and its member systems); adjusting rebate programs and/or curtail investments in energy efficiency programs, etc.

34. In any event, the terms of the forbearance arrangement require Deseret to sweep each year an amount equal to 50% of all net cash flows (after payment of minimum scheduled payments to the forbearance creditors on account of the unpaid pre-forbearance debt) from its utility operations. This makes it practically impossible to build any cash "reserve" to avoid prohibited long-term debt financing of the FIP mandated improvements, unless and without a substantial re-negotiation with the forbearance creditors.

Conclusion

35. Even should Deseret prevail in its petition for relief, it will begin immediately to incur irreparable injury absent a stay of the FIP.

36. I, Robert R. Dalley, declare under penalty of perjury under the laws of the United States that the foregoing is true and correct, to the best of my knowledge and belief.

Robert R. Dalley

Dated: October 27, 2016

To: Anderson, Lea[anderson.lea@epa.gov]
From: Rave, Norman (ENRD)
Sent: Mon 1/30/2017 5:05:50 PM
Subject: CSAPR > BART - Intervenor Briefs
ENV_DEFENSE-#794548-v1-BART_DC_State_Industry_Intervenors__Brief.PDF
ENV_DEFENSE-#794422-v1-BART_DC_DN_1657884_INTERVENOR_FOR_RESPONDENT_BRIEF__1657884__filed_by_National_Parks_Conservati 1342__Service.PDF

Lea, attached are the intervenor briefs. Ex. 5 - Attorney Client

Ex. 5 - Attorney Client

Norman

Norman Rave

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ORAL ARGUMENT NOT YET SCHEDULED

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 12-1342 (and consolidated cases)

UTILITY AIR REGULATORY GROUP,
Petitioner,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,
Respondent.

Petition for Review of Final Administrative Action of the
United States Environmental Protection Agency

PROOF INTERVENOR BRIEF OF CONSERVATION GROUPS

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DATED: January 27, 2017

ORAL ARGUMENT NOT YET SCHEDULED

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

UTILITY AIR REGULATORY GROUP, *Petitioner*, v. U.S. ENVIRONMENTAL PROTECTION AGENCY, *Respondent*.	Case No. 12-1342 (and consolidated cases)

CERTIFICATE AS TO PARTIES, RULINGS, AND RELATED CASES

In accordance with Circuit Rule 28(a)(1), National Parks Conservation Association and Sierra Club (collectively, "Conservation Groups") submit this certificate as to parties, rulings, and related cases.

(A) Parties and *Amici*

(i) Parties, Intervenors, and *Amici* Who Appeared in the District Court

This case is a petition for review of final agency action, not an appeal from the ruling of a district court.

(ii) Parties to This Case

Petitioners:

12-1342 Utility Air Regulatory Group

12-1343 National Parks Conservation Association and Sierra Club

12-1344	State of Texas and the Texas Commission on Environmental Quality
12-1425	National Parks Conservation Association and Sierra Club
12-1480	National Parks Conservation Association and Sierra Club
13-1003	National Parks Conservation Association and Sierra Club
13-1045	National Parks Conservation Association and Sierra Club
13-1129	National Parks Conservation Association and Sierra Club
13-1178	Luminant Generation Company, LLC, Sandow Power Company, LLC, Big Brown Power Company, LLC, Oak Grove Management Company, LLC, Luminant Mining Company, Big Brown Lignite Company, LLC, Luminant Big Brown Mining Company, LLC, Luminant Holding Company, LLC, and Luminant Energy Company, LLC
13-1179	State of Texas and the Texas Commission on Environmental Quality
13-1180	Louisiana Department of Environmental Quality

Respondent:

The respondent in all cases is the United States Environmental Protection Agency. Also included as a respondent in case Nos. 12-1343, 12-1425, 12-1480, 13-1003, 13-1045, and 13-1129 is Catherine McCabe,[1] in her official capacity as Acting Administrator of the United States Environmental Protection Agency.

[1] Pursuant to Federal Rule of Appellate Procedure 43(c)(2), Catherine McCabe is automatically substituted as respondent for her predecessor in office.

Intervenors:

12-1342 Big Brown Lignite Company, LLC, Big Brown Power Company, LLC, Luminant Big Brown Mining Company, LLC, Luminant Energy Company, LLC, Luminant Generation Company, LLC, Luminant Holding Company, LLC, Luminant Mining Company, LLC, Oak Grove Management Company, LLC, and Sandow Power Company, LLC have been granted leave to intervene on behalf of Petitioner.

National Parks Conservation Association, Sierra Club, and Union Electric Company have been granted leave to intervene on behalf of Respondent.

12-1343 Big Brown Lignite Company, LLC, Big Brown Power Company, LLC, Luminant Big Brown Mining Copmany, LC, Luminant Energy Company, LLC, Luminant Generation Company, LLC, Luminant Holding Company, LLC, Luminant Mining Company, LLC, Oak Grove Management Company, LLC, Sandow Power Copmany, LLC, and Utility Air Regulatory Group have been granted leave to intervene on behalf of Respondents.

12-1344 None.

12-1425 Indiana Energy Association, Inc., State of Indiana, and Utility Air Regulatory Group have been granted leave to intervene on behalf of Respondents.

12-1480 Union Electric Company has been granted leave to intervene on behalf of Respondents.

13-1003 None.

13-1045 Georgia Power Company has been granted leave to intervene on behalf of Respondents.

13-1129 None.

13-1178 None.

13-1179 None.

13-1180 None.

(iii) *Amici* in This Case

None at present.

(iv) Circuit Rule 26.1 Disclosures

See disclosure form filed separately.

(B) Rulings Under Review

Petitioners seek review of the final action taken by EPA at 77 Fed. Reg. 33,642 (June 7, 2012) and entitled "Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans."

(C) Related Cases

Conservation Groups are not aware of any related cases not already consolidated in this matter.

DATED: January 27, 2017

Respectfully submitted,

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ORAL ARGUMENT NOT YET SCHEDULED

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

UTILITY AIR REGULATORY GROUP, *Petitioner*, v. U.S. ENVIRONMENTAL PROTECTION AGENCY, *Respondent*.	Case No. 12-1342 (and consolidated cases)

RULE 26.1 DISCLOSURE STATEMENT

Pursuant to Federal Rules of Appellate Procedure 26.1 and 28(a)(1) and D.C. Circuit Rules 26.1 and 28(a)(1)(A), National Parks Conservation Association and Sierra Club make the following disclosures:

National Parks Conservation Association

Non-Governmental Corporate Party to this Action: National Parks Conservation Association.

Parent Corporations: None.

Publicly Held Company that Owns 10% or More of Party's Stock: None.

Party's General Nature and Purpose: National Parks Conservation Association, a corporation organized and existing under the laws of the District of Columbia, is a

national nonprofit organization dedicated to protecting and enhancing America's National Parks for present and future generations.

Sierra Club

Non-Governmental Corporate Party to this Action: Sierra Club.

Parent Corporations: None.

Publicly Held Company that Owns 10% or More of Party's Stock: None.

Party's General Nature and Purpose: Sierra Club, a corporation organized and existing under the laws of the State of California, is a national nonprofit organization dedicated to the protection and enjoyment of the environment.

DATED: January 27, 2017

Respectfully submitted,

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* Authorities upon which we chiefly rely are marked with an asterisk

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GLOSSARY OF ACRONYMS AND ABBREVIATIONS

Pursuant to Circuit Rule 28(a)(3), the following is a glossary of acronyms and abbreviations used in this brief:

Act	Clean Air Act
BART	Best available retrofit technology
CAIR	Clean Air Interstate Rule
CSAPR	Cross-State Air Pollution Rule
EPA	U.S. Environmental Protection Agency and Catherine McCabe, Assistant Administrator
NO_X	Nitrogen oxides
SIPs	State Implementation Plans
SO_2	Sulfur dioxide
TCEQ	Texas Commission on Environmental Quality

STATUTES AND REGULATIONS

Pertinent statutes and regulations appear in addenda to this brief, the Proof Opening Brief of Conservation Groups, and the Joint Opening Brief of State and Industry Petitioners.

STATEMENT OF THE CASE

Conservation Groups incorporate the portions of the Statement of the Case in the Brief for Respondent EPA (at 8-14) discussing the background and basis for its disapproval of the state implementation plans ("SIPs") relying on the Clean Air Interstate Rule ("CAIR") as a substitute for Best Available Retrofit Technology ("BART"), and subsequent related events.

SUMMARY OF ARGUMENT

State/Industry Petitioners' challenge to EPA's disapproval of SIPs relying on CAIR as a BART substitute is moot. CAIR no longer exists, but has been replaced by the Cross-State Air Pollution Rule ("CSAPR"). Accordingly, there is no live controversy over whether EPA should have allowed CAIR as a BART substitute, and no effective relief the Court can grant to State/Industry Petitioners on this claim. Even if the claim were not moot, EPA's disapproval of state plans that relied on CAIR was lawful and rational, given that this Court had declared CAIR invalid in *North Carolina v. EPA*, 531 F.3d 896, 901 (D.C. Cir. 2008). Likewise, there is no lawful or rational basis for State/Industry Petitioners' request to have

the obsolete, legally invalid CAIR continue to operate as a BART substitute "alongside" CSAPR.

ARGUMENT

I. SINCE CAIR HAS BEEN REPLACED BY CSAPR, THE ISSUE OF WHETHER EPA SHOULD HAVE ALLOWED CONTINUED RELIANCE ON CAIR AS A BART SUBSTITUTE IN 2012 IS MOOT.

As the Supreme Court has explained, "a federal court has no authority 'to give opinions upon moot questions or abstract propositions, or to declare principles or rules of law which cannot affect the matter in issue in the case before it.'" *Church of Scientology of California v. United States*, 506 U.S. 9, 12 (1992) (quoting *Mills v. Green*, 159 U.S. 651, 653 (1895)). Accordingly, "if an event occurs while a case is pending on appeal that makes it impossible for the court to grant 'any effectual relief whatever' to a prevailing party, the appeal must be dismissed." *Church of Scientology*, 506 U.S. at 12 (quoting *Mills*, 159 U.S. at 653); *Theodore Roosevelt Conservation P'ship v. Salazar*, 661 F.3d 66, 79 (D.C. Cir. 2011).

Here, because CSAPR has replaced CAIR in its entirety, there is no effective relief that the Court can provide to State/Industry Petitioners. Following the Court's order lifting the stay of CSAPR in *EME Homer City*, *see* Order at 3, *EME Homer City Generation L.P. v. EPA*, No. 11-1302 (D.C. Cir. Oct. 23, 2014), EPA terminated CAIR, renounced its own obligations in administering CAIR's emission

allowance trading programs, and began implementing CSAPR instead of CAIR. *See* 79 Fed. Reg. 71,663 (Dec. 3, 2014), JA____. These changes took effect on December 31, 2014. *See, e.g.*, 40 C.F.R. § 51.124(s)(1) (terminating obligations under CAIR for control of sulfur dioxide). Accordingly, this case is moot because "even the most favorable of rulings could not turn back the clock." *Beethoven.com LLC v. Librarian of Cong.*, 394 F.3d 939, 950 (D.C. Cir. 2005), *as amended* (Feb. 4, 2005).

This Court confronted a similar attempt to reanimate a superseded regulatory scheme in *Theodore Roosevelt Conservation Partnership*, 661 F.3d at 79. There, a hunting association alleged the Bureau of Land Management had unlawfully failed to enforce the terms of a Record of Decision issued by the Bureau in 2000, notwithstanding that a later Record of Decision had superseded the 2000 Record of Decision in its entirety. *Id.* This Court rejected the hunting association's claims as moot, explaining that "[w]e can neither invalidate, nor require the Bureau to adhere to, a Record of Decision that has 'disappeared into the regulatory netherworld.'" *Id.* (quoting *Nw. Pipeline Corp. v. FERC*, 863 F.2d 73, 77 (D.C. Cir. 1988)). Like the 2000 Record of Decision in *Theodore Roosevelt Conservation Partnership*, CAIR has been entirely superseded; accordingly, the question of whether EPA should have approved states' reliance thereon as a BART substitute is moot.

Although this Court has sometimes vacated administrative orders challenged in proceedings that have become moot in order to avoid preclusive effects attaching to the unreviewed orders, caselaw does not support such relief here. This Court has recognized that vacating broadly applicable agency action is not appropriate when "'what moots the dispute before us does not necessarily nullify the agency action.'" *Chamber of Commerce of the United States v. EPA*, 642 F.3d 192, 211 (D.C. Cir. 2011) (quoting *Radiofone v. FCC*, 759 F.2d 936, 940 (D.C. Cir. 1985) (Scalia, J., concurring)) (dismissing as moot challenges to EPA's waiver of preemption as to California motor vehicle emission standards without vacating EPA's waiver decision). Here, what moots the dispute – the repeal of CAIR and its replacement by CSAPR – validates, rather than nullifies, EPA's 2012 disapproval of the CAIR-for-BART SIPs.

II. EPA'S DISAPPROVAL OF STATE PLANS THAT RELIED ON CAIR AS A BART SUBSTITUTE WAS LAWFUL AND RATIONAL.

Even if State/Industry Petitioners' claim were not moot, their challenge to EPA's action fails on the merits. Because *North Carolina* (decided in 2008) expressly found CAIR to be legally invalid and directed that it be replaced, EPA lawfully and rationally found that it could no longer approve reliance on CAIR as a BART substitute. An agency cannot rely on invalid rules to satisfy its statutory duties. *See, e.g.*, *Delaware Dep't of Natural Res. and Envtl. Control v. EPA*, 785 F.3d 1, 16 (D.C. Cir. 2015) (EPA action arbitrary and capricious where

significantly grounded in a requirement that did not exist); *Williams Field Servs. Grp. v. FERC*, 194 F.3d 110, 119 (D.C. Cir. 1999) (agency action has no reasoned, principled basis where action relied on existence of settlement agreement that was no longer in place). This Court held that *North Carolina* "meant that the initial approval of the CAIR SIPs was in error at the time it was done." *EME Homer City Generation, L.P. v. EPA*, 795 F.3d 118, 133 (D.C. Cir. 2015) ("*Homer City II*") (emphasis added). The Court relied in part on Supreme Court precedent holding that "'[a] judicial construction of a statute is an authoritative statement of what the statute meant before as well as after the decision of the case giving rise to that construction.'" *Id.* at 133-34 (quoting *Rivers v. Roadway Express, Inc.*, 511 U.S. 298, 312-13 (1994)). Thus, at the time of the 2012 EPA action at issue here, CAIR was invalid as a matter of law, making EPA's disapproval of states' reliance on CAIR as a BART substitute both lawful and rational.

That *North Carolina* did not immediately vacate CAIR is of no moment. The Court left CAIR in effect "temporarily because doing so was necessary to 'at least temporarily preserve the environmental values covered by CAIR' until it could be 'replaced by a rule consistent with'" the *North Carolina* opinion. *Homer City II*, 795 F.3d at 134 (quoting *North Carolina*, 550 F.3d at 1178). "[C]ritically, the decision to remand without vacatur did not alter the core holding of *North Carolina*" that CAIR "contained 'fatal flaws' and needed to be replaced." *Homer*

City II, 795 F.3d at 134 (quoting *North Carolina*, 550 F.3d at 901). Thus, the Court's decision to temporarily leave CAIR in place was meant as a stopgap to prevent a worsening of pollution, not a license to rely on an invalid rule to evade other mandates under the Act.

Moreover, the stopgap CAIR program left in place after *North Carolina* could not achieve the long-term emission reductions required to satisfy sources' BART obligations. As EPA explained, 77 Fed. Reg. 33,642, 33,647/2 (June 7, 2012), JA____, the Act and EPA rules require sources to maintain BART control equipment and meet the BART emission limits for as long as the source continues to operate. *See* 40 C.F.R. § 51.308(e). Because EPA correctly found that CAIR could not continue in effect indefinitely (given its invalidation by this Court, and this Court's directive to replace it expeditiously), EPA lawfully disapproved SIPs relying on CAIR as a BART substitute.[1] Had EPA approved permanent reliance on CAIR as a BART substitute, as State/Industry Petitioners appear to seek, states could permanently evade the Act's BART mandate simply by claiming they had satisfied BART via CAIR, even after CAIR ceased to exist.

[1] The EPA action challenged here allowed states to continue to rely on CAIR as a BART substitute for long as it remained in place. 77 Fed. Reg. at 33,647/2-3, JA____. Thus, State/Industry Petitioners have no basis for claiming the action somehow left them vulnerable to enforcement or other action while litigation over CSAPR and EPA remand actions therefrom were resolved.

For all the foregoing reasons, EPA acted lawfully and rationally in disapproving the plans relying on CAIR as a BART substitute.

III. EPA'S SUBSEQUENT ACTIONS DO NOT UNDERMINE ITS REJECTION OF STATE HAZE PLANS THAT RELIED ON CAIR.

Contrary to State/Industry Petitioners' claims (at 41-48), EPA's disapproval of states' reliance on CAIR as a BART substitute in the action at issue here was not improper merely because EPA subsequently allowed some states to continue to rely on CAIR for limited purposes after *North Carolina* invalidated CAIR. As EPA notes (at 55-56), those actions were conditioned on the state replacing CAIR with CSAPR once the latter was affirmed or revised, and/or findings that state-specific factors warranted temporary reliance on the CAIR reductions. Moreover, to the extent there was material inconsistency between EPA's 2012 disapproval of the state plans that relied on CAIR and subsequent EPA actions, the inconsistency would at most require EPA to justify taking a different approach in those <u>subsequent</u> actions – it would not retroactively justify overturning EPA's original approach in 2012 of disapproving reliance on CAIR as a BART substitute. *See Noramco of Delaware v. DEA*, 375 F.3d 1148, 1156 n.7 (D.C. Cir. 2004) ("Challenging the DEA's decision here based on the agency's *subsequent* position, however, 'puts the cart before the horse.' … It is the DEA's position here to which it will be held in the later decisions") (emphasis in original, citations omitted); *Intercollegiate Broadcast Sys. v. Copyright Royalty Bd.*, 574 F.3d 748, 759 (D.C.

Cir. 2009) ("Failure to conform with subsequent agency action cannot be a basis for a finding of arbitrariness").

IV. STATE/INDUSTRY PETITIONERS' PROPOSED REMEDY IS UNLAWFUL AND IRRATIONAL.

Contrary to State/Industry Petitioners' assertion, CAIR could not somehow continue to operate alongside of CSAPR. As this Court has held, "CAIR contained 'fatal flaws' and needed to be replaced." *Homer City II*, 795 F.3d at 134 (quoting *North Carolina*, 531 F.3d at 901); *see also* EPA Br. at 9. Under § 7410(*l*) of the Act, EPA is prohibited from approving any plan revision that would interfere with any applicable requirement of the Act. 42 U.S.C. § 7410(*l*). Approving SIPs that rely on a legally invalid CAIR as a BART substitute would plainly interfere with the Act's BART mandate, in violation of § 7410(*l*), by allowing states to substitute a nonexistent program for BART. *See also Ctr. for Energy and Economic Dev. v. EPA*, 398 F.3d 653, 660 (D.C. Cir. 2005) ("*CEED*") (holding that EPA could not approve BART alternative that relied on premise invalidated in prior D.C. Circuit decision).

Even if not flatly unlawful, attempting to graft CAIR onto CSAPR would be impossible as a practical matter. State/Industry Petitioners do not and cannot explain how CAIR can be implemented now that EPA has replaced it, sunsetted its applicability, and renounced the Agency's own role in implementing it. *See* 79 Fed. Reg. 71,663, JA____ (terminating the temporarily-extended implementation

of CAIR). The haze plans State/Industry Petitioners seek to have this Court endorse predate these events. Yet nowhere in their brief or their comments to EPA below do State/Industry Petitioners address this fundamental problem, much less demonstrate how an unlawful, revoked CAIR program could possibly assure better-than-BART emission reductions. Nor do they even suggest how CAIR could somehow continue to operate "alongside" the CSAPR program that completely supplanted it.

Indeed, State/Industry Petitioners appear to seek exemption from any requirement to ensure actual emission reductions via BART or an EPA-approved BART alternative. Their Preliminary Statement explains that they seek to restore the "protection" of CAIR as an alternative to BART, a description consistent with no longer needing to do anything to satisfy BART requirements and relying instead on the non-existent CAIR program.[2] Such a result is flatly contrary to the Act. This Court's precedents make plain that BART substitutes must assure greater reasonable progress than source-specific BART, a test that a non-existent program obviously cannot meet. *CEED*, 398 F.3d at 655; *Utility Air Regulatory Grp. v. EPA*, 471 F.3d 1333, 1336 (D.C. Cir. 2006) ("*UARG*").

[2] State/Industry Petitioners' Preliminary Statement notes that they are pursuing this challenge "to avoid the prospect of being left with neither the protection of [CSAPR as an alternative to BART] *nor* the protection of the CAIR-related provision that EPA's rule unlawfully revoked." State/Industry Petitioners Br. at 4-5.

Even if State/Industry Petitioners intend to resume implementing some reinvented version of CAIR, and to rely thereon for reductions in the pollution that causes regional haze, they do not rationally explain how such a program would work – nor can they. The implementation of CAIR relied heavily on EPA involvement, for example, in administering the CAIR emission allowance trading program. But EPA has rescinded that program, as well as its own obligation to administer it. 79 Fed. Reg. 71,663, JA____. Thus, it is no longer possible to implement the regional haze implementation plans that State/Industry Petitioners ask this Court to order EPA to approve. Even if State/Industry Petitioners' concept of implementing CAIR through those plans were otherwise valid, significant revisions to the plans themselves would be needed to achieve that objective – for example, to address how CAIR's allowance trading system would work without EPA's involvement. Merely retroactively vacating EPA's disapproval of CAIR-for-BART plans will not make those plans workable in a world where CAIR no longer exists.

Moreover, because EPA has replaced the CAIR trading program with CSAPR, and because the emission budgets and governing rules are substantially different under the two programs, they do not work together. For example, CAIR and CSAPR have different rules governing the banking of allowances for use in future years. *See* 76 Fed. Reg. 48,208, 48,321/1 (Aug. 8, 2011), JA____ (banking

permissible under CAIR, but not under CSAPR). In addition, CSAPR imposes different deadlines and is also more prescriptive than CAIR with regard to, among other things, a state's emission allowance allocation methods and the ability of states to expand the program to cover additional sources. *Id.* at 48,321/2-3, JA____. Thus, even if EPA were correct that CAIR and CSAPR each qualify as alternatives to BART, there has been no showing that implementing a mixture of these two distinct programs would achieve the same results.

State/Industry Petitioners' request that the Court vacate EPA's revocation of 40 C.F.R. § 51.308(e)(4) as it existed before June 7, 2012, *see* State/Industry Petitioners Br. at 48, further illustrates the inherent infeasibility of a piecemeal resurrection of CAIR. The regulatory text State/Industry Petitioners want to restore would enable states to satisfy BART requirements if they "meet the emission reduction requirements of [CAIR] by participating in one or more of the EPA-administered CAIR trading programs for SO_2 and NO_X." 40 C.F.R. § 51.308(e)(4) (2011). Even if this language were restored to the C.F.R., it would be meaningless because EPA has rescinded its administration of the CAIR trading programs for SO_2 and NO_x. *See id.* §§ 51.123(ff), .124(s). There are no EPA-administered CAIR trading programs in which states can participate.

Nor do State/Industry Petitioners' comments on EPA's notice proposing disapproval of the haze plans at issue shed any light on how State/Industry

Petitioners believe CAIR can be partially reactivated. On the contrary, the approach Petitioner Texas Commission on Environmental Quality ("TCEQ") suggested in its comments conflicts with State/Industry Petitioners' insistence on relying on CAIR to satisfy BART. TCEQ recommended that instead of limited SIP disapprovals, "EPA should provide for limited approvals for all states that relied upon CAIR as an element of their BART analysis. Limited approvals are necessary to assure both states and sources that their reliance upon the CAIR was, and remains, valid during the period when CAIR remains legally effective." EPA-HQ-OAR-2011-0729-0234 attach.2 at 2, JA____ (emphasis added). Therefore, Petitioner TCEQ recognized that CAIR could not continue to act as a BART alternative after CAIR terminated.

CONCLUSION

For these reasons, and those stated by EPA, the Court should dismiss the petitions of the State/Industry Petitioners.

DATED: January 27, 2017

Respectfully submitted,

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CERTIFICATE OF COMPLIANCE WITH TYPE-VOLUME LIMIT

Counsel hereby certifies, in accordance with Federal Rule of Appellate Procedure 32(g)(1), that the foregoing **Proof Intervenor Brief of Conservation Groups** contains 2,738 words, as counted by counsel's word processing system, and thus complies with the 5,000 word limit established by the Court.

Further, this document complies with the typeface and type-style requirements of Federal Rule of Appellate Procedure 32(a)(5) & (a)(6) because this document has been prepared in a proportionally spaced typeface using **Microsoft Word 2010** using **size 14 Times New Roman** font.

DATED: January 27, 2017

/s/ David S. Baron
David S. Baron

CERTIFICATE OF SERVICE

I hereby certify that on this 27th day of January, 2017, I have served the foregoing **Proof Intervenor Brief of Conservation Groups** on all registered counsel through the Court's electronic filing system (ECF).

/s/ David S. Baron
David S. Baron

ORAL ARGUMENT NOT YET SCHEDULED

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

No. 12-1342 (and consolidated cases)

UTILITY AIR REGULATORY GROUP,
Petitioner,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY,
Respondent.

Petition for Review of Final Administrative Action of the
United States Environmental Protection Agency

ADDENDUM TO THE PROOF INTERVENOR BRIEF OF CONSERVATION GROUPS

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DATED: January 27, 2017

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REGULATIONS

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Unconstitutional or PreemptedPrior Version Held Invalid EME Homer City Generation, L.P. v. E.P.A., D.C.Cir., Aug. 21, 2012

Code of Federal Regulations
Title 40. Protection of Environment
Chapter I. Environmental Protection Agency (Refs & Annos)
Subchapter C. Air Programs
Part 51. Requirements for Preparation, Adoption, and Submittal of Implementation Plans (Refs & Annos)
Subpart G. Control Strategy (Refs & Annos)

40 C.F.R. § 51.123

§ 51.123 Findings and requirements for submission of State implementation plan revisions relating to emissions of oxides of nitrogen pursuant to the Clean Air Interstate Rule.

Effective: December 3, 2014
Currentness

(a)(1) Under section 110(a)(1) of the CAA,42 U.S.C. 7410(a)(1), the Administrator determines that each State identified in paragraph (c)(1) and (2) of this section must submit a SIP revision to comply with the requirements of section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), through the adoption of adequate provisions prohibiting sources and other activities from emitting NO_X in amounts that will contribute significantly to nonattainment in, or interfere with maintenance by, one or more other States with respect to the fine particles ($PM_{2.5}$) NAAQS.

(2)(a)[1] Under section 110(a)(1) of the CAA, 42 U.S.C. 7410(a)(1), the Administrator determines that each State identified in paragraph (c)(1) and (3) of this section must submit a SIP revision to comply with the requirements of section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), through the adoption of adequate provisions prohibiting sources and other activities from emitting NO_X in amounts that will contribute significantly to nonattainment in, or interfere with maintenance by, one or more other States with respect to the 8–hour ozone NAAQS.

(3) Notwithstanding the other provisions of this section, such provisions are not applicable as they relate to the State of Minnesota as of December 3, 2009.

(b) For each State identified in paragraph (c) of this section, the SIP revision required under paragraph (a) of this section will contain adequate provisions, for purposes of complying with section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), only if the SIP revision contains control measures that assure compliance with the applicable requirements of this section.

(c) In addition to being subject to the requirements in paragraphs (b) and (d) of this section:

(1) Alabama, Delaware, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West

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Virginia, Wisconsin, and the District of Columbia shall be subject to the requirements contained in paragraphs (e) through (cc) of this section;

(2) Georgia, Minnesota, and Texas shall be subject to the requirements in paragraphs (e) through (o) and (cc) of this section; and

(3) Arkansas, Connecticut, and Massachusetts shall be subject to the requirements contained in paragraphs (q) through (cc) of this section.

(d)(1) The State's SIP revision under paragraph (a) of this section must be submitted to EPA by no later than September 11, 2006.

(2) The requirements of appendix V to this part shall apply to the SIP revision under paragraph (a) of this section.

(3) The State shall deliver 5 copies of the SIP revision under paragraph (a) of this section to the appropriate Regional Office, with a letter giving notice of such action.

(e) The State's SIP revision shall contain control measures and demonstrate that they will result in compliance with the State's Annual EGU NO_X Budget, if applicable, and achieve the State's Annual Non–EGU NO_X Reduction Requirement, if applicable, for the appropriate periods. The amounts of the State's Annual EGU NO_X Budget and Annual Non–EGU NO_X Reduction Requirement shall be determined as follows:

(1)(i) The Annual EGU NO_X Budget for the State is defined as the total amount of NO_X emissions from all EGUs in that State for a year, if the State meets the requirements of paragraph (a)(1) of this section by imposing control measures, at least in part, on EGUs. If the State imposes control measures under this section on only EGUs, the Annual EGU NO_X Budget for the State shall not exceed the amount, during the indicated periods, specified in paragraph (e)(2) of this section.

(ii) The Annual Non–EGU NO_X Reduction Requirement, if applicable, is defined as the total amount of NO_X emission reductions that the State demonstrates, in accordance with paragraph (g) of this section, it will achieve from non–EGUs during the appropriate period. If the State meets the requirements of paragraph (a)(1) of this section by imposing control measures on only non–EGUs, then the State's Annual Non–EGU NO_X Reduction Requirement shall equal or exceed, during the appropriate periods, the amount determined in accordance with paragraph (e)(3) of this section.

(iii) If a State meets the requirements of paragraph (a)(1) of this section by imposing control measures on both EGUs and non–EGUs, then:

(A) The Annual Non–EGU NO_X Reduction Requirement shall equal or exceed the difference between the amount specified in paragraph (e)(2) of this section for the appropriate period and the amount of the State's Annual EGU NO_X Budget specified in the SIP revision for the appropriate period; and

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(B) The Annual EGU NO_X Budget shall not exceed, during the indicated periods, the amount specified in paragraph (e)(2) of this section plus the amount of the Annual Non–EGU NO_X Reduction Requirement under paragraph (e)(1)(iii)(A) of this section for the appropriate period.

(2) For a State that complies with the requirements of paragraph (a)(1) of this section by imposing control measures on only EGUs, the amount of the Annual EGU NO_X Budget, in tons of NO_X per year, shall be as follows, for the indicated State for the indicated period:

State	Annual EGU NO_X budget for 2009-2014 (tons)	Annual EGU NO_X budget for 2015 and thereafter (tons)
Alabama	69,020	57,517
Delaware	4,166	3,472
District of Columbia	144	120
Florida	99,445	82,871
Georgia	66,321	55,268
Illinois	76,230	63,525
Indiana	108,935	90,779
Iowa	32,692	27,243
Kentucky	83,205	69,337
Louisiana	35,512	29,593
Maryland	27,724	23,104
Michigan	65,304	54,420
Minnesota	31,443	26,203
Mississippi	17,807	14,839
Missouri	59,871	49,892
New Jersey	12,670	10,558
New York	45,617	38,014
North Carolina	62,183	51,819
Ohio	108,667	90,556
Pennsylvania	99,049	82,541

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South Carolina	32,662	27,219
Tennessee	50,973	42,478
Texas	181,014	150,845
Virginia	36,074	30,062
West Virginia	74,220	61,850
Wisconsin	40,759	33,966

(3) For a State that complies with the requirements of paragraph (a)(1) of this section by imposing control measures on only non–EGUs, the amount of the Annual Non–EGU NO_X Reduction Requirement, in tons of NO_X per year, shall be determined, for the State for 2009 and thereafter, by subtracting the amount of the State's Annual EGU NO_X Budget for the appropriate year, specified in paragraph (e)(2) of this section from the amount of the State's NO_X baseline EGU emissions inventory projected for the appropriate year, specified in Table 5 of "Regional and State SO_2 and NO_X Budgets", March 2005 (available at http://www.epa.gov/cleanairinterstaterule).

(4)(i) Notwithstanding the State's obligation to comply with paragraph (e)(2) or (3) of this section, the State's SIP revision may allow sources required by the revision to implement control measures to demonstrate compliance using credit issued from the State's compliance supplement pool, as set forth in paragraph (e)(4)(ii) of this section.

(ii) The State-by–State amounts of the compliance supplement pool are as follows:

State	Compliance supplement pool
Alabama	10,166
Delaware	843
District of Columbia	0
Florida	8,335
Georgia	12,397
Illinois	11,299
Indiana	20,155
Iowa	6,978
Kentucky	14,935
Louisiana	2,251
Maryland	4,670
Michigan	8,347

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Minnesota	6,528
Mississippi	3,066
Missouri	9,044
New Jersey	660
New York	0
North Carolina	0
Ohio	25,037
Pennsylvania	16,009
South Carolina	2,600
Tennessee	8,944
Texas	772
Virginia	5,134
West Virginia	16,929
Wisconsin	4,898

(iii) The SIP revision may provide for the distribution of credits from the compliance supplement pool to sources that are required to implement control measures using one or both of the following two mechanisms:

(A) The State may issue credit from compliance supplement pool to sources that are required by the SIP revision to implement NO_X emission control measures and that implement NO_X emission reductions in 2007 and 2008 that are not necessary to comply with any State or federal emissions limitation applicable at any time during such years. Such a source may be issued one credit from the compliance supplement pool for each ton of such emission reductions in 2007 and 2008.

(1) The State shall complete the issuance process by January 1, 2010.

(2) The emissions reductions for which credits are issued must have been demonstrated by the owners and operators of the source to have occurred during 2007 and 2008 and not to be necessary to comply with any applicable State or federal emissions limitation.

(3) The emissions reductions for which credits are issued must have been quantified by the owners and operators of the source:

(i) For EGUs and for fossil-fuel-fired non–EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBut/hr, using emissions data determined in accordance with subpart H of part 75 of this chapter; and

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(ii) For non–EGUs not described in paragraph (e)(4)(iii)(A)(3)(i) of this section, using emissions data determined in accordance with subpart H of part 75 of this chapter or, if the State demonstrates that compliance with subpart H of part 75 of this chapter is not practicable, determined, to the extent practicable, with the same degree of assurance with which emissions data are determined for sources subject to subpart H of part 75.

(4) If the SIP revision contains approved provisions for an emissions trading program, the owners and operators of sources that receive credit according to the requirements of this paragraph may transfer the credit to other sources or persons according to the provisions in the emissions trading program.

(B) The State may issue credit from the compliance supplement pool to sources that are required by the SIP revision to implement NO_X emission control measures and whose owners and operators demonstrate a need for an extension, beyond 2009, of the deadline for the source for implementing such emission controls.

(1) The State shall complete the issuance process by January 1, 2010.

(2) The State shall issue credit to a source only if the owners and operators of the source demonstrate that:

(i) For a source used to generate electricity, implementation of the SIP revision's applicable control measures by 2009 would create undue risk for the reliability of the electricity supply. This demonstration must include a showing that it would not be feasible for the owners and operators of the source to obtain a sufficient amount of electricity, to prevent such undue risk, from other electricity generation facilities during the installation of control technology at the source necessary to comply with the SIP revision.

(ii) For a source not used to generate electricity, compliance with the SIP revision's applicable control measures by 2009 would create undue risk for the source or its associated industry to a degree that is comparable to the risk described in paragraph (e)(4)(iii)(B)(2)(i) of this section.

(iii) This demonstration must include a showing that it would not be possible for the source to comply with applicable control measures by obtaining sufficient credits under paragraph (e)(4)(iii)(A) of this section, or by acquiring sufficient credits from other sources or persons, to prevent undue risk.

(f) Each SIP revision must set forth control measures to meet the amounts specified in paragraph (e) of this section, as applicable, including the following:

(1) A description of enforcement methods including, but not limited to:

(i) Procedures for monitoring compliance with each of the selected control measures;

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(ii) Procedures for handling violations; and

(iii) A designation of agency responsibility for enforcement of implementation.

(2)(i) If a State elects to impose control measures on EGUs, then those measures must impose an annual NO_X mass emissions cap on all such sources in the State.

(ii) If a State elects to impose control measures on fossil fuel-fired non–EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then those measures must impose an annual NO_X mass emissions cap on all such sources in the State.

(iii) If a State elects to impose control measures on non–EGUs other than those described in paragraph (f)(2)(ii) of this section, then those measures must impose an annual NO_X mass emissions cap on all such sources in the State or the State must demonstrate why such emissions cap is not practicable and adopt alternative requirements that ensure that the State will comply with its requirements under paragraph (e) of this section, as applicable, in 2009 and subsequent years.

(g)(1) Each SIP revision that contains control measures covering non–EGUs as part or all of a State's obligation in meeting its requirement under paragraph (a)(1) of this section must demonstrate that such control measures are adequate to provide for the timely compliance with the State's Annual Non–EGU NO_X Reduction Requirement under paragraph (e) of this section and are not adopted or implemented by the State, as of May 12, 2005, and are not adopted or implemented by the Federal government, as of the date of submission of the SIP revision by the State to EPA.

(2) The demonstration under paragraph (g)(1) of this section must include the following, with respect to each source category of non–EGUs for which the SIP revision requires control measures:

(i) A detailed historical baseline inventory of NO_X mass emissions from the source category in a representative year consisting, at the State's election, of 2002, 2003, 2004, or 2005, or an average of 2 or more of those years, absent the control measures specified in the SIP revision.

(A) This inventory must represent estimates of actual emissions based on monitoring data in accordance with subpart H of part 75 of this chapter, if the source category is subject to monitoring requirements in accordance with subpart H of part 75 of this chapter.

(B) In the absence of monitoring data in accordance with subpart H of part 75 of this chapter, actual emissions must be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to subpart H of part 75 of this chapter and using source-specific or source-category-specific assumptions that ensure a source's or source category's actual emissions are not overestimated. If a State uses factors to estimate emissions, production or utilization, or effectiveness of controls or rules for a source category, such factors must be chosen to ensure that emissions are not overestimated.

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(C) For measures to reduce emissions from motor vehicles, emission estimates must be based on an emissions model that has been approved by EPA for use in SIP development and must be consistent with the planning assumptions regarding vehicle miles traveled and other factors current at the time of the SIP development.

(D) For measures to reduce emissions from nonroad engines or vehicles, emission estimates methodologies must be approved by EPA.

(ii) A detailed baseline inventory of NO_X mass emissions from the source category in the years 2009 and 2015, absent the control measures specified in the SIP revision and reflecting changes in these emissions from the historical baseline year to the years 2009 and 2015, based on projected changes in the production input or output, population, vehicle miles traveled, economic activity, or other factors as applicable to this source category.

(A) These inventories must account for implementation of any control measures that are otherwise required by final rules already promulgated, as of May 12, 2005, or adopted or implemented by any federal agency, as of the date of submission of the SIP revision by the State to EPA, and must exclude any control measures specified in the SIP revision to meet the NO_X emissions reduction requirements of this section.

(B) Economic and population forecasts must be as specific as possible to the applicable industry, State, and county of the source or source category and must be consistent with both national projections and relevant official planning assumptions, including estimates of population and vehicle miles traveled developed through consultation between State and local transportation and air quality agencies. However, if these official planning assumptions are inconsistent with official U.S. Census projections of population or with energy consumption projections contained in the U.S. Department of Energy's most recent Annual Energy Outlook, then the SIP revision must make adjustments to correct the inconsistency or must demonstrate how the official planning assumptions are more accurate.

(C) These inventories must account for any changes in production method, materials, fuels, or efficiency that are expected to occur between the historical baseline year and 2009 or 2015, as appropriate.

(iii) A projection of NO_X mass emissions in 2009 and 2015 from the source category assuming the same projected changes as under paragraph (g)(2)(ii) of this section and resulting from implementation of each of the control measures specified in the SIP revision.

(A) These inventories must address the possibility that the State's new control measures may cause production or utilization, and emissions, to shift to unregulated or less stringently regulated sources in the source category in the same or another State, and these inventories must include any such amounts of emissions that may shift to such other sources.

(B) The State must provide EPA with a summary of the computations, assumptions, and judgments used to determine the degree of reduction in projected 2009 and 2015 NO_X emissions that will be achieved from the implementation of the new control measures compared to the relevant baseline emissions inventory.

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(iv) The result of subtracting the amounts in paragraph (g)(2)(iii) of this section for 2009 and 2015, respectively, from the lower of the amounts in paragraph (g)(2)(i) or (g)(2)(ii) of this section for 2009 and 2015, respectively, may be credited towards the State's Annual Non–EGU NO_X Reduction Requirement in paragraph (e)(3) of this section for the appropriate period.

(v) Each SIP revision must identify the sources of the data used in each estimate and each projection of emissions.

(h) Each SIP revision must comply with § 51.116 (regarding data availability).

(i) Each SIP revision must provide for monitoring the status of compliance with any control measures adopted to meet the State's requirements under paragraph (e) of this section as follows:

(1) The SIP revision must provide for legally enforceable procedures for requiring owners or operators of stationary sources to maintain records of, and periodically report to the State:

(i) Information on the amount of NO_X emissions from the stationary sources; and

(ii) Other information as may be necessary to enable the State to determine whether the sources are in compliance with applicable portions of the control measures;

(2) The SIP revision must comply with § 51.212 (regarding testing, inspection, enforcement, and complaints);

(3) If the SIP revision contains any transportation control measures, then the SIP revision must comply with § 51.213 (regarding transportation control measures);

(4)(i) If the SIP revision contains measures to control EGUs, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter.

(ii) If the SIP revision contains measures to control fossil fuel-fired non–EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter.

(iii) If the SIP revision contains measures to control any other non–EGUs that are not described in paragraph (i)(4)(ii) of this section, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter, or the State must demonstrate why such requirements are not practicable and adopt alternative requirements that ensure that the required emissions reductions will be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to subpart H of part 75 of this chapter.

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(j) Each SIP revision must show that the State has legal authority to carry out the SIP revision, including authority to:

(1) Adopt emissions standards and limitations and any other measures necessary for attainment and maintenance of the State's relevant Annual EGU NO $_X$ Budget or the Annual Non–EGU NO $_X$ Reduction Requirement, as applicable, under paragraph (e) of this section;

(2) Enforce applicable laws, regulations, and standards and seek injunctive relief;

(3) Obtain information necessary to determine whether air pollution sources are in compliance with applicable laws, regulations, and standards, including authority to require recordkeeping and to make inspections and conduct tests of air pollution sources; and

(4)(i) Require owners or operators of stationary sources to install, maintain, and use emissions monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such stationary sources; and

(ii) Make the data described in paragraph (j)(4)(i) of this section available to the public within a reasonable time after being reported and as correlated with any applicable emissions standards or limitations.

(k)(1) The provisions of law or regulation that the State determines provide the authorities required under this section must be specifically identified, and copies of such laws or regulations must be submitted with the SIP revision.

(2) Legal authority adequate to fulfill the requirements of paragraphs (j)(3) and (4) of this section may be delegated to the State under section 114 of the CAA.

(l)(1) A SIP revision may assign legal authority to local agencies in accordance with § 51.232.

(2) Each SIP revision must comply with § 51.240 (regarding general plan requirements).

(m) Each SIP revision must comply with § 51.280 (regarding resources).

(n) Each SIP revision must provide for State compliance with the reporting requirements in § 51.125.

(o)(1) Notwithstanding any other provision of this section, if a State adopts regulations substantively identical to subparts AA through II of part 96 of this chapter (CAIR NO $_X$ Annual Trading Program), incorporates such subparts by reference into its regulations, or adopts regulations that differ substantively from such subparts only as set forth in paragraph (o)(2) of this section, then such emissions trading program in the State's SIP revision is automatically approved as meeting the requirements of paragraph (e) of this section, provided that the State has the legal authority to take such action and to implement its responsibilities under such regulations. Before January 1, 2009, a State's regulations shall be considered to be substantively identical to subparts AA through II of part 96 of this chapter, or differing substantively only as set forth in paragraph (o)(2) of this section, regardless of whether the State's regulations include the definition of "Biomass",

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paragraph (3) of the definition of "Cogeneration unit", and the second sentence of the definition of "Total energy input" in § 96.102 of this chapter promulgated on October 19, 2007, provided that the State timely submits to the Administrator a SIP revision that revises the State's regulations to include such provisions. Submission to the Administrator of a SIP revision that revises the State's regulations to include such provisions shall be considered timely if the submission is made by January 1, 2009.

(2) If a State adopts an emissions trading program that differs substantively from subparts AA through II of part 96 of this chapter only as follows, then the emissions trading program is approved as set forth in paragraph (o)(1) of this section.

(i) The State may decline to adopt the CAIR NO_X opt-in provisions of:

(A) Subpart II of this part and the provisions applicable only to CAIR NO_X opt-in units in subparts AA through HH of this part;

(B) Section 96.188(b) of this chapter and the provisions of subpart II of this part applicable only to CAIR NO_X opt-in units under § 96.188(b); or

(C) Section 96.188(c) of this chapter and the provisions of subpart II of this part applicable only to CAIR NO_X opt-in units under § 96.188(c).

(ii) The State may decline to adopt the allocation provisions set forth in subpart EE of part 96 of this chapter and may instead adopt any methodology for allocating CAIR NO_X allowances to individual sources, as follows:

(A) The State's methodology must not allow the State to allocate CAIR NO_X allowances for a year in excess of the amount in the State's Annual EGU NO_X Budget for such year;

(B) The State's methodology must require that, for EGUs commencing operation before January 1, 2001, the State will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31, 2006 for 2009, 2010, and 2011 and by October 31, 2008 and October 31 of each year thereafter for the 4th year after the year of the notification deadline;

(C) The State's methodology must require that, for EGUs commencing operation on or after January 1, 2001, the State will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31 of the year for which the CAIR NO_X allowances are allocated; and

(D) The State's methodology for allocating the compliance supplement pool must be substantively identical to § 97.143 (except that the permitting authority makes the allocations and the Administrator records the allocations made by the permitting authority) or otherwise in accordance with paragraph (e)(4) of this section.

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(3) A State that adopts an emissions trading program in accordance with paragraph (o)(1) or (2) of this section is not required to adopt an emissions trading program in accordance with paragraph (aa)(1) or (2) of this section or § 96.124(o)(1) or (2).

(4) If a State adopts an emissions trading program that differs substantively from subparts AA through HH of part 96 of this chapter, other than as set forth in paragraph (o)(2) of this section, then such emissions trading program is not automatically approved as set forth in paragraph (o)(1) or (2) of this section and will be reviewed by the Administrator for approvability in accordance with the other provisions of this section, provided that the NO_X allowances issued under such emissions trading program shall not, and the SIP revision shall state that such NO_X allowances shall not, qualify as CAIR NO_X allowances or CAIR NO_X Ozone Season allowances under any emissions trading program approved under paragraphs (o)(1) or (2) or (aa)(1) or (2) of this section.

(p) Notwithstanding any other provision of this section, a State may adopt, and include in a SIP revision submitted by March 31, 2007, regulations relating to the Federal CAIR NO_X Annual Trading Program under subparts AA through HH of part 97 of this chapter as follows:

(1) The State may adopt, as CAIR NO_X allowance allocation provisions replacing the provisions in subpart EE of part 97 of this chapter:

(i) Allocation provisions substantively identical to subpart EE of part 96 of this chapter, under which the permitting authority makes the allocations; or

(ii) Any methodology for allocating CAIR NO_X allowances to individual sources under which the permitting authority makes the allocations, provided that:

(A) The State's methodology must not allow the permitting authority to allocate CAIR NO_X allowances for a year in excess of the amount in the State's Annual EGU NO_X budget for such year.

(B) The State's methodology must require that, for EGUs commencing operation before January 1, 2001, the permitting authority will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by April 30, 2007 for 2009, 2010, and 2011 and by October 31, 2008 and October 31 of each year thereafter for the 4th year after the year of the notification deadline.

(C) The State's methodology must require that, for EGUs commencing operation on or after January 1, 2001, the permitting authority will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31 of the year for which the CAIR NO_X allowances are allocated.

(2) The State may adopt, as compliance supplement pool provisions replacing the provisions in § 97.143 of this chapter:

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(i) Provisions for allocating the State's compliance supplement pool that are substantively identical to § 97.143 of this chapter, except that the permitting authority makes the allocations and the Administrator records the allocations made by the permitting authority;

(ii) Provisions for allocating the State's compliance supplement pool that are substantively identical to § 96.143 of this chapter; or

(iii) Other provisions for allocating the State's compliance supplement pool that are in accordance with paragraph (e)(4) of this section.

(3) The State may adopt CAIR opt-in unit provisions as follows:

(i) Provisions for CAIR opt-in units, including provisions for applications for CAIR opt-in permits, approval of CAIR opt-in permits, treatment of units as CAIR opt-in units, and allocation and recordation of CAIR NO_X allowances for CAIR opt-in units, that are substantively identical to subpart II of part 96 of this chapter and the provisions of subparts AA through HH that are applicable to CAIR opt-in units or units for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied;

(ii) Provisions for CAIR opt-in units, including provisions for applications for CAIR opt-in permits, approval of CAIR opt-in permits, treatment of units as CAIR opt-in units, and allocation and recordation of CAIR NO_X allowances for CAIR opt-in units, that are substantively identical to subpart II of part 96 of this chapter and the provisions of subparts AA through HH that are applicable to CAIR opt-in units or units for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied, except that the provisions exclude § 96.188(b) of this chapter and the provisions of subpart II of part 96 of this chapter that apply only to units covered by § 96.188(b) of this chapter; or

(iii) Provisions for applications for CAIR opt-in units, including provisions for CAIR opt-in permits, approval of CAIR opt-in permits, treatment of units as CAIR opt-in units, and allocation and recordation of CAIR NO_X allowances for CAIR opt-in units, that are substantively identical to subpart II of part 96 of this chapter and the provisions of subparts AA through HH that are applicable to CAIR opt-in units or units for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied, except that the provisions exclude § 96.188(c) of this chapter and the provisions of subpart II of part 96 of this chapter that apply only to units covered by § 96.188(c) of this chapter.

(q) The State's SIP revision shall contain control measures and demonstrate that they will result in compliance with the State's Ozone Season EGU NO_X Budget, if applicable, and achieve the State's Ozone Season Non–EGU NO_X Reduction Requirement, if applicable, for the appropriate periods. The amounts of the State's Ozone Season EGU NO_X Budget and Ozone Season Non–EGU NO_X Reduction Requirement shall be determined as follows:

(1)(i) The Ozone Season EGU NO_X Budget for the State is defined as the total amount of NO_X emissions from all EGUs in that State for an ozone season, if the State meets the requirements of paragraph (a)(2) of this section by imposing control measures, at least in part, on EGUs. If the State imposes control measures under this section on

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only EGUs, the Ozone Season EGU NO_X Budget for the State shall not exceed the amount, during the indicated periods, specified in paragraph (q)(2) of this section.

(ii) The Ozone Season Non–EGU NO_X Reduction Requirement, if applicable, is defined as the total amount of NO_X emission reductions that the State demonstrates, in accordance with paragraph (s) of this section, it will achieve from non–EGUs during the appropriate period. If the State meets the requirements of paragraph (a)(2) of this section by imposing control measures on only non–EGUs, then the State's Ozone Season Non–EGU NO_X Reduction Requirement shall equal or exceed, during the appropriate periods, the amount determined in accordance with paragraph (q)(3) of this section.

(iii) If a State meets the requirements of paragraph (a)(2) of this section by imposing control measures on both EGUs and non–EGUs, then:

(A) The Ozone Season Non–EGU NO_X Reduction Requirement shall equal or exceed the difference between the amount specified in paragraph (q)(2) of this section for the appropriate period and the amount of the State's Ozone Season EGU NO_X Budget specified in the SIP revision for the appropriate period; and

(B) The Ozone Season EGU NO_X Budget shall not exceed, during the indicated periods, the amount specified in paragraph (q)(2) of this section plus the amount of the Ozone Season Non–EGU NO_X Reduction Requirement under paragraph (q)(1)(iii)(A) of this section for the appropriate period.

(2) For a State that complies with the requirements of paragraph (a)(2) of this section by imposing control measures on only EGUs, the amount of the Ozone Season EGU NO_X Budget, in tons of NO_X per ozone season, shall be as follows, for the indicated State for the indicated period:

State	Ozone season EGU NO_X budget for 2009-2014 (tons)	Ozone season EGU NO_X budget for 2015 and thereafter (tons)
Alabama	32,182	26,818
Arkansas	11,515	9,596
Connecticut	2,559	2,559
Delaware	2,226	1,855
District of Columbia	112	94
Florida	47,912	39,926
Illinois	30,701	28,981
Indiana	45,952	39,273
Iowa	14,263	11,886

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Kentucky	36,045	30,587
Louisiana	17,085	14,238
Maryland	12,834	10,695
Massachusetts	7,551	6,293
Michigan	28,971	24,142
Mississippi	8,714	7,262
Missouri	26,678	22,231
New Jersey	6,654	5,545
New York	20,632	17,193
North Carolina	28,392	23,660
Ohio	45,664	39,945
Pennsylvania	42,171	35,143
South Carolina	15,249	12,707
Tennessee	22,842	19,035
Virginia	15,994	13,328
West Virginia	26,859	26,525
Wisconsin	17,987	14,989

(3) For a State that complies with the requirements of paragraph (a)(2) of this section by imposing control measures on only non–EGUs, the amount of the Ozone Season Non–EGU NO_X Reduction Requirement, in tons of NO_X per ozone season, shall be determined, for the State for 2009 and thereafter, by subtracting the amount of the State's Ozone Season EGU NO_X Budget for the appropriate year, specified in paragraph (q)(2) of this section, from the amount of the State's NO_X baseline EGU emissions inventory projected for the ozone season in the appropriate year, specified in Table 7 of "Regional and State SO_2 and NO_X Budgets", March 2005 (available at: http://www.epa.gov/cleanairinterstaterule).

(4) Notwithstanding the State's obligation to comply with paragraph (q)(2) or (3) of this section, the State's SIP revision may allow sources required by the revision to implement NO_X emission control measures to demonstrate compliance using NO_X SIP Call allowances allocated under the NO_X Budget Trading Program for any ozone season during 2003 through 2008 that have not been deducted by the Administrator under the NO_X Budget Trading Program, if the SIP revision ensures that such allowances will not be available for such deduction under the NO_X Budget Trading Program.

(r) Each SIP revision must set forth control measures to meet the amounts specified in paragraph (q) of this section, as applicable, including the following:

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(1) A description of enforcement methods including, but not limited to:

(i) Procedures for monitoring compliance with each of the selected control measures;

(ii) Procedures for handling violations; and

(iii) A designation of agency responsibility for enforcement of implementation.

(2)(i) If a State elects to impose control measures on EGUs, then those measures must impose an ozone season NO_X mass emissions cap on all such sources in the State.

(ii) If a State elects to impose control measures on fossil fuel-fired non–EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then those measures must impose an ozone season NO_X mass emissions cap on all such sources in the State.

(iii) If a State elects to impose control measures on non–EGUs other than those described in paragraph (r)(2)(ii) of this section, then those measures must impose an ozone season NO_X mass emissions cap on all such sources in the State or the State must demonstrate why such emissions cap is not practicable and adopt alternative requirements that ensure that the State will comply with its requirements under paragraph (q) of this section, as applicable, in 2009 and subsequent years.

(s)(1) Each SIP revision that contains control measures covering non–EGUs as part or all of a State's obligation in meeting its requirement under paragraph (a)(2) of this section must demonstrate that such control measures are adequate to provide for the timely compliance with the State's Ozone Season Non–EGU NO_X Reduction Requirement under paragraph (q) of this section and are not adopted or implemented by the State, as of May 12, 2005, and are not adopted or implemented by the federal government, as of the date of submission of the SIP revision by the State to EPA.

(2) The demonstration under paragraph (s)(1) of this section must include the following, with respect to each source category of non–EGUs for which the SIP revision requires control measures:

(i) A detailed historical baseline inventory of NO_X mass emissions from the source category in a representative ozone season consisting, at the State's election, of the ozone season in 2002, 2003, 2004, or 2005, or an average of 2 or more of those ozone seasons, absent the control measures specified in the SIP revision.

(A) This inventory must represent estimates of actual emissions based on monitoring data in accordance with subpart H of part 75 of this chapter, if the source category is subject to monitoring requirements in accordance with subpart H of part 75 of this chapter.

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(B) In the absence of monitoring data in accordance with subpart H of part 75 of this chapter, actual emissions must be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to subpart H of part 75 of this chapter and using source-specific or source-category-specific assumptions that ensure a source's or source category's actual emissions are not overestimated. If a State uses factors to estimate emissions, production or utilization, or effectiveness of controls or rules for a source category, such factors must be chosen to ensure that emissions are not overestimated.

(C) For measures to reduce emissions from motor vehicles, emission estimates must be based on an emissions model that has been approved by EPA for use in SIP development and must be consistent with the planning assumptions regarding vehicle miles traveled and other factors current at the time of the SIP development.

(D) For measures to reduce emissions from nonroad engines or vehicles, emission estimates methodologies must be approved by EPA.

(ii) A detailed baseline inventory of NO_X mass emissions from the source category in ozone seasons 2009 and 2015, absent the control measures specified in the SIP revision and reflecting changes in these emissions from the historical baseline ozone season to the ozone seasons 2009 and 2015, based on projected changes in the production input or output, population, vehicle miles traveled, economic activity, or other factors as applicable to this source category.

(A) These inventories must account for implementation of any control measures that are adopted or implemented by the State, as of May 12, 2005, or adopted or implemented by the federal government, as of the date of submission of the SIP revision by the State to EPA, and must exclude any control measures specified in the SIP revision to meet the NO_X emissions reduction requirements of this section.

(B) Economic and population forecasts must be as specific as possible to the applicable industry, State, and county of the source or source category and must be consistent with both national projections and relevant official planning assumptions including estimates of population and vehicle miles traveled developed through consultation between State and local transportation and air quality agencies. However, if these official planning assumptions are inconsistent with official U.S. Census projections of population or with energy consumption projections contained in the U.S. Department of Energy's most recent Annual Energy Outlook, then the SIP revision must make adjustments to correct the inconsistency or must demonstrate how the official planning assumptions are more accurate.

(C) These inventories must account for any changes in production method, materials, fuels, or efficiency that are expected to occur between the historical baseline ozone season and ozone season 2009 or ozone season 2015, as appropriate.

(iii) A projection of NO_X mass emissions in ozone season 2009 and ozone season 2015 from the source category assuming the same projected changes as under paragraph (s)(2)(ii) of this section and resulting from implementation of each of the control measures specified in the SIP revision.

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(A) These inventories must address the possibility that the State's new control measures may cause production or utilization, and emissions, to shift to unregulated or less stringently regulated sources in the source category in the same or another State, and these inventories must include any such amounts of emissions that may shift to such other sources.

(B) The State must provide EPA with a summary of the computations, assumptions, and judgments used to determine the degree of reduction in projected ozone season 2009 and ozone season 2015 NO_X emissions that will be achieved from the implementation of the new control measures compared to the relevant baseline emissions inventory.

(iv) The result of subtracting the amounts in paragraph (s)(2)(iii) of this section for ozone season 2009 and ozone season 2015, respectively, from the lower of the amounts in paragraph (s)(2)(i) or (s)(2)(ii) of this section for ozone season 2009 and ozone season 2015, respectively, may be credited towards the State's Ozone Season Non–EGU NO_X Reduction Requirement in paragraph (q)(3) of this section for the appropriate period.

(v) Each SIP revision must identify the sources of the data used in each estimate and each projection of emissions.

(t) Each SIP revision must comply with § 51.116 (regarding data availability).

(u) Each SIP revision must provide for monitoring the status of compliance with any control measures adopted to meet the State's requirements under paragraph (q) of this section as follows:

(1) The SIP revision must provide for legally enforceable procedures for requiring owners or operators of stationary sources to maintain records of, and periodically report to the State:

(i) Information on the amount of NO_X emissions from the stationary sources; and

(ii) Other information as may be necessary to enable the State to determine whether the sources are in compliance with applicable portions of the control measures;

(2) The SIP revision must comply with § 51.212 (regarding testing, inspection, enforcement, and complaints);

(3) If the SIP revision contains any transportation control measures, then the SIP revision must comply with § 51.213 (regarding transportation control measures);

(4)(i) If the SIP revision contains measures to control EGUs, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter.

