# APPENDIX K

## Summary of  Public Comments and Staff Responses

**OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY**

**SUMMARY OF PUBLIC COMMENTS AND STAFF RESPONSES**
**OKLAHOMA'S PLANNING PERIOD 2 REGIONAL HAZE SIP**

**COMMENTS RECEIVED DURING PUBLIC COMMENT PERIOD**
**JUNE 1, 2022 THRU JULY 1, 2022**

**Written Comments**

**U.S. Environmental Protection Agency** – Submitted as an attachment to an email received on July 1, 2022, from Mr. Michael Feldman, Chief, $SO_2$ and Regional Haze Section, State Planning Implementation Branch, U.S. EPA Region 6.

**1.** **COMMENT:** **Pollutants and Source Categories Evaluated** – The Regional Haze Rule requires states to consider evaluating major and minor stationary sources, mobile sources, and area sources in developing its long-term strategy. 40 CFR 51.308(f)(2)(i). Section 4 of the SIP narrative states that "NOx emissions are not dominated by one source category, but instead are heavily contributed to by the point, nonpoint, and on-road sectors." (See page 20 of SIP narrative). Section 4 also notes that that the proportion of NOx emissions attributable to nonpoint sources increased slightly from 2014 to 2017. Given the large proportion of Oklahoma's NOx emissions attributable to oil and gas nonpoint sources, we encourage ODEQ to reconsider whether it would be appropriate and reasonable to evaluate potential NOx control strategies for nonpoint sources in a four-factor analysis. The four-factor analyses can be for individual sources or large groups of sources or sectors, where appropriate.

**RESPONSE:** States have the discretion to determine which sources will be evaluated and the rule requires that states describe the criteria used to determine which sources are evaluated (see 40 CFR 51.308(f)(2)(i)). A four-factor analysis involves consideration of costs, necessary time, energy effects and environmental effects other than air quality, and the useful life of the facility. In most cases, EPA guidance suggests using 30 years as the useful life of a facility and when considering the necessary time only to set a timetable for installing any controls. Few control strategies negatively affect the environment as a whole. Therefore, the results of the four-factor analysis most commonly and critically depend on the economic costs of control. Notably, the language of the regulation does not exclude the consideration of unquantifiable or noneconomic costs, or economic costs that persons or entities other than owners or operators of facilities may bear. In the case of petroleum and natural gas sources, DEQ also must consider very carefully the energy effects of any regulation, especially considering the scale of the contribution of the industry in the state to the North American and global fuel supply.

Finally, DEQ is unaware of any inexpensive and effective technologies to reduce $NO_x$ emissions from large numbers of small petroleum and natural gas sources beyond those already widely adopted control techniques. An expensive control regime would lead to a diminution of petroleum and natural gas production and an increase in prices on local and global markets. In the months before the due date for the submission of this implementation plan revision, reliable economists anticipated large and rapid increases in these costs even before any controls that this plan might adopt.

Accordingly, DEQ decided not to evaluate individual small sources for potential controls under this implementation plan revision. The four-factor analyses conducted in preparation of this implementation plan revision imposed a non-trivial cost burden on the several sources selected for analysis. Such an analysis necessarily imposes a greater burden on a smaller business, and this burden may inhibit expansion, drive the business toward bankruptcy, and deter new entrants into the market.

**2.** **COMMENT:** **Source Selection Analysis** – The AOI study that ODEQ relied on in the source selection analysis used 2016 as the baseline emissions year but based on feedback from EPA, the SIP narrative explains that "DEQ did remove some sources and their corresponding emissions, such as the Big Brown Power Plant, from the source selection calculations." (See page 31 of the SIP narrative). A review of Appendix D reveals that in addition to the removal of sources in Texas that have permanently shut down, sources in Oklahoma whose emissions appear to have been removed from the source selection calculations include OG&E Muskogee Generating Station, OG&E Sooner Generating Station, PSO Northeastern Power Station. We note that entirely removing all SO2 and NOx emissions for these Oklahoma facilities is not an appropriate approach given that while recent implementation of controls at these facilities have resulted in large emissions reductions, these facilities still emit some SO2 and/or NOx emissions. Therefore, ODEQ should revise the individual source contribution calculations for these facilities by using actual emissions from a recent year (such as 2020 or 2021) to more accurately reflect current emissions and potential visibility impacts from these facilities following implementation of controls. We offer comments on ODEQ's decision to forego a four-factor analysis on BART sources elsewhere in this document.

Based on our review of Appendix D, it appears that ODEQ's removal of emissions for these facilities from the source-selection calculations did not result in any additional Oklahoma sources being selected for four-factor analysis. If so, we encourage ODEQ to discuss this in section 6.2.1. of the SIP narrative.

**RESPONSE:** DEQ based its removal of these facilities in certain portions of its analysis of emission inventories on its interpretation of EPA advice. And since DEQ performed the source selection analysis after the removal of these emissions, it would be speculative to say whether the removal of these emissions resulted in additional sources meeting the source selection criteria. In theory, a few additional sources may have been selected. However, the removal of these sources from the inventory does not change the ranking of the other sources.

DEQ disagrees that it should revise the individual source contribution calculations to a more recent year. DEQ requires the owner or operator of a permitted source of air emissions to submit an inventory before April 1st on the year after the emissions occurred. Emissions inventory staff then verify the correctness of submitted emissions. States could submit data to EPA in the national emissions inventory for 2020 as late as March 31, 2022. Appendix D reflects the information that was available at the time sources were selected for analysis, which was in 2020, before emission inventories for that year were due at the state level and certainly before they were complete at the federal level for the national emissions inventory. DEQ therefore reasonably cannot supply an emissions inventory for 2020 or 2021 before the due date for the submission of this implementation plan revision, especially considering the duration of requisite nonpublic and public reviews. Table 5-9 already presents emission data from 2019 for sources that installed best available retrofit technology.

DEQ analyzed emissions for 2016 because EPA based its most recent complete modeling platform off emissions in that year. In the interests of fairness, DEQ does not comingle emissions data from other years with data for 2016. The area-of-influence study evaluated both emissions data and meteorological conditions for 2016, and emissions and weather interact in various ways that cause considerable potential for erroneous conclusions with a mismatch in years.

3. **COMMENT:** **<u>Source Selection Analysis</u>** – ODEQ used both a Q/d threshold of 5 or greater and an individual source contribution threshold of 0.5% or greater for selecting sources to evaluate in a four-factor analysis. Based on our review of Appendix D, it appears that Elmore City Gas Plant was not selected for four-factor analysis even though it has a Q/d- NOx of 5 and an individual source contribution (%EWRT*Q/d- NO3) of 0.5%. Please provide explanation in the SIP narrative on why this facility was not selected for four-factor analysis for NOx.

**RESPONSE:** Elmore City Gas Plant, a natural gas liquid extractor in Garvin County, Oklahoma, 118 km from the Wichita Mountains, emitted 562 tons of $NO_x$ in 2016. Computing $Q/d$ = 562 tons $year^{-1}$/118 km = 4.76 tons $year^{-1}$ $km^{-1}$, slightly less than 5.0 tons $year^{-1}$ $km^{-1}$. Therefore, this screening threshold eliminates this source from further consideration. The Excel spreadsheet included as Appendix D has been updated to reflect more decimal places to make the *Q/d* cut-off more apparent. The SIP narrative has been updated to reflect that a *Q/d* of greater than or equal to 5.0 tons $year^{-1}$ $km^{-1}$ was the selection criteria.

4. **COMMENT:** **<u>Source Selection Analysis</u>** – Section 6.2.1. of the SIP narrative states that the NOx and SO2 sources selected for four-factor analysis represent 12% of NOx emission and 55% of SO2 emissions from all point sources in Oklahoma from the 2016 inventory. EPA's July 8, 2021 "Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period" Memorandum explains that "A state that relies on a visibility (or proxy for visibility impact) threshold to select sources for four-factor analysis should set the threshold at a level that captures a meaningful portion of the state's total contribution to visibility impairment to Class I areas." (See 2021 Clarifications Memo at 3). The SIP narrative should provide additional discussion and justification for the thresholds selected by ODEQ for identifying sources for further evaluation. The SIP

narrative states that "The 0.5% threshold identified twelve total sources, which is a reasonable number of sources that warranted further analysis in the form of a four-factor analysis and on which to focus limited available resources." See SIP narrative at 32. The SIP narrative should explain why twelve sources is a reasonable number of sources beyond merely noting that the State has limited available resources. Consistent with the memo, the SIP revision should explain how the percentage of emissions captured through ODEQ's source selection methodology represents a meaningful portion of the state's total contribution to visibility impairment at the Wichita Mountains.

**RESPONSE**: Neither statute nor regulation nor guidance nor the clarification memorandum offer a quantitative definition of "meaningful" in this context, which implicitly leaves much discretion to state agencies in the preparation of their SIP. For $SO_2$ sources, DEQ conducted or evaluated four-factor analyses on sources that represented 55% of contributing emissions in 2016, and 31% of contributing emissions in 2016 came from sources that later installed best available retrofit technology. DEQ asserts that the combination qualifies as a meaningful proportion of all contributing emissions of $SO_2$.

As stated in the SIP, as compared to $SO_2$, a larger number of $NO_x$ sources have smaller individual contributions. DEQ conducted further analysis on 12% of contributing emissions of $NO_x$ from inventoried sources within Oklahoma. A further 12% of contributing emissions in 2016 came from sources that installed best available retrofit technology (BART). Although the total proportion of 25% falls well short of majority of contributing emissions, this implementation plan revision assesses four-factor analyses for eight of the most prolific sources of $NO_x$ pollution in Oklahoma. DEQ does not want to impose a large paperwork burden on owners or operators of sources without an ultimate environmental benefit and perceives that control equipment may cost smaller emitters even more per unit emissions reduced than the seven selected sources. Moreover, despite the considerable number of stationary point sources in Oklahoma with emissions below the threshold, most visibility impairment results from emissions originating outside of Oklahoma, such as Texas, other states, and foreign countries. In consideration of these factors, DEQ contends that its selection of sources for four-factor analyses fulfills the regulatory requirements of the regional haze rule.

Furthermore, the July 10, 2021, clarifications memorandum from EPA arrived long after the completion of the analysis and only a couple of weeks before the regulatory deadline for submission of this implementation plan revision. Especially given the duration of the review process, DEQ cannot make major revisions to this implementation plan revision or redo an extensive analysis of emissions sources in response to this memorandum.

5. **COMMENT:** **<u>Source Selection Analysis</u>** – ODEQ's approach of automatically foregoing a four-factor analysis for the Oklahoma BART sources identified in the source selection analysis is not consistent with our regulations and guidance. 40 C.F.R. 51.308(e)(5) specifically notes that "[a]fter a State has met the requirements for BART… BART-eligible sources will be subject to the requirements of paragraphs (d) and (f) of this section, as applicable, in the same manner as other sources." EPA's August 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period"

elaborates that "[S]tates may not categorically exclude all BART-eligible sources, or all sources that installed BART controls, as candidates for selection for analysis of control measures." See August 2019 Guidance at 25. EPA's 2021 Clarifications Memo further clarifies that "A state relying on an "effective control" to avoid performing a four-factor analysis for a source should demonstrate why, for that source specifically, a four-factor analysis would not result in new controls and would, therefore, be a futile exercise." (See 2021 Clarifications Memo at 5). Consistent with the rule, guidance and clarifications memo, ODEQ should provide further explanation in the SIP to justify the decision not to evaluate these BART sources in the four-factor analysis based on source-specific factors that would provide justification for no further evaluation consistent with our guidance. Alternatively, without such justification, the BART sources that were automatically eliminated from further analysis should be evaluated in a full four-factor analysis to determine if further controls are necessary and whether existing measures at those sources are necessary for reasonable progress.

This feedback applies to the OG&E Muskogee Generating Station and all NOx BART sources. Only Units 4 and 5 of the OG&E Muskogee Station are subject to BART, while Unit 6 (a coal-fired unit with no existing SO2 controls and only overfire air for NOx control) is not subject to BART and thus was not evaluated or controlled under regional haze in the first planning period. Additionally, NOx BART sources that were automatically eliminated from further analysis were all required to install combustion controls (low-NOx Burners or low-NOx Burners with Overfire Air) rather than post-combustion controls, and some appear to continue to have considerable NOx emissions. Therefore, further analysis of potential controls for these sources or detailed discussion on why it is reasonable to assume for these units that a full four-factor analysis would likely result in the conclusion that any further controls are not necessary should be included in the SIP. As discussed below, Arkansas and Missouri specifically identified the Muskogee Generating Station as reasonably anticipated to impair visibility at one or more of their Class I areas. We also note that OG&E Muskogee Generating Station is located closer to Arkansas' Class I areas and Missouri's Class I area than to Oklahoma's own Class I area. OG&E Muskogee is located 178.11 km from Caney Creek; 187.37 km Upper Buffalo; 231.48 km from Hercules Glades; and 330.27 km from Wichita Mountains. Therefore, the Q/d values of this source with respect to Caney Creek, Upper Buffalo, and Hercules Glades are greater than the Q/d value with respect to Wichita Mountains (See Appendix C of the proposed SIP).

**RESPONSE**: EPA states that the DEQ cannot "automatically foreg[o] a four-factor analysis for the Oklahoma BART sources…." However, the DEQ's decision to generally not add electricity generating units (EGUs) to the list of facilities required to undergo a four-factor analysis was *deliberate* rather than "automatic," and it was based in part on their being subject to Cross-State Air Pollution Rule (CSAPR) requirements. DEQ believes that their participation in CSAPR would result in equal or better progress in aggregate than that which would result from adding the requirement for source-specific four-factor analyses. It would, therefore, be best to defer focus on those sources until a later RH Planning Period and to allow the full benefits and implementation nuances of BART and CSAPR to mature.

As DEQ noted, emissions from OG&E Muskogee Generating Station and other fossil-fueled EGUs over 25 Megawatts (MWs) are subject to the CSAPR $NO_x$ Ozone-Season Group 2 Trading Program, codified at 40 CFR Part 97, Subpart EEEEE. This subpart establishes various provisions for the CSAPR $NO_x$ Ozone Season Group 2 Trading Program, under Section 110 of the Clean Air Act and under the Federal Implementation Plan (FIP) codified at 40 CFR §52.38. Under this subpart, the facility owner is required to designate an official representative, monitor emissions, keep records, and make reports in accordance with §§97.830 through 97.835. The monitoring program must comply with 40 CFR Part 75 or an alternative monitoring program must be requested and approved. CSAPR $NO_x$ Ozone Season Group 2 allowances are periodically allocated to the facility and at the completion of the allowance transfer deadline for the control period in a given year the permittee is required to hold, in the source's compliance account administered by the EPA Clean Air Markets Division (CAMD), sufficient allowances available for deduction for such control period under §97.824(a) in an amount not less than the tons of total $NO_x$ emissions for the control period from all CSAPR $NO_x$ Ozone Season Group 2 units at the facility.

Participation in a $NO_x$ and/or $SO_2$ trading program that provides greater aggregate $NO_x$ and/or $SO_2$ emissions reductions than would be provided by adoption of BART exempts the facility from the requirement to adopt BART to demonstrate reasonable progress toward achieving the national goal of improved natural visibility conditions. The preamble to the final rule, "Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans," June 7, 2012, 77 FR 33642 (hereinafter referred to as the "Better than BART" final rule), explains that the states may rely on trading programs to achieve necessary emissions reductions in lieu of adopting BART requirements.

> Rather than requiring source-specific BART controls, states also have the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provides greater reasonable progress towards improving visibility than BART. 40 CFR §51.308(e)(2). The EPA provided states with this flexibility in the Regional Haze Rule, adopted in 1999, and further refined the criteria for assessing whether an alternative program provides for greater reasonable progress in three subsequent rulemakings. 64 FR 35714 (July 1, 1999);

> 70 FR 39104 (July 6, 2005); 71 FR 60612 (October 13, 2006). [Better than BART final rule at 77 FR 33644.]

The preamble went on to present a series of criteria under which a trading program may be determined to be "better than BART," and showed that the CSAPR ozone-season trading program met all those criteria.

> In our proposal, we described a technical analysis that we conducted to determine whether compliance with the Transport Rule would satisfy regional haze BART-related requirements. This technical analysis is the basis of this final action in which we are finalizing our determination that the Transport Rule achieves greater reasonable progress towards the national goal of achieving natural visibility conditions than source-specific BART. For this final rule, an updated sensitivity analysis was conducted to account for subsequent revisions to certain state budgets in the Transport Rule. This analysis is described in section III.B.4 of this notice. [Better than BART final rule at 77 FR 33645]

Further, the preamble explains that a state may consider emissions reductions from such a trading program in demonstrating progress toward achieving improved visibility.

> As described above, in 2005 (70 FR 39104) the EPA amended its Regional Haze Rule to provide that states participating in the CAIR cap-and-trade programs need not require affected BART-eligible EGUs to install, operate and maintain BART for emissions of $SO_2$ and $NO_x$. 40 CFR §51.308(e)(4). As EPA noted in explaining its reasons for adopting this approach, ''[nothing] in the CAA or relevant case law prohibits a State from considering emissions reductions required to meet other CAA requirements when determining whether source-by-source BART controls are necessary to make reasonable progress. Whatever the origin of the emission reduction requirement, the relevant question for BART purposes is whether the alternative program makes greater reasonable progress.'' 70 FR at 39143. [Better than BART final rule at 77 FR 33645/3]

Finally, a state may rely on either an approved SIP or FIP that establishes enforceable requirements applicable to EGUs.

> Similarly, a *regional haze* SIP or FIP that relies on 40 CFR §51.308(e)(4) does not impose enforceable requirements on EGUs. However, a state may take advantage of this provision only if it is subject to an underlying Transport Rule FIP (or SIP approved as meeting the requirements of the trading program). We note that the underlying Transport Rule FIP or SIP does contain the applicable requirements that

will ensure that the emissions reductions from the Transport Rule will occur. [Better than BART final rule at 77 FR 33647]

While the Better than BART rule was later withdrawn, that occurred because, at the time, the D.C. Circuit Court rejected the original CSAPR rule and EPA imposed the requirement for states to incorporate BART requirements into their Regional Haze SIPs. Later, the U.S. Supreme Court reversed the decision of the D.C. Circuit Court and reinstated the original CSAPR rule. However, the BART requirements had already been adopted and there was no revisitation of the issues raised in the Better than BART rule. DEQ believes that the justification provided in the development of the rule stands. It is too late to undo the BART controls put into place for units subject to those requirements in the first planning period, but for EGUs currently subject to a CSAPR trading program, there is no need to perform a four-factor analysis. For those EGU sources that were selected for a four-factor analysis in this second planning period per DEQ's source selection criteria, the responses confirm that there are no additional cost-effective controls that should be implemented. The emissions reductions guaranteed by an EGU’s participation in a CSAPR trading program are more than sufficient to meet the Round 2 goals.

Furthermore, the CSAPR Update’s ozone-season $NO_x$ trading program yields significant benefits in addition to the $NO_x$ reductions, which would lead to reductions in SO2 and PM-2.5 as well. Because it constitutes a sector-wide cap-and-trade program and because it limits use of allowances to ensure that each state achieves significant $NO_x$ reductions each year, it incentivizes a variety of emissions reductions strategies including demand shift away from coal-fired units to natural gas, prioritizing operation of natural gas combined cycle (NGCC) units equipped with selective catalytic reduction (SCR) controls, and indirectly boosts renewables generation. These additional benefits have the effect of reducing both $SO_2$ and PM-2.5 emissions in addition to the $NO_x$ reductions targeted by the rule. In a response-to-comment document [“Response to Comments Document,” Docket Number EPA-HQ-OAR-2011-0729 Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Retrofit Technology (BART) Determinations, Limited SIP Disapprovals, and Federal Implementation Plans (76 FR 82219; December 30, 2011), U.S. Environmental Protection Agency, Office of Air and Radiation, May 30, 2012.], a number of commenters raised objections to the Better than BART rule, which were rejected. In rejecting the arguments, EPA noted that participation in a CSAPR rule yielded overall superior visibility improvements than would have been the case if some units had been subjected to individual four-factor analyses. For illustration, example comments, and the response are reproduced below.

**Commenter: William O’Sullivan, New Jersey Division of Air Quality**
**Comment:**

The State of New Jersey does not support the proposed rule. Based on the cumulative assessment of all BART-eligible sources in the Mid-Atlantic Northeast Visibility Union (MANE-VU) region, all member states with BART -eligible facilities contribute to visibility impairment at Class I areas. As a member state, the State of New Jersey followed the subsequent MANE-VU Board decision that any source that meets the BART eligibility requirements should be subject to a top-down BART determination. The USEPA approved the State of New Jersey's Regional Haze State Implementation Plan revision, including BART determinations, reasonable progress goals, and sulfur in fuels rule, effective February 2, 2012. Coal-fired electric generating units (EGUs) that do not have add-on air pollution controls are very high emitters of $NO_x$ and $SO_2$ which contribute to the formation of regional haze, and BART-eligible EGUs should be subject to BART. At a minimum, any coal-fired EGU greater than 25 megawatt (MW) in size should be required to meet the presumptive limits outlined in the as outlined in Appendix Y to Part 51-Guidelines for BART Determinations under the Regional Haze Rule.

To allow CSAPR as an alternative to BART within the eastern half of the United States would diminish the potential for greater reductions of visibility-impairing emissions from upwind states, and would impair NJDEP's efforts to protect and restore visibility at the Brigantine Wilderness Area in the Edwin B. Forsythe National Wildlife Refuge. I urge the USEPA to reconsider substituting CSAPR for CAIR as an alternative to source-specific BART determination for EGUs.

**Commenter: Kathryn M. Amirpashaie/Sierra Club**
**Comment:**
EPA’s position that CSAPR is “better than BART” is flawed; CSAPR is not better than BART and will not achieve greater reasonable progress to natural visibility conditions in these states than BART. Therefore, CSAPR cannot serve as an alternative to BART under the RHR. Therefore, EPA’s proposed partial FIPs as to Alabama, Mississippi, North Carolina, and South Carolina must be abandoned. Sierra Club does agree with EPA’s partial disapproval of Alabama, Mississippi, North Carolina, and South Carolina’s SIPs due to their reliance on CAIR as the BART-alternative. For many of the same reasons that CSAPR is an inappropriate BART alternative, CAIR is also an inappropriate alternative.

**EPA Response:**
The EPA acknowledges the comments of the many organizations and individuals who responded to our request for comment. In the preamble to the proposed rule and in the Technical Support Document (TSD) for the proposed rule, the EPA

> presented the results of a national air quality modeling analysis that support the determination that the regional trading programs of CSAPR will result in better reasonable progress towards improving visibility at Class I areas than source specific BART. The EPA established that the two-pronged test for determining the adequacy of a BART alternative program, as defined by the Regional Haze Rule, was met.
> [Response to Comments Document, page 16.]

In response to a comment from the National Parks Conservation Association, the analysis offered targets the superior emissions reductions (both $NO_x$ and $SO_2$) provided by subjecting *all* EGUs over the 25 MW applicability threshold to the CSAPR trading program than what would have been provided by BART and, by implication, a Round 2 four-factor assessment on a subset of EGUs.

> In the preamble to the proposed rule and in the TSD for the proposed rule, the EPA presented the results of a national air quality modeling analysis that support the determination that the regional trading programs of CSAPR will result in better reasonable progress towards improving visibility at Class I areas than source-specific BART. The EPA established that the two-pronged test for determining the adequacy of a BART alternative program, as defined by the regional haze rule, was met. The trading programs of CSAPR apply to all electric generating units (EGUs) in a CSAPR state compared to only a limited number of sources that may be BART-subject. The EPA's analysis demonstrated that emission reductions from a much larger number of EGUs located across a large regional area resulted in greater visibility improvement at the affected Class I areas. The commenters maintain that EPA underestimated the emission reductions that would be achieved at BART-eligible EGUs by relying on what the commenter maintains are EPA's too-high presumptive limits for BART. The EPA believes that assuming application of presumptive limits contained in EPA's BART Guidelines (40 CFR Part 51 Appendix Y) to all BART-eligible units (over 100 MW for $SO_2$ controls and over 25 MW for $NO_x$ controls) across a broad region is a reasonable and appropriate method for estimating the emissions reductions from application of source-specific BART. The EPA disagrees that it is necessary to conduct an EGU-specific analysis for each BART-eligible EGU. The commenter's assertion that BART is represented by the application of selective catalytic reduction (SCR) for $NO_x$ control and scrubbers for $SO_2$ control ignores the definition of BART. The determination of a BART emission limit considers existing controls on the unit, the cost of new controls, the remaining useful life of the unit, the visibility improvement reasonably expected from the controls, and other non-air and energy considerations. Thus it is speculative to assume that every BART eligible EGU

> would be required to apply additional controls or to assume the highest level of emission reduction due to those controls. See also 71 FR 606012, 60619 (Oct. 13, 2006) ("We believe that the presumptions represent a reasonable estimate of a stringent case BART, particularly because in developing a BART benchmark they would be applied across the board to a wide variety of units with varying impacts on visibility, at power plants of varying size and distance from Class I areas.").
> [Response to Comments Document, page 17.]

Oklahoma EGUs only participate in the ozone-season $NO_x$ trading program and, as a result, The Better than BART rule would only have excluded them from the requirement to undergo a $NO_x$ four-factor analysis. However, the DEQ reviewed the analysis performed by EPA in support of the Better than BART rule and the emissions reduction trends (both $NO_x$ and $SO_2$) from EGUs subject to the CSAPR Update and concluded that participation in the ozone-season $NO_x$ trading program has yielded superior visibility improvement than would have been the case had the units been subject to individual four-factor analyses for $NO_x$ and/or $SO_2$. As a precaution, in the small number of instances where DEQ had concerns EGUs were subject to a four-factor analysis. The findings supported our original analysis.

In addition, the cost-effectiveness review performed by DEQ included an assessment of the knee-of-the-curve analysis that EPA performed in developing state ozone-season allowance budgets under the original CSAPR rule and the CSAPR update. DEQ concluded that the cost-of-control analysis performed for the CSAPR Update (approximately $1,800 per ton of $NO_x$) is also appropriate for use in this round of Regional Haze planning. Further, the CSAPR approach *in effect* yields *sector-wide* emission reductions as if controls established at that cost threshold had been enforced on each unit in the sector, not just those selected for a four-factor analysis. Participation in the CSAPR Update ozone-season $NO_x$ trading program provides greater sector-wide emission reductions (at the cost threshold considered appropriate by DEQ) than would have been provided if a subset of units had been selected individually for such an analysis. Thus, a unit-by-unit analysis would be a futile exercise and would yield fewer emission reductions. This assessment is inclusive of OG&E Muskogee's Unit 6, all of the BART units, and the remaining fossil-fueled EGUs in this sector.

EPA's comment #24 points out that "…the transport program under CAA section 110(a)(2)(D)(i)(I) is an entirely separate program from regional haze, serving a different statutory purpose and involving the consideration of factors that may have no relationship to the regional haze program." DEQ is fully aware of this distinction, and would note that the Regional Haze program focuses exclusively on aesthetics with the ultimate goal of a view of Class I areas unimpeded by anthropogenic sources of haze. In contrast, the CSAPR rule and the CSAPR Update focus on the achievement of health-based ambient air quality standards. While DEQ would in no way diminish the importance of these aesthetics, we are sure that EPA would acknowledge that health-based standards are a more substantive component of human flourishing, and compliance with the CSAPR Update provides greater public benefit while also achieving the necessary reductions to meet the aesthetic goals of the Regional Haze program. Indeed, continued progress in reducing interstate transport of pollutants is the best hope for reaching natural visibility conditions at Oklahoma's Class I Area.

