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By email: r6air_okhaze@epa.gov

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Re: EPA Docket EPA-R06-OAR-2010-0190

Summary of Comments

The Sierra Club and WildEarth Guardians (hereinafter "Sierra Club") respectfully submit the following comments on the Environmental Protection Agency ("EPA" or "USEPA") regional haze Federal Implementation Plan ("FIP") for the State of Oklahoma. Our organizations represent thousands of Oklahomans and hundreds of thousands of others throughout the nation that care deeply about protecting public health, air quality at the national parks and wilderness areas, and local economies supported by recreation and tourism. Sierra Club prepared these comments with technical expertise from Camille Sears, Paul Chernick of Resource Insight Inc. and John Plunkett of Green Energy Economics. Their curriculum vitae are attached here.

On March 22, 2011, EPA proposed to partially approve and partially disapprove Oklahoma's proposed regional haze State Implementation Plan ("SIP"). Sierra Club supports EPA's proposal that will reduce substantial quantities of haze-forming pollutants as required by law, however, Sierra Club encourages EPA to require more stringent reductions in some areas. A FIP is necessary because Oklahoma's SO_2 BART plan is business as usual and fails to meet the relevant statutory and regulatory requirements.

Oklahoma submitted Best Available Retrofit Technology ("BART") determinations for six subcritical pulverized coal boilers: Sooner units 1 & 2: Muskogee units 4 & 5; and Northeastern units 3 & 4 ("plants"). EPA rejected Oklahoma's BART determination for sulfur dioxide ("SO_2") because the proposed emissions limit was actually higher than four units already achieve, costs of controls were overestimated and impacts were underestimated. EPA's plan gives Oklahoma a choice to reduce SO_2

emissions: install dry scrubbers on six coal-burning units or switch to natural gas to achieve lower emissions.

Our modeling expert has verified EPA's determination that its proposed BART limits will improve visibility at the Wichita Mountains and other nearby Class I areas. Additionally, as described below, we have determined through modeling that all the units specified above violate the SO_2 NAAQS, and thus will require further controls to come into compliance with that standard. This is another reason supporting EPA's FIP.

While both of the compliance options described in the FIP are feasible, Sierra Club's technical experts have determined that the fuel-switching option is preferable because it avoids a host of potential costs and environmental impacts that will be incurred if the plants continue to burn coal; integrates better with increased wind-power development; and allows the utilities to employ a range of lower-cost options, including energy-efficiency programs, use of existing facilities, short-term purchase of energy from under-utilized facilities, long-term purchase contracts from excess capacity, and increased use of renewable energy.

Either option could cause rates to increase somewhat, however, Oklahoma has the eighth lowest average electricity rates in the country, at 6.94¢/kWh in 2009, compared to a national average of 9.82¢/kWh. Rates are higher in every neighboring state: Arkansas, Kansas, Missouri, Colorado, New Mexico, and especially Texas, which has rates 42% higher than Oklahoma's. Some of this differential may result from the fact that other states have emission controls on a higher percentage of their coal plants. Of the 322 GW of coal capacity nation-wide, about 190 GW (or 58%) is scrubbed, including about 116 GW of retrofits. Of the 5,300 MW of coal capacity in Oklahoma, only 520 MW (or 10%) is scrubbed.

Though the State of Oklahoma and OG&E and PSO ("the utilities") contend that EPA's proposal infringes on state's rights because air pollution and haze are not contained within state's borders, the Clean Air Act is a state and federal partnership. Oklahoma had flexibility to draw up an implementation plan that meets regulatory requirements, but it did not do so. When a state plan fails to meet requirements, EPA has no choice but to issue a federal implementation plan.[1]

Each state must make a contribution to meeting Congress' national clean air objectives by lowering emissions. Oklahoma's emissions are responsible for visibility degradation in Missouri, New Mexico and Texas,[2] just as surely as Texas' emissions affect Oklahoma.[3] Oklahoma has pointed to Texas as a major contributing source of air pollution in the state.[4] Oklahoma is one of the first states that must reduce emissions

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[1] 42 U.S.C. 7410(c).
[2] 76 Fed. Reg.16168, 16175.
[3] 76 Fed. Reg.16168, 16176 ("ODEQ indicated that emissions from other states, especially Texas, impeded Oklahoma's ability to meet the URP.")
[4] Oklahoma Fights Texas Over Pollution, (Nov. 17, 2010), *available at* http://www.koco.com/news/25831323/detail.html

because it further along in the regional haze process, but Texas will also have to significantly reduce its emissions. EPA made this clear in its proposal for Oklahoma by delaying action on Oklahoma's reasonable progress goal. "We are not taking action on Oklahoma's submitted RPGs because, as described more fully below, we must first evaluate and act upon the RH SIP revision submitted by the State of Texas."[5]

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Background

In order to protect their "intrinsic beauty and historical and archeological treasures,"[6] Congress established a national goal to reduce human-caused haze pollution and achieve natural visibility conditions at national parks, wilderness areas, and other designated Class I areas by 2064.[7] In order to meet this goal, states are required to design an implementation plan to reduce, and ultimately eliminate, haze from air pollution

[5] 76 Fed. Reg. 16168, 16176.
[6] See H.R. Rep. No.95-294, at 203-04 (1977).
[7] See 42 U.S.C. § 7491(a)(1); 40 C.F.R. § 51.308(d)(1).

sources within its borders that may reasonably be anticipated to cause or contribute to visibility impairment at any protected area located within or beyond that state's boundaries.

Each SIP must provide "emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress towards meeting the national goal."[8] Two of the most critical features of a regional haze SIP are requirements for (1) the installation of BART technology for delineated major stationary sources of pollution and (2) a long-term strategy for making reasonable progress towards the national visibility goal.[9]

Pollutants that cause visibility impairment also harm public health. Haze pollutants include nitrogen oxides ("NOx"), sulfur dioxide ("SO_2"), particulate matter ("PM"), ammonia, and sulfuric acid. NOx is a precursor to ground level ozone, which is associated with respiratory diseases, asthma attacks, and decreased lung function. In addition, NOx reacts with ammonia, moisture, and other compounds to form particulates that can cause and worsen respiratory diseases, aggravate heart disease, and lead to premature death.[10] Similarly, SO_2 increases asthma symptoms, leads to increased hospital visits, and can form particulates that aggravate respiratory and heart diseases and cause premature death.[11] PM can penetrate deep into the lungs and cause a host of health problems, such as aggravated asthma, chronic bronchitis, and heart attacks.[12]

EPA estimated that in 2015, full implementation of the Regional Haze Rule nationally will prevent 1,600 premature deaths, 2,200 non-fatal heart attacks, 960 hospital admissions, and over 1 million lost school and work days.[13] The Regional Haze Rule will result in health benefits valued at $8.4 to $9.8 billion annually.[14] More than 100,000 children and 365,000 adults are diagnosed with asthma in Oklahoma, and hospitalizations in Oklahoma due to asthma cost roughly $57.9 million in 2007 alone.[15] According to the Clean Air Task Force, the 6 units at issue in the proposed rule annual cause approximately 118 deaths, 181 heart attacks, 2,037 asthma attacks, 86 hospital admissions, 74 cases of chronic bronchitis, and 129 emergency room visits.[16]

While the Regional Haze Rule was designed to provide redress for visibility

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[8] 42 U.S.C. § 7491(b)(2).
[9] 42 U.S.C. § 7491(b)(2)(A) & (B).
[10] EPA, Health – Nitrogen Dioxide, http://www.epa.gov/air/nitrogenoxides/health.html (last visited Apr. 1, 2011).
[11] EPA, Health – Sulfur Dioxide, http://www.epa.gov/air/sulfurdioxide/health.html (last visited Apr. 1, 2011).
[12] EPA, Health & Environment – Particulate Matter, http://www.epa.gov/air/particlepollution/health.html (last visited Apr. 1, 2011).
[13] EPA, Fact Sheet – Final Clean Air Visibility Rule, http://www.epa.gov/visibility/fs_2005_6_15.html (last visited Apr. 1, 2011).
[14] Id.
[15] Oklahoma State Dept. of Health, Asthma Surveillance Report (2008), *available at* http://www.ok.gov/health/documents/Asthma%20Surveillance%20Report_2008.pdf
[16] Clean Air Task Force, Death and Disease from Power Plants, *available at* http://www.catf.us/coal/problems/power_plants/existing/map.php?state=Oklahoma

impairment, the BART Guidelines expressly provide for the consideration of non-air quality environmental impacts in step four of the 5-step BART process. [17] This consideration includes the environmental impact on human health.

Visibility impairment is measured in deciviews, which is a perceptible change in visibility. The higher the deciview value is, the worse the impairment.[18] Each deciview change is an equal incremental change in visibility perceived by the human eye.

