VIA ELECTRONIC MAIL

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RE: Coalition to Protect America's National Parks, National Parks Conservation Association and Sierra Club Comments on Arkansas Division of Environmental Quality's Proposed Regional Haze Planning Period II State Implementation Plan

Dear Ms. Droke:

Please accept these comments submitted on behalf of the Coalition to Protect America's National Parks, National Parks Conservation Association and Sierra Club (the "Conservation Organizations") regarding the Arkansas Division of Environmental Quality's ("ADEQ") proposed Regional Haze State Planning Period II State Implementation Plan ("Proposed SIP").

The Coalition to Protect America's National Parks ("Coalition") is a non-profit organization composed of over 2,100 retired, former and current employees of the National Park Service ("NPS"). The Coalition studies, speaks, and acts for the preservation of America's National Park System. As a group, we collectively represent over 40,000 years of experience managing and protecting America's most precious and important natural, cultural, and historic resources.

National Parks Conservation Association ("NPCA") is a national organization whose mission is to protect and enhance America's National Parks for present and future generations. NPCA performs its work through advocacy and education, with its main office in Washington, D.C. and 24 regional and field offices. NPCA has over 1.5 million members and supporters nationwide, with more than 9,400 in Arkansas. NPCA is active nationwide in advocating for strong air quality requirements to protect our parks, including submission of petitions and comments relating to visibility issues, regional haze State Implementation Plans, climate change and mercury impacts on parks, and emissions from individual power plants and other sources of pollution affecting National Parks and communities. NPCA's members live near, work at, and recreate in all the national parks, including those directly affected by emissions from Arkansas's sources.

Sierra Club is a national nonprofit organization with 67 chapters and more than 832,000 members dedicated to exploring, enjoying, and protecting the wild places of the earth; to practicing and promoting the responsible use of the earth's ecosystems and resources; to educating and enlisting humanity to protect and restore the quality of the natural and human environment; and to using all lawful means to carry out these objectives. The Sierra Club has long participated in Regional Haze rulemaking and litigation across the country in order to advocate for public health and our nation's national parks.

As explained in detail below, we have serious concerns regarding ADEQ's Proposed SIP. At a minimum, ADEQ must correct the following flaws:

1. ADEQ has not adequately documented key data that underlies its SIP proposal, and ADEQ's proposed SIP fails to include documentation necessary to independently review the availability of cost-effective controls.
2. ADEQ's treatment of the Regional Haze Rule's consultation requirement in Section 51.308(f)(2)(ii) is entirely perfunctory and does not satisfy the rule's requirements.
3. ADEQ impermissibly exempts EGUs and non-EGUs from further control analysis based on the state's purported compliance with the Uniform Rate of Progress.
4. The Proposed SIP fails to properly establish reasonable progress goals and fails to consider the statutory reasonable progress factors for EGUs and non-EGUs, and instead relies on factors that Congress did not intend for states to consider to exempt those sources from reasonable, cost-effective controls.
5. ADEQ's control evaluation for the state's EGU sector—and Flint Creek in particular—fails to satisfy the Regional Haze Rule's requirement that the state include the "robust" technical demonstration showing that no additional controls are reasonable.
6. ADEQ's control evaluation for the state's non-EGU sector contain fatal flaws, lack the required supporting technical documentation and fail to include reasoned bases to support its 'do nothing' approach at the Domtar A.W. LLC, Ashdown Mill, and the five sources of concern to the Conservation Organizations that the state totally ignored. Additionally, the state's proposed SIP for FutureFuel Chemical Company is flawed for similar reasons: it lacks any controls for NOx; and its analysis for SO_2 is inaccurate, incomplete, and arbitrary.

7. ADEQ's interstate consultation is inconsistent with the requirements of the Regional Haze Rule.
8. ADEQ's must reevaluate, consider and incorporate the Federal Land Managers' comments.

As it currently stands, ADEQ's Proposed SIP does not meet the legal requirements of the Clean Air Act or federal regulations, and therefore cannot be approved by the U.S. Environmental Protection Agency ("EPA"). We urge ADEQ to revise the plan to address the fundamental flaws identified in these comments.

I. LEGAL FRAMEWORK

A. The Clean Air Act's Visibility Provisions and the Regional Haze Rule

The Clean Air Act establishes "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." 42 U.S.C. § 7491(a)(1). To that end, EPA issued the Regional Haze Rule, which requires the states (or EPA where a state fails to act) to make incremental, "reasonable progress" toward eliminating human-caused visibility impairment at each Class I area by 2064. 40 C.F.R. § 51.308(d)(1), (d)(3). Together, the Clean Air Act and EPA's Regional Haze Rule require states to periodically develop and implement state implementation plans ("SIPs"), each of which must contain a long-term strategy encompassing *enforceable* "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward the national goal." 42 U.S.C. § 7491(b)(2); *see also* 42 U.S.C. § 7410(a)(2); 40 C.F.R. § 51.308.

In developing its long-term strategy, a state must consider all anthropogenic sources of visibility impairment and evaluate different emission reduction strategies, including and beyond those prescribed by the BART provisions.[1] A state should consider "major and minor stationary sources, mobile sources and area sources."[2] At a minimum, a state must consider the following factors in developing its long-term strategy:

> (A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
> (B) Measures to mitigate the impacts of construction activities;
> (C) Emissions limitations and schedules for compliance to achieve the reasonable progress goal;

[1] 40 C.F.R. § 51.308(f).
[2] *Id.* § 51.308(f)(2)(i).

> (D) Source retirement and replacement schedules;
> (E) Smoke management techniques for agriculture and forestry management purposes including plans as currently exist within the State for these purposes;
> (F) Enforceability of emission limitations and control measures; and
> (G) The anticipated net effect on visibility due to projected changes in point, area, and mobile emissions over the period addressed by the long-term strategy.[3]

Additionally, a state:

> Must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated and how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy.[4]

In developing its plan, the state must document the technical basis for the SIP, including monitoring data, modeling, and emission information, including the baseline emission inventory upon which its strategies are based.[5] All of this information is part of a state's revised SIP and subject to public notice and comment. A state's reasonable progress analysis must consider the four factors identified in the Clean Air Act and regulations. *See* 42 U.S.C. § 7491(g)(1); 40 C.F.R. § 51.308(f)(2)(i) ("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 anthropogenic source of visibility impairment.").

Notably, the statute does *not* list visibility improvement as a fifth factor in the reasonable progress analysis, and in implementing those statutory factors, EPA has made clear that it is *not* appropriate to reject a cost-effective control measures based on purportedly insufficient visibility benefits. In determining whether each state's haze plan satisfies the statutory mandate to make reasonable progress, EPA reviews adherence to the above-mentioned criteria and whether the state follows the requirements to consult with other states and federal land managers, and reasonably considers the four statutory factors for reasonable progress. 40 C.F.R. §§ 51.308(d)(1)(iii)-(iv); (d)(3); (f).

B. EPA's 2017 Revisions to the Regional Haze Rule

On January 10, 2017, the EPA revised the Regional Haze Rule to strengthen and clarify the reasonable progress and consultation requirements of the rule. *See*

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[3] *Id.* § 51.308(f)(2)(iv).
[4] 40 C.F.R. § 51.308(f)(2)(i).
[5] 40 C.F.R. § 51.308(f)(2)(i).

generally 82 Fed. Reg. 3078. In particular, the rule revisions make clear that states are to *first* conduct the required four-factor analysis for its sources, considering the four statutory factors, and *then* use the results from its four-factor analyses and determinations to develop the reasonable progress goals.[6] Thus, the rule "codif[ies]" EPA's "long-standing interpretation" of the SIP "planning sequence" States are required to follow:

> (1) [C]alculate baseline, current and natural visibility conditions, progress to date and the [Uniform Rate of Progress] URP;
> 2) [D]evelop a long-term strategy for addressing regional haze by evaluating the four factors to determine what emission limits and other measures are necessary to make reasonable progress;
> (3) [C]onduct regional-scale modeling of projected future emissions under the long-term strategies to establish RPGs and then compare those goals to the URP line; and
> (4) [A]dopt a monitoring strategy and other measures to track future progress and ensure compliance.[7]

Thus, the Regional Haze Rule makes clear that a state must conduct four-factor analysis and cannot rely on uniform rate of progress as an excuse for failing to perform the core functions of the law:

> The CAA requires states to determine what emission limitations, compliance schedules and other measures are necessary to make reasonable progress by considering the four factors. The CAA does not provide that states may then reject some control measures already determined to be reasonable if, in the aggregate, the controls are projected to result in too much or too little progress. Rather, the rate of progress that will be achieved by the emission reductions resulting from all reasonable control measures is, by definition, a reasonable rate of progress. … [I]f a state has reasonably selected a set of sources for analysis and has reasonably considered the four factors in determining what additional control measures are necessary to make reasonable progress, then the state's analytical obligations are complete if the resulting RPG for the most impaired days is below the URP line. *The URP is not a safe harbor*, however, and states may not subsequently reject control measures that they have already determined are reasonable.[8]

Moreover, for each Class I area within its borders, a state must determine

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[6] 82 Fed. Reg. 3,078, 3,090-91 (Jan. 10, 2017).
[7] *Id.* at 3,091.
[8] *Id. at* 3,093 (emphasis added).

the uniform rate of progress, which is the amount of progress that, if kept constant each year, would ensure that natural visibility conditions are achieved in 2064. 40 C.F.R. § 51.308(d)(1)(i)(B). If a state establishes reasonable progress goals that provide for a slower rate of improvement in visibility than the uniform rate of progress, the state must provide a technically "robust" demonstration, based on a careful consideration of the statutory reasonable progress factors, that "there are no additional emission reduction measures for anthropogenic sources or groups of sources" that can reasonably be anticipated to contribute to visibility impairment in affected Class I areas.[9]

Although many states addressed the Clean Air Act's BART requirements in their initial regional haze plans, EPA's 2017 revisions to the Regional Haze Rule make clear that BART was not a once-and-done requirement. Indeed, states "will need" to reassess "BART-eligible sources that installed only moderately effective controls (or no controls at all)" for any additional technically-achievable controls in the second planning period.[10]

To the extent that a state declines to evaluate additional pollution controls for any source relied upon to achieve reasonable progress based on that source's planned retirement or decline in utilization, it must incorporate those operating parameters or assumptions as enforceable limitations in the second planning period SIP. The Clean Air Act requires that "[e]ach state implementation plan . . . *shall*" include "enforceable limitations and other control measures" as necessary to "meet the applicable requirements" of the Act. 42 U.S.C. § 7410(a)(2)(A). The Regional Haze Rule similarly requires each state to include "enforceable emission limitations" as necessary to ensure reasonable progress toward the national visibility goal.[11] Therefore, where the state relies on a sources' plans to permanently cease operations or projects that future operating parameters (*e.g.*, limited hours of operation or capacity utilization) will differ from past practice, or if this projection exempts additional pollution controls as necessary to ensure reasonable progress, then the state "must" make those parameters or assumptions into enforceable limitations. [12]

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[9] 40 C.F.R. § 51.308 (f)(2)(ii)(A).

[10] 82 Fed. Reg. at 3,083; *see also id.* at 3,096 ("states must evaluate and reassess all elements required by 40 CFR 51.308(d)").

[11] *See* 40 C.F.R. § 51.308(d)(3) ("The long-term strategy must include enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals established by States having mandatory Class I Federal areas.").

[12] 40 C.F.R. §§ 51.308(i); (d)(3) ("The long-term strategy must include enforceable emissions limitations, compliance schedules . . ."); (f)(2) (the long-term strategy must include "enforceable emissions limitations"); *see also* Memorandum from Peter Tsirigotis, Director at EPA Office of Air Quality Planning and Standards, to EPA

Finally, the state's SIP revisions must meet certain procedural and consultation requirements.[13] The state must consult with the Federal Land Managers ("FLMs") and look to the FLMs' expertise of the lands and knowledge of the way pollution harms them to guide the state to ensure SIPs do what they must to help restore natural skies. The rule also requires that in "developing any implementation plan (or plan revision) or progress report, the State must include a description of how it addressed any comments provided by the Federal Land Managers."[14]

C. EPA's July 8, 2021 Regional Haze Clarification Memorandum

On July 8, 2021, EPA issued a memo which further clarified certain aspects of the revised Regional Haze Rule and provided further information to states and EPA regional offices regarding their planning obligations for the Second Planning Period.[15] EPA's July 2021 "Clarification Memo" confirms that certain aspects of ADEQ's proposed SIP are fundamentally flawed and cannot be approved. Particularly relevant here, EPA made clear that States must secure additional emission reductions that build on progress already achieved, there is an expectation that reductions are additive to ongoing and upcoming reductions under other CAA programs.[16] In evaluating sources for emission reductions, EPA emphasized that:

Air Division Directors Regions, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," EPA-457/B-19-003, at 22 (Aug. 2019), https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf. ["2019 Guidance"] ("in selecting sources for control measure analysis," the state may choose "not selecting sources that have an enforceable commitment to be retired or replaced by 2028"); *id*. at 34 (To the extent a retirement or reduction in operation "is being relied upon for a reasonable progress determination, the measure would need to be included in the SIP and/or be federally enforceable.") (citing 40 C.F.R. § 51.308(f)(2)); 2019 Guidance at 43 ("[i]f a state determines that an in-place emission control at a source is a measure that is necessary to make reasonable progress and there is not already an enforceable emission limit corresponding to that control in the SIP, the state is required to adopt emission limits based on those controls as part of its long-term strategy in the SIP via the regional haze second planning period plan submission.").

[13] For example, in addition to the Regional Haze Rule requirements, states must also follow the SIP processing requirements in 40 C.F.R. §§ 51.104, 51.102.

[14] *Id*. § 51.308(i)(3).

[15] July 8, 2021 Memo from Peter Tsirogotis to Regional Air Directors, Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period at 3, https://www.epa.gov/visibility/clarifications-regarding-regional-haze-state-implementation-plans-second-implementation [hereinafter, "2021 Clarification Memo"].

[16] *Id*. at 2.

> Source selection is a critical step in states' analytical processes. All subsequent determinations of what constitutes reasonable progress flow from states' initial decisions regarding the universe of pollutants and sources they will consider for the second planning period. States cannot reasonably determine that they are making reasonable progress if they have not adequately considered the contributors to visibility impairment. Thus, while states have discretion to reasonably select sources, this analysis should be designed and conducted to ensure that source selection results in a set of pollutants and sources the evaluation of which has the potential to meaningfully reduce their contributions to visibility impairment.[17]

Thus, it is generally not reasonable to exclude from further evaluation large sources or entire sectors of visibility impairing pollution. Moreover, the Clarification Memo reiterates that the fact that a Class I area is meeting the Uniform Rate of Progress is "not a safe harbor" and does not excuse the state from its obligation to consider the statutory reasonable progress factors in evaluating reasonable control options.[18]

For sources that have previously installed controls, states should still evaluate the "full range of potentially reasonable options for reducing emissions," including options that may "achieve greater control efficiencies, and, therefore, lower emission rates, using their existing measures."[19] Moreover, "[i]f a state determines that an in-place emission control at a source is a measure that is necessary to make reasonable progress and there is not already an enforceable emission limit corresponding to that control in the SIP, the state is required to adopt emission limits based on those controls as part of its long-term strategy in the SIP via the regional haze second planning period plan submission."[20] This means that so-called "on-the-way" measures, including anticipated shutdowns or reductions in a source's emissions or utilization, that are relied upon to forgo a four-factor analysis or to shorten the remaining useful life of a source "*must* be included in the SIP" as enforceable emission reduction measures.[21] In addition, the Clarification Memo makes clear that a state should generally not reject cost-effective and otherwise reasonable controls merely because there have been emission reductions since the first planning period owing to other ongoing air pollution control programs or merely because visibility is otherwise projected to improve at Class I areas. Finally, the Clarification Memo confirms EPA's recommendation that states take into consideration environmental justice concerns and impacts in issuing any SIP revision for the second planning period.

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[17] *Id*. at 3.
[18] *Id*. at 2.
[19] *Id*. at 7.
[20] *Id*. at 8.
[21] *Id*. at 8-9 (emphasis added).

In sum, EPA's 2021 Clarification Memo makes clear that the states' regional haze plans for the second planning period must include meaningful emission reductions to make reasonable progress towards the national goal of restoring visibility in Class I areas. The Clarification Memo confirms that ADEQ's efforts to avoid emission reductions—by asserting, for example, that reductions are not necessary because visibility has improved, because reductions are anticipated at some later date or due to implementation of another program, or because a source has some level of control—is at odds with Arkansas's haze obligations under the Clean Air Act and the Regional Haze Rule itself.

II. ADEQ'S PROPOSED SIP FAILS TO MEET THE REQUIREMENTS OF THE CLEAN AIR ACT AND REGIONAL HAZE RULE.

Section 51.308(f)(2)(i) of the Regional Haze Rule requires a SIP to include a description of the criteria the state has used to determine the sources or groups of sources it evaluated for potential controls.

A. ADEQ's Cost-Effectiveness Thresholds For Reasonable Progress Determinations Are Arbitrary and Incorrectly Determined.

1. ADEQ unreasonably used first planning period controls for this second round four-factor analyses.

First, there is no reasonable justification for using first round cost-effectiveness thresholds for second round four-factor analyses, as ADEQ has done in this Proposed SIP. The agency bases its cost-effectiveness threshold on a statistical analysis it performed of first round BART and reasonable progress determinations, escalated to 2019 dollars using the Chemical Engineering Plant Cost Index (CEPCI). But first round BART and reasonable progress determinations were focused on the largest sources with controls that were very cost-effective or resulted in large cumulative reductions in emissions. As a result of these controls and the uneconomical nature of many under-controlled coal-fired EGUs, many of these types of sources are now at least partially controlled or retired. The cheapest sources of emissions reductions have now been addressed.

To achieve the Clean Air Act's goals, smaller sources and somewhat less cost-effective controls must be required. These controls may result in less cumulative emissions reduction but are nevertheless necessary in order to make continued progress toward the national goal of a return to natural visibility. To deny this reality by using first round cost-effectiveness thresholds would render regional haze progress static, as the same or similar controls would be continuously rejected. EPA recognizes this with regard to visibility impacts in its Clarifications Memo:[22]

[22] *Id.* at 14.