A new Subsection *6.3.1. Sources subject to CSAPR requirements* has been added to the SIP narrative to clarify how CSAPR requirements factored into DEQ's source selection process.

**6.** **COMMENT:** **<u>Source Selection Analysis</u>** – PSO Northeastern Unit 3, which is currently required under BART requirements to comply with an $SO_2$ emission limit of 0.40 lb/MMBtu based on operation of dry sorbent injection (DSI), was also required under the AEP/PSO Regional Haze Agreement (from the first planning period) to develop a monitoring program for Unit 3 to determine whether increased $SO_2$ removal efficiencies can be achieved during normal operations using existing DSI. The SIP narrative states that based on the monitoring program and the terms of the AEP/PSO Regional Haze Agreement, PSO concluded that the resulting federally enforceable emission rate for Unit 3 should be 0.37 lb/MMBtu on a 30-day rolling average basis and that ODEQ concurs with the company's determination. The SIP narrative notes that the revised $SO_2$ emission limit for Unit 3 will be incorporated into a future permit modification. We encourage ODEQ to provide additional information as to the planned timing of this permit modification, to the extent possible. We also note that if ODEQ makes the determination that the new 0.37 lb/MMBtu emission limit for Unit 3 is necessary to make reasonable progress, then ODEQ must adopt this emission limit as part of its long-term strategy for the second planning period and include the limit in its SIP. This issue is discussed in greater detail below.

**RESPONSE**: DEQ's AQD Permitting Section has not yet completed discussions with AEP/PSO on lowering the 0.40 lb/MMBTU for PSO Northeastern Unit 3. The facility's proposed TV permit renewal is currently in EPA review. Once issued, discussions will be completed, to allow for processing of an NSR permit and TV permit modification to accommodate a limit change.

DEQ does not find this 7% reduction in the lb/MMBTU limit of $SO_2$ emissions for PSO Northeastern Unit 3 necessary to make reasonable progress, particularly considering that the existing RH implementation plan (and Title V permit) already requires that the facility incrementally reduce capacity utilization and cease operations before the conclusion of this planning period. Therefore, including the new short-term emission limit as part of its long-term strategy for the second planning period would be superfluous.

7. **COMMENT:** **<u>Four-Factor Analyses</u>** – For each of the selected sources, and for each emission unit evaluated, the four-factor analysis should clearly identify the baseline control scenario, and associated emissions and emissions limits (lb/MMBtu, tons/year, lb/ton, etc., depending on unit type) used in the analysis. Further guidance regarding these issues can be found on pages 29 and 30 of our August 2019 Guidance, respectively. See also 40 C.F.R. 51.308(f)(2)(iii). The State should provide appropriate documentation of all this information, including with citations to regulatory and technical documents. We specifically recommend that the SIP narrative identify existing emission limits and where those limits are located (e.g., in the SIP, in a federal and/or state permit, in a consent decree). In addition, we recommend that the SIP narrative discuss how these limits compare to the baseline emissions used in the four-factor analyses. ODEQ has not provided analysis consistent with these recommendations, but rather agrees with all aspects of the submitted four-factor analyses and the conclusions made by the facilities without providing an independent assessment and discussion of the State's review of these analyses. The State should document their review and decision-making process when determining reasonable control measures. Such documentation should include the State's assessment of the analysis performed under each factor and how it weighed the four statutory factors to allow for stakeholder review and comment. After this review, if ODEQ determines that no additional (i.e., new) measures are necessary to make reasonable progress for a particular source, it must then determine whether the source's existing measures are necessary to make reasonable progress. See section 4 (pages 8 – 12) of the Clarifications Memo for information on determining when a source's existing measures are necessary to make reasonable progress. Generally, a source's existing measures are needed to prevent future emission increases and are thus needed to make reasonable progress. If ODEQ concludes that the existing controls at a selected source are necessary to make reasonable progress, ODEQ must adopt emissions limits based on those controls as part of its long-term strategy for the second planning period and include those limits in its SIP (to the extent they do not already exist in the SIP).

Alternatively, if ODEQ can demonstrate that the source will continue to implement its existing measures and will not increase its emission rate, it may be reasonable for the State to conclude that the existing controls are not necessary to make reasonable progress. Such a demonstration should be supported by documentation, such as the data and analysis described in the Clarifications Memo. In such case, the emission limits may not need to be adopted into the long-term strategy and SIP. We recommend that ODEQ clearly state its determination for each source and explain whether it is including either existing or new emission limits for each source in the long-term strategy and SIP (or whether emission limits already exist in the SIP). See August 2019 Guidance at 43; Clarifications Memo at 8-9.

**RESPONSE:** In general, the information, data, and documentation that EPA has suggested is provided or referenced in the individual four-factor analyses (and corresponding supplemental submissions) included in Appendix E, and pertinent portions are included in related discussions in the SIP document itself. [Note that, although submitted confidential business information (CBI) does not appear in Appendix E, each affected source has supplied a copy of the CBI documentation to EPA.] As time allows, DEQ will supplement the SIP document by repeating additional details in the body and/or additional documents in the appendices, as requested. Such details/documents may include copies of existing permits, lists/descriptions of existing permit limits and requirements, and baseline emissions if significantly different. There are perhaps portions where more explicit discussions could be added of DEQ's review and assessment of each four-factor analysis. Some of these additions could only be added in a supplement to the current SIP revision, given EPA's implication that the added details must allow for stakeholder review and comment, i.e., a full additional round of FLM and State/Tribal consultation, followed by EPA and public review.

Sources for which no additional measures were found to be cost-effective in their four-factor analyses still remain subject to the same program requirements, as applicable, that require consideration of Class I Area visibility impacts of any significant emissions increases (i.e., prevention of significant deterioration (PSD)).

**8.** **COMMENT:** **<u>Four-Factor Analyses</u>** – We recommend that for each selected source, the State consider whether the source can achieve or is already achieving a lower emission rate using its existing measures. If a source is capable of operating or is already operating at a lower emission rate than assumed either (1) as the basis for not conducting a full four-factor analysis or (2) as the baseline for four-factor analysis, that lower rate should be analyzed as a potential control measure. Similarly, we recommend ODEQ consider whether equipment upgrades might be reasonable. If either more efficient use of existing measures or equipment upgrades are potentially reasonable control options, the State should either conduct a four-factor analysis or explain why it is reasonable to forgo doing so. See Clarifications Memo at 5, 7.

**RESPONSE:** DEQ's review of sources selected (or considered) for the four-factor analyses did not identify any additional cases (other than Mustang Gas' Binger Gas Plant and ONEOK's Maysville Gas Plant as outlined in Section 6 of the SIP) where a source was capable of operating or is already operating at a lower emission rate than assumed, or where equipment upgrades or shutdowns might reasonably be required. In absence of an identified issue that would threaten Oklahoma's continued visibility improvement towards the goal, DEQ knows of no legal authority it possesses to unilaterally impose such limits or requirements. If additional facilities identified such opportunities and voluntarily agreed to implement them, enforceable consent orders could be prepared and submitted as a supplement to the SIP Revision, or developed for inclusion in the next planning period revision or 5-year progress report.

**9.** **COMMENT:** **<u>Four-Factor Analyses</u>** – Please include line-item cost breakdowns, cost calculations (preferably in Excel spreadsheet format), and all vendor quotes obtained for all the control options evaluated in the four-factor analyses. This is consistent with the Regional Haze Rule, which requires that in establishing its long-term strategy for regional haze, a state 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. 40 CFR 51.308(f)(2)(iii).

**RESPONSE:** DEQ believes that it has provided adequate documentation of the technical basis for the proposed SIP revision as the regional haze rule does not mandate the level of detail that must be included. However, DEQ will again review the documentation and, as time allows, will supplement the SIP with any additional information it feels may assist in EPA's review, and will attempt to present it in a form that EPA prefers if and when necessary.

**10.** **COMMENT:** **<u>Continental Carbon</u>** – The four-factor analysis submitted by the company and the summary provided by ODEQ in Section 6.4.1.5 the SIP narrative explain that Continental Carbon entered into a federally enforceable consent decree with EPA on May 7, 2015, requiring the removal of the three thermal oxidizer units at the facility and replacement with two clean gas and energy cogeneration units, each with a selective catalytic reduction (SCR) system for the control of NOx emissions and a dry scrubber for the control of $SO_2$ emissions. Section 6.4.1.5 of the SIP narrative explains that the two clean gas and energy cogeneration units were installed in the fall of 2018 and that the dry scrubbers have been installed but are still being modified to operate effectively. The SIP narrative also explains that project completion will result in a new permitted limit of approximately 708 tpy of $SO_2$ for the units. As discussed elsewhere in this document, ODEQ must make a determination whether the source's existing measures are necessary to make reasonable progress and if ODEQ concludes that the existing measures are necessary to make reasonable progress, ODEQ must adopt emissions limits based on those controls as part of its long-term strategy for the second planning period and include those limits in its SIP (to the extent they do not already exist in the SIP). Alternatively, ODEQ could demonstrate that the existing controls are not necessary to make reasonable progress through a demonstration supported by the data and analysis described in the Clarifications Memo. See August 2019 Guidance at 43; Clarifications Memo at 8-12. Also discussed elsewhere in this document, if either more efficient use of these existing measures or equipment upgrades are potentially reasonable control options and a more stringent emission limit is feasible for the Continental Carbon units, we recommend that the four-factor analysis consider this or alternatively, the State should explain why it is reasonable to forgo doing so. See Clarifications Memo at 5, 7.

**RESPONSE:** Adhering to the requirements of the federal consent decree by Continental Carbon will certainly lead to continued improvements in the visibility conditions at the Wichita Mountains Wilderness Area. However, this does not mean that DEQ is concluding that the existing measures are necessary to make reasonable progress. EPA's Clarifications Memo, states, "if a state can demonstrate that a source will continue to implement its existing measures and will not increase its emission rate, it may not be necessary to require those measures under the regional haze program in order to prevent future emissions increases. In this case, a state may reasonably conclude that a source's existing measures are not necessary to make reasonable progress and thus do not need to be included in the SIP." The Clarification Memo goes on to state that "[t]he existence of an enforceable emission limit or other enforceable requirement (*e.g.*, a work practice standard or operational limit) reflecting a source's existing measures may also be evidence that the source will continue implementing those measures. A federally enforceable and permanent requirement provides the greatest certainty and, therefore, is the preferred and best evidence." DEQ concludes that Continental Carbon's federal consent decree meets this degree of evidence, and therefore no further documentation is required.

**11.** **COMMENT:** **<u>DCP Chitwood Gas Plant</u>** – The use of a 7% interest rate in the cost analysis is not appropriate. For consistency with EPA's Control Cost Manual, the cost analysis should be based on either the bank prime rate or a company-specific interest rate, if available.[1] Since the Regional Haze Rule is intended to evaluate the private cost of controls, the Control Cost Manual directs entities to use the bank prime rate when estimating costs of controls in cases where a company-specific interest rate is not available.[2] If a company-specific interest rate is available and is being used to estimate the cost of controls, documentation supporting that interest rate should be provided with the cost analysis. Section 6.4.2.7 of the SIP narrative states that at the suggestion of EPA, DEQ calculated the cost options at a lower interest rate (3.25%) than the rate used by DCP (7%)

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[1] The bank prime rate is based on the federal funds rate, which is set by the Federal Reserve. The current bank prime rate can be found at https://www.federalreserve.gov/releases/h15/ and historical data on the bank prime rate can be found at https://fred.stlouisfed.org/series/PRIME.

[2] See EPA Control Cost Manual at 15-17. The Control Cost Manual can be found at https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf.

for the NOx controls evaluated for the DCP Chitwood Gas Plant. Other than stating that the lowest cost option was reduced to approximately $2,400 per ton of NOx removed, there is no additional information or revised cost calculations to reflect the bank prime rate provided in the proposed SIP. We recommend that the cost analysis document and use the bank prime rate at the time of the analysis and that cost calculations and a summary table presenting ODEQ's revised cost-effectiveness ($/ton) numbers (similar to Table 6-4) be included in the final SIP submittal.

Even when using an unsupported interest rate of 7%, the costs of NOx controls for engines C-1, C-2, C-4, C-6, and C-7 are still within the range of what we have considered reasonable in the past. As we noted in the "Cost Thresholds" section of this document, it is reasonable to expect that cost thresholds in the second planning period should be higher than in the first planning period. We note that by taking these comments into account and adjusting both the interest rate used in the cost analysis and the selected cost thresholds, ODEQ could find these controls to be necessary for reasonable progress and strengthen its long-term strategy by securing additional emissions reductions and visibility benefits.

**RESPONSE:** The prime rate was set to a historically low 3.25% on March 16, 2020, in response to a global pandemic. This prime rate is not indicative of normal circumstances and had not been set this low since the financial crisis in 2008. As of June 16, 2022, the bank prime rate became 4.75%, which was the third increase in 2022. Current economic conditions suggest the bank prime rate may go higher still. EPA's Cost Control Manual provides guidance for the development of accurate and consistent costs for air pollution control devices, but its use is not required by regulation. DEQ accepted interest rates used in cost analyses submitted by facilities with reasonable justifications. DEQ calculated the costs of controls with the former 3.25% prime interest rate per EPA's request, and it did not change DEQ's decision on the selection of controls. DEQ does not feel it is necessary to create a revised cost-effectiveness summary table.

DEQ disagrees that it is reasonable to expect that cost thresholds in the second planning period should be higher than in the first planning period. As technological advances in controls are realized, costs for control equipment may decrease. In addition, equipment retirements may occur that make controls unnecessary. See DEQ's response to comment #12 below for further rationale why control scenarios for DCP's engines are not considered cost effective.

**12.** **COMMENT:** **<u>DCP Chitwood Gas Plant</u>** – Section 6.4.2.7 of the SIP narrative states that "Although the lower end of these costs [of NOx controls on the DCP Chitwood Gas Plant units] might be considered reasonable under certain circumstances, the four-factor analysis also addressed the amount of uncertainty associated with the control costs, the feasibility of the retrofits, and the potential emission reductions. Based on this information, the company concluded that no control option was determined to be cost-effective. DEQ concurs that this is a reasonable conclusion." (See SIP narrative at page 40). However, the reason why there is uncertainty associated with the cost, feasibility, and potential emission reductions of the retrofit controls evaluated is because the four-factor analysis provided by the company "discuss[es] general hypothetical retrofit scenarios for these types of engines, but these scenarios are not based on an engineering analysis specific to each subject engine." (See Appendix E of the proposed SIP). The four factor analysis submitted by the company states that "These are unique engines and, if any analysis herein suggests that an engine may be amenable to retrofit actions as a function of a 4-factor analysis, then such engine would require a detailed, engineered engine health analysis and engineering and vendor assessment of whether that engine specifically can successfully accommodate a retrofit action. Such detailed engineering assessments would provide more accuracy around technical feasibility and cost and may conclude that a particular retrofit action is, for example, not technically feasible to be successfully implemented, or not economically reasonable." Id. If ODEQ's determination that controls are not necessary is based on consideration of the uncertainty associated with the four factor analysis provided by the company, ODEQ should provide a site-specific analysis and engineering study (or request the company to do so) to more accurately determine the feasibility and cost of retrofit controls at these units and reconsider whether the determination that no controls are necessary is reasonable based on the updated analysis. We offer recommendations regarding ODEQ's cost threshold selection elsewhere in this document.

**RESPONSE:** DEQ's determination that controls are not necessary for DCP's Chitwood Gas Plant is based upon the four-factor analysis and subsequent responses included in Appendix E. DEQ believes that EPA has taken the quoted sentence from DCP's report out of context. DEQ has determined there are no cost-effective control technologies for DCP's engines. DEQ further understands that should a different, lower cost threshold be used to make these control scenarios appear to be cost-effective, a more thorough analysis of the engine(s) in question would need to be performed. This more thorough analysis may show that the control is technically infeasible in its entirety or may show higher costs that would still make the control not feasible.

**13.** **COMMENT:** **<u>GRDA Unit 2</u>** – The four-factor analysis submitted to ODEQ by the company states that it is based on a forecasted/projected annual capacity factor but the company states that it is not definitive. In a follow up response to ODEQ, the company confirmed that the forecasted capacity factor is based on recent historical operations of the facility from 2016-2020. Please explain what is meant by the statement that the forecasted capacity factor is not definitive and how this factor may impact the four-factor analysis and assessment of potential controls.

**RESPONSE:** DEQ interprets this statement to mean that GRDA provided the forecasted capacity factor based on recent historical operations data, and their best assessment of present circumstances and expectations in all aspects of the power sector. The forecast is therefore naturally subject to change as operations change. Although a good average of the most recent data, if operations change significantly in a single year, the forecasted capacity factor may be less reflective of actual conditions. It seems reasonable to assume that the four-factor analysis would be affected if the forecasted capacity factor were to change significantly and could also, therefore affect the assessment of potential controls. These same uncertainties are also true of many other assumptions made during a cost analysis for this unit, or for any unit subject to a four-factor analysis. The footnote did go on to state that "[t]he increasing levels of renewables generation in the Southwest Power Pool mean that the current conditions for economic dispatch of coal-fired generation are not likely to change."

**14.** **COMMENT:** **GRDA Unit 2** – The assumption of a shortened remaining useful life in the cost analysis for controls evaluated for Unit 2 is based on "operating projections." However, the four-factor analysis states that this projected remaining life for Unit 2 is subject to change and in a follow-up response to ODEQ, the company confirmed that Unit 2 does not have an enforceable shutdown date. As discussed in the August 2019 Guidance, this is not an appropriate approach. The Guidance explains that "In the situation where an enforceable shutdown date does not exist, the remaining useful life of a control under consideration should be full period of useful life of that control as recommended by EPA's Control Cost Manual." See August 2019 Guidance at 34. ODEQ should revise the four-factor analysis accordingly.

**RESPONSE:** Absent an enforceable shutdown date, all remaining useful life calculations are just reasonable assumptions based on past practices, performance, and future projections. However, to determine if EPA had a legitimate concern, DEQ performed a cursory cost calculation for the lowest cost control equipment option, in this case DSI at $21,187. Using a 30-year equipment life, as EPA suggests would be more appropriate, still results in a cost of approximately $12,000/ton, which is not considered by DEQ to be cost effective for $SO_2$ control. All other control options would have higher dollar-per-ton costs and therefore were not calculated. DEQ has added this information to the SIP.

**15.** **COMMENT:** **Mustang- Binger Gas Plant** – In Mustang-Binger Gas Plant's follow-up response to ODEQ's request for additional information on the four-factor analysis, the company retracted its original statement that it is not feasible to control the four engines evaluated in the four-factor analysis using air fuel ratio controllers (AFRC). The company also confirmed that three of the four engines (CM-2323, CM-2324, and CM-2325) already operate with AFRC. The company should evaluate the cost of AFRC for engine CM-2322 in the four-factor analysis to determine if those controls are necessary for reasonable progress.

**RESPONSE:** DEQ confirmed with Mustang Gas that they are committed to adding both an AFRC and NSCR to CM-2322 as indicated in their second four-factor response. This language has been corrected in the RH Plan.

**16. COMMENT: OG&E Horseshoe Lake** – For the time necessary for implementation, the four-factor analysis states that the company anticipates that it would take a minimum of four years to install SCR on the evaluated units. In comments EPA provided to ODEQ after review of an early draft SIP, we noted that based on historical data, the installation of SCR at similar units can be typically completed in three years. In OG&E's follow-up response to ODEQ's request for additional information on the four-factor analysis, the company explains that estimates of the time needed for installation of SCR at a "typical" gas-fired plant are not applicable to Horseshoe Lake, which is among the oldest active plants in the country and has a unique physical configuration that limits the available space for SCR installation. (See Appendix E of the proposed SIP). The four-factor analysis should provide additional information on the plant's "unique physical configuration" and explain in more detail how this affects the time necessary for implementation of SCR at the Horseshoe Lake units.

**RESPONSE**: Because of the great cost of controls, this implementation plan does not require the installation of selective catalytic reduction at this facility, regardless of the time required for such installation. Therefore, DEQ does not consider such an analysis necessary to come to this conclusion or appropriate at this time. In addition, it is well known that current supply chain issues in the aftermath of the COVID-19 pandemic are affecting all aspects of business, including planning and contracting for the installation of SCR. Historical data is not relevant in today's current economic climate.

**17. COMMENT: OG&E Horseshoe Lake** – The assumption of a shortened remaining useful life (20 years) in the cost analysis for NOx controls evaluated for Units 6, 7, and 8 is not appropriate without an enforceable shutdown date for these units. As discussed in EPA's August 2019 Guidance, "In the situation where an enforceable shutdown date does not exist, the remaining useful life of a control under consideration should be full period of useful life of that control as recommended by EPA's Control Cost Manual." See August 2019 Guidance at 34. Furthermore, in a follow up response to ODEQ, the company states that "OG&E is willing to consider enforceable air permit conditions that require retirements for these units no later than 20 years from the effective date of the SIP." (See Appendix E of the proposed SIP). However, ODEQ does not appear to take this information into account in their review and decision-making process when determining reasonable control measures for this source.

**RESPONSE**: Because of the great cost of controls, even assuming thirty years or more of future operations, this SIP would not require the installation of SCR at this facility. DEQ therefore does not consider such an analysis necessary to come to this conclusion or appropriate at this time.

**18. COMMENT: <u>OG&E Horseshoe Lake</u>** – The use of a 7% interest rate in the cost analysis is not appropriate. As discussed earlier in this section of this document, the cost analysis should be based on either the bank prime rate or a company-specific interest rate for consistency with the Control Cost Manual. If a company-specific interest rate is available and is being used to estimate the cost of controls, documentation supporting that interest rate should be provided with the cost analysis.

**RESPONSE**: A lower interest rate, even if Oklahoma Gas and Electric could obtain one in the future economy, would diminish the net cost of controls, even assuming a thirty-year useful life of the facility, inadequately to alter its conclusion that no potential cost-effective controls exist. See also, DEQ's response to Comment #11 regarding interest rates.

**19. COMMENT: <u>Oxbow Kremlin Calcining Plant</u>** – The assumption of a 20-year remaining useful life in the cost evaluation of controls is not sufficiently supported with documentation that is site-specific for the Oxbow Kremlin Calcining Plant. As discussed in EPA's August 2019 Guidance, "Annualized compliance costs are typically based on the useful life of the control equipment rather than the life of the source, unless the source is under an enforceable requirement to cease operation." See August 2019 Guidance at 33. We note that the Oxbow Port Arthur Calcining facility located in Port Arthur, Texas, began operations in 1935 and is currently still operating. According to the four-factor analysis provided to ODEQ by the company, the Oxbow Kremlin Calcining Plant commenced operation in the 1963-1970 time frame. The Oxbow website also states that the three kilns at the Kremlin Calcining Plant were built in the late 1960's and early 1970's.[3] Unless there is additional site-specific information that would limit the life of Kremlin Calcining Plant, such as a federally enforceable requirement to cease operation, the four factor analysis should be based on the useful life of the control equipment. Based on what we have historically observed and available literature, an assumption of 30 years for the equipment life of scrubbers and DSI is reasonable and consistent with EPA's Control Cost Manual. Revising the four-factor analysis to reflect an assumption of 30 years for the equipment life of $SO_2$ controls at this source would result in lower $/ton numbers that ODEQ may find to be cost-effective.

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[3] See *https://www.oxbow.com/Services_Value_Added_Services_Calcining.html*.

**RESPONSE:** As mentioned previously, EPA's Cost Control Manual is guidance and not mandated. DEQ concurs that the remaining useful life for Oxbow's facility is based on the remaining useful life of the control equipment versus the life of the source. However, as addressed in Oxbow's second response, EPA's Cost Control Manual states " …we expect an equipment life of 20 to 30 years for wet FGD systems." Although EPA uses 30 years in its example calculations, the Cost Control Manual does not state that 30 years is the only acceptable remaining useful life timeframe. No changes have been made to the SIP.

**20.** **COMMENT:** **<u>Oxbow Kremlin Calcining Plant</u>** – The four-factor analysis and the company's follow-up response to ODEQ's request for additional information explain that average hourly $SO_2$ emission rates (measured at each kiln during the January 2015 to December 2019 period) were used as the basis for the O&M cost estimates while annual average $SO_2$ emission rates (during the January 2018 to December 2019 period) were used as the basis for the calculation of tons of $SO_2$ emissions reduced and cost-effectiveness of the control technologies evaluated. The company explains that average hourly SO2 emission rates from the January 2015 to December 2019 period were used as the basis for the O&M cost estimates because they were determined to be representative of typical operating conditions and fluctuations experienced at each kiln. On the other hand, annual average $SO_2$ emission rates form the January 2018 to December 2019 period were used as the basis for the calculation of $SO_2$ tons removed because these more recent emissions data reflect an increase in the sulfur content of the green petroleum coke and are expected to be more representative of future emissions from the facility. Please explain why the O&M cost estimates are not also based on January 2018 to December 2019 emissions data, given that the company believes these more recent emissions data are expected to be representative of future emissions.

**RESPONSE:** DEQ's review of the original four-factor analysis did not expose any methodological concerns that would have materially affected the conclusions reached. Oxbow's response to the DEQ's additional request answered the question raised by EPA during the previous review of our Draft Regional Haze SIP. DEQ appreciates EPA's concerns regarding Oxbow's use of average hourly emission rates for O&M costs versus their use of annual average emission rates to assess available $SO_2$ emission reductions available and the cost-effectiveness of control technologies that could be employed to achieve those emissions reductions; however, DEQ does not believe that a recalculation of the O&M costs would yield a different conclusion and, therefore, there is no need to ask Oxbow to perform additional cost calculations at this time.

**21.** **COMMENT:** **<u>Panhandle Eastern Cashion Compressor Station</u>** – Section 6.4.2.6. of the SIP narrative explains that engine testing data recently provided to ODEQ by the company provides lower and more accurate estimates of the NOx emissions from the facility's engines compared to the conservative estimates of NOx emissions the company had previously reported and upon which ODEQ's source selection analysis was based. The SIP narrative states that had the actual emissions data been used when selecting sources for the four-factor analysis, this facility would have been excluded for small contribution. Please specify if this means that the %EWRT*Q/d of the facility would have fallen below ODEQ's selected threshold of 0.5%. The SIP narrative should provide the %EWRT*Q/d for the facility using the actual emissions data provided by the company to support ODEQ's conclusions regarding this facility.

**RESPONSE**: Panhandle Eastern claims a *Q*/*d* of 3.6 tons year$^{-1}$ km$^{-1}$, based on 465.4 tons of $NO_x$ emissions in 2016 and a distance to the Wichita Mountains of 129 km, the distance to the closest point in the wilderness area. The area-of-influence study assumed 146 km, the distance to the monitor, which corresponds to *Q*/*d* of 3.2 tons year$^{-1}$ km$^{-1}$. Those lower emissions, which DEQ accepts as valid, mean that this emission source falls below the 5.0 tons year$^{-1}$ km$^{-1}$ *Q/d* cutoff for further analysis. It accounts for 0.4% of the aggregate product of extinction-weighted residence time and ratio of quantity of emissions to distance to the Wichita Mountains; this statistic moreover also falls below the 0.5% %EWRT**Q/d* cutoff for further analysis.