Best Available Retrofit Technology (BART)

One of the most important parts of a regional haze plan is the requirement that major older sources of air pollution modernize their control equipment by installing BART. BART limits are required for major stationary sources that were in existence on August 7, 1977 and began operating after August 7, 1962 and emit air pollutants that may reasonably be anticipated to cause or contribute to any impairment of visibility is a Class I area.[19] The term "major stationary source" is defined as sources that have the potential to emit 250 tons or more of any pollutant and fall within one of 26 categories of industrial sources defined by the Act.[20] A BART-eligible source is one that meets the above criteria and is responsible for an impact on visibility in a Class I area of 0.5 deciview or more.[21]

BART is defined as an emission limitation:

> . . .**based on the degree of reduction achievable through the application of the best system of continuous emission reduction** for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.[22]

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[17] Section IV.D. of the BART Guidelines at 40 C.F.R. Part 51, Appendix Y.
STEP 1 -- Identify All Available Retrofit Control Technologies,
STEP 2-- Eliminate Technically Infeasible Options
STEP 3-- Evaluate Control Effectiveness of Remaining Control Technologies,
STEP 4-- Evaluate Impacts and Document the Results, and
STEP 5 – Evaluate Visibility Impacts.

[18] Details about the deciview can be found in the preamble to the regional haze rule. 64 Fed. Reg. 35714, 35725 (July 1, 1999).

[19] 42 U.S.C. § 7491(b)(2)(A).

[20] 42 U.S.C. § 7491(g)(7).

[21] 40 C.F.R. Part 51, Appendix Y.

[22] 40 C.F.R. §51.301, emphasis added

Sulfur Dioxide (SO_2) BART

Sierra Club supports EPA's determination that Oklahoma's proposed sulfur dioxide BART limits for coal-fired units do not comply with haze regulations. Under Oklahoma's proposal, most of the units could actually increase their emissions. Oklahoma proposed business as usual: no control and an emission limit of .65 lbs/MMBTU, which is higher than actual emissions from four of the boilers.[23] Oklahoma's proposal was based on significant errors in its BART analysis. It overestimated the costs of controlling SO_2 emissions, and it underestimated the visibility benefits.

To address the deficiencies in Oklahoma's submission, EPA proposed to limit sulfur dioxide emissions from six coal-fired boilers to .06 lbs/MMBTU. This emissions limit is based on the amount of control that can be achieved with dry scrubbers, but Oklahoma has flexibility how it chooses to meet this limit. Wet scrubbers can achieve greater control than dry scrubbers, but EPA did not require the more stringent limit because its analysis found that, in this particular case, "the visibility modeling does not show a consistent, clear benefit for wet scrubbing."[24] As EPA points out, however, "there are significant advantages to wet scrubbing that OG&E and/or AEP/PSO may find attractive as a means of satisfying our proposed FIP."[25] "Wet scrubbing achieves better mercury control, avoids the high short-term SO_2 emission rates during atomizer change-out at a dry scrubber, creates a reusable byproduct, and does not contaminate the dry ash."[26]

Cost

BART cost effectiveness evaluates the cost of controlling pollution in dollars per ton of pollutant removed. Cost effectiveness is calculated according the EPA Air Pollution Control Cost Manual,[27] as stipulated in the BART Guidelines.[28] The cost manual provides a level playing field to estimate the cost of pollution control equipment, which is important in the BART analysis since cost effectiveness is compared to other BART estimates. A control technology is considered to be "cost effective" if it falls within a reasonable range of cost-effectiveness estimates.[29]

As EPA showed in its vigorous report, Oklahoma overestimated the cost of installing dry scrubbers by as much as five times. Oklahoma estimated costs based on a much bigger scrubber than what it assumed in its BART analysis, double-counted some

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23 76 Fed. Reg. 16168, 16182.
24 76 Fed. Reg. 16168, 16185.
25 76 Fed. Reg. 16168, 16188.
26 EPA's Technical Support Document, App. C at p. 51.
27 U.S. EPA, EPA Air Pollution Control Cost Manual, Report EPA/452/B-02-001, 6th Ed., January 2002 ("Cost Manual").
28 40 C.F.R. Pt. 51, App. Y at page 25.
29 70 Fed. Reg. 39168 (July 6, 2005).

costs, and did not use the conventions from the EPA's cost manual.[30] Table 4 in the proposed rule shows EPA's corrected cost figures compared to Oklahoma's estimates.

TABLE 4—CONTRAST OF DRY SCRUBBER COST EFFECTIVENESS

	EPA's projected cost ($/ton SO2 removed)	ODEQ projected cost ($/ton SO2 removed)
Sooner 1	$6,348	$1,291
Sooner 2	7,147	1,291
Muskogee 4	7,378	1,317
Muskogee 5	7,493	1,317
Northeastern 3	3,294	1,544
Northeastern 4	3,294	1,544

These corrected figures show that dry scrubbers are a cost effective control option. EPA's corrected figures for wet scrubbers are similar, found in Table 7. Sierra Club supports EPA's thorough analysis and conclusion that both dry scrubbers and wet scrubbers are cost effective controls in Oklahoma.[31]

Visibility Impacts

Oklahoma also underestimated the visibility impacts of controlling sulfur dioxide emissions. EPA's modeling, which Sierra Club's expert has confirmed, shows that dry scrubbing will result in 2.89 deciview improvement in visibility at the Wichita Mountains. Adding modern sulfur dioxide controls to these older Oklahoma coal plants will also improve visibility at Caney Creek and Upper Buffalo in Arkansas, Salt Creek in New Mexico, and Hercules-Glades in Missouri by a cumulative total of 8.20 deciviews.[32]

Based on modeled visibility improvement, Sierra Club agrees that the SO_2 emissions from Units 4 and 5 of the OG&E Muskogee plant, Units 1 and 2 of the OG&E Sooner plant, and Units 3 and 4 of the AEP/PSO Northeastern plant should be controlled with the SO_2 BART proposed by USEPA.

USEPA prepared CALPUFF modeling to determine the effectiveness of SO_2 BART emission limits on improving visibility in four Class I areas: Wichita Mountains (Oklahoma), Caney Creek (Arkansas), Hercules-Glades (Missouri), and Upper Buffalo (Arkansas). Visibility improvement is measured in delta deciviews (Δ dv), with deciview being a haze index based on aerosol light extinction capabilities. The results of USEPA's CALPUFF visibility modeling are found in Appendix B to their FIP Technical Support

[30] 76 Fed. Reg. 16168, 16183.
[31] 76 Fed. Reg. 16168, 16187; *see* Revised BART Cost-Effectiveness Analysis for Flue Gas Desulfurization at Coal-Fired Electric Generating Units in Oklahoma.(Oct. 2010) (App. C to EPAs Technical Support Document).
[32] Table 9 in 76 Fed. Reg. 16168, 16186.

Document.[33] The results of USEPA's visibility modeling analyses are presented as maximum and average 98th percentile Δ dv impacts for modeling years 2001–2003.

Sierra Club requested and received the CALPUFF modeling files used by USEPA Region 6 in their BART modeling analyses. The modeling files included CALPUFF, CALPOST, and POSTUTIL input and output files for all of the units subject to BART. Also included were CALMET meteorological data files and regional ozone files for years 2001 through 2003. In addition, Sierra Club also received CALPUFF and related modeling files prepared by OG&E and AEP/PSO as part of their BART application analyses, and the CALPUFF files prepared by the Oklahoma Department of Environmental Quality ("ODEQ").

Sierra Club reviewed USEPA's Technical Support Document for the Oklahoma Regional Haze State Implementation Plan and Federal Implementation Plan, with appendices, and the CALPUFF modeling files described above. We also prepared CALPUFF runs to examine the sensitivity of higher background ammonia levels on visibility improvement from USEPA's proposed SO_2 BART (dry scrubbing). Furthermore, we reviewed USEPA's emission calculations and speciation and concur with the results they obtained. While our review was not exhaustive, Sierra Club believes that USEPA's CALPUFF modeling and SO_2 BART determinations are appropriate.

While remodeling various CALPUFF scenarios, we noticed several possibly incorrect input values. Sierra Club did not have the time to evaluate the effects of these potential input concerns, but it does not appear that remodeling with corrected values will substantially change results and conclusions developed by USEPA, ODEQ, and the BART applications. The input values are as follows:

- The base elevation for OG&E Muskogee units 4&5 are modeled as 326 meters. Using AERMAP and the National Elevation Dataset ("NED"), the base elevation for OG&E Muskogee is 157 meters. These base elevations appear to be the same in both EPA's and OG&E's CALPUFF input files (input group 13a).

- The base elevation for OG&E Sooner units 1&2 are modeled as 326 meters. Using AERMAP and NED, the base elevation for OG&E Sooner is 286 meters. These base elevations appear to be the same in both EPA's and OG&E's CALPUFF input files (input group 13a).

- USEPA's modeled stack gas exit velocity for OG&E Sooner unit 2, LNB, WFGD scenario, is 38.35 meters/second. OG&E's modeling uses 28.35 meters/second.

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[33] USEPA, Appendix B, Refined Best Available Retrofit Technology (BART) Modeling Report: OG&E Sooner Generating Station, OG&E Muskogee Generating Station, and AEP/PSO Northeastern Generating Station, March 2011, pp. B-18 – B-21.

Cumulative Impact and Benefit

EPA appropriately considered the full degree of visibility improvement resulting from the installation of BART controls by considering in its analysis and capturing in its determination the cumulative visibility benefit of installing BART across all Class I areas affected. The cumulative impact of a source's emissions on visibility as well as the cumulative benefit of emission reductions is a necessary consideration as part of the fifth step in the BART analysis. Assessing cumulative impacts makes sense as regional haze is a regional issue and reflects the degree of visibility improvement which may reasonably be anticipated from the use of BART.

