APPENDIX E

Four-Factor Analyses

SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

KEVIN STITT
Governor

Joe Araiza
Continental Carbon
16850 Park Row
Houston, TX 77084

July 1, 2020

Subject: Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Mr. Araiza:

This letter is to inform you that the Oklahoma Department of Environmental Quality (DEQ) has identified the Carbon Black Production Facility located in Kay County, Oklahoma, as subject to a four-factor reasonable progress analysis under the Regional Haze Rule. DEQ is in the development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

The states in the Central States Air Resources Agencies (CenSARA) organization, which include Oklahoma, contracted with Ramboll US Corporation (Ramboll) to produce a study examining the impact of stationary sources of NOx and SO_2 on each Class 1 area in the central region of the United States. DEQ used a method based on this study to determine which sources may have the greatest potential for contributing to visibility impairment at Oklahoma's Class 1 area: the Wichita Mountains Wilderness Area.

DEQ must develop a long-term strategy to address visibility impairment and make "reasonable" progress toward a goal of no anthropogenic visibility impairment by 2064. The Regional Haze Rule provides four factors (40 CFR §51.308(f)(2)(i)) by which a state must consider potential control measures for the long-term strategy: 1) the cost of compliance; 2) the time necessary for compliance; 3) the energy and non-air quality environmental impacts of compliance; and 4) the remaining useful life of existing sources subject to this requirement.

DEQ requests that Continental Carbon perform a four-factor analysis of all potential control measures for SO_2 on the following emission units at the Carbon Black Production Facility:

1. EUG 5 – Production Units 1 through 4

For any technically feasible control measure, the following information should be provided in detail:

I. Emission reductions achievable by implementation of the measure
    a. Baseline emission rate (lb/hr, lb/MMBTU, etc)
    b. Controlled emission rate (same form as baseline rate)
    c. Control effectiveness (percent reduction expected)
    d. Annual emission reductions expected (ton/year)

II. Time necessary to implement the measure

III. Remaining useful life
   a. Remaining useful life of the control measure, or
   b. The corresponding life of the unit may be used if an enforceable shutdown date of the emission unit is no later than 2028.

IV. Energy and non-air quality environmental impacts of the measure.
   a. Detail any cost of energy, waste disposal, regulatory requirement, etc. incurred with implementation of the control measure.

V. Cost of implementing the measure
   a. Capital costs
   b. Annual operating and maintenance costs
   c. Annualized costs

DEQ respectfully requests that your company submit a report containing the complete 4-factor analysis no later than September 1, 2020. This will allow DEQ to review and identify any cost-effective control measure to be incorporated into the Regional Haze state implementation plan prior to the submission deadline of July 31, 2021.

Please contact DEQ if you have any questions about the method for conducting a 4-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical review required under the Rule.

Thank you for your assistance with this matter. Please contact Cooper Garbe at 405-702-4169 or Melanie Foster at 405-702-4218 for your questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

Continental Carbon

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August 4, 2020

Kendal Stegman, Director
Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

RE: Regional Haze Program – 4-Factor Analysis
Continental Carbon Company
Carbon Black Production Facility

Dear Mr. Stegman:

The purpose of this letter is to comply with the request received by Oklahoma Department of Environmental Quality (ODEQ) dated July 1, 2020 requesting a "4-factor" analysis from Continental Carbon to assist ODEQ in its development of a regional haze strategy in its upcoming state implementation program update. Some information in the request is considered confidential business information and has been submitted in a separate letter.

Below is a summary of the data requested by ODEQ and Continental Carbon's responses:

I. Emission reductions achievable by implementation of the measure (Note: the numbers below are based on permitted emission rates in the facility's current PSD and Title V air permits.

a. Baseline emission rate (lb/hr, lb/MMBTU, etc)
Emissions from the thermal oxidizers are currently permitted for 5,257 pounds per hour (lb/hr) of sulfur dioxide (SO_2).

b. Controlled emission rate (same form as baseline rate)
Two waste gas boilers were installed at Ponca City in the Fall of 2018. The units are still in the commissioning phase. A dry scrubber system will be installed on each boiler unit and is expected to be operational in early 2021. The scrubbing system will reduce SO_2 emissions to approximately 272 lbs/hr.

c. Control effectiveness (percent reduction expected)
Approximately 95% reduction of SO_2 is expected.

d. Annual emission reductions expected (ton/year)
A reduction in approximately 15,800 tons of SO_2 is expected.

II. Time necessary to implement the measure
The SO_2 scrubber systems are expected to be online and operational in the first quarter of 2021.

III. Remaining useful life
a. Remaining useful life of the control measure, or

b. The corresponding life of the unit may be used if an enforceable shutdown date of the emission unit is no later than 2028.

The waste gas boilers and associated equipment, including the SO_2 scrubber have a life expectancy of 20-25 years.

IV. Energy and non-air quality environmental impacts of the measure.

a. Detail any cost of energy, waste disposal, regulatory requirement, etc. incurred with implementation of the control measure. **[Submitted under separate cover, as contains Confidential Business Information]**

V. Cost of implementing the measure

a. Capital costs
b. Annual operating and maintenance costs
c. Annualized costs

[Submitted under separate cover, as contains Confidential Business Information]

If you have any questions concerning this submittal, please contact me at (281) 647-3807 or at email address: jaraiza@continentalcarbon.com

Sincerely,

Joe Araiza, P.E.
Sr. Manager, EHS

Continental Carbon®

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Houston, TX 77084

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Kendal Stegman, Director
Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

... Program ... 4-Factor Analysis

73101-167777

SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

KEVIN STITT
Governor

January 31, 2022

Joe Araiza
Continental Carbon
16850 Park Row
Houston, TX 77084

Subject: Additional clarifications on Continental Carbon's 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Mr. Araiza:

In a letter dated July 1, 2020, the Oklahoma Department of Environmental Quality (DEQ) identified the Carbon Black Production Facility located in Kay County, Oklahoma, as subject to a four-factor reasonable progress analysis under the Regional Haze Rule as part of DEQ's development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

On August 4, 2020, Continental Carbon submitted its four-factor analysis to DEQ. Continental Carbon included in its response that there were no additional cost-effective sulfur dioxide (SO_2) control measures available for EUG 5 – Production Units 1 through 4, other than what was being made operational in 2021 in response to EPA Consent Decree 5:15-cv-00290F. DEQ included these conclusions in its draft Regional Haze SIP for Planning Period 2 that was shared with the Federal Land Managers and the U.S. Environmental Protection Agency (EPA). DEQ requests that Continental Carbon review its four-factor analysis for potential SO_2 control measures for emission unit group (EUG) 5 – Production Units 1 through 4 and respond to the following questions, which are based on EPA's review of Oklahoma's draft SIP. We understand that much of the requested data/analysis may be gleaned or explained from DEQ's permitting and compliance files, and/or Continental Carbon's full unredacted submittal. However, your response will allow Continental Carbon to document the information that best explains and supports the conclusions of Continental Carbon's four-factor analysis. DEQ intends to continue its analysis in parallel.

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

2. 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.

3. Please clarify whether the SO_2 scrubbing systems planned for installation are for only two of the Production Units for which DEQ requested information and whether there are any technically feasible SO_2 controls for the units on which SO_2 scrubbing systems are not planned to be installed.

4. Please clarify whether the estimate of anticipated annual SO_2 emission reductions (15,800 TPY) is for each unit individually or if this is the combined anticipated annual emissions reductions across all units.

5. Please provide documentation of the equipment life used to calculate costs of SO_2 scrubber controls. EPA recommends 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[1]. Any deviations from the Control Cost Manual need to be documented and an appropriate rationale provided. See Guidance at 33-34.[2]

6. 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.

DEQ respectfully requests that Continental Carbon respond to EPA's questions no later than February 28, 2022. Thank you for your assistance with this matter. Please contact Melanie Foster at 405-702-4218 for any questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

[1] https://www.epa.gov/sites/default/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf
[2] https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

Continental Carbon

February 25, 2022
Ms. Kendal Stegmann
Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

SUBJECT: Response to 4-Factor Analysis on Control Scenarios Request
Clean Air Act Regional Haze Program
Continental Carbon
Ponca City Facility

Dear Ms. Stegmann:

Continental Carbon is submitting this response to the four-factor analysis additional clarification request from the Oklahoma Department of Environmental Quality (ODEQ) received on January 31, 2022 for the Ponca City (Facility). This response is being provided per the deadline of February 28, 2022 as specified in the request.

ODEQ Information Request

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

   EUG -5 are the carbon black production units that were previously controlled by thermal oxidizers. As part of the EPA consent order, the control devices for these units are being changed to a dry scrubber system.

2. *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.*

   The baseline emissions provided were for the combined emissions from the four production units.

3. *Please clarify whether the SO_2 scrubbing systems planned for installation are for only two of the Production Units for which DEQ requested information and whether there are any technically feasible SO2 controls for the units on which SO_2 scrubbing systems are not planned to be installed.*

The SO_2 scrubbing system required by Consent Decree 5:15-cv-00290-F requires all four production units be controlled. The ODEQ permit issued Permit No. 2004-302-C(M-4) requires the four production units to be controlled by the two dry scrubbers. There will not be any production units without SO2 controls.

4. *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.*

   This is the anticipated reduction for site-wide SO_2 emissions.