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(ii) If the SIP revision contains measures to control fossil fuel-fired non–EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter.

(iii) If the SIP revision contains measures to control any other non–EGUs that are not described in paragraph (u)(4)(ii) of this section, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter, or the State must demonstrate why such requirements are not practicable and adopt alternative requirements that ensure that the required emissions reductions will be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to subpart H of part 75 of this chapter.

(v) Each SIP revision must show that the State has legal authority to carry out the SIP revision, including authority to:

(1) Adopt emissions standards and limitations and any other measures necessary for attainment and maintenance of the State's relevant Ozone Season EGU NO X Budget or the Ozone Season Non–EGU NO X Reduction Requirement, as applicable, under paragraph (q) of this section;

(2) Enforce applicable laws, regulations, and standards and seek injunctive relief;

(3) Obtain information necessary to determine whether air pollution sources are in compliance with applicable laws, regulations, and standards, including authority to require recordkeeping and to make inspections and conduct tests of air pollution sources; and

(4)(i) Require owners or operators of stationary sources to install, maintain, and use emissions monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such stationary sources; and

(ii) Make the data described in paragraph (v)(4)(i) of this section available to the public within a reasonable time after being reported and as correlated with any applicable emissions standards or limitations.

(w)(1) The provisions of law or regulation that the State determines provide the authorities required under this section must be specifically identified, and copies of such laws or regulations must be submitted with the SIP revision.

(2) Legal authority adequate to fulfill the requirements of paragraphs (v)(3) and (4) of this section may be delegated to the State under section 114 of the CAA.

(x)(1) A SIP revision may assign legal authority to local agencies in accordance with § 51.232.

(2) Each SIP revision must comply with § 51.240 (regarding general plan requirements).

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(y) Each SIP revision must comply with § 51.280 (regarding resources).

(z) Each SIP revision must provide for State compliance with the reporting requirements in § 51.125.

(aa)(1) Notwithstanding any other provision of this section, if a State adopts regulations substantively identical to subparts AAAA through IIII of part 96 of this chapter (CAIR Ozone Season NO_X Trading Program), incorporates such subparts by reference into its regulations, or adopts regulations that differ substantively from such subparts only as set forth in paragraph (aa)(2) of this section, then such emissions trading program in the State's SIP revision is automatically approved as meeting the requirements of paragraph (q) of this section, provided that the State has the legal authority to take such action and to implement its responsibilities under such regulations. Before January 1, 2009, a State's regulations shall be considered to be substantively identical to subparts AAAA through IIII of part 96 of the chapter, or differing substantively only as set forth in paragraph (o)(2) of this section, regardless of whether the State's regulations include the definition of "Biomass", paragraph (3) of the definition of "Cogeneration unit", and the second sentence of the definition of "Total energy input" in § 96.302 of this chapter promulgated on October 19, 2007, provided that the State timely submits to the Administrator a SIP revision that revises the State's regulations to include such provisions. Submission to the Administrator of a SIP revision that revises the State's regulations to include such provisions shall be considered timely if the submission is made by January 1, 2009.

(2) If a State adopts an emissions trading program that differs substantively from subparts AAAA through IIII of part 96 of this chapter only as follows, then the emissions trading program is approved as set forth in paragraph (aa)(1) of this section.

(i) The State may expand the applicability provisions in § 96.304 to include all non–EGUs subject to the State's emissions trading program approved under § 51.121(p).

(ii) The State may decline to adopt the CAIR NO_X Ozone Season opt-in provisions of:

(A) Subpart IIII of this part and the provisions applicable only to CAIR NO_X Ozone Season opt-in units in subparts AAAA through HHHH of this part;

(B) Section 96.388(b) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(b); or

(C) Section 96.388(c) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(c).

(iii) The State may decline to adopt the allocation provisions set forth in subpart EEEE of part 96 of this chapter and may instead adopt any methodology for allocating CAIR NO_X Ozone Season allowances to individual sources, as follows:

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(A) The State may provide for issuance of an amount of CAIR Ozone Season NO_X allowances for an ozone season, in addition to the amount in the State's Ozone Season EGU NO_X Budget for such ozone season, not exceeding the amount of NO_X SIP Call allowances allocated for the ozone season under the NO_X Budget Trading Program to non–EGUs that the applicability provisions in § 96.304 are expanded to include under paragraph (aa)(2)(i) of this section;

(B) The State's methodology must not allow the State to allocate CAIR Ozone Season NO_X allowances for an ozone season in excess of the amount in the State's Ozone Season EGU NO_X Budget for such ozone season plus any additional amount of CAIR Ozone Season NO_X allowances issued under paragraph (aa)(2)(iii)(A) of this section for such ozone season;

(C) The State's methodology must require that, for EGUs commencing operation before January 1, 2001, the State will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31, 2006 for the ozone seasons 2009, 2010, and 2011 and by October 31, 2008 and October 31 of each year thereafter for the ozone season in the 4th year after the year of the notification deadline; and

(D) The State's methodology must require that, for EGUs commencing operation on or after January 1, 2001, the State will determine, and notify the Administrator of, each unit's allocation of CAIR Ozone Season NO_X allowances by July 31 of the calendar year of the ozone season for which the CAIR Ozone Season NO_X allowances are allocated.

(3) A State that adopts an emissions trading program in accordance with paragraph (aa)(1) or (2) of this section is not required to adopt an emissions trading program in accordance with paragraph (o)(1) or (2) of this section or § 51.153(o)(1) or (2).

(4) If a State adopts an emissions trading program that differs substantively from subparts AAAA through IIII of part 96 of this chapter, other than as set forth in paragraph (aa)(2) of this section, then such emissions trading program is not automatically approved as set forth in paragraph (aa)(1) or (2) of this section and will be reviewed by the Administrator for approvability in accordance with the other provisions of this section, provided that the NO_X allowances issued under such emissions trading program shall not, and the SIP revision shall state that such NO_X allowances shall not, qualify as CAIR NO_X allowances or CAIR Ozone Season NO_X allowances under any emissions trading program approved under paragraphs (o)(1) or (2) or (aa)(1) or (2) of this section.

(bb)(1)(i) The State may revise its SIP to provide that, for each ozone season during which a State implements control measures on EGUs or non–EGUs through an emissions trading program approved under paragraph (aa)(1) or (2) of this section, such EGUs and non–EGUs shall not be subject to the requirements of the State's SIP meeting the requirements of § 51.121, if the State meets the requirement in paragraph (bb)(1)(ii) of this section.

(ii) For a State under paragraph (bb)(1)(i) of this section, if the State's amount of tons specified in paragraph (q)(2) of this section exceeds the State's amount of NO_X SIP Call allowances allocated for the ozone season in 2009 or in any year thereafter for the same types and sizes of units as those covered by the amount of tons specified in

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paragraph (q)(2) of this section, then the State must replace the former amount for such ozone season by the latter amount for such ozone season in applying paragraph (q) of this section.

(2) Rhode Island may revise its SIP to provide that, for each ozone season during which Rhode Island implements control measures on EGUs and non–EGUs through an emissions trading program adopted in regulations that differ substantively from subparts AAAA through IIII of part 96 of this chapter as set forth in this paragraph, such EGUs and non–EGUs shall not be subject to the requirements of the State's SIP meeting the requirements of § 51.121.

(i) Rhode Island must expand the applicability provisions in § 96.304 to include all non–EGUs subject to Rhode Island's emissions trading program approved under § 51.121(p).

(ii) Rhode Island may decline to adopt the CAIR NO_X Ozone Season opt-in provisions of:

(A) Subpart IIII of this part and the provisions applicable only to CAIR NO_X Ozone Season opt-in units in subparts AAAA through HHHH of this part;

(B) Section 96.388(b) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(b); or

(C) Section 96.388(c) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(c).

(iii) Rhode Island may adopt the allocation provisions set forth in subpart EEEE of part 96 of this chapter, provided that Rhode Island must provide for issuance of an amount of CAIR Ozone Season NO_X allowances for an ozone season not exceeding 936 tons for 2009 and thereafter;

(iv) Rhode Island may adopt any methodology for allocating CAIR NO_X Ozone Season allowances to individual sources, as follows:

(A) Rhode Island's methodology must not allow Rhode Island to allocate CAIR Ozone Season NO_X allowances for an ozone season in excess of 936 tons for 2009 and thereafter;

(B) Rhode Island's methodology must require that, for EGUs commencing operation before January 1, 2001, Rhode Island will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31, 2006 for the ozone seasons 2009, 2010, and 2011 and by October 31, 2008 and October 31 of each year thereafter for the ozone season in the 4th year after the year of the notification deadline; and

(C) Rhode Island's methodology must require that, for EGUs commencing operation on or after January 1, 2001, Rhode Island will determine, and notify the Administrator of, each unit's allocation of CAIR Ozone

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Season NO_X allowances by July 31 of the calendar year of the ozone season for which the CAIR Ozone Season NO_X allowances are allocated.

(3) Notwithstanding a SIP revision by a State authorized under paragraph (bb)(1) of this section or by Rhode Island under paragraph (bb)(2) of this section, if the State's or Rhode Island's SIP that, without such SIP revision, imposes control measures on EGUs or non–EGUs under § 51.121 is determined by the Administrator to meet the requirements of § 51.121, such SIP shall be deemed to continue to meet the requirements of § 51.121.

(cc) The terms used in this section shall have the following meanings:

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Allocate or allocation means, with regard to allowances, the determination of the amount of allowances to be initially credited to a source or other entity.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other nonmerchantable material, and that is;

(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Clean Air Act or CAA means the Clean Air Act, 42 U.S.C. 7401, et seq.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12–month period starting on the date the unit first produces electricity and during any calendar year after the calendar year in which the unit first produces electricity—

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(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input;

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

Combustion turbine means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated duct burner, heat recovery steam generator, and steam turbine.

Commence operation means to have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber.

Electric generating unit or EGU means:

(1)(i) Except as provided in paragraph (2) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(ii) If a stationary boiler or stationary combustion turbine that, under paragraph (1)(i) of this section, is not an electric generating unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become an electric generating unit as provided in paragraph (1)(i) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(2) A unit that meets the requirements set forth in paragraphs (2)(i)(A), (2)(ii)(A), or (2)(ii)(B) of this definition paragraph shall not be an electric generating unit:

(i)(A) Any unit that is an electric generating unit under paragraph (1)(i) or (ii) of this definition:

(1) Qualifying as a cogeneration unit during the 12–month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(2) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(B) If a unit qualifies as a cogeneration unit during the 12–month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (2)(i)(A) of this section for at least one calendar year, but

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subsequently no longer meets all such requirements, the unit shall become an electric generating unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (2)(i)(A)(2) of this section.

(ii)(A) Any unit that is an electric generating unit under paragraph (1)(i) or (ii) of this definition commencing operation before January 1, 1985:

(1) Qualifying as a solid waste incineration unit; and

(2) With an average annual fuel consumption of non-fossil fuel for 1985–1987 exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).

(B) Any unit that is an electric generating unit under paragraph (1)(i) or (ii) of this definition commencing operation on or after January 1, 1985:

(1) Qualifying as a solid waste incineration unit; and

(2) With an average annual fuel consumption of non-fossil fuel for the first 3 calendar years of operation exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).

(C) If a unit qualifies as a solid waste incineration unit and meets the requirements of paragraph (2)(ii)(A) or (B) of this section for at least 3 consecutive calendar years, but subsequently no longer meets all such requirements, the unit shall become an electric generating unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 1990 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

Generator means a device that produces electricity.

Maximum design heat input means the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

NAAQS means National Ambient Air Quality Standard.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Non–EGU means a source of NO_X emissions that is not an EGU.

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NO_X Budget Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts A through I of this part and § 51.121, as a means of mitigating interstate transport of ozone and nitrogen oxides.

NO_X SIP Call allowance means a limited authorization issued by the Administrator under the NO_X Budget Trading Program to emit up to one ton of nitrogen oxides during the ozone season of the specified year or any year thereafter, provided that the provision in § 51.121(b)(2)(ii)(E) shall not be used in applying this definition.

Ozone season means the period, which begins May 1 and ends September 30 of any year.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a "solid waste incineration unit" as defined in section 129(g)(1) of the Clean Air Act.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

$$LHV = HHV - 10.55(W + 9H)$$

Where:

LHV = lower heating value of fuel in Btu/lb,

HHV = higher heating value of fuel in Btu/lb,

W = Weight % of moisture in fuel, and

H = Weight % of hydrogen in fuel.

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

Unit means a stationary, fossil-fuel-fired boiler or a stationary, fossil-fuel-fired combustion turbine.

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Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process, excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (e.g., space heating or domestic hot water heating); or

(3) Used in a space cooling application (i.e., thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

(dd) New Hampshire may revise its SIP to implements control measures on EGUs and non–EGUs through an emissions trading program adopted in regulations that differ substantively from subparts AAAA through IIII of part 96 of this chapter as set forth in this paragraph.

(1) New Hampshire must expand the applicability provisions in § 96.304 of this chapter to include all non–EGUs subject to New Hampshire's emissions trading program at New Hampshire Code of Administrative Rules, chapter Env–A 3200 (2004).

(2) New Hampshire may decline to adopt the CAIR NO_X Ozone Season opt-in provisions of:

(i) Subpart IIII of this part and the provisions applicable only to CAIR NO_X Ozone Season opt-in units in subparts AAAA through HHHH of this part;

(ii) Section 96.388(b) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(b); or

(iii) Section 96.388(c) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(c).

(3) New Hampshire may adopt the allocation provisions set forth in subpart EEEE of part 96 of this chapter, provided that New Hampshire must provide for issuance of an amount of CAIR Ozone Season NO_X allowances for an ozone season not exceeding 3,000 tons for 2009 and thereafter;

(4) New Hampshire may adopt any methodology for allocating CAIR NO_X Ozone Season allowances to individual sources, as follows:

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(i) New Hampshire's methodology must not allow New Hampshire to allocate CAIR Ozone Season NO_X allowances for an ozone season in excess of 3,000 tons for 2009 and thereafter;

(ii) New Hampshire's methodology must require that, for EGUs commencing operation before January 1, 2001, New Hampshire will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31, 2006 for the ozone seasons 2009, 2010, and 2011 and by October 31, 2008 and October 31 of each year thereafter for the ozone season in the 4th year after the year of the notification deadline; and

(iii) New Hampshire's methodology must require that, for EGUs commencing operation on or after January 1, 2001, New Hampshire will determine, and notify the Administrator of, each unit's allocation of CAIR Ozone Season NO_X allowances by July 31 of the calendar year of the ozone season for which the CAIR Ozone Season NO_X allowances are allocated.

(ee) Notwithstanding any other provision of this section, a State may adopt, and include in a SIP revision submitted by March 31, 2007, regulations relating to the Federal CAIR NO_X Ozone Season Trading Program under subparts AAAA through HHHH of part 97 of this chapter as follows:

(1) The State may adopt, as applicability provisions replacing the provisions in § 97.304 of this chapter, provisions for applicability that are substantively identical to the provisions in § 96.304 of this chapter expanded to include all non–EGUs subject to the State's emissions trading program approved under § 51.121(p). Before January 1, 2009, a State's applicability provisions shall be considered to be substantively identical to § 96.304 of this chapter (with the expansion allowed under this paragraph) regardless of whether the State's regulations include the definition of "Biomass", paragraph (3) of the definition of "Cogeneration unit", and the second sentence of the definition of "Total energy input" in § 97.102 of this chapter promulgated on October 19, 2007, provided that the State timely submits to the Administrator a SIP revision that revises the State's regulations to include such provisions. Submission to the Administrator of a SIP revision that revises the State's regulations to include such provisions shall be considered timely if the submission is made by January 1, 2009.

(2) The State may adopt, as CAIR NO_X Ozone Season allowance allocation provisions replacing the provisions in subpart EEEE of part 97 of this chapter:

(i) Allocation provisions substantively identical to subpart EEEE of part 96 of this chapter, under which the permitting authority makes the allocations; or

(ii) Any methodology for allocating CAIR NO_X Ozone Season allowances to individual sources under which the permitting authority makes the allocations, provided that:

(A) The State may provide for issuance of an amount of CAIR Ozone Season NO_X allowances for an ozone season, in addition to the amount in the State's Ozone Season EGU NO_X Budget for such ozone season, not exceeding the portion of the State's trading program budget, under the State's emissions trading program approved under § 51.121(p), attributed to the non–EGUs that the applicability provisions in § 96.304 of this chapter are expanded to include under paragraph (ee)(1) of this section.

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(B) The State's methodology must not allow the State to allocate CAIR Ozone Season NO_X allowances for an ozone season in excess of the amount in the State's Ozone Season EGU NO_X Budget for such ozone season plus any additional amount of CAIR Ozone Season NO_X allowances issued under paragraph (ee)(2)(ii)(A) of this section for such ozone season.

(C) The State's methodology must require that, for EGUs commencing operation before January 1, 2001, the permitting authority will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X Ozone Season allowances by April 30, 2007 for 2009, 2010, and 2011 and by October 31, 2008 and October 31 of each year thereafter for the 4th year after the year of the notification deadline.

(D) The State's methodology must require that, for EGUs commencing operation on or after January 1, 2001, the permitting authority will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X Ozone Season allowances by July 31 of the year for which the CAIR NO_X Ozone Season allowances are allocated.

(3) The State may adopt CAIR opt-in unit provisions as follows:

(i) Provisions for CAIR opt-in units, including provisions for applications for CAIR opt-in permits, approval of CAIR opt-in permits, treatment of units as CAIR opt-in units, and allocation and recordation of CAIR NO_X Ozone Season allowances for CAIR opt-in units, that are substantively identical to subpart IIII of part 96 of this chapter and the provisions of subparts AAAA through HHHH that are applicable to CAIR opt-in units or units for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied;

(ii) Provisions for CAIR opt-in units, including provisions for applications for CAIR opt-in permits, approval of CAIR opt-in permits, treatment of units as CAIR opt-in units, and allocation and recordation of CAIR NO_X Ozone Season allowances for CAIR opt-in units, that are substantively identical to subpart IIII of part 96 of this chapter and the provisions of subparts AAAA through HHHH that are applicable to CAIR opt-in units or units for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied, except that the provisions exclude § 96.388(b) of this chapter and the provisions of subpart IIII of part 96 of this chapter that apply only to units covered by § 96.388(b) of this chapter; or

(iii) Provisions for applications for CAIR opt-in units, including provisions for CAIR opt-in permits, approval of CAIR opt-in permits, treatment of units as CAIR opt-in units, and allocation and recordation of CAIR NO_X allowances for CAIR opt-in units, that are substantively identical to subpart IIII of part 96 of this chapter and the provisions of subparts AAAA through HHHH that are applicable to CAIR opt-in units or units for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied, except that the provisions exclude § 96.388(c) of this chapter and the provisions of subpart IIII of part 96 of this chapter that apply only to units covered by § 96.388(c) of this chapter.

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(ff) Notwithstanding any provisions of paragraphs (a) through (ee) of this section, subparts AA through II and AAAA through IIII of part 96 of this chapter, subparts AA through II and AAAA through IIII of part 97 of this chapter, and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2014, the Administrator:

(i) Rescinds the determination in paragraph (a) of this section that the States identified in paragraph (c) of this section must submit a SIP revision with respect to the fine particles ($PM_{2.5}$) NAAQS and the 8–hour ozone NAAQS meeting the requirements of paragraphs (b) through (ee) of this section; and

(ii) Will not carry out any of the functions set forth for the Administrator in subparts AA through II and AAAA through IIII of part 96 of this chapter, subparts AA through II and AAAA through IIII of part 97 of this chapter, or in any emissions trading program provisions in a State's SIP approved under this section;

(2) The Administrator will not deduct for excess emissions any CAIR NO_X allowances or CAIR NO_X Ozone Season allowances allocated for 2015 or any year thereafter;

(3) By March 3, 2015, the Administrator will remove from the CAIR NO_X Allowance Tracking System accounts all CAIR NO_X allowances allocated for a control period in 2015 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X allowances will be required with regard to emissions or excess emissions for such control periods; and

(4) By March 3, 2015, the Administrator will remove from the CAIR NO_X Ozone Season Allowance Tracking System accounts all CAIR NO_X Ozone Season allowances allocated for a control period in 2015 and any subsequent year, and, thereafter, no holding or surrender of CAIR NO_X Ozone Season allowances will be required with regard to emissions or excess emissions for such control periods.

Credits

[70 FR 25319, May 12, 2005; 71 FR 25301, 25370, April 28, 2006; 71 FR 74793, Dec. 13, 2006; 72 FR 59203, Oct. 19, 2007; 74 FR 56726, Nov. 3, 2009; 76 FR 48353, Aug. 8, 2011; 79 FR 71671, Dec. 3, 2014; 81 FR 13279, March 14, 2016]

SOURCE: 36 FR 22398, Nov. 25, 1971; 51 FR 40665, Nov. 7, 1986; 52 FR 24712, July 1, 1987; 55 FR 14249, April 17, 1990; 56 FR 42219, Aug. 26, 1991; 57 FR 32334, July 21, 1992; 57 FR 52987, Nov. 5, 1992; 58 FR 38821, July 20, 1993; 60 FR 40100, Aug. 7, 1995; 62 FR 8328, Feb. 24, 1997; 62 FR 43801, Aug. 15, 1997; 62 FR 44903, Aug. 25, 1997; 63 FR 24433, May 4, 1998; 64 FR 35763, July 1, 1999; 65 FR 45532, July 24, 2000; 72 FR 28613, May 22, 2007, unless otherwise noted.

AUTHORITY: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

Current through January 19, 2017; 82 FR 7611.

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Footnotes

1 So in original; (a) was probably inadvertently added. See 70 FR 25319.

End of Document

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Unconstitutional or PreemptedPrior Version Held Invalid EME Homer City Generation, L.P. v. E.P.A., D.C.Cir., Aug. 21, 2012

Code of Federal Regulations
Title 40. Protection of Environment
Chapter I. Environmental Protection Agency (Refs & Annos)
Subchapter C. Air Programs
Part 51. Requirements for Preparation, Adoption, and Submittal of Implementation Plans (Refs & Annos)
Subpart G. Control Strategy (Refs & Annos)

40 C.F.R. § 51.124

§ 51.124 Findings and requirements for submission of State implementation plan revisions relating to emissions of sulfur dioxide pursuant to the Clean Air Interstate Rule.

Effective: December 3, 2014
Currentness

(a)(1) Under section 110(a)(1) of the CAA,42 U.S.C. 7410(a)(1), the Administrator determines that each State identified in paragraph (c) of this section must submit a SIP revision to comply with the requirements of section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), through the adoption of adequate provisions prohibiting sources and other activities from emitting SO_2 in amounts that will contribute significantly to nonattainment in, or interfere with maintenance by, one or more other States with respect to the fine particles ($PM_{2.5}$) NAAQS.

(2) Notwithstanding the other provisions of this section, such provisions are not applicable as they relate to the State of Minnesota as of December 3, 2009.

(b) For each State identified in paragraph (c) of this section, the SIP revision required under paragraph (a) of this section will contain adequate provisions, for purposes of complying with section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), only if the SIP revision contains control measures that assure compliance with the applicable requirements of this section.

(c) The following States are subject to the requirements of this section: Alabama, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the District of Columbia.

(d)(1) The SIP revision under paragraph (a) of this section must be submitted to EPA by no later than September 11, 2006.

(2) The requirements of appendix V to this part shall apply to the SIP revision under paragraph (a) of this section.

(3) The State shall deliver 5 copies of the SIP revision under paragraph (a) of this section to the appropriate Regional Office, with a letter giving notice of such action.

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(e) The State's SIP revision shall contain control measures and demonstrate that they will result in compliance with the State's Annual EGU SO_2 Budget, if applicable, and achieve the State's Annual Non–EGU SO_2 Reduction Requirement, if applicable, for the appropriate periods. The amounts of the State's Annual EGU SO_2 Budget and Annual Non–EGU SO_2 Reduction Requirement shall be determined as follows:

(1)(i) The Annual EGU SO_2 Budget for the State is defined as the total amount of SO_2 emissions from all EGUs in that State for a year, if the State meets the requirements of paragraph (a) of this section by imposing control measures, at least in part, on EGUs. If the State imposes control measures under this section on only EGUs, the Annual EGU SO_2 Budget for the State shall not exceed the amount, during the indicated periods, specified in paragraph (e)(2) of this section.

(ii) The Annual Non–EGU SO_2 Reduction Requirement, if applicable, is defined as the total amount of SO_2 emission reductions that the State demonstrates, in accordance with paragraph (g) of this section, it will achieve from non–EGUs during the appropriate period. If the State meets the requirements of paragraph (a) of this section by imposing control measures on only non–EGUs, then the State's Annual Non–EGU SO_2 Reduction Requirement shall equal or exceed, during the appropriate periods, the amount determined in accordance with paragraph (e)(3) of this section.

(iii) If a State meets the requirements of paragraph (a) of this section by imposing control measures on both EGUs and non–EGUs, then:

(A) The Annual Non–EGU SO_2 Reduction Requirement shall equal or exceed the difference between the amount specified in paragraph (e)(2) of this section for the appropriate period and the amount of the State's Annual EGU SO_2 Budget specified in the SIP revision for the appropriate period; and

(B) The Annual EGU SO_2 Budget shall not exceed, during the indicated periods, the amount specified in paragraph (e)(2) of this section plus the amount of the Annual Non–EGU SO_2 Reduction Requirement under paragraph (e)(1)(iii)(A) of this section for the appropriate period.

(2) For a State that complies with the requirements of paragraph (a) of this section by imposing control measures on only EGUs, the amount of the Annual EGU SO_2 Budget, in tons of SO_2 per year, shall be as follows, for the indicated State for the indicated period:

State	Annual EGU SO_2 budget for 2010-2014 (tons)	Annual EGU SO_2 budget for 2015 and thereafter (tons)
Alabama	157,582	110,307
Delaware	22,411	15,687
District of Columbia	708	495

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Florida	253,450	177,415
Georgia	213,057	149,140
Illinois	192,671	134,869
Indiana	254,599	178,219
Iowa	64,095	44,866
Kentucky	188,773	132,141
Louisiana	59,948	41,963
Maryland	70,697	49,488
Michigan	178,605	125,024
Minnesota	49,987	34,991
Mississippi	33,763	23,634
Missouri	137,214	96,050
New Jersey	32,392	22,674
New York	135,139	94,597
North Carolina	137,342	96,139
Ohio	333,520	233,464
Pennsylvania	275,990	193,193
South Carolina	57,271	40,089
Tennessee	137,216	96,051
Texas	320,946	224,662
Virginia	63,478	44,435
West Virginia	215,881	151,117
Wisconsin	87,264	61,085

(3) For a State that complies with the requirements of paragraph (a) of this section by imposing control measures on only non–EGUs, the amount of the Annual Non–EGU SO_2 Reduction Requirement, in tons of SO_2 per year, shall be determined, for the State for 2010 and thereafter, by subtracting the amount of the State's Annual EGU SO_2 Budget for the appropriate year, specified in paragraph (e)(2) of this section, from an amount equal to 2 times the State's Annual EGU SO_2 Budget for 2010 through 2014, specified in paragraph (e)(2) of this section.

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(f) Each SIP revision must set forth control measures to meet the amounts specified in paragraph (e) of this section, as applicable, including the following:

(1) A description of enforcement methods including, but not limited to:

(i) Procedures for monitoring compliance with each of the selected control measures;

(ii) Procedures for handling violations; and

(iii) A designation of agency responsibility for enforcement of implementation.

(2)(i) If a State elects to impose control measures on EGUs, then those measures must impose an annual SO_2 mass emissions cap on all such sources in the State.

(ii) If a State elects to impose control measures on fossil fuel-fired non–EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then those measures must impose an annual SO_2 mass emissions cap on all such sources in the State.

(iii) If a State elects to impose control measures on non–EGUs other than those described in paragraph (f)(2)(ii) of this section, then those measures must impose an annual SO_2 mass emissions cap on all such sources in the State, or the State must demonstrate why such emissions cap is not practicable, and adopt alternative requirements that ensure that the State will comply with its requirements under paragraph (e) of this section, as applicable, in 2010 and subsequent years.

(g)(1) Each SIP revision that contains control measures covering non–EGUs as part or all of a State's obligation in meeting its requirement under paragraph (a) of this section must demonstrate that such control measures are adequate to provide for the timely compliance with the State's Annual Non–EGU SO_2 Reduction Requirement under paragraph (e) of this section and are not adopted or implemented by the State, as of May 12, 2005, and are not adopted or implemented by the federal government, as of the date of submission of the SIP revision by the State to EPA.

(2) The demonstration under paragraph (g)(1) of this section must include the following, with respect to each source category of non–EGUs for which the SIP revision requires control measures:

(i) A detailed historical baseline inventory of SO_2 mass emissions from the source category in a representative year consisting, at the State's election, of 2002, 2003, 2004, or 2005, or an average of 2 or more of those years, absent the control measures specified in the SIP revision.

(A) This inventory must represent estimates of actual emissions based on monitoring data in accordance with part 75 of this chapter, if the source category is subject to part 75 monitoring requirements in accordance with part 75 of this chapter.

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(B) In the absence of monitoring data in accordance with part 75 of this chapter, actual emissions must be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to part 75 of this chapter and using source-specific or source-category-specific assumptions that ensure a source's or source category's actual emissions are not overestimated. If a State uses factors to estimate emissions, production or utilization, or effectiveness of controls or rules for a source category, such factors must be chosen to ensure that emissions are not overestimated.

(C) For measures to reduce emissions from motor vehicles, emission estimates must be based on an emissions model that has been approved by EPA for use in SIP development and must be consistent with the planning assumptions regarding vehicle miles traveled and other factors current at the time of the SIP development.

(D) For measures to reduce emissions from nonroad engines or vehicles, emission estimates methodologies must be approved by EPA.

(ii) A detailed baseline inventory of SO_2 mass emissions from the source category in the years 2010 and 2015, absent the control measures specified in the SIP revision and reflecting changes in these emissions from the historical baseline year to the years 2010 and 2015, based on projected changes in the production input or output, population, vehicle miles traveled, economic activity, or other factors as applicable to this source category.

(A) These inventories must account for implementation of any control measures that are adopted or implemented by the State, as of May 12, 2005, or adopted or implemented by the federal government, as of the date of submission of the SIP revision by the State to EPA, and must exclude any control measures specified in the SIP revision to meet the SO_2 emissions reduction requirements of this section.

(B) Economic and population forecasts must be as specific as possible to the applicable industry, State, and county of the source or source category and must be consistent with both national projections and relevant official planning assumptions, including estimates of population and vehicle miles traveled developed through consultation between State and local transportation and air quality agencies. However, if these official planning assumptions are inconsistent with official U.S. Census projections of population or with energy consumption projections contained in the U.S. Department of Energy's most recent Annual Energy Outlook, then the SIP revision must make adjustments to correct the inconsistency or must demonstrate how the official planning assumptions are more accurate.

(C) These inventories must account for any changes in production method, materials, fuels, or efficiency that are expected to occur between the historical baseline year and 2010 or 2015, as appropriate.

(iii) A projection of SO_2 mass emissions in 2010 and 2015 from the source category assuming the same projected changes as under paragraph (g)(2)(ii) of this section and resulting from implementation of each of the control measures specified in the SIP revision.

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(A) These inventories must address the possibility that the State's new control measures may cause production or utilization, and emissions, to shift to unregulated or less stringently regulated sources in the source category in the same or another State, and these inventories must include any such amounts of emissions that may shift to such other sources.

(B) The State must provide EPA with a summary of the computations, assumptions, and judgments used to determine the degree of reduction in projected 2010 and 2015 SO_2 emissions that will be achieved from the implementation of the new control measures compared to the relevant baseline emissions inventory.

(iv) The result of subtracting the amounts in paragraph (g)(2)(iii) of this section for 2010 and 2015, respectively, from the lower of the amounts in paragraph (g)(2)(i) or (g)(2)(ii) of this section for 2010 and 2015, respectively, may be credited towards the State's Annual Non–EGU SO_2 Reduction Requirement in paragraph (e)(3) of this section for the appropriate period.

(v) Each SIP revision must identify the sources of the data used in each estimate and each projection of emissions.

(h) Each SIP revision must comply with § 51.116 (regarding data availability).

(i) Each SIP revision must provide for monitoring the status of compliance with any control measures adopted to meet the State's requirements under paragraph (e) of this section, as follows:

(1) The SIP revision must provide for legally enforceable procedures for requiring owners or operators of stationary sources to maintain records of, and periodically report to the State:

(i) Information on the amount of SO_2 emissions from the stationary sources; and

(ii) Other information as may be necessary to enable the State to determine whether the sources are in compliance with applicable portions of the control measures;

(2) The SIP revision must comply with § 51.212 (regarding testing, inspection, enforcement, and complaints);

(3) If the SIP revision contains any transportation control measures, then the SIP revision must comply with § 51.213 (regarding transportation control measures);

(4)(i) If the SIP revision contains measures to control EGUs, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of part 75 of this chapter.

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(ii) If the SIP revision contains measures to control fossil fuel-fired non–EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of part 75 of this chapter.

(iii) If the SIP revision contains measures to control any other non–EGUs that are not described in paragraph (i)(4)(ii) of this section, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of part 75 of this chapter, or the State must demonstrate why such requirements are not practicable and adopt alternative requirements that ensure that the required emissions reductions will be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to part 75 of this chapter.

(j) Each SIP revision must show that the State has legal authority to carry out the SIP revision, including authority to:

(1) Adopt emissions standards and limitations and any other measures necessary for attainment and maintenance of the State's relevant Annual EGU SO_2 Budget or the Annual Non–EGU SO_2 Reduction Requirement, as applicable, under paragraph (e) of this section;

(2) Enforce applicable laws, regulations, and standards and seek injunctive relief;

(3) Obtain information necessary to determine whether air pollution sources are in compliance with applicable laws, regulations, and standards, including authority to require recordkeeping and to make inspections and conduct tests of air pollution sources; and

(4)(i) Require owners or operators of stationary sources to install, maintain, and use emissions monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such stationary sources; and

(ii) Make the data described in paragraph (j)(4)(i) of this section available to the public within a reasonable time after being reported and as correlated with any applicable emissions standards or limitations.

(k)(1) The provisions of law or regulation that the State determines provide the authorities required under this section must be specifically identified, and copies of such laws or regulations must be submitted with the SIP revision.

(2) Legal authority adequate to fulfill the requirements of paragraphs (j)(3) and (4) of this section may be delegated to the State under section 114 of the CAA.

(l)(1) A SIP revision may assign legal authority to local agencies in accordance with § 51.232.

(2) Each SIP revision must comply with § 51.240 (regarding general plan requirements).

(m) Each SIP revision must comply with § 51.280 (regarding resources).

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(n) Each SIP revision must provide for State compliance with the reporting requirements in § 51.125.

(o)(1) Notwithstanding any other provision of this section, if a State adopts regulations substantively identical to subparts AAA through III of part 96 of this chapter (CAIR SO_2 Trading Program), incorporates such subparts by reference into its regulations, or adopts regulations that differ substantively from such subparts only as set forth in paragraph (o)(2) of this section, then such emissions trading program in the State's SIP revision is automatically approved as meeting the requirements of paragraph (e) of this section, provided that the State has the legal authority to take such action and to implement its responsibilities under such regulations. Before January 1, 2009, a State's regulations shall be considered to be substantively identical to subparts AAA through III of part 96 of the chapter, or differing substantively only as set forth in paragraph (o)(2) of this section, regardless of whether the State's regulations include the definition of "Biomass", paragraph (3) of the definition of "Cogeneration unit", and the second sentence of the definition of "Total energy input" in § 96.202 of this chapter promulgated on October 19, 2007, provided that the State timely submits to the Administrator a SIP revision that revises the State's regulations to include such provisions. Submission to the Administrator of a SIP revision that revises the State's regulations to include such provisions shall be considered timely if the submission is made by January 1, 2009.

(2) If a State adopts an emissions trading program that differs substantively from subparts AAA through III of part 96 of this chapter only as follows, then the emissions trading program is approved as set forth in paragraph (o)(1) of this section.

(i) The State may decline to adopt the CAIR SO_2 opt-in provisions of subpart III of this part and the provisions applicable only to CAIR SO_2 opt-in units in subparts AAA through HHH of this part.

(ii) The State may decline to adopt the CAIR SO_2 opt-in provisions of § 96.288(b) of this chapter and the provisions of subpart III of this part applicable only to CAIR SO_2 opt-in units under § 96.288(b).

(iii) The State may decline to adopt the CAIR SO_2 opt-in provisions of § 96.288(c) of this chapter and the provisions of subpart II of this part applicable only to CAIR SO_2 opt-in units under § 96.288(c).

(3) A State that adopts an emissions trading program in accordance with paragraph (o)(1) or (2) of this section is not required to adopt an emissions trading program in accordance with § 96.123 (o)(1) or (2) or (aa)(1) or (2) of this chapter.

(4) If a State adopts an emissions trading program that differs substantively from subparts AAA through III of part 96 of this chapter, other than as set forth in paragraph (o)(2) of this section, then such emissions trading program is not automatically approved as set forth in paragraph (o)(1) or (2) of this section and will be reviewed by the Administrator for approvability in accordance with the other provisions of this section, provided that the SO_2 allowances issued under such emissions trading program shall not, and the SIP revision shall state that such SO_2 allowances shall not, qualify as CAIR SO_2 allowances under any emissions trading program approved under paragraph (o)(1) or (2) of this section.

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(p) If a State's SIP revision does not contain an emissions trading program approved under paragraph (o)(1) or (2) of this section but contains control measures on EGUs as part or all of a State's obligation in meeting its requirement under paragraph (a) of this section:

(1) The SIP revision shall provide, for each year that the State has such obligation, for the permanent retirement of an amount of Acid Rain allowances allocated to sources in the State for that year and not deducted by the Administrator under the Acid Rain Program and any emissions trading program approved under paragraph (o)(1) or (2) of this section, equal to the difference between—

(A) The total amount of Acid Rain allowances allocated under the Acid Rain Program to the sources in the State for that year; and

(B) If the State's SIP revision contains only control measures on EGUs, the State's Annual EGU SO_2 Budget for the appropriate period as specified in paragraph (e)(2) of this section or, if the State's SIP revision contains control measures on EGUs and non–EGUs, the State's Annual EGU SO_2 Budget for the appropriate period as specified in the SIP revision.

(2) The SIP revision providing for permanent retirement of Acid Rain allowances under paragraph (p)(1) of this section must ensure that such allowances are not available for deduction by the Administrator under the Acid Rain Program and any emissions trading program approved under paragraph (o)(1) or (2) of this section.

(q) The terms used in this section shall have the following meanings:

Acid Rain allowance means a limited authorization issued by the Administrator under the Acid Rain Program to emit up to one ton of sulfur dioxide during the specified year or any year thereafter, except as otherwise provided by the Administrator.

Acid Rain Program means a multi–State sulfur dioxide and nitrogen oxides air pollution control and emissions reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Allocate or allocation means, with regard to allowances, the determination of the amount of allowances to be initially credited to a source or other entity.

Biomass means—

(1) Any organic material grown for the purpose of being converted to energy;

(2) Any organic byproduct of agriculture that can be converted into energy; or

(3) Any material that can be converted into energy and is nonmerchantable for other purposes, that is segregated from other nonmerchantable material, and that is;

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(i) A forest-related organic resource, including mill residues, precommercial thinnings, slash, brush, or byproduct from conversion of trees to merchantable material; or

(ii) A wood material, including pallets, crates, dunnage, manufacturing and construction materials (other than pressure-treated, chemically-treated, or painted wood products), and landscape or right-of-way tree trimmings.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Clean Air Act or CAA means the Clean Air Act, 42 U.S.C. 7401, et seq.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12–month period starting on the date the unit first produces electricity and during any calendar year after the calendar year in which the unit first produces electricity—

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input;

(3) Provided that the total energy input under paragraphs (2)(i)(B) and (2)(ii) of this definition shall equal the unit's total energy input from all fuel except biomass if the unit is a boiler.

Combustion turbine means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated duct burner, heat recovery steam generator, and steam turbine.

Commence operation means to have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber.

Electric generating unit or EGU means:

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(1)(i) Except as provided in paragraph (2) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(ii) If a stationary boiler or stationary combustion turbine that, under paragraph (1)(i) of this section, is not an electric generating unit begins to combust fossil fuel or to serve a generator with nameplate capacity of more than 25 MWe producing electricity for sale, the unit shall become an electric generating unit as provided in paragraph (1)(i) of this section on the first date on which it both combusts fossil fuel and serves such generator.

(2) A unit that meets the requirements set forth in paragraphs (2)(i)(A), (2)(ii)(A), or (2)(ii)(B) of this definition paragraph shall not be an electric generating unit:

(i)(A) Any unit that is an electric generating unit under paragraph (1)(i) or (ii) of this definition:

(1) Qualifying as a cogeneration unit during the 12–month period starting on the date the unit first produces electricity and continuing to qualify as a cogeneration unit; and

(2) Not serving at any time, since the later of November 15, 1990 or the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale.

(B) If a unit qualifies as a cogeneration unit during the 12–month period starting on the date the unit first produces electricity and meets the requirements of paragraphs (2)(i)(A) of this section for at least one calendar year, but subsequently no longer meets all such requirements, the unit shall become an electric generating unit starting on the earlier of January 1 after the first calendar year during which the unit first no longer qualifies as a cogeneration unit or January 1 after the first calendar year during which the unit no longer meets the requirements of paragraph (2)(i)(A)(2) of this section.

(ii)(A) Any unit that is an electric generating unit under paragraph (1)(i) or (ii) of this definition commencing operation before January 1, 1985:

(1) Qualifying as a solid waste incineration unit; and

(2) With an average annual fuel consumption of non-fossil fuel for 1985–1987 exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).

(B) Any unit that is an electric generating unit under paragraph (1)(i) or (ii) of this definition commencing operation on or after January 1, 1985:

(1) Qualifying as a solid waste incineration unit; and

(2) With an average annual fuel consumption of non-fossil fuel for the first 3 calendar years of operation exceeding 80 percent (on a Btu basis) and an average annual fuel consumption of non-fossil fuel for any 3 consecutive calendar years after 1990 exceeding 80 percent (on a Btu basis).

(C) If a unit qualifies as a solid waste incineration unit and meets the requirements of paragraph (2)(ii)(A) or (B) of this section for at least 3 consecutive calendar years, but subsequently no longer meets all such requirements, the unit shall become an electric generating unit starting on the earlier of January 1 after the first calendar year during which the unit

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first no longer qualifies as a solid waste incineration unit or January 1 after the first 3 consecutive calendar years after 1990 for which the unit has an average annual fuel consumption of fossil fuel of 20 percent or more.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

Generator means a device that produces electricity.

Maximum design heat input means the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as of the initial installation of the unit as specified by the manufacturer of the unit.

NAAQS means National Ambient Air Quality Standard.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings as of such installation as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as of such completion as specified by the person conducting the physical change.

Non–EGU means a source of SO_2 emissions that is not an EGU.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Solid waste incineration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine that is a “solid waste incineration unit” as defined in section 129(g)(1) of the Clean Air Act.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself.

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit. Each form of energy supplied shall be measured by the lower heating value of that form of energy calculated as follows:

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LHV = HHV − 10.55(W + 9H)

Where:

LHV = lower heating value of fuel in Btu/lb,

HHV = higher heating value of fuel in Btu/lb,

W = Weight % of moisture in fuel, and

H = Weight % of hydrogen in fuel.

Unit means a stationary, fossil-fuel-fired boiler or a stationary, fossil-fuel fired combustion turbine.

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process, excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (e.g., space heating or domestic hot water heating); or

(3) Used in a space cooling application (i.e., thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

(r) Notwithstanding any other provision of this section, a State may adopt, and include in a SIP revision submitted by March 31, 2007, regulations relating to the Federal CAIR SO_2 Trading Program under subparts AAA through HHH of part 97 of this chapter as follows. The State may adopt the following CAIR opt-in unit provisions:

(1) Provisions for CAIR opt-in units, including provisions for applications for CAIR opt-in permits, approval of CAIR opt-in permits, treatment of units as CAIR opt-in units, and allocation and recordation of CAIR SO_2 allowances for CAIR opt-in units, that are substantively identical to subpart III of part 96 of this chapter and the provisions of subparts AAA through HHH that are applicable to CAIR opt-in units or units for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied;

(2) Provisions for CAIR opt-in units, including provisions for applications for CAIR opt-in permits, approval of CAIR opt-in permits, treatment of units as CAIR opt-in units, and allocation and recordation of CAIR SO_2 allowances for CAIR opt-in units, that are substantively identical to subpart III of part 96 of this chapter and the provisions of subparts AAA through HHH that are applicable to CAIR opt-in units or units for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied, except that the provisions exclude § 96.288(b) of this chapter and the provisions of subpart III of part 96 of this chapter that apply only to units covered by § 96.288(b) of this chapter; or

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(3) Provisions for applications for CAIR opt-in units, including provisions for CAIR opt-in permits, approval of CAIR opt-in permits, treatment of units as CAIR opt-in units, and allocation and recordation of CAIR SO_2 allowances for CAIR opt-in units, that are substantively identical to subpart III of part 96 of this chapter and the provisions of subparts AAA through HHH that are applicable to CAIR opt-in units or units for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied, except that the provisions exclude § 96.288(c) of this chapter and the provisions of subpart III of part 96 of this chapter that apply only to units covered by § 96.288(c) of this chapter.

(s) Notwithstanding any provisions of paragraphs (a) through (r) of this section, subparts AAA through III of part 96 of this chapter, subparts AAA through III of part 97 of this chapter, and any State's SIP to the contrary:

(1) With regard to any control period that begins after December 31, 2014, the Administrator:

(i) Rescinds the determination in paragraph (a) of this section that the States identified in paragraph (c) of this section must submit a SIP revision with respect to the fine particles ($PM_{2.5}$) NAAQS meeting the requirements of paragraphs (b) through (r) of this section; and

(ii) Will not carry out any of the functions set forth for the Administrator in subparts AAA through III of part 96 of this chapter, subparts AAA through III of part 97 of this chapter, or in any emissions trading program in a State's SIP approved under this section; and

(2) The Administrator will not deduct for excess emissions any CAIR SO_2 allowances allocated for 2015 or any year thereafter.

Credits

[70 FR 25328, May 12, 2005; 71 FR 25302, 25372, April 28, 2006; 71 FR 74793, Dec. 13, 2006; 72 FR 59204, Oct. 19, 2007; 74 FR 56726, Nov. 3, 2009; 76 FR 48353, Aug. 8, 2011; 79 FR 71671, Dec. 3, 2014; 81 FR 13279, March 14, 2016]

SOURCE: 36 FR 22398, Nov. 25, 1971; 51 FR 40665, Nov. 7, 1986; 52 FR 24712, July 1, 1987; 55 FR 14249, April 17, 1990; 56 FR 42219, Aug. 26, 1991; 57 FR 32334, July 21, 1992; 57 FR 52987, Nov. 5, 1992; 58 FR 38821, July 20, 1993; 60 FR 40100, Aug. 7, 1995; 62 FR 8328, Feb. 24, 1997; 62 FR 43801, Aug. 15, 1997; 62 FR 44903, Aug. 25, 1997; 63 FR 24433, May 4, 1998; 64 FR 35763, July 1, 1999; 65 FR 45532, July 24, 2000; 72 FR 28613, May 22, 2007, unless otherwise noted.

AUTHORITY: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

Current through January 19, 2017; 82 FR 7611.

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ORAL ARGUMENT NOT YET SCHEDULED

No. 12-1342 (consolidated with Nos. 12-1343, 12-1344, 12-1425, 12-1480, 13-1003, 13-1045, 13-1129, 13-1178, 13-1179, and 13-1180)

IN THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

UTILITY AIR REGULATORY GROUP, *et al.*,

***Petitioner*,**

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*,

***Respondents*.**

On Petitions for Review of Final Action of the United States Environmental Protection Agency

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JOINT BRIEF OF STATE AND INDUSTRY INTERVENOR-RESPONDENTS

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CERTIFICATE AS TO PARTIES, RULINGS, AND RELATED CASES

Pursuant to D.C. Circuit Rule 28(a)(1), State and Industry Intervenor-Respondents—the State of Indiana; the Utility Air Regulatory Group; Georgia Power Company; Union Electric, doing business as Ameren Missouri; the Indiana Energy Association, Inc.; and Luminant Generation Company LLC, Big Brown Power Company LLC, Oak Grove Management Company LLC, Luminant Mining Company LLC, Big Brown Lignite Company LLC, Luminant Big Brown Mining Company LLC, Luminant Energy Company LLC, Sandow Power Company LLC, and Luminant Holding Company LLC—state as follows:

A. Parties, Intervenors, and *Amici*.

Since these consolidated cases involve direct review of a final agency action, the requirement to furnish a list of parties, intervenors, and *amici curiae* that appeared below is inapplicable. These cases involve the following parties:

Petitioners:

Case No. 12-1342: Utility Air Regulatory Group.

Case No. 12-1343: The National Parks Conservation Association ("NPCA") and Sierra Club.

Case No. 12-1344: The State of Texas and the Texas Commission on Environmental Quality (collectively "Texas").

Case No. 12-1425: NPCA and Sierra Club.

Case No. 12-1480: NPCA and Sierra Club (transferred from the United States Court of Appeals for the Eighth Circuit).

Case No. 13-1003: NPCA and Sierra Club (transferred from the United States Court of Appeals for the Fourth Circuit).

Case No. 13-1045: NPCA and Sierra Club (transferred from the United States Court of Appeals for the Eleventh Circuit).

Case No. 13-1129: NPCA and Sierra Club (transferred from the United States Court of Appeals for the Sixth Circuit).

Case No. 13-1178: Luminant Generation Company LLC, Big Brown Power Company LLC, Oak Grove Management Company LLC, Luminant Mining Company LLC, Big Brown Lignite Company LLC, Luminant Big Brown Mining Company LLC, Luminant Energy Company LLC, Sandow Power Company LLC, and Luminant Holding Company LLC (transferred from the United States Court of Appeals for the Fifth Circuit).

Case No. 13-1179: The State of Texas and the Texas Commission on Environmental Quality (transferred from the United States Court of Appeals for the Fifth Circuit).

Case No. 13-1180: The Louisiana Department of Environmental Quality (transferred from the United States Court of Appeals for the Fifth Circuit).

Respondents:

Respondents are the United States Environmental Protection Agency ("EPA") (in all of the above cases) and Gina McCarthy,* Administrator of EPA (in Case Nos. 12-1343, 12-1425, 12-1480, 13-1003, 13-1045, and 13-1129).

Intervenors:

Intervenors in support of Petitioners in Case Nos. 12-1342 and 12-1344 are Luminant Generation Company LLC, Big Brown Power Company LLC, Oak Grove Management Company LLC, Luminant Mining Company LLC, Big Brown Lignite Company LLC, Luminant Big Brown Mining Company LLC, Luminant Energy Company LLC, Sandow Power Company LLC, and Luminant Holding Company LLC.

Intervenors in support of Respondents in Nos. 12-1343, 12-1425, 12-1480, 13-1003, 13-1045, and 13-1129 are the State of Indiana; the Utility Air Regulatory Group; Georgia Power Company; Union Electric, doing business as Ameren Missouri; the Indiana Energy Association, Inc.; and Luminant Generation Company LLC, Big Brown Power Company LLC, Oak Grove Management Company LLC, Luminant Mining Company LLC, Big Brown Lignite Company

* Gina McCarthy ceased to serve as EPA Administrator as of January 20, 2017. E. Scott Pruitt has been nominated as her successor.

LLC, Luminant Big Brown Mining Company LLC, Luminant Energy Company LLC, Sandow Power Company LLC, and Luminant Holding Company LLC.

Intervenors in support of Respondents in Nos. 12-1342, 12-1344, 13-1178, 13-1179, and 13-1180 are NPCA and Sierra Club.

Amici Curiae

There are no *amici curiae* in these cases.

B. Ruling Under Review

These consolidated cases involve petitions to review final EPA action entitled "Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans," 77 Fed. Reg. 33,642 (June 7, 2012), JA___-___.

C. Related Cases

These cases have not previously been before this Court or any other court, apart from those of the consolidated cases, as noted above, that were transferred to this Court from other circuit courts of appeals (which took no dispositive or other action on the merits of the cases). Cases that involve related issues, but that do not involve review of the same EPA action challenged in the present cases, are pending, and held in abeyance at the present time, in the United States Courts of Appeals for the Fourth Circuit (*Utility Air Regulatory Group v. EPA*, No. 12-1664

(filed May 22, 2012); *National Parks Conservation Ass'n, et al. v. EPA*, No. 12-2300 (filed Oct. 19, 2012)) and the Sixth Circuit (*Utility Air Regulatory Group v. EPA*, No. 12-3627 (filed May 29, 2012); *Utility Air Regulatory Group v. EPA*, No. 12-3772 (filed June 25, 2012)). In addition, the United States Courts of Appeals for the Third Circuit and the Eighth Circuit have issued decisions in cases that, in part, involved issues closely related to issues raised by the present cases. *National Parks Conservation Ass'n v. EPA*, 803 F.3d 151 (3d Cir. 2015); *Nebraska v. EPA*, 812 F.3d 662 (8th Cir. 2016); *National Parks Conservation Ass'n v. McCarthy*, 816 F.3d 989 (8th Cir. 2016), *amending National Parks Conservation Ass'n v. McCarthy*, 811 F.3d 1005 (8th Cir. 2016).

RULE 26.1 DISCLOSURE STATEMENTS

Pursuant to Rule 26.1 of the Federal Rules of Appellate Procedure and D.C. Circuit Rule 26.1, Industry Intervenor-Respondents make the following statements:

The ***Utility Air Regulatory Group*** ("UARG") is a not-for-profit association of individual electric generating companies and national trade associations. UARG participates on behalf of certain of its members collectively in Clean Air Act administrative proceedings that affect electric generators and in litigation arising from those proceedings. UARG has no outstanding shares or debt securities in the hands of the public and has no parent company. No publicly held company has a 10% or greater ownership interest in UARG.

Georgia Power Company is a regulated public utility that provides electric power to customers in Georgia. Georgia Power Company owns and/or operates more than 16,500 megawatts of power generation capacity and serves more than 2.4 million customers in all but four of Georgia's 159 counties. Georgia Power Company is a wholly owned subsidiary of The Southern Company, which is a registered public utility holding company and a publicly held corporation. One hundred percent of Georgia Power's common stock is owned by The Southern Company. Other than The Southern Company, no publicly held company owns 10 percent or more of any of Georgia Power Company's stock.

Union Electric, doing business as Ameren Missouri ("Ameren") states that it is a wholly-owned subsidiary of Ameren Corporation, a publicly traded entity on the New York Stock Exchange.

The Indiana Energy Association, Inc., is a 501(c) non-profit corporation that serves as a trade association for Indiana gas and electric utilities. It has no parent companies, subsidiaries or affiliates that have issued shares or debt securities to the public, and no publicly held company has a ten percent or greater ownership interest in the Indiana Energy Association, Inc.

Big Brown Lignite Company LLC, was formerly a wholly owned subsidiary of Luminant Holding Company LLC that owned the lignite reserves associated with the Big Brown Power Plant. As a result of a Chapter 11 financial restructuring process, Big Brown Lignite Company LLC no longer exists as a separate entity and has been merged into Luminant Mining Company LLC, whose corporate disclosure statement is provided herein.

Big Brown Power Company LLC, a Texas limited liability company, is the legal entity that owns Big Brown Power Plant in Freestone County, Texas. Big Brown Power Company LLC is a wholly owned subsidiary of Vistra Asset Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Operations Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Intermediate

Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Energy Corp., which is a publicly held corporation. Vistra Energy Corp. is traded publicly on the OTCQX market under the symbol "VSTE." Apollo Management Holdings L.P., Brookfield Asset Management Private Institutional Capital Adviser (Canada), L.P., and Oaktree Capital Management, L.P. are publicly held entities, and each have subsidiaries that own more than 10% of Vistra Energy Corp.'s stock.

Luminant Big Brown Mining Company LLC, was formerly a wholly owned subsidiary of Luminant Holding Company LLC that owned the mine assets utilized in connection with mining lignite used to fuel the Big Brown Power Plant. As a result of a Chapter 11 financial restructuring process, Luminant Big Brown Mining Company LLC no longer exists as a separate entity and has been merged into Luminant Mining Company LLC, whose corporate disclosure statement is provided herein.

Luminant Energy Company LLC, a Texas limited liability company, is the legal entity that conducts the wholesale energy sales and purchases and commodity risk management and trading activities for the Luminant Entities. Luminant Energy Company LLC is a wholly owned subsidiary of Vistra Operations Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Intermediate Company LLC, which is a Delaware

limited liability company and is a wholly owned subsidiary of Vistra Energy Corp., which is a publicly held corporation. Vistra Energy Corp. is traded publicly on the OTCQX market under the symbol "VSTE." Apollo Management Holdings L.P., Brookfield Asset Management Private Institutional Capital Adviser (Canada), L.P., and Oaktree Capital Management, L.P. are publicly held entities, and each have subsidiaries that own more than 10% of Vistra Energy Corp.'s stock.

Luminant Generation Company LLC, a Texas limited liability company, is the legal entity that owns numerous Luminant generation facilities and assets associated with Luminant's competitive power generation business in the State of Texas. Luminant Generation Company LLC is a wholly owned subsidiary of Vistra Asset Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Operations Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Intermediate Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Energy Corp., which is a publicly held corporation. Vistra Energy Corp. is traded publicly on the OTCQX market under the symbol "VSTE." Apollo Management Holdings L.P., Brookfield Asset Management Private Institutional Capital Adviser (Canada), L.P., and Oaktree Capital Management, L.P. are publicly held entities, and each have subsidiaries that own more than 10% of Vistra Energy Corp.'s stock.

Luminant Holding Company LLC was formerly a wholly owned subsidiary of Texas Competitive Electric Holdings Company LLC that was a holding company for the Luminant entities. As a result of a Chapter 11 financial restructuring process, Luminant Holding Company LLC no longer exists as a separate entity and has been merged into Luminant Generation Company LLC, whose corporate disclosure statement is provided herein.

Luminant Mining Company LLC, a Texas limited liability company, is the legal entity that owns the mine assets utilized in connection with mining lignite used to fuel the Big Brown Power Plant, Monticello Power Plant, and the Martin Lake Power Plant as well as certain mine assets utilized in connection with mining lignite used to fuel the Sandow 4 Power Plant and the Sandow 5 Power Plant. Luminant Mining Company LLC also owns the lignite reserves associated with the Big Brown Power Plant. Luminant Mining Company LLC is a wholly owned subsidiary of Vistra Asset Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Operations Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Intermediate Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Energy Corp., which is a publicly held corporation. Vistra Energy Corp. is traded publicly on the OTCQX market under the symbol "VSTE." Apollo Management Holdings L.P., Brookfield Asset

Management Private Institutional Capital Adviser (Canada), L.P., and Oaktree Capital Management, L.P. are publicly held entities, and each have subsidiaries that own more than 10% of Vistra Energy Corp.'s stock.

Oak Grove Management Company LLC, a Delaware limited liability company, is the legal entity that owns the facility and related assets associated with Oak Grove Units 1 and 2, new lignite-fueled generation units near Robertson County, Texas. Oak Grove Management Company LLC is a wholly owned subsidiary of Vistra Asset Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Operations Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Intermediate Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Energy Corp., which is a publicly held corporation. Vistra Energy Corp. is traded publicly on the OTCQX market under the symbol "VSTE." Apollo Management Holdings L.P., Brookfield Asset Management Private Institutional Capital Adviser (Canada), L.P., and Oaktree Capital Management, L.P. are publicly held entities, and each have subsidiaries that own more than 10% of Vistra Energy Corp.'s stock.

Sandow Power Company LLC, a Texas limited liability company, is the legal entity that owns the Sandow Unit 5 facility, a new lignite-fueled generation unit located in Rockdale, Texas, and related assets. Sandow Power Company LLC

is a wholly owned subsidiary of Vistra Asset Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Operations Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Intermediate Company LLC, which is a Delaware limited liability company and is a wholly owned subsidiary of Vistra Energy Corp., which is a publicly held corporation. Vistra Energy Corp. is traded publicly on the OTCQX market under the symbol "VSTE." Apollo Management Holdings L.P., Brookfield Asset Management Private Institutional Capital Adviser (Canada), L.P., and Oaktree Capital Management, L.P. are publicly held entities, and each have subsidiaries that own more than 10% of Vistra Energy Corp.'s stock.