> Evaluation of control measures for relatively smaller sources (with commensurate smaller visibility benefits from each individual source) will be needed to continue making reasonable progress towards the national goal. This is true for the second planning period, as many of the largest individual visibility impairing sources have either already been controlled (under the RHR or other CAA or state programs) or have retired. To this end, EPA is reiterating that visibility thresholds used for BART and other analyses in the first planning period (e.g., 0.5 deciviews) are, in most cases, not appropriate thresholds for selecting sources or evaluating the impact of controls for reasonable progress in the second planning period.

DEQ must revise its cost-effectiveness threshold to a more reasonable value that recognizes this reality. For example, states have established the following thresholds for the second-round regional haze plans, including: Arizona ($4,000 to $6,500/ton)[23], New Mexico ($7,000 per ton)[24], Oregon ($10,000/ton)[25], Washington ($6,300/ton for Kraft pulp and paper power boilers)[26], and Colorado ($10,000/ton).[27]

2. ADEQ's Use of Sector-Based Thresholds is Inappropriate.

For this Proposed SIP, ADEQ created a cost-effectiveness threshold for each sector. It does this by reviewing cost-effectiveness values resulting from BART and reasonable progress determinations during the first planning period. ADEQ then escalates those values to 2019 dollars, and then uses these figures to establish acceptable cost-effectiveness thresholds for each sector for this planning period. ADEQ justifies this approach by noting the following on page V-14:

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[23] *See, e.g.,* Arizona Department of Environmental Quality, 2021 Regional Haze Four-Factor Initial Control Determination, Tucson Electric Power Springerville Generating Station, at 15, https://www.azdeq.gov/2021-regional-haze-sip-planning

[24] *See* NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf

[25] *See, e.g.,* September 9, 2020 Letter from Oregon Department of Environmental Quality to Collins Forest Products, at 1-2, https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf

[26] *See, e.g.,* Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, https://fortress.wa.gov/ecy/ezshare/AQ/RegionalHaze/docs/RespondFLM20210111.pdf

[27] *See* Colorado Department of Public Health and Environment, In the Matter of Proposed Revisions to Regulation No. 23, November 17 to 19, 2021 Public Hearing, Prehearing Statement, at 7, https://drive.google.com/drive/u/1/folders/1TK41unOYnMKp5uuakhZiDK0-fuziE58v

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

This argument is inappropriate because it implicitly considers affordability, which is not one of the four statutory factors. In fact, neither the Clean Air Act nor the Regional Haze Rule makes any distinction concerning how the four factors should be applied to different sectors. ADEQ must either use the same cost-effectiveness threshold for all sources or distinguish between sources using a valid methodology that complies with the Regional Haze Rule and Clean Air Act.

B. Flint Creek, An Arkansas EGU, Merits Reasonable Progress Controls for NOx and Further Review for SO2.

1. ADEQ's Four Factor Analysis for Flint Creek NOx Controls is Unreasonable Because ADEQ Assumed Unreasonably Low Emissions Reductions from Installation of an SNCR at Flint Creek.

Flint Creek is currently required to meet a NOx BART emission limit of 0.23 lb/MMBtu on a 30-boiler operating day average.[28] It meets this requirement with low-NOx burners with separated overfire air ("LNB/SOFA"). On pdf page 10 of its report (the pages are not numbered), SWEPCO, the operator of Flint Creek, takes the position that because EPA assumed a selective noncatalytic reduction ("SNCR") controlled NOx emission limit of 0.20 lbs/MMbtu, which is roughly similar to its current baseline, the addition of SNCR would not appreciably reduce NOx and therefore SWEPCO's evaluation does not consider it.

ADEQ does not accept this position, but reasons that an SNCR control of 10% reduction (from current emissions) is appropriate to evaluate, based on the difference between its understanding of the vendor's estimate for SNCR + LNB/OFA

[28] ADEQ, Title V Operating Permit for Flint Creek Power Plant, Permit No. 0276-AOP-R9 https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/0276-AOPR9.pdf

and just LNB/OFA used in the BART evaluation. On page V-46, ADEQ then makes the following convoluted argument:

> Additionally, the difference between the maximum monthly NOx emission rate during the baseline (0.20 lb/MMBTU) and the lower range of controlled emission rates provided by the vendor for LNB/OFA/SNCR (0.18 lb/MMBTU) would result in a 10% emission reduction. Therefore, an inlet emission rate of 0.20 lb/MMBTU and a control efficiency of 10% is appropriate to use for determining costs to ensure that the system is adequately sized to accommodate maximum inlet concentrations.
>
> The difference between the average monthly emission rate during the baseline (0.186 lb/MMBTU) and a controlled emission rate of 0.18 lb/MMBTU is 3.22%. Therefore, DEQ estimates that Flint Creek could achieve up to a 3.22% emission reduction from baseline emissions if SNCR were installed.

Thus, ADEQ goes from a low SNCR efficiency of 10% to an extremely low SNCR efficiency of 3.22%.

To investigate a reasonable estimate for a controlled SNCR monthly limit, we conducted a review of all coal-fired EGUs configured the same as Flint Creek but fitted with SNCR. Specifically, the monthly NOx emissions of all coal-fired, dry bottom wall fired EGUs fitted with SNCR systems were examined from 2012 – 2021. The result of this review reveals many examples of EGUs with extended monthly NOx averages continuously below 0.15 lbs/MMBtu. A few notable examples are presented in Table 1:[29]

Table 1. Notable EGU SNCR Installation Monthly NOx Performance

Facility Name	Unit ID	Month	Year	Operating Time	Avg. NOx Rate (lb/MMBtu)
Big Cajun 2	2B3	1	2016	684.61	0.1104
Big Cajun 2	2B3	2	2016	679.97	0.112
Big Cajun 2	2B3	3	2016	145.39	0.1059
Big Cajun 2	2B3	4	2016	720	0.1133
Big Cajun 2	2B3	5	2016	693.27	0.1185
Big Cajun 2	2B3	6	2016	662.18	0.109
Big Cajun 2	2B3	7	2016	744	0.1173

[29] *See* Attachment A, "AR EGU emissions.xlsx," worksheet "EGUs with SNCR."

Facility Name	Unit ID	Month	Year	Operating Time	Avg. NOx Rate (lb/MMBtu)
Big Cajun 2	2B3	8	2016	744	0.1127
Big Cajun 2	2B3	9	2016	571.93	0.1049
Big Cajun 2	2B3	10	2016	689.66	0.1151
Big Cajun 2	2B3	11	2016	600.37	0.1167
Big Cajun 2	2B3	12	2016	586.69	0.1181
Laramie River	3	1	2021	615.99	0.1388
Laramie River	3	2	2021	416.55	0.1405
Laramie River	3	3	2021	507.85	0.1417
Laramie River	3	4	2021	494.51	0.1385
Laramie River	3	5	2021	615.73	0.1374
Laramie River	3	6	2021	364.13	0.1431
Laramie River	3	7	2021	610.58	0.1402
Laramie River	3	8	2021	725.91	0.1384
Laramie River	3	9	2021	691.61	0.1414
Laramie River	3	10	2021	23.82	0.1435
Laramie River	3	11	2021	0	
Laramie River	3	12	2021	481.72	0.1342
Leland Olds	1	1	2021	607.47	0.1401
Leland Olds	1	2	2021	581.2	0.1541
Leland Olds	1	3	2021	594.05	0.1279
Leland Olds	1	4	2021	16.73	0.1696
Leland Olds	1	5	2021	94.67	0.1214
Leland Olds	1	6	2021	616.59	0.1237
Leland Olds	1	7	2021	744	0.1344
Leland Olds	1	8	2021	744	0.1321
Leland Olds	1	9	2021	634.12	0.1333
Leland Olds	1	10	2021	701.75	0.1328
Leland Olds	1	11	2021	696.34	0.1332
Leland Olds	1	12	2021	615.32	0.1336
Monticello	3	1	2017	735.08	0.1364
Monticello	3	2	2017	602.94	0.1331
Monticello	3	3	2017	26.88	0.1126
Monticello	3	4	2017	689.32	0.1344
Monticello	3	5	2017	655.06	0.1378

Facility Name	Unit ID	Month	Year	Operating Time	Avg. NOx Rate (lb/MMBtu)
Monticello	3	6	2017	720	0.1389
Monticello	3	7	2017	675.64	0.136
Monticello	3	8	2017	670.45	0.1383
Monticello	3	9	2017	672.35	0.139
Monticello	3	10	2017	744	0.13
Monticello	3	11	2017	516.21	0.1383
Monticello	3	12	2017	261.77	0.1405
Salem Harbor Station	3	1	2012	715.25	0.0584
Salem Harbor Station	3	2	2012	696	0.0585
Salem Harbor Station	3	3	2012	395.07	0.0537
Salem Harbor Station	3	4	2012	405.05	0.0464
Salem Harbor Station	3	5	2012	269.76	0.0807
Salem Harbor Station	3	6	2012	312.57	0.0849
Salem Harbor Station	3	7	2012	285.31	0.0708
Salem Harbor Station	3	8	2012	368.18	0.0859
Salem Harbor Station	3	9	2012	21.28	0.0683
Salem Harbor Station	3	10	2012	265.64	0.1041
Salem Harbor Station	3	11	2012	219.32	0.1084
Salem Harbor Station	3	12	2012	376.81	0.1355
W H Sammis	5	1	2014	744	0.114
W H Sammis	5	2	2014	672	0.1213
W H Sammis	5	3	2014	686.17	0.1221
W H Sammis	5	4	2014	720	0.1373
W H Sammis	5	5	2014	597.74	0.134
W H Sammis	5	6	2014	478.57	0.1475

Facility Name	Unit ID	Month	Year	Operating Time	Avg. NOx Rate (lb/MMBtu)
W H Sammis	5	7	2014	650.3	0.1052
W H Sammis	5	8	2014	677.66	0.1186
W H Sammis	5	9	2014	180.78	0.1342
W H Sammis	5	10	2014	643.18	0.1204
W H Sammis	5	11	2014	625.07	0.1097
W H Sammis	5	12	2014	155.59	0.191

As can be seen from this data, there are many examples of coal-fired EGUs with the same boiler configuration as Flint Creek with SNCR systems that consistently result in monthly NOx emissions below 0.15 lbs/MMBtu. Three points should be noted concerning this data. First, many of these EGUs are no longer base load units and are not operated continuously, but nevertheless manage to maintain adequate exhaust gas temperature so as to effectively operate their SNCR systems.[30] Second, it is likely that the monthly NOx emissions shown above do not represent the best performance for many of these units, as evidenced by the variation in some of the data. In other words, these SNCR systems are likely performing to meet permitting limits not regional haze SIP emission limits. Third, although only EGUs with coal as the primary fuel were selected, some units may burn significant amounts of gas, which would lower the NOx emissions. Although beyond the scope of this report, this could be easily determined by examining monthly reported fuel data in EIA Form 923.[31] Nevertheless, the above results indicate that SWEPCO's position that a Monthly NOx limit of 0.20 lbs/MMBtu serves as an SNCR floor is not a reasonable conclusion. A monthly NOx limit of 0.14 lbs/MMBtu or lower appears reasonable.

2. *ADEQ's Flint Creek Cost Effectiveness Analysis for SNCR is Inflated.*

ADEQ presents its SNCR cost-effectiveness calculation of $6,790/ton in a spreadsheet in Appendix I. This figure is over-stated for several reasons.

First, as explained in the section above, ADEQ's calculation unreasonably assumes a 3% SNCR efficiency. In reality, an SNCR system would achieve higher efficiency. Second, ADEQ also assumes a 20-year equipment life, which should be

[30] Luminant's Monticello power plant permanently retired in 2018, but as noted, data from 2017 demonstrates that the plant was routinely achieving NOx emission rates below 0.15 lbs/MMbtu, indicating that even at low loads, the three units were able to maintain stack temperatures and exit velocities sufficient to operate the controls.

[31] *See* https://www.eia.gov/electricity/data/eia923/.

30 years. Third, it appears that ADEQ has used an outdated source of information for calculating the SNCR cost-effectiveness, which is indicated in the "Read Me" worksheet of Appendix I shows ADEQ used EPA's Control Cost Manual 6th Edition of January 2002 instead of the most recent 2019 update.

We corrected those errors in the revised cost-effectiveness calculation below, in Table 2. In doing so, we used EPA's revised SNCR spreadsheet, which accompanies the April 25, 2019 update to the Control Cost Manual.[32] The results are presented below:[33]

Table 2. Selected Inputs and Outputs for the Flint Creek SNCR Cost-Effectiveness Calculation

Fuel type	Coal	
Retrofit factor	1	
MW rating	588	MW
HHV	8,599	Btu/lb
Annual MWh output	2,682,649	MWh
Total System Capacity Factor (CF_{total})	0.521	
Net plant heat input rate (NPHR)	10	MMBtu/MW
Desired SNCR efficiency	24	Percent
NOx inlet	0.184	lb/MMBtu
NOx outlet	0.140	lb/MMBtu
Reagent	Ammonia	
Plant elevation	1,155	Feet
Desired dollar-year	2020	
Interest rate	3.50	Percent
Equipment life	30	Years
Total Capital Investment (TCI)	$12,331,670	
Direct Annual Costs (DAC)	$490,901	
Indirect Annual Costs (IDAC)	$676,392	
Total Annual Costs (TAC) = DAC + IDAC	$1,167293	
NOx removed	592	tons/year
Cost-effectiveness	**$1,971**	**$/ton**

[32] Section 4, Chapter 1, Selective Noncatalytic Reduction, April 2019. See https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution. Section 4.
[33] See Attachment B "Flint Creek SNCR CCM cost-effectiveness.xlsm," for more details concerning the input choices.

In revising ADEQ's cost-effectiveness calculation, ammonia was selected as the reagent instead of urea, which ADEQ chose, as an ammonia-based SNCR system is significantly more cost-effective. This calculation assumes default values for a number of parameters for which site-specific data was not available, such as the cost of electricity, water, etc., which can be corrected, although the effect on the cost-effectiveness figure will be small. It is readily seen that DEQ's SNCR cost-effectiveness figure of $6,790/ton is greatly inflated by over three times. Indeed, when those errors are corrected, it is clear that SNCR for Flint Creek is well within the range of costs that states have found cost-effective for the purposes of reasonable progress. As discussed, several states have adopted much higher thresholds for cost-effectiveness in their second-round regional haze plans, including Arizona ($4,000 to $6,500/ton), New Mexico ($7,000 per ton), Oregon ($10,000/ton), Washington ($6,300/ton for Kraft pulp and paper power boilers), and Colorado ($10,000/ton).[34] ADEQ must corrects its cost effectiveness calculation for Flint Creek, and it should select SNCR, at a minimum, as a reasonable progress control for the plant.

3. SCR is similarly cost effective for Flint Creek.

On page V-47, ADEQ presents its updated SCR cost-effectiveness figure of $5,771/ton, which the agency then dismisses out of hand and without explanation. Although we have significant doubts about the accuracy of ADEQ's SCR cost calculation, we note that, even at $5,771 per ton, the cost of SCR is well within the range of cost calculations that other states have adopted as reasonable, as noted above. Indeed, in its comments on the proposed SIP, the FLM concluded that for Flint Creek, "selective catalytic reduction (SCR), is a cost-effective emissions reduction strategy. At a minimum, additional cost effectiveness analysis should focus on similar facilities implementing comparable emissions controls, rather than relying on summary statistics based upon broad source categories.[35] As discussed below, ADEQ arbitrarily and unreasonably refused, however, to provide any explanation for rejecting the Forest Service's recommendation. More important, the agency's conclusory assertion that SCR controls exceeds the maximum cost-effectiveness threshold for BART determinations is irrelevant.[36] The second planning period is concerned with reasonable progress, not BART, and EPA has explained that the thresholds used for BART in the first planning period "are, in most cases, not appropriate thresholds for selecting sources or evaluating the impact of controls for reasonable progress in the second planning period."[37] In other words, ADEQ may not simply adopt BART cost-effectiveness thresholds without explaining why those thresholds are appropriate. As explained above, ADEQ must revise its cost-effectiveness threshold to explain how the state's conclusory adoption

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[34] *See* Section II.A.1 above.
[35] Proposed SIP, App'x D. at pdf p. 259.
[36] Proposed SIP, App'x D at pdf p.345-46.
[37] *Id.* at 14.

of BART cost thresholds will ensure reasonable progress toward natural visibility. Because $5,771 per ton is within the range of costs that other states have deemed cost-effective for this second planning period—e.g., Arizona ($4,000 to $6,500/ton)[38], New Mexico ($7,000 per ton)[39], Oregon ($10,000/ton)[40], Washington ($6,300/ton for Kraft pulp and paper power boilers)[41], and Colorado ($10,000/ton).[42] ADEQ must explain why those cost thresholds are not also appropriate here. The should find that an SCR is a cost-effective reasonable progress control for Flint Creek.

