APPENDIX I

Informal Environmental Protection Agency Comments

EPA Comments on Pre-Proposal Draft Oklahoma RH SIP
November 2021

Pollutants and Source Categories Evaluated

1. We recommend that the SIP include additional discussion in support of ODEQ's decision to focus on addressing NOx and SO2 emissions in the second planning period. Section 6.1 of the draft SIP states that "Particulates of ammonium nitrate and ammonium sulfate make up the greatest percentage of impairment contribution at the WMWA. Therefore, ODEQ chose to focus on NOx and SO2 emissions for analysis in this implementation plan revision" (see page 24). We recommend that additional discussion be included in this section comparing light extinction values attributed to each particulate species to support the decision to focus on NOx and SO2 emissions.

2. We recommend that the SIP include additional discussion in support of ODEQ's decision to evaluate potential control strategies only for point sources in this planning period. 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 discusses that the majority of SO2 emissions continue to be attributed to the point source category of the inventory. Although not directly stated, this appears to be part of ODEQ's reasoning for evaluating controls only for point sources and, if so, should be clearly identified as such. With respect to NOx, Section 4 notes that NOx emissions are not dominated by one source category, but instead are heavily contributed to by the point, nonpoint, and on-road sectors. It is also noted that the proportion of NOx emissions attributable to nonpoint sources increased slightly from 2014 to 2017. The SIP should include a discussion that clearly explains and provides support for ODEQ's decision to focus on evaluating controls for point sources in this planning period. Given the large proportion of NOx emissions attributable to oil and gas nonpoint sources, the SIP should evaluate potential control strategies for these sources or include a justification for the decision not to evaluate these sources in the four-factor analysis.

Source Selection Analysis

3. The AOI study that ODEQ relied on in the source selection analysis used 2016 as the baseline emissions year. As pointed out in the draft SIP, a number of sources contributing to visibility impairment at the Wichita Mountains have shut down or have significantly reduced their emissions since 2016. The draft SIP specifically identifies the Big Brown Power Plant in Texas as a source that has since shut down, and we note that Sandow and Monticello are two other Texas sources that have also shut down since 2016. These shutdowns are not reflected in the emissions inventory used in the AOI study. Similarly, the emission inventory used in the AOI study does not reflect the significant SO2 emissions reductions resulting from installation of controls or conversion to natural gas in 2018 to satisfy SO2 BART

requirements in the first planning period for Units 1 and 2 at the OG&E Sooner Plant and Units 4 and 5 at the OG&E Muskogee Plant.

The draft SIP acknowledges that there have been some major changes in emissions since 2016, and therefore a change in contribution percentages from the remaining facilities, however “DEQ believes adjusting emission profiles of a select few sources and recalculating potential contribution results in a misrepresentation of potential improvement by controlling the remaining sources” (see page 26). It is unclear in what way ODEQ believes this would result in a misrepresentation of potential improvement. In fact, Section 6.3 later points to the use of 2016 emission data in the AOI study as part of the justification for further eliminating any BART sources identified for evaluation because this data “did not include many of the control applications required in previous implementation plan revisions.” We recommend that the source selection analysis be updated to account for the significant emissions reductions that have taken place at the aforementioned sources given that the use of 2016 emissions for these sources could be significantly impacting the calculated contribution percentages relied on for source selection and could be resulting in not bringing forward other sources for evaluation for which cost-effective controls may be available. In addition to or as an alternative to updating the emissions data for sources that have shut down or installed controls in recent years, ODEQ could use absolute AOI results instead of the percentage relative AOI results to identify the largest visibility contributors in Oklahoma in the source selection analysis. This approach would avoid having to recalculate the individual source contribution percentages.

4. Section 6.2.1. of the draft SIP explains that two thresholds were applied in selecting sources for evaluation in the four-factor analysis: an individual source contribution threshold (% EWRT*Q/d) equal to or greater than 0.5% and a Q/d threshold of 5. The discussion of the process and order in which the thresholds were applied and the sources that were eliminated from further evaluation at each step is unclear. For instance, it is stated that “The 0.5% threshold identified 12 total sources [for evaluation]…” Was this intended to state that the application of the two thresholds identified 12 total sources? The sentence that follows reads “Eight of the thirty originally identified sources were eliminated from further analysis, because they were too small to be considered after using the 0.5% contribution metric discussed above.” For greater clarity, we recommend identifying the thirty sources in the original list and explaining the process for compiling the original list of thirty sources. We also recommend identifying the eight sources that were eliminated based on application of the 0.5% contribution threshold.