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*Authorities upon which we chiefly rely are marked with asterisks.

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GLOSSARY OF ABBREVIATIONS, ACRONYMS, AND TERMS

Act	Clean Air Act
BART	best available retrofit technology
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CSAPR	Cross-State Air Pollution Rule
EGUs	electric generating units
EPA	Environmental Protection Agency
FIP	federal implementation plan
NOx	nitrogen oxide
SIP	state implementation plan
SO_2	sulfur dioxide

JURISDICTION

For the reasons discussed below and in the Brief for Respondent U.S. Environmental Protection Agency ("EPA Br."), this Court lacks jurisdiction to entertain Argument I of Environmental Petitioners' opening brief because Environmental Petitioners failed to comply with the requirements of *Oljato Chapter of the Navajo Tribe v. Train*, 515 F.2d 654, 665-67 (D.C. Cir. 1975). To the extent Arguments II, III, and IV of Environmental Petitioners' brief constitute or incorporate collateral attacks on EPA's 1999, 2005, and 2006 regional haze rules, this Court lacks jurisdiction to hear those arguments because they are time-barred. Clean Air Act ("CAA") § 307(b)(1), 42 U.S.C. § 7607(b)(1) (petitions for review of any final EPA action must be brought within 60 days after notice of that action appears in the Federal Register). This Court otherwise has jurisdiction under 42 U.S.C § 7607(b)(1).

STATEMENT OF ISSUES

This brief adopts the statement of issues 1 through 4 in EPA's brief.

STATUTES AND REGULATIONS

The Addendum to the Corrected Opening Brief of State and Industry Petitioners (Oct. 31, 2016) reproduces pertinent statutes and regulations.

STATEMENT OF THE CASE

To avoid duplication, this brief does not repeat the background presented in EPA's brief. State and Industry Intervenor-Respondents, however, emphasize that

not only has this Court twice upheld EPA's use of alternatives to the CAA's best available retrofit technology ("BART") requirements—in *Center for Energy & Economic Development v. EPA*, 398 F.3d 653 (D.C. Cir. 2005) ("*CEED*"), and *Utility Air Regulatory Group v. EPA*, 471 F.3d 1333 (D.C. Cir. 2006) ("*UARG*")—but also, as discussed below, the Ninth, Tenth, and Eighth Circuits have affirmed their use as well.

The Ninth Circuit, in *Central Arizona Water Conservation District v. EPA*, 990 F.2d 1531 (9th Cir. 1993), recognized expressly EPA's authority to promulgate BART alternatives to address CAA regional haze requirements. That court held EPA "has the discretion to adopt implementation plan provisions other than those provided by BART analyses in situations where the agency reasonably concludes that more 'reasonable progress' will thereby be attained." *Id.* at 1543. EPA's 1999 regional haze rule, as well as its 2005 and 2006 revisions to that rule, reflect the Ninth Circuit's holding. *See* 64 Fed. Reg. 35,714, 35,739 (July 1, 1999) (BART alternatives are permissible when they make greater reasonable progress than BART); 70 Fed. Reg. 39,104, 39,137 (July 6, 2005) (incorporating two-prong test in 40 C.F.R. § 51.308(e)(3) for demonstrating greater reasonable progress than BART); 71 Fed. Reg. 60,612, 60,618 (Oct. 13, 2006) (describing how requirements under other CAA provisions may be deemed better-than-BART alternatives).

In *WildEarth Guardians v. EPA*, 770 F.3d 919 (10th Cir. 2014), the Tenth Circuit affirmed EPA's approval of a "cap-and-trade" program to address sulfur dioxide ("SO_2") emissions from electric generating units ("EGUs") in New Mexico, Utah, and Wyoming as a valid BART alternative. In that case, EPA approved a BART alternative that used the presumptive BART limits codified in EPA's BART Guidelines as the basis for the "BART benchmark" against which to judge the adequacy of the BART alternative. *Id.* at 928-29. The court dismissed a challenge by environmental organizations (including both Environmental Petitioners here, National Parks Conservation Association and Sierra Club) to the BART alternative's reliance on the presumptive BART emission rates, holding their claim was a time-barred challenge to EPA's 2006 regional haze rule. *Id.* at 929-30.

In two separate cases, the Eighth Circuit upheld an EPA federal implementation plan ("FIP") for Nebraska and EPA's approval of a Minnesota state implementation plan ("SIP") against challenges brought by the Environmental Petitioners in this case; both those plans—like the rule they challenge here—relied on the Cross-State Air Pollution Rule ("CSAPR") to satisfy BART. *Nebraska v. EPA*, 812 F.3d 662 (8th Cir. 2016); *Nat'l Parks Conservation Ass'n v. McCarthy*, 816 F.3d 989 (8th Cir. 2016) ("*NPCA*"), *amending Nat'l Parks Conservation Ass'n v. McCarthy*, 811 F.3d 1005 (8th Cir. 2016). The Eighth Circuit twice upheld the

validity of assessing BART alternatives by comparing average visibility improvements under BART and average visibility improvements under CSAPR at all affected Class I areas. *Nebraska*, 812 F.3d at 669-70; *NPCA*, 816 F.3d at 994-96.

CSAPR-for-BART has been adopted as the BART compliance mechanism for EGUs in at least 14 states. The June 7, 2012 rule that is the subject of this case, 77 Fed. Reg. 33,642, JA__-__, not only finalized the CSAPR-for-BART provision in EPA's rules; it also promulgated CSAPR-for-BART FIPs for 12 states.[2] Additional states are subject to CSAPR-for-BART SIPs or FIPs that EPA approved or promulgated separately,[3] and Alabama has submitted for EPA approval a SIP that relies on CSAPR-for-BART, *see* 81 Fed. Reg. 59,869 (Aug. 31, 2016); 81 Fed. Reg. 87,503, 87,508 (Dec. 5, 2016), and other states may do so.

SUMMARY OF ARGUMENT[4]

Environmental Petitioners present four principal arguments in challenging EPA's CSAPR-for-BART rule. They add a fifth argument in the alternative, attempting to preserve for *en banc* review the question whether this Court should

[2] Those states are Georgia, Indiana, Iowa, Kentucky, Michigan, Missouri, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, and West Virginia.

[3] Those include Nebraska, 77 Fed. Reg. 40,150 (July 6, 2012), and Minnesota, 77 Fed. Reg. 34,801 (June 12, 2012).

[4] This brief is intended as a supplement to Arguments I through V in EPA's brief, which are not repeated herein.

overturn its clear holdings affirming BART alternatives. Most of their arguments are not properly before the Court, and none has merit.

Environmental Petitioners' first argument—that CSAPR-for-BART is predicated in part on CSAPR budgets that this Court remanded—was not presented for consideration by EPA as required by section 307(d)(7)(B) of the CAA, 42 U.S.C. § 7607(d)(7)(B), and therefore was not preserved for judicial review. Environmental Petitioners' remedy is to seek EPA reconsideration of the rule. Moreover, their arguments that the remand of a subset of the CSAPR budgets requires reversal of the CSAPR-for-BART determination rest on speculation and misinterpretation of EPA's past policy positions. Although Environmental Petitioners fault EPA for not conducting further technical analysis to demonstrate the CSAPR-for-BART determination remains valid, EPA has conducted and published that analysis.

Environmental Petitioners argue it was unlawful for EPA to use the presumptive BART emission rates codified in EPA's BART Guidelines when it assessed whether CSAPR would achieve greater reasonable progress than BART, and that EPA instead should have made source-by-source BART determinations for all EGUs subject to CSAPR. EPA's underlying rules expressly allow use of the presumptive BART rates for evaluation of BART alternatives like CSAPR, and the Tenth Circuit correctly held that any challenge to those rule provisions must have

been brought within 60 days after publication of EPA's 2006 regional haze rule. Further, because Environmental Petitioners were petitioners in the Tenth Circuit litigation, they are precluded from relitigating that issue here.

Environmental Petitioners assert EPA should have evaluated CSAPR as a BART alternative by comparing visibility improvements under BART to visibility improvements under CSAPR *and* BART together. EPA's rules do not contemplate, much less require, such a facially implausible method of evaluation. Rather, the approach EPA took in making its CSAPR-for-BART determination is the same approach it took in its Clean Air Interstate Rule ("CAIR")-for-BART rulemaking, which this Court upheld. Environmental Petitioners' argument amounts to a *de facto* challenge to rules EPA promulgated in 2005 and 2006 and is thus precluded.

EPA properly assessed the average visibility improvement across all Class I areas in the states within the CSAPR region, as well as average improvement nationwide. That methodology comports with EPA's rules and has twice been upheld by the Eighth Circuit against challenges by Environmental Petitioners. To the extent Environmental Petitioners contend EPA was obligated to use their alternative, preferred methods for evaluating improvement, their arguments are precluded by rule provisions that EPA promulgated in 2005.

Finally, in arguing that EPA's rules authorizing BART alternatives violate the CAA, Environmental Petitioners advocate overruling this Court's *CEED* and *UARG* decisions. Those arguments are not properly before the Court and in any event are meritless and should be rejected.

ARGUMENT

I. Environmental Petitioners' Claims Related to the Remand of Some States' CSAPR Budgets Are Not Properly Before This Court and in Any Event Lack Merit.

Environmental Petitioners' argument that the remand of four states' SO_2 emission budgets and eleven states' ozone-season nitrogen oxide ("NOx") emission budgets undermines the rationale for the CSAPR-for-BART rule is not properly before the Court. The CAA provides that "[o]nly an objection to a rule . . . which was raised with reasonable specificity during the period for public comment . . . may be raised during judicial review." 42 U.S.C. § 7607(d)(7)(B).[5] By definition, such an objection cannot be based on actions that occurred long after EPA promulgated the CSAPR-for-BART rule that Environmental Petitioners challenge. The proper procedure in these circumstances is for Environmental Petitioners to seek EPA reconsideration of the CSAPR-for-BART rule, which they have not done. *See, e.g., Oljato*, 515 F.2d at 665-67.

[5] EPA's CSAPR-for-BART rulemaking was subject to CAA section 307(d)(7)(B) because it promulgated visibility-protection regulations under part C of title I of the CAA and FIPs under CAA section 110(c). *See* CAA § 307(d)(1)(B), (J), 42 U.S.C. § 7607(d)(1)(B), (J).

Moreover, the positions Environmental Petitioners take have no merit and no record basis. For instance, they merely assert that the budget remands upend the basis for the CSAPR-for-BART determination. Their arguments ignore that eight of the eleven states with remanded ozone-season NOx budgets are now subject to even more stringent budgets under the CSAPR Update rule;[6] two of the other three remain subject to CSAPR's annual NOx program;[7] and all four states with remanded SO_2 budgets have either adopted (or committed to adopt) the CSAPR SO_2 and annual NOx budgets into their SIPs or remain in the CSAPR SO_2 and annual NOx programs through a FIP.[8]

Thus, withdrawal of certain CSAPR FIP requirements for Florida, and possibly—depending on future actions—for Texas, are the only "potentially material changes to the scope of CSAPR coverage resulting from the D.C. Circuit's remand." 81 Fed. Reg. at 78,956. And the proposal to withdraw Texas from CSAPR's annual trading programs is just that—a proposal. Texas sources currently remain subject to the CSAPR FIPs for the annual SO_2 and NOx

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[6] *See* 81 Fed. Reg. 78,954, 78,957 (Nov. 10, 2016); 81 Fed. Reg. 74,504 (Oct. 26, 2016); *see also* EPA Br. at 14.

[7] *See* EPA Br. at 15.

[8] *See* 81 Fed. Reg. at 78,956; 81 Fed. Reg. 65,899 (Sept. 26, 2016) (final action regarding Georgia's SIP); 81 Fed. Reg. at 59,869 (final action regarding Alabama's SIP); 81 Fed. Reg. 56,512 (Aug. 22, 2016) (final action regarding South Carolina's SIP).

programs, and their removal from those programs may not be finalized. Indeed, several commenters opposed the proposal.[9] Further, the Assistant to the President and Chief of Staff has directed EPA not to send any regulation to the Office of the Federal Register until EPA's next Administrator has reviewed and approved the regulation.[10] Thus, it is questionable whether EPA's proposal on Texas will be finalized, and the mere possibility that it will be cannot form the basis for any challenge by Environmental Petitioners in this case.

In addition, EPA conducted and described in a public notice a "sensitivity analysis" that shows that the Florida change and the possible Texas change to CSAPR's coverage do not undermine EPA's CSAPR-for-BART determination. *See* EPA Br. at 15-17. Environmental Petitioners' arguments that EPA failed to conduct additional analysis to support the CSAPR-for-BART rule and that EPA "expressly disavow[ed]" a finding that the CSAPR Update Rule would support the CSAPR-for-BART determination, Brief of Conservation Groups ("Envtl. Pet. Br.") at 14, predate notice of EPA's sensitivity analysis.

Environmental Petitioners also allege that EPA previously found that an emission trading program cannot be a valid BART alternative "where this Court

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[9] *See* Comments of Luminant on "Interstate Transport of Fine Particulate Matter: Revision of Federal Implementation Plan Requirements for Texas," Doc. EPA-HQ-OAR-2016-0598-0013 (Jan. 9, 2017).

[10] *See* 82 Fed. Reg. 8346 (Jan. 24, 2017).

has invalidated the emission budgets in that trading program," referring to EPA's decision to disapprove SIPs that relied on the CAIR-for-BART rule after CAIR was remanded in *North Carolina v. EPA*, 531 F.3d 896 (per curiam), *modified on reh'g*, 550 F.3d 1176 (D.C. Cir. 2008) (per curiam). Envtl. Pet. Br. at 14, 19-20. Of course, whether EPA acted properly in disapproving CAIR-for-BART SIPs is a subject of this litigation and is addressed in State and Industry Petitioners' brief, which argues EPA was compelled to approve the CAIR-for-BART SIPs. But even assuming *arguendo* that EPA had discretion to disapprove CAIR-for-BART SIPs, EPA was not bound to take similar action with respect to CSAPR-for-BART SIPs and FIPs once this Court issued its remand in *EME Homer City Generation, L.P. v. EPA*, 795 F.3d 118 (D.C. Cir. 2015) ("*EME Homer City II*"). *EME Homer City II* did not invalidate CSAPR but simply held that EPA had incorrectly calculated budgets for a subset of states. As the above discussion and EPA's brief show, post-remand developments will in nearly every case result in equal or greater emissions reductions than would have occurred under the remanded budgets, as confirmed by EPA's sensitivity analysis.

The cases Environmental Petitioners cite do not support their arguments. In *Delaware Department of Natural Resources v. EPA*, this Court remanded a rule because EPA failed to heed comments explaining that a key assumption underlying EPA's rule was mistaken. 785 F.3d 1, 16 (D.C. Cir. 2015). EPA was not mistaken

as to any assumption underlying the CSAPR-for-BART rule, and CSAPR continues to apply even in states where budgets may be revised, including Texas. In *Williams Field Services Group, Inc. v. FERC*, 194 F.3d 110, 118-19 (D.C. Cir. 1999), a settlement that formed the basis for agency action was no longer in place, resulting in vacatur of the agency's order. In contrast, CSAPR remains in place, and the basis for the CSAPR-for-BART rule is not undermined. *Kiyemba v. Obama*, 559 U.S. 131 (2010) (per curiam), reflects a Supreme Court determination to allow lower courts to hear factual issues before it rules on appeal, and *Hatim v. Gates*, 632 F.3d 720 (D.C. Cir. 2011) (per curiam), involved a remand for further proceedings in light of subsequent contrary legal decisions. Neither case informs the issues here.

II. EPA's Use of the Presumptive BART Limits To Evaluate CSAPR as a Better-than-BART Alternative Comports with EPA's Rules, Is Reasonable, and in Any Event Is Not Properly Before This Court.

The underlying BART rules provide three ways by which to compare a BART alternative to BART and to demonstrate that the alternative will achieve greater reasonable progress than BART. EPA opted to use one of the tests in 40 C.F.R. § 51.308(e)(3). That provision states, in relevant part, that when "the distribution of emissions" under a BART alternative would differ significantly from the emissions distribution that would occur with BART, a state or EPA may demonstrate that the BART alternative is better than BART through computer

modeling. That modeling must show: (1) no visibility degradation in any affected class I area; and (2) an overall improvement in visibility compared to BART over all affected class I areas. *Id.* § 51.308(e)(3)(i),(ii). To make this comparison, a state or EPA develops a BART benchmark, *i.e.*, an estimation of visibility improvements that would result from application of BART controls. *See* 70 Fed. Reg. at 39,106.

Environmental Petitioners claim EPA misapplied this test by relying, in part, on the presumptive BART limits to establish a BART benchmark for comparing CSAPR to BART. EPA's brief (at 27-36) demonstrates that EPA properly applied this test and identified an appropriate BART benchmark. State and Industry Intervenor-Respondents supplement EPA's response below.

Ordinarily, a BART benchmark is based on "a determination of BART for each source subject to BART and covered by the [BART] alternative program." 40 C.F.R. § 51.308(e)(2)(i)(C). But when the alternative "has been designed to meet a requirement other than BART," *id.*, such as the "good neighbor" requirement of CAA section 110(a)(2)(D)(i), 42 U.S.C. § 7410(a)(2)(D)(i), as is the case with CSAPR, *EME Homer City II*, 795 F.3d at 123, then a state or EPA "may determine the [BART benchmark] . . . based on both source-specific *and category-wide information*, as appropriate." 40 C.F.R. § 51.308(e)(2)(i)(C) (emphasis added). The presumptive BART limits are precisely the sort of source-

category-wide information the rules authorize states and EPA to rely on for BART benchmarks. *See* 71 Fed. Reg. at 60,619 ("the presumptions represent a reasonable estimate of a stringent case BART . . . because . . . they would be applied across the board to a wide variety of units with varying impacts on visibility, at power plants of varying size and distance from Class I areas"). EPA specifically noted this fact in the June 7, 2012 rule under review here. 77 Fed. Reg. at 33,649-50, JA__-__. Moreover, EPA's 2006 rulemaking promulgating the provision that governs how states or EPA are to compare BART to a BART benchmark specifically says that use of presumptive BART emission rates to develop a BART benchmark is appropriate for BART alternatives *regardless* of whether the measures used as BART alternatives are required by other provisions of the CAA:

> [T]he presumptions for EGUs in the BART guidelines should be used for comparison to a trading program or other alternative measure, unless the State determines that such presumptions are not appropriate for particular EGUs.

71 Fed. Reg. at 60,619.

Because reliance on the presumptive limits was authorized by EPA's 2006 rule revising the BART-alternative provisions, this issue cannot be relitigated now as part of a challenge to EPA's June 2012 rule. Indeed, Environmental Petitioners already have litigated—unsuccessfully—this issue in the Tenth Circuit. *WildEarth Guardians* addressed SIPs submitted by New Mexico, Utah, and Wyoming and

approved by EPA.[11] Those SIPs included a BART-alternative analysis much like the one used to support the CSAPR-for-BART determination.[12] Environmental Petitioners' challenge to that BART benchmark was untimely; the court held that any challenge to the determination that the presumptive limits can serve as a BART benchmark must have been brought "within 60 days of the EPA's publication of the 2006 amendment to the Regional Haze Rule." *WildEarth Guardians*, 770 F.3d at 930 (citing 42 U.S.C. § 7607(b)(1)). For the same reason, this Court lacks jurisdiction to hear Environmental Petitioners' challenge to EPA's use of the presumptive limits as the BART benchmark in the CSAPR-for-BART rulemaking. *Med. Waste Inst. v. EPA*, 645 F.3d 420, 427 (D.C. Cir. 2011) (CAA's 60-day filing deadline is "jurisdictional") (citation omitted). Moreover, because both Environmental Petitioners were petitioners in the Tenth Circuit case and the jurisdictional issue was resolved against them there, they are precluded from re-litigating that issue here. *Nat'l Ass'n of Home Builders v. EPA*, 786 F.3d 34, 41

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[11] As noted, the petitioners in that case included both Environmental Petitioners in the present cases.

[12] *Compare WildEarth Guardians*, 770 F.3d at 929 (explaining that the better-than-BART analysis in that case relied on presumptive BART emission rates for all EGUs except two sources where lower BART rates were already in place) *with* 77 Fed. Reg. at 33,649, JA___ (noting EPA relied on the presumptive rates to determine the BART benchmark "unless an actual emission rate at a given unit with existing controls is lower").

(D.C. Cir. 2015) ("Issue preclusion applies to threshold jurisdictional issues . . . as well as issues going to a case's merits.").[13]

III. EPA Properly Conducted Its Comparison of CSAPR and BART.

Environmental Petitioners argue that the CSAPR-for-BART determination is flawed because, in evaluating whether CSAPR would achieve greater reasonable progress than BART, EPA failed to compare visibility under CSAPR to visibility under *both* CSAPR and BART. Envtl. Pet. Br. at 32-35. Their preferred test is as illogical as it sounds, has no basis in the CAA or EPA's rules, and is not properly before this Court.

In evaluating whether a BART alternative will achieve greater reasonable progress than BART, a state or EPA must: (i) conduct "[a]n analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program" (*i.e.*, assess the BART benchmark); and (ii) assess "the projected emissions reductions achievable through the trading program or other alternative measure." 40 C.F.R. § 51.308(e)(2)(i)(C), (D). Comparing BART to the BART-alternative measure would be infeasible and

[13] That would be true even if this Court were to view the jurisdictional question differently from the Tenth Circuit, *see, e.g.*, *Yamaha Corp. v. United States*, 961 F.2d 245, 258 (D.C. Cir. 1992)—though no basis would exist for this Court to do so given its recognition of CAA section 307(b)(1)'s clear jurisdictional time-bar.

meaningless if states or EPA were required to include emission reductions attributable to the BART-alternative measure in their analysis of emission reductions attributable to BART.

Furthermore, Environmental Petitioners fail to recognize that BART and a BART alternative do not exist in a vacuum—that one cannot obtain realistic estimates of emission reductions under joint implementation of both programs simply by adding the emission reductions calculated under EPA's BART scenario to the emission reductions calculated under EPA's BART-alternative scenario, as Environmental Petitioners do in their brief. Envtl. Pet. Br. at 34. That approach is unworkable because, *inter alia*, the results of five-factor BART analyses for sources would not be the same after implementation of a BART alternative; such BART analyses could be expected, in many cases, to yield less stringent BART requirements.

EPA's approach, on the other hand, is eminently reasonable. By evaluating emission reductions and visibility improvements that are attributable to BART alone and comparing them to reductions and improvements that are attributable to the BART alternative alone, EPA can determine whether the alternative will achieve greater reasonable progress than BART. EPA took that approach in its CSAPR-for-BART rule and in its CAIR-for-BART rule, which this Court affirmed. *See UARG*, 471 F.3d at 1337.

Environmental Petitioners appear to argue that their preferred test is necessary at least when the proposed BART alternative is a program required under another CAA provision. Envtl. Pet. Br. at 11, 33. Their argument fails to recognize that, as EPA's brief explains, the test they propose would effectively *prohibit* BART alternatives that constitute measures required under other CAA provisions—even though EPA's 2005 and 2006 rules expressly confirm such alternatives are permissible. 40 C.F.R. § 51.308(e)(2)(i)(C) (describing flexible analytical procedures for approving BART alternatives where "the emissions trading program or other alternative measure has been designed to meet a requirement other than BART"). In this respect, Environmental Petitioners' challenge is, at bottom, not to the 2012 CSAPR-for-BART determination but to EPA's long-standing BART-alternative rules that predate that determination. Accordingly, in this respect as well, Environmental Petitioners' challenge is barred. 42 U.S.C. § 7607(b)(1).

Moreover, this Court in *UARG* rejected the argument that a measure required under another CAA program cannot serve as a BART alternative. *UARG*, 471 F.3d at 1341. A test that, like Environmental Petitioners' preferred test, effectively would preclude such programs as BART alternatives cannot be squared with that decision.

IV. EPA's Approach to Evaluating Improvements Across Affected Class I Areas Was Reasonable and Consistent with the BART Rules.

To evaluate the visibility improvements attributable to CSAPR and those attributable to BART, EPA assessed the average improvement across all Class I areas in the states that are subject to CSAPR and neighboring states, as well as the average improvement nationwide. This comported with the regional haze rules' provisions addressing assessment of a BART alternative under the regulatory test EPA applied in its CSAPR-for-BART rulemaking:

> The modeling would demonstrate "greater reasonable progress" if both of the following two criteria are met:
>
> > (i) Visibility does not decline in any Class I area, and
> >
> > (ii) There is an *overall improvement* in visibility, determined by comparing the *average differences* between BART and the alternative *over all affected Class I areas*.

40 C.F.R. § 51.308(e)(3)(i)-(ii) (emphases added).

This test is reasonable and was applied in the rulemaking that this Court affirmed in *UARG*. *See* 471 F.3d at 1336. EPA determined CAIR-for-BART in the same manner it determined CSAPR-for-BART. *See id.* at 1336-37, 1340-41 (describing the test EPA used to assess CAIR-for-BART and finding "CAIR-for-BART is far better than BART" under that test). The Eighth Circuit likewise has upheld—twice—application of this test in the rulemaking under review here. *Nebraska*, 812 F.3d at 669-70; *NPCA*, 816 F.3d at 995-96.

Environmental Petitioners argue, however, that EPA erred by not adopting and using a *different* methodology, by evaluating specific subsets of Class I areas or even individual Class I areas. Envtl. Pet. Br. at 12, 38-46. EPA's 2005 and 2006 rules eschew any requirement of such an analysis. Accordingly, here again, Environmental Petitioners' claim is an untimely collateral attack on EPA's long-standing BART rules and must be dismissed. *See* 70 Fed. Reg. at 39,156; 42 U.S.C. § 7607(b)(1).

Environmental Petitioners nonetheless characterize their preferred methodologies as "more realistic," Envtl. Pet. Br. at 38, and, on that basis, contend EPA should have used them. But they wholly fail to demonstrate that EPA's approach was arbitrary or unsupported. EPA reasonably concluded that its approach to evaluating visibility impacts was more accurate and reliable than the approaches Environmental Petitioners prefer. *See* EPA Br. at 41-46.

Environmental Petitioners' putative regulatory arguments likewise lack merit. They claim the BART rules require that BART alternatives be compared to BART on a state-by-state basis. Envtl. Pet. Br. at 42-43. They quote three provisions of the BART rules that describe the showing (or elements of the showing) required to support a BART alternative:

- "A demonstration that the emissions trading program or other alternative measure will achieve greater reasonable progress than

would have resulted from the installation and operation of BART at all sources subject to BART in the State and covered by the alternative program." 40 C.F.R. § 51.308(e)(2)(i).

- "An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program." *Id.* § 51.308(e)(2)(i)(C).
- "A State which opts under 40 CFR 51.308(e)(2) to implement an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART may satisfy the final step of the demonstration required by that section as follows: . . . . If the distribution of emissions is significantly different, the State must conduct dispersion modeling to determine differences in visibility between BART and the trading program for each impacted Class I area, for the worst and best 20 percent of days." *Id.* § 51.308(e)(3).

None of these provisions requires state-by-state analyses of impacts on Class I areas. That these provisions use the word "State," which is the reason Environmental Petitioners cite them, merely reflects that EPA's rules generally presume that in most cases a state will conduct the better-than-BART analysis

while developing a regional haze SIP—a state implementation plan—for that state. EPA's application of 40 C.F.R. § 51.308(e)(3) by averaging across all affected Class I areas in a multi-state area—for a rule that, like the CAIR-for-BART rule upheld by this Court, expressly covers a multi-state area—is reasonable, not in conflict with the BART-alternative rules, and entitled to deference.

Finally, that 40 C.F.R. § 51.308(e)(2)(i)(E) provides an independent criterion for evaluating a BART alternative under a "clear weight of evidence" standard in no way supports Environmental Petitioners' argument that EPA erred in rejecting their preferred methodology. Envtl. Pet. Br. at 44. Although the clear-weight-of-evidence standard gives the regulatory agency broad discretion to consider many kinds of information, it plainly does not mandate any particular methodology, and EPA fully and reasonably explained why it would not have used Environmental Petitioners' preferred approach if it had chosen to invoke that provision. *See* EPA Br. at 43-46.

V. Environmental Petitioners' Statutory Argument Is Untimely, Is Inconsistent with Precedent, and Would Disrupt Implementation of the Regional Haze Program.

Environmental Petitioners' final argument is that this Court wrongly decided *CEED* and *UARG* and that the CAA forbids BART alternatives. Envtl. Pet. Br. at 47-53. State and Industry Intervenor-Respondents agree with EPA that this argument is both untimely and meritless. As EPA's brief observes, Environmental

Petitioners' argument is contrary not only to this Court's decisions but also to decisions of the Eighth and Ninth Circuits, EPA Br. at 48, and, as discussed above, it conflicts with the Tenth Circuit's *WildEarth Guardians* decision as well. Thus, were this Court to overrule its previous decisions,[14] it would not only abandon its own established jurisprudence but also diverge from the uniform case law of three sister circuits, creating, for the first time, a circuit split on this issue of statutory interpretation.

Such an unwarranted departure would also disrupt implementation of the CAA's regional haze program. BART and BART alternatives are the centerpiece of the program's first implementation period, which ends in 2018, and many states, as well as EPA, are relying on BART alternatives to meet regional haze regulatory obligations. An unprecedented ruling at this late date prohibiting BART alternatives could frustrate progress toward visibility improvements.

Finally, under the judicial review scheme enacted by Congress, no court has jurisdiction to entertain any challenge to EPA's long-standing regulatory authorization of BART alternatives. The time to challenge that authorization expired—at the latest—60 days after publication of EPA's 2006 BART-alternative rules. 42 U.S.C. § 7607(b)(1). Any such challenge has been foreclosed for more than a decade.

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[14] As Environmental Petitioners concede (at 47), no panel of this Court may do so.

CONCLUSION

EPA's CSAPR-for-BART determination is reasonable, supported, and consistent with the CAA, EPA's underlying BART and BART-alternative rules, and the decisions of all courts, including this Court, that have addressed the relevant issues. Moreover, Environmental Petitioners raise challenges that are untimely, and thus not properly before the Court, and present arguments that they did not first present for agency consideration. For the foregoing reasons, and those presented in EPA's brief, their petition for review should be dismissed or denied.

Dated: January 27, 2017

Respectfully submitted,

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CERTIFICATE OF COMPLIANCE

Pursuant to Rule 32(a), (f), and (g) of the Federal Rules of Appellate Procedure and Circuit Rules 32(e)(1) and (e)(2)(C), I hereby certify that the foregoing Joint Brief of State and Industry Intervenor-Respondents contains 4,989 words, as counted by a word processing system that includes headings, footnotes, quotations, and citations in the count, and that this brief therefore is within the word limit of 5,000 words as established by the Court in its Order of May 17, 2016. I also certify that this brief complies with the typeface and type-style requirements of Rule 32(a)(5) and (6) of the Federal Rules of Appellate Procedure because it has been prepared in a proportionally spaced typeface using Microsoft Word 2010 with 14-point Times New Roman font.

/s/ Norman W. Fichthorn
Norman W. Fichthorn

CERTIFICATE OF SERVICE

I hereby certify that on this 27th day of January, 2017, I served the foregoing Joint Brief of State and Industry Intervenor-Respondents on all registered counsel in these consolidated cases through the Court's CM/ECF system.

/s/ Norman W. Fichthorn
Norman W. Fichthorn

BEFORE THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In re:	)	
	)	
Promulgation of Air Quality	)	
Implementation Plans; State of	)	Docket No. EPA-R06-OAR-2015-0189
Arkansas; Regional Haze and	)	
Interstate Visibility Transport Federal	)	
Implementation Plan; Final Rule	)	
	)	

Arkansas Electric Cooperative Corporation's
Petition for Reconsideration and Request for Administrative Stay

In accordance with Section 307 of the Clean Air Act, 42 U.S.C. § 7607(d)(7)(B), Arkansas Electric Cooperative Corporation (AECC) respectfully requests that the U.S. Environmental Protection Agency (EPA) reconsider and grant an immediate administrative stay of the compliance deadline and toll the effective date of certain requirements in the final rule entitled "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan; Final Rule" (Final FIP), published at 81 Fed. Reg. 66332 on September 27, 2016. AECC understands that Entergy Arkansas, Inc. and Entergy Mississippi Inc. submitted a comprehensive petition for reconsideration and administrative stay of the Final FIP (Entergy Petition), and AECC incorporates by reference the Entergy Petition into this petition. In this petition, AECC specifically highlights the unique impact EPA's Final FIP would have on AECC's operation and ability to supply affordable power to its members.

I. Introduction

AECC is an Arkansas not-for-profit electric utility owned by 17 distribution cooperatives across the state of Arkansas (members), which in turn are owned by the utility customers they serve. AECC's mission is to provide reliable, affordable, responsible electric service to its members. As a result, AECC is a consumer advocate representing more than 38 percent of the residential consumers in Arkansas, i.e. approximately 520,000 end-use consumers. AECC's service territory extends into 74 of Arkansas's 75 counties, and covers more than 60 percent of the state's geographic area.

AECC owns more than 3500 megawatts (MW) of diverse generation resources including coal, natural gas, gas/oil, and hydropower. AECC also has access to 500 MW of wind, hydropower and biomass pursuant to purchased power agreements. AECC's Board has purposefully invested in a diverse array of generation resources in order to provide the most reliable and affordable electricity for its cooperative members across the state.

The wisdom of this resource diversification is evident in the fact that AECC's wholesale cost to its members is one of the lowest in the country at approximately 4.9

cents/kilowatt hour (kwh).[1] This affordability is absolutely necessary for the large proportion of AECC's low income households: Arkansas has the 9th lowest per capita income in the United States,[2] and 19.1 percent of its citizens[3] and 26 percent of the state's children live below the poverty level .[4] Since AECC serves the rural communities in the state and most of the areas in the Delta, the percentage of electric cooperative households and children in poverty is much higher than the state average served by investor-owned utilities.

The EPA published the Final FIP for Regional Haze for Arkansas on Tuesday, September 27, 2016. The Final FIP requires, among other things, installation of SO2 controls (scrubbers) on th e units located at the Flint Creek Power Plant – which AECC owns jointly with American Electric Power's Southwestern Electric Power Company (AEP) – as well as the White Bluff Steam Electric Station Units I and II in Redfield, Arkansas (White Bluff) and the Independence Steam Electric Station Units I and II in Newark, Arkansas (Independence) –all of which AECC co -owns with Entergy Corporation, including its operating company Entergy Arkansas, Inc. (EAI or Entergy).

White Bluff I and II and Independence I and II represent a total of approximately 1168 MW of generating capacity for AECC , out of a total of 3500 MW . These four units entered commercial operation between 1980 and 1984, and could potentially operate indefinitely into the future absent economic or regulatory constraints. As a 35% owner of White Bluff and Independence, AECC will be forced to spend approximately $700 million dollars to prepare to install the required controls. Collectively, EAI, AECC, and other co-owners of the units will be force d to spend approximately $2 billion. Because of the extreme financial hardship AECC will face if the Final FIP is not stayed,AECC has already begun discussion about possible retirement of both White Bluff and Independence in order to meet the imminent compliance deadline of October 27, 2021 , rather than add scrubbers to those units.

Regarding White Bluff, a recent economic impact study of this plant's contribution to the regional economy demonstrates that this plant provides hundreds of millions in annual revenues to businesses, schools, and the communities in some of the most impoverished counties in the country.[5] The removal of these revenues from some of the poorest communities in the nation is unconscionable. These families, farms, schools and businesses have nowhere to turn for replacement income. The loss of the White Bluff

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[1] *See* Arkansas Electric Cooperative Corporation Annual Report 2015 (received by the Arkansas PSC on April 29, 2016), available at http://www.apscservices.info/RcvdDocs/3_1_05022016_1_1.pdf (calculated by dividing the net revenue by the number of kilowatt hours).

[2] Michael Pakko, Personal Income – 2015Q4, ARKANSASECONOMIST.COM (March 24, 2016) (citing U.S. Bureau of Economic Analysis).

[3] 2015 American Community Survey 1-Year Profiles, Individuals Below Poverty Level by State, WWW.CENSUS.GOV. (ranking Arkansas as the second state, after Louisiana, with the highest number of citizens living below the poverty level).

[4] Arkansas Demographics of Poor Children, National Center for Children in Poverty, WWW.NCCP.ORG (last updated April 6, 2016) (state data calculated using the 2010-2014 American Community Survey, representing information from 2014).

[5] Willlie Lee Brooks, Jr., *What is the Economic Impact of the White Bluff Electric Power Plant?* (May 30, 2014), available at www.arkleg.state.ar.us (accessible via google searching "Economic Impact Study of White Bluff").

plant more than two decades early would have devastating impacts on this region and a large portion of Arkansas, particularly the members AECC serves.

AECC respectfully requests that EPA reconsider and grant an immediate administrative stay of a number of the requirements imposed on White Bluff and Independence. Specifically, AECC requests EPA reconsider and administratively stay the (1) best available retrofit technology (BART) requirements related to sulfur dioxide (SO_2) emission control equipment at White Bluff, (2) 18-month compliance deadline for installation of oxides of nitrogen (NOx) controls at these units, (3) NOx limit that applies at low loads and the three-hour averaging period for NOx compliance, and (4) imposition of reasonable progress controls on Independence.

With respect to the request for stay, any costs of compliance for AECC are passed directly to AECC's members, who in turn pass them along to their members—many of whom are already struggling financially. These expenditures would be wholly unnecessary if AECC's legal challenges to the FIP are successful. Not only does justice require a stay of the FIP, but these legal challenges are based on sound legal principles and are likely to succeed on the merits, and making a stay is in the public interest and necessary to prevent irreparable harm to AECC and its members. In contrast, no significant harm will result to either EPA or the public from a stay of the FIP, given that the emission reductions and resulting visibility improvements contemplated under the Final FIP will be incremental at best.[6]

II. Request for Reconsideration

The Clean Air Act requires the Administrator of EPA to grant reconsideration of a proceeding if a petitioner "can demonstrate . . . it was impracticable to raise [an] objection" to a final action within the time for public comment or if "the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." 42 U.S.C. § 7607(d)(7)(B). As demonstrated below, EPA must grant reconsideration of the Final FIP, because the FIP is riddled with clear errors and EPA failed to provide adequate notice and opportunity to comment on requirements that are of central relevance to the Final FIP.

A. The 18-month compliance deadline for installation of low-NOx burners and separated overfire air (LNB/SOFA) was decided without due process and is arbitrary and capricious.

The Final FIP changed the timeframe for NOx burners' installation on five units from 3 years to 18 months without allowing the interested parties any opportunity to comment.[7] This requirement is not a logical outgrowth of the proposed FIP, and such a tight compliance timeframe is both extremely difficult—if not impossible—to meet and

[6] 81 Fed. Reg. at 66386.

[7] 81 Fed. Reg. at 66344, 66358. In the proposed FIP, EPA invited public comment on the appropriateness of the proposed compliance dates for emission limits of Domtar Ashdown Power Boiler No. 2. only. 80 Fed. Reg. 18988 ("We are proposing to require compliance with the emission limit no later than 3 years from the effective date of the final rule, and are inviting public comment on the appropriateness of this compliance date.") EPA did not invite comments on other proposed compliance dates for any other units.

unprecedented. In fact, u pon review of other Regional Haze Rule FIPs issued by EPA, AECC believes that t he Arkansas Final FIP is the first time EPA has ever issued a FIP requiring a compliance date of less than 3 years to install LNB/SOFA.

In the 2015 Proposed FIP, published at 80 Fed. Reg. 18944, EPA proposed to require installation and operation of LNB/SOFA on the W hite Bluff and Independence units "no later than 3 years from the effective date of the final rule, consistent with [its] regional haze regulations."[8] EPA justified this proposal, stat ing "as is generally the case for installation of NOx controls on EGUs, we expect that 3 years from the date of our final action would be sufficient time for Independence to install and operate LNB/SOFA controls at Units 1 and 2 and to comply with the asso ciated emission limits."[9] Moreover, in the Final FIP, EPA stated thatto determine what is "as expeditiously as practicable" for installation and operation of a control technology, "the states and EPA usually consider the amount of time it generally takes to install and operate that type of technology at similar sources and the compliance dates that have been required for the installation and operation of the same type of control technology at similar sources in other regional haze actions."[10]

Directly contrary to EPA's own statements in the Proposed FIP and the Final FIP, EPA finalized an 18 -month compliance deadline for White Bluff and Independence to install LNB/SOFA on five units based on comments from environmental groups stating that LNB/SOFA could be installed in six to eight months.[11] EPA agreed with the environmental groups with no further explanation and imposed the 18 -month deadline, as opposed to its own proposed 3-year compliance period.

For LNB/SOFA, three years is generally considered the time required for installation. For Arkansas specifically, AECC agrees the three -year time frame is "as expeditious as practicable," especially considering there are four units at White Bluff and Independence within the same regional transmission organization system that would be affected by outages during the period.

In any case, EPA's newly-imposed 18-month requirement is not feasible. Accelerated construction schedules would be required at additional expense to AECC's members. Outages to install the controls could not be optimally scheduled to minimize the cost of replacement energy and could also compromise system reliability . In short, the lack of due process in EPA's requested comment on 3 years, to an imposition of an 18 month deadline requires EPA to re consider its unprecedented and impracticable compliance deadline.

[8] 80 Fed. Reg. at 18975.
[9] 80 Fed. Reg. at 18996.
[10] 81 Fed. Reg. at 66376-77.
[11] 81 Fed. Reg. at 66342.

B. The NOx emission limits for White Bluff and Independence are not a logical outgrowth of the proposed rule and parties did not have a meaningful opportunity to comment.

In addition to EPA's failure to provide an opportunity to comment on the compliance date, EPA also failed to allow an opportunity to comment on the rolling 3-hour average limit when the units operate below 50 percent capacity.

In its proposed FIP, EPA proposed a NOx BART emission limit of 0.15 lb/MMBtu on a 30-boiler-operating day rolling average based on the installation and operation of LNB/SOFA with a 3-year compliance deadline.[12] Although EPA did not specifically solicit comments on this proposal, Entergy proposed a rolling 30-boiler-operating day average emission rate of 1,342.5 lb NOx/hr at each coal-fired unit at White Bluff and Independence to address the potential for a higher NOx emission rate at operating rates of less than 50% of unit capacity.[13] And, in the alternative, Entergy suggested a bifurcated emission limit a limit of 1,342.5 lb NOx/hr, based on a rolling 30-boiler operating day average for all unit operation (0-100% of capacity), and a limit of 0.15 lb NOx/MMBtu, based on a rolling 30-boiler operating day average, to include only those hours for which the unit was dispatched at 50% or greater of maximum capacity.[14]

The Final FIP requires the units at White Bluff and Independence to each meet NOx emission limits of 0.15 lb/MMBtu on a rolling 30-boiler operating day basis at loads of 50-100 percent of maximum heat input rating and a rolling 3-hour average limit of 671 lb/hr at loads of less than 50 percent of maximum heat input rating.[15] These emission limits, which must be met beginning April 27, 2018, are based on the installation of LNB/SOFA on each unit.[16] It cannot be said that the Final FIP's averaging period and emission limits are a logical outgrowth of the proposed rule, as EPA suggests.[17] For the reasons explained in Entergy's Petition, these limits and averaging periods are unworkable for low-load operation and will result in exceedances of the limit.[18]

The Final FIP's averaging period and limits are arbitrary and capricious, unprecedented, and exceed the bounds of a "logical outgrowth" of the proposed FIP. As it stands, the Final FIP is "in violation of the procedures mandated by the notice and comment provisions of the APA." *Am. Fed'n of Labor & Cong. of Indus. Organizations v. Donovan,* 757 F.2d 330, 340 (D.C. Cir. 1985). Thus, EPA must revise the averaging time to a 30-boiler-operating day period and the limit to the achievable value specified in the Entergy Petition to allow the unavoidable NOx spikes that occur during start-ups and load changes to level off over the averaging period, which results in a limit that is possible to achieve.

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[12] 80 Fed. Reg. at 18970, 18997.
[13] Entergy Arkansas, Inc. Comments on the Proposed Regional Haze and Interstate Visibility Report Federal Implementation Plan for Arkansas, Docket No. EPA-R06-OAR-2015-0189 (Aug. 7, 2015), at 51-52.
[14] *Id.*
[15] 40 C.F.R. §§ 52.173(c)(6)-(8); 81 Fed. Reg. at 66344
[16] 81 Fed. Reg. at 66344.
[17] 81 Fed. Reg. at 66344.
[18] *See* Entergy Petition.

C. Independence should not have been included in the Final FIP.

AECC believes that the intent of the Regional Haze Rule is to place primary emphasis during the first planning period on BART-eligible units and the secondary emphasis on units that are not BART-eligible *only* if the state was not meeting its visibility goals. Arkansas is meeting its visibility goals and, therefore, units that are not BART-eligible should not be addressed during the first planning period.

Arkansas is meeting its visibility goals. Plus, EPA agrees that Independence is not a BART-eligible unit.[19] Therefore, Independence should be excluded from the first regional haze planning period as controls are not required at this time. EPA did not appropriately analyze which sources, if any, should be controlled for reasonable progress on visibility and did not follow the procedures it has regularly used in other regional haze FIPs. Further, emission limits on Independence during the first planning period are unnecessary to demonstrate reasonable progress as Arkansas already is below the glide path for the first planning period. In short, it is an impermissible overreach to include Independence.

In its Final FIP, EPA claimed that it began its reasonable progress analysis by determining "whether additional controls on Arkansas sources are necessary to make reasonable progress in the first regional haze planning period."[20] The EPA's analysis is flawed and unprecedented, given that the proposed emission limits for Independence, as well as other sources in Arkansas, are not necessary to achieve reasonable progress for background visibility.[21] The CAA requires regional haze implementation plans to determine whether reductions in a source's emissions are *necessary* to achieve reasonable progress for the planning period under consideration. 42 U.S.C. § 7491(b)(2). Moreover, ""neither the Clean Air Act nor the Regional Haze Rule requires source-specific analysis in the determination of reasonable progress goals." *Texas v. EPA*, 829 F.3d 405, 428 (5th Cir. 2016) (quoting *Wildearth Guardians v. EPA*, 770 F.3d 919, 944 (10th Cir. 2014)).

According to the IMPROVE monitoring data submitted by EAI,[22] Caney Creek and Upper Buffalo already are meeting the EPA's proposed RPGs and Arkansas' RPGs and that visibility impairment continues to trend downward. Because Arkansas' Class I areas already surpassed the RPGs and the URP goals, reasonable progress controls during the first planning period are not necessary to ensure reasonable progress towards the natural visibility goals, as stated in 42 U.S.C. § 7941(b)(2).

Essentially, it appears that, for certain regional haze SIPs and FIPs, EPA deemed a control to be "reasonable" if it is "cost-effective."[23] This is concerning because it does not

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[19] 81 Fed Reg. at 66336, 66350.
[20] 81 Fed. Reg. at 66350.
21 Entergy submitted IMPROVE data that further confirms that visibility in the two Arkansas Class I areas are already better than the RPGs that EPA finalized for the areas. *See* Entergy Petition.
[22] Entergy Arkansas Inc., Supplemental Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, Docket No. EPA-R06-OAR-2015-0189 (submitted on Aug. 8 2016). ADEQ also submitted data showing that Caney Creek and Upper Buffalo will be below the glide path in 2018. State of Arkansas, State Implementation Plan Review for the Five-Year Regional Haze Progress Report, at 55-56 (May 2015).
[23] 81 Fed. Reg. at 66353.

consider the costs in relation to visibility improvement or lack thereof. The Final FIP requires controls on Independence because it alleges the plant is "a significant source of SO2 and NOx" and controls would be cost-effective. Whether or not a plant is a significant source of visibility impairing pollutants is not a statutory factor that states must consider in evaluating reasonable progress controls and neither is cost-effectiveness a statutory standard that allows EPA to exceed its jurisdiction.

Specifically, EPA's assertion that Independence warrants additional controls relies entirely on the Ag ency's claim that the controls would be cost -effective, on a dollar per ton basis.[24] EPA gave no consideration to whether the controls and resulting emissions reductions would actually improve visibility in any Class I areas and, in fact, recognized that controls would not be necessary for Arkansas Class I areas to meet their URPs.[25] The absurd result is that EPA is proposing that a public utility and its customers be required to invest more than $1 billion in power plant controls that would have negligible, if any, impacts on visibility in any Class I areas when such measures are unnecessary for Arkansas to achieve its reasonable progress goals. Such a jurisdictional overstep is not legally permissible and should be reconsidered.

III. Request for Administrative Stay

The legal standard for an administrative stay is broader than the standard for a judicial stay. The Clean Air Act provides that EPA may grant a stay if the agency has decided to reconsider the rule. 42 U.S.C. § 7607(d)(7)(B). Under the Administrative Procedures Act, EPA has authority to stay the requirements of a FIP when "justice so requires . . . pending judicial review." 5 U.S.C. § 705. No other conditions are imposed on the Agency's authority to issue a stay. AECC respectfully requests that EPA stay the Final FIP, specifically §§ 52.173(c)(6) -(8) and §§ 52.173(c)(24) -(26). A s this section demonstrates, a stay of the FIP would prevent harms to AECC and its member-owners and will not negatively affect visibility. In addition, a stay will permitwell-justified further consideration of the Final FIP.

Absent an administrative stay AECC and other petitioners will suffer various forms of irreparable injury, harming AECC members and impairing Arkansas' economy. Moreover, t he costs imposed by the Final FI P on electric generation capacity within Arkansas are substantial. The Final FIP will impose approximately $2 billion in costs, and no discernible benefit will accrue during the relevant implementation period covered by the SIP submittal under review, whi ch ends in 2018. Owner/operators of five coal-fired units within Arkansas are required to install scrubbers by October 2021 and LNB/SOFA by April 2018. These costs will likely challenge the economic viability of these units, and it is possible that some of the units will shut down rather than incur the costs of installing the required controls causing additional costs in the form of replacement power.

Installing dry scrubbers on all four units would be a massive undertaking and an extreme financial and technological hardship for AECC. This work would have to begin immediately, as the process requires the entirety of the five years allotted in the Final FIP.

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[24] *Id.*
[25] 80 Fed. Reg. at 18,992.

Of the $2.1 billion that Entergy estimates it would spend for scrubbers on White Bluff and Independence AECC is financially responsible for 35% of the total cost – or approximately $700 million. Based on Entergy's estimates, AECC would need to spend $9 million within the first six months, and $31 million within first 12 months, $84 million within 18 months, and $156 million within 24 months. These estimates do not include the costs for LNB/SOFA which are required to be installed by April 2018.

If Entergy decides to deactivate the units, then AECC must procure replacement power. This would consist of designing, gaining regulatory approval for, constructing, and making operational a new alternative generating unit. Depending on the site that is selected for the new units, rights-of-way will likely need to be obtained. Transmission – both electrical and gas – would need to be planned and built to connect the new units to the grid. Specifically, to construct replacement generation as quickly as possible, AECC must select a location, prepare and submit environmental permit applications, prepare requests for proposals, select vendors, and received Arkansas Public Service Commission approval.

Accordingly, in order to meet the October 2021 deadline, planning must begin immediately to limit, as much as possible, the duration of member exposure to market prices. In the meantime, even maintaining reliability through the purchase of power would require AECC to accelerate planned transmission projects which would only drive up the costs of those projects.

If all four units are shut down in October of 2021, AECC would need to add an estimated 500 megawatts of firm generation capacity. Estimates of the cost of this new replacement generation would be approximately $490 million. The levelized investment recovery costs of this generation capacity to AECC's member cooperatives would be approximately $34 million annually. AECC would also need to add an estimated additional 250 megawatts of replacement generation capacity by year 2026. This would require a further investment of approximately $245 million – or a further increase of approximately $17 million annually to AECC's members.

The Supreme Court has declared that "[o]ne would not say that it is even rational. . . to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits." *Michigan v. EPA*, 135 S. Ct. 2699, 2707 (2015). Moreover, courts have often issued stays to similarly situated petitioners challenging other FIPs. *See, e.g., Texas v. United States EPA*, 829 F.3d 405, 424 (5th Cir. 2016) (staying implementation of Texas FIP imposing over $2 billion in costs); *Oklahoma v. EPA*, 723 F.3d at 1206-07 (staying implementation of rule imposing $1.2 billion in costs).

In addition to the harm that will result absent a stay, AECC has a strong likelihood of success in establishing that EPA exceeded its statutory authority by imposing emission controls that will not affect the reasonable progress goals covered by the first round of implementation plans. State implementation plans must be designed to achieve the reasonable progress goals for the period covered by the plan, *i.e.* the December 2007 to July 31, 2018 period. *Texas v. United States EPA*, 829 F.3d at 429. When Arkansas submitted its plan in 2008, the regulations in effect required states "to set the emissions controls necessary to achieve the reasonable progress goal for 2018." *Id.* (stating that courts assess agency actions according to the effective statutes and regulations at the time

of the relevant activity) (citing *Caring Hearts Personal Home Servs., Inc. v. Burwell*, 824 F.3d 968, 971 (10th Cir. 2016)).

In its Final FIP, EPA stated:

> In this instance, we are taking final action on the Arkansas Regional Haze FIP 9 years after the state's initial SIP submission was due. As a result, only some of the control measures that we have determined are necessary to satisfy the BART and reasonable progress requirements will be installed by the end of 2018. Some controls will not be installed until 2021.[26]

Measures that would be implemente d at the end of or after the 2018 period are not appropriate for inclusion in a FIP that is purportedly filling a gap in the 2008 SIP revision covering a period to end in 2018. The regional haze planning process requires "control strategies to cover an initial implementation period extending to the year, 2018, with a reassessment and revision of those strategies, as appropriate, every 10 years." [27] Thus, it is improper for EPA to prescribe controls that are not required until the end of the first planning period, or thereafter, given that such con trols will not affect the reasonable progress goal for the first implementation period. Even if such controls were determined appropriate for this planning period, the 18-month compliance date is unjustifiable, was implemented without allowing interested p arties an opportunity to comment in contravention of due process, and materially deviates from other FIP compliance dates.

As demonstrated above, a stay is in the public interest and necessar y to prev ent irreparable harm to AECC and its members. In contrast, no significant harm will result to either EPA or the public from a stay of the Final FIP, given that Arkansas already is below the glide path and many of the emission reductions and resulting visibility improvements contemplated under the Final FIP will be incremental at best. [28] Thus, EPA should grant AECC's stay request.

IV. Conclusion

For the foregoing reasons, and the reasons set forth in Entergy's Petition, EPA should grant AECC's petition for reconsideration and administrative stay of the Final FIP.

Respectfully submitted,

[26] 81 Fed. Reg. at 66410.
[27] 64 Fed. Reg. at 35,734.
[28] 81 Fed. Reg. at 66386.

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November 23, 2016

VIA EMAIL AND FEDEX

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Mr. Ron Curry
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Re: Petition for Reconsideration and Request for Stay of Entergy Arkansas Inc. et al. of the Arkansas Regional Haze and Interstate Visibility Transport Federal Implementation Plan, EPA Docket No. EPA-R06-OAR-2015-0189

Dear Administrator Curry:

Entergy Arkansas Inc., Entergy Mississippi Inc., and Entergy Power, LLC (collectively "Entergy") respectfully submit the enclosed Petition for Reconsideration and Request for Stay ("Petition") of the U.S. Environmental Protection Agency's ("EPA" or "Agency") final "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan" ("Final FIP"). 81 Fed. Reg. 66,332 (Sept. 27, 2016).

The Petition includes exhibits that contain Confidential Business Information for Entergy and for a third party. The exhibits have been partially redacted to remove non-pertinent information and are clearly marked as "Redacted and Confidential Business Information." Entergy also is providing a copy of the exhibits without the aforementioned confidential exhibits. Due to their length, both versions of the exhibits to the Petition are being provided on the enclosed CDs. An additional copy of the Petition is enclosed to be time-stamped and returned in the attached envelope.

Thank you for your consideration of the enclosed Petition for Reconsideration and Request for Stay. If you have any questions, please contact me at (202) 639-7728.

Sincerely,

Debra J. Jezouit
Counsel to Entergy Services Inc.

Enclosures

cc: The Honorable Gina McCarthy, Administrator
U.S. Environmental Protection Agency

BEFORE THE UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY

In re:	)	EPA Docket No.
	)	
Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan	)	EPA-R06-OAR-2015-0189

Petition for Reconsideration and Request for Stay of Entergy Arkansas Inc., et al., of the Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan

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Entergy Arkansas Inc. ("EAI"), Entergy Mississippi Inc. ("EMI"), and Entergy Power, LLC (collectively "Entergy") respectfully submit this petition for reconsideration and request for stay ("Petition") of the U.S. Environmental Protection Agency's ("EPA" or "Agency") final "Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan" ("Final FIP").[1] As discussed below, Entergy requests that EPA reconsider and stay elements of the Final FIP that relate to Entergy's White Bluff and Independence plants. To avoid the significant, irreparable harms that already have begun to occur, Entergy respectfully requests that EPA take action on this Petition by February 1, 2017. The administrative stay requested by Entergy would not cause adverse visibility impacts in Arkansas' Class I areas.

I. INTRODUCTION AND SUMMARY

The Final FIP affects four coal-fired electric generating units owned by Entergy: two at the White Bluff Electric Power Plant ("White Bluff") and two at the Independence Steam Electric Station ("Independence"), which will impose costs on Entergy, its co-owners and its customers of approximately $2 billion for minimal visibility benefits. Specifically, the Final FIP requires each coal-fired unit at White Bluff and Independence to meet a sulfur dioxide ("SO_2") emission limit of 0.06 lb/MMBtu by October 27, 2021.[2] This emission limit is based on the installation of a dry scrubber (flue gas desulfurization ("FGD") technology) on each unit. The Final FIP also will require each coal-fired unit to meet a nitrogen oxides ("NOx") emission limit of 0.15 lb/MMBtu on a rolling 30-boiler operating day basis at loads of 50-100 percent of maximum heat input rating, and a rolling 3-hour average limit of 671 lb/hr at loads of less than 50 percent of maximum heat input rating.[3] These emission limits, which must be met beginning

[1] 81 Fed. Reg. 66,332 (Sept. 27, 2016).
[2] *Id.* at 66,339, 66,416, 66,420.
[3] *Id.* at 66,416-17.

April 27, 2018, are based on the installation of low-NOx burners and separated overfire air ("LNB/SOFA") on each unit.

The Petition must be granted because EPA failed to provide adequate notice and opportunity to comment on significant, burdensome requirements in the Final FIP that affect the requirements imposed on Entergy's units, are of central relevance to the outcome of the Final FIP, and are not logical outgrowths of the proposed rule ("Proposed FIP").[4] Additionally, the Final FIP contains clear errors that must be corrected. These administrative shortcomings demand reconsideration and a stay of key elements of the Final FIP. Specifically, Entergy requests that EPA reconsider the following:

- the imposition of reasonable progress controls on Independence;
- EPA's determination that dry FGD technology constitutes best available retrofit technology ("BART") for White Bluff for SO_2 emissions;
- the 18-month deadline for installation of NOx controls at White Bluff and Independence;
- the adoption of source-specific NOx BART in lieu of reliance on the emissions reductions resulting from implementation of the Cross-State Air Pollution Rule ("CSAPR");[5] and
- the NOx limit and three-hour averaging period for NOx compliance that applies when units at White Bluff and Independence operate at low loads.

A stay of certain requirements in the Final FIP is necessary because justice so requires and to avoid irreparable harm to Entergy and its co-owners, customers, and communities while EPA reconsiders the Final FIP, and while the U.S. Court of Appeals for the Eighth Circuit ("Eighth Circuit") considers Entergy's petition for review of those requirements.[6] The pollution controls at White Bluff and Independence required by the Final FIP would cost approximately *$2 billion* to design, permit, purchase, and install. Absent a stay, Entergy will be forced to make a costly Hobson's choice: (1) commence designing, permitting, purchasing, and installing the required controls immediately; or (2) commence planning to decommission White Bluff and Independence by the Final FIP compliance deadline in 2021. Either course of action causes irreparable harm. The first option would require Entergy to expend $150 million or more just within the next 18 months that could be rendered entirely unnecessary by a grant of reconsideration. The second option would require an array of costly steps planning for decommissioning the units and would ultimately lead to a host of significant harms to Entergy and its co-owners, customers, and local economies. Furthermore, Entergy could not avoid these harms by changing course at a later date, because it will either already have expended multiple millions of dollars on equipment that will serve no purpose (if it initially selected the first option), or it will be too late to install the controls in time to meet the deadline (if it initially selected the second option).