4. ADEQ must review Flint Creek for potential upgrades to the scrubber.

Flint Creek's historical monthly SO_2 and NOx emissions are shown below:[43]

Figure 1. Flint Creek Historical SO_2 and NOx Emissions

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[38] *See, e.g.,* Arizona Department of Environmental Quality, 2021 Regional Haze Four-Factor Initial Control Determination, Tucson Electric Power Springerville Generating Station, at 15, https://www.azdeq.gov/2021-regional-haze-sip-planning

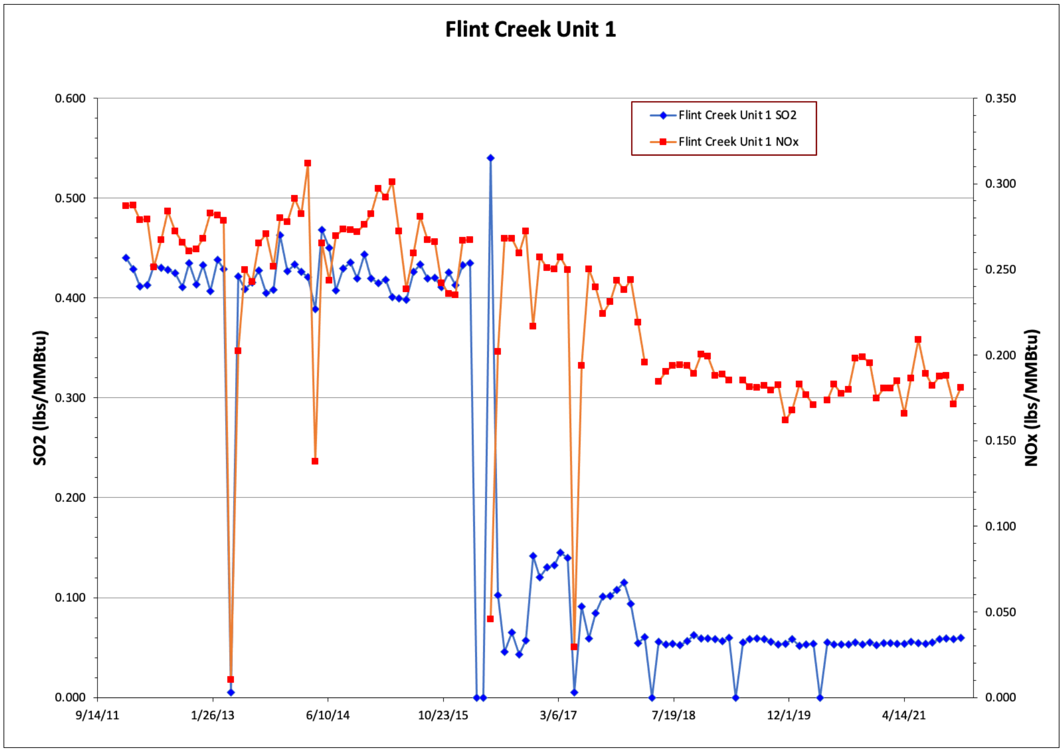
[39] *See* NMED and City of Albuquerque, Regional Haze Stakeholder Outreach Webinar #2, at 12, https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf

[40] *See, e.g.,* September 9, 2020 Letter from Oregon Department of Environmental Quality to Collins Forest Products, at 1-2, https://www.oregon.gov/deq/aq/Documents/18-0013CollinsDEQletter.pdf

[41] *See, e.g.,* Washington Department of Ecology, Draft Responses to comments for chemical pulp and paper mills, at 5, 6, and 8, https://fortress.wa.gov/ecy/ezshare/AQ/RegionalHaze/docs/RespondFLM20210111.pdf

[42] *See* Colorado Department of Public Health and Environment, In the Matter of Proposed Revisions to Regulation No. 23, November 17 to 19, 2021 Public Hearing, Prehearing Statement, at 7, https://drive.google.com/drive/u/1/folders/1TK41unOYnMKp5uuakhZiDK0-fuziE58v

[43] *See* Attachment A, "AR EGU emissions.xlsx."



From the above graph, the SO_2 and NOx emission improvements can be readily seen following the installation of the controls noted above. Flint Creek's annual SO_2 emissions before and after it installed its NID scrubber are as follows:

Table 3. Flint Creek Historical Annual SO_2 emissions

Year	SO_2 (tons)	Avg. SO_2 Rate (lb/MMBtu)
2021	852.8	0.056
2020	536.1	0.053
2019	736.0	0.057
2018	854.8	0.061
2017	1,594.6	0.110
2016	1,637.0	0.144
2015	6,445.2	0.417
2014	7,968.1	0.432
2013	6,699.4	0.422
2012	8,409.4	0.425

Averaging the annual SO_2 emissions from 2012 – 2015, which is prior to the installation of Flint Creek's scrubber, results in a value of 0.424 lbs/MMBtu. Averaging the annual SO_2 emissions from 2019 – 2021 inclusive, after the installation of its scrubber and following a period of some erratic behavior, results in a value of 0.055 lbs/MMBtu. This indicates a scrubber efficiency of approximately 87% ((0.424 - 0.055) / 0.424 = 0.870). This level of efficiency is significantly under the capability advertised by the manufacturer, and as widely reported for the technology.[44] However, it is not known if there is a practical emission floor for NID technology. Because further optimizing the performance of Flint Creek's NID system would likely be very cost-effective, ADEQ must require that Flint Creek investigate the optimization of its NID scrubber system.

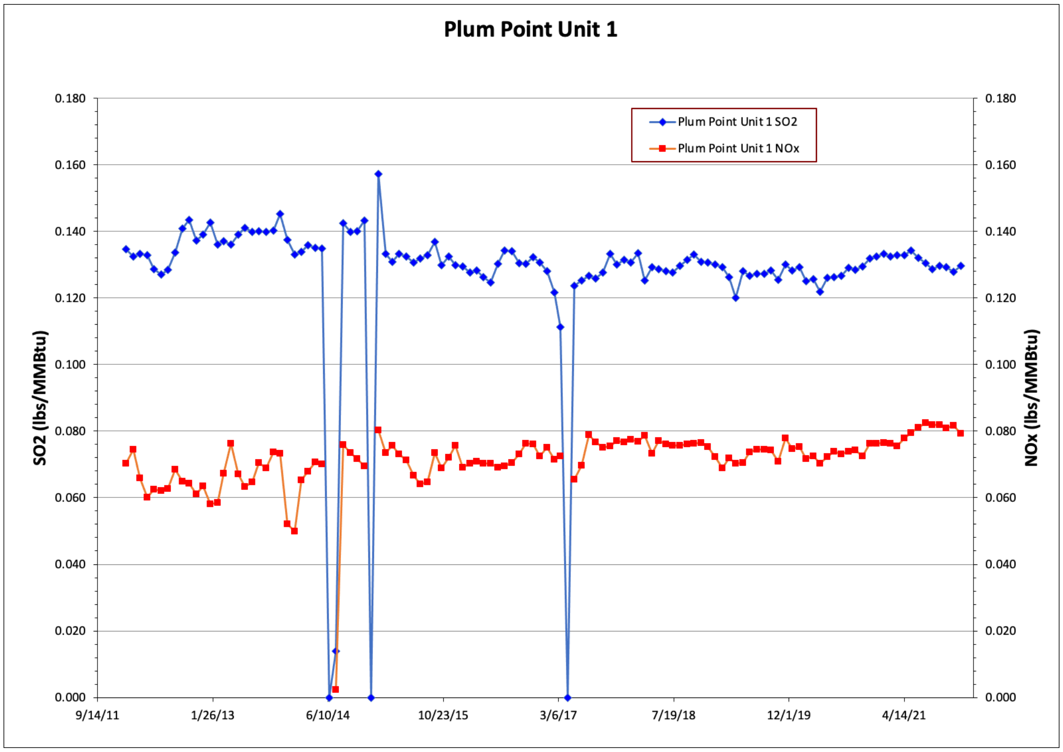
C. Plum Point, An Arkansas EGU, Should Have Been Reviewed for Reasonable Progress Controls and Cost-Effective Emissions Reductions Are Likely Available.

Plum Point is an additional source that ADEQ should have reviewed. Had ADEQ considered sources with a Q/d threshold of 5 or higher, as it should have, the Plum Point coal-burning EGU would have been considered for reasonable progress controls. Plum Point has a Q/d of 16.3 for Upper Buffalo and 11.9 for Caney Creek.

Plum Point is a single EGU of 720 MW dry bottom wall fired EGU that primarily burns subbituminous coal. It is fitted with a dry scrubber and SCR system. Plum Point's historical monthly SO_2 and NOx emissions are provided in Figure 2.

Figure 2. Plum Point Historical SO_2 and NOx Emissions.

[44] For instance, see https://www.power-eng.com/emissions/air-pollution-control-equipment-services/circulating-dry-scrubbers-a-new-wave-in-fgd/, https://network.bellona.org/content/uploads/sites/3/2016/05/1_Forum_EnergyClimate-Dialogue_Alstom_Presentation_ukr.pdf, Control Cost Manual, Section 5, SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, April 2021. Page 1-44.



As can be seen Figure 2, Plum Point's NOx emissions have been experiencing a gradual increase since at least 2012. This, and the fact that its SCR system is not performing at a level of 0.05 lbs/MMBtu, which is considered well controlled, indicates that its SCR system can be optimized or upgraded.

As for SO_2, EIA data indicates that Plum Point's sulfur content in 2020 averaged 0.24 wt percent, and that the higher heating value of its coal averaged 17.38 MMBtu/ton.[45] The average annual SO_2 emission rate for 2020 was 0.128 lbs/MMBtu.[46] The monthly theoretical uncontrolled SO_2 emission rate for Plum Point 0.55 lbs/MMBtu, and the scrubber theoretical efficiency was then calculated as approximately 77% only. An EGU's dry scrubbing system should be capable of a 95% efficiency. As EPA has repeatedly indicated, upgrading scrubber systems is expected to be very cost-effective.

Thus, ADEQ should (1) require that Plum Point undergo a four-factor analysis and (2) require that it examine upgrades/optimizations of its SCR and scrubber systems.

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45 See EIA Form 923, available here: https://www.eia.gov/electricity/data/eia923/.

46 See Attachment A, "AR EGU emissions.xlsx."

D. ADEQ's Analyses For The Non-EGUs Are Inconsistent With The Clean Air Act and Regional Haze Rule Requirements.

For the non-EGUs, ADEQ's Proposed SIP fails to satisfy the Clean Air Act and the Regional Haze Rule's analytical requirements in numerous ways. As discussed below, ADEQ made a half-hearted attempt at meeting the analytical requirements. There are several overarching issues common to all sources that ADEQ reviewed. For example, there is no record in the Proposed SIP that ADEQ questioned any of the facility capital cost items and otherwise asked for any documentation to support them. Additionally, as discussed elsewhere in these comments, ADEQ's source selection methodology is flawed and its use of a 70 percent threshold is misapplied, which resulted in it failing to consider numerous sources discussed below. ADEQ's reasonable progress analysis, which as discussed elsewhere in these comments, relies on the first-round cost-effectiveness is misplaced. Furthermore, also discussed elsewhere in these comments, it is inappropriate for ADEQ to use sector-based cost-effective thresholds.

1. Review of the Four-Factor Analysis Conducted for FutureFuel Chemical Company

FutureFuel Chemical Company (FFCC) is located in Independence County, the source "is a supplier of specialty organic chemical intermediates used in the manufacture of color film and photographic paper, paints and coatings, plastics and bottle polymers, medical supplies, prescription medicines, food supplements, household detergents, agricultural products, and biofuel."[47] ADEQ identified its three coal-fired boilers for Four-Factor Analyses[48] because "[n]inety-nine percent of the facility's SO_2 emissions and seventy-two percent of the facility's NOx emissions come from three coal-fired boilers used to produce steam and destroy chemical wastes."[49] ADEQ's Proposed SIP further explains that:

> The three coal-fired boilers are balanced draft steam generation boilers designed to operate at 70 MMBtu/hr per unit. The units share a common primary fuel conveying system, a common ash handling system, and a common 200-foot-tall stack. Each unit is equipped with its own ESP to control particulate emissions.[50]

The three coal-fired boilers "do not have existing controls for NOx or SO2."[51] ADEQ determined that the result of FFCC's four-factor analyses should be the use of 2%

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[47] See Attachment C: Arkansas DEQ Title V Permit No. 1085-AOP-R14, at 6 (Feb. 24, 2020).
[48] Proposed SIP at V-9.
[49] Proposed SIP at V-25, citing 2016 ADEQ Emission Inventory.
[50] Proposed SIP at V-25.
[51] Proposed SIP at V-25.

sulfur coal and no additional NOx control, and ADEQ's Proposed SIP appears to propose effectuating the sulfur coal requirement in the draft Administrative Order in Appendix G.

According to the NPCA analysis of sources likely impacting class I areas[52], the cumulative Q/d for the source is 65.9, and closest Class I Area impacted is Hercules-Glades Wilderness with a Q/d of 15.7.

There are three overarching issues with the Four-Factor Analysis for FFCC, which are discussed below.

a) ADEQ and FFCC include unjustified charges.

The Regional Haze Rule (RHR) makes clear that the *state* has a duty to conduct a "robust" analysis of potential reasonable progress controls, and must "document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I Federal area it affects."[53] If a source prepares a flawed, incomplete or undocumented Four-Factor Analysis, the state must either require the source to make the necessary corrections or make the corrections itself and ensure that the Four-Factor Analyses is accurately and completely documented *before* the start of the public notice and comment period. This lack of basic

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[52] NPCA calculated Q using the 2017 NEI for non-EGUs and for power plants NPCA used 2019 AMDP (EPA Air Markets Data Program). This information is from the NPCA interactive map that provides users access to point and non-point source emissions data based on NPCA's assessment of publicly available information curated to identify sources and industrial sectors of concern to visibility in Class I area national parks and wilderness areas. The sources identified likely merit review by states to determine whether and what emission reduction options are feasible to achieve reasonable progress towards the restoration of natural visibility at Class I areas, and otherwise benefit progress toward clean air in all of our communities. The map lets one visualize the locations and details of emission sources, the level of emissions of different pollutants, and the Class I areas potentially affected by each source. The interactive map also provides information on emissions from oil and gas infrastructure such as wells, drilling rigs, compressor stations, pipelines, and refineries at the county level. Additional layers are available to visualize the 8-hour Ozone (2015) nonattainment areas as well as vulnerable populations by county density, including people of color and people living below the poverty line; https://npca.maps.arcgis.com/apps/MapSeries/index.html?appid=73a82ae150df4d5a8160a2275591e45d.

[53] 40 C.F.R. § 51.308(f)(2)(iii).

documentation not only precludes the state and any independent reviewer from verifying the respective utility modeling or control cost analyses, but it is contrary to the Act and the RHR.[54]

Contrary to the RHR requirement to document the basis for costs, ADEQ neither questioned nor asked for information regarding FFCC's offsite liquid waste disposal cost of $25,396,988 per year. While there are many gas-fired industrial boilers that can also burn various types of liquid fuels and even co-fire a variety of solid, liquid and natural gas fuels, this charge appears to account for offsite waste disposal of liquid wastes that FFCC currently burns in its three coal-fired boilers. Zeroing this charge ADEQ's revised cost analysis reduces it from $11,146/ton to $436/ton.[55]

This charge must be justified and documented. ADEQ must require that FFCC explain why it is not including the savings of not having to dispose of coal ash in its analysis, or include this savings and also that FFCC correct its analysis in one of the three ways: (1) explain why it cannot specify replacement boilers that have this capability; (2) revise its costs to specify such boilers; or (3) delete the offsite liquid waste disposal cost of $25,396,988 per year.

b) <u>ADEQ and FFCC's SO_2 cost-effectiveness analyses are flawed.</u>

ADEQ requested that FFCC consider five strategies for reducing SO_2 emissions: Fuel Switching from coal to natural gas; wet Gas Scrubber; Spray Dryer Absorber; In-Duct Dry Sorbent Injection; and Fuel Switching to a lower sulfur coal. There are seven issues regarding FFCC's analyses and ADEQ's failure to correct the issues.

The first issue with FFCC's Four-Factor Analysis for reducing SO2 emissions is use of the wrong model to estimate wet scrubber costs. FFCC's Four-Factor Analyses use of EPA's IPM model is inappropriate because there is a more reliable method of calculating costs, notably, EPA's Control Cost Manual update included a cost model for the packed bed scrubber, which is widely used in industrial settings.[56] However, because ADEQ failed to require that FFCC's Four-Factor Analysis was accurately and completely documented *before* the start of the public notice and comment period (*i.e.*, it lacks site-specific information necessary for a cost-effectiveness analysis of the wet packed scrubber) the public is precluded from

[54] 2019 Guidance at 22.
[55] Proposed SIP, Appendix G-4, worksheet "FFCC Boiler replacement x 3."
[56] *See e.g.*, EPA, Cost Reports and Guidance for Air Pollution Regulations, Section 5 - SO2 and Acid Gas Controls, (April 2021), https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

independently using EPA's cost model to estimate costs. ADEQ must require the FFCC to use EPA's updated model, including complete documentation, as this type of scrubber system is likely more applicable to FFCC than the ones it has assumed.

Second, ADEQ failed to require that FFCC evaluate a single SO_2 emission control system for its three coal-fired boilers. FFCC asserts that two and preferably three scrubbers are required. This is despite that fact that "[t]he three coal fired boilers share a common primary fuel conveying system, a common ash handling system, and a common 200-foot-tall stack."[57] A single large absorber, packed tower, or single wet scrubber adsorber are commonly used and are capable of treating much larger gas flows than those from FFCC's boilers. Similarly, FFCC states that it assumes two DSI systems.[58] ADEQ must require that FFCC evaluate control cost analyses based on a single system, which would result in significant cost savings.

Third, contrary to the RHR requirement to document the basis for costs, ADEQ failed to require that FFCC document several SO_2 cost items. These five items include:

- FFCC's claim that the demolition of its existing control room is (1) necessary and (2) will cost $1,000,000;
- FFCC's claim that a pipeline from its wet scrubber to its waste water treatment plant will cost $700,000;
- FFCC's claim that a sulfuric acid tank and line for its wet scrubber installation are (1) necessary and (2) will cost $1,000,000;
- FFCC's claim for an extended outage and all costs related to that (*e.g.*, boiler rental, plant shutdown, offsite disposal, etc.) must be documented. Typically, scrubber installations do not require long outages, as most of the demolition and installation of new equipment can be performed without disruption to the plant's operation, with the outage reserved for the tie-in. The wet packed tower scrubber cost analysis previously discussed is designed for industrial applications and doesn't even consider outages. The IPM cost models FFCC uses inherently consider outages for the EGU controls they were designed to estimate, so FFCC must demonstrate that additional outage consideration is justified; and
- FFCC used a contingency of 30% and ADEQ reduced this to 20%. However, a 20% contingency for a wet scrubber is still too high, as the Control Cost Manual indicates: "A default value of 10% of the direct and indirect costs is typically used for CF [contingency factor]. However,

[57] See Attachment C: Arkansas DEQ Title V Permit No. 1085-AOP-R14, at 86, (Feb. 24, 2020) ("FFCC").
[58] FFCC at 30.

values of between 5% and 15% may be used."[59] Unless documentation is provided that justifies a higher value, ADEQ must require that the low end of this range be used.

Fourth, ADEQ failed to require that FFCC provide the required supporting documentation for selected costs items in its wet scrubber, SDA, and DSI cost-effectiveness calculations.[60] Moreover, ADEQ failed to require that FFCC use a cost model appropriate to the source.[61] Instead, ADEQ allowed FFCC to use cost models EPA developed for EGUs, which FFCC is not. Furthermore, the cost models FFCC used are also inappropriate because they were developed for use at EGU boilers of different sizes. Notably, the WFGD cost model is not applicable to EGUs under 100 MW in size nor is the SDA cost model applicable to EGUs under 50 MW in size.

EPA's separate IPM DSI cost model states that it is applicable for EGUs but does not specify a MW size limitation.[62] However, the IPM DSI cost model does state, "DSI technology, however, should not be applied to fuels with sulfur content greater than 2 lb SO_2 / MMBtu."[63] Neither FFCC nor ADEQ indicate the actual

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[59] EPA, Control Cost Manual, Section 5, SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, at 1-79 (April 2021).