5. *Please provide documentation of the equipment life used to calculate costs of SO_2 scrubber controls. EPA recommends 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[1]. Any deviations from the Control Cost Manual need to be documented and an appropriate rationale provided. See Guidance at 33-34.[2]*

   The controls are required as part of Consent Decree 5:15-cv-00290-F and the equipment useful life is based on EPA guidance in the cost control manual for similar units. The control equipment is also included in a federally enforceable permit and has been installed since the baseline date for the regional haze analysis. Based on the latest monitoring data, Oklahoma is on track to meet the regional haze benchmark. The addition of the required controls will significantly reduce SO_2 and NO_x emissions from the Facility.

6. *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.*

   The permitted emissions were used for the anticipated annual emissions reduction.

If you have any questions or comments please do not hesitate to contact me at (281) 647-3744.

Sincerely,

Dr. S J Marlborough

Sidney Marlborough MSc PhD
Senior EHS Manager
Continental Carbon

Steven Ondak
DCP Operating Co.
3201 Quail Springs Pkwy, Ste. 100
Oklahoma City, OK 73134

July 1, 2020

Subject: Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Mr. Ondak:

This letter is to inform you that the Oklahoma Department of Environmental Quality (DEQ) has identified the Chitwood Gas Plant located in Grady County, Oklahoma, as subject to a four-factor reasonable progress analysis under the Regional Haze Rule. DEQ is in the development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

The states in the Central States Air Resources Agencies (CenSARA) organization, which include Oklahoma, contracted with Ramboll US Corporation (Ramboll) to produce a study examining the impact of stationary sources of NOx and SO_2 on each Class 1 area in the central region of the United States. DEQ used a method based on this study to determine which sources may have the greatest potential for contributing to visibility impairment at Oklahoma's Class 1 area: the Wichita Mountains Wilderness Area.

DEQ must develop a long-term strategy to address visibility impairment and make "reasonable" progress toward a goal of no anthropogenic visibility impairment by 2064. The Regional Haze Rule provides four factors (40 CFR §51.308(f)(2)(i)) by which a state must consider potential control measures for the long-term strategy: 1) the cost of compliance; 2) the time necessary for compliance; 3) the energy and non-air quality environmental impacts of compliance; and 4) the remaining useful life of existing sources subject to this requirement.

DEQ requests that DCP perform a four-factor analysis of all potential control measures for NOx on all fuel-burning equipment with a heat input of 50 MMBTU/hr or more including but not limited to the following emission units at the Chitwood Gas Plant:

1. C-1 through C-4; Cooper-Bessemer GMV-8
2. C-5; Clark HRA-8
3. C-6 and C-7; Ingersol-Rand KVS-8
4. C-8 and C-9; Cooper-Bessemer GMV-10

For any technically feasible control measure, the following information should be provided in detail:

I. Emission reductions achievable by implementation of the measure

   a. Baseline emission rate (lb/hr, lb/MMBTU, etc)
   b. Controlled emission rate (same form as baseline rate)
   c. Control effectiveness (percent reduction expected)
   d. Annual emission reductions expected (ton/year)

II. Time necessary to implement the measure

III. Remaining useful life
   a. Remaining useful life of the control measure, or
   b. The corresponding life of the unit may be used if an enforceable shutdown date of the emission unit is no later than 2028.

IV. Energy and non-air quality environmental impacts of the measure.
   a. Detail any cost of energy, waste disposal, regulatory requirement, etc. incurred with implementation of the control measure.

V. Cost of implementing the measure
   a. Capital costs
   b. Annual operating and maintenance costs
   c. Annualized costs

DEQ respectfully requests that your company submit a report containing the complete 4-factor analysis no later than September 1, 2020. This will allow DEQ to review and identify any cost-effective control measure to be incorporated into the Regional Haze state implementation plan prior to the submission deadline of July 31, 2021.

Please contact DEQ if you have any questions about the method for conducting a 4-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical review required under the Rule.

Thank you for your assistance with this matter. Please contact Cooper Garbe at 405-702-4169 or Melanie Foster at 405-702-4218 for your questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

REGIONAL HAZE FOUR-FACTOR REASONABLE PROGRESS ANALYSIS

DCP Operating Co.
Chitwood Gas Plant

Prepared By:

Kyle Dunn, PE – Managing Consultant
Jeremy Jewell – Principal Consultant

TRINITY CONSULTANTS
5801 E. 41st St.
Suite 450
Tulsa, OK 74135
(918) 622-7111

October 1, 2020

Project 203702.0123

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1. INTRODUCTION

Trinity Consultants (Trinity) prepared this report on behalf of DCP Operating Co. (DCP) in response to the July 1, 2020 "Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program" (the July 1, 2020 request) from the Oklahoma Department of Environmental Quality (the ODEQ) to DCP's Chitwood Gas Plant (Chitwood). ODEQ requested that DCP perform a four-factor analysis of all potential control measures for NO_X on all fuel-burning equipment with a heat input of 50 million British thermal units per hour (MMBTU/hr) or more. There is no equipment at Chitwood that exceeds this threshold, but ODEQ also explicitly requested an analysis for nine natural gas-fired engines (Units C-1 to C-9). DCP is authorized to operate these engines under the authority of ODEQ Part 70 Operating Permit No. 2016-1248-TVR3 ("the permit").

The engine types and horsepower ratings for each affected unit are as follows:

- C-1, C-2, C-3, and C-4: 880-hp (7.3 MMBTU/hr) Cooper-Bessemer GMV-8 two-stroke lean-burn (2SLB)
- C-5: 880-hp (7.3 MMBTU/hr) Clark HRA-8 2SLB
- C-6 and C-7: 1320-hp (9.5 MMBTU/hr) Ingersol-Rand KVS-8 four-stroke lean-burn (4SLB)
- C-8 and C-9: 1100-hp (9.5 MMBTU/hr) Cooper-Bessemer GMV-10 2SLB

C-5 has been out-of-service since 2006. The engine will be removed from the permit, and control measures for this unit will not be addressed further in this report. C-4 and C-8 are also currently out-of-service but will still be evaluated as part of this analysis. Additionally, DCP would like to point out that all affected engines are well below the established threshold of 50 MMBTU/hr for conducting a control measures analysis.

C-1, C-2, C-3, C-4, C-8, and C-9 are collectively referred to in this report as the "GMV engines", and C-6 and C-7 are referred to as the "KVS engines".

The following specific technical and economic information, where applicable, is provided in this report for each emissions reduction option considered in accordance with instructions in the July 1, 2020 request:

- Technical feasibility
- Control effectiveness
- Emissions reductions
- Time necessary for implementation[1]
- Remaining useful life[1]
- Energy and non-air quality environmental impacts[1]
- Costs of implementation[1]

[1] These are the four factors that must be included in evaluating emission reduction measures necessary to make reasonable progress determinations. *See* 40 CFR § 51.308(f)(2)(i).

2. NO_X EMISSIONS REDUCTION OPTIONS

This report addresses the following NO_X emissions reduction options for the Chitwood units:

- Selective Catalytic Reduction (SCR)
- Clean Burn Technology (CBT)
- Good Combustion Practices

Potential hypothetical retrofit control options were identified through a comprehensive review of the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) and consultation with engine and control system engineering firms.

Good combustion practices include following concepts from engineering knowledge, experience, and manufacturer's recommendations to reduce NO_X emissions that are caused by oxidation of nitrogen in the combustion air during fuel combustion. Higher combustion temperatures and insufficiently mixed air and fuel in the cylinder can increase these emissions. Practices to reduce emissions can include, but are not limited to, proper equipment maintenance, routine inspections, and conducting overhauls as appropriate. These good combustion practices are currently in use at Chitwood, as required by various conditions in the permit. Accordingly, no further assessment of this control practice has been included in this report.

The remaining contents of this report discuss general hypothetical retrofit scenarios for these types of engines, but these scenarios are not based on an engineering analysis specific to each subject engine. 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.

2.1 Technical Feasibility

Clean Burn Technology (CBT) is another term for utilizing combustion mixtures with lean air-to-fuel ratios. This method of reducing NO_X emissions involves reconfiguring the engines by adding or enhancing an air-to-fuel ratio controller to make the unit capable of operating at ratios that generate less NO_X emissions. A combustion mixture with a higher air-to-fuel ratio results in reduced NO_X emissions because using fuel-lean mixtures lowers the combustion temperature by diluting energy input. 2SLB engines are typically designed to operate at the high air-to-fuel ratios employed in CBT, so by design these units are generally not amenable to an increase in air-to-fuel ratio to receive significant NO_X reduction benefits. Additionally, in order to avoid derating the engine, combustion air must be increased at constant fuel flow. To achieve this, the engine will need to be retrofitted with a turbocharger, which forces additional air into the combustion chamber, as well as an automatic air-to-fuel ratio controller. Many 2SLB engines, such as naturally aspirated engines, do not have identical air-to-fuel ratios in each cylinder, which can result in limited ability to vary the air-to-fuel ratio. Considering these limitations, and based on the advanced age and type of engine, it is difficult to determine potential costs and emissions reductions without a site assessment and further evaluation of the engines. Additionally, reliability issues could also arise from being unable to properly scope the project. For example, flame front impingement of the power cylinder heads could cause failure of the power cylinder and significant downtime. If any of the control options evaluated here are preliminarily deemed amenable to retrofit in the opinion of the agency and may be required by ODEQ, then DCP requests a minimum of three months to complete a full engineering and vendor evaluation, including an engine health analysis, and potentially update both the information provided in this report and the conclusions drawn in or from this report. However, DCP was able to obtain cost estimates from Siemens Energy assuming that these technical limitations can be overcome. The estimated costs and emissions reductions are included in Appendix A. Two separate CBT options were provided by the vendor, one that reduced emissions to 6 g/hp-hr (herein referred to the as the "6 gram" or "6 g" option) and one that reduced emissions to 1 g/hp-hr (herein referred to the as the "1 gram" or "1 g" option). Note, the 1 gram option will result in CO emissions increasing by approximately 40%. 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.