22. **COMMENT: Western Farmers Hugo Power Plant** – The use of a 7% interest rate in the cost analysis is not appropriate. As discussed earlier in this section of this document, the cost analysis should be based on either the bank prime rate or a company-specific interest rate for consistency with the Control Cost Manual. In the company's follow-up response to ODEQ's request for additional information, the company dismisses EPA's comment that the use of a 7% interest rate is inappropriate and states that using the bank prime rate (3.25%), the cost-effectiveness of dry flue gas desulfurization (DFGD) and wet flue gas desulfurization (WFGD) would be $6,830/ton and $7,091/ton, respectively, and the overall conclusion of no controls necessary for reasonable progress would remain unchanged. We reaffirm that the cost analysis should document and use the bank prime rate at the time of the analysis and calculations used in estimating the cost-effectiveness using the bank prime rate should be provided in the SIP to allow EPA and the public to review and evaluate this information.

**RESPONSE:** As EPA mentions in its comment, Western Farmers provided revised cost estimates using the 3.25% bank prime rate in its follow-up response and these revised cost estimates did not change the selection of controls. EPA and the public were afforded the opportunity to review and evaluate the cost estimate information as it was included in Appendix E of the SIP as referenced in the SIP narrative for the Hugo Plant. However, DEQ will add these cost estimates directly to the narrative as well. Please see also DEQ's response to comment #11 for further discussion regarding interest rates.

**23.** **COMMENT:** **<u>Western Farmers Hugo Power Plant</u>** – The cost estimates for DFGD and WFGD were based on cost estimates from the Technical Support Document for EPA's 2011 Oklahoma $SO_2$ BART FIP. The company escalated those cost numbers, which were based on 2009 dollars, to 2019 dollars using CEPCI escalation indices. The EPA's Control Costs Manual does not recommend escalating costs over more than 5 years. Therefore, we recommend that a new cost analysis be conducted for DFGD and WFGD controls that is based on year dollars consistent with the year the analysis is conducted instead of relying on an outdated cost analysis that is escalated over a 10-year period.

**RESPONSE:** As included in Western Farmers' second response, the estimated total capital costs for both DFGD and WFGD were lower than the estimates for neighboring coal-fired plants. Although maybe not EPA's preferred method, DEQ does not believe the method of cost calculation used by Western Farmers is in error and sees no reason to revise the estimates in its SIP.

**24.** **COMMENT:** **<u>Cost Thresholds</u>** – ODEQ appears to avoid selecting a cost threshold for $SO_2$ controls but points to \$5,000/ton as being "widely used as a reasonable threshold in evaluating $SO_2$ compliance costs for Regional Haze" (See page 46 of SIP narrative), and notes that Texas selected a cost threshold of \$5,000/ton and Arkansas selected a cost threshold of \$5,086/ton for EGU boilers. The SIP narrative states that "Evaluating the thresholds used by neighboring states that affect Oklahoma or are affected by Oklahoma as a guidepost is a reasonable approach when setting a reasonable cost threshold." (See page 46 of SIP narrative). The SIP narrative points to Texas and Arkansas as having used \$5,000/ton as a cost threshold in the second planning period but EPA is also currently aware of other states considering up to \$10,000/ton as reasonable. We note that the first planning period involved the evaluation of BART controls at sources that were older and mostly uncontrolled. Considering the iterative nature of the regional haze program, it is reasonable to expect that following the installation of controls at the largest sources during the first planning period, sources with lower emissions and thus potentially less cost-effective controls (i.e., higher \$/ton figures) will likely be pulled in for evaluation in the second and subsequent planning periods. It may be a more appropriate approach to select cost thresholds for the second planning that are higher than those from the first planning period. Ultimately, if a state applies a threshold for cost/ton to evaluate control measures, the selected cost threshold should be justified based on a review of the sources selected for evaluation and the available controls for this planning period.

Regarding ODEQ's selection of a $NO_x$ control cost threshold in the range of $1,400 to $2,000/ton, which is based on the estimated marginal cost of complying with CSAPR Update ozone season $NO_x$ emissions budgets, we note that the transport program under CAA section 110(a)(2)(D)(i)(I) is an entirely separate program from regional haze, serving a different statutory purpose and involving the consideration of factors that may have no relationship to the regional haze program. There were numerous source-specific $NO_x$ controls estimated to cost over $2,000/ton that were found to be cost-effective in the first planning period by states and/or EPA. We recommend ODEQ look to examples and precedent within the regional haze program as a starting point for evaluating what may be cost-effective in making reasonable progress on visibility in the second planning period. We further note that the CSAPR Update was, by its own terms, only a partial remedy to the problem of interstate ozone transport for the 2008 ozone NAAQS, intended to obtain near-term emissions reductions by the 2017 ozone season. EPA has never made any finding that the control strategy in the CSAPR Update constituted the only emissions controls for $NO_x$ at EGUs that could be found to be cost-effective. Thus, we see no basis for the CSAPR Update to serve as a cost-effectiveness benchmark for Oklahoma's second planning period Regional Haze SIP. ODEQ's selection of a cost threshold of $1,400 to $2,000/ton for $NO_x$ controls in the second planning period does not seem appropriate or sufficiently justified. EPA suggests ODEQ consider applying a more robust cost threshold based on the full range of first planning period costs found to be reasonable, in addition to more recent control cost assumptions, including those found in other state plans for the second planning period.

We note that by taking the above comments into account and increasing the control cost thresholds, ODEQ could strengthen its long-term strategy and secure additional emissions reductions and visibility benefits. For instance, increasing the $NO_x$ control cost threshold could potentially result in several of the engines at the DCP Chitwood Plant being identified as cost-effective. $NO_x$ controls for five of the engines evaluated at the DCP Chitwood Plant were estimated by the company to cost in the range of $3,250 - $5,800.

**RESPONSE:** The regional haze rule does not set a specific cost threshold or methodology for determining if a control technology is reasonable, and therefore cost thresholds are made on a state-by-state basis. Cost threshold selections by an individual state are naturally, at least in part, influenced by the amount of progress needed to be under the uniform rate of progress for its Class I area or the Class I areas it affects. The decision by an individual state to use a higher cost threshold, such as the $10,000 mentioned by EPA, does not automatically imply that Oklahoma should select a same or similar cost threshold. As stated in its SIP, DEQ generally considers $5,000/ton to be a reasonable cost threshold for $SO_2$, and that it is also in-line with its neighboring states. As mentioned elsewhere, DEQ does not agree that the iterative nature of the regional haze program automatically means that the cost threshold should increase in each successive planning period. In fact, when other air programs have reduced emissions nation-wide as well as within the state, and visibility progress is continuing to be made as documented by actual monitoring results, a reasonable cost threshold need not be increased from the previous planning period.

DEQ is aware that the CSAPR Update serves a different statutory purpose than regional haze. DEQ seeks to meet all its statutory obligations, but places particular emphasis on those programs that relate to public health, which is the case for the CSAPR Update since it relates to the National Ambient Air Quality Standard for ozone. Therefore, DEQ still concludes that compliance with the CSAPR Update provides a greater public benefit while also achieving the necessary reductions to meet the aesthetic goals of the Regional Haze program. This is discussed further in DEQ's response to comment #5. For the above-stated reasons, DEQ believes that it is not unreasonable to consider the CSAPR Update cost threshold for $NO_x$ in cost determinations for regional haze.

DEQ believes that the cost thresholds in its SIP are appropriate for this second planning period and therefore no changes are necessary.

**25.** **COMMENT:** **Cost Thresholds** – Section 6.8 of the SIP narrative discusses the selection of cost thresholds and notes that "Because the emission units under evaluation are existing rather than new units, ODEQ concluded that Best Available Control Technology (BACT) cost factors would be inappropriate." (See page 36.) Please provide further clarification on this statement, including a discussion of the "cost factors" ODEQ is referring to.

**RESPONSE:** DEQ did not mean to imply that there were individual cost factors related to BACT that DEQ considered but rather that the application of the BACT dollar-per-ton cost-effectiveness threshold may not be appropriate when setting a cost threshold for existing units under regional haze. DEQ has clarified this language in the SIP.

**26.** **COMMENT:** **Long-Term Strategy** – ODEQ must clearly identify the enforceable emission limitations, compliance schedules, and other measures that are being included in the long-term strategy for the second planning period. Section 6.9 of the SIP narrative states that "[In addition to the ongoing air pollution control programs, the Smoke Management Plan, and the construction regulations in OAC 252:100-29], DEQ incorporates into its long-term strategy, the reductions documented in the four-factor analyses discussed in Section 6.4 above. See also Appendices E, F & G. Specifically, requirements and limitations associated with ONEOK's removal of seven engines and commitment to removing the remaining six before the end of Planning Period 2 (i.e., 12/31/2028) at the Maysville Gas Plant as agreed to in Regional Haze Agreement No. 22-085." No other requirements and limitations aside from those for the ONEOK Maysville Gas Plant appear to be included in Oklahoma's long-term strategy. This is inconsistent with section 6.4.2.3. of the SIP narrative, where ODEQ identifies non-selective catalytic reduction (NSCR) as a cost-effective control for engine CM-2322 at the Mustang Gas Binger Plant (at an estimated cost of $24.67/ton NOx removed) and states that the source will be required to install and operate this control technology no later than one year following EPA's approval of this portion of the Oklahoma Regional Haze SIP based on the four-factor analysis.

When a state determines that a particular control is necessary for reasonable progress based on an evaluation of the four statutory factors, that control must be included in the state's long-term strategy. In this case, given that the four-factor analysis summary presented in the SIP narrative states that ODEQ is requiring the installation of NOx controls on engine CM-2322 based on the four-factor analysis provided by the company, a NOx emission limit consistent with the operation of this control equipment, reporting and recordkeeping requirements, and a compliance schedule must be included in the long-term strategy for the second planning period and must be clearly identified as such in the SIP. This is consistent with 40 CFR §51.308(f)(2), which states that "The long-term strategy must include the enforceable emission limitations, compliance schedules, and other measures that are necessary to make reasonable progress, as determined pursuant to (f)(2)(i) through (iv)."

**RESPONSE:** DEQ intended for engine CM-2322 at the Mustang Gas Binger Gas Plant to be included in its LTS, which is why DEQ made reference to the "reductions documented in the four-factor analyses discussed in Section 6.4 above." However, DEQ has revised Section 6.9 to be more explicit as it relates to engine CM-2322.

**27.** **COMMENT:** **<u>Long-Term Strategy</u>** – The "Executive Summary" section of the draft SIP states that "Considering the advanced progress toward natural conditions thus far, the time remaining in planning period 2 (2018 – 2028), the results of the four-factor analyses, and financial uncertainty associated with Oklahoma's sources, DEQ selected a long-term strategy that recognizes and relies in large part upon the existing pollution control programs and clean energy technology advances that have resulted in and will continue to result in advanced progress. As older emission units continue to be replaced or retired, emission reductions will likely continue along the recent trends, and meeting a reasonable progress goal will be achievable with this long-term strategy." (See page 5 of SIP narrative). It is not clear how much weight ODEQ placed on the "financial uncertainty associated with Oklahoma's sources" in developing the long-term strategy given that this "financial uncertainty" does not appear to be discussed in detail elsewhere in the SIP. In any case, we do not consider "financial uncertainty associated with Oklahoma's sources" to be an appropriate justification for ODEQ's conclusion that controls are not necessary for reasonable progress.

Additionally, the statement that "emission reductions will likely continue along the recent trends, and meeting a reasonable progress goal will be achievable with this long-term strategy" suggests a potential misunderstanding of the regional haze requirements and confusion regarding the relationship between RPGs and the long-term strategy. The Clean Air Act, 42 USC section 7491(b)(2), requires that SIPs contain long-term strategies for making reasonable progress towards the national visibility goal. The Regional Haze Rule establishes a framework of periodic, comprehensive SIP revisions to implement this mandate. 40 CFR 51.308(f) requires that each periodic SIP revision contain a strategy for making reasonable progress for the applicable period. The increment of progress that is "reasonable progress" for a given implementation period is determined through the four statutory factors. 40 CFR 51.308(f)(2)(i). EPA has explained that reasonable progress cannot be determined prior to or independently from the analysis of control measures for sources. See 82 FR 3078, 3091/3 (Jan. 10, 2017); Clarifications Memo at 6. ODEQ must therefore determine what is necessary to make reasonable progress in the second implementation period by using the four factors to analyze control measures for sources. While progress made in the first implementation period, ongoing emission trends, and anticipated changes in emissions (including due to shutdowns, on-the-way controls, or other factors) may inform a state's regional haze planning process, these circumstances alone do not satisfy a state's obligation to determine and include in its SIP the measures that are necessary to make reasonable progress. Therefore, any suggestion that a state's goal in a given planning period should be to establish a long-term strategy that achieves the RPG is incorrect and contrary to the Regional Haze Rule requirements. This statement should be removed from the SIP.

**RESPONSE**: DEQ has removed the "financial uncertainty" statement from the Executive Summary as it is at least partially encompassed within the 4-factor analyses submitted by the selected facilities. This statement was originally also meant to include why DEQ focused on the sources it did and did not choose to embark on source selection outside of point sources. However, since this is explained better and in more detail elsewhere in the SIP its removal from the Executive Summary is appropriate. DEQ has also removed from the Executive Summary the statement "and meeting a reasonable progress goal will be achievable with this long-term strategy."

**28.** **COMMENT: <u>Progress Report</u>** – The Regional Haze Rule provides that the plan revision due on or before July 31, 2021, must include a commitment by the State to meet the requirements of paragraph (g) of this section. See 40 CFR 51.308(f). Consistent with this regulatory requirement, language should be added to Section 5 of the SIP narrative with a commitment to submit the January 31, 2025, progress report. See also August 2019 Guidance, Appendix D at D-5.

**RESPONSE**: DEQ has added a reference to the required January 31, 2025, progress report and 40 C.F.R. 51.208(f) to Section 5 of the SIP.

**29.** **COMMENT: Progress Report** – The Regional Haze Rule requires States to include in the SIP revision an assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred since the period addressed in the most recent plan required under paragraph (f) including whether or not these changes in anthropogenic emissions were anticipated in that most recent plan and whether they have limited or impeded progress in reducing pollutant emission and improving visibility. See 40 CFR 51.308(g)(5). The SIP Progress Report portion of the proposed SIP does not appear to address whether the changes in anthropogenic emissions discussed in Section 5.6 of the proposed SIP were anticipated in the most recent plan required under paragraph (f). The final SIP must address all portions of 40 CFR 51.308(g)(5).

**RESPONSE**: No one can anticipate every change in emissions. Nevertheless, the previously submitted implementation plan revision contained enough expressions of uncertainty in succeeding economic conditions and petroleum and natural gas production that the actual emissions fell mostly within the expected range. The previous implementation plan, however, failed to anticipate the magnitude of reduction in sulfureous emissions throughout large portions of the country. A shift in electric generation from coal to natural gas caused these reductions, which resulted in an unanticipated net benefit to visibility improvement at the Wichita Mountains. Smaller unforeseen reductions in emissions occurred on account of other EPA regulatory actions as well. Clarifying language has been added to Section 5.6.

**30.** **COMMENT: State-to-State and FLM Consultation** – The SIP narrative contains a statement on page 43 that seems to indicate that the legal standard triggering consultation is "significant" contribution to or impairment of visibility. (See "The Arkansas Division of Environmental Quality (ADEQ) identified two facilities in Oklahoma reasonably anticipated to impair visibility significantly at the Caney Creek Wilderness Area: OG&E Muskogee Generating Station and WFEC Hugo Generating Station.") The phrase "reasonably anticipated to impair visibility significantly" is not used in the federal regulation. (See Sec. 6.6, p. 34; 6.6.3, 6.6.4, p. 35). The legal standard is "reasonably anticipated to contribute to visibility impairment" 40 CFR 51.308(f)(2)(ii), which suggests a much lower threshold than "reasonably anticipated to impair visibility significantly." ODEQ should review the state of its consultations to ensure that they consistent with and can be justified under the "reasonably anticipated to contribute to visibility impairment" legal standard of 51.308(f)(2)(ii).

**RESPONSE:** DEQ's state consultations were consistent with the legal standards in 40 C.F.R. §51.308(f)(2)(ii). The term "significantly" in the aforementioned sentence was inadvertently left in and has now been removed. EPA's references to the other sections and page numbers correspond to the FLM draft version rather than the public comment version of the RH SIP to which these comments pertain. No other changes are needed.

**31.** **COMMENT:** **State-to-State and FLM Consultation** – The SIP should include all available documentation of Oklahoma's consultations with other states, including copies of all correspondence between Oklahoma and other states. This is consistent with the requirement of 40 CFR 51.308(f)(2)(ii)(C) that "[a]ll substantive interstate consultations must be documented." The proposed SIP currently includes copies of two letters received by Oklahoma from the Missouri and Arkansas with "asks" from these states and copies of letters sent by Oklahoma to Texas, Nebraska, Louisiana, and Arkansas with "asks" from Oklahoma. However, there is no documentation of when/how Oklahoma responded to the letters it received or when/how Nebraska, Louisiana, and Arkansas responded to the "ask" letters sent by Oklahoma. Copies of any response letters sent or received by Oklahoma to these or any other states as part of state-to-state consultation must be included in the SIP. If there was no further written correspondence exchanged after the initial "ask" letters, Section 6 of the SIP narrative or Appendix A should document any follow-up discussions between the states.

**RESPONSE:** The RH SIP includes all documentation of consultation between the states. DEQ did not provide a written response to the "ask" letters from Missouri or Arkansas nor did DEQ receive written responses to its "ask" letters to Texas, Nebraska, Louisiana, and Arkansas. Consultation occurred as documented in the table in Appendix A through additional meetings with states or during monthly CenSARA RH calls. Through the CenSARA RH calls, Oklahoma was aware when each state had information available regarding the facilities that they were evaluating for four-factor analysis and when those results were available for review.

**32.** **COMMENT:** **State-to-State and FLM Consultation** – Section 6 of the SIP narrative should clearly state if there is any disagreement between Oklahoma and another state regarding the outcome of the state-to-state consultation and/or the emission reduction measures necessary to make reasonable progress in a Class I area. In particular, Section 6.5 of the SIP narrative is vague as to whether Oklahoma agrees with Texas regarding the outcome of the consultation. Given the large contribution to visibility impairment at Wichita Mountains from Texas sources, any disagreement between the two states regarding the sources that should be analyzed, or control requirements should be clearly discussed.

**RESPONSE:** Oklahoma and its neighboring states worked together well through the RH consultation process. Although each state may have taken a slightly different approach to it source selection and four-factor analyses, DEQ believes emission reduction measures necessary to make reasonable progress at the Wichita Mountains Wilderness Area are being taken. No disagreement need be documented in the RH SIP.

**33.** **COMMENT:** **State-to-State and FLM Consultation** – The identification of the Muskogee Generating Station by both Arkansas and Missouri as reasonably anticipated to impair visibility at one or more of their Class I areas (see Sections 6.6.1 and 6.6.3) lends further support to our concern regarding ODEQ's decision to automatically eliminate the OG&E Muskogee Generating Station from further analysis on the basis that this is a BART source. As we discussed elsewhere in this document, OG&E Muskogee Unit 6 is a coal-fired unit and is not subject to BART and thus was not evaluated or controlled under regional haze in the first planning period. In light of Oklahoma's consultation with Arkansas and Missouri, ODEQ should evaluate Unit 6 in a full four-factor analysis to determine if SO2 and/or NOx controls are necessary.

**RESPONSE:** Please see DEQ's response to EPA Comment #5 above.

**34.** **COMMENT:** **State-to-State and FLM Consultation** – The Regional Haze Rule at 40 CFR 51.308(i)(4) requires that the plan (or plan revision) provide procedures for continuing consultation between the State and Federal Land Manager on the implementation of the visibility protection program. The proposed SIP revision does not appear to specifically address this requirement. The final SIP submittal must address this requirement at 40 CFR 51.308(i)(4).

**RESPONSE**: DEQ added acknowledgement of these provisions of federal regulation and assurances of its intent to follow said regulations to its implementation plan.

**35.** **COMMENT:** **Environmental Justice** – As discussed in the Clarifications Memo, states have discretion to consider environmental justice in determining the measures that are necessary to make reasonable progress and formulating their long-term strategies, as long as such consideration is reasonable and not contrary to the regional haze requirements. *See* Clarifications Memo at 16. We encourage Oklahoma to consider whether there may be equity and environmental justice impacts in the development of its regional haze strategy for the second planning period, including impacts on tribal lands. *Id.* Section 8.2 of the SIP narrative provides a discussion of Oklahoma's consultation with Oklahoma tribes during the SIP development process. We also encourage Oklahoma to describe any outreach to other communities with environmental justice concerns or underserved communities that the State conducted, the opportunities Oklahoma has provided for communities to give feedback on its proposed strategy, and the consideration Oklahoma gave environmental justice and impacts on tribal lands in its technical analyses.

**RESPONSE**: The Wichita Mountains lies in the historic territory of the Comanche nation, but no person currently legally inhabits this wilderness area. EPA's EJSCREEN 2.0 was run for a 10-mile radius around the Wichita Mountains Wilderness Area, and as expected, none of the Environmental Justice Indexes for air quality were near the 80$^{th}$ percentile that EPA suggests may warrant further investigation. DEQ aims to enforce environmental laws in all parts of Oklahoma, and believes that all people should be protected from the impacts of environmental pollution regardless of race, national origin, or income. DEQ is committed to ensuring such protection through the development, implementation, and consistent enforcement of environmental laws and regulations. Oklahoma currently attains all national ambient air quality standards.

In addition, DEQ ran EJSCREEN 2.0 for a 5-mile radius around each of the 12 sources selected for four-factor analyses. None of the Environmental Justice Indexes for air quality were over the 80$^{th}$ percentile nationally, which is the criteria that EPA suggests may warrant further investigation to determine if an EJ Community is present. The EJSCREEN reports are included in Appendix J.

Section 8 of this implementation plan revision describes the consultation and outreach process, including outreach to our Tribal partners and the general public. DEQ did not receive any relevant response to its outreach to our Tribal partners beyond an acknowledgement of receipt of our outreach attempts in some instances.

**36.** **COMMENT: <u>Other Observations</u>** – The Regional Haze Rule requires that states submit an implementation plan that includes an analysis of the actual progress made during the previous implementation period up to and including the period for calculating current visibility conditions, for the most impaired days and the clearest days. See 40 CFR 51.308(f)(1)(iv). Appendix D of the August 2019 Guidance explains that the "actual progress made during the previous implementation period up to and including the period for calculating current visibility conditions" is determined by calculating the difference between the average visibility condition in the period of 2003-2007 and the average visibility condition for each subsequent 5-year period, up to and including the 5-year period that determines current visibility conditions. See August 2029 Guidance, Appendix D, at D-1. Consistent with the Regional Haze Rule and our guidance, this analysis should be added to the SIP.

**RESPONSE**: DEQ supplied annual statistics for the period of interest in various tables in chapter 3. DEQ added averages for three 5-year periods to Table 3-8 as suggested by EPA.

As shown by the individual year data that was already included, the 5-year average deciview on the 20% most impaired days has trended downward since monitoring began demonstrating that actual progress has been made.

**37.** **COMMENT:** **<u>Other Observations</u>** – Provision # 28 of the Consent Order between ODEQ and ONEOK contained in Appendix F provides that "This agreement shall remain open until the Regional Haze SIP into which it is incorporated is superseded by a subsequent EPA-approved Regional Haze SIP." This provision is vague. For instance, it is not clear if the portion of the provision stating "This agreement shall remain open…" is intended to mean that the agreement shall remain in effect and binding upon the parties, or whether something else is intended. Additionally, the portion of the provision stating "…until the Regional Haze SIP into which it is incorporated is superseded by a subsequent EPA-approved Regional Haze SIP" could be interpreted in more than one way. It is not clear if the State and the company interpret this provision to mean that when EPA approves Oklahoma's Regional Haze SIP for the third planning period, the Regional Haze SIP for the second planning period will be considered to be "superseded" and thus the ONEOK Consent Order will no longer be effective. If so, this provision is inappropriate given that when EPA approves a revision to a SIP, the revision either adds to the existing SIP and/or may replace or revise specific provisions in the existing SIP but it does not necessarily supersede the previously approved SIP. Therefore, provision #28 should be removed or redacted from the final SIP submitted to EPA.

**RESPONSE:** Paragraph #28 of the ONEOK Consent Order has been redacted in the version of the Consent Order being submitted for inclusion in Oklahoma's Regional Haze SIP for the Second Planning Period (see Appendix F).

**38.** **COMMENT:** **<u>Other Observations</u>** – Section 3.2 of the SIP narrative discusses the deciview visibility index at the Wichita Mountains and states that Table 3-8 lists the 2018 RPGs for the Wichita Mountains. However, it appears that this is erroneously labeled as "EPA-calculated RPG for 2028" in Table 3-8. We recommend that the label in Table 3-8 be corrected to state "EPA-calculated RPG for 2018."

**RESPONSE:** This typo in Table 3-8 has been corrected.

**39.** **COMMENT:** **<u>Other Observations</u>** – Figure 4-4 presented in the SIP narrative shows the breakdown of Oklahoma 2014 NEI NOx emissions, including the breakdown of oil and gas NOx emissions. In light of the large proportion of Oklahoma NOx emissions from oil and gas, it would be informative for ODEQ to include a breakdown of NOx emissions by category for 2017 NEI emissions as well given that 2017 is the most recent year of NEI data available.

**RESPONSE:** Figure 4-4 has been updated to include a side-by-side breakdown of 2014 and 2017 NEI $NO_x$ emissions data, including the breakdown of oil and gas $NO_x$ emissions. The comparison shows that the ratio of sources, and therefore contributions, has stayed relatively stable between 2014 and 2017.

**40.** **COMMENT:** **<u>Other Observations</u>** – Section 1 of the SIP narrative includes a short summary of Oklahoma's request under the Safe, Accountable, Flexible, Efficient Transportation Equity Act of 2005 (SAFETEA) to administer the State's environmental regulatory programs in certain areas of Indian Country. At the end of that paragraph is the statement: "For the purposes of this Planning Period 2 RH SIP, DEQ intends to request information and seek reductions as necessary to meet the goals of the RH Rule in all areas of the state." (See SIP narrative at page 6). This statement is not sufficiently clear or specific. The state should, following the contours of any approval pursuant to Section 10211(a) of the Safe, Accountable, Flexible, Efficient Transportation Equity Act of 2005: A Legacy for Users, Pub. Law 109-59, 119 Stat. 1144, 1937 (August 10, 2005), expressly address the geographic scope of where the plan will apply and to what areas of Indian country.

**RESPONSE:** DEQ has modified the final sentence of this paragraph to clarify that it plans to implement the RH program in accordance with EPA's October 1, 2020, approval of Oklahoma's request under SAFETEA. This should be considered sufficiently clear and specific.

**DCP Operating Company, LP** – Submitted as an email received on June 29, 2022, from Ms. Lynn Holt, Principal Environmental Specialist, with respect to those portions of the SIP relevant to DCP Operating – Chitwood Gas Plant.