EPA Region 9 has considered cumulative visibility benefits in its BART determinations for the Four Corners Power Plant and Navajo Generating Station.[34] Region 6 employed a cumulative visibility benefits analysis when determining BART in the FIP for the San Juan Generating Station,[35] and states such as Wyoming and Oregon have proposed regional haze SIPs employing cumulative benefits analyses. Likewise, the federal land managers charged with protection of Class I areas routinely rely on a cumulative assessment of visibility impacts and benefits when determining the level of emissions controls that are cost-effective and technically feasible.[36]

Natural Gas Switch is Best Option for Oklahoma

Natural Gas Switch is Feasible

Sierra Club supports EPA's suggestion that switching the BART-eligible boilers from coal to natural gas is the best option to achieve sulfur dioxide reduction in Oklahoma.[37] Paul Chernick of Resource Insight Inc. has provided the following comments on the natural gas option. Thousands of megawatts of coal-fired boilers have been converted to burn gas,[38] including many units converted to oil in the 1960s and 1970s and later to gas, as well as more recent conversions, such as that of Conectiv's Edge Moor plant in 2010. Additional thousands of megawatts of coal capacity have been repowered to more efficient gas combined-cycle operation, including South Carolina's Urquhart, Xcel's Riverside, and TECo's Bayside Station (the repowered Gannon coal units 5 and 6).

Of the three stations with BART-eligible coal units, two have existing major gas supplies. The Muskogee site includes a 173 MW gas boiler plant. Expanding gas supply along an existing pipeline is generally less expensive and faster than building a new line.

[34] See, e.g., 75 Fed.Reg.64221, 64229–30 (Oct. 19, 2010) (Four Corners Power Plant); 75 Fed. Reg. 10174 (Mar. 5, 2010) (Navajo Generating Station).

[35] 76 Fed.Reg. at 501–04.

[36] See, e.g., NPS, General BART Comments, Navajo Generating Station 7/24/09.

[37] 76 Fed. Reg. 16168, 16188.

[38] Examples include the three large New York City plants (Astoria, Arthur Kill, and Ravenswood), as well as units in Connecticut (Montville) and Massachusetts (West Springfield) and Long Island (Barrett).

The Northeastern site includes a 527 MW gas-fired combined-cycle plant and a 473 MW gas-fired steam plant.

The natural-gas conversion projects can be accomplished quickly and without any consequences to the regional power system. Natural-gas conversion projects generally require less than a year. Actual unit shutdowns are generally accomplished in off-peak seasons. The Southwest Power Pool ("SPP") covers Oklahoma, Kansas, most of Nebraska, and portions of Texas, Arkansas, Missouri, Louisiana, and New Mexico, plus adjacent areas in the remainder of Arkansas and Missouri.[39] Winter peak loads in SPP are about 12,000 MW lower than summer loads, and winter generation capacity is about 1,000 MW higher. Loads in the spring and fall are even lower. Regional power supply should be more than adequate even if a few of the roughly 500-MW BART-eligible units are shut down simultaneously in off-peak months.

Even some overlap of outages into the summer should not cause any problems. Capacity in SPP exceeded the required reserve level by about 4,500 MW in 2010 and is projected to exceed requirements by about 6,500 MW in 2014. There is clearly enough capacity to allow the shutdown of multiple 500-MW BART-eligible units, even in the summer.

Natural Gas Switching is Superior to Scrubbers

Sierra Club views the non-scrubbing compliance option more broadly than simply switching the existing units to burn gas. It should be approached as a flexible strategy that might rely on a combination of fuel-switching, energy-efficiency deployment, increased use of existing gas capacity, and increased wind development.

The gas-switching option is superior to the scrubbers in several respects:

- The switching option reduces NOx emissions, eliminates emissions of mercury and other air toxics, nearly eliminates particulates and SO_2, ends the production of toxic fly ash and bottom ash, and avoids the need for disposal of scrubber waste.
- The scrubber option leaves the utilities vulnerable to future environmental costs, particularly addition of baghouses for control of particulates and heavy metals under the pending MACT rule and the costs of better containing coal combustion residuals. The fuel-switching option avoids these expenditures.
- A baghouse for any of these 500-MW units would cost about 85 million in capital, \$0.63/kW yr annually, and consume about 0.6% of the unit's energy and capacity.[40]

[39] The transmission system in the remainder of Louisiana and even western Mississippi is managed by SPP, and generation in this area may also be available to Oklahoma utilities, but this area is not included in the analysis below. The non-SPP portions of Texas and New Mexico are parts of the Texas (ERCOT) and Western (WSCC) interconnections, and are not well connected to SPP.

[40] Sergent & Lundy, IPM Model – Revisions to Cost and Performance for APC Technologies, March 2011, *available at* http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/append5_5.pdf

- The North American Electric Reliability Council ("NERC") estimates that complying with requirements to contain coal ash and scrubber waste would cost about $30 million in capital investment (or $180 million for the six units) plus $15–$37.50 per ton of residual.[41] For the amount of ash generated by the BART-eligible units in 2005, this would be $2–$5 million annually for the six units if they can continue selling fly ash and bottom ash, and $9 million if the environmental restrictions and other factors preclude sale of the ash. In addition, based on the FGD waste produced per MWh at scrubbed plants that also burn Wyoming-mined Powder River Basin coal, scrubbing the six BART-eligible units could produce more than 600,000 tons of FGD waste byproducts, which could cost up to $22 million annually, depending on the extent to which forthcoming rules restrict reuse of those product.
- The six BART-eligible units are all over 30 years old. If they continue to operate as baseload coal-fired units, they are likely to require major repairs, rehabilitation or replacement within a decade of installation of the scrubbers. After conversion to less-corrosive gas firing, the units would operate at low capacity factors or spend most of their time in standby, avoiding those additional costs.
- As the amount of wind in Oklahoma and the SPP rises, fossil generation will need to ramp production up and down more frequently, and to shut down for various periods of time during high wind production. The switching option would result in plants better suited to integrate with variable wind generation, both technically (since coal plants generally ramp more slowly than gas plants and often require longer periods between starts and stops) and economically (since the large investment in scrubbing and other environmental compliance will be partially stranded if coal units are often ramped down to accommodate wind energy, while gas plants would avoid their fuel costs).
- Oklahoma is a major exporter of natural gas, but a major importer of coal, including the coal burned by the six units.[42] The scrubbing option would continue those imports, requiring rail transport of large amounts of coal, while the switching option would use an indigenous resource.

If Oklahoma Gas & Electric ("OG&E") and Public Service Company of Oklahoma ("PSO" or "PSO/AEP") do not scrub these BART-eligible units, they would have a number of attractive options for meeting their customers' needs while keeping emissions below those anticipated in the FIP. The switching option is consistent with a much broader compliance strategy, in which some of the six units may be converted to burn gas in their boilers, as EPA suggests, while others are replaced by a combination of:

- Reduced energy use and peak load through energy-efficiency programs and demand response.

[41] 2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations, NERC, October 2010, p. 5
[42] Oklahoma purchases all of its coal—$494 million annually—from Wyoming, except for a small test burn of Colombian coal in 2010.

- Increased use of the utilities' gas-fired plants.
- Spot or short-term contract purchases from other utilities and generators.
- Purchase of existing plants, especially efficient gas combined-cycle merchant plants.
- Long-term contract purchases from existing plants.
- Increased purchases from or ownership of new wind farms.

Details of Resources Available as Part of a Switching Strategy

1. Existing Generation of the Owners of BART-eligible Units

Both the OG&E and PSO utilities own gas resources that are significantly underutilized. As shown in Table 1 below, bringing these units to reasonably full output (60% for steam plants and modern combustion turbines and 85% for gas combined-cycle) would produce 41,200 GWh annually, more than twice the annual generation by the six BART-eligible units of about 19,000 GWh.

OG&E owns 2,665 MW of gas-fired steam plants, which operated at an average capacity factor of only about 19% in 2009; 91 MW of modern, high-efficiency combustion turbines, which have operated at capacity factors of 2–5% in recent years;[43] and 1,165 MW of combined-cycle gas, which operated at an average capacity factor of 52%.[44]

PSO owns 2,192 MW of gas-fired steam plants, which operated at an average capacity factor of only about 19% in 2009; about 310 MW of modern, high-efficiency combustion turbines; and 689 MW of combined-cycle gas, which operated at an average capacity factor of 52%. In addition, its sister American Electric Power ("AEP") operating company Southwest Electric Power Company ("SWEPCo"), owns 1,818 MW of gas-fired steam plants and about 290 MW of modern combustion turbines in SPP, which operated at an average capacity factor of only about 30% in 2009. In addition to the steam plants, OGE and PSO/SWEPCo own 91 MW and 604 MW respectively of modern, high-efficiency combustion turbines, which have operated at capacity factors of 2–5% in recent years, but could operate as essentially baseload generators.

These plants could easily operate at higher capacity factors of 60% as to the gas steam plants (most of which were originally designed as baseload units) and the modern combustion turbines (many cogeneration systems and combined-cycle plants use similar combustion turbines in baseload operation) and 85% for the gas combined-cycle units, all

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[43] These combustion turbines are about as efficient as the gas steam plants.

[44] All capacity ratings in these comments are summer capacities from the Energy Information Administration EIA-860 database. Capacity factors are computed from the energy provided in the EIA-923 database.

of which are modern and designed to run as baseload service (generally with great flexibility).