[60] FFCC indicates in Attachments B-1.5, B-1.6, and B-1.7 that it has relied on EPA's IPM cost models for selected costs items in its wet scrubber, SDA, and DSI cost-effectiveness calculations, but it neither provided nor did DEQ request the supporting detailed calculations and documentation.

[61] This issue becomes clear when one reviews the text in the "Read Me" worksheet, which states that:

This spreadsheet can be used to estimate capital and annualized costs for three types of acid gas scrubbers:

(1) Wet flue gas desulfurization (WFGD) systems used to control SO_2 emissions from coal-fired utility boilers over 100 MW.

(2) Spray dryer absorber (SDA) used to control SO_2 emissions from coal-fired utility boilers of equal to or greater than 50 MW.

(3) Wet packed-bed scrubbers used to control acid gases from industrial emission sources of any size.

[62] *See e.g.* EPA, Documentation of EPA's Power Sector Modeling Platform v6, Chapter 5, Attachment 5-5 DSI Cost Development Methodology, IPM Model – Updates to Cost and Performance for APC Technologies Dry Sorbent Injection for SO2/HCl Control Cost Development Methodology (May 2018) https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.

[63] *See e.g.* EPA, Documentation of EPA‘s Power Sector Modeling Platform v6, Chapter 5, Attachment 5-5 DSI Cost Development Methodology, IPM Model – Updates to Cost and Performance for APC Technologies Dry Sorbent Injection for SO2/HCl Control Cost Development Methodology, at 3 (May 2018)

SO_2 emission rate for the three coal-fired boilers, as they calculate SO_2 reductions as a percentage of the annual reported SO_2 emissions. However, assuming FFCC's stated 3% sulfur content and its minimum 11,100 Btu/lb heating value, its calculated SO_2 emissions would be 5.4 lbs/MMBtu, using the following equation:

$$SO_2\left(\frac{lbs}{MMBtu}\right)$$
$$= S\,(wt.\%)\;x\;Heat\;Content\;\left(\frac{lbs}{Btu}\right)x\;1{,}000{,}000\left(\frac{Btu}{MMBtu}\right)x\left\{\frac{64\frac{lbs}{mole}SO_2}{32\frac{lbs}{mole}S}\right\}x\left(\frac{1}{100\%}\right)$$

ADEQ's calculation in worksheet FFC LSC of Appendix G-4, based on coal data provided by FFCC, is 5.1 lbs/MMBtu. In either case, the IPM DSI cost model is also not applicable.

FFCC does not disclose how it calculated the equivalent MW size of its boilers, which is a required input to the IPM cost models. Assuming the boiler's heat rating is expressed in terms of heat output, then the equivalent conversion is 1 MWh = 3.413 MMBtu.[64] Since the combined rating for all three of FFCC's boilers is 210 MMBtu/hr, then assuming that rating is expressed as heat input, the equivalent MW rating would be only approximately 21 MW. Thus, as discussed above, EPA's IPM wet and dry scrubber cost models, are invalid for FFCC's application.

However, EPA's workbook also contains worksheets, that can be used to calculate the cost-effectiveness of packed bed scrubbers for industrial boilers such as

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https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.

[64] *See e.g.*, U.S. Environmental Protection Agency Combined Heat and Power Partnership, Output-Based Regulations: A Handbook for Air Regulators, (Aug. 2014), (Aug. 2014), https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwifyOrEtPb0AhUcHzQIHSwVB5sQFnoECAMQAQ&url=https%3A%2F%2Fwww.epa.gov%2Fsites%2Fproduction%2Ffiles%2F2015-07%2Fdocuments%2Foutput-based_regulations_a_handbook_for_air_regulators.pdf&usg=AOvVaw2BXiFdN4b4S2YLVL3q7YGn. (If the boiler's heat rating is expressed in terms of heat *input*, then one must use a more detailed conversion using the boiler's efficiency and assumed steam turbine and generator efficiencies. For these types of boilers, the equivalent MW typically roughly works out to be 1/10 of the heat input, expressed in MMBtu/hr.

FFCC's boilers.[65] This is the cost model FFCC should have used and ADEQ must require that it do so.

Fifth, ADEQ erroneously accepted FFCC's assumptions of a wet scrubber efficiency of 94% and a dry scrubber efficiency of 92%. EPA has indicated on a number of occasions that for the purpose of cost-effectiveness calculations, these efficiencies should be 98% and 95%, respectively. For example, EPA's Control Cost Manual explains that:

> Several vendors supply scrubbers of various sizes that are designed for specific industrial applications, such as sulfur recovery units (SRUs), fluidized catalytic cracking units (FCCUs), sulfuric acid production plants, aluminum production, and other non-ferrous metal smelters. These systems typically achieve control efficiencies greater than 98%; however, the removal efficiency achieved can be lower for systems where the waste gas characteristics are variable (e.g., varying acid gas concentrations, flow rates, or temperature).[66]

Spray dryers can achieve SO_2 removal efficiencies up to 95%, depending on the type of coal burned. A second type of dry scrubbing system is the CDS, which can achieve over 98% reduction in SO_2 and other acid gases.[67] ADEQ must assume these efficiencies in its cost-effectiveness calculations for FFCC.

Sixth, ADEQ did not require documentation of coal data FFCC assumed, which is much higher than EGUs in Arkansas currently burn. As indicated above, assuming FFCC's minimum coal heat requirement of 11,100 Btu/lb, this would result in a calculated outlet emission rate of approximately 5.4 lbs/MMBtu.

Because one of FFCC's strategies is to reduce its coal sulfur content and ADEQ has proposed to accept FFCC's four-factor analysis of reducing its coal sulfur content to 2%, ADEQ must require documentation of the following:

- FFCC's current coal sulfur content and heating value.

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[65] EPA, Documentation of EPA's Power Sector Modeling Platform v6, Chapter 5, (May 2018), https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6

[66] EPA, Control Cost Manual, Section 5 SO_2 and Acid Gas Controls, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, at 1-5, (April 2021), https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[67] *Id.* at 1-11.

- ADEQ should require that FFCC provide SO_2 (and NOx) monitoring data, preferable for the last five years (because it appears that FFCC's permit requires a Continuous Emission Monitoring System (CEMS)).
- Evidence that FFCC has thoroughly investigated the availability of lower sulfur coal. A prior permit issued for this source (when it was owned by Eastman), indicates the following in its historical review of permitting actions: "Permit 262-AR-5 was issued on July 23, 1982. This permit authorized an increase in sulfur content of the coal fueling the coal boilers. The sulfur limit was raised from 1 to 4 percent."[68] It is unclear if this 1 percent sulfur limit applied to all the coal-fired boilers at the source, which would have included the three coal-fired boilers under investigation since they were operating at that time. FFCC and ADEQ should investigate this and if the three boilers covered under the four-factor analysis were in fact previously held to coal with a 1% sulfur content, then ADEQ should demonstrate why these boilers cannot return to this same limitation.

Finally, ADEQ's determination that a switch to a 2% sulfur coal with a cost-effectiveness of \$2,171/ton is preferable to a switch to a 1.5 % sulfur coal with a cost-effectiveness of \$2,774/ton is arbitrary, because clearly, switching to the 1.5% sulfur coal is also cost-effective. The Federal Land Manager's (FLM) consultation comments mirror this comment, strongly encouraging ADEQ to implement the 1.5% sulfur coal emission strategy for FFCC's three coal-fired boilers.[69] ADEQ's reliance on EPA's 2019 guidance to respond to the FLM's concern is misplaced.[70]

In summary, ADEQ's proposed decision that switching to a coal with a 2% sulfur content is premature for the following reasons:

- FFCC and ADEQ used cost models which are invalid in these applications.
- FFCC failed to use the proper cost model.
- It appears FFCC inflated the cost-effectiveness of scrubbing SO2.
- FFCC failed to document critical data concerning the coal it currently burns and has not demonstrated that it has fully investigated the

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[68] Operating Air Permit Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation #26: Permit #: 1085-AOP-R0, issued to Eastman Chemical Company, Arkansas Eastman Division 2800 Gap Road Batesville, AR 72503 Independence County CSN: 32-0036. Page 10.
[69] Proposed SIP at D-5-7.
[70] 2019 Guidance at 40 ("States may consider the incremental differences in cost and visibility benefits between the alternative control measures for a single source and may use an incremental version of the cost/ton and cost/inverse megameters metrics when doing so.").

availability of the lowest sulfur coal available. Regarding the latter, it has merely listed coal sale prices from "Broker A and Broker B." At a minimum, it must provide primary data to ADEQ concerning lower sulfur data availability. If such data is claimed as confidential, it must be proven as such. Because all states have established procedures for handling and storing confidential business information, this should not present any problems for ADEQ.

Moreover, ADEQ's decision to not select the lowest sulfur coal is arbitrary. EPA's 2021 Clarification Memo explained that where a state identifies cost-effective controls (as it has done so here in the figure of $2,774/ton) it is improper for the state to improperly use visibility as a fifth factor to reject that option.[71]

c) ADEQ and FFCC's NOx cost-effectiveness calculations for SCR and SNCR are likely extremely inflated.

Similar to the lack of documentation and related issues identified above for the cost of SO_2 controls, ADEQ failed to require that FFCC document cost of NOx controls. ADEQ must require documentation and/or resolution of these cost issues, which include the following:

- The SCR and SNCR cost-effectiveness calculations include many of the same issues described above including the demolition of the old control room, expenses related to plant shut down, and contingency.
- The reference for most of the large capital cost items is listed as "Control Cost Manual," with no further explanation. DEQ must require that all of these costs and any side calculations are provided.
- FFCC has assumed an SCR efficiency of only 80%. For EGUs, an SCR system can typically be relied upon to provide over 90% control with NOx outlets down to 0.05 lbs/MMBtu or lower.[72] An SCR system at FFCC should be able

[71] 2021 Clarification Memo at 13.

[72] *See e.g.*, 76 Fed. Reg. 491 (Jan. 11, 2011) (proposed action) and 76 Fed. Reg. 52388 (Aug. 22, 2011) (final action) (In particular, see the discussion at 76 Fed. Reg. 52404, where EPA explained that "The Havana Unit 9 data shows that it has operated under 0.05 lbs/MMBtu from mid-2009 to the end of 2010 on a continuous basis. In fact, this unit has operated under 0.035 lbs/MMBtu for much of that time. The Parish Unit 7 data shows that it has operated under 0.05 lbs/MMBtu from mid-2006 to mid-2010 on a continuous basis. In fact, this unit has operated for months at approximately 0.035 lbs/MMBtu, and for approximately 2 years at approximately 0.04 lbs/MMBtu. The Parish Unit 8 data show that it has operated almost continuously under 0.045 lbs/MMBtu since the beginning of 2006. Other units' data show months of continuous operation below 0.05 lbs/ MMBtu. We believe this data demonstrates that similar coal fired units that have been retrofitted with SCRs are

to achieve similar results. However, there is no record in its Proposed SIP that ADEQ required FFCC to provide its monitoring data (which is required as part of its Title V permit), and so verification of FFCC's 80% efficiency claim appears absent. DEQ must remedy this.

- FFCC has assumed an SNCR efficiency of 40%. SNCR performance is highly site dependent, so ADEQ must require that FFCC provide documentation for this value.
- In correcting FFCC's SNCR cost-effectiveness calculation, ADEQ assumed an SNCR equipment life of only 20 years. While a number of EGU contractors have been assuming an equipment life of twenty years for SNCR systems, by inappropriately referencing EPA's Control Cost Manual, the April 25, 2019, SNCR update of the Control Cost Manual which states on page 1-53, "Thus, an equipment lifetime of 20 years is assumed for the SNCR system in this analysis."[73] However, this information in the Control Cost Manual is a calculation example and does not indicate that EPA universally considers the equipment life for all SNCR systems installed on EGUs to be twenty years. In fact, just prior to this statement, EPA explains that, As mentioned earlier in this chapter, SNCR control systems began to be installed in Japan the late 1980's. Based on data EPA collected from electric utility manufacturers, at least 11 of approximately 190 SNCR systems on utility boilers in the U.S. were installed before January 1993. In responses to another Institute of Coal Research (ICR), petroleum refiners estimated SNCR life at between 15 and 25 years.[74]

Therefore, based on a 1993 SNCR installation date, these SNCR systems are at least twenty-nine years old, which all other considerations aside, strongly argues for a thirty-year equipment life. Furthermore, an SNCR system is much less complicated than a SCR system, for which EPA clearly indicates the life should be thirty years. In an SNCR system, the only parts exposed to the exhaust stream are lances with replaceable nozzles. The injection lances must be regularly checked and serviced, but this can be done relatively quickly, if necessary, is relatively inexpensive, and should be considered a maintenance item. In this regard, the lances are analogous to SCR catalyst, which is not considered when estimating equipment life. All other items, which comprise the vast majority of the SNCR

capable of achieving NOx emission limits of 0.05 lbs/MMBtu on a continuous basis."); *see also*, EPA analysis and graph for the SCR performance at the Cardinal plant and other top performing SCR systems, NM041.8003, Exhibit 2, Best SCR Retrofit, (June 8, 2011), at 2-18 https://www.regulations.gov/document/EPA-R06-OAR-2010-0846-0129.

[73] EPA, Control Cost Manual, Section 4, Chapter 1, Selective Noncatalytic Reduction, at 1-53 (April 25, 2019), https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

[74] *Id.* at 1-53 - 1-54.

system capital costs, are outside the exhaust stream and should be considered to last the life of the facility or longer.

While FFCC's SCR cost-effectiveness calculation for its three boilers was \$17,703/ton, and ADEQ calculated a cost-effectiveness figure of \$25,183/ton (making several revisions), once corrections are made to FFCC's undocumented cost figures and improper parameters, and SCR cost-effectiveness recalculated using EPA's Control Cost Manual SCR cost model,[75] the result is \$4,061/ton, as seen in the table below.[76]

Table 4. Selected Inputs and Outputs for the FFCC SCR Cost-Effectiveness Calculation

Fuel type	Coal	
Retrofit factor	1	
MW rating	210	MW
HHV	10,938	Btu/lb
Annual MWh output	86,266,102	MWh
Total System Capacity Factor (CF_{total})	0.513	
Net plant heat input rate (NPHR)	10	MMBtu/MW
NOx inlet	0.525	lb/MMBtu
NOx outlet	0.05	lb/MMBtu
Reagent	Ammonia	
Plant elevation	275	feet
Desired dollar-year	2020	
Interest rate	3.50	Percent
Equipment life	30	years
Total Capital Investment (TCI)	\$13,812,956	
Direct Annual Costs (DAC)	\$155,289	
Indirect Annual Costs (IDAC)	\$754,882	
Total Annual Costs (TAC) = DAC + IDAC	\$910,104	
NOx removed	224	tons/year
Cost-effectiveness	**\$4,061**	**\$/ton**

[75] EPA, Control Cost Manual, Section 4, https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[76] *See* Attachment Q: "FFCC SCR CCM Cost-effectiveness.xlsm."

Two explanations regarding the cost-effectiveness calculation. First, FFCC indicates on page 42, that its cost-effectiveness calculation assumes two SCR systems for the three boilers but does not indicate how this would actually be configured. As discussed earlier regarding the SO_2 analysis, FFCC's permit indicates that the three coal fired boilers share a common primary fuel conveying system, a common ash handling system, and a common 200-foot stack, which suggests that a single SCR system could be used. That was assumed in the above calculation.

Second, FFCC states that exhaust reheaters would be needed in order to keep the temperature in an optimal range. This may be the case, as SCR system efficiency depends on the catalyst temperature.[77] However, FFCC must demonstrate this. Also, FFCC must separately break out the cost of exhaust reheaters so that cost can be critiqued. Consequently, the cost of a reheater is not included in the revised calculations above. If a reheater is indeed required, it would worsen the cost-effectiveness (increased $/ton). ADEQ must require that both of these issues be addressed and documented by FFCC.

ADEQ must require that FFCC provide the necessary documentation and make the necessary corrections for the cost-effectiveness of SCR.

FFCC's cost-effectiveness calculation for SNCR is also likely extremely inflated. FFCC's SNCR cost-effectiveness calculation for its three boilers was $20,049/ton, and ADEQ calculated a cost-effectiveness figure of $22,161/ton (making several revisions).

As with the SCR calculation, FFCC's SNCR cost-effectiveness was recalculated using EPA's Control Cost Manual SNCR cost model.[78] In so doing, considerations were given to the SNCR configuration. Unlike an SCR installation, which can potentially serve multiple boilers, the calculation acknowledges that an SNCR installation must necessarily be at least partially boiler-specific in that the lances to inject the reagent and the piping that serves them must be installed in each boiler. However, some economy can be realized from centrally locating the reagent storage, most of the pumps and distribution equipment, and control system. EPA's Control Cost Manual SNCR cost model does not accommodate such a configuration. Therefore, two versions were run: (1) a version that assumed a combined boiler (210 MMBtu/hr) which would have one larger reagent storage,

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[77] EPA, Control Cost Manual, Chapter 2, Selective Catalytic Reduction, Section 4, at pdf 20 (June 2019), https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[78] EPA, Control Cost Manual, Section 4, https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

pumping and distribution equipment, etc.; and (2) a version that assumed one of the individual boilers (70 MMBtu/hr) with a smaller version of that equipment.

Once the necessary corrections were made to FFCC's undocumented cost figures and improper parameters, and the SNCR cost-effectiveness recalculated using EPA's Control Cost Manual SNCR cost model, the result is $3,036/ton, for the assumptions based on a combined boiler figuration, and $4,946/ton, for the assumptions based on an individual boiler, as seen in the tables below.[79]

Table 5. Selected Inputs and Outputs for the FFCC SNCR Combined Boiler Cost-Effectiveness Calculation

Fuel type	Coal	
Retrofit factor	1	
MW rating	210	MW
HHV	11,841	Btu/lb
Annual MWh output	86,266,102	MWh
Total System Capacity Factor (CF_{total})	0.555	
Net plant heat input rate (NPHR)	10	MMBtu/MW
Desired SNCR efficiency	40	Percent
NOx inlet	0.525	lb/MMBtu
NOx outlet	0.315	lb/MMBtu
Reagent	Ammonia	
Plant elevation	275	feet
Desired dollar-year	2020	
Interest rate	3.50	Percent
Equipment life	30	years
Total Capital Investment (TCI)	$4,161,420	
Direct Annual Costs (DAC)	$97,394	
Indirect Annual Costs (IDAC)	$228,254	
Total Annual Costs (TAC) = DAC + IDAC	$325,648	
NOx removed	107	tons/year
Cost-effectiveness	**$3,036**	**$/ton**

[79] The detailed calculations and inputs are available in Attachment S: FFCC SNCR CCM combined boiler cost-effectiveness.xlsm, and Attachment T: FFCC SNCR CCM one boiler Cost-effectiveness.xlsm.