SCR is considered technically feasible for all the affected units, but the control device vendor (AeriNOx Inc.) stated that SCR should not be used to reduce NO_X emissions from the GMV and KVS engines as they currently exist and are configured due to the large variance in NO_X outlet emissions and the high likelihood of combustion instability that will cause SCR to have poor control issues. Based on this guidance, it was determined that SCR would potentially be technically feasibly only after applying some type of CBT to stabilize the outlet emissions and combustion, and even then, the result may not be technically feasible. Additionally, there may be insufficient space in the facility to accommodate SCR systems, and as such, SCR may not be technically feasible under these circumstances.

2.2 Control Effectiveness

Table 2-1 lists the expected emission rates for the potentially technically feasible NO_X emissions reduction options. The controlled emission rates are based on vendor estimates included in Appendix A, and are subject to the qualifications, above, regarding detailed unit-specific engineering and vendor evaluations, if needed.

Table 2-1. Control Effectiveness of NO_X Emissions Reduction Options

NO_X Reduction Option	Control Efficiency (%)
CBT (6 g)	46 - 57
CBT (1 g)	91 - 93
CBT+SCR (1 g)	91 - 93

2.3 Emissions Reductions

Table 2-2 presents the controlled emission rates and emission reduction potentials for the technically feasible NO_X emissions reduction options. Baseline emission rates were based on RY2019 emissions, and emissions reductions were based on estimates provided by Siemens Energy and AeriNOx Inc. In order to account for year-to-year variability, and to provide a more accurate assessment of potential reductions, the RY2019 emissions were equally redistributed for each engine type and each engine service. C-1 and C-2 are in refrigeration service, C-4 is in inlet service, and the remaining engines are all in residue service. For the engines in residue service, emissions were only redistributed within each engine type (i.e., GMV-8, GMV-10, and KVS). The year-to-year variability is common with these types of facilities and can be attributed to various issues such as engine availability and maintenance. Therefore, we believe the proposed approach for baseline emissions most accurately represents typical engine operation. Detailed emissions calculations are included in Appendix A.

Table 2-2. Baseline and Controlled Emission Rates and Emissions Reductions of Control Options

Unit	Baseline NO_X Emission Rate (tpy)	NO_X Reduction Option	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
C-1	89.61	CBT (6 g)	38.40	51.21
		CBT (1 g)	6.40	83.21
		CBT+SCR (1 g)	6.40	83.21
C-2	89.61	CBT (6 g)	38.40	51.21
		CBT (1 g)	6.40	83.21
		CBT+SCR (1 g)	6.40	83.21
C-3	19.38	CBT (6 g)	8.31	11.07
		CBT (1 g)	1.38	18.00
		CBT+SCR (1 g)	1.38	18.00
C-4	72.36	CBT (6 g)	31.01	41.35
		CBT (1 g)	5.17	67.19
		CBT+SCR (1 g)	5.17	67.19
C-6	83.59	CBT (6 g)	45.59	38.00
		CBT (1 g)	7.60	75.99
		CBT+SCR (1 g)	7.60	75.99
C-7	83.59	CBT (6 g)	45.59	38.00
		CBT (1 g)	7.60	75.99
		CBT+SCR (1 g)	7.60	75.99
C-8	54.74	CBT (6 g)	23.46	31.28
		CBT (1 g)	3.91	50.83
		CBT+SCR (1 g)	3.91	50.83
C-9	54.74	CBT (6 g)	23.46	31.28
		CBT (1 g)	3.91	50.83
		CBT+SCR (1 g)	3.91	50.83

2.4 Time Necessary for Implementation

A minimum of five (5) years, counting from the effective rule applicability date of an approved determination, would be needed for implementing all of the controls, especially if controls are required for multiple engines as DCP will need to stagger the implementation so only one engine is down at a time.

The ODEQ's regional haze second planning period (2PP) state implementation plan (SIP) must be submitted to EPA by July 31, 2021. Conservatively assuming a one-year EPA approval process, the earliest that any determination would be approved is August 1, 2022. Adding the times necessary for implementation to this date results in an earliest possible implementation date of all controls of August 1, 2027.

2.5 Remaining Useful Life

Except for C-5, DCP has no plans to retire any of the affected units at Chitwood. The remaining useful life (RUL) value for SCR and CBT is assumed to be 30 years based on guidance in EPA's Control Cost Manual.[2]

2.6 Energy and Non-Air Quality Environmental Impacts

SCR systems create a demand for electricity that currently does not exist, creates a new solid waste stream (spent catalyst) that must be managed, and poses a threat for potentially significant non-air quality environmental impacts because it requires the storage of large amounts of ammonia or urea. The storage of aqueous ammonia in quantities greater than 10,000 pounds is regulated by EPA's risk management program (RMP) because the accidental release of ammonia has the potential to cause serious injury and death.

Additionally, SCR will result in emissions of unreacted ammonia to the atmosphere (i.e., ammonia slip) during any periods of time when temperatures are too low for effective operation or if too much ammonia is injected (possibly in an attempt to reduce NO_X further). Ammonia emissions will react to directly form ammonium sulfate and ammonium nitrate – the compounds most responsible for regional haze in the Wichita Mountains Wildlife Refuge Class I area – emissions of ammonium sulfate and ammonium nitrate would detract from any haze-reducing NO_X emissions reductions from application of SCR.

The installation of CBT will result in increased noise output, which could affect both employee safety and nearby residences.

2.7 Costs

The following tables summarize the estimated costs, including total and annualized capital costs, annual operations and maintenance (O&M) costs, and cost effectiveness based on vendor estimates and the emission reduction values from Table 2-2 for the NO_X reduction options. These cost estimates are calculated according to the methods and recommendations in the EPA Air Pollution Control Cost Manual using vendor quotes as well as default assumptions from the Control Cost Manual.[3] These cost estimates are subject to the qualifications, above, regarding detailed unit-specific engineering and vendor evaluations, if needed.

Table 2-3. Estimated Costs of NO_X Emissions Reduction Options

Unit	NO_X Reduction Option	Capital Costs ($)	Annualized Capital Costs ($/year)	Annual O&M Costs ($/year)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
C-1	CBT (6 g)	2,073,250	167,076	56,474	223,550	4,366
	CBT (1 g)	2,822,000	227,415	59,024	286,439	3,442
	CBT+SCR (1 g)	2,318,250	186,819	117,474	304,293	3,657
C-2	CBT (6 g)	2,073,250	167,076	56,474	223,550	4,366
	CBT (1 g)	2,822,000	227,415	59,024	286,439	3,442
	CBT+SCR (1 g)	2,318,250	186,819	117,474	304,293	3,657

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[2] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual
[3] U.S. EPA, "Air Pollution Control Cost Manual", available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

C-3	CBT (6 g)	2,073,250	167,076	56,474	223,550	20,186
	CBT (1 g)	2,822,000	227,415	59,024	286,439	15,917
	CBT+SCR (1 g)	2,318,250	186,819	117,474	304,293	16,909
C-4	CBT (6 g)	2,073,250	167,076	56,474	223,550	5,407
	CBT (1 g)	2,822,000	227,415	59,024	286,439	4,263
	CBT+SCR (1 g)	2,318,250	186,819	117,474	304,293	4,529
C-6	CBT (6 g)	1,573,250	126,783	56,474	183,257	4,823
	CBT (1 g)	2,332,000	187,927	59,024	246,951	3,250
	CBT+SCR (1 g)	1,823,250	146,929	103,334	250,263	3,293
C-7	CBT (6 g)	1,573,250	126,783	56,474	183,257	4,823
	CBT (1 g)	2,332,000	187,927	59,024	246,951	3,250
	CBT+SCR (1 g)	1,823,250	146,929	103,334	250,263	3,293
C-8	CBT (6 g)	2,135,250	172,072	56,474	228,546	7,306
	CBT (1 g)	2,934,000	236,441	59,024	295,465	5,813
	CBT+SCR (1 g)	2,405,250	193,830	128,389	322,219	6,339
C-9	CBT (6 g)	2,135,250	172,072	56,474	228,546	7,306
	CBT (1 g)	2,934,000	236,441	59,024	295,465	5,813
	CBT+SCR (1 g)	2,405,250	193,830	128,389	322,219	6,339

Current emissions estimates are based on AP-42 factors and based on previous stack testing on C-9, DCP expects that actual emissions may be less, resulting in higher cost effectiveness values. For example, if C-9 were to utilize the highest test result value for RY2019 (8.9 g/hp-hr), the cost effectiveness value for the CBT (1 g) option would increase from $5,813/ton to $9,565/ton.