[4] 80 Fed. Reg. 18,944 (Apr. 8, 2015).

[5] *See* Petition for Reconsideration and Request for Administrative Stay of Arkansas Department of Environmental Quality, at 5-8 (Nov. 22, 2016) (hereinafter "ADEQ Petition").

[6] Specifically, Entergy seeks a stay of 40 C.F.R. §§ 52.173(c)(6)-(8) with respect to White Bluff and §§ 52.173(c)(24)-(26) with respect to Independence.

A stay would avoid irreparable harm yet would have no adverse impact on visibility in either Arkansas Class I area, as monitoring data show that current visibility already is better than the reasonable progress goals ("RPGs") established by EPA for this implementation period and that visibility in the Class I areas continues to improve.

Immediate action on this Petition is urgently needed to avoid the harms described herein. Therefore, Entergy respectfully requests that EPA take action in response to this Petition by February 1, 2017. In the absence of a grant of reconsideration and stay by that time, Entergy will consider the Petition to be denied, unless the parties have jointly agreed to a longer period of time for EPA to take action on the Petition.

II. DESCRIPTION OF PETITIONERS

EAI is an electric utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in portions of Arkansas. EAI provides electrical utility service to approximately 712,000 electric customers, deriving 81 percent of its operating revenues from electric customers in 2015. EAI owns portions of White Bluff and Independence and operates both plants. EAI is a regulated utility company subject to the rate and general operating jurisdiction of the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). All of the common stock of EAI is owned by Entergy Corporation.

EMI is an electric utility engaged primarily in the generation, purchase, transmission, distribution and sale of electricity in portions of Mississippi, and is a co-owner of Independence. EMI provides electrical utility service to approximately 447,000 electric customers, deriving 89 percent of its operating revenues from electric customers in 2015. EMI is a regulated utility company subject to the rate and general operating jurisdiction of the Mississippi Public Service Commission and FERC. All of the common stock of EMI is owned by Entergy Corporation.

Entergy Power, LLC is an electric utility company that sells electric energy at wholesale and is a co-owner of Independence. Its principal business office is located in Little Rock, Arkansas. Entergy Power, LLC is an indirect wholly owned subsidiary of Entergy Corporation.

III. REQUEST FOR RECONSIDERATION

A. Reconsideration Is Required Under Clean Air Act Section 307(d)(7)(B).

EPA *must* grant reconsideration of a final action when a petitioner "can demonstrate to the Administrator that it was impracticable to raise [an] objection [during the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule."[7] In such a situation, reconsideration is mandatory, as the Clean Air Act ("CAA") commands that EPA "*shall* convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed."[8] EPA must grant this Petition because

[7] 42 U.S.C. § 7607(d)(7)(B).
[8] *Id.* (emphasis added).

(1) Entergy's objections are to actions EPA took in the Final FIP, or developments since the comment period closed, and thus could not have been raised during the comment period on the Proposed FIP; (2) the objections arose during the period for judicial review; and (3) the objections are of central relevance to the outcome of this rulemaking.

Reconsideration also is appropriate to correct clear errors, as the CAA provides for judicial invalidation of rules if errors are "so serious and related to matters of such central relevance to the rule that there is a substantial likelihood that the rule would have been significantly changed if such errors had not been made."[9] EPA should grant this Petition to address serious errors that are of central relevance to the Final FIP.

B. EPA Should Reassess its Imposition of Reasonable Progress Controls on Independence in Light of More Recent Air Quality Data and Corrected Contribution Data.

Data that became available after the close of the public comment period on the Proposed FIP confirm that reasonable progress controls on Independence for the first planning period are wholly unnecessary. Additionally, EPA's reasonable progress analysis relies on a false characterization of Independence's contribution to visibility impairment in Class I areas. EPA should reconsider the Final FIP and the controls on Independence in light of more recent air quality data, as well as corrected data regarding Independence's contribution to visibility impairment.

According to Interagency Monitoring of Protected Visual Environments ("IMPROVE") monitoring data for 2015, which became available subsequent to the close of the comment period, visibility continues to improve at a greater rate than the uniform rate of progress ("URP") in the Caney Creek Wilderness Area ("Caney Creek") and the Upper Buffalo Wilderness Area ("Upper Buffalo").[10] In addition, the recent IMPROVE data further confirm that visibility in the two Arkansas Class I areas already is better than the RPGs that EPA finalized for the areas. EPA set the RPGs for the 20 percent worst days at 22.47 deciviews ("dv") for Caney Creek and at 22.51 dv for Upper Buffalo.[11] The recent IMPROVE data for both Class I areas demonstrate that monitored visibility impairment in the areas already is well below EPA's RPGs, as well as Arkansas' RPGs, and that visibility impairment is continuing to trend downward.[12] Given that Caney Creek and Upper Buffalo already have surpassed the URP goals, Arkansas' RPGs, and EPA's final RPGs for the first planning period, reasonable progress controls during the first planning period are not "*necessary*" to ensure reasonable progress towards the natural visibility goal.[13] There is simply no standard of reasonable progress that necessitates controls on

[9] 42 U.S.C. § 7607(d)(8).
[10] Assessment of Recent Class I Area IMPROVE Monitoring Data prepared by Trinity Consultants, Inc., at 3 (Aug. 8, 2016, updated Nov. 15, 2016) (hereinafter "Trinity Report") (attached as Exhibit A).
[11] 81 Fed. Reg. at 66,354.
[12] Trinity Report at 3. Actual visibility impairment at Caney Creek in 2015 was 20.41 dv, below Arkansas' RPG of 22.48 dv and EPA's final RPG of 22.47. Actual visibility impairment at Upper Buffalo in 2015 was 19.96 dv, below Arkansas' RPG of 22.52 and EPA's final RPG of 22.51. *Id.*
[13] *See* 42 U.S.C. § 7491(b)(2) (requiring regional haze implementation plans to contain measures "necessary to make reasonable progress toward meeting the national goal").

Independence for this planning period, especially in light of the fact that the Regional Haze Program is designed to achieve its goals over a long horizon – by 2064.

EPA also should reconsider the need for NOx controls on Independence based on a corrected understanding of the plant's contribution to visibility impairment. In the Final FIP, EPA justified the need for NOx controls on Independence based on a false characterization of the plant's contribution to visibility impairment. EPA stated that, "Entergy's CAMx modeling shows that nitrate from Independence is responsible for 30 – 40% of the visibility impairment in Arkansas' Class I areas on 2 of the 20% worst days."[14] This statement is false and must be corrected. EPA's statement indicates that on two of the 20 percent worst days, *30-40 percent of all impairment* at Arkansas' Class I areas is due to nitrates derived from NOx emissions from Independence. In reality, *30-40 percent of the impairment on these days that is due to nitrates* is attributable to Independence. But nitrates are a minute portion of visibility impairment at Arkansas' two Class I areas. The average total nitrate contribution from Independence to visibility impairment on these days is only 0.02 percent at Upper Buffalo and 0.03 percent at Caney Creek. Thus, the actual contribution is over three orders of magnitude less than EPA stated.

Entergy had no opportunity to comment on this mischaracterization of Independence's nitrate contribution to visibility impairment, which is of central relevance to the outcome of the rule. EPA should correct this mischaracterization and clearly acknowledge that the contribution of Independence to visibility impairment in Arkansas' Class I areas is almost meaningless.

In sum, EPA should reconsider the necessity of reasonable progress controls for Independence in light of the recent IMPROVE monitoring data as well as a corrected assessment of Independence's contribution to visibility impairment in Arkansas' Class I areas.

C. The SO_2 BART Determination in the Final FIP for White Bluff Failed to Consider Critical Information.

1. EPA materially misunderstood Entergy's comments regarding EPA's proposed SO_2 BART determination for White Bluff.

The Final FIP imposes SO_2 limits on White Bluff Units 1 and 2 premised on the installation of dry FGD, which EPA found to be cost-effective based on a 30-year amortization period.[15] EPA failed to consider Entergy's proposal to cease combusting coal in 2027 and 2028, which would limit the remaining useful coal-fired lives of the units and significantly alter the cost-effectiveness of SO_2 controls.[16] Entergy had no notice of or opportunity to timely comment

[14] 81 Fed. Reg. at 66,359.
[15] *Id.* at 66,335, 66,360.
[16] Entergy Arkansas Inc. Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, at 5 (Aug. 7, 2015) (Docket ID No. EPA-R06-OAR-2015-0189-0153) (hereinafter "EAI Comments") (attached as Exhibit B).

on EPA's failure, which was only evident in the Final FIP and EPA's associated Response to Comments.[17]

In the Final FIP, EPA unreasonably mischaracterized Entergy's White Bluff proposal, resulting in the Agency's failure to properly determine BART for White Bluff Units 1 and 2. EPA acknowledged that a binding requirement to cease combustion of coal at White Bluff would limit the remaining useful lives of Units 1 and 2 for the purpose of evaluating SO_2 controls, but mistakenly assumed that Entergy had not offered such a proposal. EPA explained, "If Entergy's alternative proposal had included accepting a binding requirement to burn only natural gas at White Bluff Units 1 and 2 after coal combustion ceases, or a binding requirement to completely shut down the units, *then we would agree that it would be appropriate to assume that SO_2 emissions from White Bluff will be zero beginning in 2027/2028*."[18] However, contrary to EPA's assertion, Entergy explicitly made such a commitment in its comments on the Proposed FIP:

> As part of a multi-unit plan to improve visibility and to better manage its generation assets for reliability and costs, Entergy proposes to cease burning coal at White Bluff Units 1 and 2 by 2027 and 2028, one unit per year, *and is prepared to take an enforceable commitment to that effect*.[19]

EPA's conclusion that Entergy "does not propose…adopting a binding requirement to burn only natural gas or completely shut down the units"[20] is inexplicable in light of the plain language of Entergy's proposal. Because EPA determined that a binding requirement to cease burning coal would allow the Agency to assume that SO_2 emissions would be zero subsequent to the cessation of coal combustion, EPA must reconsider the SO_2 BART determination for White Bluff. Failure to do so is unreasonable and arbitrary and capricious.

EPA also asserted that Entergy's proposal to cease using coal at White Bluff appeared tied to EPA's acceptance of Entergy's separately proposed emission limits for Independence.[21] That assertion is incorrect. Nowhere in its comments did Entergy claim that its acceptance of a binding requirement to cease burning coal at White Bluff Units 1 and 2 was contingent on EPA's agreement to the emission limits that Entergy was proposing for Independence. Although Entergy proposed an approach addressing all four coal-fired units at White Bluff and Independence and provided modeling of its proposal demonstrating that its approach would achieve virtually the same visibility benefits as EPA's Proposed FIP for significantly less cost,[22] Entergy did not indicate that its proposed emission limits for Independence were a necessary element of its White Bluff proposal. In fact, in its comments, Entergy explicitly stated that the

[17] 81 Fed. Reg. at 66,335, 66,360; Response to Comments for the Federal Register Notice for the State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan, at 52-54 (Aug. 31, 2016) (Docket ID No. EPA-R06-OAR-2015-0189-0187).
[18] 81 Fed. Reg. at 66,356-57 (emphasis added).
[19] EAI Comments at 5 (emphasis added).
[20] 81 Fed. Reg. at 66,356.
[21] *Id.* at 66,358 ("Entergy's comments provide no indication that it is willing to accept a binding requirement to cease coal combustion at White Bluff by 2027/2028, unless we also accept the elements of its alternative proposal that are applicable to Independence as satisfying the reasonable progress requirements.").
[22] EAI Comments at 45-46.

interim emissions reductions it offered, which included the emission limits for Independence, were a *complement* to its proposal for White Bluff.[23]

2. EPA did not account for Entergy's proposal regarding the remaining useful life of White Bluff in analyzing SO_2 controls.

Had EPA appropriately characterized Entergy's proposal for White Bluff, EPA would have used a shorter remaining useful life for White Bluff in its BART analysis. Proper accounting of remaining useful life is critical because, as EPA acknowledged in the Final FIP, "a shorter remaining useful life [at White Bluff Units 1 and 2] might result in a conclusion that dry scrubbers are not cost-effective…."[24] Indeed, as explained in Entergy's comments, Entergy's proposal for White Bluff rendered EPA's proposed BART determination inapplicable, requiring EPA to undertake a new BART analysis to address the remaining useful coal-fired life of the units.[25] Because EPA's FGD cost-effectiveness analysis failed to take into account Entergy's proposed binding commitment to cease combusting coal at White Bluff, a failure on which Entergy could not previously have provided comment, EPA must reconsider this issue. In doing so, EPA also should reconsider the cost-effectiveness of dry scrubbers in light of the correct control cost information, as explained in the following section.

3. Dry FGD is not cost-effective at White Bluff.

EPA calculates that installing and operating dry FGD at White Bluff would cost $2,565 per ton of SO_2 removed for Unit 1 and $2,421 per ton of SO_2 removed for Unit 2.[26] However, these cost estimates fail to account for Entergy's proposal, discussed above, regarding the remaining useful life of the units as well as data regarding the actual cost of controls. Had this information been properly considered, EPA should have estimated that the costs per ton of SO_2 removed would range from approximately $7,100 to $8,000 per ton of SO_2 removed, which is patently *not* cost-effective.[27]

EPA's cost estimate *failed to include over $495 million* that Entergy will be required to incur to install dry FGD on the White Bluff units.[28] EPA rejected certain costs in the analysis prepared for Entergy by Sargent & Lundy because Entergy did not provide to EPA the underlying 2009 and 2013 Alstom quotes on which Sargent & Lundy's cost analysis relied.[29] Because Entergy had no notice that EPA would require submission of these quotes, which contain non-public, highly confidential and proprietary information, to validate Entergy's cost analysis, Entergy is providing redacted versions of these quotes now.[30] The Alstom quotes

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[23] *Id.* at 4 ("Entergy is prepared to offer meaningful interim emission reductions to complement its proposed commitment to cease coal-fired operations at White Bluff and assure that Arkansas remains on a path that is below the URP for the long term.").
[24] 81 Fed. Reg. at 66,356.
[25] EAI Comments at 5.
[26] 81 Fed. Reg. at 66,386.
[27] Memorandum from Sargent & Lundy (Nov. 18, 2016) (hereinafter "Sargent & Lundy Memo") (attached as Exhibit C).
[28] *See* Sargent & Lundy Memo at 2.
[29] 81 Fed. Reg. at 66,383.
[30] 2009 Alstom Report (attached as Exhibit D) and 2013 Alstom Report (attached as Exhibit E). These reports contain confidential business information. Non-pertinent information has been redacted.

demonstrate that EPA improperly excluded extensive costs associated with "Balance of Plant" items, which are items not included in the FGD supplier's scope, but which are necessary to integrate the FGD system into the plant.[31] The quotes also demonstrate that EPA underestimated escalation by using the Chemical Engineering Plant Cost Indices ("CEPCI") instead of relying on more accurate information from the vendor.

The more detailed and accurate cost analysis prepared by Sargent & Lundy, which includes costs improperly excluded by EPA and correctly predicts tons removed, estimates that dry FGD cost-effectiveness will range from approximately $7,100 to $8,000 per ton if the units cease combusting coal in 2027-2028.[32] Even if certain costs rejected by EPA were excluded in Sargent & Lundy's cost estimate (i.e., allowance for funds used during construction ("AFUDC"), escalation, and owner's costs), the cost-effectiveness of dry FGD at White Bluff would range from approximately $5,400 to $6,100 per ton.[33] Regardless of which estimate is used, these costs exceed those that EPA has previously rejected in other BART analyses and thus are too high to represent BART for the White Bluff units.[34] As a result, dry FGD cannot constitute SO_2 BART for White Bluff Units 1 and 2. Accordingly, EPA should reconsider the White Bluff SO_2 BART.

4. EPA must reconsider SO_2 BART for White Bluff even in the absence of a DSI analysis.

In the Final FIP, EPA argues, for the first time, that it would be necessary to assess dry sorbent injection ("DSI") as an interim control if the White Bluff units cease to combust coal, and indicates that this lack of DSI analysis somehow negates EPA's obligation to conduct a reasonable BART analysis of dry FGD at the White Bluff units. Entergy did not have notice of or an opportunity to comment on this assertion, which is of central relevance to the Final FIP. The lack of a DSI analysis, which EPA had not previously requested, does not absolve EPA of its obligation to properly assess the cost-effectiveness of dry FGD.

EPA explains in the Final FIP that "[b]ecause Entergy has provided no analysis to demonstrate that there is no more effective interim SO_2 control that would constitute BART, the company's proposed strategy is not adequate to ensure that the BART requirements for White Bluff Units 1 and 2 will be met."[35] EPA ties the lack of a DSI analysis to its determination that it

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[31] Upon further review, Sargent & Lundy determined that costs associated with ductwork downstream of the booster fans were included in the Alstom quote. The updated cost estimates in this Petition remove these costs. Sargent & Lundy Memo at 2.
[32] *Id.* at 3.
[33] *Id.*
[34] EPA declined to impose dry FGD as BART in Arizona, where the average cost effectiveness was estimated to be $5,090/ton. Proposed Arizona Regional Haze FIP, 79 Fed. Reg. 9,317, 9,331-33 (Feb. 18, 2014); Final Arizona Regional Haze FIP, 79 Fed. Reg. 52,420, 52,436 (Sept. 3, 2014). In North Dakota, EPA approved the state's determination that a cost effectiveness of $6,525 per ton was excessive for NOx controls and did not constitute BART. Proposed North Dakota FIP, 76 Fed. Reg. 58,570, 58,630 (Sept. 21, 2011); Final North Dakota Regional Haze FIP, 77 Fed. Reg. 20,894, 20,896 (Apr. 6, 2012). And, in Montana, EPA concluded that certain SO_2 controls with a cost effectiveness of $5,442/ton and $6,365/ton were not cost effective. Proposed Montana Regional Haze FIP, 77 Fed. Reg. 23,988, 24,047 (Apr. 20, 2012); Final Montana Regional Haze FIP; 77 Fed. Reg. 57,864, 57,866 (Sept. 18, 2012).
[35] 81 Fed. Reg. at 66,356.

need not even consider Entergy's finding that FGD is not cost-effective in light of its proposal for White Bluff. This is a false premise; the appropriateness of DSI as an interim control measure is irrelevant to the assessment of whether dry FGD is cost-effective. As outlined above, EPA failed to account for the proposed remaining useful life of Units 1 and 2 when assessing dry FGD as a control technology, as well as certain costs associated with such controls, and must do so now on reconsideration. To the extent that EPA *also* believes that an assessment of DSI as a potential control technology is warranted, such assessment is wholly independent of the FGD assessment.

Despite the fact that EPA's request for a DSI analysis arose for the first time in the Final FIP, Entergy is willing to develop and provide the analysis if EPA grants reconsideration on SO_2 BART for White Bluff. Additionally, Entergy understands that the Arkansas Department of Environmental Quality ("ADEQ") will develop a state implementation plan ("SIP") to replace portions of the Final FIP, including the BART controls for White Bluff, and Entergy will submit a DSI analysis to ADEQ, if required, as part of the SIP development process.

D. EPA's LNB/SOFA Assumptions Are Unsupported and Unreasonable, and Must Be Revised.

EPA should reconsider whether NOx controls should be required for either White Bluff or Independence. As addressed in Section III.A above, NOx controls on Independence to address reasonable progress are unnecessary for this first planning period. Further, EPA should reconsider its imposition of source-specific NOx BART controls in the Final FIP and instead determine that compliance with CSAPR is acceptable for compliance with the NOx BART requirements in Arkansas, including for White Bluff, as addressed more fully in ADEQ's Petition for Reconsideration and Request for Administrative Stay.[36]

However, if EPA denies reconsideration on these threshold issues, EPA must grant reconsideration on the compliance deadline and NOx emission limits applicable to both White Bluff and Independence. The compliance deadline and NOx limits are not logical outgrowths of the Proposed FIP, are not reasonable and fraught with errors, and are of central relevance to EPA's determination of NOx BART in the rulemaking.

1. EPA must extend the 18-month timeline for the installation of LNB/SOFA to Three Years.

a. The 18-month deadline is not a logical outgrowth of the proposed rule and was promulgated in error.

The Final FIP unlawfully shortens the compliance deadline for the NOx emission limits for White Bluff and Independence from three years to 18 months.[37] EPA proposed a three-year NOx compliance deadline for these plants and did not indicate in the Proposed FIP that it was considering a shorter deadline. The 18-month deadline is not a logical outgrowth of the proposed compliance deadline. While Entergy stated in its comments that it was prepared to

[36] ADEQ Petition at 5-8.
[37] 81 Fed. Reg. at 66,338, 66,354.

meet the proposed three-year deadline,[38] it lacked notice and had no opportunity to comment on its ability to comply with a shortened compliance deadline.

EPA erred in relying on comments from environmental organizations when contracting the compliance timeline.[39] First, the environmental organizations requested a shorter compliance deadline only for White Bluff, not for Independence.[40] Indeed, while the organizations asserted that LNB/SOFA could be installed on Independence in under a year, the comment concluded that "three years is more than reasonable."[41] Even if the environmental organizations had requested a shortened compliance deadline for both plants, it is well-established that EPA "cannot bootstrap notice from a comment." *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 549 (D.C. Cir. 1983); *Am. Fed'n of Labor v. Donovan*, 757 F.2d 330, 340 (D.C. Cir. 1985).

Further, the environmental organizations' comments on installation of LNB/SOFA fail to provide a reasonable justification for the shorter compliance timeline. The comments were based on an expert report, which, in turn, relied on a 10-year-old vendor association report that did not consider permitting considerations, a company's internal project development and approval process, site-specific factors, or reliability concerns.[42] The vendor association report explicitly recognized that "[v]ariations in the schedule may occur due to site specific conditions that may increase or decrease the typical deployment time."[43] The vendor report also does not appear to allow sufficient time for testing and optimization of equipment, providing only one week for commissioning and startup.[44] Because the environmental organization comments relied on outdated, generic information about timing, they do not provide a proper basis for the shortened deadline for these specific units. Notably, EPA has not even attempted to provide any explanation of how this shorter deadline is reasonable for White Bluff and Independence in light of site-specific and company-specific considerations. Nor does EPA appear to have required such a short timeframe for the installation of controls in other regional haze plans. Even for AEP's Flint Creek plant, where SO_2 control equipment *is installed and functioning already*, EPA granted the company 18 months to make any modifications necessary to ensure the controls can meet the BART limit.[45]

b. The 18-month deadline is unreasonable.

The 18-month deadline to install LNB/SOFA at White Bluff and Independence is infeasible, as it does not guarantee sufficient time to develop, plan, permit, install, tune, and test the equipment. Specifically, a project of this scope requires Entergy to develop a prevention of significant deterioration ("PSD") permit application, obtain a PSD permit, comply with the

[38] EAI Comments at 13-14.
[39] 81 Fed. Reg. at 66,378.
[40] Comments of Earthjustice, National Parks Conservation Association, and Sierra Club at 25 (Aug. 7, 2015) (Docket ID No. EPA-R06-OAR-2015-0189-0153) (hereinafter "Sierra Club Comments").
[41] *Id.* at 39.
[42] *Id.* at 25; Technical Support Document to Comments of Conservation Organizations, Prepared by Victoria R. Stamper, at 46 (Aug. 5, 2015) (Docket ID No. EPA-R06-OAR-2015-0189-0171) (hereinafter "Stamper Report").
[43] Typical Installation Timelines for NOx Emission Control Technologies on Industrial Sources, Institute of Clean Air Companies, at 4 (Dec. 4, 2006), available at https://c.ymcdn.com/sites/icac.site-ym.com/resource/resmgr/ICAC_NOx_Control_Installatio.pdf.
[44] *Id.*
[45] 81 Fed. Reg. at 66,338.

company's internal planning and prudence review procedures, complete a request for proposal ("RFP") process, select a vendor, procure equipment, schedule outages, install equipment, and then tune and test the equipment. Completion of all of these steps will require more than 18 months, even though Entergy already has obtained the necessary PSD permit for White Bluff, and is in the process of developing the PSD permit application for Independence.[46] Entergy would only be able to complete installation and tuning of LNB/SOFA on all four units by the final deadline if it circumvented its internal planning and prudence review procedures and completed the tuning and testing process *after* the compliance deadline.

The internal process that must be completed before the performance of any equipment work is robust, with preparation for this work just getting underway with respect to Independence. First, projects over $20 million, like the installation of LNB/SOFA, are subject to an internal company approval process that includes risk review and investment procedures. This process takes approximately two months and requires approval from several levels of Entergy management. Once the review process has been completed, Entergy can undertake project-specific planning. An engineer will draft project specifications based on the Final FIP requirements and design characteristics, a process that takes approximately two months. These specifications will be included in an RFP, which will be put out for a four- to six-week bidding process. Once a vendor is selected, negotiation of the final contract will take an additional four to six weeks.

Simultaneous to this internal process, Entergy must prepare a PSD permit application for the installation of LNB/SOFA at Independence.[47] Despite the fact that work already is proceeding, the earliest the application will be ready for submittal to ADEQ will be mid-December. ADEQ approval is expected to take, at a minimum, between six and eight months, resulting in permit issuance between mid-June and mid-August 2017, but this process could take longer for a variety of reasons outside of Entergy's control. For example, the permitting process could be extended if significant public comments are received on the draft permit that must be addressed by the ADEQ before a final permit can be issued, due to agency resource constraints, or due to an appeal of the final permit to the Arkansas Pollution Control and Ecology Commission, which, absent additional regulatory proceedings, would result in an automatic stay of the permit pending final resolution of the appeal.

Once the permit is issued and the final contract has been signed, the selected vendor must design and fabricate the equipment, which takes approximately eight months. Outages must be scheduled for all four units, each lasting between six and seven weeks. Once installation is complete, each unit will need to undergo four weeks of boiler tuning and two weeks of performance verification testing to demonstrate that the controls are achieving the anticipated NOx reductions. After this, Entergy will have to perform a final phase of fine-tuning and training. During the final phase, which lasts approximately five months, each unit will undergo a three-month procedure review during which the system description is re-written to include the new equipment and components, and the operating procedures are updated. This process cannot

[46] Although Entergy already has acquired control equipment for one unit at White Bluff, equipment still must be obtained for the second White Bluff unit and both Independence units to comply with the requirements in the Final FIP.

[47] As noted above, Entergy already has obtained a permit to install LNB/SOFA on White Bluff but does not yet have all the equipment needed to do so.

be truncated as it requires the operators to observe performance during all operating scenarios, including startup, shutdown, and periods of load transition. The staff must then be trained on both the system description and the operating procedures, which typically takes a month. An additional month is needed to validate operating configurations to determine which combinations result in the best load profile. It would be imprudent not to complete the entire training and fine-tuning process prior to the compliance deadline.

Even with a truncated schedule, Entergy cannot reasonably expect to meet the 18-month deadline. At best, Entergy could take the following steps, which increase risk and cost without any guarantee of compliance. It could circumvent its normal internal procedures, including its risk and prudence reviews and its process for obtaining competitive bids from multiple vendors. Entergy would be required to perform a more limited risk and prudence review, would have to forgo a complete bidding process in favor of using a pre-selected vendor that can fabricate and install the equipment as quickly as possible, and may even need to engage this vendor prior to having all regulatory approvals in hand. These internal procedures are in place to attempt to ensure cost recovery, and failure to comply with them puts the company at risk of making investments that the APSC later determines are not in the public interest and therefore not eligible for cost recovery. The schedule also does not allow for any delays associated with the PSD permitting process.

Finally, even with these truncated procedures, and assuming final PSD permit issuance in mid-June to mid-August 2017, the timeframe allowed in the Final FIP is insufficient for Entergy to conduct thorough testing and tuning of the NOx control equipment, where unforeseen issues frequently arise and must be addressed to ensure compliance. For example, it is common during the installation process to discover previously unknown equipment issues that complicate installation or hinder the expected performance of the installed equipment. Installation of controls involves many variables and each unit has unique characteristics, resulting in unpredictable challenges. As an example, small, unforeseen differences in mill performance or coal pulverization could result in problems that must be addressed to ensure the LNB/SOFA equipment performs as expected.

In light of these site-specific considerations, including the mandatory regulatory approval process, EPA should grant reconsideration and revise the 18-month deadline to provide the full three years provided in the Proposed FIP for installation of LNB/SOFA at White Bluff and Independence. This will allow time for Entergy to comply with its internal planning and prudence review procedures, to obtain all required approvals, and ensure that the controls are properly tuned prior to the compliance deadline. At a minimum, EPA should grant reconsideration and provide at least 30 months for the installation of LNB/SOFA at White Bluff and Independence as this is the minimum amount of time Entergy anticipates that the NOx compliance deadline could be met even by truncating its internal procedures and barring any unforeseen issues.

2. EPA must revise the NOx limit and averaging period that apply during periods of low load.

In the Final FIP, EPA unlawfully introduced, for the first time, a NOx emission limit of 671 lb/hr on a rolling 3-hour average that applies when the White Bluff and Independence units are operating at less than 50 percent of their maximum heat input capacity.[48] In contrast, EPA had proposed an emission limit of 0.15 lb/MMBtu on a 30 boiler-operating-day rolling average that would apply regardless of the capacity at which the units were operating.[49] Entergy did not have notice of or an opportunity to comment on the significant change in the Final FIP to the limit and averaging period that apply when the units are operating at low loads. Entergy explained in its comments on the Proposed FIP that a higher limit is necessary during periods of low load operation because the LNB/SOFA system is designed to operate primarily in the range of 50-100 percent of unit load, and the vendor would not guarantee that LNB/SOFA could meet a limit of 0.15 lb/MMBtu for operating loads below 50 percent.[50] While Entergy appreciates EPA's apparent attempt to account for periods of low load in the Final FIP, EPA must reconsider the emission rate and averaging period that apply when the units are operating at less than 50 percent of the maximum heat input capacity.

First, Entergy did not have an opportunity to comment on the new emission limit and averaging period that apply during low load operation. EPA has not explained why either the limit that it established or the shorter averaging period are appropriate for either White Bluff or Independence, given that they were not raised or considered in the Proposed FIP or in Entergy's comments. The final limit and averaging period are not logical outgrowths of the Proposed FIP and they are plainly unlawful, arbitrary and capricious. EPA must grant reconsideration of these elements of the Final FIP.

Second, the new averaging period is unworkable for low load operation and will result in exceedances of the limit. During periods of load transition and, in particular, periods of reduced load, NOx is very sensitive to changing conditions such as air flow, fuel flow, and burner tilt position. When load is being ramped up or down, and mills are put in or out of service, NOx can spike to levels well above typical levels for short periods of time. Within minutes of the excursion, NOx typically will return to and stabilize at the steady state level. With the short 3-hour averaging period, a single 15-minute spike in NOx could result in NOx exceeding the low-load NOx emission limit for a 3-hour period, even if the remaining 165 minutes were below compliance levels.[51] A 30-boiler-operating-day period is necessary to moderate the variations in NOx due to load transition and low load.

Finally, the low-load NOx emission limit, which EPA set at one half the limit proposed by Entergy, also is problematic. It offers no compliance margin, which is necessary to account for increased NOx levels that occur as a function of low load operation, and the unavailability of SOFA when the unit is operated at less than 30 percent of capacity. When load falls below 50 percent, NOx levels increase as a percentage of heat input, trending upwards as load is reduced. This phenomenon is due to the increased levels of excess air that are used to ensure safe boiler

[48] 81 Fed. Reg. at 66,344, 66,354.
[49] 80 Fed. Reg. at 18,974, 18,997.
[50] EAI Comments at 50.
[51] *See* Memorandum from Foster Wheeler (hereinafter "Foster Wheeler Memo") (attached as Exhibit F).

operation during low loads. During load swings, control systems lead load increases with increases in air flow and follow load decreases with reductions in air flow. This excess air leads to NOx formation from nitrogen-laden air. Not only are NOx emissions generated at a higher rate at low load, but NOx control options are limited during these periods. SOFA is unavailable when the boiler operates below 30 percent capacity, including during startup, because there is insufficient air to support both good combustion and maintain overfire air flow to the boiler. As a result, the SOFA system cannot provide any NOx reduction during these operational periods.

Accordingly, EPA should reconsider the NOx limit and averaging time that applies to periods of low load operation and adopt the limit requested by Entergy in its comments: a rolling 30-boiler operating day average emission rate of 1,342.5 lb NOx/hr at each coal-fired unit at White Bluff and Independence.[52] At the least, EPA should revise the NOx averaging time to a 30-boiler-operating day period, and the limit to 895 lb/hr.[53] This will allow the inevitable NOx variations to be smoothed out over the averaging period, resulting in a limit that is possible to achieve.

IV. REQUEST FOR STAY

A. EPA Should Grant a Stay Pursuant to the CAA and the APA.

Section 307(d)(7)(B) of the CAA authorizes EPA to stay the effectiveness of a rule for up to three months during reconsideration,[54] which can be extended for additional three-month periods. Additionally, the Administrative Procedure Act ("APA") authorizes EPA to stay the effectiveness of a rule indefinitely. Under the APA, "[w]hen an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review."[55] EPA has applied this standard to CAA actions.[56]

Unlike a judicial stay, an administrative stay does not require a demonstration of irreparable harm. The APA states:

> When an agency finds that justice so requires, it may postpone the effective date of action taken by it, pending judicial review. On such conditions as may be required and to the extent necessary to prevent irreparable injury, the reviewing court . . . may issue all necessary and appropriate process to postpone the effective date of an agency action or to preserve status or rights pending conclusion of the review proceedings.[57]

The APA deliberately contrasts what is required for an administrative stay—"justice so requires"—and a judicial stay—"conditions as may be required" and "irreparable harm." Similarly, CAA Section 307(d)(7)(B) authorizes an administrative stay, but does not premise that

[52] EAI Comments at 49.
[53] Foster Wheeler Memo at 4.
[54] *See* 42 U.S.C. § 7607(d)(7)(B).
[55] 5 U.S.C. § 705.
[56] *See, e.g.,* Prevention of Significant Deterioration ("PSD") and Nonattainment New Source Review ("NSR"): Aggregation, 75 Fed. Reg. 27,643 (May 18, 2010).
[57] 5 U.S.C. § 705. EPA has stayed a rule pursuant to Section 705 even after the rule's effective date has passed. *See Stay of Federal Water Quality Criteria for Metals*, 60 Fed. Reg. 22,228 (May 4, 1995).

stay on a finding of irreparable injury, noting simply that "[t]he effectiveness of the rule may be stayed during such reconsideration…for a period not to exceed three months."[58]

EPA should administratively stay the Final FIP's emission limitations for White Bluff and Independence while it addresses the issues identified above in Entergy's Petition, and while the Eighth Circuit considers Entergy's petition for review of the Final FIP. Specifically, Entergy requests that EPA stay 40 C.F.R. §§ 52.173(c)(6)-(8) with respect to White Bluff and §§ 52.173(c)(24)-(26) with respect to Independence. As explained below, a delay in implementation of the FIP would prevent harms to Entergy, with negligible visibility impact, while the Final FIP is reviewed. An administrative stay also would allow ADEQ time to develop its replacement SIP.

B. Justice Requires that EPA Grant a Stay.

1. Compliance with the SO_2 limits would immediately and irreparably harm Entergy, its co-owners, employees, customers, and communities.

To meet the Final FIP's SO_2 emission limits at White Bluff and Independence, Entergy must make plans for compliance now. Implementation of the Final FIP requires Entergy to make a Hobson's choice as soon as possible to either (1) permit, design, gain regulatory approval for, construct, install, and tune dry scrubbers on all four units by October 27, 2021, or (2) deactivate the units by that date, eliminate 230 Entergy jobs in rural Arkansas,[59] dramatically reduce the local tax revenues, and commit to new resources to replace a significant portion of its generating capacity. Either path for compliance with the SO_2 emission limits at White Bluff and Independence is a complex undertaking that must be pursued independently for each unit, and will result in immediate and irreparable harm to Entergy, its co-owners,[60] and local economies.

To ensure compliance, either path would require Entergy to begin making commitments and significant financial investments in the immediate future and without state agency review of the proposed path. Entergy must pursue both potential paths for as long as there is regulatory uncertainty.[61] Entergy would suffer irreparable harm if it is forced to proceed before EPA acts

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[58] 42 U.S.C. § 7607(d)(7)(B).

[59] Entergy also directly employs several hundred contractors over the course of the year, for both seasonal outage work and ongoing plant support.

[60] As described in petitions for reconsideration of the Final FIP filed by co-owners of the White Bluff and Independence plants, the harms to these co-owners would be significant. For example, deactivation of both plants in October of 2021 would create the immediate need to add an estimated 500 megawatts ("MW") of firm generation capacity to the Midcontinent Independent System Operator ("MISO") side of the Arkansas Electric Cooperative Corporation ("AECC") system. This replacement capacity is estimated to require the investment of $490,000,000. The levelized investment recovery cost of this generation capacity to AECC's member cooperatives would be approximately $34,000,000 annually. Jonesboro City Water and Light estimates that replacement of its share of ownership of the generation capacity of the White Bluff and Independence units in 2021 would result in increased costs between $16.3 million and $25 million, *in 2021 alone*, which translates to a 17-27 percent increase in customer rates. *See* Petition for Reconsideration and Request for Administrative Stay of AECC and Petition for Reconsideration and Request for Administrative Stay of Energy & Environmental Alliance of Arkansas ("EEAA").

[61] Either choice would cause irreparable harm in so far as significant financial investments would need to be made that could not be reversed if the Final FIP were later revised or vacated. Additionally, due to the lead time needed to install FGD technology or to prepare for permanent retirement, more time is needed to select one of these two options than the Final FIP allows. As described in this section, regulatory reviews are required for both paths, so the

on the Petition and before the Eighth Circuit determines the merits of Entergy's petition for review of the Final FIP. And yet, to meet the compliance deadline, it will be compelled to do so or risk noncompliance with the Final FIP. The first path, installing dry scrubbers on all four units, would be a massive undertaking costing approximately $2 billion. The first phase of this multi-phase project would have to begin as soon as the decision to proceed was made, as the process would require the entirety of the five years allotted in the Final FIP, as explained in further detail below, including spending over $150 million in the first 18 months alone. The second path, deactivating the units, is complicated and costly in different ways, as explained below. Both paths cause Entergy irreparable harm.

Given the lead times for either path, Entergy must start immediately to conduct analyses and reviews to support its internal decision-making process, which will take several months. Entergy's internal review process would assess both approaches, particularly analyzing and comparing the economics of each approach, and would be coordinated with the co-owners of White Bluff and Independence. Assessing the costs of the two approaches is extremely complicated. For example, for EAI to retire an existing generating unit, EAI must provide at least six months' notice to MISO, the regional transmission operator that dispatches White Bluff and Independence, of its intent to retire the unit. Because of the interconnected nature of the electric grid, a decision to retire a unit can have implications for the remainder of the grid, some of which may require upgrades to the transmission system to ensure that the grid can be operated reliably after the generating unit is retired. Accordingly, owners/operators of a generating unit typically would request that MISO perform an "Attachment Y-2 study," which would determine, on a non-binding basis, whether the retirement of the generating unit (i.e., White Bluff or Independence) would impact transmission system reliability, or whether the plant would need to continue to operate until transmission upgrades or other system changes to maintain reliability can be completed. In Entergy's experience, an Attachment Y-2 study takes approximately three to four months for a standard request. However, this situation is far from standard; assessing the retirement of four units totaling nearly 3400 MW of capacity may take much longer. Entergy would incorporate the Attachment Y-2 results into its internal economic analysis. Depending on the time needed to perform the economic analysis, coordinate with co-owners, and obtain the results of MISO's Attachment Y-2 study, this decision-making process would take between six and nine months.

Compliance with the FIP also requires EAI, the operator of all four units, along with the other co-owners of White Bluff and Independence to adhere to other regulatory processes, each unique to each co-owner.[62] In similar cases involving significant capital investments at existing generating units, EAI has sought a declaratory order from the APSC confirming that the selected path is in the public interest.[63] Because EAI is a rate-regulated entity, costs prudently incurred in the provision of electrical service typically are recoverable from customers, but cost recovery can occur only after the costs are reviewed by the APSC and a regulatory rate adjustment is made. In

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compressed timeline mandated by the Final FIP requires Entergy to simultaneously prepare for both paths in the event that the selected path does not earn regulatory approval.

[62] For example, EMI also has regulatory reviews and approvals before the Mississippi Public Service Commission that it must pursue. *See also* Petition for Reconsideration and Request for Stay of Energy and Environmental Alliance of Arkansas.

[63] *See. e.g.,* APSC Docket No. 09-024-U (Seeking public interest finding for installation of environmental controls at White Bluff Units 1 and 2).

other words, a public interest finding addresses the prudence of the investment; it does not address the prudence of the management of the incurrence of the costs nor does it modify base rates or effect other charges to include those costs (which would be the result of a separate review by the APSC in a later proceeding). If cost recovery is not approved or if recovery is significantly delayed, EAI could be deprived of a reasonable opportunity to receive adequate recovery of costs incurred.[64] In either case, the preparation of the application and supporting testimony could take up to six months. Additionally, completion of discovery, an APSC-determined procedural schedule with multiple rounds of testimony from the APSC General Staff, Attorney General, and other intervenors, a public hearing, and the issuance of a final order, could take an additional 14 months to complete. Accordingly, the state regulatory process may take as long as 20 months, and that is prior to any potential challenge by EAI to the APSC's final order, which could include a petition for rehearing and subsequent appeal.

Should Entergy choose to install dry scrubbers on all four units, Entergy would be forced to make considerable expenditures within the next few years, effectively prohibiting any alternative approach. Of the approximately $2 billion that Entergy estimates it would spend for scrubbers on White Bluff and Independence, Entergy would need to spend well in excess of $38 million within the first year, $150 million within 18 months, and $305 million within 24 months.[65]

The work to install the dry scrubbers also would need to begin immediately to comply with the FIP's five-year deadline. During the preliminary engineering phase of the project, which is expected to take between six and 12 months, an engineer would need to develop detailed specification requirements for the engineering, procurement, and construction of the FGD systems. Contractors would need at least three months to develop proposals, and then several weeks would be required to evaluate the proposals and award the contract. Because White Bluff and Independence have different co-owners, two separate FGD contracts would need to be developed. Afterward, the FGD contractor at each plant would proceed with the detailed engineering phase, during which every component required for a complete and operable FGD system would be designed and fabricated. Next, the engineered components would be delivered to the sites and the FGD contractor at each site would erect them and integrate them into the existing plants. A tie-in outage must be taken for each unit so that physical connections to existing systems can be made. Because Entergy would not take simultaneous outages at all four units for reliability reasons, and because there would be two FGD contracts awarded at different times, the construction phase likely would be staggered by approximately one year across all four units. Once constructed, equipment startup and commissioning would occur, followed by operational tuning and performance optimization. Performance testing would then

[64] EAI has elected to be regulated pursuant to Ark. Code Ann. § 23-4-1201 et seq., which provides that a public utility may choose to be regulated under a formula rate review mechanism that provides for an annual streamlined review of a public utility's rates and designation of a test period based on a projected test year. EAI's APSC-approved Rate Schedule No. 44, Formula Rate Plan Rider ("Rider FRP") provides for annual adjustment of customers' rates based on a comparison of EAI's earned return on common equity and its target return rate approved by the APSC. However, pursuant to Ark. Code Ann. § 23-4-1207 and Rider FRP, the annual Rider FRP revenue increase or decrease for each rate class shall not exceed four percent of each rate class' revenue. Accordingly, in complying with the FIP, EAI may pursue cost recovery for those costs pursuant to Rider FRP or other potential cost recovery mechanisms.

[65] These estimates were developed by Sargent & Lundy but do not include the significant costs for AFUDC, escalation and owner's costs that Entergy also will incur. Sargent & Lundy Memo at 5.

be conducted to confirm compliance with emission limits. The FGD contractor would need approximately three years to complete engineering and construction of one unit, followed by up to six months of commissioning, startup, performance optimization, and performance testing.

Alternatively, were Entergy to choose deactivation, the company would have to secure additional regulatory approvals as quickly as possible to provide for a smooth transition to replacement power by the 2021 deadline. The company must provide six months' notice to MISO before a generator can be retired (the "Attachment Y" process described above). .

Entergy next would need to procure and build replacement power because White Bluff and Independence currently are needed for Entergy to provide reliable electricity generation to its customers and meet its obligations to MISO. Entergy's resource planning process would consist of designing, gaining regulatory approval for, constructing, and making operational a new alternative generating unit. Entergy anticipates that the replacement generation would be a combined cycle gas turbine ("CCGT"),[66] which may require construction of a new gas pipeline to the selected site. Depending on the site that is selected for the CCGT, rights-of-way may need to be obtained. Transmission would need to be planned and built to connect the new CCGT with the grid. To construct replacement generation as quickly as possible, Entergy must prepare an environmental permit application, prepare RFPs for the construction, select a vendor, and submit a permit application. The time required for this process means that replacement power would not be available for five years at the earliest, thus exposing customers to market capacity prices in the interim. Accordingly, planning must begin immediately to limit, as much as possible, the duration of customer exposure to market prices. In the meantime, even maintaining reliability through the purchase of power would require Entergy to accelerate planned transmission projects. A project that currently is planned to be completed in 2024 would have to be accelerated to be completed in 2020, at an additional cost of $8 million and with a start date in 2017.

Ceasing operations at White Bluff and/or Independence would cause irreparable harm to Entergy employees and the communities in which they work. The total number of jobs created and supported by the White Bluff plant alone is estimated to be 1,237.[67] Entergy itself employs 105 full-time employees at White Bluff, along with 10 Entergy Service Company employees that support White Bluff full time. White Bluff also employs approximately 300 contractors for at least six weeks in the spring and fall each year for planned outage support. Additionally, there are about 20 contractors that work full time in security, coal dust management, janitorial, lawn maintenance, ash management and scaffolding support. At Independence, Entergy employs 108

[66] White Bluff cannot be replaced by renewable energy. White Bluff provides approximately 1,600 MW of reliable capacity to the MISO system and there are no practical or reasonable renewable generation options to meet the MISO resource adequacy requirements currently satisfied by White Bluff. Replacement of White Bluff would require 3,200 MW of solar power (necessitating 22,000 acres of panels), or 10,000 MW of wind generation (necessitating 7,000 windmills that would have to be located in the plains states hundreds of miles away from Entergy's load). Additionally, there is insufficient biomass fuel available to supply a 1,600 MW replacement biomass plant, and even if sufficient fuel were available, it would take an impracticable amount of trucks to deliver the necessary fuel. None of these options is feasible.

[67] Willie Lee Brooks, Jr., Senior Analyst, Economic & Financial Risk, *What is the Economic Impact of the White Bluff Electric Power Plant?*, at 2, Arkansas Electric Cooperative Corporation (May 30, 2014), available at http://www.arkleg.state.ar.us/assembly/2015/Meeting%20Attachments/890/I12666/HANDOUT%202%20-%20HIGHLEY%20%20Economic%20Impact%20of%20White%20Bluff%20Electric%20Pwr%20Plant.pdf

full-time employees, along with seven Entergy Service Company employees that support Independence full time. Independence also employs 83 contractors, who provide janitorial services, maintenance support, ash disposal services, and work on insulation and scaffolding during outages. If White Bluff and Independence were to cease operations, the company would have to lay off or reassign its employees, and the contractors would be out of work. These shutdowns would have significant impacts on the rural Arkansas communities where the plants are located. For example, the estimated the value of White Bluff to the local economy is $173 million.[68]

2. Compliance with the NOx limits would immediately and irreparably harm Entergy, its co-owners, employees, customers, and communities.

As explained above in Section III.D, the 18-month deadline to install LNB/SOFA at White Bluff and Independence is infeasible, as it does not provide sufficient time to develop, plan, permit, install, and appropriately tune the equipment. Entergy could complete installation of LNB/SOFA at all four units by the final deadline only by circumventing its normal internal procedures and the tuning and training process. Entergy would be forced to perform a more limited risk and prudence review, would have to forgo a competitive bidding process in favor of using a pre-selected vendor for fabrication and installation, and may even need to engage this vendor prior to having all regulatory approvals in hand. These procedures are in place to attempt to ensure cost recovery, and failure to comply with them puts the company at risk of making investments that the APSC later determines are not in the public interest and therefore ineligible for cost recovery. Additionally, Entergy would be forced to comply with the emission limits prior to the conclusion of its tuning and training procedures. Even with these truncated procedures, the schedule does not allow for any unforeseen issues in the installation and tuning process, which frequently arise and complicate installation or hinder the expected performance of the installed equipment.

Implementation of the Final FIP forces Entergy to choose between two untenable options each resulting in irreparable harm and unnecessary risk: (1) increasing costs and risk through rushed work and non-compliance with company prudence procedures, with no guarantee of FIP compliance once the work is completed, and (2) taking more time than the Final FIP permits, resulting in cessation of operation of the White Bluff and Independence units until LNB/SOFA can be installed. Beyond the fact that cessation of operations would necessitate Entergy to obtain costly replacement power on the open market, critically, it also could cause reliability issues, as generation from White Bluff and Independence is necessary for Entergy to provide reliable electricity generation to its customers and meet its obligations to MISO. In light of this, EPA must issue a stay of the deadline for compliance with the NOx limits until a more appropriate deadline can be set.

[68] *Id.*

3. A stay would prevent harm to Entergy and its co-owners, customers, and communities but would still allow Arkansas to meet its regional haze goals.

Arkansas already is below the URP and EPA's RPGs, and thus a delay in the implementation of the FIP would not contribute to unacceptable visibility impairment. As discussed previously, the IMPROVE data for January 2014 through December 2015 show that visibility continues to improve at a greater rate than the URP in Caney Creek and Upper Buffalo.[69] The recent IMPROVE data also confirm that visibility in the two Arkansas Class I areas already is better than EPA's final RPGs for the areas.[70] Accordingly, a stay would not interfere with attainment of the URP or the RPGs.

D. Entergy Also Meets the Four Factors that Courts Consider When Assessing Judicial Stay Requests.

Although the judicial test for analyzing a request for a stay does not apply here, Entergy's request for stay nonetheless satisfies this test. First, as described above, Entergy has made a strong showing of likelihood of success on the merits. For the reasons explained in this Petition, the Final FIP contains significant errors and unreasonable requirements upon which Entergy was unable to comment during the period for public review, and that are not logical outgrowths of the Proposed FIP. The CAA *requires* that EPA reconsider these elements of the Final FIP. Second, Entergy would be irreparably harmed if the Final FIP is not stayed. As explained above, implementation of the FIP would force Entergy to make expensive choices about the installation of controls and possible deactivation of units in very short order. Entergy would be forced to spend significant amounts of money once these choices are made. Third, a stay of the rule would not cause harm. Visibility in Arkansas' Class I areas already is improving at a rate greater than the URP for each area, and the areas already have surpassed EPA's final RPGs for the first planning period. Implementation of SO_2 and NOx controls at White Bluff and Independence is not needed to achieve either the URP or the RPGs. Fourth, the balance of harms and the public interest favor a stay. A stay would prevent significant, irreparable harm to Entergy with little visibility impact, as Arkansas already has met the goals that the installation of FGD and LNB/SOFA are designed to achieve. It also would prevent the harm to employees and local communities that would ensue from the deactivation of any of the units. In light of this, a stay is appropriate and just, and should be granted.

V. CONCLUSION

For the reasons discussed above, Entergy urges EPA, by February 1, 2017, to reconsider and stay certain provisions of the Final FIP to avoid the harms to Entergy, its employees, co-owners, customers and local communities, as described herein.

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[69] Trinity Report at 3.
[70] See *supra* at 4.

Dated: November 23, 2016

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List of Exhibits

Exhibit A: Assessment of Recent Class I Area IMPROVE Monitoring Data prepared by Trinity Consultants, Inc., at 3 (Aug. 8, 2016, updated Nov. 15, 2016)

Exhibit B: Entergy Arkansas Inc. Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, at 5 (Aug. 7, 2015) (Docket ID No. EPA-R06-OAR-2015-0189-0153)

Exhibit C: Memorandum from Sargent & Lundy (Nov. 18, 2016)

Exhibit D: 2009 Alstom Report

Exhibit E: 2013 Alstom Report

Exhibit F: Memorandum from Foster Wheeler

Exhibit A

ASSESSMENT OF RECENT CLASS I AREA IMPROVE MONITORING DATA

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Trinity Project No. 163701.0059

August 8, 2016

Updated November 15, 2016

Assessment of Recent Class I Area IMPROVE Monitoring Data

Since the August 7, 2015 submittal of Trinity Consultants' *Regional Haze Modeling Assessment Report – Entergy Arkansas, Inc. – Independence Plant* (Trinity's report), the complete set of 2015 measured concentration data from the Interagency Monitoring of Protected Visual Environments ("IMPROVE") network of Class I area monitors has become available. It is prudent to review this data for the two Arkansas Class I areas – Caney Creek ("CACR") and Upper Buffalo ("UPBU") – to determine if the trends identified in Trinity's report continue.

A summary of all available haze index values – from 2002 through 2015 – are shown in the following tables. As explained in Trinity's report, the IMPROVE equation is applied to the concentration data to calculate light extinction (Mm^{-1}), and then light extinction is converted to haze index (dv).

Table 1. Haze Indices for Caney Creek

Year	Observed 20% Worst Haze Index (dv)	Observed 20% Best Haze Index (dv)
2002	27.21	11.88
2003	26.54	10.74
2004	25.34	11.11
2005	29.21	12.93
2006	25.68	12.51
2008	23.70	9.24
2009	22.68	8.09
2010	22.94	10.76
2011	22.67	11.71
2012	21.49	9.54
2013	21.35	8.61
2014	20.72	8.52
2015	20.41	7.03

Table 2. Haze Indices for Upper Buffalo

Year	Observed 20% Worst Haze Index (dv)	Observed 20% Best Haze Index (dv)
2002	26.74	12.83
2003	27.22	10.62
2004	25.58	10.74
2005	30.47	13.34
2006	25.42	13.00
2007	26.17	12.45
2008	24.60	10.49
2009	22.62	9.40
2011	23.21	11.51
2012	21.56	10.31
2013	21.25	8.60
2014	20.49	8.13
2015	19.96	7.50

The following figures illustrate how these measured values compare to the Uniform Rate of Progress ("URP") curves for each area. The figures are updates to Figures 3-3 and 3-4 of Trinity's report, and, as such, also show the projected haze index values based on the scenario-specific modeling summarized in Trinity's report.

Figure 1. Caney Creek Observed Haze Index, Uniform Rate of Progress, and Projected Haze Index

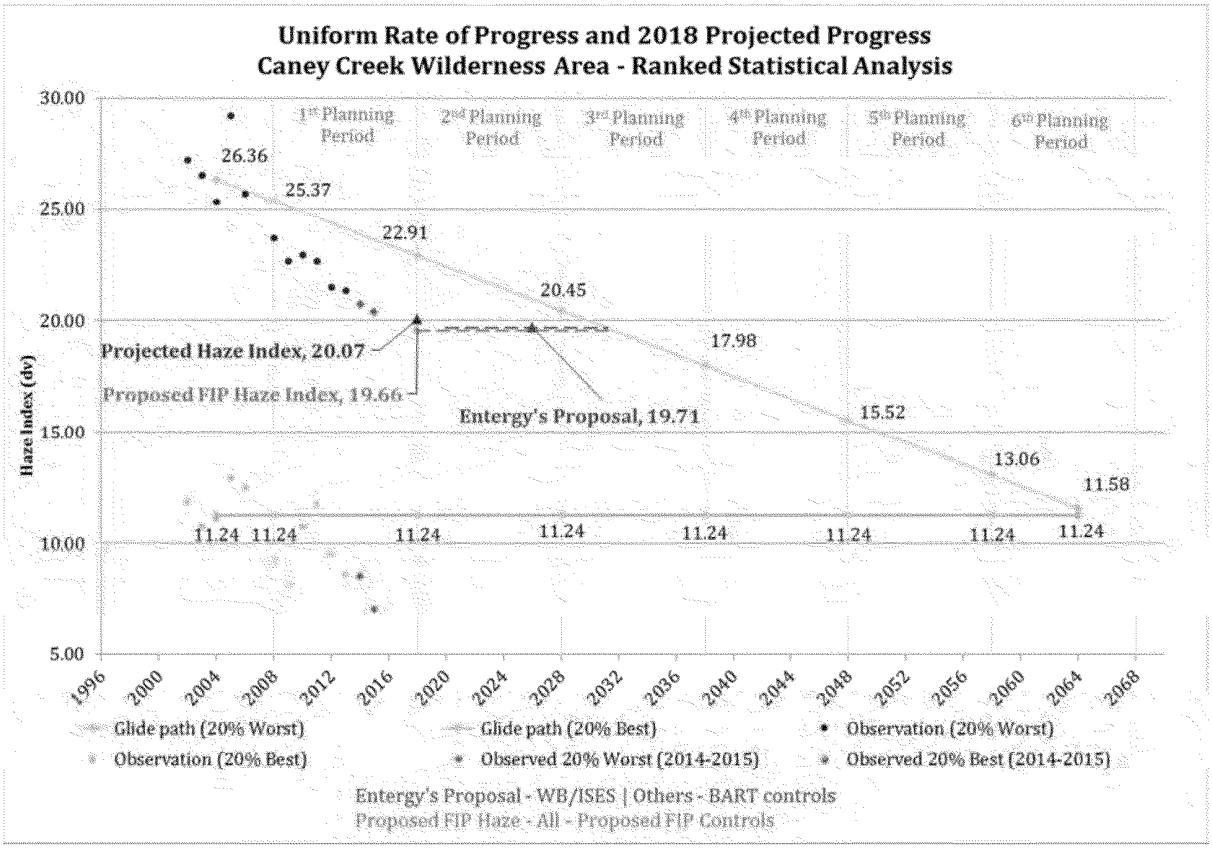
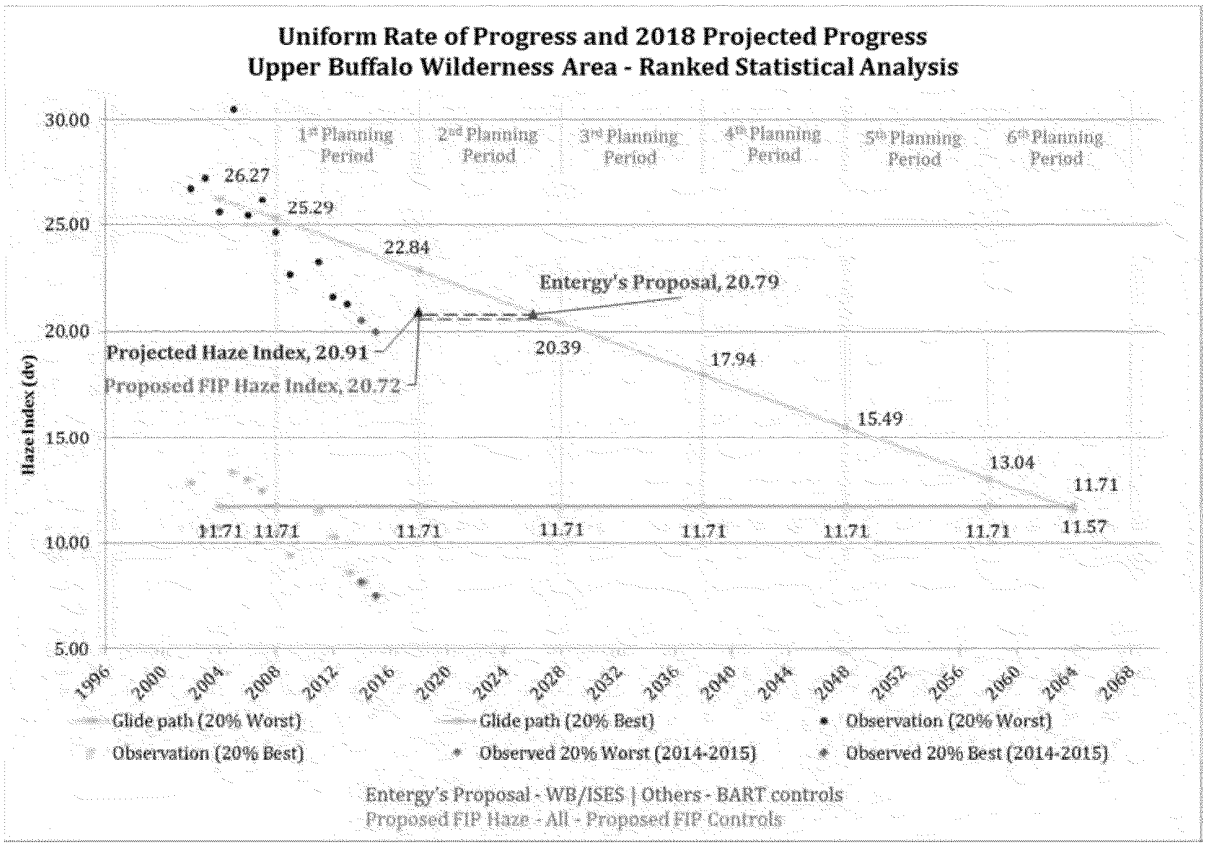


Figure 2. Upper Buffalo Observed Haze Index, Uniform Rate of Progress, and Projected Haze Index



As shown above, the actual visibility impairment at CACR and UPBU have continued to decrease through 2015. The average 20 percent worst haze indices for CACR decreased from 21.49 dv in 2012 to 20.41 in 2015. Similarly, visibility improved at UPBU, where the average 20 percent worst haze indices decreased from 21.56 dv in 2012 to 19.96 dv in 2015. As shown in the figures and table below, these values are significantly less than (i.e., better than), and ahead of schedule of, the Reasonable Progress Goals (RPGs) proposed by ADEQ[1] of 22.48 dv by 2018 for the 20 percent worst days at CACR and 22.52 dv by 2018 for the 20 percent worst days at UPBU, and those finalized by EPA[2] of 22.47 dv for CACR and 22.51 dv for UPBU.