Table 6. Selected Inputs and Outputs for the FFCC SNCR One Boiler Cost-Effectiveness Calculation

Fuel type	Coal	
Retrofit factor	1	
MW rating	70	MW
HHV	11,841	Btu/lb
Annual MWh output	28,755,368	MWh
Total System Capacity Factor (CF_{total})	0.555	
Net plant heat input rate (NPHR)	10	MMBtu/MW
Desired SNCR efficiency	40	Percent
NOx inlet	0.525	lb/MMBtu
NOx outlet	0.315	lb/MMBtu
Reagent	Ammonia	
Plant elevation	275	feet
Desired dollar-year	2020	
Interest rate	3.50	Percent
Equipment life	30	years
Total Capital Investment (TCI)	$2,364,557	
Direct Annual Costs (DAC)	$47,126	
Indirect Annual Costs (IDAC)	$129,696	
Total Annual Costs (TAC) = DAC + IDAC	$176,822	
NOx removed	36	tons/year
Cost-effectiveness	**$4,946**	**$/ton**

The combined boiler case, which resulted in a figure of $3,036/ton, is thought to be more representative of the actual cost-effectiveness, as the only significant additional capital costs that would result from installing SNCR systems on the individual boilers are two more ammonia lance installations and the associated piping to the centralized ammonia storage, distribution and control center. In either case, it is readily seen that ADEQ's SNCR cost-effectiveness figure of $22,161/ton is greatly inflated, and ADEQ must make the necessary corrections and include documentation for its revised figure.

In conclusion, both SCR and SNCR are cost-effective based on the revised calculations of $4,061 for SCR and $3,061 for SNCR (combined boiler case). Since SCR removes twice as much NOx as SNCR, then ADEQ must require SCR for this source.

2. *Review of the Four-Factor Analysis Conducted for Domtar A.W. LLC, Ashdown Mill*

The Domtar Ashdown Mill is a pulp and paper mill located in Little River County. ADEQ selected four sources for Four-Factor Analyses at this source, and explained that combined, these four emission units emit the majority of SO2 and NOx from Ashdown Mill:[80]

- Power Boiler 2 (SN-05),
- Power Boiler 3 (SN-01),
- Recovery Boiler 2 (SN-06), and
- Recovery Boiler 3 (SN-14).[81]

ADEQ requested that the source consider different strategies for reducing SO_2 and NOx, as described below.

- SO_2 for Power Boiler 2 (SN-05): (1) Installation of new add-on scrubbers operating downstream of the existing scrubbers (typical control efficiency for industrial coal-fired boilers ≈ ninety to ninety-five percent control efficiency for industrial coal-fired boilers); (2) Increasing the SO2 control efficiency of the existing scrubbers from current levels to ninety percent through the use of additional scrubbing reagent; and (3) Upgrades to the existing scrubbers.
- SO_2 for Power Boiler 3 (SN-01): (1) Installation of a wet gas scrubber (typical control efficiency for industrial coal-fired boilers ≈ ninety to ninety-nine percent); and (2) Installation of a SDA (typical control efficiency for industrial coal-fired boilers ≈ ninety to ninety-five percent).[82]
- NOx for all four units (Power Boiler 2 (SN-05), Power Boiler 3 (SN-01), Recovery Boiler 2 (SN-06), and Recovery Boiler 3 (SN-14): (1) Selective Catalytic Reduction (typical control efficiency ≈ eighty percent for industrial boilers coal and ninety percent for industrial boilers wood/bark/waste); (2) Regenerative Selective Catalytic Reduction (typical control efficiency ≈ seventy-five percent for industrial boilers wood/bark/waste); (3) Selective Non-Catalytic Reduction (typical control efficiency ≈ forty percent for industrial boilers coal).[83]

The cumulative Q/d for the source is 101.4, and closest Class I Area impacted is Caney Creek Wilderness with a Q/d of 47.0.[84] While the above emission units

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[80] Proposed SIP at V-36.
[81] *Id.* at V-9.
[82] *Id.* at V-37 – V-38.
[83] *Id.* at V-38.
[84] NPCA calculated Q using the 2017 NEI for non-EGUs and for power plants NPCA used 2019 AMDP (EPA Air Markets Data Program). This information is from the NPCA interactive map that provides users access to point and non-point source

include much of SO_2 and NOx emissions from Domtar, other significant sources are missing from Domtar and ADEQ's consideration. ADEQ's Proposed SIP contains no emission limitations for Domtar. There are numerous issues with DEQ's analysis and its proposed conclusion that no emission limitations are necessary.

a) ADEQ failed to include all emission sources at Domtar that must be considered in the Four-Factor Analysis.

First, ADEQ's Proposed SIP did not include all emissions and sources from Domtar. As part of a public record request commenters learned that No. 2 Lime Kiln and the No. 3 Lime Kiln are significant sources of NOx, as seen in the table below:

Table 7. Historical NOx Emissions from the Nos. 2 and 3 Lime Kilns

Sn:02 3 Lime Kiln	2017	NOx	1.1
Sn:09 No 2 Lime Kiln N/Gs	2017	NOx	143.0
Sn:02 3 Lime Kiln	2018	NOx	82.1
Sn:09 No 2 Lime Kiln N/Gs	2018	NOx	164.0
Sn:02 3 Lime Kiln	2019	NOx	91.6
Sn:09 No 2 Lime Kiln N/Gs	2019	NOx	151.0

These emissions are significant. ADEQ determined that Power Boiler No. 3, was required to undergo a Four-Factor Analysis, and yet the SO_2 emissions from

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emissions data based on NPCA's assessment of publicly
available information curated to identify sources and industrial sectors of concern to visibility in Class I area national parks and wilderness areas. The sources identified likely merit review by states to determine whether and what emission reduction options are feasible to achieve reasonable progress towards the restoration of natural visibility at Class I areas, and otherwise benefit progress toward clean air in all of our communities. The map lets one visualize the locations and details of emission sources, the level of emissions of different pollutants, and the Class I areas potentially affected by each source. The interactive map also provides information on emissions from oil and gas infrastructure such as wells, drilling rigs, compressor stations, pipelines, and refineries at the county level. Additional layers are available to visualize the 8-hour Ozone (2015) nonattainment areas as well as vulnerable populations by county density, including people of color and people living below the poverty line; https://npca.maps.arcgis.com/apps/MapSeries/index.html?appid=73a82ae150df4d5a8160a2275591e45d

that unit were less than NOx emissions from No. 2 Lime Kiln and the No. 3 Lime Kiln. The Act requires that ADEQ must provide a reasoned explanation for its decisions,[85] and decisions must be reasonably consistent across the State's SIP. Consistent with its decision on Four-Factor Analysis for SO_2 emissions, ADEQ must require that No. 2 Lime Kiln and the No. 3 Lime Kiln undergo Four-Factor Analyses for NOx.

b) The No. 2 Power Boiler was the subject of a SIP replacement for a Federal Implementation Plan (FIP).

The No. 2 Power Boiler was the subject of an EPA BART FIP, which required it to meet an SO_2 limit of 91.5 lbs/hr. And the history and the basis for EPA's determination is important to take into consideration. EPA's FIP emi limit was based on a 30-day boiler operating day average limit of 0.11 lb/MMBtu. It would have been met through the use of adding additional reagent to the existing venturi scrubbers along with pump upgrades, which based on data from Domtar were previously demonstrated to have achieved efficiencies of 57 – 90%, with an average 69%. EPA found that this scrubber upgrade was very cost-effective at $1,411/ton. The NOx BART determination was an emission limit of 345 lbs/hr on a thirty boiler-operating-day rolling average, achieved by the installation and operation of low NOx burners. EPA also found these controls to also be very cost-effective at $1,951/ton.

EPA's FIP also considered Power Boiler No. 1 and determined that SO_2 BART was an emission limit of 504 lb/day averaged over a rolling 30 boiler operating day period. EPA also determined that NOx BART was a limit of 207.4 lb/hr. Neither limit required any new controls.

The FIP was later replaced with a SIP approval that included a BART alternative. Instead of addressing BART individually for each boiler, this BART alternative considered the emissions of both Power Boiler Nos. 1 and 2 jointly. The difference in the resulting emissions between BART and the BART alternative for Boiler Nos. 1 and 2 are shown below:

Table 8. BART and BART Alternative Emissions for Power Boiler Nos. 1 and 2

Condition	SO_2 (tons)	NOx (tons)	PM10 (tons)
Baseline	3,544.3	3,215.8	490.6
BART	492.7	2,419.5	536.9
BART Alternative	1,907.5	2,120.3	380.18

85 *Nat'l Parks Conservation Ass'n v. E.P.A.*, 788 F.3d 1134, 1145 (9th Cir. 2015); *see also* 2021 Clarification Memo at 38.

As can be seen from the above, in comparison to BART, the BART alternative resulted in a slight improvement in NOx and PM_{10} but a large increase in SO_2. Nevertheless, EPA assessed the BART alternative and concluded that the "BART alternative results in greater visibility improvement than the BART controls at Caney Creek and on average across the four Class I areas." Below are the modeling results:

Table 9. BART and BART Alternative Modeled Visibility for Power Boiler Nos. 1 and 2

Class I Area	Baseline (dv)	BART (dv)	BART Alternative (dv)
Caney Creek	1.137	0.776	0.753
Upper Buffalo	0.163	0.103	0.104
Hercules Glades	0.118	0.057	0.069
Mingo	0.072	0.038	0.044
Total	1.490	0.974	0.970

It can be seen that the modeled results from EPA's BART Alternative achieved slightly better results at Caney Creek, but slightly worse results at the three other Class I Areas. However, through a strained interpretation, EPA concluded that because the average across all four Class I Areas was 0.004 dv better with the BART Alternative (due only to the slight improvement at Caney Creek), the BART Alternative was "better than BART" and therefore satisfied the requirement under Section 51.308(e)(2)(i)(E) for a BART alternative.

Implementation of the BART Alternative did not require any additional SO_2 or NOx controls for either boiler. In fact, EPA noted in its notice of March 16, 2020 "that because Power Boiler No. 1 has been in standby mode, it has emitted zero emissions since early 2016." In fact, Power Boiler No. 1 retired soon thereafter. Thus, it appears that the BART Alternative incorporated emissions from Power Boiler No. 1, which had already been in standby mode and was likely then scheduled for retirement, as a means of avoiding a very cost-effective scrubber upgrade and low NOx burner installation to Power Boiler No. 2.

c) <u>Domtar fails to demonstrate that the existing scrubber system for the No. 2 Power Boiler cannot be upgraded.</u>

Domtar makes the following erroneous characterizations of EPA's FIP determination that the No. 2 Power Boiler must be upgraded:

> Based on calculations presented in its February 2015 Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan (2015 FIP TSD), as presented in the 1PP SIP package

> (at 500-503), the EPA concluded that increased reagent usage at the existing scrubbers would achieve 90% control efficiency and a controlled emission rate of 91.5 pounds per hour (lb/hr). This calculation was based on a 2009-2011 annual-average emission rate of approximately 280.9 lb/hr and a back-calculated control efficiency for the existing scrubbers of approximately 69%.
>
> Domtar asserted then, and maintains now, that the control efficiency and emission rate applied by the EPA to the increased reagent usage option has not been verified as sustainable over a long-term period in practice. A one year or at least 30-day engineering study needs to be completed to confirm the EPA's assumptions. If the ADEQ decides that increased reagent usage at the No. 2 Power Boiler is a reasonable part of its long-term strategy for the RHR, then Domtar requests time to conduct such a study and update the information provided in this report once that study is complete.[86]

Domtar then cites to an A. H. Lundberg Associates study asserting that,

> Lundberg also evaluated possible upgrades to the existing scrubbers, including the elimination of bypass reheat, the installation of liquid distribution rings, the installation of perforated trays, improvements to the auxiliary system requirement, and a redesign of the spray header and nozzle configuration, *and it was concluded that any control efficiency improvement to that already being achieved was unquantifiable.*[87]

Domtar apparently uses these assertions to conclude on page 2-3 of its report that "[t]he upgrades to existing scrubbers option is not carried forward in this report because it does not provide for any quantifiable decrease in SO_2 emissions (i.e., any cost of control greater than zero would result in an undefined or infinite cost effectiveness value)."

There is a 2014 Lundberg study (which occurred prior to EPA's FIP) that is attached to Domtar's report as Appendix A. However, as the cover letter to that report explained, "the proposal is to supply add-on spray scrubbers downstream of the existing venturi scrubbers" and an examination of that proposal confirms that statement. Therefore, the Lundberg proposal mentioned in and appended to Domtar's Four-Factor Analysis concerns the addition of a new scrubber system downstream of the existing one, and not upgrades to the existing scrubber. Thus, it appears there is no documentation in Domtar's report to support its contention that upgrades to the existing scrubber system for the No. 2 Power Boiler should not be

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[86] Domtar Ashdown Mill Response to January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request, prepared by Trinity Consultants, at 2-1 (Revised May 7, 2020), Proposed SIP, Appendix H.
[87] *Id.* at 501.

evaluated. Nevertheless, ADEQ accepts Domtar's conclusion, stating on page V-40 of its Proposed SIP,

> Domtar's response to DEQ's ICR indicated that no emissions reductions are possible from upgrades to the existing scrubbers. Therefore, no further evaluation of the existing scrubber upgrades strategy is included in this analysis.

ADEQ must require that Domtar produce documentation to support its assertion or require that the No. 2 Power Boiler be re-evaluated for scrubber upgrades.

d) <u>Domtar and ADEQ made numerous errors in evaluating SO2 controls for the No. 2 Power Boiler, including existing scrubber efficiency and O&M costs.</u>

The No. 2 Power Boiler is rated at 820 MMBtu/hr. It is fitted with wet venturi scrubbers to control PM and some SO_2 and has no NOx controls other than overfire air. The following comments address the SO_2 controls Domtar considered for this boiler.

Domtar's scrubber efficiency figures and operation and maintenance (O&M) costs are based on outdated data, which is not representative of operations at the No. 2 Power Boiler. Indeed, ADEQ and Domtar rely on generic emission factors from 2011-2013, not actual measured values of the amount of each type of fuel.

Throughout its analyses, Domtar and ADEQ assume EPA's 2016 average scrubber efficiency figure of 67%. As EPA indicates in its TSD, this was based on monthly average SO_2 control efficiency data from 2011-2013. This data involved calculated SO_2 emissions from all of the various fuels then burned in Power Boiler No. 2. These calculations were based on generic emission factors and not actual measured values of the amount of sulfur in each type of fuel (unlike the equation presented above for calculating the SO_2 content of FFCC's coal). This approach introduces a great deal of uncertainty because the emission factors are not based on data representative of Domtar. Consequently, because the data is now 9 – 11 years old and Domtar's SO_2 calculations contain uncertainty, ADEQ must require that Domtar provide more current and more accurate calculations for the scrubber efficiency of Power Boiler No. 2.

Similarly, on page 2-1 of its report, Domtar states,

> The cost of increased reagent usage option was estimated in the 1PP SIP package (at 504) to be $200,000 in capital, annualized to $16,117 per year, and approximately $1,960,000 per year in direct annual operations and maintenance costs (i.e., additional reagent usage, wastewater treatment, raw

> water treatment, and energy usage) for a total annual cost estimate of $1,976,117 per year. When escalated to 2018, this becomes $2,068,732 per year.

These cost figures are similarly outdated and must be revisited, revised and properly documented. In particular, Domtar must provide documentation for its cost of additional reagent. Regarding this, as EPA noted in its FIP TSD,

> The scrubbing solution used in the venturi scrubbers is made up of three components: 15% caustic solution (i.e., NaOH), bleach plant EO filtrate (typical pH above 9.0), and demineralizer anion rinse water (approximately 2.5% NaOH). *The bleach plant EO filtrate and demineralizer anion rinse water are both waste byproducts from the processes at the plant.*

Thus, it appears that much of the reagent used is either a waste product of the plant or is already purchased in large quantities for used in making the plant's products. This suggests that that Domtar's cost for the additional reagent would be relatively low.

The fact that EPA did not critique these cost items in its 2016 FIP is not an indication that it found the documentation of these costs to be satisfactory. Rather, EPA could just as easily have viewed these costs as being inconsequential to its determination. In other words, because it viewed the controls as being cost-effective even accepting Domtar's figures, EPA may not have seen the need to question these cost items. These costs must now, however, be questioned by ADEQ.

ADEQ's Proposed SIP must contain accurate and current calculations for the scrubber efficiency for the No. 2 Power Boiler. ADEQ failed to question and require updates to Domtar's use of outdated and undocumented costs of reagent, which are questionable because it appears that much of the reagent used is either a waste product of the plant or is already purchased in large quantities for used in making the plant's products.

e) <u>A scrubber upgrade for the No. 2 Power Boiler is cost-effective.</u>

Regardless of the above errors and Domtar's failure to investigate upgrades to its existing scrubber at the No. 2 Power Boiler, it is evident that DEQ's own calculation, which results in a cost-effectiveness figure of $3,590/ton, is reasonable.

f) Domtar and ADEQ failed to consider all technically feasible NOx controls for the No. 2 Power Boiler.

The No. 2 Power Boiler has no NOx controls. EPA's 2016 FIP determined that NOx BART for the No. 2 Power Boiler was an emission rate of 345 lbs/hr on a thirty boiler-operating-day rolling average, achieved by the installation and operation of low NOx burners, which EPA found to be very cost-effective at $1,951/ton. There is no indication in the Proposed SIP that Domtar considered low NOx burners for Power Boiler No. 2, so ADEQ must require that Domtar do so. Escalation of this figure to 2020 dollars results in a cost-effectiveness of $2,146/ton,[88] which is reasonable.

g) ADEQ Must Conduct a Four-Factor Analysis for the No. 3 Power Boiler.

The No. 3 Power Boiler is rated at 790 MMBtu/hr. It has no SO_2 or NOx controls other than overfire air. Domtar's permit indicates that the No. 3 Power Boiler is constructed similarly to the No. 2 Power Boiler, in that they are both hybrid suspension/grate burners. Therefore, unless Domtar can provide documentation that low NOx burners are not an appropriate control, ADEQ must require that Domtar assess low NOx burners on Power Boiler No. 3 as well.