   The discussion then notes that “DEQ selected a Q/d threshold of 5 tons $year^{-1}$ km^{-1}…” The emissions year used for the “Q” value in this Q/d calculation must be specified. This is consistent with 40 CFR 51.308(f)(2)(iii) of the Regional Haze Rule, which requires a state to document, among other things, the emissions information on which the state is relying to determine the emission reduction measures that are necessary to make reasonable progress. A review of Appendix C and a comparison of the Q/d values presented there to the Q/d values presented in Tables 6-2 and 6-3 appear to indicate that the Q/d values used in the calculation for the % EWRT*Q/d may not be the same as those used in the Q/d values used in the application of the 5 tons $year^{-1}$ km^{-1} threshold. This is likely due to the use of different emissions years in the Q value of the Q/d calculation, but since a spreadsheet of the calculation of Q/d values used in the application of the 5 tons $year^{-1}$ km^{-1} threshold does not appear to be included in the supporting documentation (only the actual Q/d values are listed), we are unable to make this determination. If in fact different emissions years were used for the Q value, this mismatch may not be appropriate given that this approach eliminates sources at two different steps in the process using different variations of the same metric (Q/d).

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). Consistent with the memo, to further support the selection of the thresholds used in the source selection analysis, we recommend discussing what percentage of the cumulative impacts for SO2 and NOx each are captured by application of these thresholds.

5. ODEQ's approach of automatically eliminating from further consideration the BART sources identified in the source selection analysis is inappropriate. 40 C.F.R. 51.308(e)(5) specifically notes that "[a]fter a State has met the requirements for … 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 2019 Guidance 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 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, we recommend that further explanation be included in the SIP to justify the decision not to evaluate these BART sources in the four-factor analysis. Alternatively, we recommend that BART sources that were automatically eliminated from further analysis instead be evaluated in a full four-factor analysis to determine if further controls are necessary.

   Of particular concern is the automatic elimination from further analysis of the OG&E Muskogee Generating Station, the PSO Northeastern Station, and all the 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 planing 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, we recommend further analysis of potential controls for these sources or 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 NOx controls (SCR/SNCR) are not necessary.

As ODEQ is aware, PSO recently conducted a study to determine whether DSI improvements are possible at PSO Northeastern Unit 3, which was required to install and operate DSI under BART until the unit shuts down in 2026. PSO submitted to ODEQ a document titled "BART SO_2 Monitoring Program for Northeastern Power Station Unit 3" (SO_2 Monitoring Program), discussing this study and its results. Based on the study, the company has determined that the control efficiency of the existing DSI could be increased to achieve a lower SO2 emission limit for Unit 3. EPA's 2021 Clarifications Memo states that "If a source can achieve, or is achieving, a lower emission rate using its existing measures than the rate assumed for the "effective control," a state should further analyze the lower emission rate(s) as a potential control option." (2021 Clarifications Memo at 5). Consistent with the 2021 Clarifications Memo, PSO's study and the outcome of it should be discussed in the SIP. The adoption of a more stringent SO2 emission limit for Unit 3 as a result of PSO's study could provide further justification for the decision not to complete a full four-factor analysis for this unit. Alternatively, Unit 3 could be evaluated in a full four-factor analysis to determine if additional SO2 reductions are cost-effective.

Four-Factor Analyses

6. Aside from a short summary provided of each four-factor analysis submitted by the facilities, there is no real discussion of ODEQ's evaluation of the four-factor analyses submitted by the facilities. For each of the selected sources, and for each emission unit evaluated, the four-factor analysis should 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 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 a 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 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. 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 Guidance at 43; Clarifications Memo at 8-9.

7. We recommend that for each selected source the State considers 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, we recommend the State either conduct a four-factor analysis or explain why it is reasonable to forgo doing so. See Clarifications Memo at 5, 7.

Continental Carbon (evaluated for SO2 only)

8. The summary of the company's response that was made publicly available (given that the full response contains CBI) does not specify for which units the information/data is provided. Please provide a short summary/discussion of EGU 5- Production Units 1 through 4, which are the units for which ODEQ requested information for the four-factor analysis.

9. Please clarify whether the baseline emissions information provided is for each thermal oxidizer for which the request applies or for all the thermal oxidizers combined.

10. Please clarify whether the SO2 scrubbing systems planned for installation are for only two of the Production Units for which ODEQ requested information and whether there any technically feasible SO2 controls for the units on which SO2 scrubbing systems are not planned to be installed.

11. Please clarify whether the estimate of anticipated annual SO2 emission reductions (15,800 tpy) is for each unit individually or if this is the combined anticipated annual emissions reductions across all units.

12. Please provide documentation of the equipment life used to calculate costs of SO2 scrubber controls. We recommend that the equipment life used to calculate costs for each control technology option, unless constrained by an enforceable retirement date for the source, be consistent with that found in the respective chapter of the Control Cost Manual. Any deviations from the Control Cost Manual need to be documented and an appropriate rationale provided. See Guidance at 33-34.

13. The company's summary indicates that the baseline emission rate information provided is based on the facility's permitted emission rates. Please clarify whether the anticipated annual emission reductions were also calculated using the permitted emission rates as the baseline or whether actual emissions were used as the baseline.