Table 1: Under-Utilized Capacity Owned by OG&E and PSO

Owner	Plant Type	Summer MW	2009 CF	Additional Available GWh
OGE	Combined-Cycle	1,165	52%	3,368
OGE	Gas Steam	2,665	19%	9,572
OGE	Modern CT	91%	5%	438
PSO	Combined-Cycle	689	52%	1,992
PSO	Gas Steam	2,192	19%	12,673
OGE	Modern CT	310	2%	2,254
SWEPCo	Gas Steam	1,818	30%	8,759
SWEPCo	Modern CT	294	1%	2,163
Total				41,219

The cost of increasing output from these plants is limited to the cost of additional fuel. As shown in Table 2, those costs are quite reasonable. Table 2 (1) starts with the prices for Henry Hub gas futures, (2) reduces them 13% to reflect the 2006–2010 ratio of gas prices on the ONEOK system in Oklahoma to the Henry Hub price, and (3) applies heat rates of 9,500 Btu/kWh for steam plants and modern combustion turbines and 7,500 Btu/kWh for combined-cycle plants.

Table 2: Costs of Incremental Energy from Existing PSO and OG&E Plants

	Gas Price $/MMBtu		Electric Energy Cost $/MWh	
	Henry Hub	ONEOK	Gas Steam and New CTs	Combined Cycle
	[1]	[2]	[3]	[4]
Heat Rate (Btu/kWh)			9,500	7,500
2011	$4.34	$4.17	$39.6	$31.3
2012	$4.90	$4.70	$44.6	$35.2
2013	$5.27	$5.06	$48.1	$38.0
2014	$5.61	$5.39	$51.2	$40.4
2015	$5.98	$5.74	$54.5	$43.1
2016	$6.32	$6.06	$57.6	$45.5
2017	$6.60	$6.34	$60.2	$47.5
2018	$6.89	$6.62	$62.9	$49.6
2019	$7.19	$6.90	$65.5	$51.7
2020	$7.48	$7.18	$68.2	$53.8
2021	$7.77	$7.46	$70.9	$56.0
2022	$8.08	$7.76	$73.7	$58.2
2023	$8.35	$8.02	$76.2	$60.2

While they would not normally operate for long periods during the year, OG&E and PSO can call as needed on 134 MW and 163 MW of older, less-efficient owned combustion turbines that now operate at less than 1% capacity factors.[45]

2. Other Existing Generation In and Around Oklahoma

In addition to the generation owned by OG&E and PSO/AEP, a large amount of combined-cycle and steam natural-gas capacity is underutilized in Oklahoma and surrounding areas. The relevant region for this analysis includes SPP, which covers Oklahoma, Kansas, most of Nebraska, and portions of Texas, Arkansas, Missouri, Louisiana, and New Mexico, plus adjacent areas in the remainder of Arkansas and Missouri.[46] This includes about 5,000 MW of gas steam that operated at an average capacity factor of 17% in 2009, 6,800 MW of gas combined-cycle that operated at an average capacity factor of 23%, and at least 1,500 MW of modern combustion turbines

[45] These old peaking units are much less efficient than the new combustion turbines and the steam plants and would be operated only as back-up for other resources.

[46] The transmission system in the remainder of Louisiana and even western Mississippi is managed by SPP, and generation in this area may also be available to Oklahoma utilities, but this area is not included in the analysis below. The non-SPP portions of Texas and New Mexico are parts of the Texas (ERCOT) and Western (WSCC) interconnections, and are not well connected to SPP.

operating at an average capacity factor of 5%.[47] This additional potential generation from underutilized plants totals about 60,000 GWh, nearly three times the energy output of the BART-eligible units.

Table 3: Other Under-utilized Capacity In and Around Oklahoma

Plant Type	Summer MW	2009 CF	Additional GWh
Combined-Cycle	5,000	23%	27,200
Gas Steam	6,800	17%	25,600
Modern CT	1,500	5%	7,200
Total			60,000

Of the combined-cycle capacity, approximately 9,200 MW is owned by merchant generators, as listed in Table 4.[48] This capacity is generally not committed to serving load, and is sold in the spot market or under short-term contracts.

Table 4: Merchant Combined-Cycle Capacity in and around SPP

Plant	Owner	State	Summer Net MW	Capacity Factor
Oneta Energy Center	Calpine Central L P	OK	1,086	32%
Hobbs Generating Station	CAMS NM LLC	NM	526	71%
Evangeline Power Station	Cleco Evangeline LLC	LA	732	32%
Mustang Station	Denver City Energy Assoc LP	TX	486	59%
Dogwood Energy Facility	Dogwood Energy LLC	MO	614	16%
Eastman Cogeneration Facility	Eastman Cogeneration LP	TX	402	57%
Harrison County Power Project	Entergy Power Ventures LP	TX	514	12%
Green Country Energy LLC	Green Country OP Services LLC	OK	783	55%
Kiamichi Energy Facility	Kiowa Power Partners LLC	OK	1,178	51%
Pine Bluff Energy Center	Pine Bluff Energy LLC	AR	192	80%
Union Power Partners LP	Union Power Partners LP	AR	2,020	24%
Hot Spring Power Project	Hot Spring Power Co LLC	AR	642	49%
Trigen St.Louis	Trigen St Louis Energy Corporation	MO	13	37%
TOTAL			9,189	39%

As part of the overall fuel-switching strategy, OG&E or PSO may find that it is cost-effective to purchase some of these plants outright, or to purchase their capacity

[47] To simplify the tabulation of combustion turbines, this total includes only post-1998 combustion turbines in Oklahoma, Arkansas, Kansas, Nebraska and western Missouri. There may be additional efficient modern combustion turbines in these areas, as well as in SPP Texas.

[48] Some of the modern combustion turbine capacity is also owned by merchant generators.

under long-term contracts. A number of the owners of combined-cycle plants have sold all or part of their plants to utilities in recent years, including those in the table below, often at costs well below that of a new gas combined-cycle, which OG&E estimates at $1,003/kW in 2010 dollars, plus financing costs. (OG&E 2011 Integrated Resource Plan, Table 4). Some of the sales are of plants somewhat remote from Oklahoma (geographically and/or electrically); their costs are indicative of the market value of this technology in the mid-south region. Indeed, areas such as ERCOT, Louisiana, and Mississippi would tend to have higher market prices for power and power plants than the locations in Table 4.

Table 5: Sales of Combined-Cycle Plants in and around SPP

Seller	**Plant Name**	**State**	**Closing Date**	**% sold**	**Capacity (MW)[a]**	**Acquirer**	**Purchase Price**	
							$M	$/kW
NRG Energy	McClain	Okla.	7/9/04	77%	377	Oklahoma G&E	$160	$425
CLECo	Perryville	La.	6/30/05	100%	831	Entergy LA	$170	$205
Central Mississippi Generating	Attala	Miss.	3/31/06	100%	500	Entergy MS	$88	$176
Calpine	Aries/Dogwood	Mo.	2/7/07	100%	677	Kelson Energy	$234	$345
Cogentrix Energy	Ouachita	La.	5/4/07	100%	904	Entergy AR	$198	$219
Calpine	Acadia Energy	La.	8/17/07	50%	1,376	Cajun Gas Energy	$189	$137
GE Energy Financial Services	Green Country	Okla.	10/2/07	100%	904	J-Power USA Generation	$240	$265
Cogentrix	Southaven Power	Miss.	5/9/08	100%	904	Tennessee Valley Authority	$461	$510
Kelson	Redbud	Okla.	9/30/08	100%	1,338	Oklahoma Gas & Electric	$339	$253
Tennessee Valley Authority	Southaven Power	Miss.	10/6/08	70%	633	Seven States Power	$345	$545
Acadia Power Partners	Acadia 1	La.	Feb '10		580	CLECo	$304	$524
Kelson	Cottonwood	Texas	Aug '10	100%	1,279	NRG Energy	$525	$410
Calpine	Freestone	Texas	Dec '10	25%	1,038	Rayburn Coop	$215	$830
PSEG	Odessa	Texas	1/13/11		1,000	High Plains Diversified Energy	$687	$344
PSEG	Gaudelupe	Texas	1/13/11		1,000	Wayzata Investment		
Acadia Power Partners	Acadia 2	La.	4/29/11		580	Entergy LA	$300	$517
Sequent	Wolf Hollow	Texas	5/13/11	100%	720	Exelon	$305	$424
KGen Partners	Hinds	Miss.	Mid-2012	100%	520	Entergy AR	$206	$396
KGen Partners	Hot Spring	Ark.	Mid-2012	100%	630	Entergy MS	$253	$408

Notes:

a. Summer capacity reported by owner or EIA.

3. Wind Resources

While some gas capacity will be needed for effective integration of the wind output, it appears that OG&E could replace a significant share of the output of the

BART-eligible units with wind, and save money in the process. Since PSO's generation mix is very similar to OG&E's, additions of wind to PSO's portfolio are likely to be similarly favorable.