**41.** **COMMENT:** In section 6.4.2.7, second sentence, annual emissions emitted by DCP identified by ODEQ are 833 tons of NOx from various natural gas fueled engines on site. This value is not limited to only the natural gas engines on site. The 833 tons NOx includes 11 tons from other non-engine sources. The 2016 emissions inventory included 822 tons of NOx from natural gas fueled engines. In addition, DCP revised the 2016 inventory in Jan 2020. The revised inventory represented lower emissions than originally reported due to correcting the actual run hours of a diesel fired pump operation and revising emissions for another engine based on stack test data. The corrected NOx emissions for engine only sources is 765.5 tons NOx in 2016. DCP does not believe this is a major change in the draft SIP, however suggestions revision in the interest of completeness and accuracy.

**RESPONSE:** Section 6.4.2.7 has been corrected to reflect 766 TPY of $NO_x$ from the engines in 2016, as verified on the revised 2016 emissions inventory submitted to DEQ in 2020.

**42.** **COMMENT:** In Section 6.4.2.7, fourth sentence, ODEQ identified the classification of the engines as two-stroke lean burn with the exception of C-6 and C-7 which are not classified. DCP has classified these engines as four-stroke lean burn engines based on the exhaust oxygen in excess of the threshold limit of 2% excess oxygen. These engines were evaluated as such in DCP has attempted to install controls on the units in the past and was unable to achieve reliable operation at reduced combustion oxygen levels. Therefore these two (2) engines are considered and authorized as lean burn engines. While also not a significant point to the overall draft SIP, DCP feels the inclusion is important for completeness since the other engines are classified.

**RESPONSE:** Section 6.4.2.7 has been revised to identify C-6 and C-7 as four-stroke lean burn engines.

**43.** **COMMENT:** Section 6.4.2.7 states that "at the suggestion of EPA, DEQ calculated the cost options at a lower interest rate (3.25%) than the rate used by DCP (7%)". DCP disagrees with the assertion that the lower interest rate is appropriate. DCP also included the current (February 2022) cost of borrowing capital in the additional response submitted on February 17, 2022, as 5.54%. The cost of borrowing has significantly increased in the past several months, not decreased; therefore, DCP disagrees that a 3.25% rate is appropriate and respectfully suggests that 7% is a more appropriate benchmark.

**RESPONSE:** Section 6.4.2.7 has been revised to also include the 5.54% cost of borrowing capital included in DCP's 2022 response.

**Concerned Citizens** – Submitted as emails from June 28, 2022, through July 1, 2022, from Phone2Action, on behalf of the following individuals: Joe Henry, Larry Sherman, Nannette Tresner, Kathy Nix, Candace Meyer, Maurice Hawthorne, Patrick Green, Scheree Davis, Weldon Williams, Timothy Stebler, Vickie Harvey, Jay Hiller (See Appendix M for individual emails.)

**44.** **COMMENT:** The emails expressed concern that the proposed Regional Haze plan will not amount to any new reductions in pollution even though sources harm visibility in places like the Wichita Mountains, Caney Creek Wilderness, and Guadalupe Mountains National Park. The emails also said many of the sources are impacting communities hardest hit by the problem such as Garfield, Muskogee, and Choctaw counties. The email asserts that the draft SIP is inadequate and fails to require cost-effective controls for polluting sources across the state and that Oklahoma is obligated to make progress toward improving air quality and limiting haze pollution in Class I areas. The emails urge DEQ to revise the plan to 1) require emission controls for the sources the state selected for review in this planning period; 2) establish a much lower cost-of-control thresholds for reasonable progress that is in line with other states; 3) correct the inflated cost of controls calculations; and 4) thoroughly assess environmental injustice impacts as recommended by EPA.

**RESPONSE:** DEQ appreciates the emails from Oklahoma's citizens and their concern for national parks and wilderness areas. DEQ takes its role of protecting visibility at the Wichita Mountains Wilderness Area seriously. DEQ is including in its Planning Period 2 RH SIP enforceable shutdowns, removals, and controls at some of the twelve sources DEQ selected for review, as discussed in the Long-term Strategy in Section 6.9. DEQ believes the cost-of-control threshold evaluated in the Planning Period 2 RH SIP is appropriate to make incremental progress and stay under the adjusted uniform rate of progress as required under the Regional Haze Rule. DEQ also believes that this threshold is in-line with neighboring states. DEQ believes the cost-of-control calculations submitted by the 4-factor analysis sources are generally accurate and appropriate. DEQ has added in Section 6.2.2 some additional information regarding environmental justice and its evaluation using EJSCREEN 2.0 of the 12 sources selected for further analysis. The Wichita Mountains Wilderness Area is not considered a community with EJ concerns. The three counties identified in the emails (Garfield, Muskogee, and Choctaw) also do not exceed the 80$^{th}$ percentile for the Environmental Justice Indexes in EJSCREEN 2.0 related to air quality. These counties meet all national ambient air quality standards, and recent monitoring and modeling exercises confirm their $SO_2$ attainment status. EJSCREEN reports have been included as Appendix J.

**Concerned Citizens** – Submitted as emails received from June 29, 2022 through July 1, 2022 from KnowWho, a service provider, on behalf of the following individuals associated with Sierra Club: Allison Lemke, Renee Buchholtz, Gary Cathey, Lynn Rambo-Jones, Carly Costley, Dale Bushyhead, LaDonna Darius, Ellen Trump, Deborah Hirt, Joe Allen Henry, Elise Kilpatrick, Nikki Harris, Kara Mccullar, Howard Baer, Victoria Dickey, John Hinds, Radha Singh, Vicki Muir, Lisa Lewis, Cherie Wheeler, Matt Lloyd, Maggie Gibson, Barbara VanHanken, Frank Barry, Anna Blewett, Cathy Reynolds, Haley Brown, Kathy Walsh, Douglas Horton, Douglas Weirick, Robert Fiegel, Pandora Pinazza, Michael Battles, Joan York, Debe Judah, Timothy Stebler, James and Audrey Martin, Karla Hinton, Betty Ripley, Patrick Green, Cameron Cross, Lana Henson, Jolene Robertson, Jessica Sherwood, Holly Hunter (See Appendix M for individual emails.)

**45.** **COMMENT:** The emails state that Oklahoma must propose a Regional Haze Plan that effectively reduces pollution to fulfill the state's statutory and regulatory obligation to improve air quality for our wilderness areas and communities. The emails request that DEQ's plan 1) require cost-effective, technically feasible emission controls identified for the coal power plants and oil and gas facilities the state selected for review in this planning period; 2) establish a cost-effectiveness threshold for reasonable progress and one that is in line with other states; and 3) thoroughly assess environmental justice impacts (as EPA recommended).

**RESPONSE:** DEQ appreciates the emails from Oklahoma's citizens and their concern for the health and enjoyment of those visiting wilderness areas and national parks as well as the economic impacts these areas have on our economy. DEQ takes its role of protecting visibility at the Wichita Mountains Wilderness Area seriously. DEQ is including in its Planning Period 2 RH SIP enforceable shutdowns, removals, and controls at some of the twelve sources DEQ selected for review, as discussed in the Long-term Strategy in Section 6.9. DEQ believes the cost-of-control threshold evaluated in the Planning Period 2 RH SIP is appropriate to make incremental progress and stay under the adjusted uniform rate of progress as required under the Regional Haze Rule. DEQ also believes that this threshold is in-line with neighboring states. DEQ has added in Section 6.2.2 some additional information regarding environmental justice and its evaluation using EJSCREEN 2.0 of the 12 sources selected for further analysis. The Wichita Mountains Wilderness Area is not considered a community with EJ concerns. EJSCREEN reports have been included as Appendix J.

**Conservation Organizations** – Submitted as an attachment to an email received on July 1, 2022, from Ms. Natalie Levine, Climate and Conservation Program Manager, National Parks Conservation Association, on behalf of Michael B. Murray, Chair, for the Coalition to Protect America's National Parks; Chloe Crumley, Field Representative, Texas and Oklahoma, for the National Parks Conservation Association: and Sanjay Narayan, Managing Attorney for Sierra Club (together the "Conservation Organizations").

**Note:** Where possible, the original numbering from the comment letter has been referenced. Attachments referenced in the Conservation Organizations' comments are accessible here: https://drive.google.com/drive/folders/15vA5oh8a_1lnOKw2VPmL0dYtASwjZOSN?usp=sharing

**46.** **COMMENT:** **Overview Comment** – ODEQ's Draft SIP does not meet the legal requirements of the Clean Air Act or federal regulations, and should be revised to address errors, flaws, and omissions, including:

a. ODEQ has not sought or disclosed sufficient data to document the determinations underlying its SIP;

b. ODEQ has not adequately addressed the impacts of transboundary emissions originating in Texas;

c. ODEQ has arbitrarily excluded sources of pollution from its control analysis, including area sources and BART sources; and

d. ODEQ has prescribed insufficient pollution controls for those sources it has considered, relying on an unreasonable Q/d threshold, as well as incorrect cost and control data.

**RESPONSE**: Commenters later elaborate on these introductory assessments, so DEQ responds to these comments later in this document. Nevertheless, DEQ strongly disagrees with these characterizations of the public draft of its implementation plan revision for regional haze.

**47. COMMENT: <u>DEQ Has Not Sought or Made Available Critical Data Documentation Underlying its Draft SIP</u>** – For these comments, emissions and controls information for all EGUs were downloaded from EPA's Air Markets Program Data (AMPD) website.[4] Additional information was obtained from the Energy Information Agency (EIA).[5] Lastly, the Title V permits for a number of units were reviewed.

a. **2.1. ODEQ Must Include Unit-Level Emission Data in Its SIP** – In preparation for these comments, the ODEQ was requested to provide (1) unit-specific emissions information for non-EGUs (or point to where that information is kept). ODEQ promptly provided that information, along with a number of Title V permits that were requested.

Knowing and verifying the emissions from each unit and the existing controls installed on the individual units at facilities emitting hundreds to thousands of tons of air pollution annually is a critical function of an air agency that must control the emissions from these sources under a variety of state and federal programs. With respect to the regional haze program, this information is necessary to (1) verify that the right units/processes at facilities have been identified to receive four-factor analyses and (2) verify that the emissions from these units used in cost-effective calculations are actually representative of expected future operations. Therefore, although the information was promptly provided, the emissions data must be made a part of the Oklahoma Regional Haze SIP. Without this information, ODEQ cannot satisfy the documentation requirements of 40 CFR 51.308(f)(2)(iv), discussed later in these comments.

Title V permits are another essential tool, as they list all the emission limits for these units, along with testing requirements, controls, and vital information concerning the type and functioning of the units. Although the Title V permits were promptly supplied when requested, they are not downloadable from ODEQ's site. Therefore, for the same reason, ODEQ must include this information in its SIP or provide an external link to that information.

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[4] See https://ampd.epa.gov/ampd/. This information is compiled and assessed in spreadsheets that are included in this analysis.

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

b. **2.2. ODEQ Must Demand Better Cost Data Documentation** – In some cases, ODEQ correctly questioned source data, equipment life, interest rates, and other information related to the four-factor analyses provided by sources.[6] In a few cases, ODEQ has noted that even if the information were corrected, it would not have changed its decision regarding the implementation of the controls in question. However, it appears that in most cases ODEQ has accepted the source's explanations for its use of this data and information, even though doing so is demonstrably incorrect. Thus, ODEQ has failed to require that sources properly conduct cost-effectiveness calculations, as thoroughly documented in these comments.

In its 2017 revision to the Regional Haze Rule, EPA specifically emphasized the need for the proper documentation of this type of data:[7]

> We are changing proposed 40 CFR 51.308(f)(2)(iv), regarding documentation requirements, to be 40 CFR 51.308(f)(2)(iii) ... to "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 area it affects." The purpose of this provision is to require states to document all of the information on which they rely to develop their long-term strategies, which will primarily be information used to conduct the four-factor analysis. Therefore, in addition to modeling, monitoring and emissions information, we are making it explicit that states must also submit the cost and engineering information on which they are relying to evaluate the costs of compliance, the time necessary for compliance, the energy and non-air quality impacts of compliance and the remaining useful lives of sources.

The Regional Haze Guidance reinforces this point:[8]

> As part of meeting the requirement of the Regional Haze Rule for the state to document the cost and engineering information on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress (40 CFR 51.308(f)(2)(iii)), every source-specific cost estimate used to support an analysis of control measures must be documented in the SIP. If information about a source has been asserted to be confidential, we recommend the state consult with its EPA Regional office regarding whether such confidentiality is appropriate and allowed under the CAA and if so how it can be reconciled with the need for adequate documentation of the basis for the SIP.

ODEQ must therefore correct these fundamental failures in the documentation of its SIP. Unless these issues are addressed, ODEQ cannot satisfy Section 51.308(f) which

[6] See "second request letters" in Appendix E.
[7] See 82 FR 3096 (January 10, 2017).
[8] See Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, EPA-457/B19-003 August 2019. Page 32.

requires "supporting documentation for all required analyses" or Section 51.308(f)(2)(iii) which requires that ODEQ "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."

**RESPONSE:** Neither the regional haze rule nor federal law requires the Oklahoma SIP or the state's website to include every permit and all emissions data that it collects. EPA already regularly receives the necessary data from Oklahoma and every other state to develop the national emissions inventory, which it makes publicly available on its website. 40 C.F.R. §51.308(f)(2)(iv) states:

(iv) The State must consider the following additional 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) Source retirement and replacement schedules;
(D) Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs; and
(E) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

DEQ considered these factors in developing its long-term strategy. No changes to the SIP are needed.

Specific to cost documentation, DEQ believes that the responses contained in Appendix E, in concert with the information included in Section 6 of the SIP, meets the requirements of 40 C.F.R. § 51.308(f)(2)(ii).

**48. COMMENT: <u>ODEQ's Consultation Documentation Is Inadequate</u>** – It appears that the only information on ODEQ's consultation, other than the short summaries presented in Sections 6 and 8, appears in Appendix A. Appendix A contains links to some documents, including ODEQ's letters to Texas, Nebraska, Arkansas, and Louisiana. There are no links to any of the reply letters. ODEQ's consultation record is therefore incomplete.

The requirement in section 51.308(f)(2)(iii) to "document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying" extends to ODEQ's consultation requirement, as consultation is intended to determine whether additional "emission reduction measures that are necessary to make reasonable progress" are necessary.

Additionally, without this information, ODEQ cannot demonstrate under section 51.308(f)(2(ii) that it "has included in its implementation plan all measures agreed to during state-to-state consultations or a regional planning process, or measures that will provide equivalent visibility improvement." Therefore, ODEQ must fully present all responses to its letters that it received for other state agencies.

**RESPONSE**: The RH SIP includes all documentation of consultation between the states. There are no links to any reply letters because there are no reply letters. Consultation occurred as documented in the table in Appendix A through additional meetings with states or during monthly CenSARA RH calls. Through the CenSARA RH calls, Oklahoma was aware when each state had information available regarding the facilities they were evaluating for four-factor analysis and when those results were available for review. See also DEQ's responses to comments #31 through 33.

**49.** **COMMENT:** **<u>ODEQ Must Document the Impacts from Texas</u>** – Section 51.308(f)(2)(ii) requires that Oklahoma "consult with those states that have emissions that are reasonably anticipated to contribute to visibility impairment in the mandatory Class I Federal area …." Therefore, in order to address this requirement, ODEQ must first establish which states do have such impacts and the magnitude of those impacts.

Despite the fact of the well-established impact of Texas sources on the Wichita Mountains during the first planning period, ODEQ pays scant attention to the subject in its SIP. In fact, it does not present any information concerning the actual impacts from Texas sources on the Wichita Mountains. Mainly, when it does mention Texas, it does so in the context of noting emission reductions that have occurred as a result of large point sources retiring. The exception to this is in reviewing its consultations with Texas: ODEQ there notes that it requested that Texas consider 15 sources to consider "for further analysis."[9]

Consequently, ODEQ must provide documentation of the scope and magnitude of the impacts that Texas sources have on the Wichita Mountains. For that matter, it must do the same for other states as well. Unless it provides that documentation, it cannot demonstrate that it has in fact satisfied the consultation requirement in section 51.308(f)(2)(ii).

**RESPONSE**: DEQ acknowledges the contribution of emissions from sources in Texas to visibility impairment at the Wichita Mountains Wilderness Area. This information is shown in Appendices B and C and even Appendix D as well as Section 6 of the SIP. As required by the regional haze rule in 40 C.F.R. § 51.208(f)(2)(ii), and as documented in Appendix A, Oklahoma and Texas consulted on several occasions. Also as required by the regional haze rule, Oklahoma submitted an "ask" letter to Texas as included in the comment above. DEQ lacks any legal authority to compel Texas to make emission reductions. However, any emission reductions in Texas in $NO_x$ or $SO_2$ emissions will likely prove beneficial to visibility improvement at the WMWA.

[9] 27 See page 42.

**50. COMMENT: <u>ODEQ Should Have Insisted that Texas Reduce Its Emissions</u>** – On page 42, ODEQ summarizes its consultation with Texas:

> On July 17, 2020, DEQ sent a letter to TCEQ requesting Texas consider the fifteen sources listed in Table 6-5 for further analysis and to continue to consult with DEQ regarding any resulting analyses or measures at the above-listed sources. On August 11, 2020, DEQ and TCEQ held a web conference during which TCEQ communicated its planned recommendations for Texas's SIP. TCEQ's photochemical modeling projected minimal visibility benefits from potential controls on sources of interest. TCEQ concluded that further controls were not necessary to meet reasonable progress at affected Class I areas.

As indicated earlier in these comments, ODEQ has not presented any information that actually establishes the impact of Texas sources on the Wichita Mountains and must do so. Despite its failure to present that information, ODEQ obviously concluded that a number of sources in Texas have the potential to impact the Wichita Mountains. ODEQ's failure to press Texas to control its sources abuses the spirit and intent of the consultation requirements in section 51.308(f)(2(ii).

**RESPONSE**: DEQ disagrees that it is not meeting the spirit and intent of the consultation process and feels that its consultation process with Texas was adequate. See DEQ's response to comment #49 above.

**51. COMMENT: <u>Problems with ODEQ's Source Selection</u>** –

a. **6.1. ODEQ Must Consider Area Sources** – Section 40 CFR 51.308(f)(2)(i) indicates that states should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. Table 4-3 indicates that nonpoint (area) sources are the top NOx emitters of any sector for ODEQ's 2017 emission inventory. ODEQ also presents Figure 4-3, which is a pie chart depicting source-type contributions to the 2014 and 2017 NOx emission inventories, and Figure 4-4, which depicts sector contributions to the 2014 NOx emission inventory. It is unclear how Figure 4-4 relates to Figure 4-3. ODEQ must improve its presentation of its NOx emission inventory to (1) make it clear how much the oil and gas sector contributes and (2) the point and non-point source breakdown.

On page 21, ODEQ attributes the apparent increase in NOx area source contributions from 2014 to 2017, at least in part, to its improved and more accurate NOx emission inventory data gathering and accounting procedures. Regardless, it is apparent that NOx area source emissions, in particular those from the oil and gas sector, are quite significant. Because there does not appear to be any real consideration of how area sources could be analyzed and potentially controlled, it does not appear that ODEQ has satisfied section 51.308(f)(2)(i). ODEQ must therefore reexamine its source selection methodology to ensure it has properly considered area sources.

b. **6.2. ODEQ Cannot Incorporate Resource Constraints into Its Regional Haze Decision Making** – As indicated above, ODEQ does not properly assess NOx area sources. It provides the following explanation on page 22 for not doing so:

> Where appropriate, larger oil and gas point sources have been evaluated for potential NOx controls during Planning Period 2. The sheer number of small oil and gas sources makes it extraordinarily inefficient and impracticable for ODEQ, a state agency with limited means, to evaluate each source individually for possible emission reductions.

Similarly, on page 30, ODEQ indicates that one of the reasons it chose to perform a separate source selection for NOx and $SO_2$, instead of adopting the usual procedure of basing it on the combined effects of NOx and $SO_2$, was because "given the resource intensity of conducting a four-factor analysis, DEQ focused on greater emissions of one pollutant, not split between moderate emissions of two pollutants." Obviously, here, ODEQ adopted its split source selection strategy because it concluded it would result in fewer sources to evaluate, thus easing its resource burden.

Again, on page 36, ODEQ states that one of the reasons it did not subject sources that underwent a BART analysis in the first planning period to four-factor analyses was because "eliminating sources identified in the AOI study that underwent BART reduced the potential for expending valuable resources on analyzing sources with little opportunity for further reductions."

ODEQ's resource excuse for not properly considering NOx area sources, in particular those from the oil and gas sector and BART sources, is untenable. ODEQ must not base its source selection methodology on any type of resource consideration. First, as this is a *state* SIP, ODEQ is not solely responsible for mustering the resources necessary to complete the SIP. Therefore, if it requires additional resources, it should draw them from other state agencies. Second, the Clean Air Act, 42 U.S.C. §7410(a)(2)(E) requires that each SIP provide "necessary assurances that the State ... will have adequate personnel, funding, and authority under State (and, as appropriate, local) law to carry out such implementation plan (and is not prohibited by any provision of Federal or State law from carrying out such implementation plan or portion thereof).[10] This requirement of the Clean Air Act ensures that states do not underfund their environmental agencies as an excuse for not adequately administering SIPs. Thus, ODEQ cannot base any aspect of its SIP on a lack of resources. If it doesn't have adequate personnel or other resources in order to conduct a complete source selection and the resulting four-factor analyses, it is obligated to allocate and/or acquire those resources. ODEQ must therefore reexamine its source selection methodology in order to ensure that it has selected sources for four-factor analyses without regard to resource considerations.

[10] See https://www.govinfo.gov/content/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapIpartA-sec7410.htm.

c. **6.3. ODEQ Cannot Give BART Sources a Blanket Exemption to Four-Factor Analyses** – Beginning on page 35, ODEQ describes its rationale for excluding certain sources from four-factor analyses that otherwise met its single source selection methodology:

> [T]hirteen emission units at six facilities were required, through either Oklahoma's Planning Period 1 RH SIP or EPA's FIP, to implement BART controls in conjunction with Planning Period 1. All thirteen emissions units reduced NOx emissions by installation of (or in some cases utilizing existing) low-NOx burners. For the six coal-fired BART units, existing PM controls were considered to meet BART requirements. BART $SO_2$ requirements for these six units have been applied as follows: the four OG&E units have installed dry-gas desulfurization, one PSO unit was retired, and the other is applying dry-sorbent/carbon injection $SO_2$ controls until its retirement in 2026. It is unlikely that a new four-factor analysis would result in a finding that additional cost-effective controls are available and appropriate for these emission units.

ODEQ simply concludes that the mere fact that the source in question received a BART evaluation in the first planning period is sufficient criteria for excluding it from a second planning period reasonable progress analysis. In a number of cases, such as the OG&E Muskogee Units 4 and 5, Sooner Station and the PSO Northeastern Station, its decision appears sound for $SO_2$, as it is unlikely that a four-factor analysis would conclude that additional cost-effective controls for $SO_2$ are available.[11] In fact, in Sooner's case the two units are exceeding their FIP required emissions limits and now demonstrate two of the best performing dry scrubbing systems in the United States. ODEQ should therefore ensure their permits are amended to reflect this level of performance.

However, this same conclusion cannot be made for NOx for these sources, as none have any post-combustion NOx controls and remain large sources of NOx, even though some have switched to burning natural gas (Muskogee Units 4 and 5). Southwestern and Seminole are other examples.

ODEQ does not provide any documentation to demonstrate its assertion that these BART sources could not be further cost-effectively controlled. ODEQ's blanket exemption of its BART sources conflicts with the Regional Haze Rule, as indicated by Section 51.308(e)(5), which states the following:

> After a State has met the requirements for BART or implemented an emissions trading program or other alternative measure that achieves more reasonable progress than the installation and operation of BART, BART-eligible sources will

[11] Note this is not true for Muskogee Unit 6, as discussed in the next section.

> be subject to the requirements of paragraphs (d) and (f) of this section, as applicable, in the same manner as other sources.

EPA further reinforces this requirement in its 2017 Regional Haze Rule revision:[12]

> The BART requirement was a one-time requirement, but a BART-eligible source may need to be re-assessed for additional controls in future implementation periods under the CAA's reasonable progress provisions. Specifically, we anticipate that a number of BART-eligible sources that installed only moderately effective controls (or no controls at all) will need to be reassessed. Under the 1999 RHR's 40 CFR 51.308(e)(5), BART-eligible sources are subject to the requirements of 40 CFR 51.308(d), which addresses regional haze SIP requirements for the first implementation period, in the same manner as other sources going forward.

It is very likely that a properly performed NOx four-factor analysis would conclude that cost-effective controls are available for a number of these and other sources that ODEQ wrongly excludes. Thus, ODEQ's blanket BART exemption is likely illegal. ODEQ must properly assess the BART sources it has given an exemption to four-factor analyses.

d. **6.4. ODEQ Must Evaluate Muskogee 6 for Cost-effective Controls** – As indicated above, ODEQ provided Muskogee Station a blanket exemption from four-factor reviews because Units 4 and 5 had undergone BART analyses in the first round SIP review. The incorrectness of this general exemption aside, it certainly does not extend to Unit 6. Unit 6 did not undergo a BART analysis in the first planning period, as its construction date fell outside of the BART window. Although Units 4 and 5 have since switched to natural gas, at the time of the BART analyses, Units 4, 5, and 6 were essentially identical, all being 572 MW tangentially-fired Combustion Engineering boilers that burned coal.

According to information from EPA, Unit 6's NOx control consists of overfire air with no post-combustion NOx controls and has no $SO_2$ controls.[13] Just as Units 4 and 5 were evaluated for both NOx and $SO_2$, Unit 6 should now be evaluated for NOx and $SO_2$ in this planning period. Furthermore, there is no reason to conclude that the same controls that were found to be cost-effective for Units 4 and 5 in the first planning period would somehow cease to be cost-effective for Unit 6. Consequently, ODEQ must evaluate Muskogee Unit 6 for both $SO_2$ and NOx controls.

e. **6.5. ODEQ's Source Selection Strategy Is Unsound, Undocumented, and Arbitrary** – The discussion elsewhere in these comments concerning cost

[12] See 82 FR 3083 (January 10, 2017).

[13] See https://ampd.epa.gov/ampd/. This information is compiled and assessed in spreadsheets that are included in this analysis.

documentation also applies to ODEQ's source selection strategy as well: 40 CFR 51.308(f)(2)(iii) requires that ODEQ "document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which [it] is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I area it affects." As discussed below, ODEQ's source selection strategy suffers from unsound and arbitrary decision making, and a lack of documentation.

i. *6.5.1. ODEQ's Single Pollutant Source Selection Reasoning Is Unsound* – Beginning on page 30, ODEQ describes its source selection methodology. As indicated above, ODEQ did not adopt the usual procedure of selecting sources based on their combined NOx and $SO_2$ impacts. Rather, ODEQ evaluated impacts by calculating Q/d separately for NOx and $SO_2$, and provides the following justification for having done so on page 30:

> When analyzing source contribution to visibility impairment, DEQ considered NOx and $SO_2$ emissions separately instead of aggregating contributions from each pollutant for a total source contribution. Visibility impairment at the WMWA is clearly dominated by NOx in winter conditions and $SO_2$ in most of the rest of the year (see Figures 3-2 and 3-3 in Section 3). If DEQ had considered the total contribution of a source from both NOx and $SO_2$ together, the potential for visibility improvement by controlling aggregated emissions would not reasonably correspond with the MIDs identified through monitoring. Control options for NOx and $SO_2$ vary widely, resulting in the possibility that controlling one, but not both, is cost effective. The visibility improvement from controlling one pollutant at a source identified through aggregate contribution would be far less than would be considered cost effective. Additionally, given the resource intensity of conducting a four-factor analysis, DEQ focused on greater emissions of one pollutant, not split between moderate emissions of two pollutants.