E. ADEQ Failed to Require Four-Factor Analysis for Seven Non-EGU Sources.

1. ADEQ's Source Selection Methodology was Flawed.

As discussed elsewhere in these comments, ADEQ's source selection methodology arbitrarily screened out nearly all sources of visibility-impairing pollution from evaluation of cost-effective emission reductions. EPA's July 2021 Memo makes clear that ADEQ's source selection methodology is flawed and cannot be approved by EPA. Instead, states must secure additional emission reductions that build on progress already achieved; EPA's expectation is that reductions add to ongoing and upcoming reductions under other CAA programs.[89] In evaluating sources for emission reductions, EPA emphasized that:

> Source selection is a critical step in states' analytical processes. All subsequent determinations of what constitutes reasonable progress flow from states' initial decisions regarding the universe of pollutants and sources they will consider for the second planning period. States cannot reasonably determine that they are making reasonable progress if they have not

[88] $1,947 x 596.2/541.7 = $2,146, where the CEPCI values for 2016 and 2020 are 541.7 and 596.2, respectively.
[89] 2021 Clarification Memo at 2.

> adequately considered the contributors to visibility impairment. Thus, while states have discretion to reasonably select sources, this analysis should be designed and conducted to ensure that source selection results in a set of pollutants and sources the evaluation of which has the potential to meaningfully reduce their contributions to visibility impairment.[90]

ADEQ's ability to exclude sources, including non-EGUs, from reasonable progress and four-factor analyses is constrained by the clear language of the Regional Haze Rule as well as EPA's guidance to states for implementing the Rule. Specifically, ADEQ's source selection for its reasonable progress analysis must be based on reasonable factors that will actually progress the state toward achieving necessary visibility impairing pollution reductions during this second implementation period. EPA has emphasized that while states have discretion to select sources for its reasonable progress analysis, this analysis should be "designed and conducted to ensure that source selection results in a set of pollutants and sources, the evaluation of which has the potential to meaningfully reduce their contributions to visibility impairment."[91] As recognized by ADEQ each state, "must reasonably choose factors and apply them in a reasonable way given the statutory requirement to make reasonable progress towards natural visibility."[92] This step is crucial to meeting the RH Rule's mandate to eliminate anthropogenic sources of regional haze in our nation's Class I areas, and ADEQ must get it right in order to comply with its SIP obligations under the Act.

ADEQ failed to choose reasonable factors and reasonably apply them to a number of Arkansas's non-EGUs. As a result, ADEQ improperly excluded non-EGUs from its reasonable progress and Four-Factor Analyses. Specifically, ADEQ failed to include four-factor analyses for the following large non-EGU sources of visibility impairing pollutants:

- Georgia-Pacific LLC – Crossett Paper Operation,
- Evergreen Packaging – Pine Bluff,
- Dunn Compressor Station (Enable Gas Transmission, LLC),
- Albemarle Corporation – South Plant, and
- Ash Grove Cement Company Foreman Cement Plant.

Despite the request for information submitted to ADEQ, the type of information necessary to perform a four-factor review for these sources was not

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[90] *Id.* at 3.
[91] *Id.* at 3.
[92] Proposed SIP at V-1 (citing EPA's 2019 guidance, EPA, "Technical Support Document for EPA's Updated 2028 Regional Haze Modeling," https://www.epa.gov/visibility/technical-support-document-epas-updated-2028-regional-haze-modeling).

provided. Thus, only limited observations can be made. Nevertheless, ADEQ must ensure that the SIP it submits to EPA considers Four-Factor Analyses for all these sources.

2. *ADEQ's High Source Selection Threshold and Erroneous Methodology Wrongly Eliminated Five Sources from its Reasonable Progress and Four-Factor Analyses.*

a) <u>Georgia-Pacific LLC – Crossett Paper Operation</u>

The Georgia-Pacific Crossett source is a paper mill. According to ADEQ's most recently issued Title V permit, the source operates equipment and processes that support the production of consumer bath tissue on four tissue machines and associated tissue converting lines,[93] which include: Woodyard; Bleach Plant; Tissue Machine and Converting Operations; Steam Generation; Wastewater Treatment System and Miscellaneous.[94]

The cumulative Q/d for the source is 47.7, and the closest Class I Area impacted is Caney Creek Wilderness with a Q/d of 12.3.[95] And the most recently issued Title V permit emission summary explains that total allowable emissions for the source are as follows:

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[93] *See* Attachment D: Arkansas DEQ Title V Permit # 0597-AOP-R23, at 6 (Feb. 14, 2022) ("Georgia-Pacific Crossett Title V Permit").

[94] *Id.* at 7-8.

[95] NPCA calculated Q using the 2017 NEI for non-EGUs and for power plants NPCA used 2019 AMDP (EPA Air Markets Data Program). This information is from the NPCA interactive map that provides users access to point and non-point source emissions data based on NPCA's assessment of publicly available information curated to identify sources and industrial sectors of concern to visibility in Class I area national parks and wilderness areas. The sources identified likely merit review by states to determine whether and what emission reduction options are feasible to achieve reasonable progress towards the restoration of natural visibility at Class I areas, and otherwise benefit progress toward clean air in all of our communities. The map lets one visualize the locations and details of emission sources, the level of emissions of different pollutants, and the Class I areas potentially affected by each source. The interactive map also provides information on emissions from oil and gas infrastructure such as wells, drilling rigs, compressor stations, pipelines, and refineries at the county level. Additional layers are available to visualize the 8-hour Ozone (2015) nonattainment areas as well as vulnerable populations by county density, including people of color and people living below the poverty line; <u>https://npca.maps.arcgis.com/apps/MapSeries/index.html?appid=73a82ae150df4d5a8160a2275591e45d</u>

- 498 tons per year (tpy) PM;
- 266 tpy SO_2; and
- 1758.2 tpy NOx.[96]

Despite a cumulative Q/d of 47.7, the considerable concerns expressed regarding the source's impacts on the environmental justice community,[97] and the fact that Arkansas's "Environmental Justice Collaborative Action Plan" recognizes the co-benefits to environmental justice communities and Class I Areas in controlling pollutants under its regional haze SIP,[98] ADEQ eliminated this source from consideration. Indeed, ADEQ's Proposed SIP fails to mention this source at all.

The processes at the source that are primarily responsible for these emissions are mill's power boilers generate steam and provide electrical power through the use of steam generating turbines. The boilers include one multi-fuel fired combination boiler and two natural gas-fired boilers, which the Title V permit describes as follows:

- **Boiler 5A:** The 5A Boiler (SN-18) has a heat input rating of 220 million Btu per hour. The boiler is only permitted to burn natural gas. The 5A Boiler was manufactured in 1953 and has never been modified or reconstructed since it was originally constructed, and is therefore not subject to any of the NSPS regulations that apply to boilers.[99]
- **Boiler 6A:** The 6A Boiler (SN-19) has a heat input rating of 357 million Btu per hour. The boiler is only permitted to burn natural gas. The 6A Boiler was manufactured in 1962 and has never been modified or reconstructed since it was originally constructed and is therefore not subject to any of the NSPS regulations that apply to boilers. The 6A Boiler is subject to Boiler MACT as an Existing Gas 1 type boiler; as such, work practice standards

[96] Georgia-Pacific Crossett Title V Permit at 8-9. September 24, 2019 AND September 23, 2024.
[97] *See e.g.*, Emily Craine Linn, How a Paper Plant in Arkansas is Allegedly Poisoning the People of Crossett, Newsweek Magazine, (April 12, 2016), https://www.newsweek.com/crossett-arkansas-georgia-pacific-factory-pollution-446954; *see also*, https://arpanel.org/nlcrossett.
[98] *See* Attachment E: Arkansas EJ Action Plan, Environmental Justice Collaborate Action Plan, at 2, https://19january2021snapshot.epa.gov/environmentaljustice/region-6-arkansas-ej-action-plan_.html.
[99] Georgia-Pacific Crossett Title V Permit at 66.

including an annual tune-up and a one-time energy assessment are required.[100]

- **Boiler 9A.** The 9A power boiler was first issued a construction permit in 1973,[101] with subsequent permits issued over the years. The 9A Boiler (SN-22) has a heat input rating of 720 million Btu per hour and fires a combination of fuels to generate steam. The source is equipped with a wet venturi scrubber to control PM emissions. The 9A Boiler is capable of firing natural gas, bark and wood, tire derived fuel (TDF), agriculture derived fuel (ADF), refuse derived fuel (RDF), and wastewater treatment sludge. The 9A Boiler was originally constructed in 1975 and at a later date, reconfigured to include the capability to burn natural gas. The action was previously determined to not be a "modification" under the NSPS regulations. The 9A Boiler is subject to Boiler MACT as a hybrid suspension grate boiler; the unit is subject to emission limits, work practice standards, operating limits, and performance testing.[102]

The below table contains the Title V emission limitations for each of boilers.

Table 10. Georgia-Pacific LLC – Crossett Paper Boiler Emission Rates in the Title V Permit

Boiler	Title V Permit Emission Rates		
	PM10 / PM2.5	SO2	NOx
5A Boiler[103]	2.0 lb/hr 8.6 tpy	0.2 lb/hr 0.7 tpy	72.1 lb/hr 315.6 tpy
6A Boiler[104]	0.5 lb/hr (filterable PM) 3.5 tpy (filterable PM)	None	None
9A Boiler[105]	77.4 lb/hr 339.1 tpy	145.3 lb/hr 262.2 tpy	196 lb/hr 858.5 tpy

ADEQ failed to perform a Four-Factor Analysis for the Georgia-Pacific Crossett source and failed to meet the Act's legal requirements. In meeting these

[100] Georgia-Pacific Crossett Title V Permit at 66.
[101] *Id.* at 25.
[102] *Id.* at 66.
[103] *Id.* at 69.
[104] *Id.* at 67.
[105] *Id.* at 78.

requirements, ADEQ must present a review of all of the available controls for the three boilers and evaluate them.

b) Evergreen Packaging – Pine Bluff

Evergreen Packaging is located in Jefferson County. According to ADEQ's most recently issued Title V permit, the source owns and operates a pulp and paper mill and a chip mill, which was constructed in 1957 and started operation in 1958.[106] The source has two paper machines which produce coated publication paper, newsprint and bleached paperboard.[107] The source produces wood chips and fuel wood for use at the facility.[108] ADEQ's Title V permit provides the following process description for the source:[109]

> Primary operations at Evergreen include multiple fuel fired boilers, wood yard operations, chemical wood (kraft) pulping, mechanical (groundwood) pulping, chemical recovery, bleaching, papermaking, coating, finishing and shipping, and additional operations and equipment necessary to support these activities. Evergreen uses two types of pulping processes: the kraft and the groundwood pulping processes, and the facility pulps both softwood and hardwood. All kraft pulp at the mill is bleached. Evergreen also operates an associated chip mill. Primary operations at the chip mill include log handling, chipping, debarking, and additional operations and equipment necessary to support these activities.

The cumulative Q/d for the source is 40.0, and closest Class I Area impacted is Caney Creek Wilderness with a Q/d of 11.1 .[110] Title V permit contains Plantwide Applicability Limitations for the pollutants, which are as follows:

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[106] *See* Attachment F: Arkansas DEQ Title V Permit # 0580-AOP-R16, at 6 (June 11, 2021) ("Evergreen Packaging Title V Permit").
[107] *Id.* at 6.
[108] *Id.* at 6.
[109] *Id.* at 6.
[110] NPCA calculated Q using the 2017 NEI for non-EGUs and for power plants NPCA used 2019 AMDP (EPA Air Markets Data Program). This information is from the NPCA interactive map that provides users access to point and non-point source emissions data based on NPCA's assessment of publicly available information curated to identify sources and industrial sectors of concern to visibility in Class I area national parks and wilderness areas. The sources identified likely merit review by states to determine whether and what emission reduction options are feasible to achieve reasonable progress towards the restoration of natural visibility at Class I areas, and otherwise benefit progress toward clean air in all of our communities. The map lets one visualize the locations and details of emission sources, the level of emissions of different pollutants, and the Class I areas potentially affected by each source. The interactive map also provides information on emissions from oil and gas infrastructure such as wells, drilling rigs, compressor stations, pipelines, and refineries at the county level.

Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
	Plantwide Applicability Limitation (PAL)	PM	-	1077.0
		PM_{10}	-	768.3
		$PM_{2.5}$	-	654.8
		NOx	-	1458.1
		CO	-	2041.1
		SO_2	-	392.4
		VOC	-	1936.2
		TRS	-	844.3
		Lead	-	0.690
		H_2SO_4	-	17.07
		Fluorides	-	3.016
		CO_2e	-	1,969,346.7

The source's "Power Operations" – which contribute to the visibility impairing pollutants – are described in the Title V permit as follows:[111]

> Power Operations at Evergreen include three steam and/or power generating units and associated processes and equipment. Three boilers, capable of firing multiple fuels, provide steam for mill production processes and power generation. The No. 1 Power Boiler (SN-13A/B) and No. 2 Power Boiler (SN-15A/B) are primarily natural gas fired combustion units that can also fire fuel oil (including Nos. 6, 5, 4, and 2). The No. 1 Power Boiler (SN-13) uses fuel oil only during periods of natural gas curtailment, and therefore falls into the Boiler MACT's "units designed to burn gas 1 fuels" subcategory. The No. 2 Power Boiler (SN-15) is used as a back-up only and falls into the Boiler MACT's subcategory of limited use boilers. The third unit is a Bark Boiler (SN-01) that typically fires bark, dried sludge, and natural gas. Additional fuels that may be fired in the Bark Boiler include fuel oil (including Nos. 6, 5, 4, and 2), used oil, polyscrap, paper scrap, woodwaste, tire-derived fuel (TDF), and rice hulls. This unit is in the Boiler MACT's "hybrid suspension/grate burners designed to burn wet biomass/bio-based solid" subcategory. Insignificant emission units located in the Power Operations area include wet ash handling.

The below table contains the Title V emission limitations for each of boilers, and the ton per year values are the overall plantwide limits for each pollutant.

Additional layers are available to visualize the 8-hour Ozone (2015) nonattainment areas as well as vulnerable populations by county density, including people of color and people living below the poverty line; https://npca.maps.arcgis.com/apps/MapSeries/index.html?appid=73a82ae150df4d5a8160a2275591e45d.

[111] Evergreen Packaging Title V Permit at 6.

Table 11. Evergreen Packaging – Pine Bluff Boiler Emission Rates in the Title V Permit

Boiler	Title V Permit Emission Rates		
	PM PM10 PM2.5	SO2	NOx
Bark Boiler (SN-01)[112]	98.6 lb/hr (all three) 1077.0 tpy (PM)[113] 768.3 tpy (PM10)[114] 654.8 tpy (PM2.5)[115]	46.0 lb/hr 392.4 tpy[116]	137.3 lb/hr 1458.1 tpy[117]
No. 1 Power Boiler (SN-13)[118]	15.8 lb/hr (all three)	170.6 lb/hr	337.7 lb/hr
No. 2 Power Boiler (SN-15)[119]	15.8 lb/hr (all three)	170.6 lb/hr	337.7 lb/hr
No. 2 Recovery Boiler (SN-02)[120]	35.0 lb/hr (PM) 24.7 lb/hr (PM10) 24.7 lb/hr (PM2.5)	200.0 lb/hr	109.8 lb/hr
No. 3 Recovery Boiler (SN-03)[121]	35.0 lb/hr (PM) 24.7 lb/hr (PM10) 24.7 lb/hr (PM2.5)	200.0 lb/hr	109.8 lb/hr
No. 4 Recovery Boiler (SN-04)[122]	94.8 lb/hr (PM) 66.9 lb/hr (PM10) 66.9 lb/hr (PM2.5)	542.5 lb/hr	297.8 lb/hr

[112] Evergreen Packaging Title V Permit at 15.
[113] Evergreen Packaging Title V Permit at 36, plantwide limit.
[114] *Id.* at 36, plantwide limit.
[115] *Id.* at 36, plantwide limit.
[116] *Id.* at 36, plantwide limit.
[117] *Id.* at 36, plantwide limit.
[118] Evergreen Packaging Title V Permit at 16.
[119] *Id.* at 17.
[120] *Id.* at 21.
[121] *Id.* at 22.
[122] *Id.* at 23

ADEQ failed to perform a Four-Factor Analysis for the Evergreen Packaging source and failed to meet the Act's legal requirements. In meeting these requirements, ADEQ must present a review of all of the available controls for the six boilers and evaluate them.

c) <u>Dunn Compressor Station (Enable Gas Transmission, LLC)</u>

The Dunn Compressor Station (Enable Gas Transmission, LLC) is located in Logan County, and is a natural gas transmissions source.

ADEQ recently permitted increases in annual emissions, and yet failed to consider impacts on its Proposed SIP in doing so.[123] ADEQ's Title V permit provides the following process description for the source:

> Friction losses cause a pressure drop in natural gas pipelines. To maintain flow, gas must be removed from the pipeline, re-pressurized, and returned to the pipeline. Low pressure pipeline gas is pulled off line into the compressor station and is re-pressurized with reciprocating engine powered compressors and placed back into the transmission system. Dunn Compressor Station utilizes four compressor engines: a 1,500 HP Cooper-Bessemer GMWA-6 compressor engine (SN-01) and three (3) identical 4,000 HP Cooper-Bessemer 12V-250 compressor engines (SN-02 though SN-04). A 770 HP Cummins GTA-28 emergency generator (SN-08) and a 440 HP diesel air compressor (SN-35) are used for emergency situations. Support equipment, which includes various boilers, hot water heaters, a number of storage tanks, and associated piping, is included in the insignificant activities (IA) list. The facility emits HAPs related to incomplete combustion. This facility is a major source of HAPs.
>
> Periodically, the natural gas contained in piping must be vented during routine maintenance or emergency shutdowns. This venting is called blowdowns. The emissions due to compressor station blowdowns are considered insignificant activities since all of its emissions are below the listed levels. Fugitive emissions occur due to leaks at valves, seats, flanges, and other components. Fugitive equipment leaks release natural gas into the atmosphere.[124]

The compressor engines have the following installation dates:

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[123] *See* Attachment G: Arkansas Title V Permit # 1209-AOP-R7, at 5 (April 12, 2021) ("Enable Gas Transmission, LLC (Dunn Compressor Station)").
[124] *Id.* at 5.