DCP Chitwood Gas Plant (evaluated for NO_X only)

14. The four-factor analysis states that the C-5 engine has been out of service since 2006 and notes that the engine will be removed from the permit and for this reason, control measures were not evaluated for this engine. Please specify the timing for the planned removal of this unit from the permit.

15. Please explain why the anticipated control efficiency for Clean Burn Technology (CBT) is the same as the anticipated control efficiency for CBT + SCR. Generally, additional NO_X reduction would be anticipated from adding SCR to CBT.

16. A very basic breakdown of the capital costs was provided for CBT, but not for SCR. Please provide a line-item breakdown of the capital costs for SCR. If available, please provide any vendor quotes obtained for the capital costs of the controls evaluated. Additionally, a breakdown of the estimated operation and maintenance costs of CBT and SCR should be provided, as well as cost calculations used in the cost analysis.

17. 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.

Even when using an improper 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 strengthen its long-term strategy and secure additional emissions reductions and visibility benefits.

GRDA Unit 2 (evaluated for SO2 only)

18. The four-factor analysis is based on a forecasted/projected annual capacity factor but the company states that it is not definitive. Please explain if this forecasted capacity factor is based on recent historical operations. If it is not, it may not be appropriate to base the four-factor analysis on this forecasted capacity factor without an enforceable commitment to operate at that capacity factor.

19. The four-factor analysis is based on a max sulfur loading % that is based on the exclusive use of PRB coal from Wyoming, which departs from the facility’s recent historical practice of mixing the PRB coal with up to 10% Oklahoma coal. Please explain what is driving the switch to use 100% PRB coal, explain whether the switch to use 100% PRB coal is an enforceable requirement and specify how much the max sulfur loading % changed in light of this switch.

20. 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.)

[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.

21. Some of the control scenarios evaluated in the four-factor analysis include replacing the existing SDA with a new SDA with higher SO2 removal efficiency, a CDS, or WFGD. Taking into account that the existing SDA was recently installed, the company should consider whether the existing SDA would have any salvage value that could offset the cost of the new control equipment. EPA's August 2019 Guidance explains that "In some instances, the installation of a new control may involve the removal or discontinuation of existing emission controls. Such situations present special issues and states should consult with their Regional offices. For example, it may be appropriate to account for the salvage value of dismantled equipment." (See August 2019 Guidance at 31.)

22. Please provide line-item cost breakdowns, cost calculations, and any vendor quotes obtained for all the control options evaluated in the four-factor analysis. 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).

Mustang- Binger Gas Plant (evaluated for NO_X only)

23. Please provide additional justification for the elimination of an air fuel ratio controller (AFRC), which is a type of Clean Burn Technology, from further consideration without evaluating this control option in the four-factor analysis. The company states that due to the cost associated with retrofitting the engines with this control, limited operational flexibility, and an increase in regulatory requirements, Mustang does not believe it is feasible to control the engines using an AFRC. However, it appears this control option was identified as a technically feasible control option for these engine types based on the company's review of the RACT/BACT/LAER clearinghouse. Please explain whether there are unique circumstances or conditions at this plant that make AFRC technically infeasible.

24. Additional discussion is needed for the elimination of SCR from further consideration without evaluating it under the four factors. The company states that it does not believe SCR is feasible due to anticipated issues with controlling this type of engine with SCR. However, the company's review of the RACT/BACT/LAER clearinghouse revealed that a number of similar engine types are currently equipped with SCR for the control of NO_X emissions. Did the company reach out to any SCR vendors to investigate whether this control option would be technically feasible for the units at the Binger Gas Plant?

25. The company compared actual 2019 emissions inventory data to the maximum PTE emission rate to calculate the emission reductions for the SNCR control scenario. Please explain how the maximum PTE emission rate of the units was estimated/calculated for the SNCR control scenario.

26. The company states that engines CM-2324 and CM-2325 are already operated with "properly functioning NSCRs as well as with good combustion practices." The company notes that the existing control equipment has a 90% control efficiency and that it believes additional controls for these two engines would therefore be uneconomical and unnecessary. Please provide a discussion of recent actual NO_X emissions from these two engines as well as any available report or other documentation of the study/testing that was conducted to determine the control efficiency of the existing NSCR.

OG&E Horseshoe Lake (evaluated for NO_X only)

27. Please provide additional discussion on why the baseline NO_X emissions used in the four-factor analysis were based on 2016 actual emissions for the units evaluated. Actual NO_X emissions in 2020 were higher than 2016 emissions for all units and actual NO_X emissions in 2019 were at least twice as high as 2016 emissions for all units except Unit 8. Actual NO_X emissions in 2018 were also higher than 2016 emissions for all units except Unit 8. The four-factor analysis states that the year 2016 was used for this evaluation as it has been deemed most representative of 2028 operation. Please explain why actual 2016 NO_X emissions are most representative of anticipated 2028 operation.