First, it is not unusual for one pollutant to seasonally impact visibility impacts at Class I Areas. In fact, this is the usual situation for many Class I Areas.

Second, ODEQ's statement that this typical situation somehow justifies or supports its decision to separately evaluate NOx and $SO_2$ because "the potential for visibility improvement by controlling aggregated emissions would not reasonably correspond with the MIDs [Most Impacted Days] identified through monitoring" is irrational. There is no requirement or view expressed anywhere in the Clean Air Act, the Regional Haze Rule, or guidance that source selection should be tied to seasonal pollutant visibility impacts. As ODEQ indicates in Figure 61, both ammonium nitrate and ammonium sulfate impact the WMWA fairly equally. In such a situation, it makes no difference whether one pollutant or the other dominates during particular times of the year: controlling either pollutant will improve annual visibility. Furthermore, the fact that NOx and $SO_2$ both significantly impact visibility at the WMWA reinforces the need to perform source selection on the basis of "aggregated emissions." ODEQ's reference to the "the potential for visibility improvement by controlling aggregated emissions," has no relationship to the source selection process or in fact cost-effectiveness analysis. Controls are almost always assessed on the basis of how much they control one pollutant.

ODEQ is correct that, "[c]ontrol options for NOx and $SO_2$ vary widely, resulting in the possibility that controlling one, but not both pollutants, is cost effective." Again, that is not unusual. States routinely select sources by considering both NOx and $SO_2$ impacts together only to later find that only one or no pollutant controls turn out to be cost-effective. ODEQ's offhanded consideration of it during source selection wrongly biases control analyses.

ODEQ's next statement that "[t]he visibility improvement from controlling one pollutant at a source identified through aggregate contribution would be far less than would be considered cost effective" indicates a consideration that is also temporally out of order and thus biases the source selection process. ODEQ does not know at this stage of the process what controls may be cost-effective and what visibility improvement they may bring. In fact, ODEQ does not quantify the visibility improvement resulting from any of the controls it considers in any of its four-factor analyses, and thus has no basis on which to make this or similar statements.

In summary, all of ODEQ's above statements are a red herring, deflecting attention from ODEQ's apparent fundamental motivation, which it states at the end of the above quote: selecting sources by considering both NOx and $SO_2$ together would result in more sources selected, which would result in a resource drain to ODEQ. As indicated above, this conflicts with the Clean Air Act. Therefore, ODEQ must revise its source selection strategy. Either ODEQ must provide a rational basis that justifies its decision to select sources by separately considering NOx and $SO_2$, or ODEQ must selected sources on the basis of the combined impacts of NOx and $SO_2$.

*6.5.2. ODEQ's Q/d Threshold Is Arbitrary* – On page 32, ODEQ states that it began its source selection by identifying sources with a Q/d value of 5 tons per year per kilometer or greater, which as discussed above is based on separate calculations for NOx and $SO_2$. ODEQ does not present any discussion or justification for selecting a Q/d threshold of 5. As indicated above, this does not satisfy the documentation requirement of 40 CFR 51.308(f)(2)(iii). ODEQ cannot satisfy this requirement due to its complete lack of any justification for selecting its Q/d threshold of 5. This is especially important because, as discussed above, ODEQ has separately calculated Q/d for NOx and $SO_2$— an unusual strategy that should correspond to a lower Q/d value than that used by states using combined NOx and $SO_2$ emissions, which ODEQ admits to having chosen due to resource constraints.

ii. *6.5.3. ODEQ's Source Selection Threshold Is Arbitrary and Illegal* – On page 32, ODEQ states that following elimination of sources from four-factor analyses based on its single pollutant Q/d source selection described above, it further eliminated sources by applying a 0.5% or greater contribution threshold based on dividing the Extinction Weighted Residence Time (EWRT) by the distance from WMWA to the source. ODEQ's only justification for this additional threshold is expressed on page 33: "Given the successful reduction in visibility impairment over the last decade, 0.5% is an appropriate threshold for identifying sources of the greatest importance for further analysis." In fact, this exceedingly thin justification is no justification at all, but a prohibited action under the Regional Haze Rule: [14]

> Treating the URP as a safe harbor would be inconsistent with the statutory requirement that states assess the potential to make further reasonable progress towards natural visibility goal in every implementation period. Even if a state is currently on or below the URP, there may be sources contributing to visibility impairment for which it would be reasonable to apply additional control measures in light of the four factors. Although it may conversely be the case that no such sources or control measures exist in a particular state with respect to a particular Class I area and implementation period, this should be determined based on a four-factor analysis for a reasonable set of in-state sources that are contributing the most to the visibility impairment that is still occurring at the Class I area. It would bypass the four statutory factors and undermine the fundamental structure and purpose of the reasonable progress analysis to treat the URP as a safe harbor, or as a rigid requirement.

As previously mentioned, and again here, the Regional Haze Rule makes it clear that states should not eliminate sources that could have cost-effective controls from consideration because a reasonable progress goal is below the URP. EPA's recent Clarification Memo reinforces this point:[15]

> The 2017 RHR preamble and the August 2019 Guidance clearly state that it is not appropriate to use the URP in this way, i.e., as a "safe harbor." The URP is a planning metric used to gauge the amount of progress made thus far and the amount left to make. It is not based on consideration of the four statutory factors and, therefore, cannot answer the question of whether the amount of progress made in any particular implementation period is "reasonable progress." This concept was explained in the RHR preamble. Therefore, states must select a reasonable number [of] sources and evaluate

[14] 82 FR 3099 (January 10, 2017).

[15] Memorandum from Peter Tsirigotis, Dir., EPA, to Reg'l Air Dirs., Regions 1–10 (July 8, 2021), hereafter referred to as the "Clarification Memo," available here: https://www.epa.gov/visibility/clarifications-regardingregionalhaze-state-implementation-plans-second-implementation. Page 15.

> and determine emission reduction measures that are necessary to make reasonable progress by considering the four statutory factors.

> Because ODEQ used the URP as a safe harbor, it must revisit its source selection methodology, reconsider its thresholds, reasonably select a set of sources for four-factor analyses, and justify that decision making through adequate documentation.

**RESPONSE**: DEQ is not required to address all sources in all planning periods. As stated in 40 C.F.R. § 51.308(f)(2)(i) "The State should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. The State must include in its implementation plan a description of the criteria it used to determine which sources or groups of sources it evaluated…." The iterative nature of the regional haze programs allows states to focus on different sectors, sources, and units in different planning periods. Point-in-case is the first planning period that focused on BART-eligible sources, facilities built between 1962 and 1977 that had the potential to emit 250 TPY or more of any air pollutant. The focus of the first planning period was most assuredly not on area sources. In this second planning period, DEQ has broadened its focus to a variety of sources it deems are the largest contributors to visibility impairment at the WMWA based on the data. Area sources are likely contributors to some of the visibility impairment at the WMWA. However, not all area sources are from the oil and gas industry as seems to be implied in this comment. DEQ has attempted to show in Figure 4-4 that the oil and gas industry makes up about 35% (in 2017) of all of the non-biogenic $NO_x$ emissions in Oklahoma. Of that 35%, approximately half, or 17%, is from permitted sources and 18% is from area sources that are not required to operate under DEQ air quality permits. In comparison, on-road $NO_x$ emissions account for 26% of the emissions. DEQ correctly made the determination that area sources, including oil and gas area sources, did not require further evaluation during this second planning period. These sources may be included in a future planning period.

DEQ appreciates the perspective that its sister state agencies may contribute to the formulation and development of this SIP revision; however, EPA traditionally and legally recognizes only DEQ as the air pollution control agency within the Oklahoma state government. EPA regularly accepts and acknowledges the adequacy of the plenary authority of this air pollution control agency under the Constitution and legislatively enacted statutory laws of this state. This SIP revision considers the resources of DEQ as finite and thus limited, but assuredly not inadequate. The relevant regulations and guidance require each state to analyze the four statutory factors for a meaningful proportion of the sources within its territorial jurisdiction. As noted in response to other comments, the vague term “meaningful” defies quantitative definition, and DEQ asserts that this implementation plan fulfills its interpretation of that criterion.

DEQ theoretically can conduct its own four-factor analyses of the sources without contacting the owner, operator, employees, or contractors of such sources.

Nevertheless, in the interest of conducting a reasonable and fair analysis of each source, DEQ requested the owner or operator of each source to supply the necessary information and appreciates the cost and expenditures that fulfillment of such requests placed on these entities. Air pollution control agencies in numerous other states followed a similar course in preparation of their respective implementation plan revisions. DEQ believes this was a good use of its resources. As for the rationale to not spend time and resources evaluating BART sources, please see DEQ's response to comment #5 above.

$NO_x$ and $SO_2$ constitute two chemically distinct, non-interchangeable precursors of separately measured components of visibility impairment under the interagency monitoring of protected visual environments (IMPROVE) protocol. Therefore, in consultation with relevant federal land managers, DEQ chose to evaluate them separately. Under the federal system, other states may come to different conclusions. The method in this implementation plan revision resulted in the consideration of every legal source of a large majority of $SO_2$ emissions in 2016 under either BART or the four-factor analyses in this implementation plan revision. Moreover, the important criterion involving extinction-weighted residence time makes intuitive sense only when considering the two components separately, given their different source regions. Northerly winds occur commonly during periods of freezing weather in the winter months, but southerly winds dominate the rest of the year. In this situation, the pollutants correspond with different origin regions, different seasons, and different chemical pathways and environments. Consequently, DEQ, in separating the pollutants, made a special effort to capture those sources that contribute most within its territorial jurisdiction to visibility impairment at the WMWA. The above comment appears to imply that a combination of $NO_x$ and $SO_2$ might ensnare a considerable number of facilities. Realistically, however, few sources emit moderate quantities of both $SO_2$ and $NO_x$ in the inventories, such that the total quantity of both pollutants together but neither pollutant independently gives $Q/d > 5$ tons year$^{1}$ km$^{1}$ in the inventories for 2016. A cursory analysis reveals only one such source: the Wynnewood petroleum refinery in Garvin County. DEQ stands by its source selection method as reasonable and appropriate and within its jurisdiction to determine.

In choosing to use $Q/d$ as a metric for evaluating whether to analyze sources of emissions further and to consider the four statutory factors, DEQ necessarily must select a threshold for separating the sources for further four-factor analysis from those for which no further analysis applies. Commenters describe the threshold as "arbitrary," but neighboring states applied a similar threshold, and DEQ knows of no non-arbitrary threshold that it could declare.

The comment correctly implies that this SIP sets a reasonable progress goal below the uniform rate of progress even while requiring few new controls. The comment nevertheless misunderstands the language in the public draft of this implementation plan revision. DEQ notes its previously unanticipated success in improving visibility at the WMWA to instill confidence in this implementation plan revision, not to use the uniform rate of progress as a safe harbor for not requiring the further controls that the commenter prefers. DEQ applied the 0.5% contribution threshold principally to ensure selection of the most polluting subset of sources for further analysis. Any cost-effective emission controls required under this plan therefore most likely contribute to diminution of visibility impairment at the Wichita Mountains Wilderness Area or at another mandatory Class I federal area in a different state.

52. **COMMENT: <u>ODEQ's Control Determinations Are Arbitrary</u>** – ODEQ does not present a coherent basis for rejecting controls. The only explanations ODEQ provides when it rejects controls can be found in Section 6 in the short paragraph summaries it presents on each four-factor analysis, which include statements such as: "DEQ concurs this is a reasonable conclusion," or "the controls would not be cost-effective." This in fact is a violation of section 51.308(f)(2)(i) of the Regional Haze Rule:

> The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering 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. The State should consider evaluating major and minor stationary sources or groups of sources, mobile sources, and area sources. The 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. In considering the time necessary for compliance, if the State concludes that a control measure cannot reasonably be installed and become operational until after the end of the implementation period, the State may not consider this fact in determining whether the measure is necessary to make reasonable progress.

As the rule requires, ODEQ must include in its implementation plan "a description of … how the four factors were taken into consideration in selecting the measures for inclusion in its long-term strategy." Although ODEQ cites to the four-factors of section 51.308(f)(2)(i) in its SIP, during the entirety of its review, it presents no information as to how it has considered them.

Apparently realizing this error, ODEQ attempts to rectify it for "costs of compliance" beginning on page 45, near the end of its SIP and well after it has finished rejecting controls. Here, ODEQ performs a contorted attempt to cite to a NOx cost-effectiveness threshold without actually adopting it. It cites to the 2016 CSAPR rule in which EPA adopted a position that it was acceptable to develop EGU NOx ozone season emission budgets using a control stringency of $1,400 per ton. ODEQ then states that "DEQ is not selecting a $1,400 per ton NOx cost-of-control threshold; rather, DEQ believes that a NOx cost of-control level in the range of $1,400 to $2,000 is consistent with the goals of the Regional Haze program." But then one paragraph later, ODEQ states, "DEQ concludes that a NOx cost-of-control threshold in the $1,400 to $2,000 per ton range is appropriate and reasonable."

In the next paragraph, ODEQ notes that $5,000/ton has been widely used as a reasonable threshold in evaluating regional haze $SO_2$ controls. It then opines that "[t]here is no reason to assume that this cost threshold must increase at every subsequent Regional Haze planning period." ODEQ does not actually state that it is adopting a $5,000/ton threshold for $SO_2$, and concludes by stating, "Given these technical and cost considerations, DEQ affirms that the submitted analyses reached the reasonable conclusions, and this implementation plan revision does not impose a requirement to install further $SO_2$ controls on the 12 sources subject to the four-factor analysis requirement or on any other sources during this planning period."

The only rationale for "selecting" such a low NOx threshold that emerges from the record is to limit the sources it examines. ODEQ does not explain why, considering the fact that $5,000/ton has been widely used as a reasonable threshold in evaluating regional haze $SO_2$ controls, it could not have adopted it for NOx as well. This is completely arbitrary. ODEQ must revisit its entire source selection strategy and elucidate a rational basis for establishing source selection thresholds.

**RESPONSE**: DEQ emphatically does not reject controls but merely declines to require overly costly or ineffective controls. For most sources, DEQ found the "costs of compliance" too high to mandate further controls. This determination makes the "time necessary for compliance" irrelevant as installing these cost-ineffective controls on a protracted or accelerated timescale does not make them cost-effective. The non-air-quality environmental effects and energy effects of installing these controls do not mitigate their excessive cost. In assessing the controls as too costly, DEQ considered the period of usefulness of the source; an anticipated or legally required shutdown of the source at a defined or earlier date only makes such controls even less cost-effective. Consequently, for every source that DEQ considered, the cost of potential controls simply dominated the other statutory factors.

Given that neither statute nor regulation mandates a certain threshold for determination of cost-effectiveness, DEQ may determine what is a reasonable and appropriate. See also DEQ's response to comment #24 above.

**53.** **COMMENT:** **<u>ODEQ Must Include Refined Coal in Its Four-Factor Analyses</u>** – According to EIA data, a number of the EGUs in Oklahoma have burned in the past or presently burn what is referred to as "refined" coal onsite, presumably in order to take advantage of federal income tax credits. These include AES Shady Point, GREC and River Valley.[16] In order to qualify for this tax credit, the Internal Revenue Service (IRS) requires that these EGUs must demonstrate "a reduction of at least 20 percent of the emissions of nitrogen oxide (NOx) and at least 40 percent of the emissions of either sulfur dioxide ($SO_2$) or mercury (Hg) released when burning the refined coal."[17]

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

[17] See https://www.irs.gov/irb/2010-40_IRB#NOT-2010-54.

It is unknown which facilities actually claim this tax break. Regardless, for every EGU that burns refined coal, claims the tax break, and has or will undergo a four-factor analysis, DEQ must require that the EGU demonstrate any NOx reduction it has achieved from refined coal. Because refined coal is minimally required to result in a 20% NOx reduction, it must be evaluated like any other NOx control. Furthermore, if the EGU is also claiming a 40% $SO_2$ reduction, it must demonstrate that as well.

**RESPONSE**: This comment is outside the scope of the regional haze program.

**54.** **COMMENT:** **<u>Review of the Oxbow Kremlin Calcined Coke Plant Four-Factor Analysis</u>** – The Oxbow Calcining Kremlin Calcining Plant is located in Garfield County. Its Title V Permit states that it receives raw petroleum coke by truck and rail from various refinery sources. It processes this raw coke through kilns, with natural gas and propane as a supplemental fuel, in order to calcine the coke. The calcined coke is loaded into bags, trucks or railcars for final shipment to customers. The facility operates three rotary kilns. Due to the age of the facility, it has been exempted from most rules and regulations.[18] Two reports present in Appendix E are reviewed, consisting of a September 2020 Trinity Report, which references a September 2020 Sargent & Lundy (S&L) report.[19]

a. **9.1. ODEQ Must Require Documentation for the Kremlin Cost-Effectiveness Calculations** – As noted throughout this section, Kremlin's contractors, Trinity and S&L, make a number of unsubstantiated claims regarding the types of, and limitations of, the $SO_2$ control systems evaluated. Considering the evidence presented herein that many of these claims are in fact unjustified, ODEQ must demand proper documentation from Kremlin. As indicated above, this is a requirement of 40 CFR 51.308(f)(2)(iii). In addition, Kremlin's contractor S&L, which produced the control cost analyses, must be required to provide documentation for its figures; instead they have no documentation whatsoever. Lastly, ODEQ must state in the SIP that it has specifically reviewed the confidential information that has been redacted in S&L's report and has found it credible and its use acceptable.

b. **9.2 The Kremlin Plant Must include NOx in Its Four-Factor Analysis** – In Appendix E, ODEQ instructs Oxbow Calcining that the Kremlin Plant's four-factor

[18] Part 70 Permit, Air Quality Division State of Oklahoma Department of Environmental Quality, Permit Number: 2019-0973-TVR3 Oxbow Calcining LLC, revised 10/20/2006. Pdf page 2 of the July 1, 2021 staff evaluation.

[19] Regional Haze Reasonable Progress Analysis, Oxbow Calcining LLC Kremlin Calcined Coke Plant, prepared by Trinity Consultants, September 29, 2020, hereafter referred to in this section as "the Trinity Report." SO2 Control Technologies Evaluation to Support Regional Haze Rule Analysis, Revision 0, September 29, 2020, Sargent & Lundy. Hereafter referred to in this section as "the S&L Report."

analysis for its three kilns is limited to $SO_2$.[20] As the following table indicates, the Kremlin Plant's NOx emissions are significant:[21]

**Table 1. Historical NOx and $SO_2$ Emissions from the Kremlin Calcined Coke Plant**

| Year | $SO_2$ (tons) | NOx (tons) |
|---|---|---|
| 2016 | 12,663.0 | 610.4 |
| 2017 | 16,681.8 | 768.6 |
| 2018 | 17,644.7 | 771.2 |
| 2019 | 12,716.9 | 603.9 |
| 2020 | 13,656.9 | 592.0 |

The South Coast Air Control District has identified a number of potential post-combustion controls that are feasible for coke calcining kilns, including SCR, LoTOx, and UltraCat.[22] These controls are capable of 95% NOx removal. ODEQ must therefore require that NOx controls be evaluated as part of the Kremlin Calcining Plant four-factor analysis.

c. **9.3. The Kremlin $SO_2$ Scrubber Design $SO_2$ Values Are Too High** – On page 2-3 of its report, Trinity states that it adopted the S&L $SO_2$ emission figures for the three kilns when performing its cost-effectiveness calculations. These figures are compiled by S&L, along with maximum $SO_2$ values and are reproduced below:[23]

**Table 2. S&L Kremlin Kiln $SO_2$ Emissions**

| Emission | Kiln 1 | Kiln 2 | Kiln 3 | Relevant Totals |
|---|---|---|---|---|
| Hourly $SO_2$ (lb/hr) | 1,626 | 1,447 | 924 | |
| Annual Average $SO_2$ (tons) | 6,556 | 5,674 | 2,950 | 15,180 |
| Maximum Monthly $SO_2$ (tons) | 761 | 755 | 381 | |
| Maximum Annual $SO_2$ (tons) | 9,132 | 9,060 | 4,572 | 22,764 |

[20] Letter to Whitney Hall from Kendal Stegman, dated July 1, 2020. Pdf page 175 of Appendix E.
[21] Emission data obtained from https://www.deq.ok.gov/air-quality-division/emissions-inventory/state-emissions-totals-infographics/.
[22] See Preliminary Draft Staff Report, Proposed Rule 1109.1 – Emissions of Oxides of Nitrogen from Petroleum Refineries and Related Operations and Proposed Rescinded Rule 1109 – Emissions of Oxides of Nitrogen from Boilers and Process Heaters in Petroleum Refineries, August 2021. See discussion beginning on pdf page 183. Available here: http://www.aqmd.gov/docs/default-source/rule-book/Proposed-Rules/1109.1/pdsr_pr-11091_75_day.pdf?sfvrsn=6.
[23] See page 6 of the S&L Report.

According to S&L, the hourly emission rates represent the average lb/hr rates for the period of January 2015 to December 2019. The annual emission rates represent the 12-month annual average tons/yr for the period of January 2018 to December 2019. The maximum monthly emissions rates shown represent the monthly total tons/month for the baseline period of January 2018 to December 2019.

S&L states that it used the maximum values to design the $SO_2$ control equipment, reasoning that such controls would have to be designed to treat exhaust gas based on these historical conditions. However, S&L further notes that the facility's existing Operating Permit Air Permit No. 2014-1698TVR2 (M-2), dated August 9, 2017, includes a combined maximum $SO_2$ emission limit of 4,790.90 lb/hr for the facility. Therefore, the maximum monthly emission rates reflect the maximum that each unit has reached separately, but not operating all at once.

This is an important consideration: even if the facility operated 24 hours a day continuously all year (24/7/365), its permit would restrict it to a maximum annual $SO_2$ emission of 20,984 tons (4,790.9 tons x 8,760 hrs/yr x ton/2,000 lbs). However, S&L's $SO_2$ control equipment is based on a maximum of 22,764 tons. S&L therefore overdesigned its control equipment.

d. **9.4. The Kremlin Wet Scrubber Cost-Effectiveness Calculation Is Greatly Inflated** – As discussed below, the Kremlin cost-effectiveness calculations contain a number of assumptions that serve to greatly inflate Trinity's cost-effectiveness calculations. These include (1) not considering combining the exhaust from all three kilns into one flue gas cooler and one absorber, (2) actually concluding that a separate waste heat electricity generation unit is required in order to lower the scrubber inlet temperature, (3) assuming a scrubber efficiency that is too low (4) assuming a contingency that is too high, (5) assuming too many additional operational personnel are needed, and (6) assuming an equipment life that is too low. None of these flaws were corrected by ODEQ.

   i. *9.4.1. Kremlin's Scrubber Efficiency Figures Are Low* – S&L provides no justification for its assumption that Kremlin's wet scrubber should be assumed to have an efficiency of 94%, its dry scrubber 92%, and DSI 40%. On page 2-3 of its report, Trinity attempts to link these figures back to EPA's BART FIP, and to cite to EPA's action regarding the Nelson Unit 6 in Louisiana. However, Trinity's linkage fails for several reasons. In its BART FIP, EPA actually assumed wet scrubber efficiencies of 98% with a floor of 0.04 lbs/MMBtu. Similarly, EPA assumed dry (SDA) scrubber efficiencies of 95% with a floor of 0.06 lbs/MMBtu. In other words, if operation of the SDA at 94% would cause the $SO_2$ outlet to fall below 0.06 lbs/MMBtu, then whatever efficiency corresponded to 0.06 lbs/MMBtu was used. This is clearly explained in EPA's proposal.[24] A similar approach was adopted for the Entergy Nelson evaluation.[25] It should be further noted that had Trinity followed all of the procedures outlined in these two actions, from which it attempts to cherry-pick data, much of the adjustments outlined below to Kremlin's cost-effectiveness calculations would not have been necessary.

ii. *9.4.2. Kremlin Does Not Adequately Consider Cooling Options* – Beginning on page 7 of its report, S&L discusses the options to lower the flue gas temperature exiting the kilns prior to entering the $SO_2$ control devices it considers. S&L states that the flue gas temperature is approximately 1,700 – 1,850°F, and that it must be lowered to 400°F to accommodate any of the $SO_2$ controls it considers, which consists of wet scrubbing, dry scrubbing and Dry Sorbent Injection (DSI). S&L does not provide any documentation for this temperature data and ODEQ must require Kremlin to provide that data under 40 CFR 51.308(f)(2)(iii). This documentation should (1) confirm the temperature of the flue gas at the point at which it would enter the various $SO_2$ controls contemplated, and (2) confirm the upper limit of the $SO_2$ control device inlet temperature.

S&L considers three methods to reduce the temperature of the flue gas: (1) water-based quenching, (2) air-based quenching, and (3) a waste heat recovery system used to drive a steam turbine generator (one for each kiln) which produces electricity for sale to the grid.

1. **Kremlin Must Consider Closed Loop Cooling** – S&L dismisses water-based quenching because it claims that it would increase Kremlin's water usage by approximately 180% which would require an additional 1,200 gpm for the cooling alone. On page 7, S&L opines that this rate of water cannot be guaranteed "due to the unconfirmed availability and/or Enid Kaw Lake Pipeline water take-off restrictions, as well as the significant amount of water lost to atmosphere." S&L then concludes that water-based quenching is not considered to be a reliable or practical flue gas temperature control option and was not evaluated further. ODEQ must require that Kremlin provide documentation to support this water usage claim. S&L provides little

[24] See 82 FR 925. Note these values were in fact first established in the Oklahoma FIP.

[25] See 82 FR 32298: "Entergy assessed SDA and wet FGD as being capable of achieving $SO_2$ emission rates of 0.06 lb/MMBtu and 0.04 lb/ MMBtu, respectively. As we discuss in the TSD, based on review of IPM documentation, industry publications, and real-world monitoring data, we agree with the LDEQ that 98% control efficiency for wet FGD and 95% control efficiency for SDA are reasonable assumptions and consistent with the emission rates identified by Entergy."

detail concerning the water-based cooling system it envisions, only stating the following on page 7 of its report:

> This temperature reduction option requires the injection of water into new ductwork designed for the new flue gas conditions and to allow for adequate water/flue gas contact. Water-based quenching systems would require significant quantities of freshwater, which would be lost to the atmosphere through evaporation.

It appears that S&L only evaluates a wet, open loop, "once through" water-based cooling system, in which large quantities of water are allowed to evaporate and must therefore be replaced. This is perplexing, as S&L is undoubtedly aware, the power generation industry has been using water conservation cooling towers and closed loop dry cooling systems for decades. Regarding water conservation cooling towers, the oft cited reference, "Cooling Tower Fundamentals" states:[26]

> The evaporative cooling tower was originally conceived as a water conservation device, and it continues to perform that function with an ever-increasing efficiency, sacrificing only from 3% to 5% of the circulating water to evaporation, drift and blowdown. This conservation rate in excess of 95% is a boon to industrial areas which are confronted with a limited or costly water supply.