Source Number	Description[125]	Installation Date[126]
01	Cooper-Bessemer GMWA-6 Compressor Engine (1,500 HP, SI RICE, 2SLB, stationary, pre-1963, Serial No. 45842)	1963
02	Cooper-Bessemer 12V-250 Compressor Engine (4,000 HP, SI RICE, 2SLB, stationary, pre-1966, Serial No. 46030)	1966
03	Cooper-Bessemer 12V-250 Compressor Engine (4,000 HP, SI RICE, 2SLB, stationary, pre-1966, Serial No. 46958)	1966
04	Cooper-Bessemer 12V-250 Compressor Engine (4,000 HP, SI RICE, 2SLB, stationary, pre-1968, Serial No. 46959)	1968

[125] *Id.* at 11-12.
[126] *Id.* at 9.

The cumulative Q/d for the source is 38.9, and closest Class I Area impacted Upper Buffalo Wilderness with a Q/d of 18.0 .[127] The below table contains the Title V emission limitations for the source, as specified in the permit:[128]

Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	5.7	23.2
		PM_{10}	5.7	23.2
		$PM_{2.5}$	See Note*	
		SO_2	2.7	7.5
		VOC	17.2	58.2
		CO	46.1	183.7
		NO_X	711.7	2975.7
HAPs		Formaldehyde Total Other HAPs**	6.12 2.76	26.18 11.64

ADEQ failed to perform a Four-Factor Analysis for the Enable Gas Transmission, LLC (Dunn Compressor Station) and failed to meet the Act's legal requirements. In meeting these requirements, ADEQ must present a review of all of the available controls for these four engines and evaluate them.

[127] NPCA calculated Q using the 2017 NEI for non-EGUs and for power plants NPCA used 2019 AMDP (EPA Air Markets Data Program). This information is from the NPCA interactive map that provides users access to point and non-point source emissions data based on NPCA's assessment of publicly available information curated to identify sources and industrial sectors of concern to visibility in Class I area national parks and wilderness areas. The sources identified likely merit review by states to determine whether and what emission reduction options are feasible to achieve reasonable progress towards the restoration of natural visibility at Class I areas, and otherwise benefit progress toward clean air in all of our communities. The map lets one visualize the locations and details of emission sources, the level of emissions of different pollutants, and the Class I areas potentially affected by each source. The interactive map also provides information on emissions from oil and gas infrastructure such as wells, drilling rigs, compressor stations, pipelines, and refineries at the county level. Additional layers are available to visualize the 8-hour Ozone (2015) nonattainment areas as well as vulnerable populations by county density, including people of color and people living below the poverty line; https://npca.maps.arcgis.com/apps/MapSeries/index.html?appid=73a82ae150df4d5a8160a2275591e45d.

[128] Enable Gas Transmission, LLC (Dunn Compressor Station) Title V Permit at 7.

A great deal of information is available that documents the likelihood that very cost-effective controls are available for the sources at the Dunn Compressor Station. For example, a 2015 EPA publication lists the cost of Low Emission Combustion Control (LEC) for lean burn compressor engines to be $649/ton. ADEQ must also consider the information contained in the NPCA-commissioned comprehensive report on reasonable progress four-factor control analysis for the oil and gas industry.[129] This information was subsequently applied to oil and gas facilities in New Mexico and the results transmitted to the New Mexico Environment Department to aid in the development of its regional haze SIP.[130] These comments incorporate the reports by reference, as they include a great deal of applicable information that ADEQ must review and consider in developing its SIP.

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[129] *See* Attachment H: Vicki Stamper, Megan Williams, "Oil and Gas Sector Reasonable Progress Four-Factor Analysis of Controls for Five Source Categories: Natural Gas-Fired Turbines, Diesel-Fired Engines, Natural Gas-Fired Heaters and Boilers, Flaring and Incineration" (March 6, 2020).

[130] *See* Attachment I: Letter from National Parks Conservation Association, Western Environmental Law, to Sandra Ely, Michael Baca, Mark Jones, and Kerwin Singleton New Mexico Environment Department, "Comments responding to 4-factor analysis submittals from identified oil & gas operators," (July 10, 2020), https://drive.google.com/file/d/1jsmusMW2M37vRlWdFXYLjtZwSkP9QE6Z/view?usp=sharing, Assessment of Cost Effectiveness Analyses for Controls Evaluated Four – Factor Analyses for Oil and Gas Facilities For the New Mexico Environment Department's Regional Haze Plan for the Second Implementation Period," (July 2, 2020).

d) Albemarle Corporation – South Plant[131]

Albemarle Corporation-South Plant is located in Columbia County at Highway 79, is a chemical manufacturing source. ADEQ's Title V permit describes the source's process as follows:

> Bromine-containing brine is extracted from geological formations via wells, and is pumped to a treatment area where the bromine is separated through chlorination, steam stripping, and condensation. The sour gas from the brine is treated in a sulfur-removal process, and is then either used for boiler fuel or flared.
>
> Once the bromine has been isolated from the brine, it may be routed to one or more chemical processing units, where it is used in the manufacture of several different products: bromine chloride, ethylene dibromide, zinc bromide, hydrogen bromide, alkyl amines, alkyl bromides, flame retardant materials, and other bromine-related by-products.[132]

The cumulative Q/d for the source is 18.2, and closest Class I Area impacted is Caney Creek Wilderness with a Q/d of 11.9.[133] The table on page 58 contains the

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[131] *See* Attachment J: Becky Kark, "Albermarle Corp, reaches agreement to sell South Haven plant, South Have Tribune (March 7, 2021).
[132] *See* Attachment K: Arkansas DEQ Title V Permit No. 0762-AOP-R29, at 5 (effective, July 7, 2020 and expired July 7, 2020) ("Albemarle Corporation-South Plant Title V Permit").
[133] NPCA calculated Q using the 2017 NEI for non-EGUs and for power plants NPCA used 2019 AMDP (EPA Air Markets Data Program). This information is from the NPCA interactive map that provides users access to point and non-point source emissions data based on NPCA's assessment of publicly available information curated to identify sources and industrial sectors of concern to visibility in Class I area national parks and wilderness areas. The sources identified likely merit review by states to determine whether and what emission reduction options are feasible to achieve reasonable progress towards the restoration of natural visibility at Class I areas, and otherwise benefit progress toward clean air in all of our communities. The map lets one visualize the locations and details of emission sources, the level of emissions of different pollutants, and the Class I areas potentially affected by each source. The interactive map also provides information on emissions from oil and gas infrastructure such as wells, drilling rigs, compressor stations, pipelines, and refineries at the county level. Additional layers are available to visualize the 8-hour Ozone (2015) nonattainment areas as well as vulnerable populations by county density, including people of color and people living below the poverty line;

total emissions for the facility, as specified in the permit.[134] The Title V further permit provides that vent gases from the sulfur recovery plant are burned[135] in the tail gas incinerator (SR-01) to emit 3,184.0 tpy of SO_2 (at 727.0 lb.hr),[136] with emissions from the fours boilers (BH-01, BH-02, BH-03 and BB-04) permitted to emit 417 tpy of NOx under a single bubble (with no lb/hr limitation).[137] The Title V permit explains that:

> BH-01 and BH-02 have the capacity to produce 200,000 pounds of 225 psig steam per hour. This is equivalent to a heat input of 340 million BTU per hour. BH-03 and BH-04 are temporary boilers of capacity up to 100 MMBtu/hr. The boilers burn natural gas, which has been treated either in the sulfinol or the MDEA plants. They may also burn pipeline quality natural gas. They are not permitted to burn any other fuel.[138]

ADEQ failed to perform a Four-Factor Analysis for the Albemarle Corporation-South Plant and failed to meet the Act's legal requirements. In meeting these requirements, ADEQ must present a review of all of the available controls for the tail gas incinerator and four boilers and evaluate them.

e) Ash Grove Cement Company Foreman Cement Plant

Ash Grove Cement Company Foreman Cement Plant is located in Little River County and is Portland cement plant, which was issued its first permit on or about September 21, 1971.[139] ADEQ's Title V permit describes the source's process as follows:

> Cement manufacturing involves chemical and physical processing of raw materials. The raw materials used include sources of calcium, silica, alumina, and iron. These are the components necessary for the manufacture of the cement components dicalcium silicate, tricalcium silicate, tricalcium aluminate, and tetra-calcium alumino-ferite. The raw feed is prepared for use in the kiln system by sizing, grinding, and blending the various raw materials to produce the necessary mix for

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https://npca.maps.arcgis.com/apps/MapSeries/index.html?appid=73a82ae150df4d5a8160a2275591e45d.

[135] Albemarle Corporation-South Plant Title V Permit at 46.
[136] *Id.* at 9.
[137] *Id.* at 17.
[138] *Id.* at 77.
[139] *See* Attachment U: Arkansas Title V Permit No. 0075-AOP-R23, at 30 (March 24, 2021) ("Ash Grove Cement Foreman Title V Permit").

quality production. The prepared raw feed is introduced to the kiln system where it is physically and pyro-chemically transformed into cement clinker, the intermediate product of portland cement. The raw materials are exposed to air temperatures reaching up to 3,500°F through a countercurrent process in the pyroprocessing system (the rotary kiln and the preheater/precalciner tower components constitute the pyroprocessing system). The raw materials are heated to approximately 2,700°F, the temperature required to produce the chemical reactions necessary to produce quality clinker.

The carbonate source in the raw material kiln feed is limestone. It is surface mined on-site, crushed, and transported by belt conveyor from the quarry to the raw material storage building in the processing portion of the facility. Other raw materials that are sources of iron, aluminum and silica are imported by the facility and temporarily stored in the raw material storage building. These materials are then transferred into material-specific storage bins. From the bins, they are metered onto a belt in specific proportions and sent to the vertical roller mill. The roller mill pulverizes the raw materials into a "meal" that is collected by the process cyclones and baghouse and conveyed to the kiln feed blending and storage silo. From the blending silo, the raw meal is introduced into the pyroprocessing system.

The equipment the facility uses allows the company to burn a variety of fuels. Fuels the company burns include fossil fuels, energy bearing on-site and off-site generated byproducts, nonhazardous wastes, and hazardous wastes. Examples of fuels include but are not limited to coal, petroleum coke, natural gas, fuel oil, used oils from both on and off site sources, tires, waste tires, nonhazardous waste fuels, liquid waste derived fuels (LWDF), solid waste derived fuels (SWDF), bulk waste derived fuels (BWDF). Fossil fuels are typically used during startup and shutdown.[140]

[140] Ash Grove Cement Foreman Title V Permit at 6.

The cumulative Q/d for the source is 13.3, and closest Class I Area impacted is Caney Creek Wilderness with a Q/d of 13.3 .[141] The below table contains the Title V emission limitations for the source, as explained in the permit:[142]

Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	153.5	325.8
		PM_{10}	397.5	658.5
		SO_2	619.5	2701.6
		VOC	97.0	239.1
		CO	2507.4	1729.6
		NO_x	686.4	2980.1

The stack, raw mill, kiln, coal mill and bypass gas exhaust (Source Number 443.SK10) are permitted at the emission rates (lb/hr and tpy) identified in the below table:[143]

[141] NPCA calculated Q using the 2017 NEI for non-EGUs and for power plants NPCA used 2019 AMDP (EPA Air Markets Data Program). This information is from the NPCA interactive map that provides users access to point and non-point source emissions data based on NPCA's assessment of publicly available information curated to identify sources and industrial sectors of concern to visibility in Class I area national parks and wilderness areas. The sources identified likely merit review by states to determine whether and what emission reduction options are feasible to achieve reasonable progress towards the restoration of natural visibility at Class I areas, and otherwise benefit progress toward clean air in all of our communities. The map lets one visualize the locations and details of emission sources, the level of emissions of different pollutants, and the Class I areas potentially affected by each source. The interactive map also provides information on emissions from oil and gas infrastructure such as wells, drilling rigs, compressor stations, pipelines, and refineries at the county level. Additional layers are available to visualize the 8-hour Ozone (2015) nonattainment areas as well as vulnerable populations by county density, including people of color and people living below the poverty line; https://npca.maps.arcgis.com/apps/MapSeries/index.html?appid=73a82ae150df4d5a8160a2275591e45d.

[142] Ash Grove Cement Foreman Title V Permit at 12.

[143] *Id.* at 26.

443.SK10	Stack, Raw Mill, Kiln, Coal Mill and Bypass Gas Exhaust	PM PM_{10} SO_2 VOC CO NO_x	27.3 336.0 616.0[1] 44.5[1] 2,500.0[2] 678.0[1]	119.3 520.6 2,699.0 195.0 1,714.0 2,970.0

ADEQ failed to provide a Four-Factor Analysis for the Ash Grove Cement Foreman source. A top control option ADEQ must evaluate is the control option of installing catalytic ceramic filters. Several vendors are offering catalytic ceramic filter systems for baghouses that can remove NOx through embedded catalysts in the filter, particulate matter, and SO_2 with the use of dry sorbent injection, such as Tri-Mer UltraCat and Haldor Topsoe CataFlex™ catalytic filter bags that can be installed in place of or inside a standard filter bag at an existing baghouse. Such vendors claim that catalytic filters can achieve 90% or greater NOx removal.[144] Notably, the catalytic ceramic filters have been geared towards cement kilns, among other facilities, to help meet the Portland cement maximum achievable control technology (MACT) standards.[145]

Recently, cost assessments for the use of a ceramic catalytic filtration system were done for the GCC Pueblo Cement Plant and Holcim Cement Plant in Colorado.[146] ADEQ can use that information to estimate the costs of using a catalytic ceramic filtration system at the Ash Grove Cement Foreman source.

ADEQ failed to perform a Four-Factor Analysis for the Ash Grove Cement Foreman source and failed to meet the Act's legal requirements. In meeting these requirements, ADEQ must present a review of all of the available controls for the

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144 *See, e.g.*, Tri-Mer® Corporation brochure, Hot Gas Filtration Controls Particulate, SO_2, HCl and NOx in one system, https://tri-mer.com/hot-gas-treatment/hot-gas-filtration.html. (Attachment L); *see also*, Haldor Topsoe CataFlex™ brochure; and GEA BisCat – Ceramic catalyst filter information, https://www.gea.com/en/news/trade-press/2019/biscat-ceramic-catalyst-filter.jsp. (Attachment M).

145 *See* Attachment N: Air & Waste Management Association, The Magazine for Environmental Managers, Sponsored Content, "Catalytic Filter Technology Provides Important Flexibility for Controlling PM, NOx, SOx, O-HAPS," (Oct. 2018), https://pubs.awma.org/flip/EM-Oct-2018/sponsoredcontent_trimer.pdf.

146 Klafka, Steve, Wingra Engineering, GCC Rio Grande – Pueblo Cement Plant, Four-Factor Reasonable Progress Analysis (Sept. 23, 2021). (Attachment O); *see also* Klafka, Steve, Wingra Engineering, Holcim – Florence Cement Plant Florence, Colorado Four-Factor Reasonable Progress Analysis (Sept. 30, 2021), https://drive.google.com/file/d/1cCeBOBK5ZmH6ZD0jCSpvf-5p7OGQ7I7K/view?usp=sharing. (Attachment P).

stack, raw mill, kiln, coal mill and bypass gas exhaust (Source Number 443.SK10) and evaluate them.

III. ADEQ'S CONSULTATION PROCESS WAS FUNDAMENTALLY INADEQUATE.

EPA's regulations require that each applicable implementation plan for a State in which any mandatory Class I Federal area is located, contains such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress toward meeting the national goal.[147] The Clean Air Act further requires states to determine the measures necessary to make reasonable progress towards preventing future, and remedying existing, anthropogenic visibility impairment in all Class I areas.[148] Thus, "Congress was clear that both downwind states (*i.e.* , "a State in which any [mandatory Class I Federal] area . . . is located) and upwind states (*i.e.* , "a State the emissions from which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area") must revise their SIPs to include measures that will make reasonable progress at all affected Class I areas."[149]

"This consultation obligation is a key element of the regional haze program. Congress, the states, the courts and the EPA have long recognized that regional haze is a regional problem that requires regional solutions. *Vermont v. Thomas*, 850 F.2d 99, 101 (2d Cir. 1988)."[150] Congress intended this provision of the Clean Air Act to "equalize the positions of the States with respect to interstate pollution," (S. Rep. No. 95-127, at 41 (1977)) and EPA's interpretation of this requirement accomplishes this goal by ensuring that downwind states can seek recourse from EPA if an upwind state is not doing enough to address visibility transport.[151]

In developing a long-term strategy for regional haze, EPA's regulation 40 C.F.R. § 51.308(f)(2) requires that a state take three distinct steps: consultation; demonstration; and consideration. Specifically, the regulation requires:

> (ii) The State *must consult* with those States that have emissions that are reasonably anticipated to contribute to visibility impairment in the mandatory Class I Federal area to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress.
> (A) The State *must demonstrate* that it has included in its implementation plan all measures agreed to during state-to-state

[147] 42 U.S.C. § 7491(b)(2).
[148] *Id*. § 7491(a)(1).
[149] 82 Fed. Reg. at 3,094.
[150] *Id*. at 3,085.
[151] *Id*.

consultations or a regional planning process, or measures that will provide equivalent visibility improvement.

(B) The State *must consider* the emission reduction measures identified by other States for their sources as being necessary to make reasonable progress in the mandatory Class I Federal area.[152]

"Where the State has emissions that are reasonably anticipated to contribute to visibility impairment in any mandatory Class I Federal area located in another State or States, the State must consult with the other State(s) in order to develop coordinated emission management strategies."[153] Moreover, plan revisions:

> must provide procedures for continuing consultation between the State … on the implementation of the visibility protection program required by this subpart, including development and review of implementation plan revisions and progress reports, and on the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas.[154]

In its 2017 amendments to the Regional Haze Rule, EPA explained that "states *must* exchange their four-factor analyses and the associated technical information that was developed in the course of devising their long-term strategies. This information includes modeling, monitoring and emissions data and cost and feasibility studies."[155] In the event of a recalcitrant state, "[t]o the extent that one state does not provide another other state with these analyses and information, or to the extent that the analyses or information are materially deficient, the latter state should document this fact so that the EPA can assess whether the former state has failed to meaningfully comply with the consultation requirements."[156]

Finally, "[i]f a State contains sources which are reasonably anticipated to contribute to visibility impairment in a mandatory Class I Federal area in another State" that has established reasonable progress goals that are slower than the Uniform Rate of Progress, "the State must demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the

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[152] 40 C.F.R. § 51.308(f)(2) (emphasis added); *see also*, 64 Fed. Reg. 35,765, 35,735 (July 1, 1999) (In conducting the four-factor analysis, EPA explained that "…the State must consult with other States which are anticipated to contribute to visibility impairment in the Class I area under consideration … any such State must consult with other States before submitting its long-term strategy to EPA.").