28. For the time necessary for implementation, please explain why it is anticipated that it would take a minimum of four years to install SCR on one unit. Based on historical data, the installation of SCR at similar units can be typically completed in three years.

29. The assumption of a shortened remaining useful life (20 years) in the cost analysis for 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.)

30. 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.

OG&E Mustang Generating Station (evaluated for NO_X only)

31. The company's response to ODEQ states that the two units selected for evaluation were permanently retired on December 31, 2017. Please indicate whether the permit has also been

revoked and the units been dismantled. If not, please indicate whether there are plans to do so.

Oxbow Kremlin Calcining Plant (evaluated for SO2 only)

32. The assumption of a 20-year remaining useful life in the cost evaluation of controls is not sufficiently supported with documentation. 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.) 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.

33. A 10% interest rate is used in the cost analysis and it is explained that this is "based [on] confidential company-specific capital market information." The redacted version of the four-factor analysis that is publicly available must specify whether this is a company-specific interest rate. 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 used to estimate the cost of controls, adequate documentation supporting that interest rate should be provided with the cost analysis. A letter from a chief financial officer for an institution that lends to the company, or another official with the company that is in a position to know the company's debt and equity, that documents the institution's commitment to lend at the specified interest rate would be considered sufficient documentation.

34. The four-factor analysis explains that average hourly SO2 emission rates (measured at each kiln during the January 2015 to December 2019 period) and annual average SO2 emission rates (during the January 2018 to December 2019 period) were used to determine annual capacity factors for the kilns for 2018 and 2019, and these in turn were used to estimate operation and maintenance cost of controls for 2020 and future years. The four-factor analysis also states that "capacity factors are based on historical operation and may not represent future operation." Please explain why the range of years used for the average hourly SO2 emission rates and annual average SO2 emission rates are not the same. For greater clarity, the four-factor analysis should also provide the calculations for the capacity factors, with redactions in the publicly available version if necessary. The four-factor analysis should provide further discussion related to the statement that the capacity factors may not represent future operation. For instance, please explain whether there are any recent enforceable requirements that are expected to cause the capacity factors to change in the future.

Panhandle Eastern Cashion Compressor Station (evaluated for NO_X only)

35. The SIP should discuss whether ODEQ agrees with the company's assessment that the facility falls below ODEQ's Q/d threshold when NO_X emissions that are based on recent engine test data are used, and that the Cashion Station should therefore not be subject to a four-factor analysis.

36. The company should provide additional discussion of how the engine testing was conducted to determine the actual NO_X emissions from the four engines and, if available, provide the testing report or other documentation of the engine testing.

Western Farmers Hugo Power Plant (evaluated for SO2 only)

37. 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.

38. The cost estimates for DFGD and WFGD were based on cost estimates from the Technical Support Document for EPA's 2011 Oklahoma SO2 BART FIP. The company escalated those cost numbers, which were based on 2009 dollars, to 2019 dollars using CEPCI escalation indices. While escalation can be a useful tool to adjust relatively recent costs obtained from a similar project/emission unit, EPA's Control Costs Manual recommends not to escalate costs over more than 5 years. We recommend that the cost analysis be updated accordingly.

<u>Cost Thresholds</u>

39. ODEQ avoids selecting a cost threshold for SO2 controls but points to $5,000/ton as being "widely used as a reasonable threshold in evaluating SO2 compliance costs for Regional Haze" (see page 37), 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. But ODEQ ultimately agrees with the conclusions reached by the companies in the submitted analyses and dismisses all SO2 and NOx controls. The reasons given in Section 6.8.2 for dismissing all SO2 and NOx controls are that all SO2 controls were found to be in excess of $5,000/ton while all NOx controls were above the selected cost threshold of $1,400 to $2,000/ton, the progress already made in visibility improvement at the WMWA, and the uncertainty in future economic variables. We disagree with ODEQ's conclusion and the reasoning behind it. As discussed in the "Four-Factor Analyses" section of this document, we have a number of concerns with many of the four-factor analyses submitted by the companies and if the analyses were to be revised to address these concerns, the corrected $/ton of many control options would potentially be lower.

Additionally, other than pointing to the Texas and Arkansas regional haze SIPs, ODEQ's draft SIP does not provide any actual justification for the use of $5,000/ton as either a threshold or reference point for SO2 controls. EPA has not taken action on the Texas regional haze SIP, and the Arkansas regional haze SIP has not been submitted to EPA. Therefore, the selection of those cost thresholds by Texas and Arkansas has not been approved by EPA. We also remind ODEQ that the first planning period focused primarily on controlling BART sources, which in many cases were uncontrolled and generally consisted of the largest SO2 and NOx sources. Because of the iterative nature of the regional haze planning process, it is reasonable to expect that now that the largest and, in many cases, uncontrolled sources have installed controls that were required in 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. Therefore, it is reasonable to expect that a cost threshold greater than what is reflected in the $/ton cost of controls from the first planning period would be appropriate.