Also, beyond this, dry cooling uses water contained in a closed loop, resulting in no loss to evaporation. Dry cooling is common in arid location where water conservation is a necessity.[27]

Thus, considerable water savings could be realized by the use of a typical water conservation type cooling tower system or a dry cooling system. ODEQ must therefore require that Kremlin consider both a (1) water conservation type cooling tower system and (2) a dry cooling system.

2. **Kremlin Wrongly Dismisses Air Cooling** – On page 8, S&L dismisses air-based cooling. Without any documentation, S&L opines that air-based cooling may result in dew-point corrosion in the heat exchanger, causing more frequent outages. It concludes that due to the relatively larger footprint in an already severely space constrained location as compared to water-based quenching, corrosion risks and potentially

[26] Hensley, John C., ed. 2006. Cooling Tower Fundamentals. SPX Cooling Technologies, Inc. 2006. Page 65. Available here: https://spxcooling.com/wp-content/uploads/Cooling-Tower-Fundamentals.pdf.

[27] See for instance, https://spgdrycooling.com/news/dry-cooling/, or https://www.babcock.com/home/environmental/spig-cooling-systems/dry-cooling-systems, or https://www.evapco.com/dry-cooling-101.

increased maintenance costs, air-based quenching is not considered a technically feasible or practical flue gas cooling technology for the facility and therefore was not evaluated further.

First, because S&L specifies that the flue gas temperature must be cooled to 400°F, corrosion is unlikely to be an issue. The composition of the exhaust is similar to that of a coal-fired boiler, and the concern is to prevent the condensation of sulfuric acid. As the Electric Power Research Institute (EPRI) reports in its Wet Stacks Design Guide, "Depending on the sulfur content of the coal and the moisture content of the flue gas, the sulfuric acid dewpoint of the unscrubbed bypass gas is 260 to 300 degrees F (127-149°C)."[28] Thus, the exhaust temperature will be above the point at which sulfuric acid condensation should occur. S&L's completely undocumented concerns aside, even if corrosion were a problem, this is a maintenance item and is therefore not a technical feasibility issue.

Second, S&L presents no documentation concerning the size of the air-cooling system that would be needed, or that such a size prevents its implementation. As ODEQ's own permit evaluation indicates, "The facility occupies an area of 320 acres, of which approximately 80 acres have been developed for the calcining operation."[29] Thus, information in the record indicates the facility has a great deal of available space. As even a causal examination of the aerial photographs of EGUs and industrial facilities indicates, cooling systems are often located some distance away from the fuel burning unit. Thus, any amount of additional available space offers flexibility. S&L itself notes on page 3 of its report that "[t]he Kremlin facility has open space available on-site, north of the existing kilns, which can be used for any additional equipment." S&L's space constraint concerns therefore appear to be specious. ODEQ must require that Kremlin consider an air-cooled system.

3. **Kremlin Wrongly Claims an Electrical Power Generation Plant Is a Necessary Part of Scrubbing** – After erroneously dismissing water and air cooling, S&L comes to the conclusion that the only suitable cooling system for the Kremlin plant is one that captures the waste heat, and uses it to produce steam that then drives a steam turbine generator to produce electricity. If this were not incredible enough, S&L then states on page 12 of its report, "Since the primary purpose of the heat

[28] Wet Stacks Design Guide, TR-107099 9017, Final Report, November 1996, prepared by BURNS & McDonnell for Electric Power Research Institute. Page 1-6. Available here: https://www.epri.com/research/products/TR107099.

[29] ODEQ, Air Quality Division Memorandum, July 1, 2021, Evaluation of Permit Application No. 2019-0973TVR3 Oxbow Calcining LLC Kremlin Calcining Plant (FAC ID 801). Page 1.

recovery system is to provide flue gas cooling, it should be noted that auxiliary power consumption costs for the APC and supporting systems are still included in this evaluation, no credit for base plant auxiliary power consumption savings or excess power generation sale to the grid were accounted for in this evaluation." In other words, S&L claims that a separate power generation plant is a necessary requirement for the installation of a scrubber at the Kremlin plant, but concludes that *it would be improper to offset this cost by considering the value of the produced electricity*. Further inflating the cost, S&L claims that separate steam turbine generators are necessary for each of the kilns. As indicated above, both water-based dry cooling and air-cooling are widely used and technically feasible. Instead of employing one of these technologies, S&L artificially inflates Kremlin's $SO_2$ control cost-effectiveness calculations by only considering that waste heat steam turbine generators are necessary. ODEQ must correct this situation.

iii. *9.4.3. Kremlin Must Consider One Flue Gas Cooler and Scrubber for All Three Kilns* – The erroneous assumptions S&L makes with regard to the type of flue gas cooler aside, S&L considers it necessary to configure a separate flue gas cooler and induced draft fan for each kiln. S&L states on page 26 of its report that it assumed two wet flue gas systems: one to service Kilns 1 and 2 and another for Kiln 3, due to "site space constraints." On page 31, S&L makes the same assumptions for its dry scrubbing cost analysis. In addition, approximately three times as many personnel are required to operate all of this equipment than if one set of systems serviced all three kilns, which further inflates the cost. No documentation, such as site drawings or pictures was presented to substantiate these claims.

    Because combining the exhaust from all three kilns into a common duct with one induced draft fan, one cooling system, one scrubber system (likely one absorber for either dry or wet scrubbing), and a reduction in operating personnel, would result in significant cost savings, ODEQ must require that Kremlin investigate this configuration.

iv. *9.4.4. Kremlin's 20 Year Operating Life Assumption Is Not Justified* – On page 43 of its report, S&L makes the following statement regarding equipment life:

> Considering the novel application of this equipment on the calcining process, it is unknown what effects the process flue gas will have on the typical equipment life and how costs would be applied to achieve longer equipment lifespans. When the process conditions are well established, an industry standard 20-year equipment life is assumed to be representative of the most economical equipment design (i.e., material of constructions,

> equipment components and other design aspects are engineered and/or selected for ensuring the supplied system will not require complete refurbishment outside of typical manufacturer directed maintenance program for the duration of a 20-year useful life). Equipment could be designed to achieve a longer useful life but would likely result in substantially increased capital and operating costs. Thus, the 20-year equipment life of the control measures was used in the four-factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness.

There is nothing novel about the control equipment being considered or the environment in which the equipment will function. The mere fact that this equipment will be applied to a petroleum pet coke calcining plant instead of an EGU or an industrial boiler that burns petroleum coke is an insignificant determinant to equipment life. S&L's statement that "When the process conditions are well established, an industry standard 20-year equipment life is assumed to be representative of the most economical equipment design" is completely unsupported and has no relationship to any guidance or recommendations in the Control Cost Manual.

Regarding this, the Control Cost Manual states: "The life of the control is defined in this Manual as the equipment life. This is the expected design or operational life of the control equipment. This is not an estimate of the economic life, for there are many parameters and plant-specific considerations that can yield widely differing estimates for a particular type of control equipment."[30] EPA has consistently assumed a thirty-year equipment life for scrubber retrofits, scrubber upgrades, SCRs, and SNCR installations. Much of this is summarized and cited in EPA's response to comments document for its Texas and Oklahoma Regional Haze SIP final disapproval and FIP.[31]

A number of EGU contractors have been assuming an equipment life of twenty years for SNCR systems, by reference to the Control Cost Manual. The 4/25/2019 SNCR update of the Control Cost Manual does state on page 1-53, "Thus, an equipment lifetime of 20 years is assumed for the SNCR system in this analysis."[32] However, this 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. Just prior to this statement, EPA notes,

[30] See Control Cost Manual, Section 1, Chapter 2, Cost Estimation: Concepts and Methodology, November 2017, page 22.

[31] See Response to Comments for the Federal Register Notice for the Texas and Oklahoma Regional Haze State Implementation Plans; Interstate Visibility Transport State Implementation Plan to Address Pollution Affecting Visibility and Regional Haze; and Federal Implementation Plan for Regional Haze, Docket No. EPA-R06-OAR2014-0754, 12/9/2015, available here: https://www.regulations.gov/document?D=EPA-R06-OAR-2014-0754-0087. See pages 240-245, 268, and 274. See also the Texas BART FIP proposal, which conducted extensive cost determinations for scrubber upgrades, at 82 FR 930 and 938. See also Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, June 2019, pdf page 80: "For the purposes of this cost example, the equipment lifetime of an SCR system is assumed to be 30 years for power plants."

[32] Section 4, Chapter 1, Selective Noncatalytic Reduction, April 2019, page 1-53.

"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 United States 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." Therefore, based on a 1993 SNCR installation date, these SNCR systems are at least twenty-eight 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 system capital costs, are outside the exhaust stream and should be considered to last the life of the facility or longer.

Thus, all types of scrubbers, DSI systems, SCR systems, SNCR systems, and NOx combustion controls should have equipment lives of thirty years unless the unit's retirement is secured by an enforceable commitment. Unless there is a documentable reason to select a shorter life, thirty years should also be the default equipment life used for the cost analyses of these types of controls in any application. Use of a shorter equipment life artificially inflates the cost-effectiveness figures (higher $/ton).

ODEQ questioned Kremlin's use of a 20-year operating life in its January 31, 2022, letter.[33] In response, Kremlin merely reiterated the language from page 43 of the S&L report, reproduced above. ODEQ must reject this as inadequate and require that absent real documentation (not provided in this case) or an enforceable commitment for a shorter life, a 30-year equipment must be used in all cost-effectiveness calculations.

v. *9.4.5. ODEQ Must Verify Kremlin's Interest Rate* – Kremlin uses a 10% interest rate, documented by a signed affidavit by the Treasurer of Oxbow Carbon LLC, mush of which has been redacted.[34] ODEQ must state in its SIP whether it finds this documentation satisfactory. This is necessary in order to comply with the documentation requirements of 40 CFR 51.308(f)(2)(iii).

vi. *9.4.6. Miscellaneous Cost-Inflating Items That Must Be Removed From S&L's Analyses* – As indicated in Appendix A of its report, S&L included sales tax in

[33] See Appendix E, pdf page 270.
[34] See Appendix E, pdf page 279.

all of its cost analyses. It appears that for Kremlin's application, air pollution control equipment is exempt from sales tax in Oklahoma.[35] ODEQ must confirm whether this this is true and if exempt, require that it be removed.

S&L includes owner's costs and escalation during construction charges. However, as the Control Cost Manual indicates, "owner's costs and AFUDC costs are capital cost items that are not included in the EPA Control Cost Manual methodology, and thus are not included in the total capital investment (TCI) estimates in this section."[36] Similarly, regarding escalation the Control Cost Manual also states:[37]

> This Manual uses real prices for estimation of capital costs (in this case, an older capital cost to a more recent year), and other costs for any given cost analysis, not nominal prices. Using a price of reagent, catalyst, or other cost input to reflect possible price changes over the equipment lifetime is not correct in adjusting for inflation. Hence, the inclusion of price inflation via escalation estimates or having input prices reflect price changes over time as part of capital cost estimation is not allowed under the Control Cost Manual Methodology.

Therefore, DEQ must require that these cost items be removed from all control cost analyses.

S&L includes a contingency of 20% of the direct and indirect costs, which is excessive. Kremlin has presented no information that would indicate that the installation of a cooling system and a scrubber, both of which are mature technologies and have been installed on hundreds of sources, present any unique challenges. As the Control Cost Manual states: "A default value of 10% of the direct and indirect costs is typically used for CF [contingency factor]. However, values of between 5% and 15% may be used."[38] Unless documentation is provided that justifies a higher value, ODEQ must require that the low end of this range be used.

vii. *9.4.7. Revised Kremlin Wet Scrubber Cost-Effectiveness Calculation for Kiln 1* – As discussed above, S&L has taken a number of opportunities to wrongly inflate the cost-effectiveness of $SO_2$ control equipment at the Kremlin facility. Neither S&L nor Trinity have presented any significant documentation to support the key cost items. In addition, S&L only provides an all-in-one capital cost, which includes the cost of the scrubber and that of the steam turbine

[35] See https://oklahoma.gov/tax/search.html?term=pollution+control+.

[36] Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, June 2019, pdf page 65.

[37] Control Cost Manual, Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017, page 18.

[38] Control Cost Manual, Section 5, $SO_2$ and Acid Gas Controls, Chapter 1 Wet and Dry Scrubbers for Acid Gas Control, April 2021. Page 1-79. It should be noted that

generator. S&L further fails to provide costs for two other technically feasible cooling options to lower kiln flue gas temperature to that suitable for use with $SO_2$ control equipment: a dry cooler and an air cooler. Therefore, an accurate revision to S&L's inflated $SO_2$ controls cannot be performed.

Two approaches were taken to address this issue. Option 1 makes the adjustments described in the subsections above, and deletes obvious charges related to the installation of the steam turbine generator. This option inherently overpredicts the cost-effectiveness because it still retains S&L's costs for the steam turbine generator and S&L's failure to consider a single wet scrubber and cooling system that would serve all three kilns through common flue gas ducting.

Option 2 retains these corrections, plus it applies a 20% reduction in the purchased equipment and direct installation costs to estimate the savings from the substitution of dry cooling for the steam turbine generator. Because of S&L's failure to separate out the capital cost items, no documentation can be provided to support this 20% reduction. Nevertheless, it is offered as a conservative indication of the additional cost inflation inherent in S&L's costs due to inclusion of the steam turbine generator. The revised cost-effectiveness for both options are presented below:

**Table 3. Revised Cost-Effectiveness of Wet Scrubber for Kremlin Kiln 1**

| **Direct Costs** | **Unit 1** | **Option 1** | **Option 2** | **Comments** |
|---|---|---|---|---|
| Purchased Equipment Costs (PEC) | $49,178,000 | $49,178,000 | | Includes scrubber + steam turbine generator |
| Sales Tax | $2,459,000 | $0 | $0 | Assumed sales tax not applicable |
| Freight | $2,459,000 | $2,459,000 | | |
| Total PEC | $54,096,000 | $51,637,000 | $41,309,600 | Option 2 conservatively reduces Option 1 figure by 20% to delete steam turbine and assume dry cooling |
| | | | | |
| **Direct Installation Costs** | | | | |

| | | | | |
|---|---|---|---|---|
| Total Direct Installation Costs (TDIC) | $27,781,000 | $27,781,000 | $22,224,800 | Conservatively reduced by 20% in Option 2 to delete steam turbine and assume dry cooling |
| Total Direct Costs (TDC = PEC +TDIC) | $81,877,000 | $79,418,000 | $63,534,400 | |
| | | | | |
| **Indirect Costs (31% of TDC)** | $25,382,000 | $24,619,580 | $19,695,664 | |
| Owners Cost | | -$1,588,360 | -$1,270,688 | Delete disallowed owners' costs |
| Total Indirect Costs (TIC) | $25,382,000 | $23,031,220 | $18,424,976 | |
| | | | | |
| Contingency Percentage (% of TDC + TIC) | 20 | 10 | 10 | Reduce contingency to 10% |
| **Contingency** | $21,451,800 | $10,244,922 | $8,195,938 | |
| | | | | |
| **Total Capital Investment (TCI)** | $128,710,800 | $112,694,142 | $90,155,314 | |
| **Escalated TCI (2024)** | $144,865,000 | $112,694,142 | $90,155,314 | Escalation not allowed |
| | | | | |
| Equipment Life (years) | 20 | 30 | 30 | |
| Interest Rate (%) | 10 | 10 | 10 | |
| Capital Recovery Factor (CRF) | 0.1175 | 0.1061 | 0.1061 | |
| | | | | |
| **Annualized Capital Costs (CRF x TCI)** | $15,118,000 | $11,954,510 | $9,563,608 | |
| **Escalated Annualized Capital Costs** | $17,016,000 | $11,954,510 | $9,563,608 | Escalation (and double escalation) not allowed |
| | | | | |
| **Operating Costs** | | | | |

| | | | | |
|---|---|---|---|---|
| Increased Waste Disposal Costs | $991,000 | $991,000 | $991,000 | |
| Limestone Reagent Costs | $800,000 | $800,000 | $800,000 | |
| Increased Auxiliary Power Cost | $519,000 | $519,000 | $519,000 | |
| Increased Water Cost | $1,690,000 | $393,770 | $393,770 | Assume dry cooling (no water loss), so reduced to 23.3% (280 gpm/1,200 gpm)[39] |
| Demineralized Water Cost | $678,000 | $0 | $0 | Assumed to be used in the steam turbine, so deleted for dry cooling |
| **Total Variable O&M Costs** | $4,678,000 | $2,703,770 | $2,703,770 | |
| | | | | |
| **Fixed O&M Costs** | | | | |
| Labor (operator and supervisor) | $7,723,000 | $2,246,400 | $2,246,400 | CCM annual labor cost for scrubber = 12 x 2,080 hrs/yr x $60/hr. Assumed additional 1/2 for dry cooling system |
| Maintenance Materials | $1,228,000 | $1,228,000 | $1,228,000 | |
| Water Supply Pipeline Right-of-Way | $70,000 | $0 | $0 | Not needed for dry cooling |
| Water Treatment System Rental | $2,160,000 | $0 | $0 | Not needed for dry cooling |
| **Total Fixed O&M Costs** | $11,181,000 | $3,474,400 | $3,474,400 | |
| | | | | |

[39] See page 7 of the S&L report: "water requirements at the facility would increase approximately 180% of the current facility consumption rate of 670 gpm, requiring approximately 1,200 gpm for the cooling alone. Water will also be required to operate some of the $SO_2$ control systems, requiring an additional approximately 150 to 280 gpm depending on the technology."

| | | | | |
|---|---|---|---|---|
| **Indirect Operating Costs (4% of TCI)** | $5,148,000 | $4,507,766 | $3,606,213 | |
| | | | | |
| **Total Annual Operating Costs** | $21,007,000 | $10,685,936 | $9,784,383 | |
| **Escalated Total Annual Operating Cost (2004)** | $23,644,000 | $10,685,936 | $9,784,383 | Escalation not allowed |
| | | | | |
| **Total Annualized Costs** | $36,125,000 | $22,640,446 | $19,347,990 | |
| **Escalated Total Annualized Costs** | $40,660,000 | $22,640,446 | $19,347,990 | Escalation not allowed |
| | | | | |
| Control Efficiency (%) | 94 | 98 | 98 | Based on emission reduction, efficiency is 94.3. Used 98% in revised |
| Baseline $SO_2$ Emissions (tons) | 6,556 | 6,556 | 6,556 | |
| Emissions Reduction (tons) | 6,185 | 6,425 | 6,425 | |
| **Cost-Effectiveness ($/ton)** | **$6,574** | **$3,524** | **$3,011** | |

As can be seen from the above table, after correcting for the issues described above in Option 1, a cost-effectiveness of $3,524/ton results. Further making conservative and reasonable estimated corrections in Option 2 to the purchased equipment and direct installation costs to delete the steam turbine generator, further reduces the cost-effectiveness to $3,011/ton. Still, this figure is likely high, because of S&L's failure to consider a single wet scrubber and cooling system that would serve all three kilns through common flue gas ducting.

S&L and Trinity also perform a cost-effectiveness calculation for a wet scrubber assuming a water supply pipeline is not an option, and all the additional water must be trucked into the facility. However, as discussed earlier, use of a dry cooling system would not require any significant additional water, so evaluation of this option is moot.

Due to time constraints, similar calculations were not made for the wet scrubbers Kilns 2 and 3, and for Trinity and S&L's dry scrubber and DSI evaluations. However, the cost-effectiveness figures for these options would be improved by similar margins.

**RESPONSE:** DEQ's review of the original four-factor analysis did not expose any methodological concerns that would have materially affected the conclusions reached. The analysis was submitted by a reputable contractor under the supervision of a registered professional engineer. DEQ reviewed the confidential information submitted and has added this statement to the SIP. This includes the affidavit of the interest rate by Oxbow's Treasurer. DEQ is not aware of a sales tax exemption for air pollution control equipment in Oklahoma. However, even assuming sales tax costs were removed from the cost estimates, the control equipment would still be over what DEQ considers cost effective. See DEQ's responses to comment #19 for a discussion regarding the 20-year equipment life used by Oxbow Kremlin. See also DEQ's response to comment #20 above.

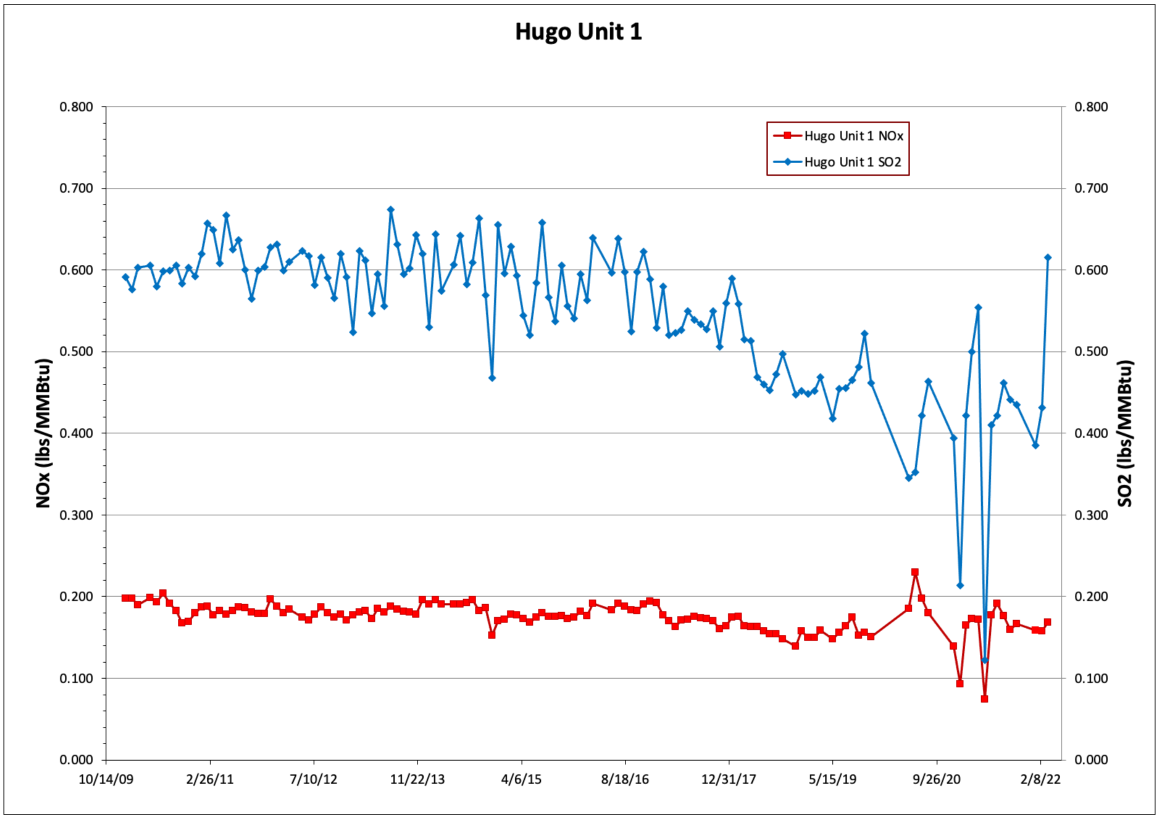
Oxbow Kremlin was selected for four-factor analysis based on its $SO_2$ emissions, not its $NO_x$ emissions. Its $NO_x$ emissions were not over the 5.0 tons $year^{-1}$ $km^{-1}$ $Q/d$ threshold for further evaluation. Based on DEQ's criteria, Oxbow was not required to evaluate the source's $NO_x$ emissions for controls.

55. **COMMENT:** <u>**Review of the Western Farmers Electric Cooperative Hugo Four-Factor Analysis**</u> – The Western Farmers Electric Cooperative (WFEC) owns and operates the Hugo Electric Generating Plant, located in Choctaw County, Oklahoma. It consists of one 477 MW dry bottom wall-fired unit that burns subbituminous coal. This unit is fitted with NOx combustion controls and no $SO_2$ controls. The four-factor report, which is present in Appendix E, is reviewed below.[40]

The $SO_2$ and NOx emissions for Hugo Unit 1 are presented below:[41]

**Figure 1. Hugo Unit 1 Historical Emissions**

[40] Regional Haze Rule Four-Factor Reasonable Progress Analysis, prepared by Trinity Consultants, August 20, 2020, hereafter referred to in this section as "the Trinity Report."
[41] See the file entitled, "OK EGU emissions.xlsx."




The gradual decrease in the $SO_2$ rate, seen to occur beginning in 2017 appears to reflect usage of a lower sulfur coal. The fluctuations present in the $SO_2$ rate likely also reflect differences in the sulfur content of the coal, since the unit has no $SO_2$ controls.

a. **10.1. Hugo's Scrubber and DSI Cost-Effectiveness Methodologies Are Invalid** – As ODEQ points out in its letter to Western Farmers, its methodology of escalating 2009 $/kW figures picked from other scrubber and DSI cost analyses is not valid, due to the length of escalation time.[42] ODEQ rightly points out that the Control Cost Manual clearly states this approach is invalid:[43]

> It should be noted that the accuracy associated with escalation (and its reverse, de-escalation) declines the longer the time period over which this is done. Escalation with a time horizon of more than five years is typically not considered appropriate as such escalation does not yield a reasonably accurate estimate. Thus, obtaining new price quotes for cost items is advisable beyond five years. If longer escalation periods are unavoidable due to limited recent cost data that is reasonably available, then the analysis should use the principles in this Manual chapter to provide as accurate an escalation as possible consistent with the Manual given the limitations of the cost analysis. The appropriate length of time for escalation can vary as a

[42] See Appendix E, pdf page 377.

[43] Control Cost Manual, Section 1 Introduction, Chapter 2 Cost Estimation: Concepts and Methodology, November 2017. Page 19 (citing Vatavuk, W., Updating the CE Plant Cost Index, Chem. Eng., pp. 62-70, January 2002).

result of significant changes in the cost of major production inputs (e.g., energy, steel, chemical reagents, etc.) and technological changes in control measures, particularly if these changes occur in an unusually short period of time. Hence, shorter time periods for escalation and de-escalation are clearly preferred over longer ones.

In this case, escalation beyond five years is not "unavoidable" since the Control Cost Manual itself provides cost models for wet and dry scrubbers.[44] Western Farmers' response that the Control Cost Manual's "rule of thumb" is not substantiated or that it is "out-of-context" is obviously incorrect.[45] Thus, ODEQ must follow through and require that Hugo properly perform its cost-estimates.

b. **10.2. Hugo's Scrubber Cost-Effectiveness Calculation Is Inflated** – Using the cost models referenced above, the cost-effectiveness was calculated for wet and dry scrubbers for the Hugo EGU. In so doing, the same emission dataset used by Trinity in its report— monthly emissions from 2018 through 2019—was also used. However, a number of corrections were made. These include the $SO_2$ inlet, which Hugo calculates as 0.462 lbs/MMBtu, which based on the data is actually 0.479 lbs/MMBtu.

Trinity refers to its calculation of the fractional time the unit operates as a "capacity factor." This is incorrect, as the capacity factor is defined as the ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.[46] Calculations based simply on the time the unit was operating overlook the usual situation in which the power plant can be listed as running for the full time period (e.g., 24 hours/day, 30 day/month, 365 days/yr) but was not running at full load. Therefore, Trinity's use of a 0.45 capacity factor is wrong and its reference to EPA's FIP's use of this methodology is incorrect.