Table 3. 2018 Reasonable Progress Goals Compared to 2015 Visibility for the 20% Worst Days

Class I Area	ADEQ-Proposed RPG for 2018 (dv)	EPA-Finalized RPG for 2018 (dv)	Actual Visibility in 2015 (dv)
Caney Creek	22.48	22.47	20.41
Upper Buffalo	22.52	22.51	19.96

[1] Arkansas's 2008 Regional Haze State Implementation Plan (SIP).
[2] September 27, 2016 final Arkansas Regional Haze Federal Implementation Plan (FIP).

Figure 3. Caney Creek Observed Haze Index, 20% Worst Days, and Proposed Reasonable Progress Goals

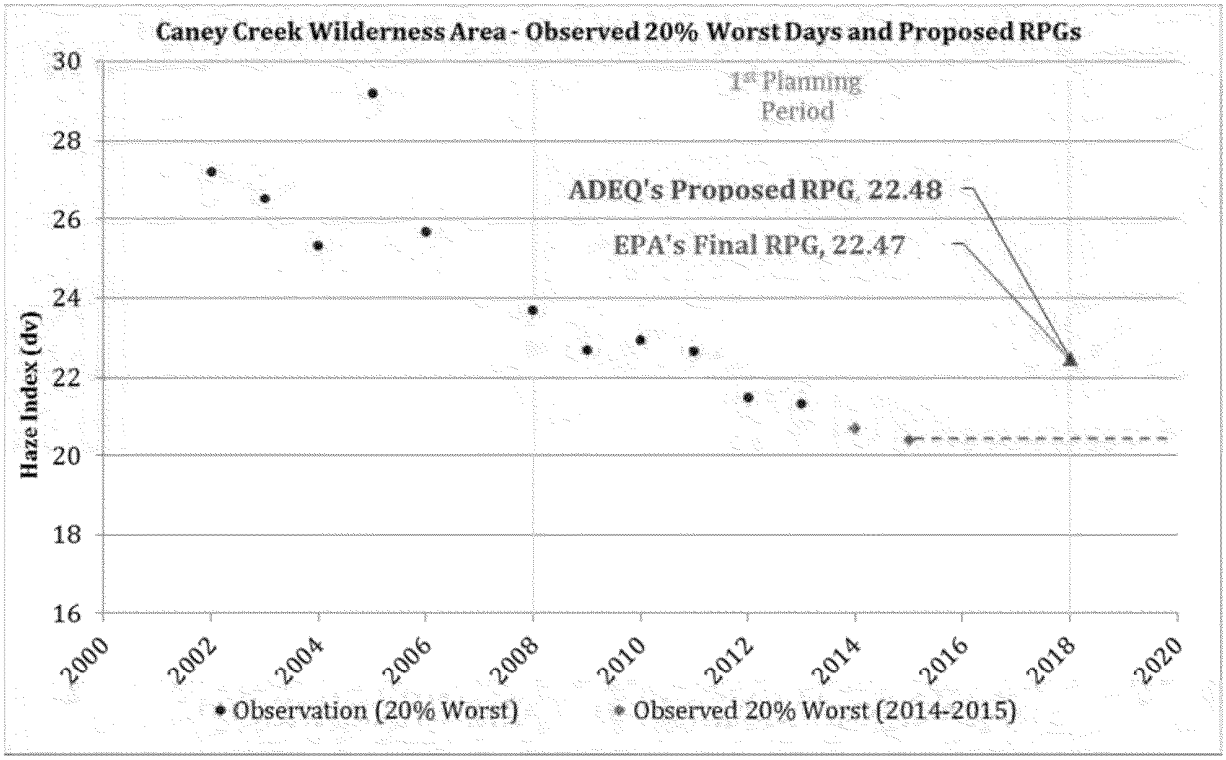


Figure 4. Upper Buffalo Observed Haze Index, 20% Worst Days, and Proposed Reasonable Progress Goals

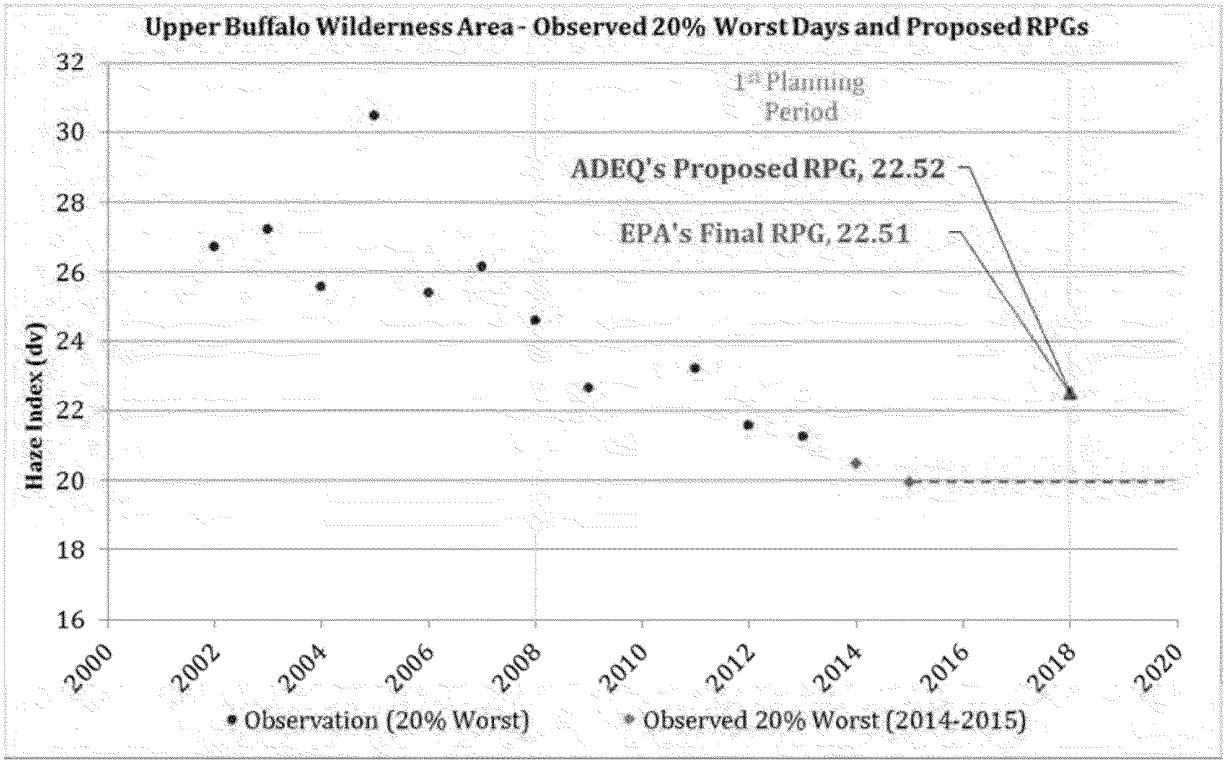


Exhibit B

Entergy Arkansas Inc.

Comments

On the Proposed Regional Haze and Interstate Visibility Transport

Federal Implementation Plan for Arkansas

Docket No. EPA-R06-OAR-2015-0189

Submitted on:
August 7, 2015

To:
U.S. Environmental Protection Agency
1445 Ross Avenue, Suite 700
Dallas, Texas 75202-2733

Via:
http://www.regulations.gov
Docket ID No. EPA-R06-OAR-2015-0189

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EXHIBITS

A. *Review of EPA's Cost Analysis for Arkansas Regional Haze Proposed Federal Implementation Plan*, Report No. SL-012913, Sargent & Lundy (July 2015).

B. *White Bluff Dry FGD Cost Estimate and Technical Basis*, Report No. SL-012831, Sargent & Lundy (July 2015).

C. *Regional Haze Modeling Assessment Report, Entergy Arkansas, Inc. - Independence Plant*, Trinity Consultants (August 4, 2015).

D. *IMPROVE Data Statistical Analysis*, Trinity Consultants (July 2015).

E. *Just-Noticeable Differences in Atmospheric Haze*, Ronald C. Henry, Department of Civil and Environmental Engineering, University of Southern California, Los Angeles, Air & Waste Management Association (2002).

F. Excerpts from *Tangential Low NOx (TLN3) System for Entergy White Bluff Units 1 & 2*, Foster Wheeler North America Corp. Proposal to Entergy (Oct. 13, 2011).

G. Memorandum from Steve deMello, Project Manager, Amec Foster Wheeler North America Corp., to Michael P. Fallon, P.E., Entergy (July 30, 2015).

H. *Evaluation of the CALPUFF Modeling System Margin of Error for a BART Analysis, Entergy Services, Inc. - Lake Catherine Plant*, Trinity Consultants (Aug. 4, 2015).

I. Entergy Arkansas Inc.'s Comments on the Proposed Approval and Promulgation of Implementation Plans; Interstate Transport State Implementation Plan; Arkansas, Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility, Docket No. EPA-R06-OAR-2008-0633.

ENTERGY ARKANSAS INC.
COMMENTS ON THE PROPOSED REGIONAL HAZE AND INTERSTATE VISIBILITY TRANSPORT FEDERAL IMPLEMENTATION PLAN FOR ARKANSAS

EPA-R06-OAR-2015-0189

I. INTRODUCTION

On April 8, 2015, the U. S. Environmental Protection Agency ("EPA" or "Agency") published in the *Federal Register*, at 80 Fed. Reg. 18,944, a proposed Federal Implementation Plan ("FIP") to address certain regional haze and visibility transport requirements for the State of Arkansas ("Proposed FIP" or "Proposal"). The Proposed FIP would address the requirements of the Regional Haze Rule and interstate visibility transport for those portions of Arkansas' State Implementation Plan ("SIP") that EPA previously had disapproved. *See* 77 Fed. Reg. 14,604 (Mar. 12, 2012). The Proposed FIP addresses the requirements for Best Available Retrofit Technology ("BART") for those sources for which EPA did not approve Arkansas' BART determinations, Reasonable Progress Goals ("RPGs"), reasonable progress controls and a long-term strategy, as well as the interstate visibility transport requirements for pollutants that affect visibility in Class I areas in nearby states.

Entergy Arkansas Inc. ("EAI" or "Entergy") owns and operates three facilities that EPA proposes to regulate under the FIP: White Bluff Electric Power Plant ("White Bluff"); Independence Steam Electric Station ("Independence"); and Lake Catherine Plant ("Lake Catherine"). EPA is proposing sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") BART limits for White Bluff Units 1 and 2, and SO_2, NOx, and particulate matter ("PM") BART limits for the Auxiliary Boiler at White Bluff. EPA also is proposing a NOx BART limit for Unit 4 at Lake Catherine. Finally, EPA is proposing emissions limits at Independence to meet reasonable progress requirements and is seeking comment on two alternative options. Under Option 1, EPA is proposing SO_2 and NOx emission limits for Units 1 and 2 at Independence. Under Option 2, EPA is proposing only SO_2 emission limits for Units 1 and 2. EPA also is soliciting comment on any alternative control measures for White Bluff Units 1 and 2 and Independence Units 1 and 2 that would address the BART and reasonable progress requirements for these four units for the current regional haze planning period.

In these comments, Entergy discusses its legal and technical concerns with the Proposed FIP. Entergy appreciates EPA's consideration of these comments, and urges EPA to make Entergy's suggested changes and issue a final FIP that provides visibility benefits without overly burdening EAI's customers and co-owners.

II. EXECUTIVE SUMMARY

The Regional Haze Program is intended to achieve gradual and steady improvement in visibility at Class I areas over the course of 64 years. The program was established under the Clean Air Act ("CAA") as a long-term program to allow major emitting sources to install controls or be phased out in a rational and economical manner to ultimately achieve natural visibility conditions at all Class I areas in the United States. The program also is intended to

recognize that regional haze is a *regional* problem; one that benefits from broad programmatic changes and the retirement of sources as they reach the end of their useful lives. EPA's Proposed FIP for Arkansas largely abandons this approach, ignores the significant improvements in visibility in Arkansas' Class I areas that already have occurred, fails to account for the improvements that are anticipated to occur based on other regulatory programs, and seeks to impose more than $2 billion in costs on EAI's customers and co-owners despite the lack of any need for, or benefit from, such a massive investment.

Entergy proposes a more reasonable, long-term, multi-unit approach to address regional haze in the Arkansas Class I areas that achieves reasonable progress, is consistent with the statutory scheme and allows Entergy to manage its generation fleet in a reliable and economic manner. In particular, Entergy proposes the following: (1) to achieve early SO_2 reductions by accepting lower SO_2 emission rate limitations at both White Bluff and Independence; (2) to achieve NOx reductions by installing NOx control technology on all four units within three years of the final FIP's effective date; and (3) to commit to the permanent cessation of coal-fired operations at White Bluff by 2028. Based on modeling by Entergy (which EPA should have conducted but failed to undertake), the difference in visibility at the Arkansas Class I areas between the proposed FIP controls and Entergy's proposal is imperceptibly small (*see* Section III.D.2 below) and does not warrant an investment of over $2 billion in scrubber technology at the plants.

Entergy's comments address a range of issues raised by the Proposal. Two issues are most critical. First, with respect to White Bluff, Entergy proposes to cease all coal-fired operations at the two coal-fired units in 2027 and 2028. This proposal necessarily changes the BART analysis for White Bluff. Because of Entergy's proposed commitment to stop burning coal, EPA's proposal to establish BART limits for White Bluff based on the installation of dry flue gas desulfurization ("FGD" or "scrubbers") must be rejected. Under the current schedule for finalizing the FIP, the scrubbers would not be installed until at least 2021, which would leave only six to seven years for EAI to recoup the approximately $1 billion in investment for dry scrubber installation. That cannot be justified economically or environmentally. Economically, the short amortization period would drive the costs of the scrubbers to over $7,500-$8,500 per ton of SO_2 removed. Environmentally, EPA projects that visibility will improve in each of Arkansas' Class I areas only by approximately one-fifth of a deciview ("dv") as a result of the proposed FIP controls on all sources in Arkansas; an amount that is absolutely undetectable. Controls on White Bluff would achieve merely a fraction of that amount.

Second, EPA's proposal to require SO_2 and NOx limits based on the installation of dry scrubbers and NOx controls on the two coal-fired units at Independence cannot be justified for the first planning period. Independence is not a BART-eligible source.[1] Accordingly, EPA may impose emission reduction requirements on Independence under the Regional Haze Program *only* to the extent *necessary* to achieve reasonable progress towards natural visibility levels. *See* 42 U.S.C. § 7491(b)(2) (implementation plans must "contain such emission limits ... as may be *necessary* to make reasonable progress") (emphasis added). The visibility in Arkansas' Class I

[1] Despite the fact that Independence is not a BART-eligible source under the Clean Air Act, EPA's analysis in the Proposal essentially and improperly treated it as such.

areas already has improved substantially in the past 10 years such that the haze index for both Class I areas currently is well below the uniform rate of progress ("URP" or "glide path") that EPA uses to ensure reasonable progress towards natural visibility conditions and that EPA had previously approved for Arkansas.[2] Based on the negligible visibility benefit from installing scrubbers at Independence, the cost of the controls is an astounding $1.33 billion to $1.53 billion per deciview improvement. *See* Section III.C.3 below. Scrubbers at Independence are simply not necessary to ensure that visibility in Arkansas' Class I areas remains below the URP, nor are they justifiable based on EPA's own analysis of the visibility benefits resulting from such a huge investment.[3]

Arkansas' Class I areas, the Caney Creek Wilderness Area ("Caney Creek") and the Upper Buffalo Wilderness Area ("Upper Buffalo"), have seen marked improvement in visibility since the start of regional haze monitoring. Based on the Interagency Monitoring of Protected Visual Environment ("IMPROVE") data, which reflects monitored visibility impairment in Class I areas, the haze index for the 20% worst ("W20") days of visibility has been steadily improving as a result of reduced emissions within Arkansas and because of broader industrial and energy trends in other states. According to modeling performed by the Central Regional Air Planning Association ("CENRAP"),[4] all of Arkansas' elevated point sources (including all power plants and large industrial sources) account for only about 2.7% and 2.3% of total light extinction within Caney Creek and Upper Buffalo, respectively. The overwhelming visibility impact comes from non-Arkansas point sources and mobile sources. Because of the Mercury and Air Toxic Standards ("MATS") rule,[5] the continuing benefits of the Clean Air Interstate Rule ("CAIR"), the next phase of the Cross State Air Pollution Rule ("CSAPR"), and implementation of the soon-to-be-released revised 8-hour ozone National Ambient Air Quality Standards ("NAAQS"), along with continuing reductions in emissions from mobile sources, the visibility at Caney Creek and Upper Buffalo will continue to improve. Based on the visibility trends in both Class I areas, the imposition of BART controls, and Entergy's proposed interim controls and proposed commitment to cease coal burning at White Bluff, no further action will be necessary to ensure that Arkansas' Class I areas remain below the URP until at least 2028 and likely even longer as a result of emissions controls that will be required by future regulatory programs and planned retirements of numerous electric generating units.

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[2] 76 Fed. Reg. 64,186, 64,194-95 (Oct. 17, 2011).

[3] The Class I areas outside of Arkansas that are potentially affected by emissions from Arkansas, similarly, are below the URP and do not need additional reductions to achieve reasonable progress or their long-term visibility goals.

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

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

EPA acknowledges that controls on Independence are not needed for Arkansas to achieve the URP. 80 Fed. Reg. at 18,992 ("We believe it is appropriate to evaluate Entergy Independence even though Arkansas Class I areas and those outside Arkansas most significantly impacted by Arkansas sources are projected to meet the URP for the first planning period."). Indeed, after the proposed BART controls are installed and White Bluff ceases coal-fired operations, Arkansas sources will not approach the URP, or glide path, for at least another decade. Entergy's analysis, based on the actual visibility impairment data, shows that Caney Creek will remain below the glide path until at least 2032 and Upper Buffalo until at least 2028 with no additional controls on in-state sources. *See* Section III.D.2 below (Figures 13 and 14). Imposing controls on Independence is simply not necessary or justified to achieve reasonable progress towards natural visibility in Arkansas' Class I areas.

EPA's reasonable progress analysis and justification for proposing stringent emission limitations at Independence are not legally defensible under the Regional Haze Program based on the costs and lack of visibility benefits of the proposed limits. EPA suggests it is only logical to require Independence to install controls because its SO_2 emissions are large and because it would be cost effective to control them. Cost effectiveness is a factor in deciding the degree of controls necessary to establish RPGs, but it is not an independent basis for imposing controls and does not determine reasonable progress goals. In this case, installing the controls on Independence that would be necessary to meet the proposed emission limits will cost EAI's customers and co-owners in excess of $1 billion. While the cost per ton of SO_2 removed may be within the range that might support a BART determination, it is nonetheless high in the context of reasonable progress controls, particularly where the benefits are small and reductions are not needed to demonstrate that Arkansas is making reasonable progress towards achieving natural visibility conditions at its Class I areas. Accordingly, Entergy objects to the RPGs that EPA is proposing for Arkansas.

EPA also improperly relied on CALPUFF modeling to justify the proposed controls at Independence, vastly overstating the impact of emissions from Independence and the benefits of installing controls. CALPUFF modeling, a single source puff model, is not an appropriate model to determine or project reasonable progress benefits. Reasonable progress is determined by evaluating the overall visibility values in Class I areas and the projected trends in visibility as a result of emissions, controls and operations at all sources contributing to visibility impairment. EPA has recognized in recent rulemakings that CALPUFF cannot do this and it is therefore arbitrary and capricious for EPA to rely on CALPUFF for this purpose here.

Entergy is prepared to offer meaningful interim emission reductions to complement its proposed commitment to cease coal-fired operations at White Bluff and assure that Arkansas remains on a path that is below the URP for the long term. Entergy proposes to meet more stringent SO_2 limits at both White Bluff and Independence beginning in 2018. In addition, Entergy proposes to install low NOx burners ("LNB") and separated overfire air ("SOFA") on both White Bluff and Independence within three years of the final FIP's effective date, assuring that there will be both near-term and long-term visibility benefits.

III. COMMENTS

A. Entergy Proposes To Cease Coal-Fired Operations At White Bluff By 2028 As Part Of A Long-Term, Multi-Unit Regional Haze Plan.

EPA's proposed BART determination for White Bluff appears to be based, in general, on the White Bluff five-factor BART analysis that Entergy provided to the Arkansas Department of Environmental Quality ("ADEQ") in October 2013 ("Revised White Bluff BART Analysis"),[6] which assumed White Bluff Units 1 and 2 would continue to combust coal for the foreseeable future. As part of a multi-unit plan to improve visibility and to better manage its generation assets for reliability and costs, Entergy proposes to cease burning coal at White Bluff Units 1 and 2 by 2027 and 2028, one unit per year, and is prepared to take an enforceable commitment to that effect.[7]

As a result of Entergy's proposal, EPA's proposed BART determination for White Bluff Units 1 and 2 has been rendered inapplicable. Entergy's proposal for White Bluff requires EPA to undertake a new BART analysis to address the remaining useful coal-fired life of the units. In addition, EPA used outdated costs in its BART analysis, improperly eliminated millions of dollars in costs necessary to install controls on White Bluff, and did not consider site-specific factors that will affect the cost calculation. When the appropriate dry scrubber costs are considered along with the units' remaining useful coal-fired life, the average cost effectiveness of dry FGD increases to a range of over $7,500 to $8,500 per ton at the White Bluff units, costs that are far too high to constitute BART.

1. EPA must take the remaining useful life of the White Bluff units into account in the BART analysis.

The CAA and EPA regulations dictate that EPA and states consider the remaining useful life of a source in BART determinations, which factors into the cost of compliance in the BART analysis. 42 U.S.C. § 7491(g)(2); 40 C.F.R. § 51.308(e)(1)(ii)(A). EPA's guidance provides a specific time period for amortization of the costs of controls where a unit's remaining useful life is limited.

> If the remaining useful life exceeds the amortization period, then the remaining useful life has essentially no effect on the control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, [EPA advises] us[ing] this shorter time period in [the BART] cost calculations.

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[6] Revised BART Five Factor Analysis, White Bluff Steam Electric Station (Oct. 2013), EPA Docket ID EPA-R06-OAR-2015-0189-0045. *See* 80 Fed. Reg. at 18,969-75. However, Entergy is confused by EPA's references in the Proposal to AEP's modeling and assumptions with respect to the BART analysis for White Bluff. *See id.* at 18,969. The references to AEP make it unclear whether EPA actually used Entergy's Revised White Bluff BART Analysis in evaluating the BART controls for White Bluff. EPA needs to confirm that it reviewed and analyzed Entergy's Revised White Bluff BART Analysis.

[7] Entergy anticipates that its compliance with a final FIP, including installing dry scrubbers or, in the alternative, ceasing coal-fired operation at White Bluff, will be subject to Arkansas Public Service Commission hearing and review.

Guidelines for BART Determinations Under the Regional Haze Rule, 40 C.F.R. Part 51, App. Y, Section IV.D.4.k ("BART Guidelines").

BART controls that may be cost effective using the standard amortization period (typically 20-30 years) may no longer be cost effective when a source's remaining useful life is factored into the analysis. *See* 79 Fed. Reg. 74,818, 74,837 (Dec. 16, 2014) ("Proposed Texas Regional Haze FIP") ("[CENRAP] noted that for sources with a relatively short remaining useful life, this consideration would have weighed more heavily against a determination that controlling those sources would have been reasonable.").

EPA determined that remaining useful life was not a meaningful factor for White Bluff given Entergy's previous plans to continue coal-fired operation at White Bluff. *See* 80 Fed. Reg. at 18,971, Tables 34 and 35 (using 30 years and the life of the equipment); Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plan (SO_2 Cost TSD), at 16 ("we typically assume a 30 year equipment life for scrubbers, as we do here."). As a result, EPA concluded that dry scrubbers on White Bluff would have an average cost effectiveness at Unit 1 of $2,227/ton and at Unit 2 of $2,101/ton. 80 Fed. Reg. at 18,971, Table 32. These cost estimates were based on a 30-year amortization period for the controls, an amortization period that is consistent with EPA's Control Cost Manual when a unit's remaining useful life is not limited. *EPA Air Pollution Control Cost Manual* (Jan. 2002) ("Control Cost Manual").[8]

Now, however, given Entergy's proposed commitment to cease coal-fired operation at White Bluff by 2027-2028, EPA will need to revise its BART analysis to take the remaining useful life of the units into account. The CAA requires that BART controls be installed "as expeditiously as practicable," but no later than five years from approval of a regional haze SIP or the issuance of a FIP. 42 U.S.C. § 7491(b)(2)(A), (g)(4); 40 C.F.R. § 51.308(e)(1)(iv). In this case, EPA has stated that it is unable to finalize the FIP until after December 15, 2015,[9] which means that any final FIP cannot have an effective date earlier than sometime in 2016. Thus, the scrubbers would be installed and operational, at the earliest, in 2021.[10] In light of Entergy's proposed commitment to cease coal-fired operations at the units in 2027 and 2028, the amortization period will be approximately six to seven years. This has a significant impact on the cost calculation, resulting in much higher costs compared to the emissions reductions achieved.

[8] The Control Cost Manual is available at http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf

[9] EPA's Response to Letter/Order (Dkt. No. 52) at 2, *Sierra Club v. McCarthy*, No. 14-cv-00643 (Jul. 15, 2015 E.D.Ark.).

[10] EPA has proposed to allow White Bluff the full five years to install the scrubbers and meet the BART SO_2 emission limits. 80 Fed. Reg. at 18,973. Entergy agrees with EPA that such major emissions control technology could not be designed, contracted for, and installed any earlier than five years from the effective date of the final regional haze FIP.

2. EPA's analysis of the costs to install dry scrubbers at White Bluff is replete with errors and artificially improves the cost effectiveness of scrubber installation at White Bluff.

EPA's analysis of the cost and cost effectiveness of installing dry scrubbers at White Bluff contains numerous flawed methodologies, incorrect assumptions and mistakes, all of which seem designed to artificially lower the actual costs of installing dry scrubbers and improve the supposed cost effectiveness of the controls. Sargent & Lundy ("S&L") has undertaken a thorough analysis of EPA's SO_2 Cost TSD and provided a report, *Report of EPA's Cost Analysis Arkansas Regional Haze Proposed Federal Implementation Plan*, No. SL-012913, Sargent & Lundy (July 2015) ("S&L FIP Cost Report") (attached as Exhibit A and incorporated by reference herein). The S&L FIP Cost Report demonstrates that EPA incorrectly specified the SO_2 emissions baseline for White Bluff, which increased expected emissions. EPA then improperly used maximum monthly emissions to estimate the tonnage reduction achievable with the scrubbers to reduce the cost per ton, and incorrectly eliminated approximately $100 million in costs that EPA's own Control Cost Manual says should be included.

(i) EPA arbitrarily eliminated two of five years in calculating baseline emissions for White Bluff.

The BART Guidelines state that baseline emissions from existing sources "should represent a realistic depiction of anticipated annual emissions for the source." 40 C.F.R. Part 51, App. Y, Section IV.D.4.d.1. In general, for the existing sources, facilities should estimate the anticipated annual emissions based upon actual emissions from a baseline period. Entergy originally had used the 2001 - 2003 baseline period. *See* Revised White Bluff BART Analysis at 4-1. EPA looked at the five-year period between 2009 and 2013, SO_2 Cost TSD at 13, Table 7, but inexplicably excluded the maximum and minimum years during this five-year period. *Id.* The effect of excluding these two years is to increase artificially the emissions baseline for White Bluff. S&L FIP Cost Report at 3. There is no reasoned explanation for excluding two of the five recent years' of emissions data in calculating the baseline. EPA should use the average emissions from all five years to determine the baseline as it is more representative of the anticipated annual emissions from the White Bluff units.

(ii) EPA uses an incorrect methodology that artificially inflates the SO_2 emission reductions achievable with scrubbers.

After having incorrectly identified the baseline emissions for White Bluff, EPA then apparently ignores the baseline emissions when estimating the SO_2 reductions that are achievable with the scrubbers. In an apparent attempt to inflate the emission reductions achievable at White Bluff through the installation of scrubbers, EPA identified the maximum monthly SO_2 emission rate in the baseline period of 2009 to 2013 for each unit and then calculated the percent reduction that would be required to achieve a controlled emission rate of 0.06 lb/MMBtu. *See* White Bluff_R6 cost revisions2.xlsx, "Cost Effectiveness" tab, EPA Docket ID EPA-R06-OAR-2015-0189-0093. The percent reduction calculated was then multiplied by the baseline emission tons to determine the tons of SO_2 reduced. *Id.* This methodology is patently incorrect. It assumes the baseline emissions are based on maximum monthly averages, which significantly overstates the annual averages actually used to calculate baseline emissions.

To correctly estimate the SO_2 emission reductions, EPA must multiply the outlet emission rate of 0.06 lb/MMBtu by the average heat input to the boiler (MMBtu/year) from the five-year baseline period. S&L FIP Cost Report at 3. As detailed in the S&L FIP Cost Report, EPA's inappropriate use of maximum monthly emission rates overstates the achievable emission reductions at White Bluff by between 150 and 900 tons per year. *Id.* at 4, Table 2.

(iii) EPA improperly underestimates the costs by approximately $200 million to justify scrubbers at White Bluff.

EPA based its cost calculations for dry FGD on the costs provided by Entergy in its Revised White Bluff BART Analysis, and presented its analysis of the costs for scrubber installation at White Bluff in its SO_2 Cost TSD. However, EPA's analysis is full of errors, which resulted in an underestimation of the scrubber costs at White Bluff by approximately $200 million.

First, the costs in the Revised White Bluff BART Analysis are significantly outdated, and EPA failed to adequately account for this factor in its analysis. The costs for a dry scrubber provided in the Revised White Bluff BART Analysis were based on (1) a study provided to Entergy by S&L in 2009, which provided a line-itemized cost estimate that included contractor equipment, material, and labor costs for two semi-dry scrubbing systems; and (2) costs provided by Alstom in December 2009 to supply two semi-dry scrubbing systems, escalated by 10% based on updated price information from Alstom. SO_2 Cost TSD, at 2. However, even with the updated cost information from Alstom, the information provided in the Revised White Bluff BART Analysis is now at least five years out of date and significantly undervalues the costs of installing dry scrubbers at White Bluff. EPA attempted to address this issue by escalating the Alstom cost information to 2013 dollars using the Chemical Engineering Plant Cost Indices ("CEPCI"). However, EPA's use of the CEPCI inadequately escalated the projected vendor costs. According to S&L, EPA underestimated escalation significantly using the CEPCI – by over $36 million – rather than using updated vendor pricing. S&L FIP Cost Report at 11. Further, this underestimation of the cost escalation was carried throughout EPA's analysis in the SO_2 Cost TSD and resulted in a total underestimation of the costs for scrubber installation of over $85 million. *Id.* at 12, Table 7.

Second, EPA improperly excluded from the cost calculation legitimate costs that Entergy would incur to install dry scrubbers at White Bluff. EPA incorrectly eliminated over $115 million in costs from Entergy's cost analysis. *See* S&L FIP Cost Report at 8, 10. EPA mistakenly assumed certain Balance of Plant ("BOP") costs were included in the Alstom scope of work, so it eliminated these costs as duplicative. As the S&L FIP Cost Report explains, EPA improperly eliminated several BOP costs from Entergy's cost analysis:

- costs for the reagent handling system;
- costs for the ductwork to supply the flue gas to the SDA and the ductwork from booster fans to the existing chimney;

- the costs to apply an acid resistant coating to the chimney shell to protect the concrete from downwash effects;
- the costs associated with replacing the continuous emissions monitoring systems ("CEMS") and associated recalibration and testing costs; and
- costs calculated as percentages of the BOP equipment, material and labor costs.

Id. at 7-8. In total, by eliminating these costs, EPA underestimated the BOP costs by approximately $31 million. *Id.* at 8. EPA also suggested that the costs for one absorber vessel could be eliminated but cited no basis for its assumption that two absorber vessels are adequate for White Bluff. Entergy disagrees with EPA's assumption regarding the number of absorber vessels for White Bluff. *See* S&L FIP Cost Report at 17.

EPA also eliminated approximately $41.7 million for Entergy's Owner's costs,[11] despite the fact that such costs are allowed under EPA's Coal Quality Environmental Cost ("CUECost") model. *Id.* at 10. EPA claimed that such costs had not been documented, were duplicative of other costs or did not appear to be valid costs under the Control Cost Manual methodology. 80 Fed. Reg. at 18,971. For example, EPA improperly eliminated Entergy's capital suspense costs without explaining why such costs were duplicative of other costs or not valid under the Control Cost Manual methodology. Capital expenditure costs include both direct assigned and allocated expenses. Allocated expenses represent overhead costs associated with administrators, engineers and supervisors to the capital projects for which they provide services. Each function at Entergy charges its overhead costs to a "Capital Suspense" project, which is then allocated to the appropriate capital project. Capital suspense, therefore, is a distribution of overhead costs associated with administrators, engineers, and supervisors and includes function specific rates and Administrative and General ("A&G") (Corporate Accounting) rates. Because capital suspense costs are a portion of total capital expenditure costs, these costs are not duplicative of other costs.[12] For example, capital suspense costs do not include labor, administrative, and related elements that are present in Entergy's Internal Control costs. *See* SO_2 Cost TSD at 9. It was entirely proper for Entergy to include these costs in its control technology cost estimates. According to EPA's Control Cost Manual, overhead costs should be counted in the total annual cost of a project. Total annual cost is comprised of direct costs, indirect costs, and recovery credits. Control Cost Manual at 2-7. Indirect costs specifically include overhead costs. *Id.* at 2-8; 3-32.

Third, EPA significantly under-estimated the direct Operating and Maintenance ("O&M") costs projected for the scrubbers by using its Integrated Planning Model ("IPM") Spray Dryer Absorber ("SDA") cost model to scale the O&M costs rather than estimating these costs using current utility pricing information. *See* SO_2 Cost TSD at 14, Table 8. The IPM model includes several assumptions that fail to take into account site-specific factors. S&L FIP Cost Report at 13-14. Accordingly, the IPM model is not consistent with the BART Guidelines,

[11] These same improper exclusions were made with respect to EPA's analysis of BART controls for NOx at White Bluff and Lake Catherine Unit 4.

[12] Entergy had previously supplied this information on capital suspense costs to EPA. *See* 80. Fed. Reg. at 18,971, n. 55.

which requires a source-specific evaluation of controls costs. BART Guidelines, at Section IV.D.5 . EPA also erroneously scaled the indirect annual costs, all of which were estimated as percentages of capital cost, by using a scaling factor that did not depend at all on the capital costs. *See* S&L FIP Cost Report at 17.

Fourth, in the design for the dry scrubbers, the Revised White Bluff BART Analysis had assumed that White Bluff would burn a coal corresponding to an uncontrolled SO_2 emission rate of 2.0 lb/MMBtu, which is in excess of the sulfur level of the coals the units have historically burned. EPA criticized Entergy for this assumption and revised the White Bluff baseline emission rates and projected post-control emission rates used for the cost effectiveness analysis. *See* SO_2 Cost TSD at 12-14. However, it is proper, when conducting a BART cost analysis, to consider future fuel flexibility. The BART Guidelines advise that "[t]he baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." 70 Fed. Reg. 39,104, 39,167 (July 6, 2005) (codified at 40 C.F.R. Part 51 App. Y). Although the BART Guidelines explain that anticipated annual emissions are *generally* estimated based on annual emissions from a baseline period assuming conditions of past practice, *id.* at 39,167-68, EPA has approved BART determinations that assume "worst-case coal scenarios." *See* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. 9,318, 9,325-26 (Feb. 18, 2014); Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. 58,570, 58,584-85 (Sept. 21, 2011). Hourly CEMS data confirm that EPA's selection of 0.68 lb/MMBtu as the design basis for the capital costs is completely inadequate and would not achieve compliance with the FIP-proposed emission limit of 0.06 lb/MMbtu unless fuel sulfur limitations were imposed. Based on historical data and potential fuels that can be fired at White Bluff, 1.2 lb/MMBtu is an appropriate fuel sulfur level to design dry FGD systems for White Bluff. *See* S&L FIP Cost Report at 15-16.

If Entergy were constrained as to the type of coal that it could burn at White Bluff after the installation of controls, it would be necessary to reflect such a constraint in the cost of compliance, as it would force Entergy to continue purchasing higher-cost, low sulfur coal. Historically, Entergy has purchased lower sulfur coal than required by permit to ensure full compliance with applicable emission rates and to minimize costs of compliance with market-based emission programs. If White Bluff were to install BART controls, such considerations would become less meaningful and lower-cost, higher sulfur coal would enable Entergy to meet its BART obligations for less cost. Nonetheless, in the S&L FIP Cost Report, S&L used White Bluff's current emission rate of 0.68 lb/MMBtu to evaluate site-specific O&M costs. S&L FIP Cost Report at 15.

Finally, although Entergy removed Allowance for Funds Used During Construction ("AFUDC") from the final Revised White Bluff BART Analysis in response to comments from EPA on the Proposed White Bluff BART Analysis, Entergy disagrees with EPA that AFUDC should not be considered in the control costs.[13] AFUDC is the time value of money on the investment in the technology that is incurred during the construction, which could reach $30 million to $60 million during the 30-46 months of construction that would be needed to install

[13] As noted in the Revised White Bluff BART Analysis, Entergy revised its five-factor analysis of controls at White Bluff as requested by EPA staff in an effort to expedite consideration of the analysis but expressly reserved the ability to include AFUDC in future cost control analyses. Revised White Bluff BART Analysis, at 5-4.

major control equipment such as scrubbers on a large unit. AFUDC includes the interest as part of the capital cost, which is standard accounting and rate-making treatment of such costs and it was appropriate for Entergy to have initially included AFUDC in the White Bluff control costs. In its comments on the Proposed White Bluff BART Analysis, EPA claimed that AFUDC is not allowed by EPA's Control Cost Manual because "the CCM uses overnight costing methodology." EPA Region 6 Comments on White Bluff BART Analysis, at 1 (Aug. 21, 2013) EPA Docket ID EPA-R06-OAR-2015-0189-0044. However, contrary to EPA's assertion, the Control Cost Manual does not even address the use of the overnight methodology as being the basis for estimating costs. *See* S&L FIP Cost Report at 6. In fact, the calculation provided as an example in the Control Cost Manual specifically includes AFUDC as a variable. Control Cost Manual at 1-32, 2-44. The fact that the example "assumes" AFUDC is equal to zero does not reflect a decision by EPA that AFUDC should be excluded from emissions control costs, but instead is an explicit recognition of that category of costs.

EPA also has claimed that the U.S. Energy Information Administration ("EIA") uses overnight costs to project plant costs. *See* S&L FIP Cost Report at 6. However, this is a mischaracterization of the EIA methodology. According to EIA, "[s]tarting from overnight cost estimates, EIA's electricity modeling explicitly takes account of the time required to bring each generating technology online and the costs of financing construction in the period before a plant becomes operational." EIA, *Updated Capital Cost Estimates for Electricity Generation Plants*, at 2, n.2 (Nov. 2010).[14] Despite EPA's claims, the Control Cost Manual does not preclude inclusion of AFUDC and the EIA specifically takes such costs into account for an electric generating unit. Accordingly, the costs of controls for dry scrubbers at White Bluff should appropriately include AFUDC.

3. The costs for dry scrubbers at White Bluff, based on current estimates, are too high to constitute BART.

EPA's use of outdated costs in its cost calculation, its exclusion of certain legitimate costs for the construction of dry scrubbers, and its failure to take into consideration fuel flexibility at White Bluff renders EPA's analysis artificially low and inappropriate for evaluating the cost effectiveness of dry scrubbers on White Bluff for regional haze purposes. To correct EPA's deficiencies, Entergy commissioned a revised dry FGD cost analysis from S&L that takes into account the current costs for dry scrubber installation as compared to the costs that would have been incurred in 2009 or 2010. *See White Bluff Dry FGD Cost Estimate and Technical Basis*, Report No. SL-012831, Sargent & Lundy (July 2015) ("2015 S&L FGD Report") (attached as Exhibit B and incorporated by reference herein). The 2015 S&L FGD Report also takes into account site-specific factors at White Bluff that have an effect on costs. Finally, the study also uses the current SO_2 emission rates at White Bluff for the O&M costs. For the capital cost estimate, S&L uses a design basis of 1.2 lb/MMBtu sulfur coal. As explained in the S&L FIP Cost Report, the current maximum monthly average emission rates are not an appropriate basis for sizing the scrubbers. The equipment must be sized to handle the maximum short-term emission rate. S&L FIP Cost Report at 14-15.

[14] Available at http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf

The Revised White Bluff BART Analysis had estimated the costs to install dry scrubbers at White Bluff to be approximately $670 million. Revised White Bluff BART Analysis, at 5-6, Table 5-3. The 2015 S&L FGD Report estimates that the total costs of dry scrubbers at White Bluff will be in excess of $1 billion. 2015 S&L FGD Report at ES-1. When the remaining useful coal-fired life of these units is factored into the analysis, dry FGD installation at White Bluff would be indisputably cost-prohibitive.

Based on the S&L analysis, operating the dry FGD systems at White Bluff for only six to seven years would result in an average cost effectiveness of **$7,689-$8,599**/ton at Unit 1 and of **$7,642-$8,546**/ton at Unit 2. S&L FIP Cost Report at 23, Table 11. EPA has determined costs of substantially less than this magnitude to be cost-prohibitive on numerous occasions, including in this very same rulemaking. For example, for AECC McClellan Unit 1, even though EPA claimed that "[s]witching to diesel is projected to result in considerable visibility improvement," EPA rejected SO_2 BART limits based on switching to diesel because EPA determined that diesel, with an average cost effectiveness of $7,145/ SO_2 ton removed, was not "cost-effective in view of the incremental visibility improvement." 80 Fed. Reg. at 18,959. EPA also rejected combustion controls as NOx BART for AECC McClellan Unit 1 based on an average cost effectiveness of $6,261/NOx ton removed, which, according to EPA "is not within the range of what we generally consider to be cost-effective." *Id.* at 18,961. Further, EPA declined to impose dry FGD as BART in Arizona, where the average cost effectiveness was estimated to be $5,091/ton. Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,331-33; Final Arizona Regional Haze FIP, 79 Fed. Reg. 52,420, 52,436 (Sept. 3, 2014). In North Dakota, EPA approved the state's determination that a cost effectiveness of $6,525 per ton was excessive for NOx controls and did not constitute BART. Proposed North Dakota FIP, 76 Fed. Reg. at 58,630; Final North Dakota Regional Haze FIP, 77 Fed. Reg. 20,894, 20,896 (Apr. 6, 2012). And, in Montana, EPA concluded that certain SO_2 controls with a cost effectiveness of $5,442/ton and $6,365/ton were not cost effective. Proposed Montana Regional Haze FIP, 77 Fed. Reg. 23,988, 24,047 (Apr. 20, 2012); Final Montana Regional Haze FIP; 77 Fed. Reg. 57,864, 57,866 (Sept. 18, 2012). Notably, although EPA found that dry sorbent injection was cost effective on a cost-per-ton basis, 77 Fed. Reg. at 24,047, EPA concluded that the costs were not justified by the visibility improvement, which it calculated to be $30 million per deciview. 77 Fed. Reg. at 57,895. This is magnitudes lower than the cost-per-deciview of dry FGD at White Bluff Units 1 and 2, which, for Unit 1, would be approximately **$3.1 billion** per deciview at Caney Creek and **$2.7 billion** per deciview at Upper Buffalo and, for Unit 2, approximately **$2.9 billion** per decivew at Caney Creek and **$2.6 billion** per deciview at Upper Buffalo.[15]

[15] These numbers were calculated from the deciview improvement attributable to White Bluff Units 1 and 2 based on EPA's "scaling methodology." *See* 80 Fed. Reg. 18,997. This methodology results in an improvement at Caney Creek of .036 dv from Unit 1 and .038 from Unit 2 and an improvement at Upper Buffalo of .040 from Unit 1 and .043 from Unit 2. Even if the deciview improvements projected from EPA's CALPUFF modeling were used, *see* 80 Fed. Reg. at 18,972, the $/deciview calculation would not support the installation of dry FGD as BART at White Bluff. Entergy estimates that the costs based on the CALPUFF modeled improvement for Unit 1 would be approximately $135 million per deciview at Caney Creek and $144 million per deciview at Upper Buffalo and, at Unit 2, the costs would be approximately $145 million per deciview at Caney Creek and $143 million per deciview at Upper Buffalo.

The CAA requires that a BART determination consider the degree of anticipated visibility improvement. 42 U.S.C. § 7491(g)(2). Accordingly, EPA cannot mandate that a source "spend millions of dollars for new technology that will have no appreciable effect on the haze." *Am. Corn Growers v. EPA*, 291 F.3d 1, 7 (D.C. Cir. 2002). However, EPA's proposed controls do exactly this. The improvements predicted at Caney Creek and Upper Buffalo from controls on White Bluff Units 1 and 2 based on EPA's scaling methodology are only a fraction of a deciview. Even the CALPUFF predicted visibility improvements at Caney Creek and Upper Buffalo from the installation of dry FGD at White Bluff Units 1 and 2 are less than 1 deciview from each unit, *see* 80 Fed. Reg. 18,972, making them imperceptible to the human eye. *See* Section III.C.2.iii below. The massive cost of installing dry scrubbers at White Bluff to achieve these insignificant improvements, whether on a dollar per deciview basis or a dollar per ton basis, would be *much higher* than the costs that EPA has previously rejected as BART and that EPA proposes to reject as BART in this Proposed Rule. Accordingly, the installation of dry scrubbers cannot be considered BART for SO_2 at White Bluff.

4. Emissions reductions at White Bluff will be achieved through interim controls.

In addition to its plan to cease combusting coal at White Bluff by 2028, Entergy proposes to meet interim SO_2 emission rate reductions prior to 2028 through a reduction in the units' permitted SO_2 emission rates. The units currently have a permitted 3-hour average SO_2 limit of 1.2 lb/MMBtu. Entergy proposes to lower this limit to a rolling 30-day average limit of 0.6 lb/MMBtu beginning in 2018.

NOx BART for all EGUs in Arkansas, including White Bluff, should be compliance with CSAPR given that EPA already has determined that CSAPR is better than BART. 77 Fed. Reg. 33,642 (June 7, 2012). EPA has proposed to take this same approach in the Texas Regional Haze FIP and has approved several state regional haze SIPs that adopted this approach. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,821; *see also* Proposed Pennsylvania SIP Approval, 80 Fed. Reg. 2,841, 2,844 (Jan. 21, 2015); Final Minnesota SIP Approval, 77 Fed. Reg. 34,801, 34,801-02 (June 12, 2012). EPA should adopt this same approach in the final Arkansas Regional Haze FIP and provide that compliance with CSAPR is NOx BART for all of Arkansas' EGUs.

However, in the event EPA continues to require Arkansas' EGUs to meet source-specific NOx BART limits in the final FIP, Entergy proposes that the units meet a rolling 30-boiler operating day average NOx limit of 1,342.5 lb NOx/hr. This limit is based on the installation of LNB/SOFA and Entergy would be prepared to meet this limit no later than three years from the effective date of the final rule.[16] *See* 79 Fed. Reg. at 18,974-75. Although the cost effectiveness

[16] As explained further in Section III.E below, this limit is different from the limit that Entergy proposed as NOx BART in its Revised White Bluff BART Analysis. The revised limit is necessary due to the changed operating conditions at White Bluff over the past few years. The plant is now economically dispatched through the Midcontinent Independent System Operator ("MISO") and is spending greater amounts of time at lower load than it did in 2013, when the Revised White Bluff BART Analysis was submitted to ADEQ, and in prior years. The emissions guarantee that Entergy received from Foster Wheeler, the vendor that Entergy has selected to supply the NOx control technology, only applies to loads of 50% of capacity or greater. Therefore, a revised limit is necessary

of installing LNB/SOFA would significantly decrease as a result of a revised remaining useful life analysis for the units, if EPA does not adopt its CSAPR equals BART approach for Arkansas, Entergy is prepared to install these controls as part of its comprehensive visibility improvement proposal.

This combination of CSAPR compliance or, in the alternative, LNB/SOFA installation, and acceptance of a lower SO_2 emission rate through the remaining useful coal-fired life of the White Bluff units should be determined to be BART for White Bluff. No additional controls are justified given Entergy's proposal to limit the number of years of coal-fired operation at White Bluff.

B. EPA's Reasonable Progress Analysis And Proposed Determination Are Inconsistent With Other Regional Haze Development Processes.

1. EPA's reasonable progress analysis does not follow prior actions.

For reasonable progress purposes, EPA failed to undertake an appropriate reasonable progress analysis, including the crucial first step of determining whether additional controls are, in fact, necessary for Arkansas to make reasonable progress. *See* Section III.C below. EPA targeted only Independence in its analysis and subsequent decision to impose SO_2 and NOx limitations on the two coal-fired units at Independence. By focusing solely on Independence, EPA's reasonable progress analysis for the proposed Arkansas FIP abandons the analytical approach and determinative standards that guided previous reasonable progress analyses and determinations. In place of the criteria and procedures that EPA established in its own guidance or utilized and applied in previous approvals/disapprovals of regional haze SIPs or promulgation of regional haze FIPs, EPA made the arbitrary decision to review Independence simply because it believes "it would be unreasonable to ignore" the facility. 80 Fed. Reg. at 18,992. EPA failed to consider any lesser level of controls, the relative costs of such controls, the effectiveness of the controls in improving visibility or the cost per deciview improvement associated with the proposed controls.

EPA arbitrarily elected to propose controls for Independence that are unnecessary for Arkansas to demonstrate reasonable progress, provide no perceptible visibility improvement and exceed the cost estimates documented for other sources under other approved plans where EPA declined to impose reasonable progress controls. Further, EPA failed to follow its own guidance, which indicates that "States should consider a broad array of sources and activities when deciding which sources or source categories contribute significantly to visibility impairment." *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, at 3-2 (June 1, 2007) ("Reasonable Progress Guidance").[17] The arbitrary evaluation process that EPA followed in the Proposal not only distorts the goals and objectives of the Regional Haze Program, but it also is contrary to EPA's own requirements for uniformity and regional consistency.

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to ensure that the White Bluff units can comply with the NOx limit at the lower loads that have become a more common operating condition for the units.

[17] Available at http://www.epa.gov/ttn/caaa/t1/memoranda/reasonable_progress_guid071307.pdf

(i) EPA failed to determine visibility impact and the scope of Arkansas sources' contribution to visibility impairment.

EPA's singular attention on Independence for reasonable progress controls is unsubstantiated and is patently arbitrary and capricious. Despite identifying the 10 largest point sources of SO_2 and NOx within Arkansas, EPA focused only on the top three: White Bluff, Independence, and Flint Creek. Because White Bluff and Flint Creek are subject to BART, EPA concluded that no additional controls are necessary at those sources and the subsequent reasonable progress analysis fell solely on Independence. *Id.* at 18,991-92. Other than stating that these plants are the three largest sources, EPA provides no explanation for ignoring the other seven large point sources.[18]

EPA's failure to assess and document the contribution to visibility impairment at any relevant Class I area from *any* Arkansas point source, including Independence, is contrary to past rulemakings and is completely inconsistent with the detailed approach taken by EPA Region 6 in its promulgation of the regional haze FIP for Texas. *See generally*, Proposed Texas Regional Haze FIP, 79 Fed. Reg. 74,818. There, the Agency completed a multi-step evaluation that included: Q/D analysis (i.e., total emissions – 24-hour maximum annualized – divided by distance to the Class I area) for each Texas point source and relevant Class I area to identify those point sources requiring further evaluation,[19] a photochemical modeling scenario utilizing source apportionment to quantify visibility impacts from the sources identified in the Q/D analysis,[20] and an extinction percentage threshold to arrive at what EPA claimed was a common breakpoint in potential visibility improvement.[21] This analysis was key to the development of EPA's approach for proposing appropriate controls by indicating for which sources the installation of controls are needed and would be worthwhile. *See id.*at 74,839 (explaining that the results "suggest that controlling a small number of sources will result in visibility benefits at both Class I areas, and that rather than evaluating controls at all facilities identified by Texas combined, a subset of those facilities (and some additional facilities not identified) may be reasonable.").

EPA took this same approach in other states. *See* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,352-53; Proposed Montana Regional Haze FIP, 77 Fed. Reg. at 24,058-59; and Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. at 58,624-26. By notable contrast, EPA's Region 6 office did not perform *any* evaluation to identify *any* Arkansas point sources contributing to visibility impairment (or the scope of contribution) at Caney Creek or Upper Buffalo. EPA also performed multi-source emissions analysis using CAMx in most of those other states rather than looking only at the potential impact on visibility using the CALPUFF,

[18] EPA must provide a reasoned basis for failing to analyze whether these other emission sources should be evaluated for reasonable progress purposes. Indeed, EPA should have conducted multi-source modeling to demonstrate that the other six largest point sources in Arkansas do not contribute to visibility impairment in the Arkansas Class I areas.

[19] *Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans (FIP TSD)*, Appendix A at A-4 (Nov. 2014) ("TX FIP TSD").

[20] *Id.* at A-15 – A-26.

[21] *Id.* at A-49.

single source model, as it did in Arkansas. *See* Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,877-78; Proposed Montana Regional Haze FIP, 77 Fed. Reg. at 24,050; Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. at 58,635.

EPA proceeded to complete the required four-factor reasonable progress analysis in those other states only after narrowing the list of potential point sources. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,872. *See also* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,138, 9,352-53 (Feb. 18, 2014); Proposed Montana Regional Haze FIP, 77 Fed. Reg. 23,988, 24,058-59 (Apr. 20, 2012); and Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. 58,570, 58,624-26 (Sept. 21, 2011). No doubt, this process was utilized because the Regional Haze Rule requires that additional controls for proposed emission reductions, as identified in an implementation plan, *must be needed to achieve reasonable progress*.[22] EPA's failure to follow these same procedures in the Arkansas Proposed FIP is completely inconsistent with its prior actions and renders the Proposed FIP arbitrary and capricious.

(ii) EPA's review and determination of cost effectiveness is inconsistent with other state programs.

EPA's disregard for consistent reasonable progress review and analysis continued into the required four-factor analysis. After making the unsubstantiated and unsupportable determination to target only Independence, EPA applied different dollar per ton cost effectiveness thresholds for proposed controls at the plant, which are out of line with the standards applied in other regional haze SIPs and FIPs. Specifically, EPA's Proposal attempts to justify a cost effectiveness of dry FGD at Independence totaling \$2,477/SO_2 ton removed for Unit 1 and \$2,686/SO_2 ton removed for Unit 2. 80 Fed. Reg. at 18,944. This far exceeds the cost threshold approved by EPA for reasonable progress controls for other states. *See* Section III.C.3 below.

(iii) EPA's evaluation and application of NOx control requirements is inconsistent with other state programs.

EPA's decision to evaluate *and propose* NOx controls at Independence stands completely opposite its decision not to even evaluate NOx controls for Texas' point sources despite similar visibility conditions. *See* Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,873 ("we are limiting our analyses to consideration of SO_2 controls for these EGU sources, as our modeling indicates that the impacts from these sources on the 20% worst days are primarily due to sulfate emissions."). EPA's decision in this Proposal to impose NOx limits on Independence is inexplicable given the very low visibility improvement projected and the fact that such limits are completely unnecessary for Arkansas to stay below the URP. *See* 40 C.F.R. §§ 51.308(d)(1)(ii) and (d)(3) (explaining that "emission reduction measures" must be necessary to achieve reasonable progress goals). Visibility at Arkansas' Class I areas is only insignificantly impacted by all Arkansas point sources, even less so by point source contributions of NOx, and almost not

[22] *See* 40 C.F.R. §§ 51.308(d)(1)(i)(B) and (d)(3). Logic dictates that if a point source's contribution to visibility impairment is determined to be insignificant then additional controls are not necessary to achieve reasonable progress.

at all by Independence. *See* Section III.C.2 below. Further, Arkansas has sufficiently documented that those same Class I areas remain well ahead of the approved URP. *See* Section III.C.1 below.

2. EPA is obliged to act consistently in promulgating rules.

Reviewed individually, the issues identified above evidence an unjustified and inconsistent application of the Regional Haze Rule. Collectively, they demonstrate EPA's complete disregard for consistent review and uniform evaluation that is required by regulation. EPA's consistency regulations strive for "standardiz[ed] criteria, procedures and policies" when "implementing and enforcing the act." 40 C.F.R. §§ 56.3(a) and (b). They further oblige the Agency to ensure that actions taken under the Clean Air Act: (1) "[a]re carried out fairly and in a manner that is consistent with the Act and Agency policy as set forth in the Agency rules and program directives" and (2) "[a]re as consistent as reasonably possible with activities of other Regional Offices." 40 C.F.R. § 56.5(a).

In EPA's Arkansas FIP Proposal, EPA abandoned the standardized criteria, procedures and policies that had been used in other regional haze SIPs/FIPs. Even more remarkable, EPA's failure to complete a necessary reasonable progress analysis is the same justification EPA used to reject Arkansas' SIP proposal in the first instance. *See* 80 Fed. Reg. at 18,991 (noting that EPA's partial disapproval of the Arkansas regional haze SIP was based, in part, on the "finding that Arkansas did not complete a reasonable progress analysis and did not properly demonstrate that additional controls were not reasonable").

C. Installing Scrubbers At Independence Is Not Necessary To Demonstrate Reasonable Progress And Cannot Be Justified At This Time.

Units 1 and 2 at the Independence Station are not subject to BART. 80 Fed. Reg. at 18,991. EPA nonetheless treats the units as if they were subject-to-BART units by ignoring whether controls at the units are needed to improve visibility and looking only at whether controls are "cost effective." EPA must first determine that further actions are necessary in Arkansas beyond BART to ensure that visibility improvement is continuing on or below the glide path. *See* 42 U.S.C. § 7491(b)(2) (implementation plans must "contain such emission limits, schedules of compliance and other measures as may be *necessary* to make reasonable progress.") (emphasis added); Reasonable Progress Guidance at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period."). Only if further action is *necessary* for reasonable progress may EPA require additional controls and, even then, EPA must evaluate which controls are appropriate based on the statutory factors. *See* 42 U.S.C. § 7491(g)(1). EPA failed to do this here.

Arkansas' Class I areas, even without the proposed BART controls, are significantly below the URP and are on track to remain so for the next several years. Nonetheless, EPA has proposed to require emissions limits at Independence Units 1 and 2 based on the installation of SO_2 and NOx controls, ostensibly to achieve reasonable progress, and has offered two options for comment. Under Option 1, each coal-fired unit at Independence would be required to meet a rolling 30-day average SO_2 emission limit of 0.06 lb/MMBtu based on the installation and

operation of dry FGD systems, and a rolling 30-day average NOx emission limit of 0.15 lb/MMBtu based on the installation and operation of LNB/SOFA. *Id.* at 18,994, 18,997. Under Option 2, the Independence coal-fired units would be required to meet only the SO_2 limit. *Id.* at 18,994.