2.8 Conclusions

Whenever assessing the economic feasibility for each of these options, the following factors must also be considered:

1. The capital costs for all the potential control options range from $1.6 MM to $2.9 MM. The approximate cost to replace each of these engines are estimated to range from $2.5 MM to $3.2 MM. It would be unreasonable to require the facility to install controls on units for which the cost for control nearly exceeds the cost for replacing the units. Further, ODEQ should not select control options that, in reality or in effect, re-define the presently authorized emission source. Requiring the acquisition and installation/operation of retrofit technologies that are approximately the cost of replacement of the source equipment would result in this scenario, and the Clean Air Act would preclude re-defining an emissions source from an agency regulation.
2. The estimated sale value for each of the existing engines is approximately $50,000. It would be unreasonable to require the facility to install controls on units for which the cost for control exceeds the value of the unit itself by at least an order of magnitude. Further, ODEQ should not select control options that, in reality or in effect, re-define the presently authorized emission source. Requiring the acquisition and installation/operation of retrofit technologies that are far beyond the present value of the source equipment would result in this scenario, and the Clean Air Act would preclude re-defining an emissions source from an agency regulation.
3. The overall capital cost for this project would be between $15 MM and $21 MM, which represents a significant financial burden for a facility of this size, and none of these costs would be recoverable,

which is not the case for some of the other units being evaluated by ODEQ (e.g., electric generating units).

4. Based on an initial evaluation, there may not be enough room at the facility to install the evaluated SCR systems.
5. DCP does not currently employ SCR at any of their facilities and will potentially need to hire additional staff with SCR-specific expertise if this control option is required.
6. Previous stack testing on C-9 suggests that actual emissions are significantly lower than the AP-42 factors used for historical emissions reporting (14 g/hp-hr for GMV and 11 g/hp-hr for KVS). Using the highest test result value for RY2019 (8.9 g/hp-hr) increases the cost effectiveness for the 1-gram options by more than 60% for the GMV units.
7. Current control costs and emissions reductions estimates were determined without first conducting a site assessment or detailed evaluation of the engines, and more refined estimates based on unit-specific engineering and vendor evaluations will likely result in higher cost effectiveness values.

Even if the additional factors listed above were not taken into consideration, DCP believes the control cost effectiveness by itself demonstrates the economic infeasibility based on previous determinations in the Regional Haze program. In 81 FR 296, EPA used a cost effectiveness threshold of $3,332/ton for the first planning period reasonable progress four-factor analyses in Texas. EPA's approval (83 FR 62230 and 84 FR 51033-40) of Arkansas' first planning period SIP revisions included a reasonable progress analysis cost effectiveness value of $2,742/ton for a control option that was not required.

Therefore, taking into consideration both the calculated $/ton effectiveness and the additional factors mentioned above, DCP has determined that the installation of any additional control is cost-ineffective and is economically unreasonable.

APPENDIX A. EMISSIONS AND COSTS CALCULATIONS DETAILS

Engine Emissions Summary

EU ID	Description	Service	Type	hp	Control	Fuel Usage (Btu/hp-hr)	Emissions Factor (g/hp-hr)	RY2019 Emissions (tpy)	Average Emissions (tpy)
C-1	Cooper-Bessemer GMV-8	Multiservice	2SLB	880	None	8300	14.0	109.57	89.61
C-2	Cooper-Bessemer GMV-8	Multiservice	2SLB	880	None	8300	14.0	69.65	89.61
C-3	Cooper-Bessemer GMV-8	Residue	2SLB	880	None	8300	14.0	19.38	19.38
C-4	Cooper-Bessemer GMV-8	Inlet	2SLB	880	None	8300	14.0	72.36	72.36
C-6	Ingersol-Rand KVS-8	Residue	4SLB	1320	None	7200	11.0	121.56	83.59
C-7	Ingersol-Rand KVS-8	Residue	4SLB	1320	None	7200	11.0	45.62	83.59
C-8	Cooper-Bessemer GMV-10	Residue	2SLB	1100	None	8270	14.0	86.75	54.74
C-9	Cooper-Bessemer GMV-10	Residue	2SLB	1100	None	8270	14.0	22.73	54.74

[1] RY2013 emissions were used to calculate the baseline for C-4 since this was the most recent year of operation

[2] Averaged emissions are based on engine type and service

Control Device Costs

Control Description	Cost Source	GMV-8 1 gram option ($)	KVS-8 1 gram option ($)	GMV-10 1 gram option ($)	GMV-8 6 gram option ($)	KVS-8 6 gram option ($)	GMV-10 6 gram option ($)
Clean burn conversion equipment and installation	Siemens	1,710,000	1,420,000	1,800,000	1,120,000	820,000	1,160,000
Intercooler bundles for turbocharger addition	Siemens	125,000	125,000	125,000	125,000	125,000	125,000
Replacement exhaust manifolds for GMV units	Siemens	220,000	--	242,000	220,000	--	242,000
Updated air intake filters and housing	Siemens	100,000	100,000	100,000	100,000	100,000	100,000
Replacement cylinder heads	Siemens	40,000	60,000	40,000	40,000	60,000	40,000
Control panel installation	Siemens	250,000	250,000	250,000	250,000	250,000	250,000
Turbocharger pad installation	DCP	50,000	50,000	50,000	50,000	50,000	50,000
Initial engine health analysis	DCP	12,000	12,000	12,000	12,000	12,000	12,000
Safety/inspector/fire watch for each engine build	DCP	100,000	100,000	100,000	100,000	100,000	100,000
Engineering costs for project/site managers and engineer	DCP	56,250	56,250	56,250	56,250	56,250	56,250
HP fuel installation to engine room for 1 gram option	DCP	43,750	43,750	43,750	--	--	--
Oxidation catalyst installation for 1 gram option	Miratech	115,000	115,000	115,000	--	--	--
Total Capital Cost for clean burn technology	**--**	**2,822,000**	**2,332,000**	**2,934,000**	**2,073,250**	**1,573,250**	**2,135,250**
SCR equipment and installation	AeriNOx	245,000	250,000	270,000	--	--	--
CBT annual maintenance costs	Siemens	59,024	59,024	59,024	56,474	56,474	56,474
SCR annual maintenance costs	AeriNOx	61,000	46,860	71,915	--	--	--

Cost Effectiveness Calculations

EU ID	Control Option	g/hp-hr	DRE %	Controlled Emissions (tpy)	Emissions Reduction (tpy)	CRF (7% AIR)	Total Capital Cost ($)	Annualized Capital Cost ($)	Annual O&M Cost ($)	Total Annual Cost ($)	$/ton
C-1	SCR (6 to 1 g)	1	83.3	6.4	32.0	0.0806	245,000	19,744	61,000	80,744	--
	CBT (6 g)	6	57.1	38.4	51.2	0.0806	2,073,250	167,076	56,474	223,550	4,366
	CBT (1 g)	1	92.9	6.4	83.2	0.0806	2,822,000	227,415	59,024	286,439	3,442
	CBT+SCR (1 g)	1	92.9	6.4	83.2	0.0806	2,318,250	186,819	117,474	304,293	3,657
C-2	SCR (6 to 1 g)	1	83.3	6.4	32.0	0.0806	245,000	19,744	61,000	80,744	--
	CBT (6 g)	6	57.1	38.4	51.2	0.0806	2,073,250	167,076	56,474	223,550	4,366
	CBT (1 g)	1	92.9	6.4	83.2	0.0806	2,822,000	227,415	59,024	286,439	3,442
	CBT+SCR (1 g)	1	92.9	6.4	83.2	0.0806	2,318,250	186,819	117,474	304,293	3,657
C-3	SCR (6 to 1 g)	1	83.3	1.4	6.9	0.0806	245,000	19,744	61,000	80,744	--
	CBT (6 g)	6	57.1	8.3	11.1	0.0806	2,073,250	167,076	56,474	223,550	20,186
	CBT (1 g)	1	92.9	1.4	18.0	0.0806	2,822,000	227,415	59,024	286,439	15,917
	CBT+SCR (1 g)	1	92.9	1.4	18.0	0.0806	2,318,250	186,819	117,474	304,293	16,909
C-4	SCR (6 to 1 g)	1	83.3	5.2	25.8	0.0806	245,000	19,744	61,000	80,744	--
	CBT (6 g)	6	57.1	31.0	41.3	0.0806	2,073,250	167,076	56,474	223,550	5,407
	CBT (1 g)	1	92.9	5.2	67.2	0.0806	2,822,000	227,415	59,024	286,439	4,263
	CBT+SCR (1 g)	1	92.9	5.2	67.2	0.0806	2,318,250	186,819	117,474	304,293	4,529
C-6	SCR (6 to 1 g)	1	83.3	7.6	38.0	0.0806	250,000	20,147	46,860	67,007	--
	CBT (6 g)	6	45.5	45.6	38.0	0.0806	1,573,250	126,783	56,474	183,257	4,823
	CBT (1 g)	1	90.9	7.6	76.0	0.0806	2,332,000	187,927	59,024	246,951	3,250
	CBT+SCR (1 g)	1	90.9	7.6	76.0	0.0806	1,823,250	146,929	103,334	250,263	3,293
C-7	SCR (6 to 1 g)	1	83.3	7.6	38.0	0.0806	250,000	20,147	46,860	67,007	--
	CBT (6 g)	6	45.5	45.6	38.0	0.0806	1,573,250	126,783	56,474	183,257	4,823
	CBT (1 g)	1	90.9	7.6	76.0	0.0806	2,332,000	187,927	59,024	246,951	3,250
	CBT+SCR (1 g)	1	90.9	7.6	76.0	0.0806	1,823,250	146,929	103,334	250,263	3,293
C-8	SCR (6 to 1 g)	1	83.3	3.9	19.6	0.0806	270,000	21,758	71,915	93,673	--
	CBT (6 g)	6	57.1	23.5	31.3	0.0806	2,135,250	172,072	56,474	228,546	7,306
	CBT (1 g)	1	92.9	3.9	50.8	0.0806	2,934,000	236,441	59,024	295,465	5,813
	CBT+SCR (1 g)	1	92.9	3.9	50.8	0.0806	2,405,250	193,830	128,389	322,219	6,339
C-9	SCR (6 to 1 g)	1	83.3	3.9	19.6	0.0806	270,000	21,758	71,915	93,673	--
	CBT (6 g)	6	57.1	23.5	31.3	0.0806	2,135,250	172,072	56,474	228,546	7,306
	CBT (1 g)	1	92.9	3.9	50.8	0.0806	2,934,000	236,441	59,024	295,465	5,813
	CBT+SCR (1 g)	1	92.9	3.9	50.8	0.0806	2,405,250	193,830	128,389	322,219	6,339