Also, Trinity calculates an $SO_2$ baseline of 3,211 tons, based on multiplying its average $SO_2$ emission rate of 0.462 lbs/MMBtu by its average annual heat input of 13,901,244 MMBtu/yr. Using the corrected $SO_2$ inlet of 0.479 results in a value of 3,327 tons, which compares more closely to an average of the 2018-2019 $SO_2$ emissions of 3,379 tons, and is the method EPA's cost model calculates $SO_2$ emissions in the analyses that follow.

Lastly, the interest rate used was 4%, which is the current Bank Prime rate. A summary of the cost-effectiveness calculations is presented below:[47]

---

[44] See the spreadsheet in Section 5: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/costreports-and-guidance-air-pollution. Alternatively, note that EPA's IPM cost models, on which these cost models are based, include wet and dry scrubbing and DSI costs, have been available since the first planning period and were used extensively.

[45] See Appendix E, pdf page 380.

[46] See https://www.eia.gov/tools/glossary/index.php?id=Capacity_factor.

[47] See the file entitled, "Hugo wetanddryscrubbers_controlcostmanualspreadsheet_may_2021.xlsm."

**Table 4. Hugo Unit 1 Dry Scrubber Cost-Effectiveness**

| **SDA Selected Input and Outputs** | | |
|---|---|---|
| Fuel type | Coal | |
| Retrofit factor | 1 | |
| MW rating | 446 | MW |
| $SO_2$ inlet (lbs/MMBtu) | 0.479 | Btu/lb |
| Annual MWh output | 1,196,982 | MWh |
| Total System Capacity Factor ($CF_{total}$) | 0.306 | |
| Net plant heat input rate (NPHR) | 11.6 | MMBtu/MW |
| $SO_2$ outlet | 0.06 | lb/MMBtu |
| Scrubber efficiency | 87.47 | 5 |
| Plant elevation | 480 | feet |
| Desired dollar-year | 2020 | |
| Interest rate | 4.00 | Percent |
| Equipment life | 30 | years |
| Total Capital Investment (TCI) | $222,908,249 | |
| Direct Annual Costs (DAC) | $6,183,184 | |
| Indirect Annual Costs (IDAC) | $12,954,172 | |
| Total Annual Costs (TAC) = DAC + IDAC | $19,137,356 | |
| $SO_2$ removed | 2,908.9 | tons/yr |
| **Cost-effectiveness** | **$6,579** | **$/ton** |

**Table 5. Hugo Unit 1 Wet Scrubber Cost-Effectiveness**

| **Wet FGD Selected Input and Outputs** | | |
|---|---|---|
| Fuel type | Coal | |
| Retrofit factor | 1 | |
| MW rating | 446 | MW |
| $SO_2$ inlet (lbs/MMBtu) | 0.479 | Btu/lb |
| Annual MWh output | 1,196,982 | MWh |
| Total System Capacity Factor ($CF_{total}$) | 0.306 | |
| Net plant heat input rate (NPHR) | 11.6 | MMBtu/MW |
| $SO_2$ outlet | 0.04 | lb/MMBtu |

| | | |
|---|---|---|
| Scrubber efficiency | 91.65 | % |
| Plant elevation | 480 | feet |
| Desired dollar-year | 2020 | |
| Interest rate | 4.00 | Percent |
| Equipment life | 30 | years |
| Total Capital Investment (TCI) | $245,391,313 | |
| Direct Annual Costs (DAC) | $6,875,794 | |
| Indirect Annual Costs (IDAC) | $14,272,716 | |
| Total Annual Costs (TAC) = DAC + IDAC | $21,148,511 | |
| $SO_2$ removed | 3,047.8 | tons/yr |
| **Cost-effectiveness** | **$6,939** | **$/ton** |

As can be seen from the above, dry and wet scrubber cost-effectiveness figures of $6,579/ton and $6,939/ton are much lower than the figures of $8,203/ton and $8,462/ton that Trinity calculates.

It should be further noted that the Hugo scrubber cost-effectiveness calculations are highly sensitive to the year of the data used, which reflects the recent declining capacity of the unit. As indicated by the following table, Hugo's capacity has declined in recent years but it experienced a slight rebound in 2021.

**Table 6. Hugo's Historical Capacity**

| **Year** | **Operating Time (hours)** | **$SO_2$ (tons)** | **Avg. $SO_2$ Rate (lb/MMBtu)** | **NOx (tons)** | **Avg. NOx Rate (lb/MMBtu)** |
|---|---|---|---|---|---|
| 2010 | 7,486.1 | 8,597.9 | 0.594 | 2,724.7 | 0.188 |
| 2011 | 8,359.6 | 9,278.5 | 0.622 | 2,730.8 | 0.184 |
| 2012 | 7,852.2 | 8,066.0 | 0.603 | 2,414.3 | 0.179 |
| 2013 | 8,468.5 | 10,877.6 | 0.602 | 3,348.2 | 0.183 |
| 2014 | 7,032.1 | 8,964.9 | 0.605 | 2,834.0 | 0.188 |
| 2015 | 8,231.2 | 8,525.5 | 0.581 | 2,593.3 | 0.175 |
| 2016 | 6,789.4 | 7,275.5 | 0.597 | 2,301.1 | 0.187 |
| 2017 | 8,010.3 | 8,136.6 | 0.537 | 2,652.6 | 0.172 |
| 2018 | 5,578.2 | 5,117.7 | 0.494 | 1,690.6 | 0.161 |

| | | | | | |
|---|---|---|---|---|---|
| 2019 | 2,302.1 | 1,640.2 | 0.464 | 571.9 | 0.158 |
| 2020 | 1,072.0 | 569.7 | 0.426 | 242.7 | 0.179 |
| 2021 | 3,265.6 | 2,427.0 | 0.447 | 957.4 | 0.173 |

Rerunning the above cost-effectiveness calculations based on the data from individual years (as opposed to Trinity's average of 2018-2019 data) results in the following:[48]

**Table 7. Hugo Unit 1 Wet and Dry Scrubber Cost-Effectiveness for Different Capacity Factors**

| Year | Dry Scrubber Cost Analysis ($/ton) | Wet Scrubber Cost Analysis ($/ton) |
|---|---|---|
| 2017 | $2,963 | $3,075 |
| 2018 | $4,486 | $4,697 |
| 2019 | $12,599 | $13,386 |

Obviously, 2020's data would result in an even higher cost-effectiveness value. Therefore, after revising Hugo's scrubber cost-effectiveness to correct the errors discussed above, ODEQ must make a determination in its SIP as to which data it finds is likely to be representative of future operations and make its four-factor determination on that basis.

c. **10.3. Trinity Does Not Provide Documentation for Its DSI Efficiency** – On page 2-1 of its report, Trinity indicates in Table 2-1 that the DSI efficiency it is using in its cost-effectiveness calculation for Hugo is 40%. It states it has adopted that figure from the October 2012 Settlement Agreement for the Public Service Company of Oklahoma (PSO) Northeastern Plant. The use of a settlement agreement, which involved consideration of the emission reduction from the retirement of another unit, is in no way any justification for a four-factor determination of Hugo. When evaluating units not subject to settlement agreements, such as in its Texas BART FIP, EPA adopted the following strategy:[49]

> We will evaluate each unit at its maximum recommended DSI performance level, according to the IPM DSI documentation,[75] assuming milled trona: 80% $SO_2$ removal for an ESP installation and 90% $SO_2$ removal for a baghouse installation.

[48] See the file, "Hugo wetanddryscrubbers_controlcostmanualspreadsheet_may_2021-yearly.xlsm."

[49] See FR 82 925 (January 4, 2017) (citing IPM Model—Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for $SO_2$ Control Cost Development Methodology, Final March 2013, Project 12847–002, Systems Research and Applications Corporation, Prepared by Sargent & Lundy, p. 7)

This level of control is within the range that can be achieved by $SO_2$ scrubbers, and thus allows a better comparison of the costs of DSI and scrubbers.

Thus, Trinity's DSI efficiency is unsupported, and by information supplied by its own co-contractor (S&L) to EPA under contract, is demonstrably low.

d. **10.4. Hugo's DSI Cost-Effectiveness Calculation Is Greatly Inflated** – As indicated above, Hugo's DSI cost-effectiveness calculation relies on the same fundamentally flawed methodology of escalating a $/kW figure picked from another DSI cost analyses. As with the scrubber cost-effectiveness calculations detailed above, EPA has provided a DSI cost-effectiveness spreadsheet that has been in wide use since the first planning period.[50]

Therefore, Hugo's DSI cost-effectiveness was calculated using the same basic inputs from the revised scrubber cost-effectiveness, along with the DSI efficiencies discussed above:[51]

[50] See https://www.epa.gov/power-sector-modeling/retrofit-cost-analyzer. Note the Retrofit Cost Analyzer incorporates cost algorithms from EPA's IPM cost models developed by S&L. These IPM cost algorithms, have been continuously updated since the first planning period.

[51] See the file entitled, "Hugo DSI Cost Estimate.xlsx."

## Table 8. Hugo DSI with ESP Cost-Effectiveness

| Variable | Designation | Units | Value |
|---|---|---|---|
| EPC Project? | | | FALSE |
| Capacity Factor | | % | **30.6** |
| Unit Size | A | (MW) | **447** |
| Retrofit Factor | B | | **1.00** |
| Heat Rate | C | (Btu/kWh) | **8544** |
| SO2 Rate | D | (lb/MMBtu) | **0.479** |
| Type of Coal | E | | PRB |
| Particulate Capture | F | | ESP |
| Sorbent | G | | Milled Trona |
| Removal Target | H | (%) | **80** |
| Heat Input | J | (Btu/hr) | 3.82E+09 |
| NSR | K | (Btu/hr) | 3.32 |
| Sorbent Feed Rate | M | (ton/hr) | 7.29 |
| Estimated HCL Removal | V | (%) | 81 |
| Sorbent Waste Rate | N | (ton/hr) | 5.71 |
| Fly Ash Waste Rate<br>Include in VOM? ☑ | P | (ton/hr) | 10.91 |
| **Aux Power**<br>**Include in VOM?** ☑ | Q | (%) | 0.33 |
| Sorbent Cost | R | ($/ton) | **170** |
| Waste Disposal Cost | S | ($/ton) | **50** |
| Aux Power Cost | T | ($/kWh) | **0.06** |
| Operating Labor Rate | U | ($/hr) | **60** |
| Interest Rate | | (%) | **4** |
| Equipment Lifetime | | (years) | **30** |

| | | |
|---|---|---|
| Annual Capacity Factor = | 30.6% | |
| Annual MWhs = | 1,198,210 | |
| Annual Heat Input MMBtu = | 10,237,509 | |
| Annual Tons SO2 Created = | 2,452 | At 100% S conversion |
| Annual Tons SO2 Removed = | 1,962 | At removal efficiency of 80% |
| Annual Avg SO2 Emission Rate, lb/MMBtu = | 0.383 | Value is AT or ABOVE a 0.1 floor ra |
| Capital Recovery factor = | 0.0578 | |
| Annual Capital Cost = | $1,012,000 | |
| Annual FOM Cost = | $404,000 | |
| Annual VOM Cost = | $5,782,000 | |
| Total Annual DSI Cost = | $7,198,000 | |
| Capital Cost, $/MWh = | 0.84 | |
| FOM Cost, $/MWh = | 0.34 | |
| VOM Cost, $/MWh = | 4.83 | |
| Total DSI Cost, $/MWh = | 6.01 | |
| Capital Cost, $/ton = | 515.93 | |
| FOM Cost, $/ton = | 205.96 | |
| VOM Cost, $/ton = | $2,948 | |
| **DSI cost-effectiveness, $/ton =** | **$3,670** | |

> Because Hugo is fitted with an ESP, an ESP was selected as the particulate control device in the cost model. Thus, equipped with an ESP and assuming 80% efficiency, a DSI cost-effectiveness figure of $3,670/ton results. These figures are in 2016 dollars. Escalated to 2020, this figure become $4,039/ton.[52] This contrasts with the absurd value of $41,003/ton that Trinity presents. Even if, the unreasonably low DSI efficiency of 40% used by Trinity was adopted, the cost-effectiveness would still be $4,058/ton, which escalated to 2020 becomes $4,466/ton. Thus, ODEQ must require that Hugo revise its DSI cost-effectiveness and correct the errors described above.

**RESPONSE:** See also DEQ's response to comment #22 and 23 above. As mentioned elsewhere in these responses, use of EPA's Cost Control Manual is not mandated by regulation. In Tables 4 and 5 of the comment above, the cost per ton is still above the level which DEQ considers cost effective for the dry or wet scrubber control options. The commenter has made many assumptions for its revision of the DSI control option. In the Sargent & Lundy *Dry Sorbent Injection for $SO_2$/HCl Control Cost Development Methodology* (April 2017) created for EPA's IPM model, it states that "$SO_2$ removal should be set at 50% with an ESP and 70% with a baghouse." The comment above states that it assumed an 80% efficiency in its DSI cost calculation. The comment later revised its calculation to match the 40% efficiency provided by WFEC which made the cost $4,466/ton, just under what DEQ would consider to be not cost effective. This very simple example demonstrates the complexity of cost calculations and the variation that can occur with differing assumptions. DEQ restates its belief that there are currently no cost-effective controls necessary at the Hugo Generating Station.

**56. COMMENT:** **Review of the Grand River Dam Authority Four-Factor Analysis** – The Grand River Dam Authority operates the Grand River Energy Center (GREC) located in Mayes County. GREC comprises three units. Unit 1 was a 540 MW coal-fired dry bottom wall-fired unit that burned subbituminous coal, but is now retired. Unit 2 is a 594 MW coal-fired dry bottom wall-fired unit that burns subbituminous coal. This unit is fitted with NOx combustion controls and a dry scrubber. Unit 3 is a 600 MW natural gas-fired combined cycle unit. The four-factor report, which is present in Appendix E, is reviewed below.[53]

The $SO_2$ and NOx emissions for GREC Unit 2 are presented below:[54]

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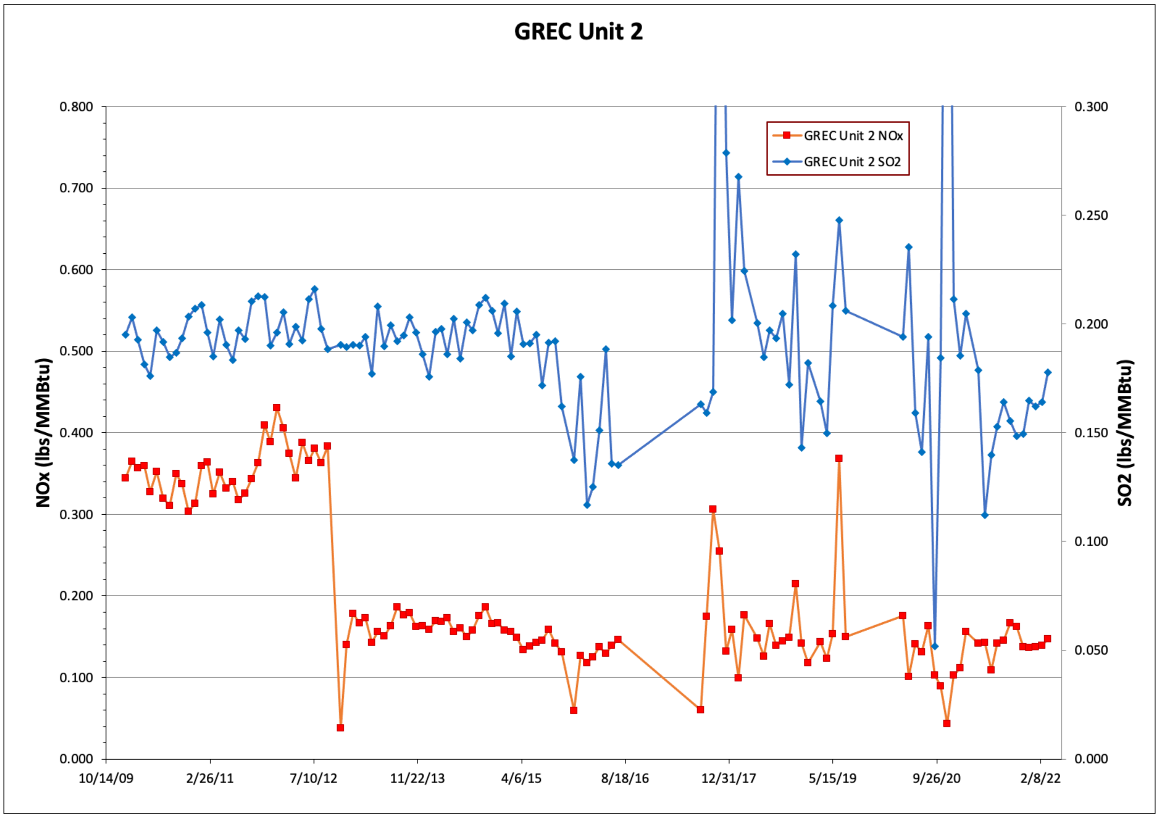
[52] The CEPCI index for 2016 is 541.7 and that for 2020 is 596.2. Thus, the figures are multiplied by the factor 596.2/541.7 = 1.10.

[53] Final Four Factor Analysis Grand River Energy Center Unit 2, prepared for Grand River Dam Authority by Black & Veatch, September 8, 2020. Hereafter referred to in this section as "the B&V report."

[54] See the file entitled, "OK EGU emissions.xlsx."

**Figure 2. GREC Unit 2 Historical Emissions**




As can be seen from the above graph, starting in September 2012, the NOx emissions for Unit 2 significantly improved. Also, beginning in late 2015, the $SO_2$ emissions for Unit 2 became erratic. There is no discussion for this in GREC's four-factor analysis and ODEQ must require it, as it impacts that analysis.

**a. 11.1. GREC's Four-Factor Report Is Fundamentally Inadequate** – GREC's four-factor report is fundamentally incomplete, as it lacks any details concerning the bottom-line cost-effectiveness figures it summarizes in Table 4-3. Consequently, there is no way for any member of the public to fully assess GREC's analysis. GREC's undocumented figures rest on a thin claim of confidentiality.

On page 1-3 and 2-1, GREC's redacts Unit 2's historical capacity factor for 2016 and 2019, which is easily back-calculated based on public data present in EPA's AMPD website and present in a spreadsheet attached to these comments.[55] Therefore, there is no justification for this redaction.

GREC redacts 2019 emission data in Table 2-1, which again is public information and thus unjustifiable.

[55] See the file entitled, "OK EGU emissions.xlsx."

In Table 3-3, GREC redacts the maximum sulfur loading of Unit 2's scrubber and on page 4-3 redacts the maximum sulfur content the scrubber can treat while functioning at an 85% efficiency. There is no conceivable commercial or competitive advantage to withholding this information, especially since GREC must report the sulfur percentage of the coal it does burn on a monthly basis to the Energy Information Agency, and this data is publicly available.[56]

In Table 3-2 GREC redacts what is indicates is its forecasted future capacity factor, which it apparently incorporated into its cost-effectiveness figures. GREC notes that its forecasted capacity factor "is not definitive; present circumstances and expectations suggest the potential value indicated. The increasing levels of renewables generation in the Southwest Power Pool mean that the current conditions for economic dispatch of coal-fired generation are not likely to change."[57]

ODEQ correctly objects to GREC's use of a forecasted capacity factor in its January 31, 2022 letter to GREC, requesting an explanation and explaining that if it is not based on recent historical operations, it may not be appropriate for GREC to base its four-factor analysis on it without an enforceable commitment to operate at that capacity factor.[58] [GREC] simply replies in its February 28, 2022 letter that "[t]he forecasted capacity factor was based on recent historical operations of GREC from 2016-2020." First, if this is actually the case, then there is no basis for GREC to redact its forecasted capacity factor, since as indicated above, historical emission data is public. Second, ODEQ is correct that unless [GREC] is willing to enter into an enforceable commitment for a reduced capacity for Unit 2, then it must base its cost-effectiveness calculations on recent historical data, which again is public information and must not be redacted.

On page 7 and elsewhere of the B&V report, GREC redacts the life of Unit 2 on which its cost-effectiveness calculations were based. ODEQ correctly objects to GREC's assumed short operating life in that same letter:

> The assumption of a shortened remaining useful life in the cost analysis for controls evaluated for Unit 2 appears to be based on "operating projections." As discussed in the August 2019 Guidance, this is not an appropriate approach. The Guidance explains that "In the situation where an enforceable shutdown date does not exist, the remaining useful life of a control under consideration should be full period of useful life of that control as recommended by EPA's Control Cost Manual." (See August 2019 Guidance at 34.)

In its reply, [GREC] states the following:

> The life of control equipment in the EPA Control Cost Manual, for example, provides a range, kg., 20 to 30 years for the assumed lifetime of a control device. It is arbitrary for EPA to force the use of one particular value within the range. The

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

[57] Page 3-2 of the B&V report.

[58] See Appendix E, pdf page 74.

study was based on the most representative value based on known conditions at the time of the study. The GREC facility does not have an enforceable shutdown date. The useful life of the controls in consideration were developed based on GRDA's understanding at the time of the unit's remaining useful life.

As indicated elsewhere in these comments, GREC's assertion that the equipment life is a flexible range from which a company can adopt any value it desires is wrong. Unless GREC is willing to enter into an enforceable commitment to the contrary, ODEQ must require that it base its cost-effectiveness calculations on a 30-year equipment life.

Also, in its January 31, 2022 letter to GREC, ODEQ again correctly requests that [GREC] provide line-item cost calculations and any vendor quotes obtained for all the control options evaluated in the four-factor analysis. ODEQ points out to GREC that documentation of the technical basis of [GREC]'s demonstration is a requirement of the Regional Haze Rule under 51.308(f)(2)(iii) (as noted several times throughout these comments). [GREC]'s reply in its February 28, 2022 letter is that its analysis contains commercially sensitive information, such as economic criteria and cost calculations and on that basis asserts a confidentiality claim. [GREC] further states that ODEQ is in possession of the unredacted version of its four-factor analysis.

ODEQ must formally review [GREC]'s confidentiality claim. As indicated below, it appears that most, if not all of the redacted material should not be considered confidential. Furthermore, GREC's general single-sentence claim that its entire cost-effectiveness analysis should be held confidential because it contains commercially sensitive information, such as economic criteria and cost calculations, is absurd. That same generalized claim could be asserted by every commercial source subject to a four-factor analysis. ODEQ must demand that GREC provide a substantially, if not entirely, unredacted cost-effectiveness calculations, or ODEQ must perform and present those calculations itself.

b. **11.2. GREC Does Not Adequately Assess Scrubber Upgrades to Unit 2** – The obvious path forward in GREC's $SO_2$ four-factor analysis for Unit 2 is to upgrade or optimize its existing dry scrubber. EPA has long recognized that scrubber upgrades are cost-effective. However, B&V minimizes this likelihood. For instance, on page 4-3, B&V states: "The current system was designed to remove 85 percent of the incoming $SO_2$ based on the design information in Section 3, while burning coal with a sulfur content of up to [redacted] percent, so there is minimal potential for upgrades within the existing system to have a significant effect on $SO_2$ removal." B&V provides no documentation for this claim. ODEQ must require the following:

- Documentation that the *scrubber system* (as opposed to just the absorber) was designed to only remove 85% of the $SO_2$ at the redacted sulfur content. ODEQ must investigate whether this efficiency figure includes a bypass, and whether this bypass can be partially or completely eliminated.

- Determination of the design scrubber efficiency *for the coal GREC is currently burning*.

- It appears from what discussion B&V does present, that it contemplates an SDA replacement and not an additional SDA module. ODEQ must clarify this and if the cost-effectiveness calculation in fact only considers replacement of the entire SDA system, ODQ must require that an additional SDA module also be considered.

- As indicated in the figure above that depicts GREC's historical emissions, beginning in late 2015, the $SO_2$ emissions for Unit 2 became erratic. Before this point, the $SO_2$ emissions were much more tightly controlled. An examination of GREC's coal sulfur data does not indicate any obvious change in the type of coal or the monthly coal sulfur content before or after this point, nor does it indicate any obvious change in the range of monthly sulfur content. ODEQ must require that this be investigated, as one obvious reason is that GREC's scrubber system may not be properly operated or maintained.

**RESPONSE:** The majority of GRDA's four-factor analysis is unredacted and publicly available. The analysis was submitted by a reputable contractor and signed off on by a registered professional engineer. DEQ and EPA have both reviewed the confidential portions of GRDA's original four-factor response. As stated elsewhere, EPA's Cost Control Manual is guidance. That being said, even with making some adjustments to the remaining useful life, the lowest cost control (DSI) would still be well above what DEQ considers to be cost effective at approximately $12,000/ton $SO_2$ removed. DEQ stands by its determination that there are no cost-effective controls for GRDA. See also DEQ's responses to comments #13 and 14.

Note: The comment states that DEQ "objects to GREC's use of a forecasted capacity factor in its January 31, 2022 letter to GREC" and that DEQ "objects to GREC's assumed short operating life in that same letter." These statements are inaccurate portrayals of the information contained in the January 31, 2022, letter. DEQ was seeking to obtain additional information from GRDA in the January 31, 2022, letter based on comments received from EPA, but DEQ did not take the stance indicated in this comment.

**57.** **COMMENT:** **Review of the OG&E Horseshoe Four-Factor Analysis** – OG&E owns and operates the Horseshoe Lake Generating Station, located in Oklahoma County, Oklahoma. It consists of five units. Unit 6 is a 167 MW natural gas wall-fired boiler. Unit 7 is a 210 MW natural gas wall-fired boiler. Unit 8 is a 404 MW natural gas tangentially-fired boiler. Units 9 and 10 are both 45.5 MW simple cycle gas turbines. None of these units have any NOx controls beyond water injection for the Units 9 and 10. Two reports were reviewed consisting of a September 2020 Trinity report, which references a September 2020 S&L report, both of which are present in Appendix E.[59] Graphs of the NOx emissions are not presented, as they do not indicate anything noteworthy.

Both S&L and Trinity's SCR cost-effectiveness figures are flawed, due to similar issues described below regarding their SNCR cost analyses, and are quite inflated. However, these calculations are not reviewed herein because after applying EPA's SCR Control Cost Manual cost model the resulting cost-effectiveness figures remain unfavorable.

a. **12.1. OG&E's SNCR Cost-Effectiveness Figures Are Greatly Inflated** – S&L does not provide any documentation for the capital costs of its SNCR cost analyses for Units 6, 7, and 8, which Trinity uses to calculate cost-effectiveness figures of $24,528/ton, $36,107/ton, and $36,066/ton, respectively.[60] In so doing, S&L utilizes several improper parameters which inflate the cost-effectiveness. These include a contingency of 20%, a 20-year operating life, and a 7% interest rate. No documentation was provided for these parameters, and as discussed earlier in these comments, they are therefore improper and ODEQ must require that they be revised.