Oklahoma and other parts of SPP have enormous potential for wind-farm development. As of July 2010, the SPP transmission interconnection queue included 111 projects, totaling 20,274 MW, plus 7,470 MW of incremental wind development under approved generation interconnection agreements, above the 3,300 MW of wind in service (First Status Report OF Southwest Power Pool, Inc., in Response to Order on Interconnection Queue Reform, Docket No. ER09-1254-000, July 30, 2010.) SPP is engaged in major transmission expansions, to bring additional wind from the western part of the region to the load centers in the east. (2010 SPP Transmission Expansion Plan, pp. 33-34) Clean Line Energy's proposed Plains and Eastern merchant transmission project would bring about 7,000 MW of wind from western Oklahoma through the Oklahoma load centers to Arkansas and Tennessee. Clean Line Energy's proposed Grain Belt Express would bring east another 3,500 MW from Kansas and the Oklahoma panhandle.

Of this tremendous potential, OG&E owns 449 MW of wind and has another 332 MW under contract, while PSO has 198 MW of wind under long-term contract. In its 2011 Integrated Resource Plan, OG&E estimates that the energy cost savings from generic wind additions displacing its current marginal energy supplies—a mix of coal and gas—would have a present value of about $2,600/kW. (IRP, May 2011, p. 32).

Production tax credits ("PTCs"), if they are extended, would provide benefits of another $840/kW. The Crossroads Wind Farm, which OG&E is currently building, is expected to cost $1,760/kW; including financing costs, taxes and operating costs, the present value of the Crossroads Wind Farm cost would be about $2,300, indicating that it will be saving OG&E customers about $300/kW without the PTC and $1,140/kW with the PTC. In the fuel-switching case, OG&E's marginal energy supplies would be somewhat more expensive, suggesting that the benefits of additional wind would be even greater as part of a least-cost plan to replace the energy from the BART-eligible coal units. The OG&E IRP shows the present value benefit of wind purchases increasing by about $280/kW in the fuel-switching case, for a total value of $580/kW for a facility like the Crossroads Wind Farm without the PTC and $1,420/kW with the PTC.

4. Utility Energy Efficiency Programs

Energy-efficiency programs funded through utility rates and implemented by the utility, state agencies or contractors have become a common and important part of plans for meeting customer loads while minimizing costs and environmental impacts. In many situations, electric energy-efficiency portfolios have consistently achieved annual electric energy savings exceeding one percent of total annual sales, with those savings continuing over many years. The leading efficiency administrators have been realizing annual electric energy savings of more than 1.5% of electric energy sales, as summarized in Table 6. These incremental annual savings accumulate over time, so that Connecticut's 2004–2010 savings, for example, have reduced 2010 sales by about 7.5% of sales.

Table 6: Incremental Annual Energy Usage Reduction Through Efficiency Programs, Selected States

State	2004	2005	2006	2007	2008	2009	2010
CA	0.9%	1.6%	0.9%	1.8%	2.5%	1.8%	
CT	1.0%	1.0%	1.1%	1.0%	1.2%	0.8%	1.4%
IA	0.6%	0.7%	0.8%	0.8%	0.9%	1.2%	1.2%
MA	0.9%	0.9%	1.0%	1.2%	1.0%	1.1%	1.3%
ME			0.5%	0.7%	0.9%	0.7%	0.8%
NJ	0.4%	0.5%	0.2%	0.3%	0.4%	0.6%	
NY	0.2%	0.6%	0.6%	0.5%	0.7%	0.6%	0.8%
RI		0.8%	1.2%	1.0%	0.8%	1.1%	1.1%
VT	0.8%	0.9%	0.9%	1.6%	2.3%	1.5%	2.0%
WI						0.6%	0.5%

Notes: Not all states have reported 2010 results. New York data are difficult to compile after 2007, due to changes in reporting and program responsibility. New York expenditures and goals increased dramatically in 2009. NY 2008-2010 values are for LIPA

Plans for 2011 and beyond are even more ambitious, with Massachusetts investor-owned utilities committed to savings of 2.4% annually by 2012 and a total of about 17% of 2020 sales (just from program activities in 2010 through 2020). In late 2010, Oklahoma's neighboring state Arkansas, which is served in part by OG&E and PSO's affiliate SWEPCo, established electric-utility efficiency goals of 0.25% of energy use in 2011, 0.50% in 2012, and 0.75% in 2013 (Docket No. 08-137-U, Order No. 15, December 10, 2010, p. 18). These savings have been quite inexpensive. Leading efficiency program administrators have spent on average about $0.24 to save a kWh each year for an average of about 12 years, or only about 2¢/kWh saved.

OG&E and PSO could easily replicate best practices in financial, marketing, and technical strategies employed by the nation's leading program administrators and achieve comparable results. In 2010, OG&E started offering a limited portfolio of residential and commercial efficiency programs in Oklahoma, which it is only committed to running through 2012. Even this very tentative first step is projected to reduce 2012 energy sales by 144 GWh or 0.63 percent. OG&E could continue ramping up its initial pilot programs over the next few years to reach the levels achieved by the leading efficiency portfolios. Meeting SWEPCo's goals in Arkansas through 2013 would be a significant step in this direction. While PSO is starting somewhat behind OG&E in this regard, PSO can build on staff experience of its affiliate in Arkansas, and adopt program designs and materials developed by OG&E and SWEPCo.

If OG&E matched the performance of the leading group of efficiency portfolios in other states by saving 1 percent of forecast sales per year, it would displace the need for 1,200 GWh/year of energy generation after 5 years and 2,100 GWh/year after 10, even after allowances for gradual decline in installed measures over time. At a savings rate of 1.5% of annual sales, OG&E could reduce electric energy requirements by 1,800

GWh/year after 5 years and 3,100 GWh/year (roughly the output of one of the Muskogee or Sooner coal units) after 10 years. Given the experience in other jurisdictions, OG&E and PSO should be able to reach the 1% annual incremental savings level by 2015 and 1.5% annual savings soon thereafter. Those same energy-efficiency programs would reduce OG&E's need for capacity by about 300–500 MW (or up to one BART-eligible unit) by 2017 and 500–700 MW by 2022.

Since PSO is a smaller utility than OG&E, and since PSO would take somewhat longer to ramp up its programs, its savings would be 25%–30% lower than OG&E's. Even so, efficiency programs could reduce energy requirements by the equivalent of a significant portion of a Northeastern coal unit.

Feasibility of Scrubber Option

Retrofitting of scrubbers is now routine in the US. Some 290 coal-fired units totaling about 116,000 MW nationwide have been retrofit with scrubbers since 1990. These retrofits have included units in 35 states, with unit sizes ranging from under 20 MW to 1,300 MW, installed in 1943 through 1996.

Three Years is a Reasonable Length of Time to Install Scrubbers

Sierra Club supports EPA's finding that three years is enough time for installation of dry scrubbers on the six BART-eligible units. EPA is required under the Clean Air Act to adopt a compliance deadline that reflects expeditious installation of pollution controls. Under the guidelines, "each source subject to BART [is] required to install and operate BART as expeditiously as practicable, but no later than five years after the date of EPA's approval."[49] (emphasis added). Three years of time from the effective date of the final rule is a reasonable length of time to install the required pollution controls and comply with these emission limitations.

The companies subject to this rule are currently on notice that they will have to comply within three years of EPA promulgation of a final rule. So, as of today, they have more than three years to comply. Engineering studies and planning can begin now.

There are numerous examples of SO_2 scrubbers being installed at coal-fired power plants within a three year timeframe. For example, a new SO_2 scrubber was installed at the Brandon Shores power plant, and according to the company's website, construction took three years.[50] American Electric Power completed construction of a scrubber at its John Amos power plant Unit 3 in three years.[51] TVA installed new SO_2 scrubbers at its Bull Run and Kingston power plants in about three years as well.[52]

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[49] 40 CFR 51.308(e)(1)(iv).
[50] *See* http://www.constellation.com/SocialResponsibility/EnvironmentalPerformance/Pages/BrandonShoresScrubber.aspx.
[51] *See* http://statejournal.com/story.cfm?func=viewstory&storyid=54167&catid=283.
[52] *See* http://www.knoxnews.com/news/2008/nov/21/new-scrubber-at-bull-run-plant-may-help-improve/. *See also* http://msbusiness.com/blog/2010/06/tva-puts-new-scrubbers-in-operation/.

Installations of SO_2 scrubbers have even been accomplished in less than three years. For example, Indianapolis Power & Light installed an SO_2 scrubber at Unit 7 of its Harding Street Station in less than three years, with construction beginning in May 2005 and being completed in September 2007.[53] A new scrubber was installed at Gulf Power Company's Plant Crist to scrub the SO_2 from 4 coal-fired boilers in less than three years from engineering design of the scrubber to operation.[54]

These are but a few of numerous such examples that SO2 scrubbers can be installed in three years or less time. Accordingly, EPA has often required scrubber installation to occur in three years or less time in its settlement agreements for purported Clean Air Act violations at coal-fired EGUs. For example, the December 2008 Consent Decree regarding Salt River Project's Coronado station required installation and operation of an SO_2 scrubber at Unit 1 by January 1, 2012 which essentially reflects three years for design, construction, and operation.[55] The October 2007 consent decree with American Electric Power requires SO2 scrubbers to be installed and operational at numerous of the units coal-fired EGUs within three years or less of the date of the settlement agreement, including John Amos Units 1, 2, and 3, Cardinal Units 1 and 2, Conesville Unit 4, Mitchell Units 1 and 2, and Mountaineer Unit 1.[56]

These examples and others provide ample support that three years for installation of SO2 controls and compliance with EPA's proposed BART limits is reasonable. In fact, these examples show that a BART compliance deadline for SO2 controls that went any longer than three years would not comport with the Clean Air Act requirement that BART be met as expeditiously as practicable.