EPA's justification for imposing SO_2 and NOx emission limits on Independence is not based on rational policy, legal or environmental grounds and, as a result, it is arbitrary and capricious. EPA's primary justification for proposing reasonable progress limits at Independence is that "it would be unreasonable to ignore a source representing more than a third of the State's SO_2 emissions and a significant portion of NOx point source emissions." *Id.* at 18,992. EPA further supports its conclusion that emission limits based on the installation of major control technology are justified based on a finding that the proposed controls at Independence are cost effective. *Id.* at 18,994-97. However, the fact that a source, which is not subject to BART, may have significant SO_2 or NOx emissions, or that it would be cost effective to control such emissions, is irrelevant for reasonable progress purposes. EPA has not used such an inapplicable and inadequate justification to identify sources for control under a reasonable progress analysis in any other Regional Haze FIP. EPA did not appropriately analyze which sources, if any, should be controlled for reasonable progress and did not follow the procedures it has regularly used in other regional haze FIPS. *See* Section III.B above. Further, emission limits on Independence during at least the first planning period are unnecessary to demonstrate reasonable progress as Arkansas already is below the glide path for the first planning period.

EPA also improperly relied on CALPUFF modeling in its reasonable progress analysis and, as a result, has significantly over-estimated Independence's contribution to visibility impairment and the deciview improvement that would result from the installation and operation of emissions controls at Independence.[23] The visibility impairment at Arkansas' two Class I areas is caused overwhelmingly by point sources outside of the state, secondary organic aerosols - biogenic ("SOAB"), mobile sources, and Arkansas area sources,[24] not by Arkansas point sources such as power plants. EPA's singular focus on Independence will not result in any meaningful improvement in visibility at Caney Creek or Upper Buffalo and will not affect Arkansas' continued progress toward the 2064 natural visibility goal, but will cost EAI's customers and co-owners over $1 billion.

1. Controls on Independence do not further the goal of the Regional Haze Program.

The goal of the Regional Haze Program is the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I areas resulting from manmade air pollution. 42 U.S.C. § 7491(a)(1). Notably, the goal is not simply to reduce

[23] It is noteworthy that EPA issued, on July 29, 2015, a proposal to remove CALPUFF from EPA's preferred list of dispersion models used for Clean Air Act purposes. 80 Fed. Reg. 45,340 (July 29, 2015).

[24] EPA defines an area source as "a collection of similar emission units within a geographic area." EPA, *Introduction to Area Source Emission Inventory Development*, at 1.1-3 (Jan. 2001) *available at* http://www.epa.gov/ttnchie1/eiip/techreport/volume03/iii01_apr2001.pdf. "Area sources collectively represent individual sources that are small and numerous, and that have not been inventoried as specific point, mobile, or biogenic sources. Individual sources are typically grouped with other like sources into area source categories." *Id.*

emissions for the sole purpose of achieving emission reductions; rather, the program is designed to reduce emissions *where necessary* to remedy and prevent visibility impairment. 42 U.S.C. § 7491(b)(2). The program undertakes a gradual approach toward this goal, to assure that reasonable progress is being made while accounting for economic and technological constraints. The program is not designed to achieve the ultimate goal of eliminating visibility impairment immediately but, rather, over time. As EPA itself noted when establishing the Regional Haze Rule, which provides the states with a 64-year period to reach natural visibility conditions at Class I areas:

> [a]dvancements in technology and changes in economic factors will likely provide opportunities for implementation of new cost effective control measures to assure reasonable progress. The structure of EPA's rule is designed to require States, through the SIP process, to review the statutory factors on a periodic basis and determine appropriate changes to their strategies based on that review.

64 Fed. Reg. 35,714, 35,752 (July 1, 1999). EPA takes this extended period of time into account in providing guidance to the states on establishing their RPGs: "you should take into account the fact that the long-term goal of no manmade impairment encompasses several planning periods. It is reasonable for you to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal." Reasonable Progress Guidance at 1-4; *see also id.* at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period for some States.").

Thus, the threshold question is whether reductions in a source's emissions are *necessary* to achieve reasonable progress for the planning period under consideration. 42 U.S.C. § 7491(b)(2) (requiring regional haze implementation plans to contain measures "necessary to make reasonable progress toward meeting the national goal") (emphasis added). Here, where Arkansas is already below the URP for this planning period and projected to remain so for more than a decade, the answer is clearly no. EPA's proposed imposition of unnecessary controls is clearly unreasonable. *See Michigan v. EPA*, 135 S.Ct. at 2706 (requiring EPA's regulatory requirements to be "within the scope of its lawful authority" and its decision-making process to be "logical and rational").

(i) Arkansas' Class I areas are, and will remain, below the glide path well beyond the first planning period.

The proposed emission limits for Independence are not necessary to achieve reasonable progress because ADEQ has demonstrated that Caney Creek and Upper Buffalo will be below the glide path in 2018. State of Arkansas, *State Implementation Plan Review for the Five-Year Regional Haze Progress Report*, at 55-56 (May 2015) ("Arkansas Five-Year Progress Report").[25] Specifically, Caney Creek and Upper Buffalo have both shown improved visibility for the most impaired and least impaired days since 2001 and are projected to continue to improve. The current five-year average shows that, as of 2011, Caney Creek has achieved 73%

[25] Available at http://www.adeq.state.ar.us/air/planning/pdfs/ar_5yr_prog_rep_reviewfinal-6-2-2015.pdf.

of Arkansas' 2018 RPG of 3.88 dv and Upper Buffalo has achieved 66% of Arkansas' 2018 RPG of 3.75 dv. Arkansas Five-Year Progress Report at 60. Based on the five-year rolling averages and projected data, both Class I areas are on schedule to achieve their 2018 RPGs for the 20% worst days. *Id.* at 55, 57. Data from Caney Creek and Upper Buffalo show that the goal of no visibility degradation on the 20% best days will be achieved and that visibility has and will continue to improve. *Id.* at 42-43. EPA acknowledges these facts in the Proposal: "Arkansas Class I areas and those outside of Arkansas most significantly impacted by Arkansas sources are projected to meet the URP for the first planning period." 80 Fed. Reg. at 18,992. As a result of emission reductions achieved through regional and national programs, including MATS, CAIR, and CSAPR, future Clean Air Act programs such as implementation of the 1-hour SO_2 NAAQS, the revised ozone NAAQS and the Clean Power Plan, as well as the reductions for White Bluff and Independence that Entergy is proposing and the BART controls that EPA has proposed for the other sources in Arkansas, there is every reason to project continued improvement in visibility in Caney Creek and Upper Buffalo well beyond 2018.[26]

Entergy has conducted additional modeling using the Comprehensive Air Quality Model with Extensions ("CAMx") and statistical analysis that supports this conclusion. The CAMx modeling demonstrates that the haze index at Caney Creek and Upper Buffalo will remain below the URP for many years to come.[27] Recent IMPROVE monitoring data show that the haze index has been consistently below the URP in both Caney Creek and Upper Buffalo. Trinity Consultants, Inc. ("Trinity") also performed statistical analyses on the data from both Caney Creek and Upper Buffalo to statistically project the haze index trend through 2018.[28] Using a Ranked Statistical Analysis, the haze index for the average of the W20 days in 2018 is projected to be 20.07 dv at Caney Creek and 20.91 dv at Upper Buffalo.[29] These numbers are far below the URP for the first planning period and demonstrate that no source in Arkansas, including Independence, needs to install controls for Arkansas to remain below the glide path. *See* Figures 1 and 2.

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[26] The 5-Year Progress Report for Missouri also demonstrates that Mingo and Hercules Glades are on track to meet the 2018 visibility goals and Missouri has determined that further reductions are not necessary. *Missouri Regional Haze Plan: 5-Year Progress Report*, at 4, 17 (Aug. 29, 2014) ("The [monitoring] analyses in the 2009 RH plan demonstrate that the 2018 visibility goals for Mingo and Hercules Glades will be largely achieved from Electric Generating Unit (EGU) emission reductions resulting from the federal Clean Air Interstate Rule (CAIR) program."); *see also* Proposed Missouri SIP, 77 Fed. Reg. 11,958, 11,966 (Feb. 28, 2012) ("EPA proposes to find that Missouri has appropriately established goals that provide for reasonable progress towards achieving natural visibility conditions."); Final Missouri SIP, 77 Fed. Reg. 38,007 (June 26, 2012).

[27] The CAMx modeling was conducted by Trinity Consultants, Inc. Trinity's *Regional Haze Modeling Assessment Report*, which describes the CAMx modeling methodology that Trinity used to evaluate the visibility improvement of controls at Independence and White Bluff, is provided as Exhibit C to these comments.

[28] Trinity's report identifying why a statistical analysis was performed on the IMPROVE data and why the Ranked Statistical Analysis was selected is included as Exhibit D to these comments and incorporated by reference herein. *IMPROVE Data Statistical Analysis*, Trinity Consultants (July 2015) ("Trinity Report").

[29] Trinity also performed a Trend Statistical Analysis of the data, which projects even lower visibility impairment of 18.02 dv at Caney Creek and 20.44 dv at Upper Buffalo, Trinity Report at Section 3.1, but Entergy is using the more robust and conservative Ranked Statistical Analysis to demonstrate the expected trend in visibility impairment.

Figure 1

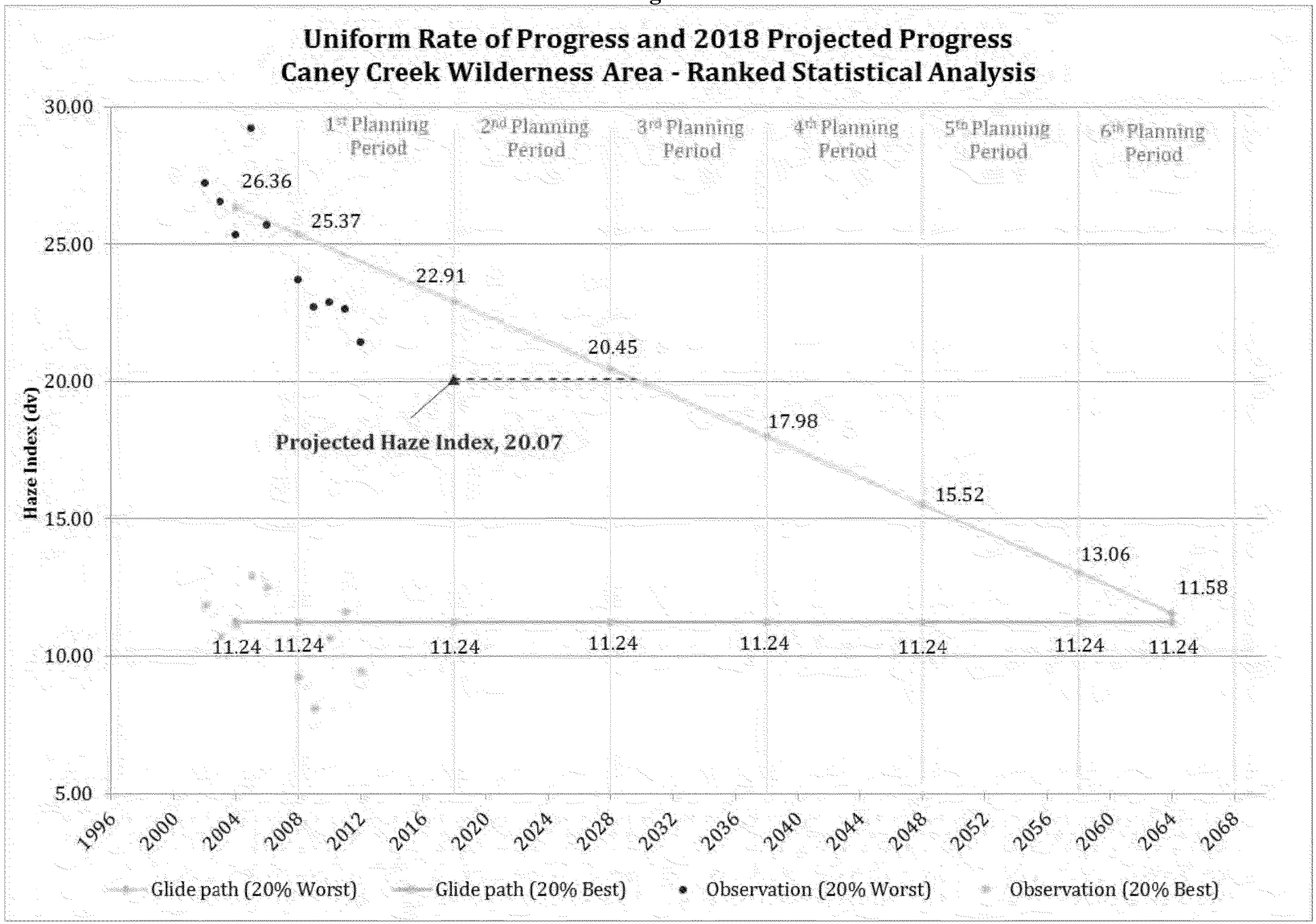
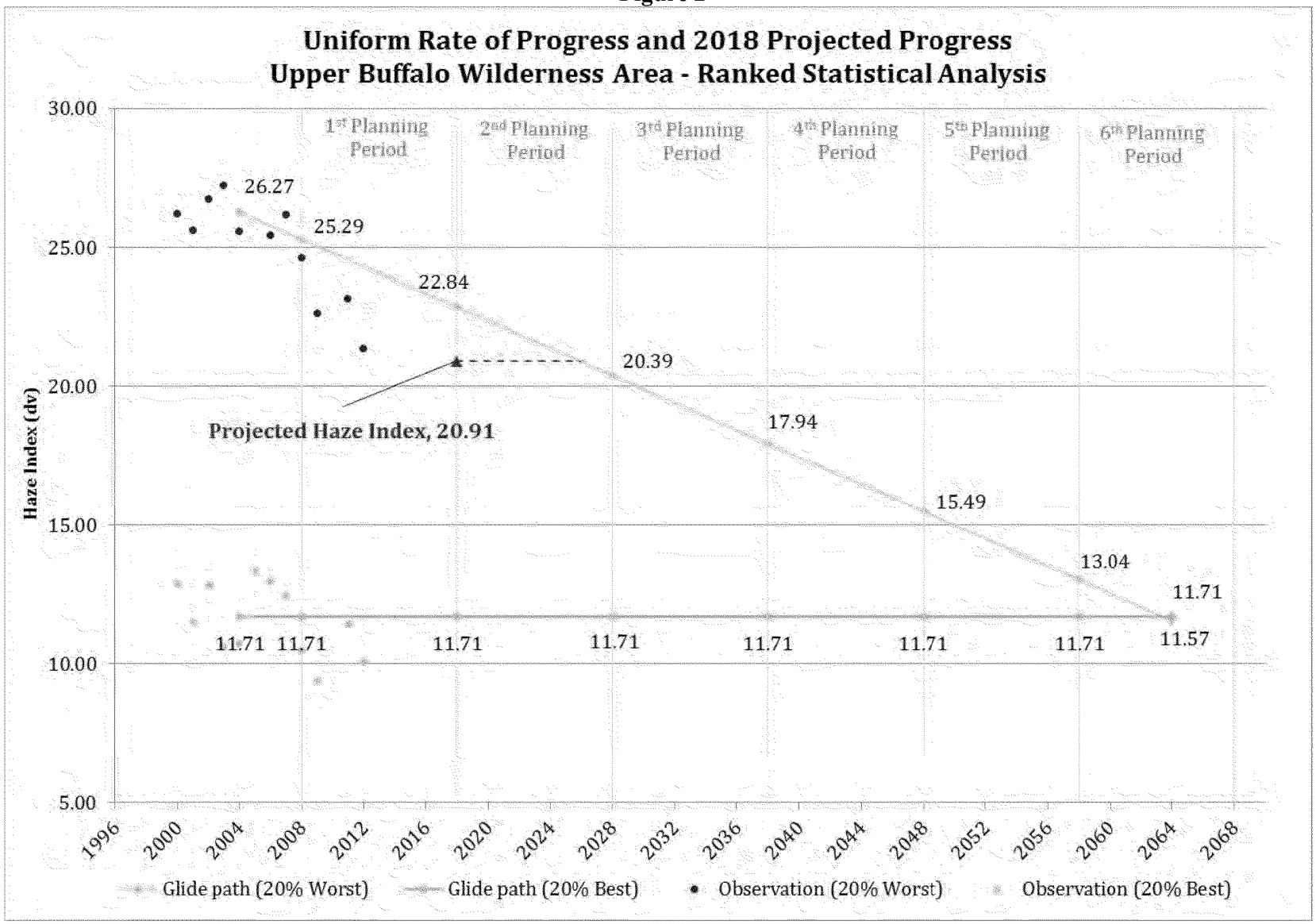

Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
11.24
Projected Haze Index, 20.07
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

Figure 2


Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.27
25.29
22.84
20.39
17.94
15.49
13.04
11.71
11.57
11.71
Projected Haze Index, 20.91
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

Figures 1 and 2 show the data plots for the 20% worst days and the 20% best days from the IMPROVE network for Caney Creek and Upper Buffalo, respectively. These plots demonstrate that the W20 days since 2007 have consistently been below the URP and that visibility is improving faster than the URP. Trinity applied a Ranked Statistical Analysis to all of the haze index values calculated using the new IMPROVE equation and the data from the IMPROVE monitoring network and constructed a future projection curve to statistically project the haze index at Caney Creek and Upper Buffalo in 2018. Trinity Report at Section 3.2. As demonstrated in Figure 1, the Ranked Statistical Analysis indicates that the haze index in 2018 at Caney Creek will be 20.07 dv, which is 2.84 dv below the URP. Indeed, if EPA does nothing at all (i.e., imposes no BART limits on sources in Arkansas or emission limits on Independence), Caney Creek would not approach the glide path until 2030. Figure 2 shows very similar results for Upper Buffalo, which would not approach the glide path until at least 2026. In light of these projections, which align with ADEQ's glide path demonstrations (*see* Arkansas Five-Year Progress Report at 57-60), SO_2 and NOx emission limits at Independence are unnecessary for reasonable progress purposes for at least a decade.

Notably, the Ranked Statistical Analysis conservatively assumes that there will be no additional emissions reductions resulting in visibility improvements after 2018, including emissions reductions from out-of-state sources, which cause over 50% of the visibility impairment in Arkansas Class I areas, or from area and mobile sources, which account for approximately 9.25% of the visibility impairment at Caney Creek and 9.68% at Upper Buffalo.[30] Assuming that MATS achieves the emissions reductions that EPA projects in terms of acid gas controls and retirements,[31] that CSAPR tightens the SO_2 emission budgets in the second phase, that sources will be forced to make additional SO_2 and NOx reductions to comply with the 1-hour SO_2 NAAQS and the revised ozone NAAQS, and that the Phase 2 CAFE fuel economy standards drive further reductions from mobile sources, the haze index in Caney Creek and Upper Buffalo will continue to improve beyond 2018 without controls on Independence.

(ii) Emissions from out-of-state sources and Arkansas mobile and area sources have a more significant impact on Arkansas' Class I areas.

In the Proposal, EPA's reasonable progress analysis primarily focuses on point source contributions to light extinction at Caney Creek and Upper Buffalo. As a result, EPA chose to limit its evaluation of potential reasonable progress controls solely to Arkansas' largest emitting point sources, and, specifically, to Independence. However, as demonstrated in Figures 3 and 4 below, Arkansas point sources are relatively insignificant contributors to visibility impairment in Caney Creek and Upper Buffalo compared to most of the other regions modeled by CENRAP and are not even the biggest source group contributor in Arkansas to visibility impairment in these Class I areas.[32]

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[30] These percentages are based on CENRAP's Particulate Matter Source Apportionment Technique ("PSAT") tool.

[31] Entergy expects the MATS Rule will go forward before the end of this planning period along with the associated emission reductions. *See* footnote 5 above.

[32] Figures 3 and 4, as well as Figures 5 and 6, were developed by extracting the modeled source apportionment extinction data from the CENRAP PSAT tool for Caney Creek and Upper Buffalo. The data obtained were organized by geographic region and source category, so that the individual contribution of each source category in each geographic region could be determined.

Figure 3

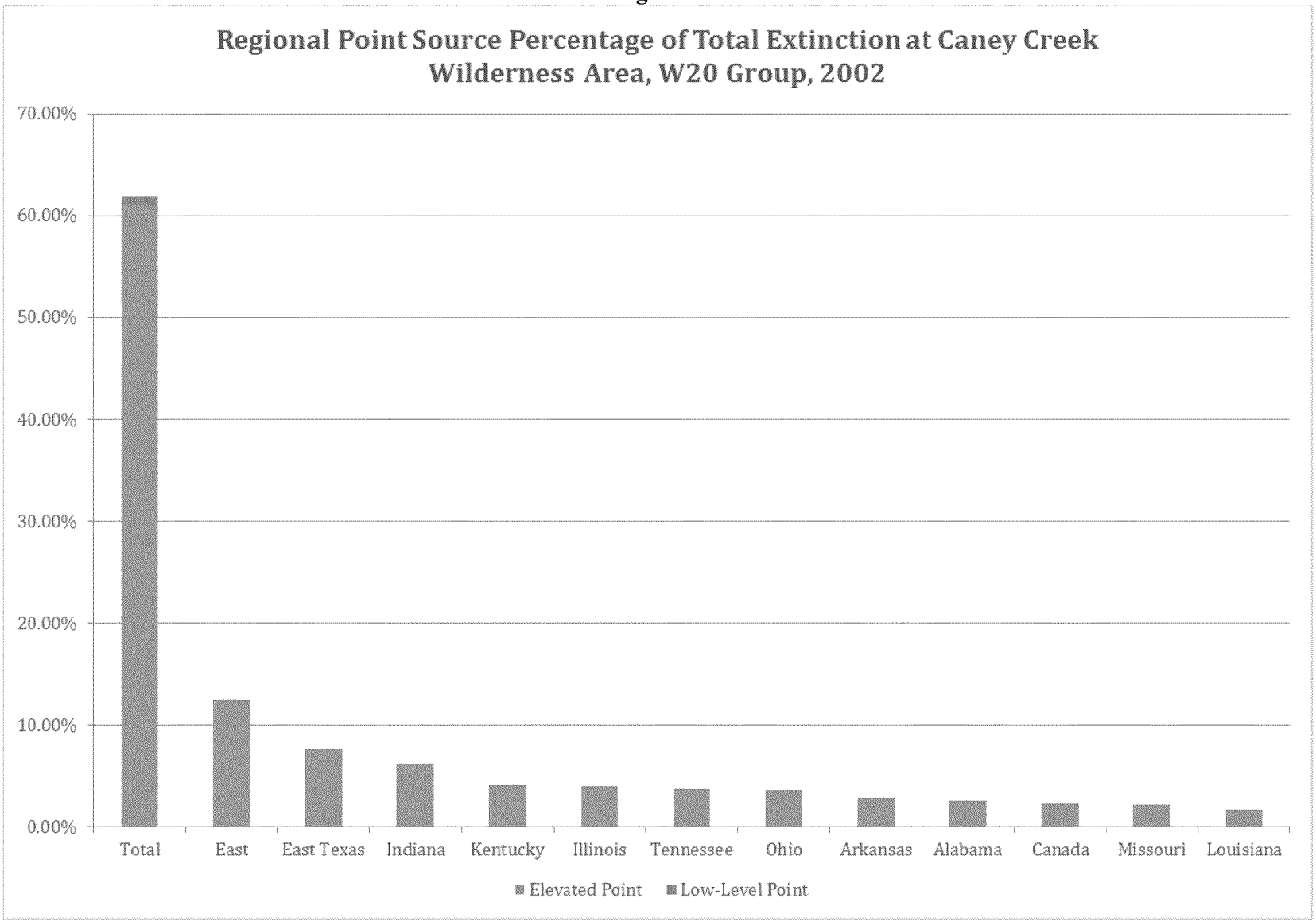
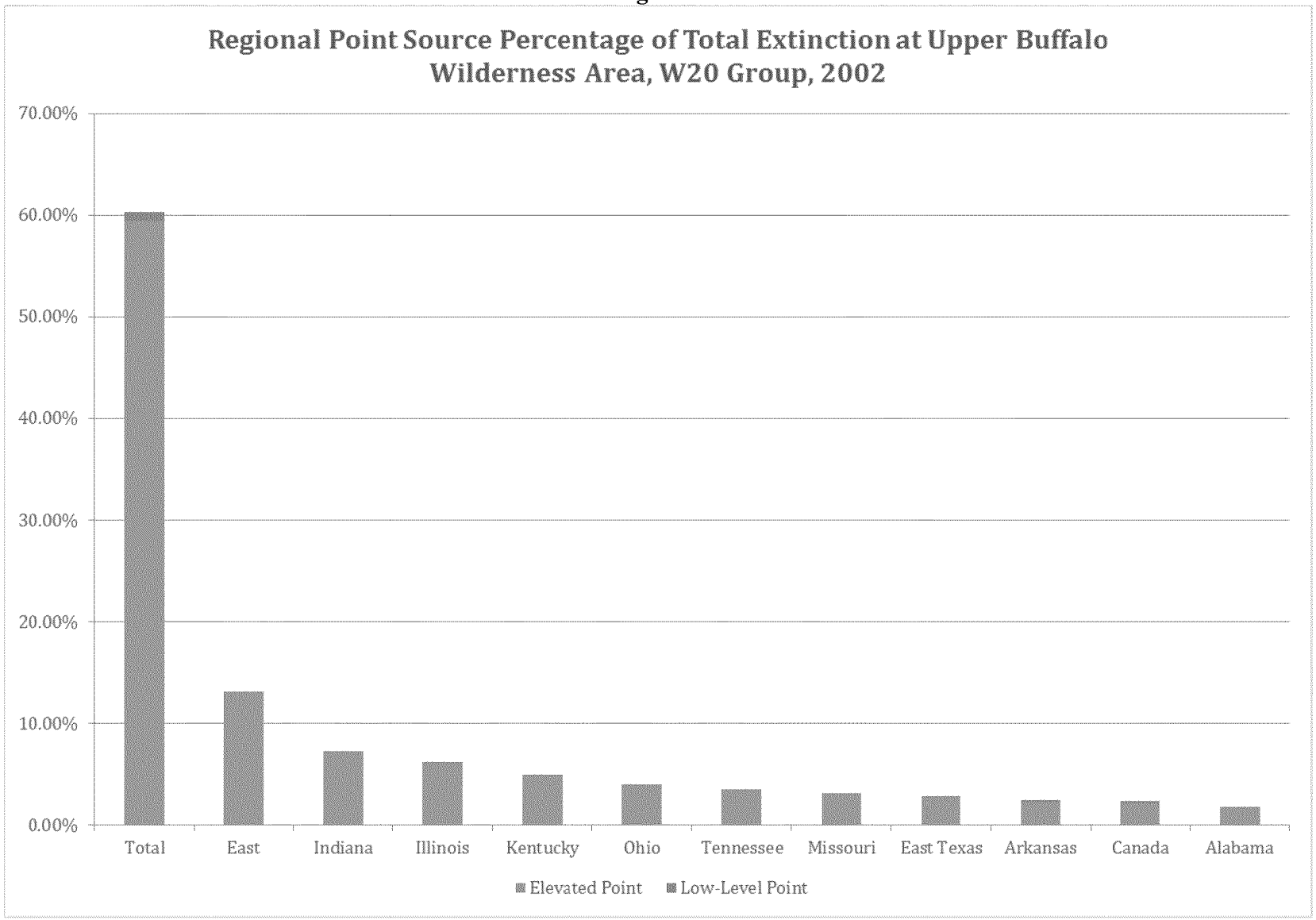

Regional Point Source Percentage of Total Extinction at Caney Creek Wilderness Area, W20 Group, 2002
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Total
East
East Texas
Indiana
Kentucky
Illinois
Tennessee
Ohio
Arkansas
Alabama
Canada
Missouri
Louisiana
Elevated Point
Low-Level Point

Figure 4


Regional Point Source Percentage of Total Extinction at Upper Buffalo Wilderness Area, W20 Group, 2002
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Total
East
Indiana
Illinois
Kentucky
Ohio
Tennessee
Missouri
East Texas
Arkansas
Canada
Alabama
Elevated Point
Low-Level Point

Figures 3 and 4 display the modeled percent contribution of elevated and low-level point sources to the total light extinction from the significantly contributing geographic regions. Also included in these figures is the combined total percentage contribution from all point sources in all geographic regions. Of a total point source contribution of 61.85% at Caney Creek in 2002, Arkansas's point sources contributed only **2.87%**, making Arkansas the eighth highest point source contributor. Similarly, of the 60.35% total point source contribution at Upper Buffalo in 2002, Arkansas was the ninth highest point source contributor with only a **2.47%** contribution.

In addition, unlike these other regions, where point sources contribute the majority of visibility impairment to Arkansas' Class I areas, most of Arkansas' share of the contribution to visibility impairment comes from Arkansas area and mobile sources, not point sources. *See* Figures 5 and 6 below.

Figure 5

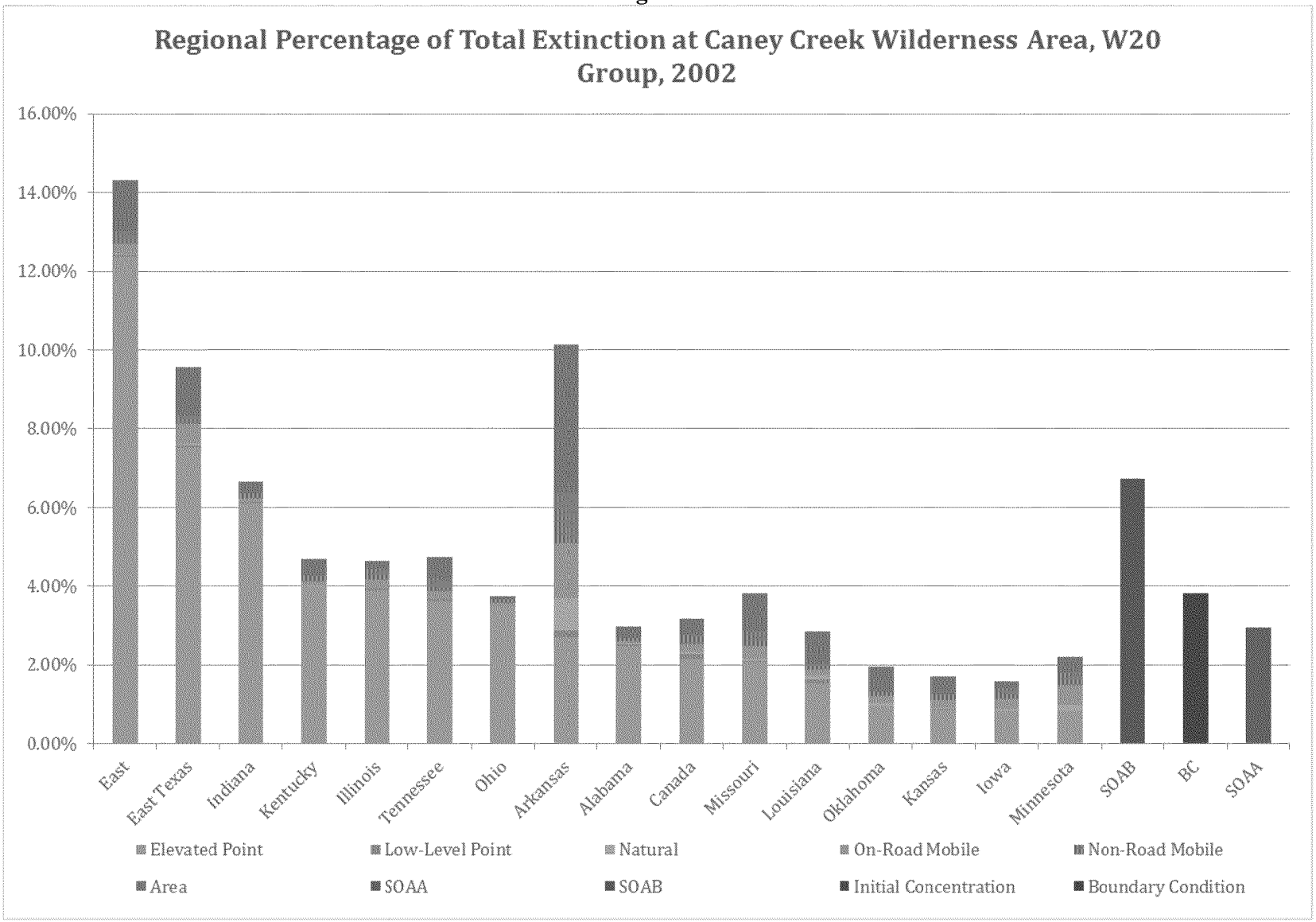
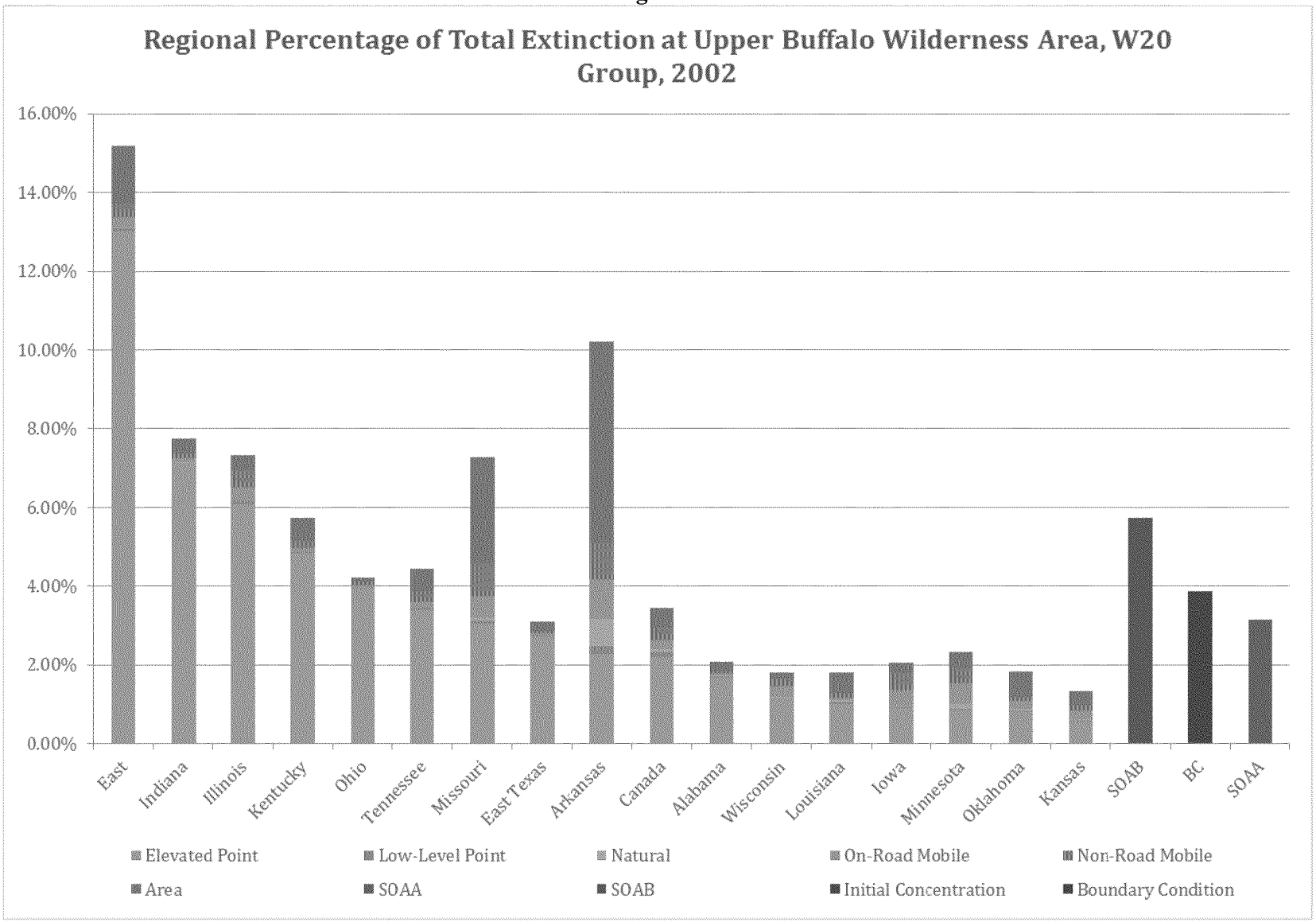

Regional Percentage of Total Extinction at Caney Creek Wilderness Area, W20 Group, 2002
16.00%
14.00%
12.00%
10.00%
8.00%
6.00%
4.00%
2.00%
0.00%
East
East Texas
Indiana
Kentucky
Illinois
Tennessee
Ohio
Arkansas
Alabama
Canada
Missouri
Louisiana
Oklahoma
Kansas
Iowa
Minnesota
SOAB
BC
SOAA
Elevated Point
Low-Level Point
Natural
On-Road Mobile
Non-Road Mobile
Area
SOAA
SOAB
Initial Concentration
Boundary Condition

Figure 6


Regional Percentage of Total Extinction at Upper Buffalo Wilderness Area, W20 Group, 2002
16.00%
14.00%
12.00%
10.00%
8.00%
6.00%
4.00%
2.00%
0.00%
East
Indiana
Illinois
Kentucky
Ohio
Tennessee
Missouri
East Texas
Arkansas
Canada
Alabama
Wisconsin
Louisiana
Iowa
Minnesota
Oklahoma
Kansas
SOAB
BC
SOAA
Elevated Point
Low-Level Point
Natural
On-Road Mobile
Non-Road Mobile
Area
SOAA
SOAB
Initial Concentration
Boundary Condition

At Caney Creek, Arkansas area sources contribute **3.75%** of the overall extinction while Arkansas' combined point source category (i.e., elevated and low-level point sources) contribute only **2.87%**. Even more significantly, Arkansas area sources contributed **5.09%** towards extinction at Upper Buffalo compared to **2.47%** from the combined Arkansas point sources.

Independence's emissions, which comprise only a portion of Arkansas' point source emissions, have even less of an effect on light extinction in either Class I area. As a result, installing emissions controls on Independence will not meaningfully change the haze index at either Class I area.

(iii) Emissions from out-of-state sources will continue to improve.

Entergy's analysis demonstrates that Arkansas' Class I areas will remain below the glide path in the first planning period and well into the second based on actual data (*see* Section III.C.1.i above); however, the analysis also demonstrates that, due to continued emissions reductions at sources outside of Arkansas, these reductions will continue, furthering Arkansas' progress towards background visibility, without controls on Independence. Point source emissions from the other states included in CENRAP's modeling have been steadily decreasing since the early 2000's and that trend is expected to continue. Indeed, a number of sources in East Coast states have recently announced retirements. The U.S. Energy Information Administration predicts that 60 gigawatts of coal-fired power plant capacity will retire by 2020.[33] These units are significant contributors to visibility impairment at Caney Creek and Upper Buffalo and their retirement will further improve visibility. The second phase of CSAPR, the 1-hour SO_2 NAAQS and the revised ozone NAAQS also will result in significant reductions in SO_2 and NOx emissions from the largest point source contributors to Caney Creek and Upper Buffalo, which are all located outside of Arkansas. *See* Figures 7 and 8 (demonstrating declining emissions trends and the contributions of EGUs).

[33] http://www.eia.gov/todayinenergy/detail.cfm?id=15031#

Figure 7

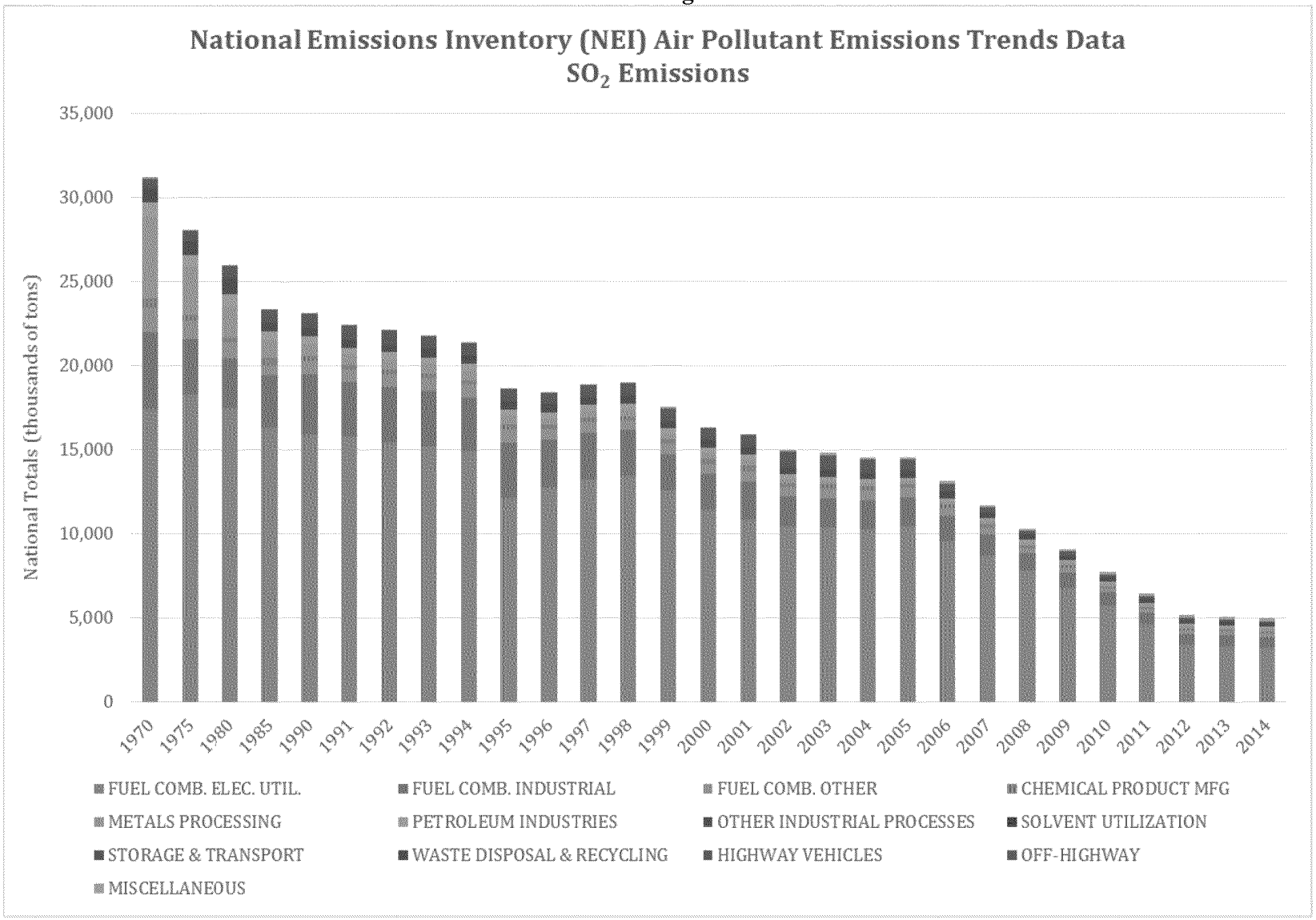
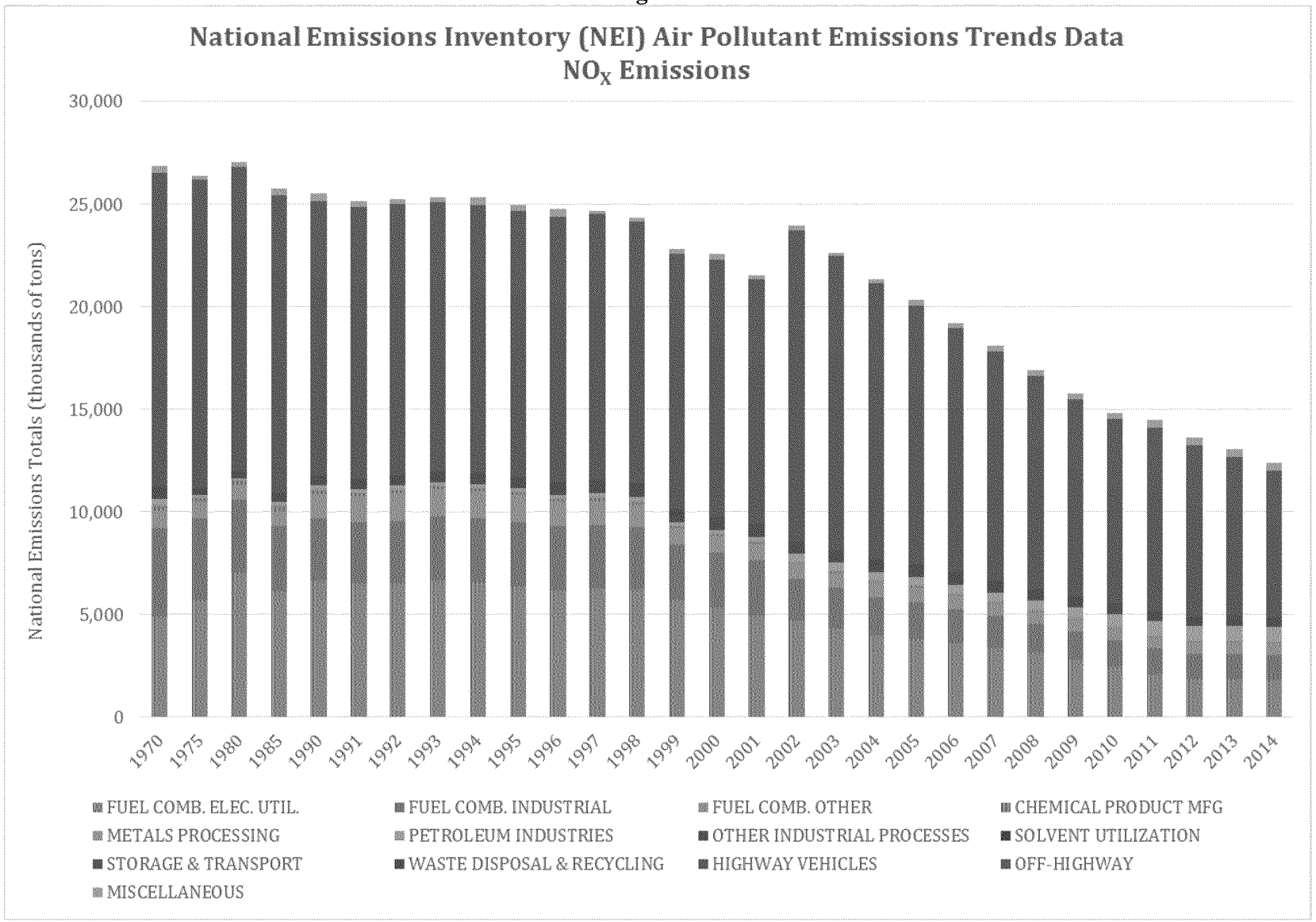

National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data
SO_2 Emissions
National Totals (thousands of tons)
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1970
1975
1980
1985
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
FUEL COMB. ELEC. UTIL.
FUEL COMB. INDUSTRIAL
FUEL COMB. OTHER
CHEMICAL PRODUCT MFG
METALS PROCESSING
PETROLEUM INDUSTRIES
OTHER INDUSTRIAL PROCESSES
SOLVENT UTILIZATION
STORAGE & TRANSPORT
WASTE DISPOSAL & RECYCLING
HIGHWAY VEHICLES
OFF-HIGHWAY
MISCELLANEOUS

Figure 8


National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data
NO_X Emissions
National Emissions Totals (thousands of tons)
30,000
25,000
20,000
15,000
10,000
5,000
0
1970
1975
1980
1985
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
FUEL COMB. ELEC. UTIL.
FUEL COMB. INDUSTRIAL
FUEL COMB. OTHER
CHEMICAL PRODUCT MFG
METALS PROCESSING
PETROLEUM INDUSTRIES
OTHER INDUSTRIAL PROCESSES
SOLVENT UTILIZATION
STORAGE & TRANSPORT
WASTE DISPOSAL & RECYCLING
HIGHWAY VEHICLES
OFF-HIGHWAY
MISCELLANEOUS

According to EPA's Reasonable Progress Guidance, the Agency should have taken the emissions reductions anticipated from CSAPR, as well as other Clean Air Act programs, into account in setting the proposed RPGs for Arkansas:

> Given the significant emissions reductions that we anticipate to result from BART, the CAIR, and the implementation of other CAA programs, including the ozone and $PM_{2.5}$ NAAQS, for many States this will be an important step in determining your RPG, and it may be all that is necessary to achieve reasonable progress in the first planning period for some States.

Reasonable Progress Guidance at 4-1. EPA completely failed to undertake this "important step" in proposing the RPGs for Arkansas and instead simply focused on controls at Independence.

2. Installation of controls on Independence Units 1 and 2 cannot be justified because of the de-minimis benefit toward reasonable progress.

EPA's own analysis counsels against imposing emission limits on Independence. EPA asserts that CENRAP modeling shows that sulfate from *all* point sources included in the regional modeling is projected to contribute to 57% of the total light extinction at Caney Creek on the W20 days in 2018 and 43% of the total light extinction at Upper Buffalo. 80 Fed. Reg. at 18,990. However, EPA recognizes that the CENRAP modeling also demonstrates that sulfate from all (elevated and low level) *Arkansas* point sources is projected to be responsible for only 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo. *Id.* The contribution of Arkansas point sources' nitrate emissions to visibility impairment at Arkansas' Class I areas is even more insignificant. According to EPA's analysis, nitrate from *all* point sources included in the regional modeling is projected to account for only 3% of the total light extinction at the Caney Creek and Upper Buffalo Class I areas, with nitrate from *Arkansas* point sources being responsible for only 0.29% of the total light extinction at Caney Creek and 0.25% at Upper Buffalo. *Id.* The Independence units' share of emissions to this minimal contribution from Arkansas point sources to visibility impairment at Caney Creek and Upper Buffalo is even less.

Entergy's CAMx modeling confirms that Independence's contribution to visibility impairment is insignificant in both Class I areas. Independence is projected to contribute to only 0.119 dv of visibility impairment at Caney Creek and Upper Buffalo on W20 days in 2018. *See* Figures 9 and 10.[34] This reflects only one half of one percent of the visibility impairment, based on modeling, on the W20 days in either Caney Creek or Upper Buffalo. Yet, based on such a miniscule contribution and with no credible explanation, EPA arbitrarily concludes that SO_2 and NOx controls at Independence are warranted.

[34] Figures 9 and 10 assume no FIP controls on any of the Arkansas sources. Also, the total haze index values presented in Figures 9 and 10 are based on Entergy's CAMx model predicted total contribution calculated using the new IMPROVE equation, whereas the projected haze index values in Figures 1, 2, and 11 - 14 are based on Trinity's Ranked Statistical Analysis and represent the average haze index for the W20 days. *See* Section III.C.1.i, above.

Figure 9

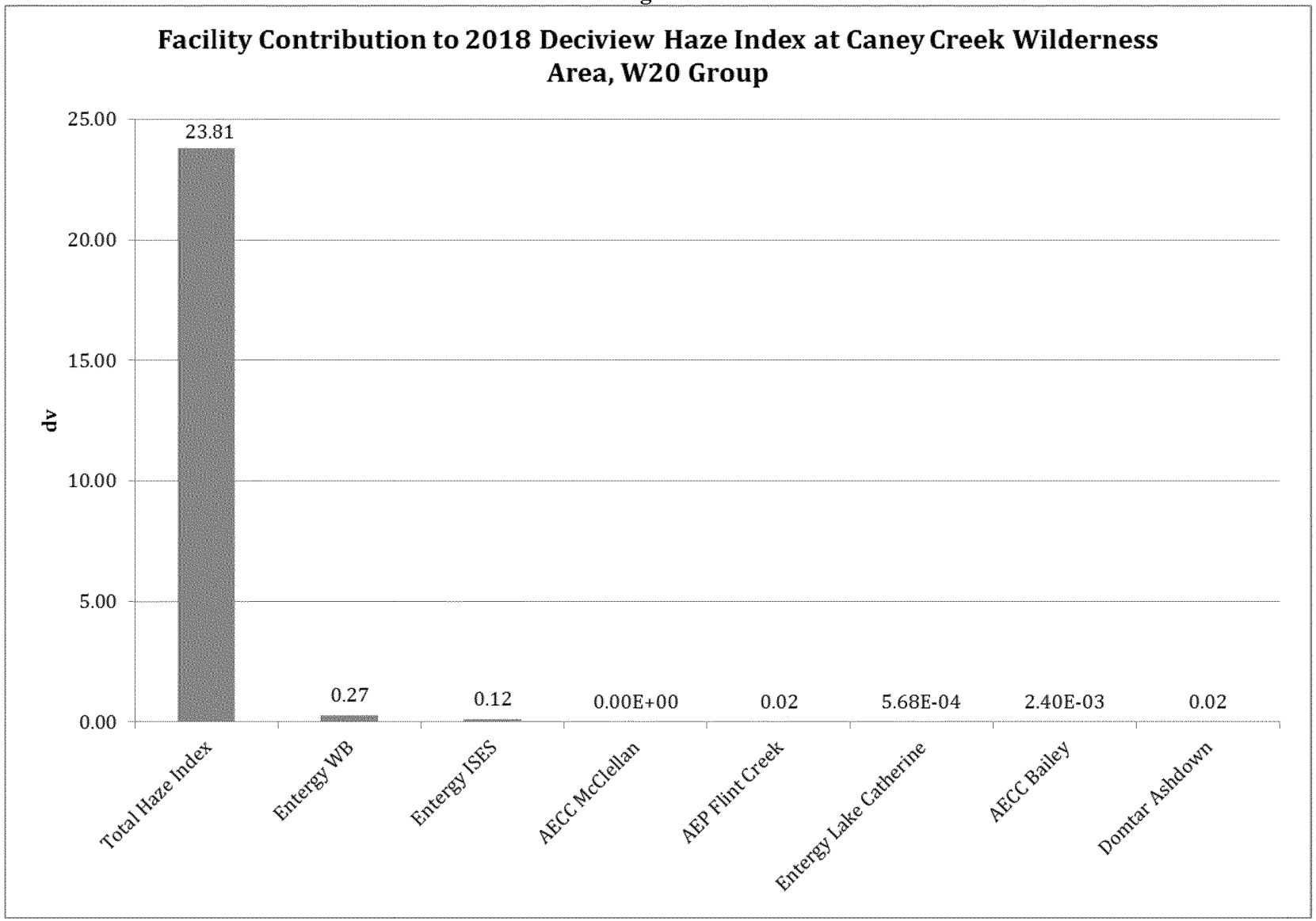
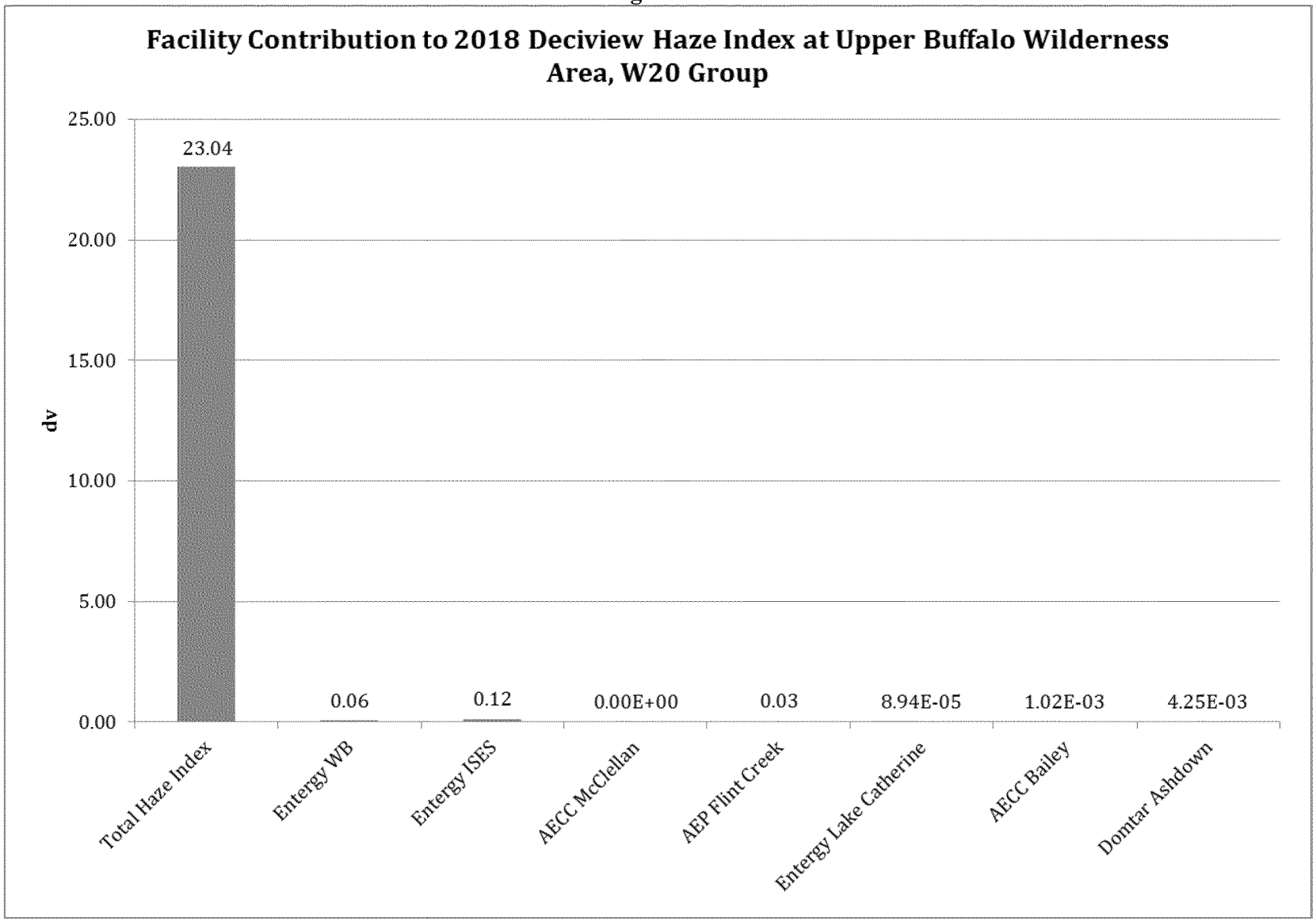

Facility Contribution to 2018 Deciview Haze Index at Caney Creek Wilderness Area, W20 Group
dv
25.00
20.00
15.00
10.00
5.00
0.00
23.81
0.27
0.12
0.00E+00
0.02
5.68E-04
2.40E-03
0.02
Total Haze Index
Entergy WB
Entergy ISES
AECC McClellan
AEP Flint Creek
Entergy Lake Catherine
AECC Bailey
Domtar Ashdown

Figure 10


Facility Contribution to 2018 Deciview Haze Index at Upper Buffalo Wilderness Area, W20 Group
dv
25.00
20.00
15.00
10.00
5.00
0.00
23.04
0.06
0.12
0.00E+00
0.03
8.94E-05
1.02E-03
4.25E-03
Total Haze Index
Entergy WB
Entergy ISES
AECC McClellan
AEP Flint Creek
Entergy Lake Catherine
AECC Bailey
Domtar Ashdown

(i) CALPUFF modeling cannot be used to justify reasonable progress controls at Independence.

Entergy acknowledges that, under the Regional Haze Rule, "the URP does not establish a 'safe harbor' for the state in setting its reasonable progress goals." 80 Fed. Reg. at 18,992 (referencing 64 Fed. Reg. at 35,732). Nonetheless, EPA must demonstrate that additional controls are rational and economically justifiable and that the amount of progress that would result will be "reasonable based upon the statutory factors." *Id.* EPA has explained that this requires a consideration of the projected visibility benefit expected from the controls. *Id.* at 18,993.