   In addition, S&L bases its cost analysis on urea-based SNCR systems, which due to the cost of the reagent, result in much less favorable (higher $/ton) cost-effectiveness figures. For these reasons, primarily due to the lack of documentation and the inability to fundamentally adjust S&L's cost analyses for ammonia-based SNCR systems, EPA's SNCR Control Cost Manual cost model was employed to more reasonable calculate the SNCR cost-effectiveness for Units 6, 7, and 8.[61] The following tables summarize the result for 40% SNCR efficiency cases for Units 6, 7, and 8:

**Table 9. Selected Input and Outputs Horseshoe Lake Unit 6, SNCR 40% Efficiency**

| | | |
|---|---|---|
| Fuel type | Natural Gas | |
| Retrofit factor | 1 | |
| MW rating | 176 | MW |
| HHV | 1,033 | Btu/lb |
| Annual MWh output | 244,799 | MWh |
| Net plant heat input rate (NPHR) | 8.2 | MMBtu/MW |

[59] Regional Haze Four-Factor Reasonable Progress Analysis, OGE, Horseshoe Lake Generating Station, prepared by Trinity Consultants, September 29, 2020. Hereafter referred to in this section as "the Trinity report." OG&E Horseshoe Lake Station Unit 6-10, Regional Haze Second Planning Period Cost Evaluation to Support Four-Factor Analysis, Sargent & Lundy, September 28, 2020. Hereafter referred to in this section as "the S&L Report."

[60] Note that Units 9, and 10 are not well suited to SNCR, as they are simple cycle combustion turbines.

[61] See https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-airpollution. Section 4. The results of these calculations are contained in the file entitled, "Horseshoe SNCR CCM cost-effectiveness.xlsm."

| | | |
|---|---|---|
| Desired SNCR efficiency | 40 | Percent |
| Time the SNCR and Boiler Operate | 106 | days |
| NOx inlet | 0.243 | lb/MMBtu |
| NOx outlet | 0.1458 | lb/MMBtu |
| Reagent | Ammonia | |
| Plant elevation | 1,079 | feet |
| NSR | 1.95 | |
| Desired dollar-year | 2020 | |
| Interest rate | 4 | Percent |
| Equipment life | 30 | years |
| Total Capital Investment (TCI) | $4,802,201 | |
| Direct Annual Costs (DAC) | $130,922 | |
| Indirect Annual Costs (IDAC) | $279,728 | |
| Total Annual Costs (TAC) = DAC + IDAC | $410,651 | |
| NOx removed | 98 | tons/year |
| **Cost-effectiveness** | **$4,209** | **$/ton** |

**Table 10. Selected Input and Outputs Horseshoe Lake Unit 7, SNCR 40% Efficiency**

| | | |
|---|---|---|
| Fuel type | Natural Gas | |
| Retrofit factor | 1 | |
| MW rating | 210 | MW |
| HHV | 1,033 | Btu/lb |
| Annual MWh output | 296,114 | MWh |
| Net plant heat input rate (NPHR) | 8.2 | MMBtu/MW |
| Desired SNCR efficiency | 40 | Percent |
| Time the SNCR and Boiler Operate | 99 | days |
| NOx inlet | 0.164 | lb/MMBtu |
| NOx outlet | 0.0984 | lb/MMBtu |
| Reagent | Ammonia | |
| Plant elevation | 1,079 | feet |
| NSR | 2.51 | |
| Desired dollar-year | 2020 | |
| Interest rate | 4 | Percent |

| | | |
|---|---|---|
| Equipment life | 30 | years |
| Total Capital Investment (TCI) | $5,037,761 | |
| Direct Annual Costs (DAC) | $137,311 | |
| Indirect Annual Costs (IDAC) | $293,450 | |
| Total Annual Costs (TAC) = DAC + IDAC | $430,760 | |
| NOx removed | 80 | tons/year |
| **Cost-effectiveness** | **$5,409** | **$/ton** |

**Table 11. Selected Input and Outputs Horseshoe Lake Unit 8, SNCR 40% Efficiency**

| | | |
|---|---|---|
| Fuel type | Natural Gas | |
| Retrofit factor | 1 | |
| MW rating | 404 | MW |
| HHV | 1,033 | Btu/lb |
| Annual MWh output | 238,021 | MWh |
| Net plant heat input rate (NPHR) | 8.2 | MMBtu/MW |
| Desired SNCR efficiency | 40 | Percent |
| Time the SNCR and Boiler Operate | 67 | days |
| NOx inlet | 0.122 | lb/MMBtu |
| NOx outlet | 0.0732 | lb/MMBtu |
| Reagent | Ammonia | |
| Plant elevation | 1,079 | feet |
| NSR | 3.10 | |
| Desired dollar-year | 2020 | |
| Interest rate | 4 | Percent |
| Equipment life | 30 | years |
| Total Capital Investment (TCI) | $6,566,060 | |
| Direct Annual Costs (DAC) | $144,066 | |
| Indirect Annual Costs (IDAC) | $382,473 | |
| Total Annual Costs (TAC) = DAC + IDAC | $526,539 | |
| NOx removed | 48 | tons/year |
| **Cost-effectiveness** | **$11,056** | **$/ton** |

Neither S&L nor Trinity provide any documentation for the SNCR efficiencies assumed in their calculations, simply assuming NOx outlet values of 0.15 lbs/MMBtu for Unit 6 and 0.12 lbs/MMBtu for Units 7 and 8. SNCR performance is in fact, very site-specific and it is difficult to predict without sophisticated modeling tools. However, the Control Cost Manual provides data that indicates a reasonable range is 40% to 60%.[62] Therefore, the above SNCR cost models were also run using that range of efficiencies. Below is a summary of the results:

**Table 12. Summary of SNCR Cost-Effectiveness for Horseshoe Lake Units 6, 7, and 8**

| Unit | 40% | 50% | 60% |
|---|---|---|---|
| 6 | $4,209/ton | $3,538/ton | $3,083/ton |
| 7 | $5,409/ton | $4,545/ton | $3,960/ton |
| 8 | $11,056/ton | $9,172/ton | $7,898/ton |

As can be seen from the above summary, S&L and Trinity's cost-effectiveness figures for SNCR are extremely inflated, even considering a modest SNCR efficiency of 40%. ODEQ must therefore reassess its determination that SNCR is not cost-effective.

**RESPONSE:** It appears that the comment above agrees with OG&E and DEQ's determination that SCR is not a cost-effective control option for the units at Horseshoe Lake. However, it takes exception to the assumptions made for SNCR. DEQ's review of the original four-factor analysis and additional information provided in OG&E's second response did not alter DEQ's judgment that no additional controls are required. See also DEQ's response to comments #16 through 18.

**58.** **COMMENT:** **<u>Review of the DCP Chitwood Gas Plant Four-Factor Analysis</u>** – DCP Operating owns and operates the Chitwood Gas Plant, located in Grady County, Oklahoma. The plant runs nine compressor engines. C-1, C-2, C-3, and C-4 are 880-hp Cooper-Bessemer GMV-8 two-stroke lean-burn (2SLB) engines. C-5 is an 880-hp Clark HRA-8 2SLB. C-6 and C-7 are 1320-hp Ingersol-Rand KVS-8 four-stroke lean-burn (4SLB) engines. C-8 and C-9 are 1100-hp Cooper-Bessemer GMV-10 2SLB engines. ODEQ states that C-5, which has been out of service, will not be included in the Title V permit renewal, which is currently being reviewed. The four-factor report, which is present in Appendix E, is reviewed below.[63]

Controls evaluated include SCR and typical Low Emissions Combustion (LEC) controls. DCP obtained a vendor quote for the LEC from Siemens and an SCR system vendor quote

[62] See Control Cost Manual, Section 4 – NOx Controls, Chapter 1, Selective Noncatalytic Reduction, Revised 4/25/2019. Page 1-2 to 1-5.

[63] Regional Haze Four-Factor Reasonable Progress Analysis, DCP Operating Co. Chitwood Gas Plant, prepared by Trinity Consultants, October 1, 2020. Hereafter referred to in this section as "the Trinity report."

from AeriNOx.[64] The LEC controls could be provided with two basic options: a 1g/hp option and a 6g/hp option.[65] The 1g/hp option included a replacement electronic high pressure fuel injection system, a direct power cylinder peak firing pressure management system, modifying the heads to receive precombustion chambers, fuel injectors for the precombustion chambers and an upgraded turbocharger. The 6g/hp option included modification to the cylinder heads to receive precombustion chambers, fuel injectors for the precombustion chambers, and an upgraded turbocharger.

Chitwood's SCR vendor indicated that it does not recommend that SCR systems be installed on uncontrolled engines (engines not already controlled to 6g/hp) due to a large variance in combustion instability and typically poor air/fuel ratio controls which can cause operational issues for the SCR system to function correctly. Consequently, SCR was only considered as an additional control after the 6g/hp LEC controls were already installed. Because the resulting 1g/hp equals the 1g/hp LEC option but at greater cost, it is not further considered in this review.

a. **13.1. Chitwood Includes Undocumented Costs in Its Cost-Effectiveness Calculation** – On page 24 (pdf) of its report, Trinity lists the cost of the equipment for the 1g/hp and 6g/hp options. Below is that information *on a per-engine basis* for the GMV-8 engines with the 1g/hp option. Costs for other engines are similar.

**Table 13. Trinity's Listing of Costs for Chitwood Engine Controls**

| | **Control Description** | **Cost Source** | **GMV-8 1 gram option ($)** |
|---|---|---|---|
| 1 | Clean burn conversion equipment and installation | Siemens | $1,710,000 |
| 2 | Intercooler bundles for turbocharger addition | Siemens | $125,000 |
| 3 | Replacement exhaust manifolds for GMV units | Siemens | $220,000 |
| 4 | Updated air intake filters and housing | Siemens | $100,000 |
| 5 | Replacement cylinder heads | Siemens | $40,000 |
| 6 | Control panel installation | Siemens | $250,000 |
| 7 | Turbocharger pad installation | DCP | $50,000 |
| 8 | Initial engine health analysis | DCP | $12,000 |
| 9 | Safety/inspector/fire watch for each engine build | DCP | $100,000 |
| 10 | Engineering costs for project/site managers and engineer | DCP | $56,250 |
| 11 | HP fuel installation to engine room for 1 gram option | DCP | $43,750 |

[64] These quotes are attached to DCP's four-factor analysis.

[65] The vendor also provided a 2g/hp option for the KVS engines but this was not explored by Trinity.

| | Control Description | Cost Source | GMV-8 1 gram option ($) |
|---|---|---|---|
| 12 | Oxidation catalyst installation for 1 gram option | Miratech | $115,000 |
| | **Total Capital Cost for clean burn technology** | **--** | **$2,822,000** |
| 13 | CBT annual maintenance costs | Siemens | $59,024 |

Siemen's quote does not contain any of the items below Item 1. In particular, the quote states, "The following pricing as mentioned above is *for a full turnkey solution* [emphasis added] and is budgetary only - non-binding for informational purposes only." It does make some assumptions, some of which that are pertinent to this review are reproduced below:

a) Power cylinder heads do not have PCCs [precombustion chambers]; but they can be machined to accept PCCs.

b) Engines do not have turbochargers, or require replacement turbochargers to meet necessary air spec for NOx reduction.

c) Existing turbo pads are adequate for supporting the new turbocharger, its mounting structure and modification to piping.

d) Assume engines have PLC [programmable logic controller] based Unit Control Panels. Our controls will be placed in their own subpanel with HMI and set adjacent to existing unit control panels.

e) An engine health assessment will be performed on the engine by DCP Midstream or by Dresser-Rand EASE program resources (charged at T&M rates) to verify engine operating condition and health prior to completing design work for the solution package.

f) Safety, inspectors, and fire watch personnel have not been included in this estimate.

Thus, there does not appear to be any requirement in the Siemens' quote for Items 2, 3, 4 and 5. Regarding Item 2, intercoolers are an integral part of turbocharging systems and the Siemens' quote indicates a "turnkey solution" and does not assume a separate intercooler installation by a third party. Regarding Items 3 and 4, the Siemens' quote does not mention the need for replacement exhaust manifolds or updated air intake filters and housings. Regarding Item 5, the Siemen's quote does not state the need for cylinder head replacement, and specifically includes modification of the existing heads for precombustion chambers. It is assumed that the vendor is familiar with the specific engines for which it is providing a quote. Regardless, GMV model cylinder heads have been modified to receive replacement precombustion chambers for many years.[66] Regarding Item 6, the Siemens' quote does assume the existence of current PLC based Unit Control Panels, but specifically states that their own panels "will be placed in their own subpanel with HMI and set adjacent to existing unit control panels." Programmable logic controllers have been in wide use in industrial environments for decades. Therefore, ODEQ must require that Chitwood justify the need for this $250,000 item, *for each engine*, which considering the information in the record, seems unlikely. Regarding Item 9, "Safety/inspector/fire watch for each engine build" is undocumented and $100,000 for each engine appears to be an excessive charge to have a worker standby with a fire extinguisher. It is difficult to understand how this cost could be higher than $56,250 cost for the project/site managers and engineer.

Regarding 12, there is no mention of the need for an oxidation catalyst in the Siemens' quote. On page 2-2 of its report, Trinity states, "An oxidation catalyst will need to be installed in order to stay under current permit values, and the cost for this additional control is included in the cost control analysis." Presumably this refers to potential increases in CO, which Siemens states in its quote could increase. However, Chitwood's Title V Permit indicates that engines C-1 through C-8 are grandfathered:[67]

> Based on emission calculations, this facility is a major source of HAP. Engines Cl through C-9 were constructed prior to December 12, 2002 and are therefore existing. However since the engines are all 4SLB & 2SLB engines with a site rating of more than 500 HP, *the engines have no applicable requirements* [emphasis added].

Specific Condition No. 6 further states, "Engine C-10 shall be operated with exhaust gases passing through a functioning catalytic converter." Thus, it appears that engines C-1 through C8 do not have any requirement "to stay under current permit values" as Trinity states above. ODEQ must therefore clarify the need to install oxidation catalysts, which Trinity lists for all the engines.

b. **13.2. Chitwood's Calculated Emissions and Emission Reductions Are Low** – On page 2-2 of its Report, Trinity discusses how it calculated the baseline NOx emissions and the NOx emissions reductions from the controls it considered. Trinity states it only considered 2019 emissions and in order to account for year-to-year variability, and to provide a more accurate assessment of potential reductions, the 2019 emissions were

[66] Olsen, D. B., Adair, J. L., & Willson, B. D. (2005). *Precombustion Chamber Design and Performance Studies for a Large Bore Natural Gas Engine. ASME 2005 Internal Combustion Engine Division Spring Technical Conference.* Available here:
https://www.researchgate.net/publication/267577761_Precombustion_Chamber_Design_and_Performance_Studies_for_a_Large_Bore_Natural_Gas_Engine.

[67] Staff permit evaluation dated April 18, 2017, page 17, which precedes the actual permit: Part 70 permit, Permit No. 2016-1248-TVR3, DCP Operating Company, LP, issued April 20, 2017.

equally redistributed for each engine type and each engine service. It states that detailed calculations are in Appendix A. However, there are not any detailed emissions calculations in Appendix A, beyond a factor termed "DRE %," which appears to represent a percentage emission reduction.

Because the emissions reported to ODEQ are in tons and the controlled emission rate from the vendor is in g/hp, a direct verification of Trinity's calculations cannot be made without additional information. ODEQ must require that Chitwood document and justify its emission reduction factor. This is a requirement of the Regional Haze Rule under 51.308(f)(2)(iii) (as noted several times throughout these comments).

Even though its controlled emission rate cannot be verified, Chitwood's baseline emission were examined, using information provided by ODEQ via a public information request.[68] The information below contrasts Trinity's emission reduction calculation with a revised version, that simply averaged the individual engine emissions from 2018-2020:[69]

**Table 14. Revised Chitwood Engine Emissions**

| EU ID | Trinity Baseline NOx | Revised Baseline NOx | DRE % | Controlled Emissions (tpy) | Emissions Reduction (tpy) | Revised Emissions Reduction (tpy) |
|---|---|---|---|---|---|---|
| C-1 GMV-8 | 89.61 | 107 | 57.1 | 38.4 | 51.2 | 61.1 |
| C-1 GMV-8 | 89.61 | 107 | 92.9 | 6.4 | 83.2 | 99.4 |
| C-2 GMV-8 | 89.61 | 71.6 | 57.1 | 38.4 | 51.2 | 40.9 |
| C-2 GMV-8 | 89.61 | 71.6 | 92.9 | 6.4 | 83.2 | 66.5 |
| C-3 GMV-8 | 19.38 | 45 | 57.1 | 8.3 | 11.1 | 25.7 |
| C-3 GMV-8 | 19.38 | 45 | 92.9 | 1.4 | 18 | 41.8 |
| C-4 GMV-8 | 72.36 | **72.36**[70] | 57.1 | 31 | 41.3 | 41.3 |
| C-4 GMV-8 | 72.36 | **72.36**[62] | 92.9 | 5.2 | 67.2 | 67.2 |
| C-6 KVS-8 | 83.59 | 90.3 | 45.5 | 45.6 | 38 | 41.1 |
| C-6 KVS-8 | 83.59 | 90.3 | 90.9 | 7.6 | 76 | 82.1 |
| C-7 KVS-8 | 83.59 | 72.8 | 45.5 | 45.6 | 38 | 33.1 |

[68] This is why this type of data is a necessary part of the SIP.
[69] See the file entitled, "Chitwood cost-effectiveness.xlsx."
[70] No emissions were reported for C-4 for 2018 through 2020, so there was no choice but to adopt Trinity's value.

| EU ID | Trinity Baseline NOx | Revised Baseline NOx | DRE % | Controlled Emissions (tpy) | Emissions Reduction (tpy) | Revised Emissions Reduction (tpy) |
|---|---|---|---|---|---|---|
| C-7 KVS-8 | 83.59 | 72.8 | 90.9 | 7.6 | 76 | 66.2 |
| C-8 GMV-10 | 54.57 | 99.3 | 57.1 | 23.5 | 31.3 | 56.7 |
| C-8 GMV-10 | 54.57 | 99.3 | 92.9 | 3.9 | 50.8 | 92.2 |
| C-9 GMV-10 | 54.57 | 62.3 | 57.1 | 23.5 | 31.3 | 35.6 |
| C-9 GMV-10 | 54.57 | 62.3 | 92.9 | 3.9 | 50.8 | 57.9 |

As can be seen from the above, in most cases the revised emissions were above those calculated by Trinity. Again, ODEQ must require that Trinity justify its calculations.

c. **13.3. Chitwood's Cost-Effectiveness Figures Are Inflated** – In addition to the issues described above, Trinity uses an undocumented 7% interest rate. As with other undocumented interest rates discussed in these comments, it has been revised to the current Bank Prime rate of 4% in the revised cost-effectiveness that follows. Note that some details of these calculations are omitted for space constraints here but are available:[71]

[71] See the file entitled, "Chitwood cost-effectiveness.xlsx" for all details related to this calculation.

## Table 15. Revised Chitwood Engine Cost-Effectiveness Figures

| EU ID | Control Option | Trinity Baseline NOx | Revised Baseline NOx | Controlled Emissions (tpy) | Emissions Reduction (tpy) | Revised Emissions Reduction (tpy) | Total Capital Cost ($) | Capital Recovery Factor (CRF) | Annualized Capital Cost ($) | Annual O&M Cost ($) | Total Annual Cost ($) | Cost-effectiveness ($/ton) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| C-1 GMV-8 | CBT (6 g) | 89.61 | 107 | 38.4 | 51.2 | 61.1 | $1,294,500 | 0.058 | $74,861 | $56,474 | $131,335 | $2,150 |
| C-1 GMV-8 | CBT (1 g) | 89.61 | 107 | 6.4 | 83.2 | 99.4 | $1,928,250 | 0.058 | $111,511 | $59,024 | $170,535 | $1,716 |
| C-2 GMV-8 | CBT (6 g) | 89.61 | 71.6 | 38.4 | 51.2 | 40.9 | $1,294,500 | 0.058 | $74,861 | $56,474 | $131,335 | $3,212 |
| C-2 GMV-8 | CBT (1 g) | 89.61 | 71.6 | 6.4 | 83.2 | 66.5 | $1,928,250 | 0.058 | $111,511 | $59,024 | $170,535 | $2,564 |
| C-3 GMV-8 | CBT (6 g) | 19.38 | 45 | 8.3 | 11.1 | 25.7 | $1,294,500 | 0.058 | $74,861 | $56,474 | $131,335 | $5,111 |
| C-3 GMV-8 | CBT (1 g) | 19.38 | 45 | 1.4 | 18 | 41.8 | $1,928,250 | 0.058 | $111,511 | $59,024 | $170,535 | $4,079 |
| C-4 GMV-8 | CBT (6 g) | 72.36 | **72.36** | 31 | 41.3 | 41.3 | $1,294,500 | 0.058 | $74,861 | $56,474 | $131,335 | $3,179 |
| C-4 GMV-8 | CBT (1 g) | 72.36 | **72.36** | 5.2 | 67.2 | 67.2 | $1,928,250 | 0.058 | $111,511 | $59,024 | $170,535 | $2,537 |
| C-6 KVS-8 | CBT (6 g) | 83.59 | 90.3 | 45.6 | 38 | 41.1 | $994,500 | 0.058 | $57,512 | $56,474 | $113,986 | $2,774 |
| C-6 KVS-8 | CBT (1 g) | 83.59 | 90.3 | 7.6 | 76 | 82.1 | $1,638,250 | 0.058 | $94,740 | $59,024 | $153,764 | $1,873 |
| C-7 KVS-8 | CBT (6 g) | 83.59 | 72.8 | 45.6 | 38 | 33.1 | $994,500 | 0.058 | $57,512 | $56,474 | $113,986 | $3,441 |
| C-7 KVS-8 | CBT (1 g) | 83.59 | 72.8 | 7.6 | 76 | 66.2 | $1,638,250 | 0.058 | $94,740 | $59,024 | $153,764 | $2,324 |
| C-8 GMV-10 | CBT (6 g) | 54.57 | 99.3 | 23.5 | 31.3 | 56.7 | $1,334,500 | 0.058 | $77,174 | $56,474 | $133,648 | $2,357 |
| C-8 GMV-10 | CBT (1 g) | 54.57 | 99.3 | 3.9 | 50.8 | 92.2 | $2,018,250 | 0.058 | $116,716 | $59,024 | $175,740 | $1,905 |
| C-9 GMV-10 | CBT (6 g) | 54.57 | 62.3 | 23.5 | 31.3 | 35.6 | $1,334,500 | 0.058 | $77,174 | $56,474 | $133,648 | $3,757 |
| C-9 GMV-10 | CBT (1 g) | 54.57 | 62.3 | 3.9 | 50.8 | 57.9 | $2,018,250 | 0.058 | $116,716 | $59,024 | $175,740 | $3,036 |

As can be seen from the above revised summary, Chitwood's cost-effectiveness is inflated and is approximately double what it should be, based on the issues noted above. These figures may improve further, depending on Trinity's NOx emission calculation.

On page 2-5 of its report, Trinity makes various arguments related to the cost of the controls. ODEQ should consider, as noted above, that these engines, with the exception of C-9, have escaped permitting limits for decades due to being grandfathered into the program. LEC controls have been regularly found to be cost-effective for many years across the United States and there is a great deal of information available to support this conclusion. For instance, in 2000, EPA calculated LEC cost-effectiveness figures for lean burn engines of $404/ton to $530/ton, depending on the efficiency, and for SCR of $1,066/ton.[72] A more recent 2015 EPA publication lists the cost of LEC for lean burn compressor engines as $649/ton.[73] Even more recently, the NPCA commissioned a comprehensive report on reasonable progress four-factor control analysis for the oil and gas industry.[74] This study cites many examples of LEC for engines similar to those used by Chitwood, resulting in much lower cost-effectiveness figures.

**RESPONSE:** See also DEQ's response to comments #11 and 12 above. As mentioned in this comment, these engines are grandfathered, which effectively means they are very old. As included in DCP's response and clarified above, the age of the engines means that their current condition would have to be individually evaluated by taking each one offline to get a true cost estimate and technical evaluation of what controls could actually be installed. These evaluations would likely find that some of the engines are not amenable to controls, and some could be controlled but likely at higher cost estimates. Even if DEQ accepted at face value the cost estimates provided in Table 15 of the comment above, the cost estimates are still above what DEQ is considering cost-effective for $NO_x$ controls for this second planning period.

**59. COMMENT:** **<u>Conclusion</u>** – We urge ODEQ to reevaluate its Draft SIP especially in light of EPA's July 8, 2021 Clarification Memo and these comments, which confirm that the Draft 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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72 See NOx Emissions Control Costs for Stationary Reciprocating Internal Combustion Engines in The NOx SIP Call States, E.H. Pechan & Associates, Inc, Revised Final Report, August 11, 2000. Available here: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution. Page 17.

73 Technical Support Document (TSD) for the Cross-State Air Pollution Rule for the 2008 Ozone NAAQS Docket ID No. EPA-HQ-OAR-2015-0500, Assessment of Non-EGU NOx Emission Controls, Cost of Controls, and Time for Compliance, U.S. Environmental Protection Agency Office of Air and Radiation November 2015. Page 13. Available here: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-andguidance-air-pollution.

74 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, Prepared for National Parks Conservation Organization by Vicki Stamper & Megan Williams.

**RESPONSE:** DEQ appreciates the time and effort put into the review of Oklahoma's Planning Period 2 Regional Haze SIP. DEQ believes that it has met the statutory and regulatory requirements for regional haze. Where appropriate, changes have been made to the SIP to further clarify how these obligations have been met as outlined in DEQ's responses to the comments above. DEQ does not plan to issue a revised SIP for public notice and comment prior to submission of the SIP to EPA.

## Oral Comments at Public Hearing

**Jeremy Jewell, Air Quality Committee Chair, Environmental Federal of Oklahoma (EFO)** –

**60.** **COMMENT:** EFO is generally supportive of the SIP.

**RESPONSE:** DEQ appreciates EFO's review and support of the Planning Period 2 RH SIP.

**61.** **COMMENT:** Note that if DEQ were to continue the IMPROVE graph out to 2020, now that 2020 IMPROVE data is available from Colorado State University, that the trend line continues even further downward.

**RESPONSE:** DEQ appreciates EFO reviewing the 2020 IMPROVE data for the Wichita Mountains Wilderness Area and highlighting that the downward trend in emissions, which equals visibility improvement, is continuing.

**62.** **COMMENT:** EFO does not support DEQ's use of 3.25% as a capital recovery interest rate in any cost effectiveness calculations, even if it is just presented as a sensitivity analysis. EFO thinks any use of the bank prime rate, which is what the 3.25% is based upon, to estimate private company borrowing capability is unreasonable regardless of EPA's recommendation to do so. In addition, since the SIP was written, the bank prime rate has increased by 31%, to 4.25%, as of today [7-1-22].

**RESPONSE:** DEQ agrees that a 3.25% interest rate does not appear to be representative of the interest rate at which companies can currently borrow capital. However, in order to address other comments received on the Planning Period 2 RH SIP, DEQ will continue to include 3.25% as an alternate calculation for some control costs.

**Jeremy Jewell, Trinity Consultants, on behalf of Oxbow Calcining in Kremlin, OK** –

**63.** **COMMENT:** In Section 6.4.2.7 of the draft SIP, in Table 6-4, the value for the "Cost of compliance (dollars per ton)" under the "City of Enid" column in the row identified by "Kiln 2," "DSI," currently says "$14,99" but should read "$14,944."

**RESPONSE:** This typo has been corrected.

**64.** **COMMENT:** In Section 6.4.1.1, on page 37, in the second-to-last sentence, there is a misspelled word. The word is "uncertainly" and should be "uncertainty."

**RESPONSE:** This typo has been corrected.