Given the broad superiority of the switching option over the scrubbing option, Sierra Club would accept the extension of the compliance period for switching to five years.

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[53] *See* Indianapolis Power & Light Company (IPL)Harding Street Station Unit 7 Scrubber Fact Sheet, available for download from http://www.iplpower.com/ipl/index?page=IPLGeneral&Menu=06000000&DocID=02039b33d0a010bcb031eea007b7f.

[54] Specifically, the award for engineering and design was awarded in May 2007 (see http://www.bv.com/wcm/press_release/05072007_1374.aspx), and the scrubber came on-line and was operational at the end of 2009 (see http://www.gulfpower.com/about/plant_crist.asp).

[55] *See* Salt River Project Agricultural Improvement and Power District Clean Air Act Settlement, Consent Decree at 15, available at http://www.epa.gov/compliance/resources/decrees/civil/caa/srp-cd.pdf.

[56] *See* American Electric Power Service Corporation Settlement, Consent Decree at 29-30, available at http://www.epa.gov/compliance/resources/decrees/civil/caa/americanelectricpower-cd.pdf.

The Oklahoma Facilities are Causing Violations of the One-Hour SO2 NAAQs

Sierra Club performed air dispersion modeling demonstrating that the SO_2 emissions from these sources are also causing violations of the one-hour SO_2 National Ambient Air Quality Standard ("NAAQS"). While USEPA's FIP and proposed SO_2 BART pertains to regional haze, the existing SO_2 NAAQS violations from the OG&E Muskogee and Sooner facilities, and the AEP/PSO Northeastern plant, will require that Oklahoma prepare a SIP demonstrating an adequate program to implement, maintain, and enforce the SO_2 NAAQS. The Clean Air Act requires that Oklahoma prepare the SO_2 NAAQS SIP by June 3, 2013.[57] USEPA's proposed SO_2 BART will have multiple benefits, including likely compliance of the one-hour SO_2 NAAQS from these subject facilities.

The one-hour SO_2 NAAQS takes the form of a three-year average of the 99th-percentile of the annual distribution of daily maximum one-hour concentrations, which cannot exceed 75 ppb.[58] This standard is to be verified using USEPA's AERMOD air dispersion model, which produces air concentrations in units of $\mu g/m^3$. The one-hour SO_2 NAAQS of 75 ppb is equal to 196.5 $\mu g/m^3$. The 99th-percentile of the annual distribution of daily maximum one-hour concentrations corresponds to the fourth-highest value at each receptor for a given year. The modeling methods we used, and the model results, are discussed below.

General Modeling Approach for SO_2 NAAQS Compliance

Sierra Club used USEPA's AERMOD v. 11103 for our dispersion modeling analysis, which is the most recent version of the model. This version also includes the output option MXDYBYYR, which greatly facilitates the information needed to determine compliance with the form of the one-hour SO_2 NAAQS. Sierra Club's modeling results are based on the fourth-highest value at each receptor in the MXDYBYYR output files, averaged over the number of years modeled.

Sierra Club's modeling results, however, do not include impacts from other nearby SO_2 NAAQS-consuming sources, nor do they include regional background levels. Accordingly, these modeled impacts are most certainly under-estimating actual total air concentrations. Moreover, the modeled impacts presented below are caused solely by each facility's SO_2 emissions.

Sierra Club developed terrain elevations for the modeled sources and receptors using USEPA's AERMAP program (v. 11103). Terrain elevation data were extracted from NED files covering the regions of interest. Sierra Club first modeled receptors in a grid

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[57] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, March 24, 2011, p. 3.

[58] USEPA, Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010.

with 200-meter spacing, and then modeled refined receptor grids with 50-meter spacing in the areas of highest initial modeled impacts.

Sierra Club also developed meteorological data for modeling each of the three BART-subject facilities. Using AERMET v. 11059, Sierra Club created AERMOD-ready surface and profile meteorological data files for years 2005 through 2009 for each facility. Surface data inputs to AERMET include Integrated Surface Hourly data ("ISHD") files and one-minute ASOS data obtained from the National Climatic Data Center ("NCDC"). The ISHD data are included in yearly ISHD DVDs sold directly by NCDC. The one-minute ASOS data were downloaded from NCDC's website, and processed with USEPA's AERMINUTE program (v. 11059).[59]

Sierra Club supplemented the ISHD files with one-minute ASOS data to reduce the number of calm hours typically found in hourly airport ASOS data. In their modeling guidance for SO_2 NAAQS designations, USEPA addresses the concern of calm hours in verifying compliance with the one-hour SO_2 NAAQS:

> In AERMOD, concentrations are not calculated for variable wind (i.e., missing wind direction) and calm conditions, resulting in zero concentrations for those hours. Since the SO_2 NAAQS is a one hour standard, these light wind conditions may be the controlling meteorological circumstances in some cases because of the limited dilution that occurs under low wind speeds which can lead to higher concentrations. The exclusion of a greater number of instances of near-calm conditions from the modeled concentration distribution may therefore lead to underestimation of daily maximum 1-hour concentrations for calculation of the design value.
>
> To address the issues of calm and variable winds associated with the use of NWS meteorological data, EPA has developed a preprocessor to AERMET, called AERMINUTE (U.S. EPA. 2011a) that can read 2-minute ASOS winds and calculate an hourly average. Beginning with year 2000 data, CDC has made freely available, the I-minute winds, reported every minute from the ASOS network. The AERMINUTE program reads these 2-minute winds and calculates an hourly average wind. In AERMET (U.S. EPA, 2004c), these hourly averaged winds replace the standard observation time winds read from the archive of meteorological data. This results in a lower number of calms and missing winds and an increase in the number of hours used in averaging concentrations.[60]

Upper air data for AERMET input are in Forecast Service Lab ("FSL") format, and are available by downloading from the National Oceanic and Atmospheric

[59] ftp://ftp.ncdc.noaa.gov/pub/data/asos-onemin/
[60] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, p. 19.

Administration ("NOAA") website.[61] Upper-air data are collected by a weather balloon that is released twice per day at selected locations (Norman, Fort Sill, and Lamont in Oklahoma). As the balloon is released, it rises through the atmosphere, and radios the data back to the surface. The measuring and transmitting device is known as either a radiosonde or rawindsonde. Data collected and radioed back include: air pressure, height, temperature, dew point, wind speed, and wind direction.

Micrometeorological parameters required for AERMET stage 3 processing were developed using USEPA's AERSURFACE program (v. 08009). The determining site characteristics are the micrometeorological parameters known as albedo, Bowen ratio, and surface roughness. Albedo is the fraction of total incident solar radiation reflected by the surface back to space (whiter surfaces have higher albedo). The Bowen ratio is an indicator of surface moisture. It is the ratio of sensible heat flux to latent heat flux and drier areas have a higher Bowen ratio. Surface roughness, shown in shorthand as ("z_0"), is an essential parameter in estimating turbulence and diffusion. Technically, it's the height above the ground that the log wind law extrapolates to zero. In essence, z_0 can be thought of as a measure of how much the surface characteristics interfere with the wind flow. Very smooth surfaces, like short grass or calm ponds, have very low values of z_0 – on the order of 0.01 meter or less. Tall and irregular surfaces, which are a greater obstacle to wind flow, have higher values of z_0 – up to 1.0 meter or more for forests.

Using AERSURFACE, Sierra Club extracted albedo, Bowen ratio, and surface roughness data from 1992 land use and land cover data for Oklahoma. Sierra Club used average moisture conditions, seasonal periods, and 60-degree sectors for AERSURFACE processing.

While BART visibility modeling analyses use actual 24-hour emissions, compliance with the one-hour SO_2 NAAQS must rely on maximum allowable emissions or federally enforceable permit limits. From USEPA's Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards:

> Consistent with past SO_2 modeling guidance (Section 4.5.2 of U.S. EPA (1994)) and regulatory modeling for other programs (Appendix W, Section 8.1), dispersion modeling for the purposes of designations should be based on the use of maximum allowable emissions or federally enforceable permit limits. Also consistent with past and current guidance, in the absence of allowable emissions or federally enforceable permit limits, potential to emit emissions (i.e., design capacity) should be used. Because of the short-term nature of the new SO_2 NAAQS, the maximum short term or hourly emission rate should be input into AERMOD for each modeled hour.[62]

[61] http://esrl.noaa.gov/raobs/

[62] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, March 24, 2011, p. 9.

Accordingly, Sierra Club's one-hour SO_2 NAAQS compliance used allowable SO_2 emissions for each of the subject facilities modeled.