Regarding ODEQ's selection of a NOx 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 NOx emission budgets, we note that there were numerous source-specific NOx 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. As discussed in the preceding paragraph, because of the iterative nature of the regional haze planning process, it is reasonable to expect that a cost threshold greater than what is reflected in the $/ton cost of controls from the first planning period would be appropriate. Therefore, the selection of a cost threshold of $1,400 to $2,000/ton for NOx controls in the second planning period does not seem appropriate or sufficiently justified.

ODEQ also states that the progress already made in visibility improvement at the WMWA and the uncertainty in future economic variables are also part of the reasoning for agreeing with the conclusions reached by the companies in the submitted analyses and dismissing all SO2 and NOx controls. The decision on what emission control measures are necessary to make reasonable progress for the second implementation period must be based on the four statutory factors, with the flexibility to also consider the visibility benefits of potential control measures evaluated along with the four statutory factors. Therefore, it is not appropriate to dismiss otherwise cost-effective controls that would provide for progress toward the goal of natural visibility conditions based on uncertainty in future economic conditions or considerations or factors other than the four statutory factors and the visibility benefits of the potential control measures evaluated.

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 NOx control cost threshold could potentially result in several of the engines at the DCP Chitwood Plant being identified as cost-effective where some of the NOx controls were estimated by the company to cost in the range of \$3,250 - \$5,800. In addition, taking our comments on appropriate interest rates into account could potentially result in lower \$/ton cost numbers for a number of controls and when this is taken into account along with our comments on cost thresholds, this could potentially result in additional NOx and SO2 controls being identified as cost-effective.

We encourage ODEQ to list the specific cost of compliance (\$/ton) for each control type in Table 6-4 of the SIP narrative rather than listing a cost range between all control types and water supply scenarios considered. We recognize that this cost information is found in Appendix D but believe that including such a summary in the SIP narrative would help the public in reviewing the draft SIP.

40. Section 6.8 of the draft SIP 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. To the extent that ODEQ is objecting to relying on control cost information from the RACT/BACT/LAER Clearinghouse to help inform a cost threshold, we note that the August 2019 Guidance states that "When the cost/ton of a possible measure is within the range of the cost/ton values that have been incurred multiple times by sources of similar type to meet regional haze requirements or any other CAA requirement, this weighs in favor of concluding that the cost of compliance is not an obstacle to the measure being considered necessary to make reasonable progress." (August 2019 Guidance at 40). Therefore, we disagree that it would be inappropriate to use cost information from the RACT/BACT/LAER Clearinghouse to help inform a cost threshold.

Long-Term Strategy

41. 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 draft SIP states that "The success of Planning Period 1 and high cost of control options in the current planning period led DEQ to develop a long-term strategy (LTS) in the current planning period reliant on existing air program rules and regulations." This language indicates that ODEQ is not including in its long-term strategy any control requirements for the sources evaluated in the four-factor analysis. However, section 6.4.2.3. of the draft SIP identifies non-selective catalytic reduction 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. If the 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 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 along with the compliance schedule identified in the SIP must be included in the long-term strategy for the second planning period and must be clearly identified as so 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)."

Similarly, 13 natural gas fueled compression engines at the ONEOK Maysville Gas Plant were brought forward for evaluation in the four-factor analysis based on ODEQ's source selection analysis. ONEOK has already removed seven of these engines and has agreed to enter into a consent order with ODEQ to remove the six remaining natural gas fueled engines by December 31, 2028. From previous communications with ODEQ, we understand that ONEOK has agreed to enter into an enforceable commitment to remove the remaining engines as an alternative to conducting a four-factor analysis for the Maysville Gas Plant. This approach is consistent with EPA's 2019 Guidance, which states that "If a source is expected to close by December 31, 2028, under an enforceable requirement, a state may consider that to be sufficient reason to not select the source at the source selection step." (See August 2019 Guidance at 20). EPA's 2021 Clarifications Memo further clarified "…on-the-way measures, including anticipated shutdowns that are relied on to forgo a four-factor analysis or to shorten the remaining useful life of a source, are necessary to make reasonable progress and must be included in a SIP." (See 2021 Clarifications Memo at 10). Our understanding is that ODEQ intends to include those engine shutdowns as a source-specific requirement in the SIP. Therefore, those engine shutdowns must be included in Oklahoma's long-term strategy for the second planning period and must be clearly identified as such in the SIP.