EPA admits that it did not perform refined, multi-state modeling to determine the amount of visibility improvements that would be achieved through the installation of controls because it would be difficult, time-consuming, and expensive. Instead, the Agency took a "thumbnail" approach in an attempt to justify the proposed controls based on how long it would take to achieve background levels. 80 Fed. Reg. at 18,997-98. EPA's use of CALPUFF, a single source model, for evaluating the reasonable progress benefits of installing controls at Independence is misplaced and clearly in error. CALPUFF is not appropriate for reasonable progress purposes as it addresses a fundamentally different question than a proper reasonable progress analysis. TX FIP TSD at A-35. As EPA itself has recognized, CALPUFF is overly simplistic and greatly overstates the effect of single source emissions. BART Guidelines, 70 Fed. Reg. 39,104, 39,121 (July 6, 2005) ("there are other features of our recommended modeling approach that are likely to overstate the actual visibility effects of an individual source. Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source."). CALPUFF also fails to show the effects of multiple sources, and is much less sophisticated in its treatment of the chemical interactions of the different pollutants in the atmosphere than CAMx.

EPA has recognized that CAMx, a photochemical transport 3-dimensional grid model, is a more appropriate modeling tool for reasonable progress purposes. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,877-78. BART analyses assess the impact of a single facility based on the maximum or 98th percentile impacts, regardless of whether the Class I area was actually experiencing high visibility impairment on any given day. Since CALPUFF does not conduct an analysis considering all the emissions from all potential sources, some of the days with the worst model-predicted concentrations could be days that are not significantly impaired. Reasonable progress modeling using a photochemical model, such as CAMx, allows EPA to evaluate impacts from a source (with all other sources included in the modeling) on a Class I area's best and worst days. *Id.* at 74,878.

The draft *EPA Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze* (Dec. 2014) ("Draft Modeling Guidance") discusses the use of photochemical grid models and notes that Community Multiscale Air Quality Model ("CMAQ") and CAMx are the most commonly used models for attainment demonstrations. The Draft Modeling Guidance specifically notes that "a modeling based demonstration of the impacts of an emissions control scenario... as part of a regional haze assessment usually necessitates the

application of a chemical transport grid model." Draft Modeling Guidance at 22.[35] Throughout the Draft Modeling Guidance, the discussion is focused on items specific to photochemical grid models such as CAMx, including emissions inventories, supporting models, pre-processors, and applying a model to changes in visibility.

According to the Draft Guidance, "the emission sources included in the analysis must be comprehensive, including emissions from all source categories" (i.e., point sources, non-point stationary sources, on-road and non-road mobile sources, fires, and biogenic sources) and "'all' sources of emissions." *Id.* at 32, 36. A CAMx modeling analysis includes a comprehensive inventory, capturing each of these source categories, which are then available to react with available precursors. By using the comprehensive inventory, this limits the amount of precursors available to react with the emissions from a facility or source in question. This has been referred to by EPA as a "dirty background analysis." CALPUFF analyses conducted in support of BART determinations do not consider the full inventory of sources and thus do not account for other pollutants challenging and consuming precursor emissions. As such, ammonia and other precursor pollutants are more fully available to react with a facility's emissions and generate haze impacts in a modeled simulation using CALPUFF. This is referred to by EPA as a "clean background analysis." Therefore, the use of CALPUFF does not reflect the interaction of pollutants in the atmosphere as accurately as CAMx does.

Notably, EPA recently issued a proposal on July 29, 2015, which would remove CALPUFF from EPA's preferred list of air dispersion models in its *Guideline on Air Quality Models* ("Guideline"), in Appendix W to 40 C.F.R. Part 51. Although EPA states that the proposed changes to the Guideline would not affect its recommendation that CALPUFF be used in the BART determination process, EPA made no such assurances regarding the use of CALPUFF for a reasonable progress analysis. Instead, EPA's proposal emphasizes the use of chemical transport models for assessing visibility impacts from a single source or small group of sources. According to the Agency,

> Chemical transport models are well suited for the purpose of estimating long-range impacts of secondary pollutants, such as $PM_{2.5}$, that contribute to regional haze and other secondary pollutants, such as ozone, that contribute to negative impacts on vegetation through deposition processes. These multiple needs require a full chemistry photochemical model capable of representing both gas, particle, and aqueous phase chemistry for $PM_{2.5}$, haze, and ozone.

80 Fed. Reg. at 45,349. CALPUFF is clearly inferior in this regard.

Indeed, EPA's *Interagency Workgroup on Air Quality Modeling Phase 3 Summary Report: Long Range Transport and Air Quality Related Values*,[36] which EPA has made available as a supporting document for the proposed revisions to Appendix W, makes clear that CALPUFF should not be used for a reasonable progress analysis. The report explains that, "[a] modeling system that treats emissions from all known anthropogenic and biogenic emissions sources with

[35] The Draft Modeling Guidance is available at http://www.epa.gov/scram001/guidance/guide/Draft_O3PM-RH_Modeling_Guidance-2014.pdf.
[36] Docket ID EPA-HQ-OAR-2015-0310-0004.

realistic chemical and physical transformations should be utilized to estimate future visibility conditions at a Class I area. The most appropriate tool that contains these qualities is a photochemical grid model [such as CAMx]." *Id.* at 6. It further explains that "the results from a BART determination or similar modeling using CALPUFF cannot be directly compared to estimated impacts of emissions controls from a single source on a reasonable progress goal…. Lagrangian puff models are not ideal for reasonable progress demonstrations since they typically characterize one or a small group of sources." *Id.* at 9.

(ii) The CALPUFF modeling vastly overstates the potential visibility improvement from controls on Independence.

EPA's CALPUFF modeling indicates that the SO_2 and NOx emission limits proposed for Independence will result in a 1.952 dv improvement in Caney Creek and a 1.782 dv improvement in Upper Buffalo. *See* Summary of Additional Modeling for Entergy Independence, at 8, Table 5 (Apr. 2015), EPA Docket ID EPA-R06-OAR-2015-0189-0147. However, this range is vastly overstated. Based on the current monitored visibility levels in Caney Creek and Upper Buffalo, the W20 days show that the visibility impairment in 2018 will be approximately 23 to 24 dv. EPA recognizes that sulfate from all of Arkansas' point sources are projected to be responsible for only about 3.6% of total light extinction at Arkansas' Class I areas based on CENRAP modeling. 80 Fed. Reg. at 18,990. This means that sulfate from *all* Arkansas point sources are projected to be responsible for only about 0.83 - 0.86 dv of impairment (23-24 dv x 3.6%). For nitrates, EPA projects that Arkansas point source emissions will account for, at most, 0.29% of the total light extinction at Arkansas' Class I areas. *Id.* at 18,990. Independence's SO_2 and NOx emissions contribute only a portion to the sulfate and nitrate percentages estimated from Arkansas point sources. It would, therefore, be impossible for the SO_2 and NOx limits proposed for Independence to result in deciview improvements at Caney Creek and Upper Buffalo of 1.952 dv and 1.782 dv, respectively. This simple example demonstrates the obvious flaw in EPA's use of CALPUFF for its reasonable progress analysis and, thus, its justification for imposing emission limits on Independence despite the fact that the Class I areas are below the URP.

Another illustration demonstrates why CALPUFF greatly overstates the benefits of overall visibility benefits from proposed emission limits. In the Proposal, EPA projects the visibility benefits from the proposed BART controls based on CALPUFF modeling. Based on CALPUFF, EPA's proposed BART limits at White Bluff, Flint Creek Power Plant, Carl E. Bailey Generating Station, John L. McClellan Generating Station, Lake Catherine and Domtar Ashdown Power Boilers will result in projected combined visibility benefits of approximately 4.3 dv at Caney Creek.[37] *See* Figure 11 below. Based on a statistical projection of the haze index in Caney Creek (*see* Section III.C.1 above), that would result in a haze index of 15.76 dv, which would put Caney Creek closer to natural background levels than the glide path. The URP

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

would not reach that haze level until approximately 2048.[38] Indeed, even if you ascribed the CALPUFF-projected benefits to Caney Creek based on the recent IMPROVE levels (approximately 22 dv between 2009 and 2012), the projected haze index would drop to 17.7 dv, which indicates no further action should be needed to remain below the URP until approximately 2038.

[38] The projected haze index at Upper Buffalo of 18.05 dv would keep Upper Buffalo below the glide path until approximately 2038 - the end of the third planning period. *See* Figure 12.

Figure 11

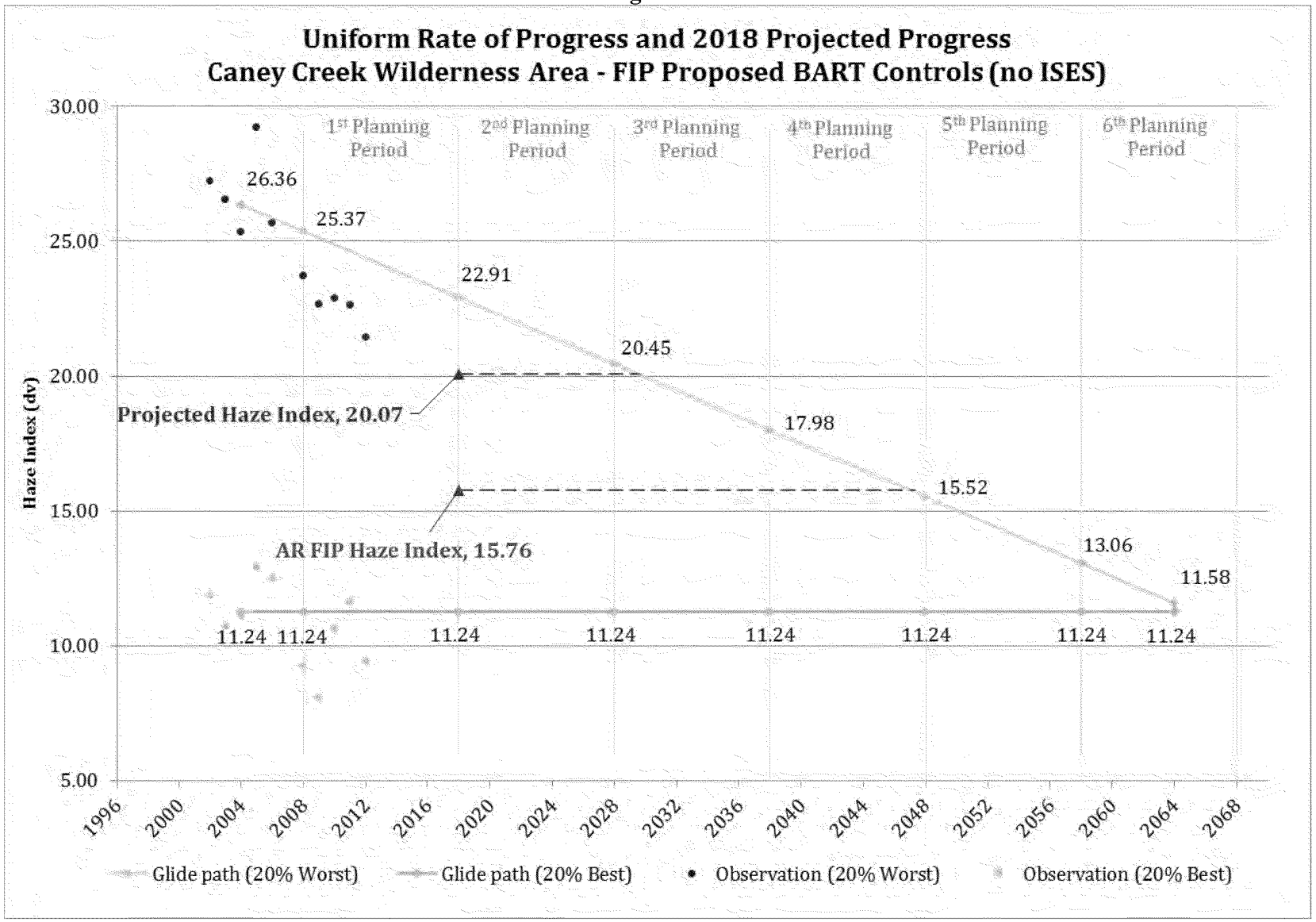
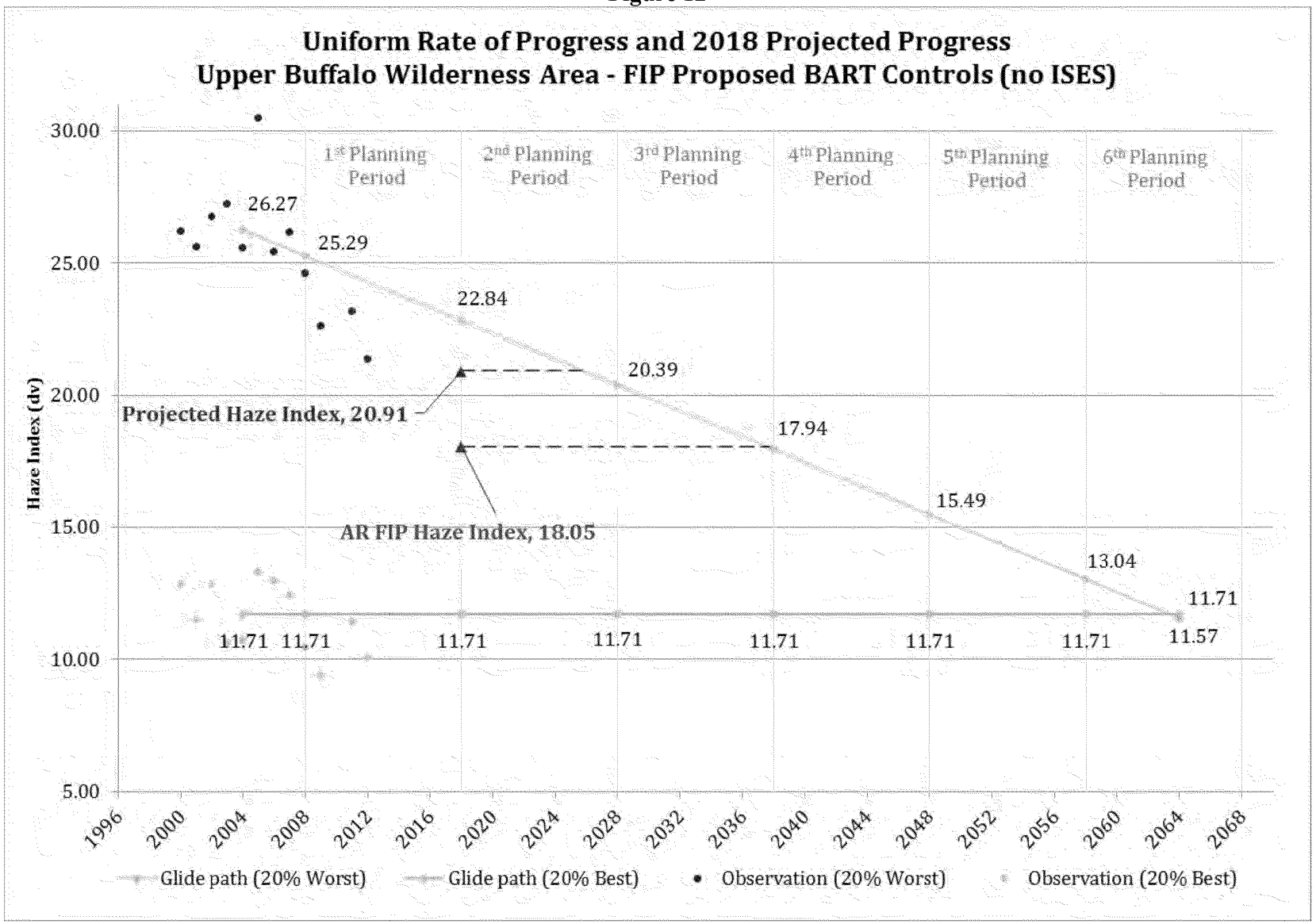

Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - FIP Proposed BART Controls (no ISES)
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
Projected Haze Index, 20.07
AR FIP Haze Index, 15.76
11.24 11.24 11.24 11.24 11.24 11.24 11.24 11.24
1996 2000 2004 2008 2012 2016 2020 2024 2028 2032 2036 2040 2044 2048 2052 2056 2060 2064 2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

Figure 12


Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - FIP Proposed BART Controls (no ISES)
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.27
25.29
22.84
20.39
17.94
15.49
13.04
11.71
11.57
11.71 11.71 11.71 11.71 11.71 11.71 11.71
Projected Haze Index, 20.91
AR FIP Haze Index, 18.05
1996 2000 2004 2008 2012 2016 2020 2024 2028 2032 2036 2040 2044 2048 2052 2056 2060 2064 2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

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

(iii) Controls on Independence will not yield perceptible visibility benefits.

As demonstrated above, EPA's CALPUFF modeling greatly overstates the visibility benefits that would result from installing controls at Independence and should be disregarded. Further, when EPA used the CENRAP model (an appropriate multi-source model) to assess overall visibility impairment, EPA concluded that the cumulative benefit of installing all of the controls in the Proposed FIP – all BART controls plus controls at Independence – would result in visibility benefits at Caney Creek of only 0.21 dv and at Upper Buffalo of only 0.19 dv. 80 Fed. Reg. at 18,998, Table 67. Since Independence represents only approximately 36% of the SO_2 point source emissions and 21% of the point source NOx emissions in Arkansas, *see id.* at 18,991, one can ascribe only a minor portion of this projected insignificant deciview improvement to controls on Independence (approximately **0.08** dv at Caney Creek and **0.07** dv at Upper Buffalo).[39] Based on this, installation of controls on Independence will yield no discernible visibility improvements.

Not only does this demonstrate the illogic of relying on CALPUFF for reasonable progress, it demonstrates that the realistic benefits resulting from installing controls at Independence will be inconsequential and will contribute virtually nothing to visibility improvement at either Class I area. According to EPA, one deciview reflects "perceptible changes" in visibility. *See* Proposed Regional Haze Rule, 62 Fed. Reg. 41,138, 41,145 (July 31, 1997) ("A one deciview change in haziness is a small but noticeable change in haziness under most circumstances when viewing scenes in mandatory Class I Federal areas."). Thus, the measure of visibility improvement is based on *noticeable changes*. By EPA's own standard, a total deciview improvement at Caney Creek of 0.21 dv from the installation of controls at all of the proposed FIP sources would not be perceptible to the human eye. Likewise, a total deciview improvement at Upper Buffalo of 0.19 dv would not be discernable. Independence's contribution to the deciview improvements EPA projects based on the CENRAP modeling would be much less; nowhere close to the 1.95 dv and 1.78 dv improvement that EPA is claiming based on CALPUFF.[40] Requiring imperceptible visibility improvements is simply unreasonable. The

[39] These values are the calculated improvement based on EPA's "scaling methodology." *See* 80 Fed. Reg. at 18,997.
[40] Even if the CALPUFF results were accurate, it is highly unlikely that such improvements would be perceptible. Studies have demonstrated that not only is the deciview scale not uniform in perception over a wide range of visibility conditions, but a 1-deciview change in visibility is not even perceptible to the human eye. *See* Exhibit E, *Just-Noticeable Differences in Atmospheric Haze*, Ronald C. Henry, Department of Civil and Environmental Engineering, University of Southern California, Los Angeles, Air & Waste Manage. Assoc. (2002). Instead, according to the Study, deciview improvements likely would need to be in the range of 2 to 5 dv to be perceptible. *Id.* at 1242, Figure 2.

CAA requires only "reasonable progress, not the *most* reasonable progress." *North Dakota v. EPA*, 730 F.3d 750, 767 (8th Cir. 2013).

In addition, the demonstration methodology used by EPA is unscientific. EPA used a ratio of emission rates from BART sources to Arkansas point sources to scale the modeled predicted haze index. First, there is no evidence to prove that the CAMx predicted modeling results are linearly correlated with emission rates. In fact, the CAMx modeling fundamentally is based on photochemical reactions. Therefore, the relationship between variation in the emission rates and predicted concentration is complicated. *See Chemical Characteristics of Inorganic Ammonium Salts in $PM_{2.5}$ in the Atmosphere of Beijing (China)*, A. Ianniello, F. Spataro, G. Esposito, I. Allegrini, M. Hu, and T. Zhu, 11 Atmos. Chem. Phys., at 10804 (2011).[41] For example, due to a high chemical affinity, an ammonia molecule reacts with SO_2 molecules to form sulfate before reacting with NOx molecules to form nitrate. If abundant SO_2 is present in the atmosphere, any increase in NOx emissions will not result in a linear increase in nitrate formation. As a result, there may not be any increase in the predicted regional haze. On the contrary, if abundant NOx molecules are present, then any reduction in SO_2 molecules will not result in a significant reduction in haze as NOx will substitute the reduced SO_2 in the reaction. Second, a deciview is a logarithmic scale based on the concept that one deciview is the minimum change in the visibility perceptible to a human observer. *See* 40 C.F.R. § 51.301 (definition of "deciview"). As such, deciviews cannot be added or subtracted directly. Therefore, fractioning or scaling deciviews based on emission rates is illogical.

(iv) EPA has offered no justification for requiring controls to achieve reasonable progress for this planning period when the controls cannot even be installed until the next planning period.

EPA further exceeds its authority by proposing to require controls in the name of achieving reasonable progress during the first planning period even though the emissions reductions the Agency proposes would not be achieved until well into the second planning period. The Proposed FIP covers a planning period of 2008-2018. The major SO_2 emissions control technology that would have to be installed at Independence to meet the proposed SO_2 emission rate limitation cannot be designed, constructed and operational in less than five years.[42] Given the likely effective date of the FIP in 2016, SO_2 controls at Independence could not be installed and operational before sometime in 2021.[43]

Adopting a reasonable progress goal for the first planning period based on the installation of controls that will not be completed until well after the deadline to achieve that reasonable progress goal makes no sense, and EPA has completely failed to explain why it is appropriate. Indeed, EPA will have multiple bites at this apple – there are still four more planning periods

[41] Available at http://www.atmos-chem-phys.net/11/10803/2011/acp-11-10803-2011.pdf.

[42] EPA recognizes this timeframe is necessary for the installation of SO_2 controls at Independence by proposing that Independence meet the SO_2 emissions limits no later than five years after the effective date of the final rule. 80 Fed. Reg. at 18,994. Entergy agrees with EPA's conclusion that a five-year timeframe would be necessary for the installation of controls at Independence.

[43] The Proposed FIP provides for NOx emission limitations to be met three years after the effective date of the FIP, which would not be earlier than sometime in 2019.

during which the necessity of reasonable progress controls can be evaluated. Controls on Independence should not be considered until these subsequent planning periods, and should not be imposed for a planning period that will have ended by the time any emissions reductions can be achieved at Independence. This is consistent with EPA's Reasonable Progress Guidance: "It is reasonable for [a state] to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal." Reasonable Progress Guidance at 1-4.

3. The proposed controls are not cost effective.

EPA's secondary justification for imposing controls on Independence is that it is, in EPA's opinion, cost effective to do so. 80 Fed. Reg. at 18,994-97. First, EPA's cost analysis for the proposed controls at Independence relies upon the control cost analysis for White Bluff, *see* SO_2 Cost TSD at 16, which is inappropriate. By simply relying on its White Bluff cost analysis without undertaking a site-specific analysis for Independence, EPA did not follow the steps necessary to identify the costs of controls for reasonable progress purposes. EPA's Reasonable Progress Guidance requires that EPA (1) identify the emissions units to be controlled; (2) identify the design parameters for the controls; and (3) develop cost estimates based upon those design parameters. Reasonable Progress Guidance at 5-1.

Second, even if the White Bluff cost analysis were sufficiently indicative of the costs to install controls at Independence, Entergy disagrees with EPA's estimated costs for the installation of dry scrubbers at White Bluff. *See* Section III.A.2 above. Assuming that dry FGD controls at Independence would cost the same as at White Bluff, the controls at Independence also would cost over $1 billion. *See* Section III.A.3 above. This is not cost effective on a $/ton basis for reasonable progress purposes as it would result in $4,234 per ton of SO_2 removed at Independence Unit 1 and $3,909 per ton of SO_2 removed at Independence Unit 2.

Finally, even if EPA's cost analysis as detailed in the SO_2 Cost TSD were correct, EPA's determination that the controls are cost effective is an insufficient basis to conclude that they must be installed for reasonable progress purposes.

(i) Requiring over $1 billion in controls at Independence to achieve an unnecessary and imperceptible change in visibility at Arkansas' Class I areas is patently unreasonable.

Despite the flaws in EPA's analysis of Entergy's costs, EPA concludes that dry FGD is cost effective at $2,477 per ton of SO_2 removed for Independence Unit 1 and $2,286 per ton of SO_2 removed for Unit 2. 80 Fed. Reg. at 18,994. Dry FGD is not cost effective for reasonable progress controls. These costs are higher than other cost per ton thresholds in RPG determinations in EPA-approved SIPs. The Kentucky Regional Haze SIP, 76 Fed. Reg. 78,194, 78,206 (Dec. 16, 2011), used $2,000 per ton SO_2 as a screening threshold for cost effectiveness based on CAIR. In the North Carolina Regional Haze SIP, 77 Fed. Reg. 11,858, 11,870 (Feb. 28, 2012), EPA approved the state's decision not to implement reasonable progress controls due to limited improvement in visibility even though cost effectiveness values were described as ranging "from 912 to 1,922 dollars per ton of SO_2 removed ($/ton SO_2), and the average costs per utility system ranged from $1,231 to $1,375/ton SO_2." EPA's estimated cost effectiveness of dry FGD at Independence is significantly higher than these thresholds, at $2,477/$SO_2$ ton

removed for Unit 1 and \$2,286/SO_2 ton removed for Unit 2. 80 Fed. Reg. at 18,994. Further, EPA has indicated that control costs found to be reasonable in the BART context may nonetheless be considered too costly in the reasonable progress context. *See* Final North Dakota SIP Approval/Disapproval, 77 Fed. Reg. 20,894, 20,936 (Apr. 6, 2012) (accepting North Dakota's determination that a level of \$2,593 per ton of SO_2 removed was not reasonable and too costly in the reasonable progress context even though it is within the range EPA "ha[s] considered reasonable in the BART context"). Despite these prior actions, EPA unreasonably concludes that the proposed controls at Independence are cost effective for reasonable progress purposes.

Additionally, EPA failed to consider the cost effectiveness of the controls relative to the visibility benefit that would result. EPA's own guidance notes that for "individual, large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation." Reasonable Progress Guidance at 5-2. Here, EPA gave no consideration to the dollar-per-deciview resulting from installing scrubbers at Independence. If EPA had done so, it would recognize that the costs are approximately **\$1.33 billion** per dv improvement at Caney Creek and **\$1.53 billion** per dv improvement at Upper Buffalo. *See* S&L FIP Cost Report at 21, Table 8. Where additional visibility improvement is not needed to remain below the glide path, such an exorbitant cost cannot be justified. *See Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1149 (9th Cir. 2015) ("*NPCA*") (upholding EPA's decision not to require reasonable progress controls because of lack of cost-effectiveness, finding reasonable EPA's explanation that "cost of compliance is only one of the four statutory requirements for reasonable progress analysis.").

(ii) EPA inappropriately revised Entergy's control cost analysis by eliminating consideration of proper costs.

EPA's cost estimates are artificially low because they fail to account for key considerations. As discussed above in Section III.A.2, EPA unjustifiably revised important aspects of Entergy's Revised White Bluff BART Analysis, upon which the reasonable progress controls cost analysis for Independence is based. At the least, EPA must re-evaluate the costs of controls based upon the 2015 S&L FGD Cost Estimate, attached as Exhibit B.

As discussed in Section III.A.3 above, S&L estimated that the costs of dry FGD at White Bluff Units 1 and 2 would be over \$1 billion, which is approximately 220% higher than EPA's estimate. Based on the 2015 S&L FGD Cost Estimate, and assuming a 30-year life for the dry FGD systems at Independence and identical costs, this results in an average cost effectiveness at Independence Unit 1 of \$4,234 and of \$3,909 at Independence Unit 2, which, as noted above, is much higher than cost per ton thresholds EPA rejected for reasonable progress determinations in other states. As importantly, the cost per deciview improvement that would result from installing these controls is estimated at approximately \$1.33 billion at Caney Creek and \$1.53 billion at Upper Buffalo. *See* S&L FIP Cost Report at 21, Table 8. Such a massive investment cannot be justified in light of the continuous improvement in visibility being achieved at both Caney Creek and Upper Buffalo.

D. EPA Should Adopt Entergy's Proposed Alternative Approach For White Bluff And Independence.

EPA has requested public comment on any alternative SO_2 and NOx control measures that would address the regional haze requirements for White Bluff Units 1 and 2 and Independence Units 1 and 2 for this planning period. 80 Fed. Reg. at 18,997. According to EPA, this includes, but is not limited to, a combination of early unit shutdowns and other emissions control measures at the four units that would achieve *greater* reasonable progress than the BART and reasonable progress requirements that EPA has proposed for the first planning period. *See id.*

1. EPA has no legal basis for requiring that a four-unit approach achieve greater reasonable progress.

EPA has offered no legal basis for its claim that an alternative four-unit approach must achieve *greater* reasonable progress than the controls that EPA has proposed, 80 Fed. Reg. at 18,997, and Entergy disagrees that such a requirement is applicable or mandated by the Clean Air Act or EPA's own Regional Haze Rule. Neither the Act nor EPA's rules impose such a requirement. To the contrary, EPA noted in the final Regional Haze Rule that states have discretion to determine what control measures must be implemented to achieve reasonable progress. 64 Fed. Reg. at 35,721. EPA further explained that "States may conclude that control strategies specifically for protection of visibility are not needed at this time because the analyses may show that existing measures are sufficient to meet reasonable progress goals." *Id.* Indeed, not only is it up to the states to determine how much must be done to ensure reasonable progress, but states conceivably could conclude that *nothing* must be done. There is no provision setting a "floor" for reasonable progress.[44]

2. Entergy's proposed approach achieves virtually identical visibility benefits as the Proposal for over $2 billion less.

Entergy is proposing near-term interim controls and the cessation of coal combustion at White Bluff by 2028. Entergy also is proposing to meet lower SO_2 emission rates at all four units by 2018, and proposes to install LNB/SOFA at all four units and meet a 30-day rolling average NOx emission rate of 1,342.5 lb NOx/hr, within three years after the effective date of the final FIP.[45] This combination of controls and lower SO_2 emission rates will ensure that the Class I areas achieve virtually the same reasonable progress as EPA's Proposal but at a cost of over $2 billion less than the Proposal. *See* Figures 13 and 14 below, which compare the projected 2018 haze index at each Arkansas Class I area based on the Ranked Statistical Analysis, to the

[44] While states that opt to implement an emissions trading program or other alternative measure rather than require sources to install, operate, and maintain BART *are* required to demonstrate that this alternative will achieve greater reasonable progress than would be achieved through the installation of source-specific BART, 40 C.F.R. § 51.308(e)(2), Entergy is not proposing a BART alternative. Rather, under Entergy's four-unit approach, the NOx control measures and lower SO_2 emission rate proposed for White Bluff would constitute BART for White Bluff while the NOx control measures and lower SO_2 emission rate proposed for Independence are more than sufficient for reasonable progress purposes for this planning period.

[45] Entergy's rationale for the proposed NOx rate is discussed in Section III.E. below.

deciview improvements projected for the following scenarios (1) Entergy's proposed controls, based on the cessation of coal-fired operations at White Bluff (referred to as "WB") and the installation of LNB/SOFA and lower SO_2 emission rate at Independence (referred to as "ISES"); and (2) installation of the Proposed FIP controls at all BART sources and Independence. Based on Entergy's modeling, the difference in the haze index between the proposed FIP controls and Entergy's proposal is 0.05 dv at Caney Creek and 0.07 at Upper Buffalo; differences that are too trivial to justify a $2 billion investment at White Bluff and Independence for the installation of dry FGD.

Figure 13

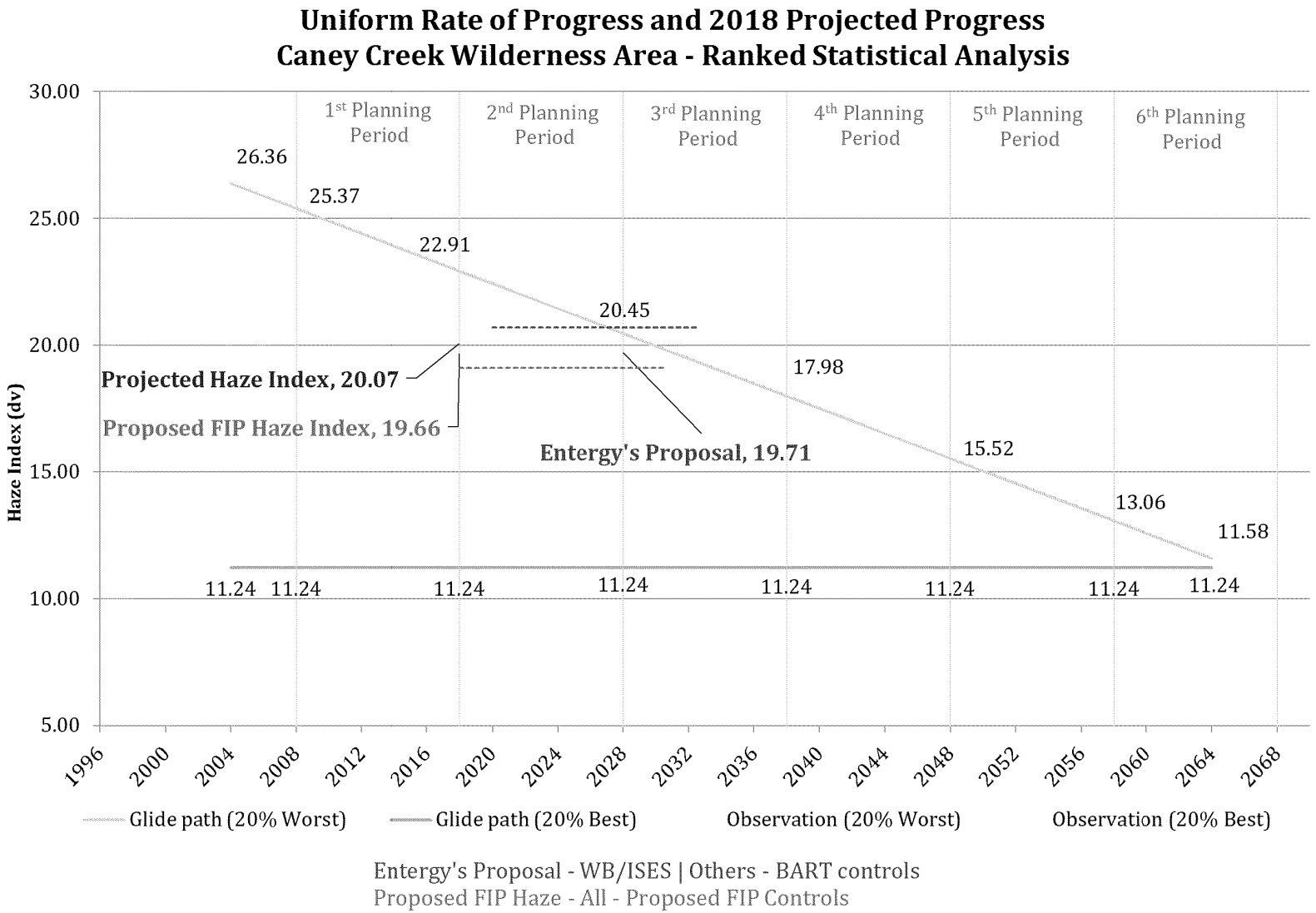
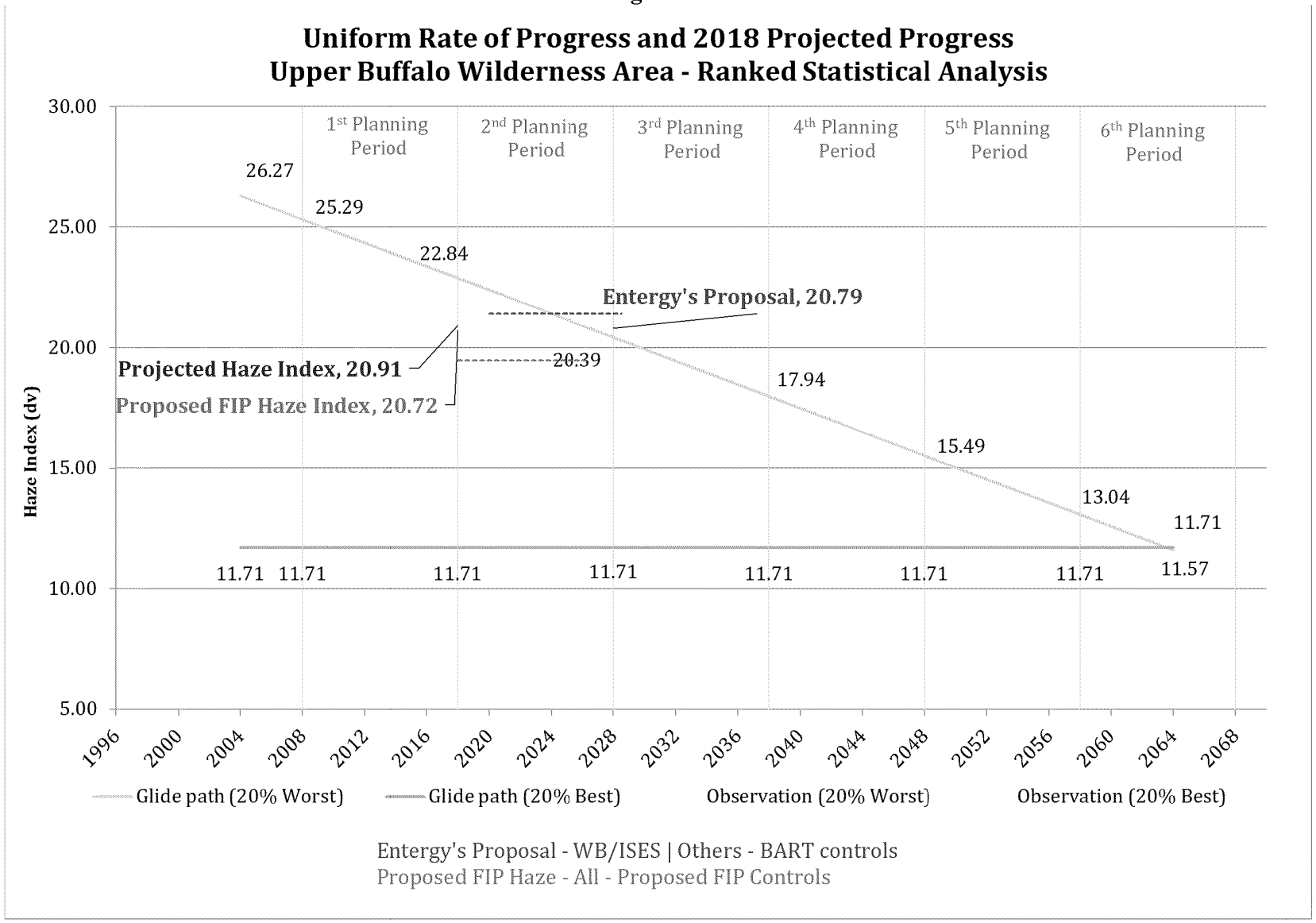

Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
11.24
Projected Haze Index, 20.07
Proposed FIP Haze Index, 19.66
Entergy's Proposal, 19.71
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)
Entergy's Proposal - WB/ISES | Others - BART controls
Proposed FIP Haze - All - Proposed FIP Controls

Figure 14


Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.27
25.29
22.84
Entergy's Proposal, 20.79
20.39
17.94
15.49
13.04
11.71
11.57
Projected Haze Index, 20.91
Proposed FIP Haze Index, 20.72
11.71 11.71 11.71 11.71 11.71 11.71 11.71
1996 2000 2004 2008 2012 2016 2020 2024 2028 2032 2036 2040 2044 2048 2052 2056 2060 2064 2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)
Entergy's Proposal - WB/ISES | Others - BART controls
Proposed FIP Haze - All - Proposed FIP Controls

Entergy's proposed approach with respect to White Bluff and Independence makes sense in light of the long-term objectives of the Regional Haze Program, the high capital costs for scrubbers, and the significant long-term environmental co-benefits from the cessation of coal-firing at the White Bluff units. Arkansas' Five-Year Progress Report demonstrates that the state currently is below the glide path for Caney Creek and Upper Buffalo, and expects to remain so through at least 2018. *See* Section III.C.1 above. Entergy's approach would help ensure that Arkansas remains below the glide path throughout the second planning period, and will produce very large additional reductions in NOx, SO_2, and PM heading into the third planning period.

Ultimately, Entergy's approach would achieve more than 170,000 tons of NOx reductions from White Bluff than the proposed FIP would achieve. While scrubbers would reduce SO_2 emissions substantially, the total visibility benefits from ceasing to use coal are at least as great. Entergy's approach also would achieve multi-pollutant co-benefits. Prior to 2028, SO_2 and NOx would be reduced, which would result in reductions in ozone and $PM_{2.5}$. Starting in 2028, Entergy's approach would produce even greater reductions in emissions of SO_2, NOx and $PM_{2.5}$, as well as achieving reductions in mercury and other hazardous air pollutants, and CO_2/CO_2e. It would reduce annual greenhouse gas emissions by approximately 11.74 million tons per year, a 275 million ton lifetime benefit over EPA's Proposal. Additionally, the elimination of coal combustion in 2027 and 2028 would reduce rail and truck traffic, allow for the closure of landfills, and reduce water usage, in addition to other environmental benefits.

3. EPA should adopt RPGs for Arkansas that reflect Entergy's proposal.

Entergy opposes the RPGs that EPA has proposed for Caney Creek and Upper Buffalo. The RPGs reflect the approved portions of Arkansas' Regional Haze SIP, the proposed FIP BART controls, and the controls proposed for Independence. 80 Fed. Reg. at 18,997. For all of the reasons discussed above in Section III.C, controls at Independence for reasonable progress purposes are not justified and including the emissions reductions based on the installation of dry FGD and LNB/SOFA at Independence renders EPA's RPGs arbitrary and capricious. EPA should recalculate the RPGs based on Entergy's proposed approach for controlling emissions at White Bluff and Independence.

E. The Proposed NOx Limits For White Bluff And Independence Cannot Be Achieved Based On The Plants' Current Operating Conditions.

The NOx emission limits proposed by Entergy for the units at White Bluff and Independence are based on the emission rate for LNB/SOFA of 0.15 lb/MMBtu that Entergy proposed in the Revised White Bluff BART Analysis. At the time Entergy submitted the Revised White Bluff BART Analysis in October 2013, all four of the coal-fired units at White Bluff and Independence were operated as base load units and spent the overwhelming majority of their operating time at loads of greater than 50% of unit capacity. Since submitting the Revised White Bluff BART Analysis,[46] Entergy transitioned to MISO in December 2013. MISO utilizes an economic dispatch model to determine which EGUs within its service territory are

[46] Entergy notes that EPA relied upon the Revised White Bluff BART Analysis to evaluate controls for Independence.

dispatched to operate and the operating load (MW) for each unit. Initially the MISO operating environment resulted in similar unit dispatch schedules for White Bluff and Independence, with all four units primarily dispatched as base-load units with some load-following operation. However, beginning in December 2014, the units at both White Bluff and Independence began to be dispatched primarily as load-following units. Since December 2014, the White Bluff and Independence units have been dispatched less frequently and, when dispatched, have spent significantly more time at low operating rates of less than 50% of unit capacity.

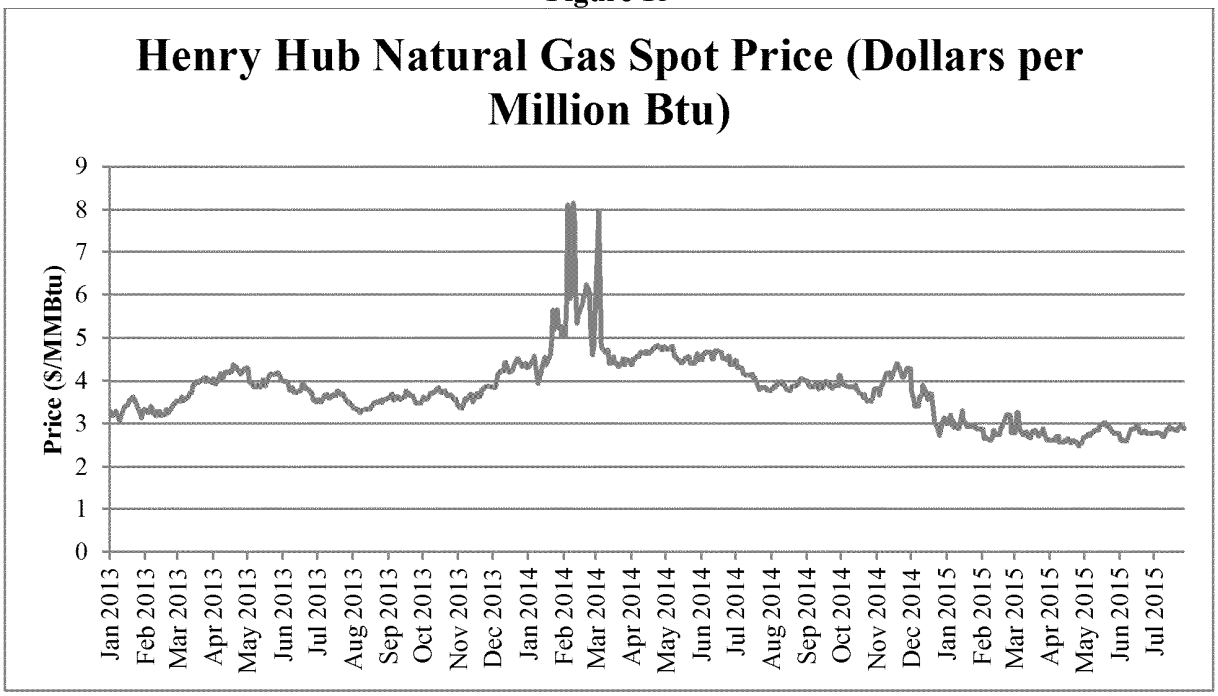
The impact of this change in dispatch of the units can be seen in the following table. The data for 2015 (through June 30) reflects a significant increase in the percentage of time that each unit is dispatched at less than 50% of operating capacity. Three of the four units have spent greater than 40% of their 2015 operating hours at less than 50% of capacity, and the two Independence units have spent nearly half of their operating time at less than 50% of capacity.

	WB1		WB2		ISES1		ISES2	
	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load
2013	624	7.96%	606	7.95%	797	10.99%	979	11.60%
2014	959	12.39%	784	10.32%	818	10.39%	1069	13.69%
2015 (YTD)*	1444	42.84%	681	27.54%	1278	48.03%	1267	49.40%

* 2015 YTD represents Jan-June 2015

This change in dispatch coincided with a sharp drop in natural gas prices which can be seen in Figure 15 below. This drop in gas prices to near $3 per MMBtu has been sustained since December 2014, and Entergy has no reason to expect any significant increase in gas pricing in the near future.

Figure 15



This change in dispatch for the units at both White Bluff and Independence is significant with regard to NOx emissions as the LNB/SOFA system is designed to operate primarily in the range of 50-100% of unit load. Entergy has selected Foster Wheeler as the LNB/SOFA vendor for White Bluff and has only been able to obtain a guarantee of less than 0.15 lb/MMBtu for operating loads in the range of 50-100% of unit capacity.[47] Since the available emission guarantee does not cover unit operation at less than 50% of capacity, Entergy requested a memorandum from Foster Wheeler regarding the impact of unit operation at less than 50% capacity on NOx emission rates. This memorandum is attached as Exhibit G to these comments. Based on input from the LNB/SOFA vendor, Entergy does not believe that the proposed emission rate of 0.15 lb/MMBtu is consistently achievable under all operating conditions. Even with a 30-day averaging period for the proposed limit, a unit which is frequently dispatched at less than 50% of capacity may not be able to achieve compliance.

This was not perceived as an issue at the time that the Revised White Bluff BART Analysis was prepared and submitted to ADEQ by Entergy as, historically and at that time, the units were operated almost exclusively as base-load units and spent less than 10% of their operating time at less than 50% of unit capacity. In the current dispatch environment, with some units spending nearly 50% of their operating time outside of the control range for LNB/SOFA, Entergy can no longer be confident that the units will be able to achieve compliance with a limit of 0.15 lb/MMBtu on a 30-day rolling average basis.

The concern arises from low-load operation during which periods of higher NOx emissions, on a lb/MMBtu basis, would not be expected to correspond to an increase in the maximum mass emission rate (lb/hr) from the units as any increase in the emission rate on a lb/MMBtu basis would be expected to be more than offset by the lower unit operating rate in MMBtu/hr to arrive at a mass emission rate (lb/hr).

To address the potential for a higher NOx emission rate (lb/MMBtu basis) at operating rates of less than 50% of unit capacity, Entergy proposes a rolling 30-boiler operating day average emission rate of 1,342.5 lb NOx/hr at each coal-fired unit at White Bluff and Independence. In the alternative, if EPA believes that a lb/MMBtu limit is necessary for the units, Entergy proposes a bifurcated NOx emission limit for each unit at both White Bluff and Independence as follows.

> For all unit operation (0-100% of capacity), a limit of 1,342.5 lb NOx/hr, based on a rolling 30-boiler operating day average.
>
> And;

[47] This range is referred to as the "control range" by Foster Wheeler. *See* Exhibit F, p. 46, for Foster Wheeler's emissions guarantee. The load ranges identified in the emissions guarantee equate to 50% to 100% of the White Bluff units' operating capacity. Entergy added .01 lb/MMBtu to Foster Wheeler's emissions guarantee to account for fluctuations in NOx emissions from the units. Controlled NOx emissions fluctuate during normal boiler operation in response to a number of design/operating parameters including, but not necessarily limited to: inlet NOx concentrations, boiler load, load changes, particulate matter loading, flue gas temperatures and flue gas velocities. A compliance margin above the vendor's emissions guarantee is recommended for establishing an enforceable limit to address such fluctuations.

For unit operation at 50-100% of capacity, a limit of 0.15 lb NOx/MMBtu, based on a rolling 30-boiler operating day average, to include only those hours for which the unit was dispatched at 50% or greater of maximum capacity.

This alternative approach would ensure that the units are operated in compliance with the LNB/SOFA design within the control range of 50-100% of capacity while providing Entergy with flexibility in demonstrating compliance. The lb/hr limit, which would apply to all operating hours, will ensure that the 30-day average emission rates remain below those on which both EPA and Entergy relied to project visibility improvements from the proposed NOx emission reductions.

F. The NOx BART Determination For Lake Catherine Unit 4 Should Be No Controls.

1. Visibility Improvement From Controls On Lake Catherine Unit 4 Cannot Be Reasonably Anticipated.

EPA has proposed NOx BART controls for Lake Catherine Unit 4 based on the installation of burners out of service ("BOOS"). *See* 80 Fed. Reg. at 18,978. To justify the visibility improvement resulting from installation of the proposed controls, EPA relied on the CALPUFF dispersion modeling system without assessing the reliability of the model to predict very small changes in visibility. In *NPCA*, the Ninth Circuit concluded that EPA had failed to justify that predicted visibility improvements were "reasonably anticipated," as required by the Clean Air Act, where the improvements were so insignificant that they were within the CALPUFF model's margin of error. *NPCA*, 788 F.3d 1134, 1146-47.

On behalf of Entergy, Trinity completed a quantitative analysis to evaluate the margin of error in the CALPUFF model for Lake Catherine Unit 4. As part of this analysis, Trinity modeled the following three scenarios:

- All BART – Includes all sources subject to BART, modeled using Pre-BART representations;
- Pre-BART – Includes only Lake Catherine Unit 4, modeled based on the current permit representation; and
- Post-BART – Includes only Lake Catherine Unit 4, modeled using Post-BART emission rate and stack parameters.

Trinity calculated the average difference between modeled values obtained using CALPUFF (including the CENRAP background) and IMPROVE monitored values for Caney Creek and Upper Buffalo for each of the three modeling scenarios. Trinity compared the regional haze design value format of average W20 days visibility for this analysis. Specifically the following comparisons were made:

- Modeled vs Measured W20 Days: The W20 days based on IMPROVE measurements were selected for each Class I area and compared with the CALPUFF results from the corresponding days.

- Measured vs. Modeled W20 Days: The W20 days based on CALPUFF modeling results were selected considering only days when IMPROVE measurements were taken. Modeled values were then compared to the IMPROVE measurements from the corresponding days.

- Measured and Modeled W20 Days: The W20 days based on IMPROVE measurements were selected and compared with the W20 days based on CALPUFF modeling disregarding temporal correlation.

A complete discussion of Trinity's analysis and results is presented in *Evaluation of the CALPUFF Modeling System Margin of Error for a BART Analysis, Entergy Services, Inc. - Lake Catherine Plant*, Trinity Consultants (Aug. 4, 2015). ("CALPUFF Margin of Error Report"), which is attached as Exhibit H and is hereby incorporated by reference. As demonstrated in the CALPUFF Margin of Error Report, the Pre-BART impact from Lake Catherine Unit 4 at Caney Creek and Upper Buffalo is inconsequential when compared with the IMPROVE measurements, which capture the impact of all other sources, including Lake Catherine, on the Class I areas.

The proposed NOx BART controls for Lake Catherine Unit 4 will result in visibility improvements that are even more inconsequential and cannot accurately be predicted by CALPUFF. Based on Trinity's analysis, the minimum calculated margin of error for CALPUFF for Lake Catherine Unit 4 is 0.93 dv. The CALPUFF predicted visibility improvement associated with EPA's proposed BART controls for Lake Catherine Unit 4 at Caney Creek and Upper Buffalo falls within this margin of error. *See* 80 Fed. Reg. at 18,978, Table 42. As such, the visibility improvements at each of these Class I areas associated with the proposed BART controls for Unit 4 cannot "reasonably be anticipated." 42 U.S.C. § 7491(g)(2); *see NPCA*, 788 F.3d 1134, 1146-47. Accordingly, EPA has not adequately demonstrated that it is appropriate to require NOx BART controls on Lake Catherine Unit 4.

2. Source-Specific Controls Should Not Be Imposed On Lake Catherine Unit 4.

If EPA finalizes a determination that Lake Catherine Unit 4 should be subject to NOx BART controls, EPA should not impose source-specific NOx controls on Lake Catherine Unit 4 but should instead find that CSAPR is better than NOx BART in Arkansas for all EGUs, as discussed in Section III.A.4 above. Compliance with CSAPR will ensure that NOx emissions from Arkansas' EGUs are limited and will improve visibility in Arkansas' Class I areas.

EPA also had evaluated controls other than BOOS for Lake Catherine Unit 4. *See* 80 Fed. Reg. at 18,976-78. Similar to BOOS, however, these controls would result in imperceptible visibility improvements in Arkansas' Class I areas. Although Entergy did not evaluate the margin of error with respect to the CALPUFF predicted visibility improvement from these other controls, EPA had rejected these controls as NOx BART for Lake Catherine Unit 4 based on costs and Entergy agrees with EPA's determination that these controls should not be considered as NOx BART for Lake Catherine Unit 4. Specifically, Entergy agrees with EPA that the incremental cost effectiveness of installing LNB/SOFA at Lake Catherine Unit 4 cannot be justified as BART. *See id.* at 18,978. Similarly, the installation of LNB/SOFA and selective non-catalytic reduction ("SNCR") or selective catalytic reduction ("SCR") cannot be justified as

BART based on either average cost effectiveness or incremental cost effectiveness. *Id.* Lake Catherine Unit 4 is a peaking unit and operated at only a two percent capacity factor in 2014.[48] The estimated incremental costs of installation of LNB/SOFA (at $14,246/ton), SNCR (at $16,029/ton), and SCR (at $11,767/ton) are simply not warranted for a unit that operates so infrequently. *See id.* at 18,978. Installation of these controls would require a massive capital investment and significant operation and maintenance costs that are impracticable for a peaking unit.

G. EPA Improperly Considered The Cumulative Visibility Improvement At All Class I Areas.

EPA's reliance on a "cumulative visibility improvement" metric is arbitrary and capricious, and has no basis in law. In assessing the visibility improvements that are predicted to be achieved through the installation of proposed controls at White Bluff, Lake Catherine, and Independence, EPA totaled the predicted improvements at all affected Class I areas to yield a cumulative visibility improvement associated with each facility. *See* 80 Fed. Reg. at 18,972 (Tables 34 and 35); 18,974 (Tables 37 and 38); 18,978 (Table 42); 18,994 (Table 64). EPA appears to have relied upon the cumulative visibility improvement across the four affected Class I areas to support its proposed NOx BART determination for Lake Catherine. 80 Fed. Reg. 18,978 (where EPA identified the cumulative visibility impact in its rationale for the Lake Catherine "Proposed NOx BART Determination"). It is improper for EPA to rely upon the cumulative visibility improvement across all affected Class I areas. BART and reasonable progress determinations instead should be based on the predicted visibility improvements at individual Class I areas.

The preamble to the BART Guidelines states that the focus of an analysis of visibility improvements associated with BART controls is to be on the "nearest Class I area" to the facility in question. 70 Fed. Reg. 39,104, 39,170 (July 6, 2005) ("One important element of the [modeling] protocol is in establishing the receptors that will be used in the model. The receptors that you use should be located in the *nearest* Class I area with sufficient density to identify the likely visibility effects of the source.") (emphasis added). While the Rule allows consideration of impacts at other nearby Class I areas, it is for the purpose of "determin(ing) whether effects at those areas *may be greater than* at the *nearest* Class I area." *Id.* (emphasis added). Summing the predicted visibility improvements at multiple Class I areas does not facilitate a determination that effects at more distant Class I areas are more significant than those at the closest Class I area.

In addition to having no basis in EPA's own regulations, the cumulative metric is deceptive and provides no information that could be used to assess whether any single Class I area would experience perceivable visibility improvements as a result of BART or reasonable progress controls. For example, EPA appears to have selected BOOS as NOx BART for Lake Catherine in part because it would achieve a cumulative visibility improvement across the four affected Class I areas of 1.215 dv. 80 Fed. Reg. at 18,978. But the cumulative metric masks the

[48] Entergy's current resource planning assumption is that Lake Catherine Unit 4 will be de-activated in mid-2025, though no final decision to this effect has yet been made.

fact that no individual Class I area would experience any discernible visibility improvement. Instead, Mingo would experience a 0.196 dv improvement, Hercules-Glades would experience a 0.175 dv improvement, Upper Buffalo would experience a 0.248 dv improvement, and Caney Creek would experience a 0.596 dv improvement. *See id.* These are imperceptible levels of improvement that do not justify installation of controls.[49] The metric therefore equates imperceptible visibility "benefits" in different areas with a much larger and indisputably discernible visibility improvement in a single area.

On a practical level, reliance on a cumulative visibility improvement is illogical. Deciview improvements at multiple areas cannot be added together to form a meaningful metric. As discussed in Section III.C.2 above, a deciview is a logarithmic scale based on the concept that one deciview is the minimum change in visibility perceptible to a human observer. Deciviews cannot be directly added or subtracted. To add or subtract the haze, one must add or subtract the total extinction values and then recalculate the haze index in deciviews. Considering the Class I areas addressed in the Proposal are hundreds of kilometers away from each other, particles from one Class I area cannot contribute to or improve the light extinction at another Class I area, therefore, adding or subtracting light extinction values is not an accurate representation of reality and would be illogical. In simple terms, a visitor to a Class I area cannot benefit from any visibility improvement that might be occurring at another Class I area. The cumulative metric represents an illusory visibility benefit; it is an improvement that cannot be perceived and therefore provides no indication of whether the proposed controls will contribute to the goal of the Regional Haze Program: to reduce human perception of visibility impairment in Class I areas. This cumulative visibility metric should be eliminated from any consideration of whether proposed controls will result in visibility improvement, including for the Lake Catherine BART analysis.