The OG&E Muskogee Facility is Causing Violations of the One-Hour SO_2 NAAQS

Sierra Club prepared a one-hour SO_2 NAAQS compliance modeling analysis of OG&E's Muskogee facility SO_2 emissions. Sierra Club modeled SO_2 emissions from units 4, 5, and 6 as follows:

Source	XUTM (m)	YUTM (m)	THT (m)	Q (g/s)	Q (lb/hr)	HS (m)	TS (K)	VS (m/s)	DS (m)
Unit 4	293097.8	3959945.8	156.21	828.576	6576.00	106.68	402.04	17.13	7.32
Unit 5	293152.3	3959955.7	156.76	828.576	6576.00	106.68	402.04	17.13	7.32
Unit 6	293225.2	3959976.2	156.95	828.576	6576.00	152.40	402.04	24.84	6.55

The SO_2 emission rates are based on permitted emission limits of 1.2 lb/MMBTU, and a boiler heat input of 5,480 MMBTU/hr for each unit.[63] Sierra Club obtained UTM source coordinates using ESRI's ArcGIS geographic information system and NAIP orthoimagery. Stack parameters for units 4, 5, and 6 were developed using USEPA's Non-Hg Case Study Chronic Inhalation Risk Assessment for the Utility MACT, which included AERMOD modeling for all three of OG&E's Muskogee coal-fired units.[64] Unit 6, which ODEQ determined is not BART-eligible, was not included in the BART modeling analysis. It is, however, a NAAQS-consuming source that must be included in any one-hour SO_2 NAAQS compliance modeling.

Sierra Club modeled OG&E Muskogee's SO_2 emissions using 2005 through 2009 surface ISHD and one-minute ASOS data from Muskogee, OK, as described above. Sierra Club used 2005 through 2009 FSL upper-air data from Norman, OK in Sierra Club AERMOD modeling analysis of this facility.

Sierra Club did not have detailed OG&E Muskogee plot plans which would provide building dimensions and locations. Using oblique GIS orthoimagery and elevation photos, it appears that building downwash may be a factor for the Muskogee facility. Using available images, we developed estimated inputs for USEPA's Building Profile Input Program for PRIME (BPIPPRM), a program that calculates projected building dimensions for AERMOD's downwash algorithms.

For this scenario, units 4, 5, and 6, with building downwash, OG&E Muskogee's SO_2 emissions result in a 1,158.5 $\mu g/m^3$ five-year average fourth-highest daily maximum one-hour SO_2 concentration. This is a violation of the one-hour SO_2 NAAQS, which

[63] ODEQ, Air Quality Division, Permit Memorandum, Evaluation of Permit Application No. 97-136-TV (M-4), Oklahoma Gas and Electric Muskogee Generating Station, June 16, 2006. See also, ODEQ, Air Quality Division, BART Application Analysis, Oklahoma Gas and Electric Muskogee Generating Station, January 15, 2010, p. 2.
[64] USEPA, Non-Hg Case Study Chronic Inhalation Risk Assessment for the Utility MACT, Appropriate and Necessary Analysis, March 16, 2011, p. 6.

occurs solely due to emissions from OG&E's Muskogee three coal-fired units. These results are summarized in the following table.

H4H Conc. ($\mu g/m^3$)	One-Hour SO_2 NAAQS ($\mu g/m^3$)	XUTM (m)	YUTM (m)
1158.51	196.50	293450	3960950

As a sensitivity analysis, Sierra Club modeled OG&E's Muskogee coal-fired units 4 and 5 with downwash inputs to AERMOD. For this scenario, OG&E Muskogee's SO_2 emissions result in a 1086.0 $\mu g/m^3$ five-year average fourth-highest daily maximum one-hour SO_2 concentration. While Sierra Club believes this is a significantly under-predicted modeled air impact, it demonstrates that OG&E's Muskogee BART-eligible units 4 and 5 are violating the one-hour SO_2 NAAQS. As before, these impacts occur solely due to SO_2 emissions from OG&E's Muskogee facility (and without emissions from unit 6). These results are summarized in the following table.

H4H Conc. ($\mu g/m^3$)	One-Hour SO_2 NAAQS ($\mu g/m^3$)	XUTM (m)	YUTM (m)
1085.97	196.50	293400	3960800

As a further sensitivity analysis, we also modeled OG&E's Muskogee coal-fired units 4, 5, and 6 without any downwash inputs to AERMOD. For this scenario, OG&E Muskogee's SO_2 emissions result in a 534.6 $\mu g/m^3$ five-year average fourth-highest daily maximum one-hour SO_2 concentration. While Sierra Club believes this is a significantly under-predicted modeled air impact, it demonstrates that even without downwash inputs, OG&E's Muskogee units 4, 5, and 6 are violating the one-hour SO_2 NAAQS. As before, these impacts occur solely due to SO_2 emissions from OG&E's Muskogee facility. These results are summarized in the following table.

H4H Conc. ($\mu g/m^3$)	One-Hour SO_2 NAAQS ($\mu g/m^3$)	XUTM (m)	YUTM (m)
534.55	196.50	291200	3956600

The OG&E Sooner Facility is Causing Violations of the One-Hour SO_2 NAAQS

Sierra Club prepared a one-hour SO_2 NAAQS compliance modeling analysis of OG&E's Sooner facility SO_2 emissions. Sierra Club modeled SO_2 emissions from units 1 and 2 as follows:

Source	XUTM (m)	YUTM (m)	THT (m)	Q (g/s)	Q (lb/hr)	HS (m)	TS (K)	VS (m/s)	DS (m)
Unit 1	674574	4036110	286.15	773.539	6139.20	152.44	430.78	34.12	6.10
Unit 2	674500	4036141	286.36	773.539	6139.20	152.44	430.78	34.12	6.10

The SO_2 emission rates are based on permitted emission limits of 1.2 lb/MMBTU, and a boiler heat input of 5,116 MMBTU/hr for each unit.[65] Sierra Club obtained UTM source coordinates using ESRI's ArcGIS geographic information system and NAIP orthoimagery. Stack parameters for units 1 and 2 were developed using USEPA's CALPUFF BART visibility improvement modeling input files.

Sierra Club modeled OG&E Sooner's SO_2 emissions using 2005 through 2009 surface ISHD and one-minute ASOS data from Stillwater, OK, as described above. Sierra Club used 2005 through 2009 FSL upper-air data from Lamont, OK in our AERMOD modeling analysis of this facility.

Sierra Club did not have detailed OG&E Sooner plot plans which would provide building dimensions and locations. Using oblique GIS orthoimagery and elevation photos, it appeared that building downwash may be a factor for the Sooner facility. Using available images, we developed estimated inputs for USEPA's Building Profile Input Program for PRIME (BPIPPRM), a program that calculates projected building dimensions for AERMOD's downwash algorithms. Our modeling analysis with estimated building dimensions, however, found equivalent results with both estimated downwash and no-downwash modeling scenarios.

For this scenario, OG&E Sooner units 1 & 2 SO_2 emissions result in a 199.1 $\mu g/m^3$ five-year average fourth-highest daily maximum one-hour SO_2 concentration. This is a violation of the one-hour SO_2 NAAQS, which occurs solely due to emissions from OG&E's Sooner coal-fired units. These results are summarized in the following table.

H4H Conc. ($\mu g/m^3$)	One-Hour SO_2 NAAQS ($\mu g/m^3$)	XUTM (m)	YUTM (m)
199.08	196.50	672400	4038900

[65] ODEQ, Air Quality Division, Permit Memorandum, Evaluation of Permit Application No. 2003-274-TVR, Oklahoma Gas and Electric Sooner Generating Station, February 7, 2006. See also, ODEQ, Air Quality Division, BART Application Analysis, Oklahoma Gas and Electric Sooner Generating Station, January 15, 2010, p. 2.

The AEP/PSO Northeastern Facility is Causing Violations of the One-Hour SO_2 NAAQS

Sierra Club prepared a one-hour SO_2 NAAQS compliance modeling analysis of AEP/PSO Northeastern facility SO_2 emissions. We modeled SO_2 emissions from units 3 and 4 as follows:

Source	XUTM (m)	YUTM (m)	THT (m)	Q (g/s)	Q (lb/hr)	HS (m)	TS (K)	VS (m/s)	DS (m)
Unit 3	257863	4035131	195.21	878.774	6974.40	183.00	424.00	18.97	8.23
Unit 4	257863	4035162	195.42	845.813	6712.80	183.00	415.00	17.46	8.23

The SO_2 emission rates are based on permitted emission limits of 1.2 lb/MMBTU, and a boiler heat input of 5,812 MMBTU/hr for unit 3 and 5,594 MMBTU/hr for unit 4.[66] We obtained UTM source coordinates using ESRI's ArcGIS geographic information system and NAIP orthoimagery. Stack parameters for units 3 and 4 were developed using USEPA's CALPUFF BART visibility improvement modeling input files.

Sierra Club modeled AEP/PSO Northeastern's SO_2 emissions using 2005 through 2009 surface ISHD and one-minute ASOS data from Tulsa, OK, as described above. Sierra Club used 2005 through 2009 FSL upper-air data from Norman, OK in Sierra Club's AERMOD modeling analysis of this facility.

Sierra Club did not have detailed AEP/PSO Northeastern plot plans which would provide building dimensions and locations. Using oblique GIS orthoimagery and elevation photos, it does not appear likely that building downwash is a factor for the Northeastern facility. Thus, Sierra Club's modeling analysis did not include building downwash inputs for this facility.

For this scenario, AEP/PSO Northeastern 3 & 4 SO_2 emissions result in a 259.3 $\mu g/m^3$ five-year average fourth-highest daily maximum one-hour SO_2 concentration. This is a violation of the one-hour SO_2 NAAQS, which occurs solely due to emissions from AEP/PSO Northeastern's coal-fired units. These results are summarized in the following table.