In addition, it is unclear if ODEQ is including in the long-term strategy its Smoke Management Plan and the state regulations on construction activities found at OAC 252:100-29. Subsections 6.10.1 and 6.10.2 under the Long-Term Strategy section of the draft SIP briefly discuss both the Smoke Management Plan and the state regulations on construction activities but do not clearly identify whether these are part of the state's long-term strategy for the second planning period. If they are part of the long-term strategy, they must be clearly identified as so. Additionally, the SIP should include a discussion of the long-term strategy requirements under 40 CFR 51.308(f)(2)(iv)(B) and (D) and explain whether ODEQ is relying on its Smoke Management Plan and state regulations on construction activities to satisfy those requirements.

42. The draft SIP on page 4 states that "Considering the advanced progress toward natural conditions thus far, the shortened planning period, the results of the four-factor analyses, and financial uncertainty associated with Oklahoma's sources, DEQ selected a long-term strategy based on existing pollution control programs and clean energy technology advances. As older emission units continue to be replaced or retire, emission reductions will likely continue along the recent trends, and meeting a reasonable progress goal will be achievable with this

long-term strategy." Regarding the length of the second planning period, there is also a statement in section 6 that "The delayed [regional haze SIP] deadline shortens the planning period from the normal ten years to just seven years." In the 2017 Regional Haze Rule Revision, EPA did extend the due date of the second planning period regional haze SIPs to July 31, 2021, but we did not change the start or end dates of the second planning period. The second planning period continues to be a 10-year period from 2018 to 2028. Therefore, we do not believe it is reasonable to include this as part of ODEQ's justification for not requiring additional controls for reasonable progress in the second planning period.

We do not consider ODEQ's reference to "the financial uncertainty associated with Oklahoma's sources" an appropriate justification for concluding that no additional controls are necessary for reasonable progress without site-specific reasons given as to why Oklahoma sources are believed to face financial uncertainty and documentation to support this position. If any factors that also have the potential to affect sources in other states are identified as part of the reason why ODEQ believes Oklahoma sources face financial uncertainty, additional explanation would be needed to explain whether (and if so, why) ODEQ believes Oklahoma sources face greater financial uncertainty than sources in other states.

Regarding the statement that older emission units will continue to be replaced or retired, without an existing federally enforceable requirement to shut down there is no guarantee that these shutdowns will actually take place. Therefore, to the extent that ODEQ is relying on these assumed shutdowns and associated emissions reductions as part of the basis for not requiring controls in the second planning period, we do not consider this an appropriate rationale.

43. Section 6 of the draft SIP states that "[C]ontrol implementation in Planning Period 2 should be relegated to only those controls absolutely necessary to achieve the reasonable progress goal for 2028 as the work on Planning Period 3 (2028-2038) will begin shortly after the submittal of this SIP and possibly before EPA approval" (see page 23). This statement 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, the idea that any controls required for the second planning period should be limited to controls necessary to achieve the 2028 RPG is incorrect and contrary to the Regional Haze Rule requirements. This statement should be removed from the SIP and we recommend that ODEQ reconsider the determination that no additional controls are necessary for the second planning period in light of this and other comments discussed in this document.

44. Section 5.2 of the draft SIP includes a discussion of the status of control measure implementation for Oklahoma sources for the first planning period and states that "The only remaining requirement from the Regional Haze Agreement is for Unit 3 at Northeastern to incrementally reduce the capacity factor until its mandatory retirement by December 31, 2026" (see page 19). For thoroughness, a discussion should be included regarding the requirements for Unit 3 at the Northeastern facility contained in the Regional Haze Agreement. The Regional Haze Agreement was part of the 2013 Oklahoma Regional Haze SIP Revision, which was approved by EPA in a March 7, 2014 final rule and requires the company to develop and propose a monitoring program to test various operating profiles and other measures in order to determine whether increased SO_2 removal efficiencies (more stringent than the approved 0.40 lb/MMBtu SO2 emission limit) can be achieved at Unit 3 during normal operations using existing DSI. It also contained additional requirements for Unit 3 dependent on the results of the required monitoring program.

    We are aware that PSO submitted to ODEQ the "BART SO_2 Monitoring Program for Northeastern Power Station Unit 3" (SO_2 Monitoring Program), dated June 25, 2019. Based on the results of the SO_2 Monitoring Program, PSO concluded that the lowest target emission rate sustainably achieved consistent with the conditions in the Regional Haze Agreement is 0.35 lb/MMBTU on a 30-day rolling average basis, and that the resulting federally enforceable emission rate should be 0.37 lb/MMBtu on a 30-day rolling average basis.[3] Section 5.3.6. of the draft SIP should discuss whether any further discussions have taken place between ODEQ and PSO and the outcome of those discussions, including whether ODEQ agrees with PSO's determination that the BART emission limit for Unit 3 should be revised to 0.37 lb/MMBtu or whether a more stringent emission limit may be appropriate. Table 5-7 of the draft SIP lists the SO2 emission limit for Unit 3 as 0.40 lb/MMBtu, with no mention of plans to revise this emission limit. The draft SIP should include an update on the status of efforts to revise the BART SO2 emission limit for Unit 3.