[1] Annualized costs based on methodologies in the EPA Air Pollution Control Cost Manual and a remaining useful life of 30 years

January 31, 2022

Steven Ondak
DCP Operating Co.
3201 Quail Springs Pkwy, Ste. 100
Oklahoma City, OK 73134

Subject: Additional clarifications on DCP's Chitwood Gas Plant 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Mr. Ondak:

In a letter dated July 1, 2020, the Oklahoma Department of Environmental Quality (DEQ) identified the Chitwood Gas Plant located in Grady County, Oklahoma, as subject to a four-factor reasonable progress analysis under the Regional Haze Rule as part of DEQ's development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

On October 1, 2020, DCP submitted its four-factor analysis to DEQ. DCP included in its response that there were no cost-effective nitrogen oxides (NO_x) control measures available for engines C-1 through C-9. DEQ included these conclusions in its draft Regional Haze SIP for Planning Period 2 that was shared with the Federal Land Managers (FLM) and the U.S. Environmental Protection Agency (EPA). DEQ requests that DCP review its four-factor analysis for potential NO_x control measures and respond to the following questions, which are based on EPA and FLM review of Oklahoma's draft SIP. We understand that some of the requested data/analysis may be gleaned or explained from DEQ's permitting and compliance files. However, your response will allow DCP to document the information that best explains and supports the conclusions of DCP's four-factor analysis. DEQ intends to continue its analysis in parallel.

1. 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.

2. Please explain why the anticipated control efficiency for Clean Burn Technology (CBT) is the same as the anticipated control efficiency for CBT plus selective catalytic reduction (SCR). Generally, additional NO_x reduction would be anticipated from adding SCR to CBT.

3. 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.

4. The federal reviewers stated that 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.

DEQ respectfully requests that DCP respond to these questions no later than February 28, 2022. Thank you for your assistance with this matter. Please contact Melanie Foster at 405-702-4218 for any questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

[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.

3201 Quail Springs Pkwy., Ste. 100
Oklahoma City, OK 73134
Direct: (405) 568-3775
Email: lcholt@dcpmidstream.com

VIA E-MAIL

February 25, 2022

Kendal Stegmann
Director, Air Quality Division
Oklahoma Department of Environmental Quality
707 N. Robinson
P.O. Box 1677
Oklahoma City, OK 73101-1677

RE: Reply to ODEQ's January 31, 2022 request for additional clarifications on DCP's October 1, 2020 regional haze 4-four analysis

Dear Ms. Stegmann:

DCP understands the DEQ's letter as requesting additional clarifications on four items: (1) DCP's timing for the planned removal of engine C-5, (2) why the anticipated control efficiency for CBT+SCR is not greater than the anticipated control efficiency for CBT alone, (3) a line-item breakdown of the capital costs for SCR, including any relevant vendor quotes, and a breakdown of the estimated operation and maintenance costs of CBT and SCR, and (4) documentation of the capital recovery interest rate used in the control cost calculations. Each of these items is addressed below.

1. Engine C-5 has not operated in several years, and DCP is amending its Title V permit renewal application that is currently under review by the DEQ to include the retirement of engine C-5. DCP has already confirmed this approach with the permit writer for the renewal permit.

2. The "CBT+SCR (1 g)" option represents the scenario where CBT reduces emissions to 6 g/hp-hr, and then SCR further reduces emissions to 1 g/hp-hr. Therefore, it has the same overall emissions reduction as the "CBT (1 g)" option. Theoretically, SCR could be installed in addition to the "CBT (1 g)" option, but this would exacerbate the already significant spacing concerns for the various control device installations, and neither DCP nor its vendors/contractors are aware of any technical documentation from which the potential incremental NO_X reduction could be estimated. The 1 g/hp-hr emissions guarantee is the lowest for which the SCR vendor, AeriNOx, provided a certification. Even this option was not recommended by the vendor though due to significant reliability concerns and increases in CO emissions.

3. The SCR quote provided by AeriNOX was a comprehensive cost estimate, and it included engineering, mixer, catalyst, silencer, control system, urea dosing panel, reagent pump station, reagent pump tank, and commissioning. The SCR operation and maintenance costs

are provided in this quote as well. If additional details are needed for DEQ's purposes, then DCP requests a list of specific items with which it can approach its vendor(s)/contractor(s).

The original cost estimate for CBT provided by Siemens via email is attached. The annual maintenance cost for CBT provided by Cooper via email is attached. The annual maintenance cost for the oxidation catalyst ($2,550 per unit) was provided by Miratech.

4. DEQ's letter states, "The federal reviewers stated that use of a 7% interest rate in the cost analysis is not appropriate." This appears to be a fundamental shift in policy. The standard, OMB-recommended 7% interest rate has been relied upon commonly for control technology analyses for a long time, including during the regional haze first planning period when the bank prime rate was exactly the same as it is now (3.25%), i.e., from December 2008 to December 2015.

   DEQ's letter also states, "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." EPA's Control Cost Manual does not present the bank prime rate as a default, absent a company-specific interest rate. It is mentioned as one of several indicators of the cost of borrowing. The purpose of the bank prime rate is also not related to the cost of capital for a private company and does not represent DCP's cost of borrowing. As of January 2022, DCP's cost of borrowing was being estimated as 5.54%. Recent inflationary economic conditions suggest that the cost of borrowing capital is increasing – likely to greater than 7%. As such, DCP's use of 7% should be considered conservatively low.

Thank you for the opportunity to provide this information. DCP looks forward to working with the DEQ in its revisions to the regional haze SIP. Please contact me at (405) 568-3775 or LCHolt@dcpmidstream.com if you have any questions or need any additional information.

Sincerely

DCP Operating Co.

Lynn Holt
Principal Environmental Specialist

cc: Steve Ondak, DCP Operating Co.
Jeremy Jewell and Kyle Dunn, Trinity Consultants

August 20, 2020

TO: Lynn Holt
DCP Operating Company, LP
Phone: 405-568-3775
Email: LCHolt@dcpmidstream.com

Reference: Chitwood, OK Compressor Station – SCR Budgetary Pricing

Dear Ms. Holt,

We are pleased to submit this budgetary proposal for an **AeriNOx™ Emissions Control System** designed to reduce exhaust emissions from multiple natural gas engines from a range of Base to 6gm and from 6gm to 1gm. Configured as noted below:

- ITEM A: BASE Emissions to 6gm NOx
- ITEM B: 6gm NOx to 1gm NOx

AeriNOx does not recommend applying SCR emissions to uncontrolled engines 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. We have included the major hardware for your evaluation. Visiting the sites and/or review of site photos and details will allow us to provide a more formal proposal. We have based the pricing on a per engine basis, however, for multiple engines at a facility we can use some common hardware (Pump station, tank, SCR controls) to help reduce overall price and space.

The **AeriNOx™ SCR Systems** offered for this project are based on engine and emissions data provided by DCP Operating Company. The enclosed proposal details the budgetary price, scope of supply, warranty, commissioning and terms and conditions necessary to achieve the required emissions limits. AeriNOx will work with DCP to review and negotiate terms and conditions.

a) EXHAUST GAS DATA & EMISSION REQUIREMENTS

Engine Data:

Parameter = 100% Load	Unit	Cooper-Bessemer GMV8-TF*	Cooper-Bessemer GMV10-TF*	Ingersoll-Rand KVS-8*
Fuel	-	CQNG	CQNG	CQNG
Engine Power	bhp	880	1000	1320
Exhaust Gas Flow Rate (wet)	lb/hr	12,625**	15,750**	11,310**
Exhaust Gas Moisture Content (actual, wet)	Vol. %	6**	6**	6**
Oxygen Content (actual, wet)	Vol. %	11**	11**	6**
Exhaust Temperature	°F	550**	550**	819**

*Per manufacturer data

**AeriNOx estimated, requires verification

Emission Control System Design Parameters:

Parameter	Unit	GMV8-TF	GMV10-TF	KVS-8
Reagent Solution	%	32.5 Urea	32.5 Urea	32.5 Urea
Aqueous Ammonia Solution Consumption Rate (at 100% engine load) approximately, per engine	gph	3.5 – A 3.1 – B	3.9 – A 3.6 – B	2.3 – A 1.9 – B
Total System Backpressure Contribution Mixer + SCR + Silencer	inH_2O	6.5	6.5	6.5
Air Consumption, per engine (Based on 87 psi nominal, max 160 psi)	scfm	8	8	8

Emissions Guarantee and Warranty:

Emission*	Current Engine Out	Required Stack Out*
NOx as NO_2 – ITEM A	11.0 g/bhp-hr	6.0 g/bhp-hr
NOx as NO_2 – ITEM B	6.0 g/bhp-hr	1.0 g/bhp-hr

** Based on 1 hour averaging with the engine operating at 100% load*

Provided the engine is operating under stable operating conditions, AeriNOx guarantees the stack emissions (In % reduction) for a period of 16,000 hours of operation or 12 months after the initial engine performance test date, or 18 months after delivery, whichever comes first. All values are per EPA-approved measurement methods, with one-hour averaging while the engine is operating at 100% load. The mechanical warranty is 12 months after commissioning or 18 months after delivery, whichever comes first.