H. EPA Must Address The Requirements Of Executive Orders 12866 And 13211.

EPA claims that the Proposal is not a "significant regulatory action" under Executive Order 12866. 80 Fed. Reg. at 18,999. Entergy disagrees. The Proposal's implementation cost to EAI alone of over $2 billion exceeds the $100 million threshold for economic significance. "By virtue of [the] longstanding Executive Order [12866] applying to significant rules issued under the Clean Air Act (as well as other statutes), the Agency must systematically assess the regulation's costs and benefits." *Michigan v. EPA*, 135 S.Ct. at 2715 (Kagan, J. dissenting). EPA states that the Proposal is not generally applicable, and therefore not subject to Executive Order 12866, because the rule "only proposes source specific requirements for particular, identified facilities (six total)." 80 Fed. Reg. at 18,999. However, a count of the number of entities regulated under a rule is not indicative of the general applicability or the significance of the economic impacts of the rule. Requiring additional controls at power plants initiates a cascade of impacts, including changes in the regional distribution of electricity and rates of thousands of electricity customers in multiple states. These far-reaching impacts merit

[49] As discussed above in Section III.F.1, EPA did not perform an analysis to confirm that the model predictions are not within the model's margin of error and, therefore, EPA has not justified that the predicted visibility improvements are "reasonably anticipated."

classifying the Proposed FIP as a regulation with general applicability and significant economic impact.

Entergy also disagrees with EPA's conclusion that the Agency is not required to assess the energy impacts of the Proposed FIP under Executive Order 13211. 80 Fed. Reg. at 19,000. The Proposal will have a significant impact on the supply, distribution, and use of energy. Installation of additional controls will require outages at multiple power plants, altering the normal supply and distribution of energy. Additionally, the more than $2 billion cost of implementing the Proposed FIP will be imposed upon EAI's customers and co-owners, impacting energy use as electricity rates climb.

EPA must prepare a cost/benefit analysis and evaluate the energy impacts of the Proposed FIP and issue these analyses for public comment before finalizing the FIP.

I. Additional Comments.

- Entergy agrees with EPA's proposal that the existing emission limits at the White Bluff Auxiliary Boiler satisfy BART for SO_2, NOx, and PM. 80 Fed. Reg. at 18,975.

- Entergy agrees that 2009-2011 should be used as the baseline period for NOx for White Bluff Units 1 and 2. 80 Fed. Reg. at 18,969.

- If EPA finalizes a source-specific NOx BART limit for Lake Catherine Unit 4, Entergy requests that EPA confirm that the unit may continue to conduct monitoring pursuant to 40 C.F.R. Part 75 Appendix E so long as it qualifies as a peaking unit. In the Proposal, EPA appears to have assumed that Unit 4 currently operates "full" NOx CEMS with a continuous NOx analyzer pursuant to 40 C.F.R. Part 60. However, because Unit 4 meets the definition of a peaking unit under 40 C.F.R. Part 75, and the unit is not subject to any NSPS Part 60 standards, Entergy does not currently operate a NOx analyzer for the unit. Under Part 75, Unit 4 qualifies as an Appendix E unit, allowing the unit to utilize a NOx correlation curve to estimate emissions and only monitor heat input and exhaust O_2 concentration.

- Entergy agrees with EPA's conclusion that wet scrubbers do not constitute BART for White Bluff and should not be installed at Independence to meet reasonable progress requirements. 80 Fed. Reg. at 18,972, 18,993.

- Entergy agrees with EPA that LNB/SOFA/SNCR or LNB/SOFA/SCR cannot be justified as BART for White Bluff based on the incremental cost effectiveness of the controls. 80 Fed. Reg. at 18,974.

- Entergy disagrees that the proposed regional haze FIP will satisfy the requirements of CAA Section 110(a)(2)(D)(i)(II), 80 Fed. Reg. at 18,998, for the reasons explained in Entergy's comments on EPA's proposed disapproval of Arkansas' SIP revision addressing interference with other states' programs for visibility protection for the 2006 revised 24-hour $PM_{2.5}$ NAAQS. These comments are attached as Exhibit I and are hereby incorporated by reference.

IV. CONCLUSION

Entergy appreciates the opportunity to comment on the Proposed FIP. Entergy strongly urges EPA to adopt a comprehensive approach to regional haze that would involve the four coal-fired units at Independence and White Bluff, as Entergy as proposed, without requiring expensive, unnecessary scrubber technology. Such an approach would ensure superior, long-term visibility benefits than would the Proposed FIP. It also would deliver important non-haze environmental benefits, including a dramatic decrease in GHG emissions, large reductions in SO_2 emissions that also contribute to long-range $PM_{2.5}$ issues, and large reductions in ozone (and $PM_{2.5}$)-forming NOx emissions. Entergy respectfully requests that EPA amend the Proposed FIP as described in these comments.

Respectfully submitted,

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ENTERGY ARKANSAS, INC.

REVIEW OF EPA'S COST ANALYSIS FOR ARKANSAS REGIONAL HAZE PROPOSED FEDERAL IMPLEMENTATION PLAN

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ATTACHMENTS

Attachment A – Cost-Effectiveness Calculation

EXECUTIVE SUMMARY

On April 8, 2015, the U.S. Environmental Protection Agency (EPA) published in the *Federal Register* a proposed rule that would partially approve and partially disapprove specific portions of the Arkansas State Implementation Plan (AR SIP) and issue a Federal Implementation Plan (FIP) that would regulate a group of Arkansas electric generating units (EGUs).[1] In this rule, EPA proposes to require additional SO_2 emission reductions that would require retrofitting new FGD systems on Entergy's White Bluff Station Units 1 and 2 and Entergy's Independence Station Units 1 and 2.

Sargent & Lundy (S&L) was contracted by Entergy to review EPA's proposed cost modifications as described in its Technical Support Document entitled, "Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan," hereinafter referred to as "FIP TSD," including one if its appendices, entitled "Appendix A. Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plant (SO_2 Cost TSD)," hereinafter referred to as "Cost TSD."

Cost-effectiveness is influenced by two variables: the total annualized cost to retrofit dry FGD systems ($/yr) and the corresponding reduction in annual SO_2 emissions (tons per year "tpy"). EPA's approach does not accurately calculate either variable.

Based on our review, the following items in EPA's analysis were identified to result in overstating the tons of SO_2 removed:

- After defining a baseline SO_2 emission period of between 2009 and 2013, EPA arbitrarily excluded the years with the maximum and minimum annual averages;
- When calculating SO_2 emission reductions due to FGD retrofits, EPA incorrectly used maximum monthly averages for baseline SO_2 emissions; and
- A controlled SO_2 limit of 0.06 lb/MMBtu is not a realistic or sustainable value to maintain on a long-term basis when considering the normal variation in operation that occurs at all coal-fueled facilities.

In addition, the following items in EPA's analysis were identified to result in understating the annualized cost of the dry FGD retrofit:

- EPA subtracted over $23 million in BOP costs for both units because they mistakenly believed the equipment to be included in Alstom's scope;
- Because EPA mistakenly removed BOP cost items that should be included in the estimate, they over-estimated and misapplied percent reductions to other cost items, resulting in cost subtractions of over $7 million for both units;

[1] *See* 80 Fed. Reg. 18,944 (April 8, 2015).

- EPA removed over $41 million per unit in Owner's Costs despite the fact that these are real costs that the Entergy will incur;
- EPA under-estimated cost escalation, and in some cases de-escalated costs, by relying on cost indices rather than using vendor pricing information, all of which resulted in under-estimating costs by more than $42 million per unit;
- EPA incorrectly utilized the IPM model, which is not designed to evaluated site-specific costs, to verify O&M costs at White Bluff;
- EPA scaled capital costs to a design fuel of 0.68 lb/MMBtu, which when compared to operating data, is completely insufficient to ensure compliance with the proposed emission limits for nearly half of the time;
- While we agree that O&M costs should be based on 0.68 lb/MMBtu, EPA's methodology to scale direct O&M costs based on fuel sulfur levels is incorrect and resulted in under-estimating these costs by over $5 million per unit;
- EPA incorrectly scaled indirect O&M costs using fuel sulfur levels, despite these costs being estimated as percentages of capital cost, which resulted in under-estimating these costs by over $4 million; and
- EPA used a remaining useful life of 30 years, when Entergy is proposing to cease coal-fired operations on these units in 2027 and 2028, resulting in a remaining useful life of 6 or 7 years.

As discussed above, S&L's analysis reveals that EPA overstates the cost-effectiveness ($/ton of SO_2 removed) to retrofit dry FGD systems at White Bluff Units 1 and 2, which EPA proposes to require in its FIP. In its approach, EPA understated the annualized cost of the control systems and overstated the tons of SO_2 that would be removed by its FIP-imposed FGD retrofits. To better address EPA's questions on scope and cost items which it did not understand, S&L has prepared an updated cost report to clarify and provide further detail around scope items and cost items included in the estimate.[2] The corrected and updated cost-effectiveness for both White Bluff units is greater than $7500/ton, which is clearly not cost effective.

With respect to EPA's Reasonable Progress Goal (RPG) analysis for SO_2 controls, EPA did not follow its own guidance document when conducting its four factor analysis of Independence. EPA failed to consider lower cost options that could reduce SO_2 emissions at Independence and instead concluded that BART-level controls were required to meet RPG. EPA did not prepare cost estimates based on design parameters for FGD systems retrofit at Independence, as required by their RPG guidance document. EPA did not conduct a dollar-per-deciview analysis, as recommended in its RPG document for these analyses to demonstrate the benefit of retrofitting dry FGD at Independence accounting for visibility benefits. When applying annualized costs to projected visibility improvements the result is over $1.3 billion/Δdv for Caney Creek and over $1.5 billion/Δdv for Upper Buffalo, which is clearly not cost effective.

[2] *See* S&L Report #012831 ("White Bluff Dry FGD Cost Estimate and Technical Basis") (July 2015).

1. INTRODUCTION

On April 8, 2015, the U.S. Environmental Protection Agency (EPA) published in the *Federal Register* a proposed rule that would partially approve and partially disapprove specific portions of the Arkansas State Implementation Plan (AR SIP) and issue a Federal Implementation Plan (FIP) that would regulate a group of Arkansas electric generating units (EGUs).[3] In this rule, EPA proposes to require additional SO_2 emission reductions that would require retrofitting new FGD systems on Entergy's White Bluff Station Units 1 and 2 and Entergy's Independence Station Units 1 and 2.

Sargent & Lundy (S&L) was contracted by Entergy to review EPA's proposed cost modifications as described in its Technical Support Document entitled, "Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan," hereinafter referred to as "FIP TSD," including one if its appendices, entitled "Appendix A. Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plant (SO_2 Cost TSD)," hereinafter referred to as "Cost TSD."

S&L's experience in the electric power industry, as well as our experience with the Entergy facilities makes us uniquely qualified to perform this review. S&L has considerable experience with the federal and state environmental regulations affecting power plant operations, as well as the specification, evaluation, selection, and implementation of emission control technologies for both gas- and coal-fueled utility power facilities, including extensive experience with various FGD technologies. For example, since 2000, S&L has provided, or is currently providing, engineering services for the implementation of over 40 wet FGD projects, 30 dry FGD projects, and 25 dry sorbent injection (DSI) projects, all of which are technologies that are used to control SO_2 emissions. Our first-hand experience with these technologies provides us with a thorough understanding of both capital and operating and maintenance (O&M) costs associated with these technologies, as well as providing us with a comprehensive understanding of the achievable emission rates and limitations of these technologies.

S&L's analysis reveals that EPA overstates the cost-effectiveness ($/ton of SO_2 removed) to retrofit dry FGD systems at White Bluff Units 1 and 2, which EPA proposes to require in its FIP. Cost-effectiveness is influenced by two variables: the total annualized cost of retrofit dry FGD systems ($/yr) and the corresponding reduction in annual SO_2 emissions (tons per year "tpy"). EPA's approach does not accurately calculate either variable. In its approach, EPA understated the annualized cost of the control systems and overstated the tons of SO_2 that would be removed by its FIP-imposed FGD retrofits.

[3] *See* 80 Fed. Reg. 18,944 (April 8, 2015).

2. Comments to the FIP TSD – SO_2 Emission Reduction Errors

The majority of S&L's comments are relative to EPA's Cost TSD; however, we note that in its FIP TSD, EPA incorrectly estimates both baseline emissions and SO_2 emission reductions that would result from the retrofit of dry FGD systems at White Bluff station. In addition, in proposing emission rates for White Bluff station, EPA proposed SO_2 emission limits that are consistent with performance guarantees offered by dry FGD suppliers during initial performance testing, not emission rates that are achievable over the 30-year life EPA assumed in its analysis. The following sections describe EPA's flawed analysis contained in the FIP TSD.

2.1 Baseline Emission Rates

Although baseline emission rates identified in Entergy's original BART analysis[4] were calculated based on the average annual emission rates from 2001 to 2003, in the FIP TSD, EPA redefines baseline emission by using a 3-year average of annual average SO_2 emissions from the years 2009 to 2013, excluding the years with the maximum and minimum annual averages.[5]

We can find no reason to reject EPA's selection of 2009 to 2013 as the baseline period as it represents more recent operation. However, the approach used by EPA to exclude the maximum and minimum values is entirely arbitrary and EPA does not explain how this approach represents a more realistic depiction of anticipated emissions from the existing sources.

The BART Guidelines state that baseline emissions from existing sources "should represent a realistic depiction of anticipated annual emissions for the source."[6] In general, for the existing sources, facilities should estimate the anticipated annual emissions based upon actual emissions from a baseline period.[7] However, EPA provides no explanation or analysis to demonstrate that the approach taken results in a realistic depiction of anticipated annual emissions from White Bluff and Independence. In addition, there is no basis for concluding that EPA's approach of excluding actual emissions data more accurately represents the actual operation of the units. Finally, to our knowledge, with the exception of EPA's proposed Texas FIP, this approach has not been used previously by EPA as a methodology for evaluating baseline emissions in other evaluations (and even if EPA had done so, it is not justified here).

The following table shows a comparison between the baseline emissions as established using EPA's approach and baseline emissions calculated as a straight average for various timeframes within the 2009-2013 period.

[4] Revised Bart Five Factor Analysis, White Bluff Steam Electric Station, Redfield, Arkansas, October 2013, Trinity Consultants.
[5] *See* EPA-R06-OAR-2015-0189-0093-White Bluff_R6 cost revisions2.xlsx, under Annual Emissions.
[6] 40 CFR Part 51 Appendix Y.
[7] *Id.*

Table 1: Comparison of Baseline SO_2 Emissions for White Bluff and Independence

Unit	EPA Approach 3 Year Average* (tons)	3 Year Average 2009-2011 (tons)	3 Year Average 2010-2012 (tons)	3 Year Average 2011-2013 (tons)	5 Year Average 2009-2013 (tons)
White Bluff 1	15,816	15,745	15,395	15,826	15,939
White Bluff 2	16,697	15,582	15,217	16,697	16,034
Independence 1	14,269	14,160	15,486	14,707	14,258
Independence 2	15,511	14,673	15,196	16,035	15,407

*EPA's approach includes 2009-2013 3-year average, excluding maximum and minimum years.

With the exception of White Bluff 1, EPA's approach of eliminating the maximum and minimum values results in higher baseline SO_2 emissions compared to averaging the entire 5-year period. In all cases, there is at least one other approach that would result in lower baseline SO_2 emissions compared to EPA's approach. By overestimating the baseline SO_2 emissions, EPA overstates the amount of SO_2 that would be removed and, thus, overstates the cost-effectiveness of the FGD retrofit projects.

2.2 SO_2 Emission Reduction

SO_2 emission reductions were estimated incorrectly by EPA for White Bluff and Independence. For each unit, EPA identified the maximum monthly SO_2 emission rate in the baseline period of 2009 to 2013 and then calculated the percent reduction that would be required to achieve a controlled emission rate of 0.06 lb/MMBtu. The percent reduction calculated was then multiplied by the baseline emission tons to determine the tons of SO_2 reduced. This methodology is incorrect because it assumes the baseline emissions calculated in the previous section are based on maximum monthly averages, which are significantly higher than the annual averages actually used to calculate baseline emissions.

The correct way to project the SO_2 emission reduction is to multiply the outlet emission rate of 0.06 lb/MMBtu by the average heat input to the boiler (MMBtu/year) from the baseline period. For example, the average heat input to White Bluff 1 over the baseline period of 2009 to 2013 was 55,829,551 MMBtu/year. Multiplying by 0.06 lb/MMBtu and then converting from pounds to tons results in estimated SO_2 emission reductions of 14,264 tons per year, as compared to EPA's 14,363. This method has been utilized by S&L on previous BART analyses, and has been accepted previously by EPA.

Table 2: SO_2 Emission Reductions for White Bluff and Independence

Unit	EPA Approach Using Maximum Monthly SO_2 emission and 3-Year Baseline (tons)	Using 5-Year Average Heat Input and Baseline (tons)
White Bluff 1	14,363	14,264
White Bluff 2	15,221	14,353
Independence 1	12,912	12,607
Independence 2	13,990	13,655

Table 2 compares EPA's incorrect methodology to estimate SO_2 emission reductions at the Entergy Units to the more accurate methodology described above of using the 5-year average heat input from the baseline period. EPA's methodology overestimated the SO_2 emission reduction in all cases and therefore overstates the cost-effectiveness of the FGD retrofits at each unit.

2.3 SO_2 Emission Rate

EPA proposed SO_2 emission rates based on the assumption that a retrofit dry FGD will achieve a controlled SO_2 emission rate of 0.06 lb/MMBtu. In our experience, this assumption is unrealistic and cannot be sustained on a continuous, long-term basis. In several places, EPA cites the IPM dry FGD cost development document, which states: the "[r]ecommended SO_2 emission floor = 0.08 lb/MMBtu."[8]

EPA's proposal is too stringent to be achievable with the retrofit of an existing unit. A controlled SO_2 limit of 0.06 lb/MMBtu is not a realistic or sustainable value to maintain on a long-term basis when considering the normal variation in operation that occurs at all coal-fueled facilities. As noted in the IPM dry FGD document, the 0.06 lb/MMBtu emission rate corresponds to the lowest available SO_2 emission guarantees from dry FGD suppliers. Compliance with a vendor's guarantee value is typically demonstrated during very short term testing conducted at ideal operating conditions. Vendor guarantees do not reflect controlled emission rates that may be achievable on a consistent long-term basis as the unit operation varies from design conditions.

Dry FGD control systems, like all large air pollution control systems, are not steady state control systems, and controlled SO_2 emissions will continually fluctuate in response to changing operating parameters. Operating parameters that may affect SO_2 emissions include the fuel sulfur content, boiler load, load changes, flue gas flow rate, and flue gas temperatures, all of which continually change during normal operation of the boiler.

[8] Sargent & Lundy LLC, *IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology*, March 2013.

Furthermore, as shown in Table 3, S&L investigated permit limits for dry FGD projects for Spray Dryer Absorber (SDA) projects similar to the dry FGD technology proposed for the White Bluff units, and Circulating Dry Scrubber (CDS) technology, which are more efficient dry scrubber systems because of increased flue gas and reagent contact through the use of a fluidized bed. As indicated, the lowest permit value for all units retrofitting dry FGD systems with averaging periods of 30 days was 0.09 lb/MMBtu, and that includes the more efficient CDS dry FGD systems. The last unit shown in the table includes the lowest permit limit of any of the dry FGD systems listed, but this value still contains the necessary margin because the averaging period is much longer (i.e. 12 months), and because the dry FGD system was installed as part of a new boiler project, so it was incorporated into the new unit design which inherently minimizes some of the design challenges associated with retrofitting, where non-ideal layouts can lead to non-ideal flow distribution inside the absorbers.

Projecting future emissions using the anticipated control system vendor guarantee (i.e., 0.06 lb/MMBtu) as EPA did is overly aggressive and provides no margin for normal operating conditions or long-term operation. A reasonable margin between the vendor guarantee value or design target, and the projected actual long-term achievable emission rate is needed to allow for normal fluctuations in the controlled emissions. In S&L's opinion, an operating margin of at least 0.02 lb/MMBtu between the vendor guarantee and projected long-term emission rate is reasonable. As indicated in Table, using a limit of 0.08 lb/MMBtu to provide the recommended margin would still be an aggressive permit limit compared to other dry FGD projects.

Table 3: SO_2 Permit Limits for Dry FGD Projects

Reference Plant	Permit SO_2 Limit	Permit Averaging Period
Plant 1 (SDA)	0.09 lb/MMBtu	30 day rolling
Plant 2 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 3 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 4 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 5 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 6 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 7 (CDS)	0.09 lb/MMBtu	30 day rolling
Plant 8 (CDS)	0.10 lb/MMBtu	30 day rolling
Plant 9 (CDS)*	0.07 lb/MMBtu	12-month rolling average

*This unit was a new unit, not a retrofit

EPA's approach to estimating controlled SO_2 emission rates is incorrect and based on a misunderstanding of the actual performance and operation of dry FGD technology. By using this approach, EPA is overestimating the tons of SO_2 removed and thus overstating the cost-effectiveness of the retrofit FGD control systems.

3. Comments to the Cost TSD – Annualized Cost Errors

S&L's remaining comments are focused on EPA's Cost TSD. Our comments follow the same organization of EPA's Cost TSD document and are contained in the following sections.

3.1 Cost TSD, Section 2 – SDA Cost Analysis Methodology

EPA states that the "Control Cost Manual uses the overnight method of cost estimating, widely used in the utility industry.[9]" To support this conclusion, EPA references its own characterization of the CCM methodology published in the preamble to the Oklahoma Regional Haze FIP.[10] Using the overnight methodology, EPA removed certain costs from the SDA cost estimate, including Owner's costs and interest incurred during the construction period. We disagree that the CCM describes an overnight approach to calculating capital costs. The CCM does not once define or even mention the overnight methodology as being the basis for estimating costs. Rather, the CCM describes a constant dollar approach that annualizes all capital costs and O&M costs (on a constant-dollar basis) over the useful life of the project.

In the Oklahoma rule EPA cited to an Energy Information Administration (EIA) document as support for using the overnight cost estimating concept. In fact, EPA stated that "EIA presents all of its projected plant costs in terms of overnight costs."[11] However, this is a mischaracterization of the methodology the EIA uses to develop capital costs for new power generation. The EIA document upon which EPA relied includes a clarifying footnote that states: "Starting from overnight cost estimates, EIA's electricity modeling explicitly takes account of the time required to bring each generating technology online and the costs of financing construction in the period before a plant becomes operational."[12] Therefore, EIA cost evaluations take into account financing costs, including AFUDC, one of the line items EPA insisted that Entergy remove[13] from the SDA capital cost estimate

Finally, EPA states that the overnight method is appropriate for BART determinations "because it allows different pollution controls equipment to be compared in a meaningful manner."[14] However, excluding financing costs will bias the cost-effectiveness comparison toward the high-capital options with extended construction periods. Project financing costs such as AFUDC may be minimal on projects that do not require significant capital and with short construction periods, but can be very significant on projects with large capital costs and extended construction periods. Excluding financing costs from the capital cost estimate results in the high-capital cost option appearing more cost-effective. Including financing costs allows the analyst to compare projects with varying capital requirements and varying construction periods.

[9] Cost TSD, page 1.
[10] *Id.*
[11] *Id.*
[12] EIA, *Updated Capital Cost Estimates for Electricity Generation Plants*, November 2010, pg. 2.
[13] *See* August 21, 2013 email from Dayana Medina of EPA Region 6 to Mary Pettyjohn of the Arkansas DEQ.
[14] *Cost TSD, page 1.*

3.2 Cost TSD Section 2.3 – Use of the 2009 Alstom Cost Analysis

EPA invited Entergy to clarify certain issues associated with Alstom's 2010 quotation, including a misunderstanding regarding the scope of the dry FGD vendor's contract. In S&L Report #012831 of our comments, we have included a report that explicitly describes the scope of supply for the dry FGD vendor as compared to the balance of plant (BOP) scope of work. EPA made several incorrect assumptions regarding Alstom's scope that led to incorrect adjustments to the BOP cost estimate, as described in Section 3.3 of our comments. Furthermore, EPA's approach to escalating the Alstom quotation was incorrect as described in Section 3.5 of our comments.

3.3 Cost TSD Section 2.4 – Use of the S&L Balance of Plant Costs

EPA mistakenly subtracted BOP costs because they mistakenly believed the equipment to be included in Alstom's scope. As described in S&L Report #012831, the reagent handling system, which feeds the dry FGD supplier's reagent preparation system were not included in Alstom's scope. The "Dry FGD Island" supplied by the dry FGD vendor includes lime day bins, slakers, slurry transfer tanks, slurry transfer pumps, slurry storage tanks, and slurry feed pumps. The BOP system includes the cost associated with the "Reagent Handling System," which includes a rail delivery and unloading system for the lime, new rail spur, renovation of existing rail spur, delivery shed building, long-term storage silos, and a pneumatic conveying system to transfer the lime reagent from the long-term storage silos to the day bins, which are within the dry FGD vendor's scope.

We agree with EPA's comment that including the NO_X control equipment for Units 1 and 2 was an oversight and should not be incorporated into the Dry FGD estimates.

EPA mistakenly subtracted a total of $1,754,000 from the BOP quote because they mistakenly believed that all of the ductwork to be in Alstom's scope. The Dry FGD supplier's scope only includes ductwork between the dry FGD, the baghouse, and the booster fans. The ductwork to supply the flue gas to the SDA and the ductwork from booster fans to the existing chimney are within the BOP scope.

EPA mistakenly deleted a total of $255,000 to paint the Chimney because it did not understand this line item. Due to lower temperatures and higher moisture of the flue gas, downwash from the gas is more likely to occur and can lead to acid attack of concrete on the chimney shell; therefore, the costs to apply an acid resistant coating to the top 50 feet of the existing chimney shell was included in the estimate.

EPA mistakenly removed a total of $390,000 for costs associating with replacing and recalibrating the Continuous Emission Monitoring Systems (CEMS). The CEMS equipment reflected in Entergy's BART analysis was required because the existing CEMS was not capable of measuring SO_2 concentrations in the controlled range with Dry FGD technology. The costs included in the original estimate to cover replacement of the existing equipment with new equipment rated for the lower SO_2 concentrations as well as the cost to calibrate and certify these

monitors including conducting a Relative Accuracy Test Audit (RATA) test.

Based on these comments, we have corrected EPA's cost subtractions in Table 4.

Table 4: Excluded BOP Costs (Corrected, Total for Both Units)

	Equipment	Material	Labor	Total
Total BOP Cost	$45,561,000	$35,120,000	$80,863,000	$161,544,000
Eliminate U1 NO_X Equipment	$3,622,000	$1,600,000	$3,073,000	$8,295,000
Eliminate U2 NO_X Equipment	$3,622,000	$1,600,000	$3,073,000	$8,295,000
Total Eliminated Cost	$7,244,000	$3,200,000	$6,146,000	$16,590,000
% BOP Items Reduced	15.90	9.11	7.60	N/A

EPA then adjusted additional cost items in the BOP estimate that were either percentages of the equipment, material, and labor costs or were related to equipment, material, and labor costs. EPA adjusted these items by applying the % reduction in cost of equipment, material and labor. Since EPA mistakenly removed cost items that should be included in the estimate, they over-estimated and misapplied percent reduction to the other items. In Table 4, we correct EPA's adjustments to remaining Entergy BOP costs by employing EPA's methodology but reducing the percentage factors to the values indicated in Table 5.

EPA excluded a total of $51,733,667 from the estimate, but Tables 4 and 5 show that only $20,724,543 was justified because NO_X control equipment had been included. Because of EPA's misconception as to the scope of work included in the BOP and Alstom estimates, they mistakenly concluded that costs were double-counted and removed $31,009,123 (total for both units) in costs that should be included. This resulted in EPA overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff.

Table 5: Adjustment to Remaining Entergy BOP Costs (Total for Both Units)

	EPA Cost TSD Reductions				Corrected Reductions*			
DESCRIPTION	Equipment	Material	Labor	Total	Equipment	Material	Labor	Total
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$0	$0	$0	$0	$0	$0
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$546,061	$546,061	$0	$0	$656,036	$656,036
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$0	$0	$0	$0	$0	$0
COST DUE TO OVERTIME - 5-10'S	$0	$0	$7,970,183	$7,970,183	$0	$0	$9,575,359	$9,575,359
COST DUE TO OVERTIME - 5-10'S	$0	$0	$0	$0	$0	$0	$0	$0
PER DIEM - @ $10 PER HOUR	$0	$0	$7,888,659	$7,888,659	$0	$0	$9,477,416	$9,477,416
PER DIEM - @ $10 PER HOUR	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS @ 1% OF EQUIPMENT	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS @ 1% OF EQUIPMENT	$327,060	$0	$0	$327,060	$400,318	$0	$0	$400,318
FREIGHT @ 5% OF MATERIAL	$0	$0	$0	$0	$0	$0	$0	$0
FREIGHT @ 5% OF MATERIAL	$0	$1,413,404	$0	$1,413,404	$0	$1,596,000	$0	$1,596,000
GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR	$0	$0	$0	$0	$0	$0	$0	$0
GENERAL & ADMINISTRATIVE (G&A) @ 5% OFMATERIAL AND LABOR	$0	$1,413,404	$2,417,281	$3,830,686	$0	$1,596,000	$2,904,116	$4,500,116
GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR	$0	$0	$1,119,810	$1,119,810	$0	$0	$1,345,337	$1,345,337
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$0	$0	$0	$0	$0	$0	$0
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$2,826,809	$4,833,794	$7,660,602	$0	$3,192,000	$5,807,308	$8,999,308
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$0	$2,240,388	$2,240,388	$0	$0	$2,691,597	$2,691,597
NON CONTRACTOR INDIRECTS	$0	$0	$0	$0	$0	$0	$0	$0
ENGINEERING - BOP	$0	$0	$7,579,481	$7,579,481	$0	$0	$9,105,970	$9,105,970
Totals				$40,576,333				$48,347,457
Reduction in Remaining BOP Costs				$11,905,667				$4,134,543
Excluded BOP Costs from Table 4								$16,590,000
TOTAL BOP Reduction								**$20,724,543**

*Same methodology used as EPA but percentages applied are from Table 4

3.4 Cost TSD Section 2.5 – Undocumented or Disallowed Cost Items

Owner's Costs include a variety of costs incurred by the owner to support the air pollution control project. Owner's Costs are project-specific, but generally include costs incurred by the Owner to manage the project, hire and retain staff to support the project, and costs associated with third party assistance associated with project development and financing. Owner's Costs typically include, but may not necessarily be limited to:

- Site investigations (geotechnical, hydrology, etc.) for project design
- Environmental permitting/approvals
- Insurance during construction
- Site security during construction
- Transmission interconnection (if applicable)
- Fuel interconnection (if applicable)
- Owner's mobilization costs
- Owner's project management and support staff
- Insurance advisor
- Labor relations consultant
- Tax consultant
- Financial advisor
- Legal advisor
- Market consultant
- Community relations/community outreach program.

Owner's Costs are real costs that the owner will incur during the project and are typically included in cost estimates prepared for large air pollution control retrofit projects. In fact, U.S. EPA's Coal Quality Environmental Cost (CUECost) model includes Owner's Costs (or "Home Office" costs) in its air pollution control system cost estimating workbook and interrelated set of spreadsheets.[15] CUECost uses a factor of 10% of the total installed cost to estimate Owner's Costs and Engineering Costs for limestone forced oxidation and lime spray dryer control systems.

To address the items in this section, we included a section in S&L Report #012831 that describes Entergy's Owner's costs and how they were developed. We believe EPA deleted these Owner's costs because EPA did not understand how they were defined and therefore, incorrectly assumed that they did not reflect real costs to Entergy. In total, EPA removed $41,741,743 per unit from the original estimate which should be included. Removing these costs resulted in EPA overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff and Independence. Detailed explanations of these costs are included in S&L Report #012831 to help EPA understand

[15] *See*, Coal Utility Environmental Cost (CUECost) Workbook Development Documentation Version 5.0, prepared by U.S. EPA, September 2009, pages 17 and 34.
Appendix B, pages B-3 and B-6.

these costs.

3.5 Cost TSD Section 2.6 – Escalation

We agree with EPA's assertion that the application of escalation is allowed by the CCM.[16] However, EPA's method of using Chemical Engineering Plant Cost Indices (CEPCI) to escalate costs to the year 2013 resulted in severely underestimating the costs associated with escalation. CEPCI are sometimes used to estimate escalation by multiplying base costs by the ratio of the index for the year costs are to be escalated to the index for the year in which the costs were originally generated. For example, EPA used CEPCI from 2009 (521.9) and 2013 (550.8) to escalate the FGD costs from a 2009 basis to a 2013 basis. Thus, EPA applied the following formula, 550.8/521.9*$247,856,184 to obtain an estimated 2013 FGD cost of $261,581,119 for both units.

Rather than estimating escalation of Alstom's pricing from 2010, S&L (on behalf of Entergy) requested updated FGD pricing from Alstom in 2013[17]. We agree with a reference cited in the CCM and authored by EPA which states, "At best [cost indices] provide a cloudy mirror…there is no substitute for current price information obtained from suppliers of those goods and services."[18] Nothing illustrates EPA's conclusion that cost indices are not to be substituted for supplier information better than comparing EPA's escalation rate to the actual escalation rate indicated in Alstom's budgetary quotations as shown in Table 6.

Table 6: Alstom Quotation Comparison (Total for Both Units)

Parameter	EPA	Vendor Quotation
FGD Cost 2009	$247,856,184	$247,856,184
FGD Cost 2013	$261,581,119	$297,904,000
Average Escalation	1.36%	4.7% per year

As shown in Table 6, EPA underestimated escalation significantly, resulting in underestimating the 2013 dry FGD costs by $36,322,881 (total for both units). In fact, EPA applied CEPCI indices in several instances from 2008 that *de-escalated* costs, resulting in lower costs in 2013 as compared to 2008. We note specifically that EPA's cost calculations ignored the updated 2012 direct annual costs provided by Entergy, and instead included the 2008 costs.[19] Table 7 summarizes how EPA incorrectly estimated escalation in its analysis for White Bluff Unit 1 and corrects that by applying an average escalation rate of 4.7% to match the Alstom quotation. We note that information from Alstom showed their pricing escalated nearly equivalently for

[16] *See* Cost TSD, Section 2.6, page 8
[17] Updated FGD pricing from Alstom is used as the basis of the 2015 cost estimate documented in S&L Report #012831.
[18] Escalation Indexes for Air Pollution Control Costs, United States Environmental Protection Agency, October 1995, pp. 3-4.
[19] *See*, EPA-R06-OAR-2015-0189-0093-White Bluff_R6 cost revisions2.xlsx, tab "Entergy Costs"

equipment/material (~4.8%) and for installation (~4.6%). Since the difference was negligible we applied the average 4.7% in the revised costs shown in Table 7. EPA's underestimation of cost escalation carried through their analysis and resulted in an incorrect reduction in the cost estimate of over $42 million per unit.

Table 7: Summary of EPA's Escalation Errors (Per Unit)[20]

Item	Entergy	EPA (2013)	Corrected Costs Including Escalation (2013)	Escalation Costs Omitted by EPA
Total Contractor Costs* (2010)	$156,974,274	$161,676,662	$180,164,213	$18,487,550
Contingency (2010)	$20,875,711	$21,501,073	$23,959,697	$2,458,624
Balance of Plant (2008)**	$102,085,500	$75,145,724	$115,401,842	$13,316,342
Balance of Plant Indirect Costs (2012) ***	$9,768,175	$0	$10,227,279	$1,494,175
Misc Contract Labor (2012)	$4,583,719	$0	$4,799,154	$215,435
Entergy Internal Costs (2012)	$20,076,644	$0	$21,020,246	$943,602
Capital suspense (2012)	$8,348,276	$0	$8,740,645	$392,369
Total Capital Investment (TCI)		$258,323,459	$319,525,752	
Direct Annual Costs (2008)	$7,901,369	$7,790,140	$9,941,130	$2,150,990
Indirect Annual Costs				
Overhead (2008)	$2,572,707	$2,536,491	$3,236,859	$700,368
Administrative Charges @ 2% of TCI		$5,166,469	$6,390,515	$1,224,046
Property Tax @ 1% of TCI		$2,583,235	$3,195,258	$612,023
Insurance @ 1% of TCI		$2,583,235	$3,195,258	$612,023
Total Indirect Annual Costs		$12,869,429	$16,017,889	
Total Escalation Costs Underestimated by EPA				**$42,607,547**

* This item reflects the updated dry FGD pricing received in 2013
** As EPA did, this item subtracts the excluded BOP costs discussed in Section 3.3 before applying the escalation
*** In the Cost TSD, EPA incorrectly used the 2008 BOP Indirect Costs from the Revised Bart Five Factor Analysis, SDA Cost analysis rather than the 2012 BOP Indirect Costs as identified. The differential between the 2008 and 2012 BOP Indirect Costs ($1,035,071) was included in the column for Escalation Costs Omitted by EPA.

[20] *See* Cost TSD, Table 5 on page 10

3.6 Cost TSD Section 2.7 – Operating and Maintenance (O&M) Costs

Although EPA claims in its proposal that it relied on the methods and principals contained within the Control Cost Manual in developing its individual control technology cost estimates, in the supporting Cost TSD EPA stated that "we can compare Entergy's O&M costs to those obtained through the use of our IPM SDA cost model."[21]

The IPM model and the Control Cost Manual provide two entirely different approaches to calculating control system capital and O&M costs. IPM is described by EPA as a multi-regional, dynamic, deterministic linear programming model used by EPA to analyze system-wide impacts of air emissions policies on the U.S. electric power sector in the 48 contiguous states and the District of Columbia.[22] The model has been used by EPA to analyze impacts associated with proposed regulatory programs such as the Clean Air Interstate Rule (CAIR) and Mercury and Air Toxics Standard (MATS). The primary purpose of the model is to provide forecasts of least-cost capacity expansion, electricity dispatch and emission control strategies for meeting energy demand and environmental, transmission, dispatch and reliability constraints. The model includes cost modules for various air quality control technologies, and S&L developed the cost algorithms used in the IPM model to estimate costs associated with DSI, SDA, and wet FGD control systems.[23] The IPM model is not referred to in either the Control Cost Manual or the BART Guidelines as an acceptable tool to develop site specific capital or O&M cost estimates.

Cost algorithms in the IPM model were developed based on a statistical evaluation of cost data available from various industry publications, and do not take into consideration site-specific cost issues.[24] The primary purpose of the IPM cost modules is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. By necessity, the cost algorithms were designed to require minimal site-specific information available from publicly available sources. Because of the limited number of site-specific inputs, the IPM cost algorithms provide order-of-magnitude control system cost estimates, but they do not provide case-by-case project-specific cost estimates meeting the requirements of the BART Guidelines, nor do the IPM equations incorporate the cost estimating methodology described in the Control Cost Manual.

Regarding O&M costs for SDA FGD systems, the IPM model includes the following assumptions that are not consistent with a site-specific O&M cost estimates:

- A fixed quantity of additional personnel to operate the equipment is included, not accounting for site-specific project and staffing needs;

[21] *See* Cost TSD, Section 2.7, page 9.
[22] *See*, EPA website: www.epa.gov/airmarkt/progsregs/epa-ipm/.
[23] *See*, e.g., IPM Model- Updates to Cost and Performance for APC Technologies Wet FGD Cost Development Methodology, Sargent & Lundy LLC, March 2013.
[24] *Id.*, at page 1.

- While we agree with the general practice of estimating maintenance material and labor costs as percentage of capital costs, the IPM model does not estimate site-specific capital costs sufficiently upon which to apply this percentage, and the assumed percentage cannot be modified to accommodate project specific requirements;
- The assumptions incorporated in the maintenance material and labor costs are propagated into the administrative labor item, and is therefore limited by the same items as the previous item;
- Reagent consumption assumes a stoichiometry that cannot be modified to match vendor-supplied guarantees for a specific application;
- Reagent consumption also depends upon a flue gas temperature into the SDA of 300°F and cannot be modified to apply site-specific temperatures;
- Reagent consumption also depends upon lime purity, which the IPM model assumes to be 90% and cannot be modified to match actual reagent supply information;
- The IPM model estimates water consumption based on gas flow and fuel sulfur levels instead of performing site-specific calculations using actual fuel properties and operating conditions;
- Waste generation is a function of the assumed lime stoichiometry discussed above as well as an assumed moisture content of 10% that cannot be modified to match vendor-supplied mass balances for specific applications; and
- The SDA flue gas pressure drop estimate included in the IPM model is an average value based on flue gas flow rate and sulfur levels instead of performing site-specific calculations that consider the actual fuel properties, operating conditions, and actual equipment sizing and arrangement.

EPA's use of IPM to benchmark O&M costs is thus not an appropriate choice for a unit-specific analysis consistent with BART guidelines. By relying on the IPM cost modules to verify dry FGD O&M costs, EPA did not adequately evaluate and account for potential project-specific site constraints that Entergy would incur to operate the FGD control systems EPA is proposing. In addition, using the IPM cost algorithms to calculate FGD control system capital or O&M costs is inconsistent with the case-by-case BART cost analysis described in the BART Guidelines for at least two reasons. First, the IPM model does not account for unit-specific design and operating parameters that can affect control system design and costs, including operating costs. Second, the IPM cost equations do not take into consideration site-specific conditions that could affect the O&M costs to operate the control system.

Please see additional comments in the next section of our comments (3.7), addressing EPA's adjustment of the O&M cost estimates to account for lower coal sulfur.

3.7 Cost TSD Section 3.1 – Entergy's Coal Sulfur Assumption

EPA states that an uncontrolled SO_2 emission rate of 2.0 lb/MMBtu at White Bluff is "far in excess of sulfur level of the coals it has historically burned," and concludes, "[t]hus Entergy has costed SO_2 scrubber systems for the White Bluff facility that are overdesigned compared to its historical needs." Based on this conclusion, EPA adjusts the capital and O&M costs using a

design sulfur level selected by EPA. While we agree with EPA that direct O&M costs be revised to 0.68 lb/MMBtu, this sulfur level is completely inadequate for the Dry FGD equipment design basis.

EPA correctly assumes that the 2.0 lb/MMBtu design basis was to preserve fuel flexibility, but their conclusions that, "either (1) this higher cost be balanced against its greater SO_2 reduction potential, or (2) that the scrubber system's capability and cost be adjusted down to match the facility's historical emissions," are without basis and inconsistent with BART guidelines.

The SO_2 emission reduction calculation depends upon the baseline emissions, baseline heat input, and the required outlet emission rate (see Section 2.2 of our comments). SO_2 emission reduction does not depend on the fuel sulfur levels selected for FGD system design, neither the BART guidelines nor the CCM address evaluating potential future SO_2 reduction based on design fuels as part of the BART analysis or cost estimating methodology. Therefore, EPA's first conclusion that the higher costs be balanced against greater SO_2 reduction potential is inconsistent with BART requirements and has no basis.

Although the BART guidelines and the CCM both account for the development of a design basis, there are no specific requirements that air pollution control design be tied to historical operating trends. Therefore, EPA's second conclusion that capital costs must be adjusted to match historical emissions is arbitrary and without basis.

Based on its erroneous conclusions, EPA selected a maximum monthly fuel sulfur level of 0.68 lb/MMBtu as the design basis used to estimate the capital costs. Figure 1 illustrates why the use of White Bluff's maximum monthly fuel sulfur level is completely insufficient. The ability to reduce SO_2 emissions depends critically upon the amount of reagent, or lime that can be added to the FGD system. With a 0.68 lb/MMBtu design basis, the reagent preparation and delivery equipment would be inadequately sized to add lime when sulfur levels increase beyond that level. As shown in Figure 1, EPA's design basis would result in emissions above the proposed emission rate for almost half of the operating time. This design approach would require limiting fuel sulfur levels to below 0.68 lb/MMBtu to ensure continuous compliance. If this is the approach EPA is intending, then the cost analysis would need to be revised to incorporate significant additional costs associated with fuel purchasing limitations. We did not include any additional O&M costs associated with fuel limitations because we believe EPA selected the design basis due to a lack of experience rather than intending to place enforceable limits on fuel purchasing at White Bluff station.

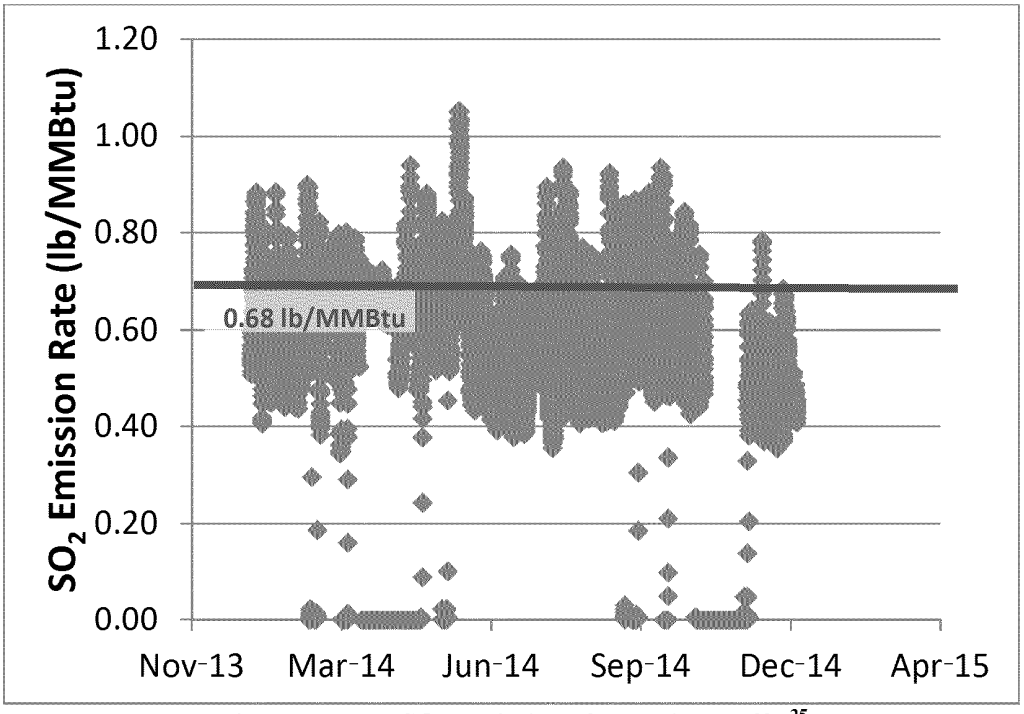

Figure 1: 2014 SO_2 Emissions for White Bluff 1[25]

While we believe that the 2008 design basis of 2.0 lb/MMBtu was appropriate at that time based on the potential to fire fuels with higher sulfur levels, based on more recent information, Entergy now believes that they will not purchase fuels with sulfur levels higher than 1.2 lb/MMBtu. The operating data shown in Figure 1 confirms that 1.2 lb/MMBtu would result in a design basis that would ensure continued compliance with EPA's proposed FIP emission rates. Therefore, we have provided a revised cost estimate based on 1.2 lb/MMBtu. To illustrate the small difference in capital costs associated with the revised design basis (1.2 lb/MMBtu versus 0.68 lb/MMBtu), S&L has included a sensitivity analysis in S&L Report #012831.

As discussed previously, we agree that it is appropriate to base direct O&M cost estimates on 0.68 lb/MMBtu fuel sulfur levels to represent average operational costs. However, EPA's adjustment factor of 0.5823 applied to direct O&M costs severely underestimated these costs. In agreement with EPA's sulfur basis, S&L developed O&M costs for the 0.68 lb/MMBtu operating case in S&L Report #012831 based on site specific consumption rate estimates and unit costs. Our report estimated O&M costs including direct variable and fixed O&M costs to be a total of $10,166,000 per unit in the first year. By comparison, EPA's calculation scales direct O&M costs of $7,790,140 by 0.5823, resulting in direct O&M costs of $4,536,199 per unit being

[25] Downloaded from EPA's Clean Air Market Database.

included in its cost-effectiveness calculation.[26] This methodology underestimated direct O&M costs by $5,629,801 per unit.

In addition, EPA applied the same O&M factor of 0.5823 to the indirect annual costs, including overhead, administrative charges, property tax and insurance, all of which depend on capital cost.[27] Therefore, assuming EPA's capital cost scaling methodology for capital cost is correct (which we do not believe is the case), then EPA should have applied the 0.9584 factor used to correct capital costs to the indirect annual costs. EPA's methodology underestimated indirect O&M costs by $4,840,192 per unit.

3.8 Cost TSD Section 4.1 – EPA's Conservatism in Cost Estimating

EPA lists two assumptions it believes are conservative in its Cost TSD. In one assumption, EPA noted that amortization from the 2008 S&L cost analysis was 40 years, but they lowered the remaining useful life to 30 years, which increases the cost-effectiveness. EPA's estimate is not conservative with regard to equipment life because, as EPA states, they, "typically assume a 30 year equipment life for scrubbers,"[28]and the 2008 amortization value from S&L was not intended to be used to conduct the BART analysis. Furthermore, as discussed in Section 3.9, the actual remaining life of these units is far below what EPA assumed.

In the second assumption, EPA concludes that two absorber vessels are not required and, thus, a 7% cost savings that could have been realized was not applied. We do not believe EPA is qualified to design dry FGD systems, and therefore not qualified to evaluate the number of vessels that are suitable for White Bluff. Dry FGD systems of this type have not been applied to units of this size, and the dry FGD supplier quoted three absorber vessels for this application based on their expertise. EPA cites no reference where fewer absorber vessels have been installed for a unit with an identical design basis, and therefore its assertion that two absorber vessels is adequate is arbitrary and without basis.

3.9 Remaining Useful Life

EPA states, "With regard to consideration of the remaining useful life of the units, we are not aware of any enforceable shutdown date for the Entergy White Bluff Plant, nor did Entergy's evaluation indicate any future planned shutdown."[29] Therefore, EPA utilized 30-years as the remaining useful life in its cost-effectiveness calculations. As stated in Entergy's comments to the proposed rule, Entergy proposes to cease coal-firing at the White Bluff units between 2027 and 2028. The proposed rule requires that the FGD controls and White Bluff be operational 5 years after the effective date of the rule. Assuming the effective date of the final rule is one year after the comment period closes, then the White Bluff FGD's will need to be operating by July of

[26] *See*, EPA-R06-OAR-2015-0189-0093-White Bluff_R6 cost revisions2.xlsx, tab "Cost-Effectiveness" Cell D4.
[27] *Id.*
[28] Cost TSD, Section 4.1 page 16.
[29] AR FIP TSD, p. 80.

2021. Based on the coal-cessation dates of White Bluff Units 1 and 2, the remaining useful life of these FGD systems is therefore between 6 and 7 years, instead of 30 years used in EPA's analysis.

4. Cost TSD Section 5 – Inclusion of Independence under Reasonable Progress Goals (RPGs)

EPA included Entergy's Independence Plant in its RPG analysis based on annual emissions from the facility.[30] It is beyond the scope of S&L's comments to address the basis upon which EPA decided to include Independence in its RPG analysis for Caney Creek and Upper Buffalo. Instead, our comments focus on the inconsistencies and errors included in EPA's RPG analysis for the Independence station.

In EPA's RPG analysis for SO_2 Controls, EPA concluded that the units at White Bluff and Independence Stations are similar enough to apply "the total annualized dry FGD and wet FGD costs [they] developed for the White Bluff units to the Independence units."[31] EPA then calculates the cost-effectiveness to retrofit FGD systems at Independence by adjusting the White Bluff cost effectiveness calculations to account for the differences in SO_2 emissions at Independence. This approach is flawed for several reasons. First, this approach includes all of the errors in EPA's cost-effectiveness analysis for White Bluff as described in the preceding sections, including errors in calculating baseline emissions, errors in calculating emission reductions, and errors associated with estimating annualized costs. Second, applying the White Bluff annualized costs to Independence is inconsistent with EPA's RPG guidance which requires cost estimates based on design parameters be developed for air pollution control systems.

To determine whether air pollution controls would be required at Independence Units 1 & 2 to meet the Reasonable Progress Goals at Caney Creek and Upper Buffalo, EPA conducted an RPG four factor analysis. The four factor analysis is described in EPA's RPG Guidance Document, and includes an evaluation of: (a) costs of compliance; (b) time necessary for compliance; (c) energy and non-air impacts; and (d) the remaining useful life of the source.[32] Regarding the first factor listed, costs of compliance, EPA suggests that, for stationary sources, the following steps be performed:

a) Identify the emissions units to be controlled;

b) Identify the design parameters for emission controls; and

c) Develop cost estimates based upon those design parameters[33]

EPA did not perform steps b and c of the RPG compliance cost evaluation. Rather, EPA relied upon an EIA database comparison as well as an aerial photo comparison of the two units to justify applying the White Bluff FGD costs to Independence. The EIA information does not contain any information that would be used to set the design basis for either FGD system;

[30] *See* 80 Fed. Reg. 18,991 (April 8, 2015).
[31] *Id.*, at page 18,992.
[32] *See* "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," U.S. EPA June 1, 2007, pg 1-3.
[33] *Id.*, at page 5-1.

therefore it cannot be used to conclude the FGD system design at Independence would be identical to White Bluff. Furthermore, EPA's use of aerial photos to indicate visual similarities between White Bluff and Independence ignores many site-specific factors that cannot be captured in a Google Earth image downloaded from the internet. Some of the site-specific factors that EPA did not account for by using this approach and which could result in different costs to retrofit FGD technology at Independence as compared to White Bluff include:

- EPA proposes the same timeline for compliance for White Bluff and Independence which will add significant labor costs due to the amount of skilled labor that would be required to construct four FGD systems in the same time period;
- EPA did not review plant operating data, such as flue gas temperatures, which affect flue gas volume, potentially requiring different equipment sizing for Independence;
- EPA did not review operating and maintenance practices at Independence, which could result in different O&M costs;
- EPA did not assess differences in underground utility interferences that could potentially change the equipment arrangement at Independence;
- EPA did not conduct subsurface geotechnical investigations to determine differences in soil conditions or distances to reach bedrock that would impact foundation design or seismic design requirements;
- EPA did not assess other seismic design requirements such as seismic risk or magnitude of potential earthquakes to determine steel design differences that may be required; and
- EPA did not assess differences in wind loads which could impact foundation and structural steel design.

In its guidance document, EPA states, "[f]or additional guidance on applying the cost of compliance factor to stationary sources, you may wish to consult the BART guidelines."[34] We note that, for EPA's RPG analysis for Independence, EPA did not revisit any of the steps required as part of a BART analysis; therefore, EPA ignored other lower cost technologies or methodologies to reduce SO_2 emissions at Independence station. EPA's inherent assumption is that BART-level SO_2 reductions are required at Independence to meet the RPGs, but it does not adequately support that assumption. EPA modeled visibility impacts of SO_2 reductions assuming FGD systems would be retrofitted at Independence, but they failed to conduct modeling using any other technology or methodology that could provide more cost-effective SO_2 reductions.

Finally, EPA also states in its RPG guidance document that for, "individual, large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation."[35] EPA's CENRAP modeling showed that the cumulative benefit of installing all of the controls proposed in the FIP would result in visibility benefits at Caney Creek of only 0.21 dv and at Upper Buffalo of only 0.19 dv.[36] Considering that

[34] *Id.*, at page 5-1.
[35] *Id.*, at page 5-2.
[36] *See* 80 Fed. Reg. 18,998, Table 67.

Independence represents only approximately 36% of the SO_2 point source emissions and 29% of the point source NO_X emissions in Arkansas, Entergy estimated the visibility improvement due to retrofitting FGD systems at Independence would be approximately 0.08 dv at Caney Creek and 0.07 dv at Upper Buffalo. Although we do not support EPA's use of the White Bluff cost estimates for Independence, we applied the White Bluff costs to retrofit dry FGD and the estimated visibility improvement due to retrofitting dry FGD systems at Independence to estimate dollar-per-deciview as suggested in EPA's RPG guidance document. Table 8 shows that retrofitting dry FGD systems at Independence is clearly not cost effective when considering the insignificant visibility improvements.

Table 8: Dollar-Per-Deciview Reduction for Dry FGD at Independence

Class I Area	Caney Creek	Upper Buffalo
Estimated Visibility Improvement[37]	0.08	0.07
Revised Annualized Costs[38]	$106,765,022	$106,765,022
$/Δdv	$1,334,562,775	$1,525,214,600

[37] The CENRAP modeling includes SO_2 and NO_X impacts; therefore, the numbers shown likely overestimate the visibility improvement based solely on SO_2 reductions.

[38] Annualized costs for Retrofitting Dry FGD at White Bluff 1 and 2 from S&L Report #012831 were used assuming a 30-year remaining useful life.

5. CONCLUSION

S&L reviewed the approach EPA takes in its proposed FIP for Arkansas, including EPA's determination of costs for retrofit dry FGD scrubbers, and EPA's evaluation of annual SO_2 emission reductions. Our analysis identifies several areas where EPA overstates the cost-effectiveness ($/ton of SO_2 removed) of the dry FGD retrofits that EPA would require in its FIP. As discussed in this analysis, cost-effectiveness is influenced by two variables: the total annualized cost to retrofit FGD controls ($/yr) and the corresponding reduction in annual SO_2 emissions (tons per year "tpy"). EPA's approach does not accurately calculate either variable. Table 9 shows how the approach EPA took understated the annualized cost of the control systems and the adjustments S&L made to correct EPA's errors.

Table 9: Adjustments to EPA's Annualized Cost for a Single Unit at White Bluff

Item	Total Capital Investment ($)	Annualized Cost ($/year)
EPA FIP	$247,537,295	$31,981,230
Corrected BOP Cost Exclusions	$263,041,857	$33,230,898
Corrected Owner's Cost Exclusions	$304,783,600	$36,595,282
Corrected Escalation	$347,391,147	$40,029,450
Corrected Operating Costs	$347,391,147	$50,499,444
Remaining Useful Lifetime Adjustment*	$347,391,147	$86,975,068 to $95,381,830
2015 Estimate (S&L Report #012831)*	**$536,185,000**	**$109,681,936 to $122,657,613**
Differential from EPA FIP*	**+ $99,853,852**	**+ $54,993,838 to $63,400,600**

* Entergy proposes to cease to use coal at White Bluff 1 and 2 between 2027 and 2028; therefore, the annualized costs are shown as a range based on a remaining useful life of 6 or 7 years.

In addition, Table 10 shows how EPA's approach overstated the tons of SO_2 that would be removed by its FIP-imposed dry FGD and the adjustments S&L made to correct EPA's mistakes.

Table 10: Adjustments to EPA's SO_2 Emission Reductions

Item	White Bluff 1 (tons)	White Bluff 2 (tons)
EPA FIP	14,363	15,221
Corrected Baseline Emission Calculation	14,474	14,617
Corrected SO_2 Emission Reduction Calculation	14,264	14,353
Differential from EPA FIP	**-99**	**-868**

EPA's errors resulted in severely overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff 1 and 2 (and then by extension in its reasonable progress analysis for Independence 1 and 2). Table 11 summarizes how EPA's errors systematically underestimated cost and overstated the cost-effectiveness to install these dry FGD systems. As Table 11 indicates when the errors are corrected and updated costs incorporated, retrofitting dry FGD systems at these units is clearly not cost-effective.

Table 11: Summary Cost-Effectiveness Impacts

Item	White Bluff 1 ($/ton)	White Bluff 2 ($/ton)
EPA's Cost Effectiveness	$2,227	$2,101
Corrected Baseline Emission Calculation	$2,210	$2,188
Corrected SO_2 Emission Reduction Calculation	$2,242	$2,228
Corrected BOP Cost Exclusions	$2,330	$2,315
Corrected Owner's Cost Exclusions	$2,566	$2,550
Corrected Escalation	$2,806	$2,789
Corrected Operating Cost	$3,540	$3,518
Corrected Remaining Useful Life *	$6,097 to $6,687	$6,060 to $6,646
2015 Estimate (S&L Report #012831) *	**$7,689 to $8,599**	**$7,642 to $8,546**
Differential from EPA FIP[1]	**+ $5,462 to $6,372**	**+ $5,541 to $6,445**

* Entergy proposes to cease to use coal at White Bluff Units 1 and 2 between 2027 and 2028; therefore, the cost effectiveness values are shown as a range based on a remaining useful life of 6 or 7 years.

With respect to EPA's RPG analysis for SO_2 controls, EPA did not follow its own guidance document when conducting its four factor analysis of Independence. EPA failed to consider lower cost options that could reduce SO_2 emissions at Independence and instead concluded that BART-level controls were required to meet RPG. EPA did not prepare cost estimates based on design parameters for FGD systems retrofit at Independence, as required by their RPG guidance document. EPA did not conduct a dollar-per-deciview analysis, as recommended in its RPG document for these analyses, to demonstrate the benefit of retrofitting dry FGD at Independence accounting for visibility benefits. When applying annualized costs to projected visibility improvements the result is **over $1.3 billion/Δdv** for Caney Creek and **over $1.5 billion/Δdv** for Upper Buffalo, which is clearly not cost effective.