[3] The 0.37 lb/MMBtu emission rate is 60 percent of the difference between 0.40 and the demonstrated emission rate (0.35 lb/MMBtu), per the terms of the AEP/PSO Settlement Agreement.

Progress Report

45. The Regional Haze Rule requires that progress reports include "An analysis tracking the change over the period since the period addressed in the most recent plan required under paragraph (f) of this section in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source or activity." 40 CFR 51.308(g)(4). The progress report section of the draft SIP (Section 5) does not include this analysis. There is a discussion of emission trends in Section 4 of the draft SIP, and to the extent that this is intended to satisfy the requirement under 40 CFR 51.308(g)(4), we recommend that the progress report section of the SIP specifically cite to Section 4 of the SIP.

46. The draft SIP states that "This Planning Period 2 RH SIP and progress report covers the time since the last progress report was submitted (September 28, 2016) through the year of the most recently available data (i.e., 2019)." (See page 3). The most recent year of IMPROVE monitor data considered in the draft SIP is 2019 and for the discussion of Oklahoma emission trends in Section 4, the most recent year of data considered is 2017. To the extent that more recent data is available, we encourage ODEQ to include such data in the draft SIP that goes out for state public notice and comment. Although the 2017 NEI is the most recent NEI currently available, ODEQ should consider more recent emissions data (2018, 2019, 2020) in the analysis of emissions changes and trends required for the progress report under 40 CFR 51.308(g). The Regional Haze Rule states that "With respect to all sources and activities, the analysis must extend at least through the most recent year for which the state has submitted emission inventory information to the Administrator in compliance with the triennial reporting requirements of subpart A of this part as of a date 6 months preceding the required date of the progress report. With respect to sources that report directly to a centralized emissions data system operated by the Administrator, the analysis must extend through the most recent year for which the Administrator has provided a State-level summary of such reported data or an internet-based tool by which the State may obtain such a summary as of a date 6 months preceding the required date of the progress report." 40 CFR 41.308(g)(4). ODEQ must ensure that the most recent year of emissions data considered in the emissions analysis required for the progress report meets these requirements.

47. The progress report in Section 5 states that "… Planning Period 1 used the 20% haziest days for analysis. Therefore, this section reports the same metric for continuity." (See page 22.) This is inconsistent with the Regional Haze Rule, which requires that progress reports due before January 31, 2025, include a discussion of the current visibility conditions for the most impaired and least impaired days; the difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions; and the change in visibility impairment for the most impaired and least impaired days over the period since the period addressed in the most recent plan required under 40 CFR 51.308(f). See 40 CFR 51.308(g)(3)(i)(A), (ii)(A), and (iii)(A). The preamble of the final 2017 Regional Haze Rule Revision explained that EPA is finalizing the requirement that all states select the 20 percent

most impaired days, *i.e.*, the days with the most impairment from anthropogenic sources, as the "worst" days for purposes of calculating baseline visibility conditions, current visibility conditions, natural visibility conditions and the URP in SIPs and, as applicable, in progress reports. See 82 FR at 3103. The preamble of that final rule also stated that under the final rule revisions, states retain the option to also present visibility data using the days with the highest overall deciview index values (*i.e.*, the 20 percent haziest days), for public information purposes. Therefore, while ODEQ may choose to discuss the 20 percent haziest days metric in the progress report, ODEQ must also discuss the 20 percent most impaired days (*i.e.*, the days with the most impairment from anthropogenic sources).

<u>State-to-State and FLM Consultation</u>

48. The draft SIP contains several statements seem to indicate that the legal standard triggering consultation is "significant" contribution to or impairment of visibility. These terms are 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 "significant" contribution or impairment. ODEQ should review the state of its consultations to ensure that they consistent with and can be justified under the "reasonably anticipated" legal standard of 51.308(f)(2)(ii).

49. The SIP should include all available documentation of Oklahoma's consultations with other states, including copies of any 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." While the draft SIP currently includes a summary of Oklahoma's consultation process with other states, we recommend that copies of any correspondence be included as well.

50. Given the large contribution to visibility impairment at Wichita Mountains from Texas sources, we recommend a more detailed discussion of Oklahoma's consultation with Texas. This should include a clearer description of the requests made by Oklahoma and whether there is any disagreement between Oklahoma and Texas regarding the outcome of the consultation.

51. The SIP should include all available documentation of Oklahoma's consultation with FLMs, including copies of any correspondence with FLMs. In addition, the public notice version of the SIP must include "a summary of the conclusions and recommendations of the Federal land managers in the notice to the public." CAA 169A(d). That is, the draft SIP submission made available for public comment at the state level must contain a summary of the FLMs' comments and recommendations. We also remind ODEQ that the final SIP submitted to EPA must include a discussion of how ODEQ addressed any comments provided by the FLMs on the draft SIP Revision. The Regional Haze Rule requires that in developing any implementation plan (or plan revision), the state must include a description of how it addressed any comments provided by the FLMs. 40 CFR 51.308(i)(3).