This guarantee is subject certain maintenance practices and engine operating conditions, as defined in the Terms & Conditions. The guarantee is also based on the emissions data provided to AeriNOx at the time of this quotation and defined in Section 1 of the Technical Description. AeriNOx reserves the right to modify Items 001 in the Scope of Supply and associated price once more accurate and complete emissions data are obtained in order to ensure the emission limits can be maintained as required.

Estimated Maintenance (Estimated)

Parameter	GMV8-TF	GMV10-TF	KVS-8
Reagent Cost Per Year (Based on $1.3/gal urea, 8760 hrs/yr)	~$39,410 – A ~$35,500 – B	$44,825 – A $40,915 – B	$25,900 – A $21,360 – B
SCR Maintenance (Less SCR Catalyst, hardware only)	$3,000	$3,000	$3,000
SCR Catalyst Replacement (Complete, hardware only)	$33,600 – A $22,500 – B	$42,000 – A $28,000 – B	$33,600 – A $22,500 – B

2. SCOPE OF SUPPLY

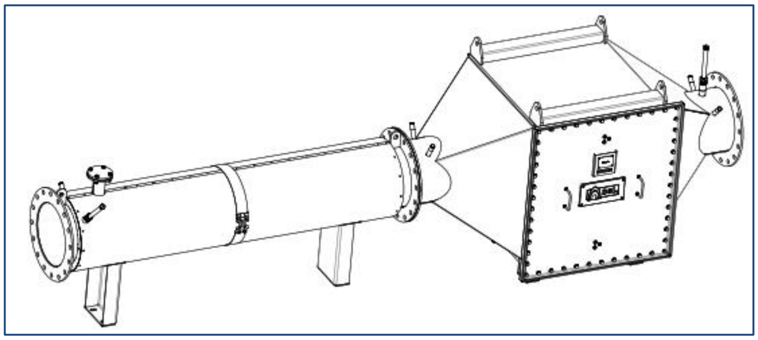
Engineering (Per Unit)

- Process & Instrumentation Diagram
- Cable Block Diagram
- Wiring Diagram
- Mechanical:
    - Mixing Duct and Injector Drawing
    - SCR Housing and Catalyst Element
- Silencer with 5ft stack
- O&M Documentation
- Commissioning Report (Post-Commissioning)

Mixer + SCR Catalyst + Silencer (Per Unit)

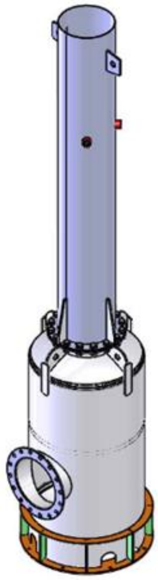
Aqueous urea solution is injected into the exhaust gas with a two-phase nozzle (air and urea solution). An air atomization nozzle is integrated into the mixer to create small droplets such that complete evaporation of the water occurs without contacting the walls of the ductwork. The mixing section with integrated injection nozzle to ensure complete conversion of aqueous urea to ammonia gas. Material: SS304

The catalyst is loaded via service panels located on the side of the housing. Housing Material: SS304. Includes (1) expansion joint.



Typical arrangement of mixing duct with SCR housing.

Note the catalyst impurity tolerance specification in Section IV.



Silencer will be a residential grade (15-20 dBA), base mounted, carbon steel with 5ft tailpipe. Painted manufacturer black paint. Includes inlet expansion joint.

SCR Control With Integrated Dosing (Per Unit)

The SCR unit is controlled by a single control system with dosing housed in a single control cabinet. Includes a Siemens Programmable Logic Controller (Simatic 1200): touch screen control with menu-guided parameter inputs (without any program change); password protection; error message and clear display.

- Siemens 1200 PLC with touch screen user interface (KTP 400)
- Power Supply: 200-230 VAC, 60Hz, ~3kW (CL 1, D2 Suitable)
- Reactor temperature (pre/post) measurement with thermocouples
- Pressure measurement (delta P over the SCR catalyst)
- eWON switch for network connection
- NOx sensor for closed-loop control
- Flow measurement for reducing agent with limit value switch
- Approximate Dimensions: 30 in L x 30 in W x 18 in D

Urea Dosing Panel (Per Unit)

All components for 32.5% urea dosing are mounted on a steel back panel in a NEMA 4X enclosure; includes steel dosing valve, magnetic valves and shut-off valves. UL Listed electrical components. All reagent fittings/devices/tubing are stainless steel. Suitable for Class 1, Div 2 indoor locations.

Reagent Pump Station (Typical Per Unit or SIte)

Eccentric screw pump station (duplex) complete with auxiliary valves, filters; ships fully assembled and pretested from our factory. The pump station has been designed for consumption levels assuming 32.5% urea. NEMA standard protection. Pump designed for indoor installation. Suitable for non-Class 1, D2 locations. Pump will support multiple engines at a common site for units that are <300ft between pump station and injection lance.

Reagent Tank (Typical Per Unit or Site)

Includes a poly-tank, vertical with insulation and heat tracing. Includes level transmitter and vent. Suitable for non-C1 D2 locations. Tank sized for minimum 30 days operation with unit at 100% load.

Commissioning (Per Unit)

Estimated at 4 man-days for the commissioning of the emission control system (Per unit) to meet the required emissions levels; includes estimated costs of travel and accommodations. We can provide qualified personnel to supervise installation at the rate of $1,350 per man-day, plus travel expenses. Additional time will be billed per the time and material rates.

3. PRICE

The given prices (shown below) for the hardware are net prices, DDP to customer location, per Incoterms 2010. All prices are in US dollars. Not included are taxes. Payment terms are net 30.

ITEM	DESCRIPTION	PRICE ($)
A	**SCR SYSTEM (PER UNIT) **BASE TO 6gm NOx**	
	GMV8-TF	**$255,000**
	GMV10-TF	**$285,000**
	KVS-8	**$260,000**
B	**SCR SYSTEM (PER UNIT) **6gm TO 1gm NOx**	
	GMV8-TF	**$245,000**
	GMV10-TF	**$270,000**
	KVS-8	**$250,000**

Based on the following payment milestone schedule:

- 30% upon award of PO/Contract
- 15% upon issue of engineering drawings
- 50% upon Ready to Ship
- 5% upon completion of AeriNOx commissioning

4. SCHEDULING & DELIVERY

Delivery of the drawings and technical documents is approximately 8 weeks after receipt of a purchase order. Ready for shipment of the hardware is approximately 20 weeks after approval of all technical details, per engine. For multiple engines and multiple sites schedule will need to be modified based on total number of engines and sites.

5. QUALITY STANDARD

The electrical components are UL listed components, where feasible. All drawings will be in both metric and English units. We reserve the right to adapt the technical design of the emission control system based on the results of the final engineering work, provided this does not impact the affect the guaranteed performance characteristics and is approved by the customer before production begins.

6. ASSUMPTIONS AND EXCEPTIONS:

Not included in the scope of supply:

- Load signal from the engine (4-20 mA)
- Structural and civil work necessary to complete the installation
- Oxidation catalyst (available as an option), requires additional site information to quote
- Urea solution (available as an option)
- Thermal insulation for the catalyst housing (available as an option)
- Expansion joints and piping not listed herein (available as an option)
- Installation of all hardware listed herein
- Compressed air, per ISO 1.3.4 requirements
- Provision for electricity and connection of the power supply to the enclosure
- System integration (design and engineering) with the building structure
- Connection to the local supply and disposal network
- Platforms and other support structures
- Any 3rd party emission certification of stack test

Should you have any questions or comments, please do not hesitate to contact me.

Sincerely,

Loran Novacek
Chief Executive Officer

AeriNOx Inc.
PO Box 490
100 S. Cherry Avenue, Suite 68
Eaton, CO 80615
Office: 970-454-5639
Cell: 970-443-3868
Email: lnovacek@aerinox-inc.com
Web: www.aerinox-inc.com

STANDARD TERMS AND CONDITIONS OF SALE
(Effective November 2017)

1. **Application.** These Standard Terms and Conditions apply to any sale of equipment, parts, materials and related services (the "Products") by AeriNOx Inc. ("AeriNOx") to any AeriNOx Customer (the "Customer"). Acceptance of these Standard Terms and Conditions by an AeriNOx Customer is an express condition of any such sale.

2. **Entire Agreement**. These Standard Terms and Conditions, the Order Confirmation (the "AeriNOx Order Confirmation") issued by AeriNOx in respect of each sale and supply of Products and any other document expressly incorporated by reference in a AeriNOx Order Confirmation (collectively, the "Agreement") constitute the entire agreement between AeriNOx and the Customer regarding a sale of Products or related services by AeriNOx to the Customer. These Standard Terms and Conditions supersede all other discussions, proposals, quotes, negotiations, statements, representations, understandings and the like, whether written or oral. AeriNOx rejects any differing or supplemental terms that may be printed or otherwise found in any purchase order or other document sent by the Customer prior to the acceptance of Agreement, except as expressly accepted by AeriNOx in writing with the signature of an authorized representative. If there are inconsistencies in the documents constituting the Agreement, such documents shall take precedence in the following order:
   i. the AeriNOx Order Confirmation;
   ii. a contract document or addendum incorporated by reference into the AeriNOx Order Confirmation; and
   iii. these Standard Terms and Conditions.