[153] 40 C.F.R. § 51.308(f)(3)(i).

[154] 40 C.F.R. § 51.308(f)(4).

[155] 82 Fed. Reg. at 3,088 (emphasis added).

[156] *Id.*

State."[157] To that end, the "State must provide a robust demonstration, including documenting the criteria used to determine which sources or groups or sources were evaluated and how the four factors required by paragraph (f)(2)(i) were taken into consideration in selecting the measures for inclusion in its long-term strategy."[158] In any event, "[a]ll substantive interstate consultations must be documented."[159]

A. Arkansas Has Not Satisfied its Consultation Obligation.

Although ADEQ identified several large sources of visibility impairment that adversely impact Arkansas's Class I Areas, the agency's interstate consultation is incomplete and does not satisfy multiple portions of 40 CFR 51.308(f)(2), in multiple respects. As an initial matter, in Appendix C of the Proposed SIP, ADEQ listed the largest sources that impact Caney Creek.

Largest Sources that Impact Caney Creek

Facility	State	2016 NOx (tons/yr)	2016 SO_2 (tons/yr)	Distance to CACR (km)	% of AOI Source Impact
Martin Lake Electrical Station	Texas	9,349.9	25,472.2	247.1	11%
Welsh Power Plant	Texas	4,799.8	11,047.0	168.2	7%
Entergy Ark-White Bluff	Arkansas	9,720.4	18,336.1	183.3	7%
CLECO Power - Dolet Hills Power Station	Louisiana	3,384.7	16,000.5	274.4	6%
Domtar A.W., Ashdown Mill	Arkansas	2,237.7	1,548.9	90.3	5%
Entergy Arkansas Inc-Independence Plant	Arkansas	9,867.1	22,569.7	283.0	5%
Muskogee Gnrtng Sta	Oklahoma	6,460.6	17,804.5	178.1	3%
Hugo Gnrtng Sta	Oklahoma	2,301.4	7,275.5	118.6	3%
AEP Pirkey Power Plant	Texas	4,214.0	4,441.0	223.7	2%
WA Parish Electric Generating Station	Texas	4,405.9	34,137.2	572.4	2%

[157] 40 C.F.R. § 51.308(f)(3)(ii)(B).
[158] *Id.*
[159] 40 C.F.R. § 51.308(f)(2)(ii)(C).

Facility	State	2016 NOx (tons/yr)	2016 SO_2 (tons/yr)	Distance to CACR (km)	% of AOI Source Impact
Entergy Louisiana - Roy S Nelson Plant	Louisiana	2,915.4	8,495.8	471.1	2%
Limestone Electric Generation Station	Texas	8,791.8	20,829.7	390.2	2%
Cogeneration Plt	Oklahoma	980.0	1,909.2	93.8	1%
Entergy La - Nelson Industrial Steam Co (NISCO)	Louisiana	1,385.7	6,209.1	471.2	1%
Weyerhaeuser Nr Company-Dierks Mill	Arkansas	201.4	23.2	39.7	1%
Albemarle Corporation-South Plant	Arkansas	113.4	1,650.4	165.7	1%
Grand River Energy Ctr	Oklahoma	2,300.2	8,987.3	218.3	1%
Oxbow Calcining	Texas	651.3	11,182.6	514.8	1%
Ash Grove Cement Company Foreman Cement Plant	Arkansas	829.7	322.0	87.8	1%
Cabot Corp - Ville Platte Plant	Louisiana	793.4	8,288.4	448.7	1%
New Madrid Power Plant Marston	Missouri	16,107.0	12,467.2	472.0	1%
Cleco - Brame Energy Center	Louisiana	3,385.3	5,703.8	365.3	1%
Ameren Missouri Labadie Plant	Missouri	6,576.4	31,113.4	541.7	1%
Rain Cii Carbon - Lake Charles Calcining Plant	Louisiana	200.7	5,600.1	485.5	1%

As indicated above, a significant amount of the total visibility impairment in Caney Creek comes from sources in other states.

Appendix D of the Proposed SIP indicates that ADEQ sent Texas a letter on February 4, 2020 which contained the statement, "DEQ requests that TCEQ consider whether performing a four-factor analysis is appropriate for each of these sources in accordance with 40 CFR 51.308(f)(2)(i) and, if so, whether any control measures for sulfur dioxide or nitrogen oxides are necessary to make reasonable progress towards natural visibility at Upper Buffalo and Caney Creek during the 2021 - 2028 planning period." The sources ADEQ identified were the top unretired Texas sources identified in the above table – Martin Lake, Pirkey, Welsh, and W.A. Parish.

In its response to ADEQ's request, Texas apparently refused to address, or ignored, potential controls at any of those sources. As an initial matter, Texas's response does not appear anywhere in the record. Arkansas's consultation is therefore incomplete and cannot be approved. ADEQ must include Texas's reply to its February 4, 2020 letter and explain whether it found this reply to be acceptable. EPA confirms this position in its 2017 Regional Haze Rule Revision:

> [S]tates must exchange their four-factor analyses and the associated technical information that was developed in the course of devising their long-term strategies. This information includes modeling, monitoring and emissions data and cost and feasibility studies. To the extent that one state does not provide another other state with these analyses and information, or to the extent that the analyses or information are materially deficient, the latter state should document this fact so that the EPA can assess whether the former state has failed to meaningfully comply with the consultation requirements.[160]

Although Texas's actual response letter does not appear to be included in the record, Appendix D indicates that, in response to ADEQ's request for four-factor analyses for Pirkey and Welsh, Texas apparently asserted that no control analysis was necessary because those facilities have announced their intent to retire.[161] As discussed above, however, to the extent that Arkansas or Texas are relying on retirements to avoid control analyses, those retirements must be made federally enforceable through the proposed SIP. Neither Welsh nor Pirkey are subject to federally enforceable retirement commitments and therefore the state must conduct a meaningful control analysis.

Aside from Texas, it does not appear that ADEQ requested four-factor analyses from any other state, even though Appendix D of the Proposed SIP makes clear that sources like Ameren's Labadie and Rush Island power plants in Missouri and Entergy's R.S. Nelson power plant in Louisiana are projected in 2028 to exceed seventy percent of cumulative percentage of the visibility impacts for NOx and SO_2 combined for Caney Creek or the Upper Buffalo.[162] The following sources in other states currently exceed ADEQ's fifty percent threshold for cumulative impacts at Arkansas Class I areas, yet Arkansas neither conducted any analysis of potential

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[160] 82 Fed. Reg. at 3088.
[161] Proposed SIP, App'x D at pdf p. 340.
[162] *Id.* at p. 51-52.

controls nor requested that those states conduct four-factor analyses: Ameren Labadie (MO); Muskogee Generating Station (OK); Ameren Labadie (MO); Cleco Dolet Hills (LA); Ameren Rush Island (MO); Entergy Nelson Generating Plant (LA); City Utilities of Springfield (MO); Grand River Energy (OK); TVA –Shawnee (KY); Thomas Hill (MO); Indiana Michigan Power Rockport (IN); Duke Energy –Gibson (IN); Prairie State Generating (IL); and Hugo Generating (OK). ADEQ's failure to consult with those states about reasonable control measures renders the proposed SIP unlawful and unapprovable.

In addition, there is no indication in Arkansas's Proposed SIP that ADEQ performed any real assessment of the likelihood of additional cost-effective controls for these or any sources in other states. ADEQ simply states on page V-49, that "[n]o specific controls were requested from any other state, including those that requested that DEQ perform four-factor analyses, or agreed to as part of consultation." Thus, Arkansas's treatment of the Regional Haze Rule's consultation requirement in Section 51.308(f)(2)(ii) is entirely perfunctory and clearly does not satisfy the intention of this requirement.

B. ADEQ Must Adapt Its Proposed SIP to Meaningfully Address and Incorporate Comments from the Federal Land Manager.

The Clean Air Act and the Regional Haze Rule require states to consult with the Federal Land Manager ("FLM")—either the National Park Service, the U.S. Forest Service or the U.S. Fish and Wildlife Service—that oversees the Class I national parks or wilderness areas impacted by a state's sources.[163] Specifically, the state "must provide the Federal Land Manager with an opportunity for consultation, in person at a point early enough in the State's policy analyses of its long-term strategy emission reduction obligation so that information and recommendations provided by the Federal Land Manager can *meaningfully inform* the State's decisions on the long-term strategy."[164] The "consultation must be early enough for state officials to meaningfully consider the views expressed by the FLMs."[165] The rule further requires states to provide for "continuing consultation" between the state and the Federal Land Manager, and to meaningfully address the FLM's comments in the proposed SIP.[166] Thus, the FLM consultation process is not a mere box checking exercise; instead, it is a mandatory, iterative process, requiring the state to meaningfully consider and incorporate into the SIP the concerns of the

[163] 42 U.S.C. § 7491(d); 40 C.F.R. § 51.308(i)(2).
[164] 40 C.F.R. § 51.308(i)(2) (emphasis added).
[165]EPA, Responses to Comments at 445, Protection of Visibility: Amendments to Requirements for State Plans; Proposed Rule (81 FR 26942, May 4, 2016), Docket No. EPA-HQ-OAR-2015-0531 (Dec. 2016) [hereinafter, "Regional Haze Rule Revision Response to Comment"].
[166] 40 C.F.R. § 51.308(i)(2); Regional Haze Rule Revision Response to Comment at 445.

agencies responsible for managing the Class I resources impacted by pollution from the state.

As discussed, in its comments on the proposed SIP, the U.S. Forest Service concluded that for Flint Creek, "selective catalytic reduction (SCR), is a cost-effective emissions reduction strategy. At a minimum additional cost-effectiveness analysis should focus on similar facilities implementing comparable emissions controls, rather than relying on summary statistics based upon broad source categories.[167] In response, ADEQ essentially ignored the Forest Service's recommendation, asserting that SCR controls exceeds the maximum cost-effectiveness threshold for BART determinations.[168] The state's explanation for refusing to require SCR at Flint Creek is arbitrary and unreasonable. The second planning period is concerned with reasonable progress, not BART, and EPA has explained that the thresholds used for BART in the first planning period "are, in most cases, not appropriate thresholds for selecting sources or evaluating the impact of controls for reasonable progress in the second planning period."[169] In other words, ADEQ may not simply adopt BART cost-effectiveness thresholds without explaining why those thresholds are appropriate. As explained above, ADEQ must revise its cost-effectiveness threshold to explain how the state's conclusory adoption of BART cost thresholds will ensure reasonable progress toward natural visibility.

IV. ADEQ SHOULD ANALYZE THE ENVIRONMENTAL JUSTICE IMPACTS OF THE PROPOSED SIP.

We urge ADEQ to take impacts to Environmental Justice communities into consideration as it evaluates all sources that impact regional haze. Indeed, sources that harm the air in our treasured Class I areas are also located in or close to environmental justice areas. According to the EPA's EJScreen tool, the sources Flint Creek, Plum Point, Futurefuel Chemical Company, Crossett Paper, Evergreen Packaging – Pine Bluff, and Albemarle Corporation – South Plant, are located in close proximity to block groups with high levels of unemployment rates and low income.

There are numerous bases for ADEQ to take Environmental Justice impacts into consideration in developing its Regional Haze SIP. First, in evaluating reasonable progress under the Clean Air Act, the state must consider all "non-air quality environmental impacts of compliance." Although the Regional Haze Rule does not define "non-air quality environmental impacts," the BART Guidelines, which should inform a state's reasonable progress analysis, explain that the term should be interpreted broadly. Moreover, under the Clean Air Act, states are permitted to include in a SIP measures that are authorized by state law but go

[167] Proposed SIP, App'x D. at pdf p. 259.
[168] *Id.* at p.345-46.
[169] *Id.* at 14.

beyond the minimum requirements of federal law.[170] Environmental justice impacts are the types of "non-air quality environmental" impacts that ADEQ should consider and doing so is consistent with the Clean Air Act.

Second, consideration of Environmental Justice impacts is also consistent with EPA's recent guidance in implementing the Regional Haze Rule. Indeed, on July 8, 2021, EPA issued guidance explicitly "encourag[ing] states to consider whether there may be equity and environmental justice impacts when developing their regional haze strategies for the second planning period," including by taking such concerns into account in their source selection and four-factor analyses.[171] EPA's guidance makes clear that states may consider beneficial Environmental Justice impacts under the "non-air quality environmental impacts" reasonable progress factor.[172] EPA has also endorsed the consideration of guidance intended for use in environmental impact assessments under the National Environmental Policy Act, which includes guidance for evaluating Environmental Justice, as part of its Regional Haze planning process.[173]

Finally, consideration of the beneficial environmental impacts of additional Regional Haze emission reductions would be consistent with, and would further, the nation's environmental justice policy goals. Under Executive Order 12,898, Federal agencies must ensure they are achieving environmental justice goals as a part of

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[170] *See Union Elec. Co v. EPA*, 427 U.S. 246, 265 (1976) ("States may submit implementation plans more stringent than federal law requires and . . . the Administrator must approve such plans if they meet the minimum requirements of s 110(a)(2)."); *Ariz. Pub. Serv. Co. v. EPA*, 562 F.3d 1116, 1126 (10th Cir. 2009) (quoting *Union Elec. Co.*, 427 U.S. at 265) ("In sum, the key criterion in determining the adequacy of any plan is attainment and maintenance of the national air standards . . . 'States may submit implementation plans more stringent than federal law requires and [ ] the [EPA] must approve such plans if they meet the minimum [Clean Air Act] requirements of § 110(a)(2).'"); *BCCA Appeal Group v. EPA*, 355 F.3d 817, 826 n. 6 (5th Cir. 2003) ("Because the states can adopt more stringent air pollution control measures than federal law requires, the EPA is empowered to disapprove state plans only when they fall below the level of stringency required by federal law.").

[171] 2021 Clarification Memo at 16.

[172] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, EPA-457/B-19-003 (Aug. 2019).

[173] *Id.* at 33. A collection of EPA policies and guidance related to the National Environmental Policy Act (NEPA) is available at https://www.epa.gov/nepa/national-environmental-policy-act-policies-and-guidance. One of these policies concerns Environmental Justice. *See*, https://www.epa.gov/nepa/environmental-justice-guidance-national-environmental-policy-act-reviews.

their mission. To further that, President Biden's Executive Order 13,990 directs agencies to review and correct federal regulations and agency actions over the last four years that conflict with the national objectives to advance and prioritize environmental justice, and to conserve and protect our national treasures and monuments consistent with federal law. Executive Order 14,008 builds on, and reaffirms, the Biden Administration's commitment to environmental justice, and directs EPA to strengthen the enforcement of the Clean Air Act. Given the plain intent of President Biden's Executive Order that EPA consider environmental justice concerns in implementing the Clean Air Act, the state should consider the environmental justice impacts of its Second Planning Period SIP both for sources located in disproportionately impacted communities, and further downwind.

Although ADEQ is not bound to adhere to those recent Executive Orders, it certainly has authority to take those factors into consideration. And even if ADEQ refuses to evaluate those impacts, EPA will be required to consider Environmental Justice impacts in reviewing Arkansas's SIP submittal. Thus, as a matter of both good public policy and efficiency, ADEQ should analyze the environmental justice impacts of its second planning period haze SIP. For those sources located near a low-income or minority community that suffers disproportionate environmental harms, ADEQ's four-factor analysis for that source should take into consideration how each considered measure would either increase or reduce the environmental justice impacts to the community. Such considerations will not only lead to sound policy decisions but are also pragmatic as pointed out above, where sectors and sources implicated under the regional haze program are of concern to disproportionately impacted communities in Arkansas. Thus, considering the intersection of these issues and advancing regulations accordingly will help deliver necessary environmental improvements across Clean Air Act programs and issue areas, reduce uncertainty for the regulated community, increase the state's regulatory efficiency, result in more rational decision making.

V. CONCLUSION

We urge ADEQ to reevaluate its Proposed SIP especially in light of EPA's July 8, 2021 Clarification Memo, which confirms that the Proposed SIP is fundamentally flawed. Due to the deficiencies outlined above and in the attached and referenced exhibits, the state must revise and reissue a valid regional haze SIP for public notice and comment. Please do not hesitate to contact us with any questions or to discuss the matters raised in these comments.

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Enclosure

List of Attachments

All Accessible Here: https://drive.google.com/drive/folders/1BMKUrn-mjHsvEtx112qETd8E051v774v?usp=sharing

A. Conservation Organizations' Spreadsheet, AR EGU emissions.xlsx. https://docs.google.com/spreadsheets/d/1YSUAFYL0zvwCGY5DCj233A0hMaLWAnAt/edit?usp=sharing&ouid=108076496712758672315&rtpof=true&sd=true.

B. Conservation Organizations' Spreadsheet, Flint Creek SNCR CCM cost-effectiveness.xlsm. https://drive.google.com/file/d/1KnHO5wNMXxkcyzFm9FwokCLjdCPGSFwY/view?usp=sharing.

C. Arkansas DEQ Title V Permit No. 1085-AOP-R14, (Feb. 24, 2020) (FFCC), https://drive.google.com/file/d/1ELryRrQLPZgzhdS6IP3O0ns115c9rT1j/view?usp=sharing.

D. Arkansas DEQ Title V Permit # 0597-AOP-R23, (Feb. 14, 2022) (Georgia-Pacific Crossett), https://drive.google.com/file/d/1ytbOdVOG53IjKIZvgZzSe8nY_GMBZ1Mj/view?usp=sharing.

E. Arkansas EJ Action Plan, Environmental Justice Collaborate Action Plan, https://19january2021snapshot.epa.gov/environmentaljustice/region-6-arkansas-ej-action-plan_.html.

F. Arkansas DEQ Title V Permit # 0580-AOP-R16, (June 11, 2021) (Evergreen Packaging), https://drive.google.com/file/d/1pU_nulOlGiSqieb55lhAyyD91HgZrKfJ/view?usp=sharing.

G. Arkansas Title V Permit # 1209-AOP-R7, (April 12, 2021) (Enable Gas Transmission, LLC (Dunn Compressor Station)), https://drive.google.com/file/d/184vjyCoHMJSe8sV19n3aLfkncqrFFWQD/view?usp=sharing.

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