52. 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 Section 6.6.) 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 planing period. In light of Oklahoma's consultation with Arkansas and Missouri, we encourage ODEQ to consider evaluating Unit 6 in a full four-factor analysis to determine if SO2 and/or NOx controls are necessary.

<u>Other Observations</u>

53. There are a number of instances throughout the draft SIP that refer to the regional haze requirements under 40 CFR 51.308(d). (See pages 4, 5, and 24). We remind ODEQ that 40 CFR 51.308(d) contains regulatory regional haze requirements for the first planning period while 40 CFR 51.308(f), (g), and (i) contain the regulatory regional haze requirements for the second planning period. When citing or describing the regulatory regional haze requirements for the second planning period, the SIP should cite to 40 CFR 51.308(f), (g), and (i), as appropriate. E.g., in section 6.2, the long term strategy requirements for the second planning period are in 51.308(f)(2), not 51.308(d)(3) as stated in the draft.

54. There are some instances where the SIP either points to the progress already made in visibility improvement or states that visibility impairment is expected to continue to decrease below the uniform rate of progress (URP) during the second planning period at the Wichita Mountains and other Class I areas that may be impacted by Oklahoma sources. (See Section 5.7 on page 23 and Section 6.8.2 on page 37). To the extent that these statements form part of the basis of ODEQ's decision not to require controls for the second planning period, we remind ODEQ that the preamble to the 2017 Regional Haze Rule Revision explains that being below the URP glidepath is not a safe harbor. (See 82 FR at 3093, 3099, 3100.) As discussed in the August 2019 Guidance, consideration that a Class I area is below the glidepath could serve to demonstrate that, after a state has gone through its source selection and control measure analysis, it has no "robust demonstration" obligation per 40 CFR 51.308(f)(3)(ii)(A) and/or (B). (See August 2019 Guidance at 22). However, consideration that a Class I area is below the glidepath cannot be used as the basis for rejecting controls.

55. Section 6.4.2.5 of the draft SIP states that "ONEOK agreed to a consent order with DEQ (Oklahoma DEQ Air Quality Consent Order, Case No. 21-097) as the enforceable mechanism for removing the remaining natural gas fueled engines before 2029." (See page 32.) For consistency with the draft Consent Order, we recommend that the language in that statement be revised to read "… as the enforceable mechanism for removing the remaining natural gas fueled engines by December 31, 2028."

56. Tables 3-1 through 3-8 present IMPROVE monitoring data for the Wichita Mountains that shows the visibility impairment due to each particulate species. The data is presented for each year from 2001-2019 as well as for “Baseline,” “2015-2019,” and “Natural.” For greater clarity, please specify what year or range is assumed for the “Baseline,” and for the “2015-2019” data please clarify if this represents the five-year rolling average.

57. Section 3.2 of the draft SIP discusses the deciview visibility index at the Wichita Mountains and states that “The reasonable progress goals (RPGs) at the Wichita Mountains for 2018, listed in [Table 3-8], reflect the revised RPGs calculated by EPA and included in the Federal Register notice preamble (and associated Technical Support Document) for actions taken on Texas’ and Oklahoma’s RH implementation plans on January 5, 2016 (81 Fed. Reg. 296, January 5, 2016).” First, we note that we do not believe that the revised 2018 RPG for the Wichita Mountains that EPA included in the January 5, 2016 final rule is an appropriate 2018 RPG for ODEQ to rely on or use as a benchmark given that it was part of a Federal Implementation Plan (FIP) action that has since been remanded. Since that final action was remanded, the controls required under that FIP are not effective and were never implemented. Therefore, that revised 2018 RPG value is not an accurate reflection of the controls measures that were actually in place for Texas sources at the end of 2018. Second, we also note that ODEQ’s statement that Table 3-8 lists 2018 RPGs for the Wichita Mountains may be in error, as the table does not appear to list any RPGs.

58. Page 18 of the draft SIP states that “Figure 4-2 shows that oil and gas operations, whether as a point or area source, accounted for 38% of the NOx emission in Oklahoma (with biogenics removed from consideration) in 2014.” We encourage ODEQ to include a breakdown of NOx emissions by category for 2017 NEI emissions as well given that this is the most recent year of NEI data available. Additionally, we note that it appears that ODEQ’s statement should point to Figure 4-3 rather than 4-2.

59. The last sentence in Section 5.5 states that “The following graphs show the changes in SO2 and NOx emissions from 2002-2017 within the major sectors.” (See page 23.) However, these graphs do not appear to have been included within this section of the draft SIP or anywhere else in the draft SIP. Please add these graphs to the SIP and we also encourage ODEQ to consider including more recent emissions data in these graphs.

60. 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.