3. **Terms of Payment.** Unless otherwise agreed by AeriNOx in writing, signed by an agent of AeriNOx, AeriNOx invoices for the Customer's purchase of Products are payable within thirty (30) days of the date of the invoice with place of payment to be PO Box 490, Eaton, Colorado 80308 or as designated in the AeriNOx Agreement. Should payment not be made to AeriNOx when due, such payment shall bear an interest at the rate of one and one-half percent (1½%) per month (18% per annum). The charging of such interest shall not be construed as obligating AeriNOx to grant any extension of time in the terms of payment. No cash discount shall be available to the Customer. If prior to any delivery of Products, AeriNOx has concern regarding timely payment of the purchase price because of a material adverse change in Customer's circumstances or otherwise, AeriNOx may require payment of all or additional parts of the purchase price before shipment or delivery and/or AeriNOx may require satisfactory security for the payment of the purchase price.

4. **Cancellation of Contract before Delivery.** In the event the Customer cancels the Agreement after the date such Agreement is accepted, Customer agrees to pay the following charge as liquidated damages in lieu of actual damages, it being understood and agreed between the parties that actual damages to AeriNOx would be impractical or extremely difficult, time consuming and expensive to ascertain. It is as follows:

% of Time Elapsed From Date of Agreement to Time of Cancellation (calendar days)	% of Sales Price Due (Not including Shipping Costs)
0 ≤ % Time Elapsed < 33 1/3%	50%
33 1/3 ≤ % Time Elapsed < 50%	75%
50 ≤ % Time Elapsed < 66 2/3%	85%
66 2/3 ≤ % Time Elapsed < 80%	95%
80% ≤ % Time Elapsed ≤ 100%	100%

5. **Delivery Terms.** Each Product subject to sale shall be shipped in accordance with the International Commercial Trade Terms known as IncoTerms 2010 specified in the AeriNOx Agreement. If shipping instructions are not so specified for any supply of Products, such supply shall be shipped ex works (IncoTerms 2010). Ex works deliveries of the shipped Products are deemed complete upon release of the Products to the Customer's carrier at AeriNOx' facilities (the "AeriNOx Plant") located in Eaton, Colorado, United States of America; or one of AeriNOx's partner facilities located in Canada, Germany or elsewhere. If the Customer is unable or unwilling to accept physical delivery at the time specified for delivery, AeriNOx may store Customer's Products at Customer's cost and the delivery of such Products shall be deemed complete as of the date of storage.

6. **Taxes.** Unless otherwise expressly provided for in an AeriNOx Agreement, or otherwise implicit in the IncoTerms 2010 specified for a particular supply, the price of the Products shall not include sales, use, excise, value added or any similar taxes, duties or other export/import charges.

7. **Delivery Schedule.** Time for delivery is approximate and starts on the later of the date specified in the AeriNOx Agreement or the receipt by AeriNOx of any advance payment or first payment as set forth in the AeriNOx Agreement. Should Customer not make an advance payment or first payment as set forth in the AeriNOx Agreement, AeriNOx may request from the Customer credit approval or placement of security for the balance of the purchase price. Unless otherwise specified in an AeriNOx Agreement, AeriNOx shall not be liable for losses of any kind incurred by the Customer for delays in or failure to deliver all or any part of the Products. Changes in the delivery schedules requested by the Customer must be in writing and received by AeriNOx at least two (2) business days prior to the previously scheduled delivery date. AeriNOx is under no obligation to accept any changes in delivery dates requested by the Customer.

8. **Title Retention.** Title or ownership of the Products shall not pass to the Customer, notwithstanding delivery thereof, but shall remain vested in AeriNOx until the purchase price of the Products is paid in full. As security for the full payment of the purchase price of the Products, the Customer hereby grants to AeriNOx, and AeriNOx hereby reserves, a purchase money security interest and charge in the Products and in all substitutions, replacements and additions thereto and the proceeds thereof. Until such time of full payment, the Customer shall: (a) insure the

Products against loss, damage or destruction for full replacement value; and (b) execute such additional documents as AeriNOx shall request for the confirmation or perfection of such security interest and charge. Upon any default by the Customer, and subject to applicable law, AeriNOx may repossess and deal with the Products as it shall see fit and retain all payments which have been made by the Customer for the account of the purchase price as liquidated damages. Upon any such realization of security, the Customer shall remain liable for any deficiency in the purchase price and shall reimburse AeriNOx for all costs and expenses, including reasonable legal fees, incurred in enforcing its rights. All rights and remedies of AeriNOx are cumulative and in addition to those available at law or in equity.

9. **AeriNOx Property.** All supplies, materials, tools, jigs, dies, gauges, fixtures, molds, patterns, equipment and other items procured by AeriNOx to perform the supply of Products under its Agreement with Customer shall be and shall remain the property of AeriNOx under all circumstances, including, without limitation, reimbursement of AeriNOx by the Customer for all or any portion of the cost of such items.

10. **Risk of Loss.** Unless otherwise specified or confirmed in the AeriNOx Agreement, the risk of loss or damage to the Products, including any repaired or replaced items, and the responsibility for the payment of insurance premiums and freight passes to the Customer upon AeriNOx's delivery as provided in Sections 5 and 7 above. No loss of or damage to the Products or any part or portion thereof shall relieve the Customer from its obligations for payment hereunder.

11. **Inspection, Rejection, Remedy.** Customer shall have the right to reasonable inspection of the Product after delivery to destination, which inspection shall be completed within ten (10) days of the date of delivery to destination. Any rejection by Customer as to part or all of the Product shall be in writing, specifically stating the damage or design non-conformance. In such event, AeriNOx shall have a reasonable period of time to determine the validity of and, if necessary, to repair any damage to a Product or correct a design non-conformance of a Product. Should a design non-conformance form the basis of the Customer's rejection, at AeriNOx's option and if appropriate, it may replace part or all of the Product. Upon validating damage to a Product or a design non-conformance, AeriNOx shall provide Customer with a date certain for completion of repair or replacement or provision of a design conforming item.

Subsequent to installation and commissioning and within the Product warranty period, should the Product delivered be found not to meet functional specifications set forth in the AeriNOx Agreement for measured emissions, AeriNOx shall provide a date certain for bringing the Product into functional conformance per the AeriNOx Agreement. The time period to do so shall not exceed sixteen (16) weeks from the date of discovery of failure to meet functional specifications. The time period within which to correct such a functional non-conformance shall commence at the later of the commissioning date or the date that the emissions non-conformance was discovered.

Customer's failure to make rejection as herein stated, or to allow AeriNOx to cure Customer's objections, shall be deemed to conclusively establish acceptance by Customer of the Product.

12. **Limited Warranties.** AeriNOx warrants that each Product is free of defects in material and workmanship strictly in accordance with the terms and conditions of the limited warranty statement specified or confirmed in the AeriNOx Agreement. Copies of Product Warranties are available from AeriNOx upon request. Throughout the Warranty Period, AeriNOx warrants that the Product will achieve the emissions levels set forth in the accepted AeriNOx Agreement, subject to the following conditions:

a) the Product is operated and maintained at all times in accordance with AeriNOx's written instructions;
b) the Customer's equipment is operated and maintained at all times in accordance with all manufacturer's instructions and guidelines;
c) the Customer's equipment, during operation, never exceeds the engine-out emissions rate, the flow rate or temperature levels set forth in the AeriNOx Agreement;
d) the Customer's equipment never falls below the lower temperature limits stated in the AeriNOx Agreement;
e) the Customer operates the equipment so as to eliminate any Oxides of Nitrogen (NOx), Carbon Monoxide (CO) and Total Hydrocarbons (THC) fluctuations greater than one (1%) respectively of the engine-out emissions stated in the engine performance data; and
f) all operating parameters including engine load, fuel consumption, and hours of operation are recorded and/or logged hourly (excluding exhaust gas flow rates, engine-out emissions data and post-after treatment emissions data).

Emissions levels, temperature and flow rates from Customer's equipment and the Product discharge point shall be tested at the Customer's expense, in accordance with a mutually agreed upon test procedures and protocol consistent with customary and accepted industry practices. AeriNOx's limited warranty shall expire in the event the Product is misused, neglected, not properly maintained or operated other than for its intended use or purpose by the Customer.

If the above conditions are met and the Product fails to achieve the output performance stated in the AeriNOx Agreement within the Warranty Period, AeriNOx shall replace or modify and adjust its Product as needed to meet such output performance standards. Consistent with Section 11 above, Customer is required to notify AeriNOx, in writing, of any specific defect(s) and provide AeriNOx with complete documentation of the defect(s) and proof of satisfaction of all conditions, a) through f), of this Section 12. If AeriNOx is unable to achieve the output performance standards under the AeriNOx Agreement conditions, Customer may rescind the sale, and AeriNOx shall return the purchase price that shall be Customer's sole remedy for breach of the warranty made in this paragraph. In no event shall AeriNOx be responsible for consequential or punitive damages or otherwise.

13. **NO OTHER WARRANTIES EXPRESS OR IMPLIED.** THE LIMITED PRODUCT WARRANTIES REFERRED TO IN SECTION 12 ABOVE ARE EXCLUSIVE AND IN LIEU OF ALL OTHER EXPRESS OR IMPLIED WARRANTIES OR CONDITIONS IN RESPECT OF THE PRODUCTS, INCLUDING, WITHOUT LIMITATION, ALL IMPLIED WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE. THE REMEDIES PROVIDED IN THE APPLICABLE PRODUCT WARRANTY ARE THE CUSTOMER'S SOLE REMEDIES FOR ANY FAILURE OF AERINOX TO COMPLY WITH ITS WARRANTY OBLIGATIONS.