[66] ODEQ, Air Quality Division, Permit Memorandum, Administrative Amendment to Permit No. 2003-410-TVR (M-2), American Electric Power, Public Service Company of Oklahoma, Northeastern Power Station, August 9, 2010. See also, ODEQ, Air Quality Division, BART Application Analysis, AEP-Public Service Company of Oklahoma, Northeastern Power Plant, January 19, 2010, p. 2.

H4H Conc. (µg/m^3)	One-Hour SO_2 NAAQS (µg/m^3)	XUTM (m)	YUTM (m)
259.31	196.50	254550	4033400

Nitrous Oxide (NOx) BART

Under these specific circumstances, Sierra Club supports EPA's determination that low-NOx burners are appropriate as BART. In most cases, we support BART limits that reflect the use of Selective Catalytic Reduction ("SCR") and a .035 lbs/MMBTU limit. Here, EPA proposes to accept Oklahoma's BART emission limit of .15 lbs/MMBTU based on what can be achieved with low-NOx burners ("LNBs") with overfire air ("OFAs"). Low-Nox burners with OFA controls can achieve roughly 50-70% NOx reduction, compared with 90% reduction that SCR can achieve. However, in this case, both Oklahoma and EPA found that the additional visibility benefits from SCR are not justified by the additional cost of that control.[67]

EPA's proposed NOx emissions limit meets the BART presumptive limit; however, we note that presumptive BART limits are intended as guideposts, not de facto standards suitable for adoption by all BART-eligible sources. EPA's BART guidelines include presumptive BART emission limits for EGUs which were based on EPA's broad review of the control technologies and emission limits that could be met cost effectively at a wide range of coal-fired power plants. The presumptive BART limits developed by the previous administration did not consider impacts on visibility and were set at the least-stringent end of the range of potential limits. In addition, the cost thresholds used to support those limits were far below the costs generally accepted in Best Available Control Technology Analyses.

In most cases, Sierra Club supports BART limits that reflect the use of SCR and a .035 lbs/MMBTU limit. SCR technologies are the industry standard and EPA recognizes that they "are routinely designed and have routinely achieved a NOx control efficiency of 90%."[68] The EPA recently proposed a NOx limit of 0.05 lbs/mmbtu for the San Juan Generating Station in New Mexico, but this limit was based on 83% instead of the well-accepted 90% removal efficiency.

For example,in Sierra Club's comments on the San Juan Generating Station, Sierra Club submitted a technical basis, including support from major catalyst vendors, to show that 90% removal efficiency is feasible and should be required. Sierra Club also provided evidence showing that an emission rate of 0.035 lbs/mmbtu is being achieved at other units, even without a permit limit requiring it. Furthermore, in three years (when SJGS will be required to meet the new limit under EPA's proposal), SCR technology will

[67] EPA's Technical Support document, page 42.
[68] See, e.g., EPA's Technical Support Document for San Juan Generating Station at p. 30.

improve to even greater levels of efficiency than exist today, thereby making a limit of 0.035lb/mmbtu not only reasonable, but also a modest standard.[69]

Particulate Matter (PM) BART

Under these specific circumstances, Sierra Club supports EPA's determination that existing Electrostatic Precipitators ("ESPs") and a 0.1lbs/MMBTU emissions limit is appropriate as BART for particulate matter. In most cases, we support fabric filters and baghouses for PM control and an emissions limit of at least 0.015 lb/MMBTU. Arizona's proposed regional haze SIP includes this BART emissions limit for Cholla Units 2, 3 and 4.[70] EPA required as BACT at the Desert Rock facility a 0.010 lb/MMBtu emissions limit, along with an opacity limit no higher than 10% to show continuous compliance with the particulate matter BART limits.[71]

Here, EPA proposes to accept Oklahoma's BART emission limit of 0.1 lbs/MMBTU based on what can be achieved with existing ESPs. Fabric filters (or baghouses) can achieve better control than ESPs, however, in this case, both Oklahoma and EPA found that the additional visibility benefits are not justified by the additional cost of that control.[72]

Installing baghouses would also achieve better SO_2 controls. The addition of a baghouse will improve SO_2 removal efficiency because of less pluggage of particulate in the scrubber and improved liquid-to-gas contact.

The forthcoming Maximum Achievable Control Technology ("MACT") standards for electrical generating steam generating units ("EGUs") will likely require baghouses for the units at issue.[73] The Oklahoma units would be subject to a mercury emission limit of 0.008 lb/GWh.[74] EPA's Toxic Release Inventory provides that Sooner's mercury emissions for 2009 were 0.031lbs/GWh; Muskogee 0.031 lbs/GWh; and Northeastern 0.029 lbs/GWh.[75] To achieve a 0.008 lb/GWh emissions rate, the plants will require a new PM control in order to lower their emissions by more than 30%. It is well known that coal-fired boilers equipped with baghouses achieve better control of mercury than those equipped with ESPs. Mercury control at bituminous coal-fired

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69 See San Juan Citizens Alliance et al. Comments to EPA on EPA Docket No. EPA-R06-OAR-2010-0846 (Apr. 4, 2011).

70 Arizona DEQ, Plans, Regional Haze and Visibility, Cholla BART analysis (Jan. 2008), *available at* http://www.azdeq.gov/environ/air/haze/index.html

71 See 75 Fed.Reg. 64221, 64223 (October 19, 2010).

72 *E.g.,* EPA's Technical Support document, page 42.

73 76 Fed. Reg. 24976, available at http://www.epa.gov/ttn/atw/utility/utilitypg.html

74 76 Fed. Reg. 24976, 25127, TABLE 2 TO SUBPART UUUUU OF PART 63. Powder River Basin coal, which is the type of coal burned at these units, typically has a heat value in excess of 8300 Btu/lb.

75 TRI: http://www.epa.gov/tri/
EIA: http://www.eia.doe.gov/cneaf/electricity/page/eia423.html
Formula: lbs Hg/(net generation (mwh)/1000).

boilers with a cold-side ESP and a wet scrubber averaged 81% as compared to 98% control achieved with a baghouse and wet scrubber.[76]

Updated PM controls may also be necessary at the Oklahoma units to meet EPA's proposed PM limit for non-mercury metal hazardous air pollutants ("HAPs"). EPA assumed many coal-fired power plants would need to be retrofitted with baghouses to meet the total PM limit in its regulatory impact analysis for the proposed MACT rule.[77] The compliance timeframe of the EGU MACT rule will be similar to BART. EPA is required to finalize its EGU MACT rule by November 16, 2011. Under the proposed MACT rule (and as required by the Clean Air Act), existing sources will be required to comply with the MACT rule within three years of promulgation – or by approximately the end of 2014 which is about the same timeframe that would be required to meet BART requirements.

Ammonia and Sulfuric Acid Mist Bart

Sierra Club requests that EPA set emission limits for ammonia similar to those proposed for the San Juan Generating Station BART rulemaking.[78] Ammonia emissions are important because they react with SO_2 and NOx to form ammonium sulfate and ammonium nitrate particles, which are very effective in impairing visibility. States must exercise "best judgment to determine whether VOC or ammonia emissions from a source are likely to have an impact on visibility in the area." 70 FR 39162. Thus, Sierra Club requests that EPA set the ammonia emission limit at a rate no higher than the 2.0 parts per million as proposed at San Juan. We also support requiring installation of CEMs to monitor this pollutant.

Sierra Club also requests that EPA set an emission limit for sulfuric acid mist, as it proposed as part of the San Juan Generating Station BART rulemaking.[79] Sierra Club urges EPA to set an emission rate no higher than the 1.06 x 10-4 lb/MMBtu for each unit as proposed at San Juan. Sierra Club agrees that this rate is supportable based on use of low reactivity catalyst and the most current information from the Electric Power Research Institute. If continuous emission monitors are technically infeasible for this pollutant, we also urge EPA to require stack test monitoring on a more frequent basis than annual monitoring. EPA should clarify whether the set emission limit is required under the regional haze program as part of a BART determination for the facility, and must be complied with within 3 years of the date of the final rule.

[76] US EPA, Performance and Cost of Mercury and Multi-Pollutant Emission Control Technology Applications on Electric Utility Boilers, EPA-600/R03-110 (October 2003) at 7.
[77] EPA, Regulatory Impact Analysis of the Proposed Toxics Rule, available at http://www.epa.gov/ttn/atw/utility/utilitypg.html
[78] 76 Fed.Reg. 503-4 (January 5, 2011).
[79] 76 Fed.Reg. 503-4 (January 5, 2011).

Conclusion

Thank you for the opportunity to submit comments on EPA's proposed regional haze FIP for Oklahoma. Please consider all comments for the final rule. As described above, Sierra Club typically finds that wet scrubbers constitute BART for sulfur dioxide, selective catalytic reduction for nitrous oxides, and baghouses for particulate matter. However, under these particular circumstances, Sierra Club supports EPA's proposed FIP requiring dry scrubbers, low-NOx burners with OFA, and Electrostatic Precipators.

We ask that EPA approve the proposed FIP and provide Oklahoma with compliance options of: installing dry scrubbers within three years; switching to gas; or, decommissioning units within five years.

Sincerely,

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On behalf of Sierra Club and WildEarth Guardians