14. **LIMITATION OF LIABILITY.** THE TOTAL CUMULATIVE LIABILITY OF AERINOX TO THE CUSTOMER FOR ALL LIABILITIES OF ANY KIND, WHETHER BASED ON TORT, NEGLIGENCE, CONTRACT, WARRANTY, STRICT LIABILITY OR OTHERWISE, ARISING FROM OR RELATING TO THE AERINOX AGREEMENT SHALL NOT BE GREATER THAN THE AGGREGATE PURCHASE PRICE OF THE PRODUCTS SUPPLIED BY AERINOX UNDER SUCH AGREEMENT.

15. **Consequential Damages.** AeriNOx shall not be liable for and shall be held harmless by the Customer from any damage, loss, claim or expense, including without limitation indirect, special, consequential, incidental or punitive damages in relation to loss of use of facilities or equipment, loss of production, revenue or profits, downtime costs, or costs of capital or of substitute equipment or services arising directly or indirectly from the Products or the sale thereof, including without limitation the manufacture, handling, use, installation, operation or dismantling of the Products, whether alleged in contract, negligence or otherwise.

16. **Re-sale of Products.** In respect of any re-sale of the Products or sale of any Customer product which incorporates a Product as a component, the Customer shall indemnify, defend and hold AeriNOx harmless against any and all claims, actions, liabilities and expenses (including all legal fees, on a substantial indemnity basis) arising from a representation or warranty to a third party for the Products made by the Customer other than, as limited by the Product Warranties, or arising from an allegation of process patent infringement relating to a Customer process in which the Products are used as a component part.

17. **Survival.** All payment obligations, provisions for the limitation of or protection against liability of AeriNOx and any other provision of an Agreement which by its nature is continuing, shall survive the termination, cancellation or expiration of such Agreement.

18. **Permits.** The Customer shall obtain, at its expense, all licenses, permits and approvals for the purchase, delivery, shipment, installation and use of any Products.

19. **Force Majeure.** AeriNOx shall be excused from the timely performance of its obligations in the sale or other supply of Products and/or services if its performance is impeded or prevented by circumstances beyond its control (other than its own financial difficulties) (a "Force Majeure Event") and AeriNOx shall take all reasonable steps or actions to mitigate the effect of the delay. This provision shall specifically apply to Section 7 above. Upon the occurrence and the termination of a Force Majeure Event, AeriNOx shall promptly provide the Customer with written notice and reasonable particulars of the Force Majeure Event. Either party may terminate any Agreement affected by a Force Majeure Event if such circumstances continue for more than six (6) months and written notice of termination is delivered to the non-terminating party. Upon and notwithstanding any such termination, the Customer shall pay AeriNOx for that portion of the Products manufactured or delivered prior to the date of the above mentioned initial notice of the Force Majeure Event. Notwithstanding anything in this Section 19, the Customer shall extend any security granted for the payment of the purchase price of Products for a period equal to the delay caused by the Force Majeure Event.

20. **Governing Law.** The sale of the Products and this Agreement are and shall be governed by the laws of the State of Colorado and the laws of the United States of America as applicable therein. Each of the parties irrevocably attorns and agrees to the exclusive jurisdiction of the Courts of the State of Colorado, provided that the parties shall not be prevented from seeking injunctions or other temporary relief or enforcing judgments of the Courts of Colorado in another jurisdiction.

21. **Confidential Information.** Proprietary or confidential information disclosed for supply of any Products may not be used or disclosed by the recipient, Customer or AeriNOx other than for the express purpose for which it was disclosed. The owner of such proprietary or confidential information shall be responsible for designating it as such by clear and timely notice thereof to the recipient at the time of or before its conveyance to the recipient.

22. **Assignment.** Neither party may assign all or any part of the AeriNOx Agreement without the prior written consent of the other party.

23. **Waiver, Amendment.** Any waiver, modification or amendment of an Agreement shall only be effective if such waiver, modification or amendment is contained in a written instrument prepared or otherwise accepted in writing by AeriNOx and Customer and signed by their respective authorized agents.

24. **Suspension, Cancellation or Termination.** Subject to Sections 4, 11 and 19 hereof, no AeriNOx Agreement may be cancelled or suspended by the Customer without the express written consent of AeriNOx, such consent to be granted in AeriNOx's sole and unrestricted discretion and upon such terms, including the payment of all costs incurred and profits foregone, as AeriNOx may require. Termination may be effected as set forth in Section 19 by either party.

25. **Severability and Reconstruction or Termination.** If a binding court determination, ruling or judgment is made that a provision of these Standard Terms and Conditions or any other document which forms the AeriNOx Agreement is unenforceable (in whole or in part), then such provision shall be void only to the extent that such determination, ruling or judgment requires, and the parties shall replace such void provision with one that is enforceable and valid and, to the greatest extent permitted by law, serves the intent and purpose of the void provision. No other provision shall be affected as a result thereof, and, accordingly, the remaining provisions shall remain in full force and effect as though such void, voidable or inoperative provision had not been contained herein.

REFERENCES

Fairbanks Morse Engine
Abbvie North / Abbvie South – Puerto Rico
Project Contact: Jonathan Hoke
Engines: 2 x MAN 9L-50/60DF Engines

Equipment: SCR Controls, Exhaust Silencer and 48in insulated exhaust piping

Peterson Power
Taylor Farms and True Leaf Farms - California
Project Contact: Mike Short
Units: 2 x Caterpillar G3516H NG Engines

Equipment: SCR Controls, 100% NH3 dosing, housing, elements, EGHX, Silencer

Martin Energy
Multiple N.E. and California Based Projects
Project Contact: Derek Loganbill
Units: Multiple Siemens NG Engines

Equipment: SCR Controls, Dosing, Pump Station, Housing/Elements

Enbridge Energy
Danville, KY
Project Contact: Bob Amsberry
Units: 2 x GE Frame 3 Turbines

Equipment: SCR Controls, Enclosure, NH3 Tank, Unloading Station, Support Structure, Ducting, Silencer, Tailpipe

Kyle Dunn

Subject: FW: DCP Midstream // GMV modifications for haze - Indicative Pricing for Turnkey Solution

Thank you for taking some time to speak with Steve and me earlier – it was a pleasure to speak with you.

As promised, we committed to provide some indicative pricing that includes the required hardware, engineering and project management labor, and field service supervision, commissioning, and required subcontractor labor to deliver a complete turnkey package. Moving towards a proposal stage, we would need to confirm unit serial numbers, HP ratings, equipment on the engines and any known modifications made to the units over the years.

The table below shows the basic engine details we were provided with:

Emission Unit ID No.	Emission Unit Description	NOx g/bhp-hr	NOx lb/hr	NOx t/yr
Compressor Engines				
C-1	Cooper-Bessemer GMV-8	14.0	27.16	118.96
C-2	Cooper-Bessemer GMV-8	14.0	27.16	118.96
C-3	Cooper-Bessemer GMV-8	14.0	27.16	118.96
C-4	Cooper-Bessemer GMV-8	14.0	27.16	118.96
C-5	Clark HRA-8	14.0	27.16	118.96
C-6	Ingersol-Rand KVS-8	11.0	32.01	140.21
C-7	Ingersol-Rand KVS-8	11.0	32.01	140.21
C-8	Cooper-Bessemer GMV-10	14.0	33.92	148.71
C-9	Cooper-Bessemer GMV-10	14.0	33.92	148.71

The following pricing as mentioned above is for a full turnkey solution and is budgetary only - non-binding for informational purposes only. Under no circumstances shall it establish any obligation or liability on Siemens Energy's behalf nor shall it be considered to be a firm or binding offer by Siemens Energy. We also need to state that the worldwide outbreak of the coronavirus disease ("COVID-19"), affects or is likely to affect usual business activities and/or the execution of work describe here.

Since we currently don't have the specific HP ratings – DCP will need to convert the gms/bhp-hr to lbs/hr and tons/yr.

2- Stroke

Item	Unit	Pricing	Scope of Work	Lead Time	Emissions
1	GMV-8	**$1,710,000**	HPFi, iBALANCE, ePCi, Turbocharger	Hardware – 24 weeks	1g/hp NOx
2	HRA-8	**$1,710,000**			
3	GMV-10	**$1,800,000**			
4	GMV-8	**$1,120,000**	Modified Heads for PCC, ePCi, Turbocharger	Hardware – 24 weeks	6g/hp NOx
5	HRA-8	**$1,120,000**			
6	GMV-10	**$1,160,000**			

4- Stroke

Item	Unit	Pricing	Scope of Work	Lead Time	Emissions
1	KVS-8	**$1,420,000**	HPFi, iBalance, ePCi, Turbocharger	Hardware – 24 weeks	1g/hp NOx
2		**$1,300,000**	Port4, iBalance, ePCi, Turbocharger		2g/hp NOx
3		**$820,000**	Modified Heads for PCC, ePCi, Turbocharger		6g/hp NOx

The solution for the maximum reduction in emissions (1g) is intended to include the following items:

- Installation of HPFi™
  - HPFi – Direct into Cylinder High Pressure Fuel Injection system
  - An electronically controlled fueling system
- Installation iBALANCE™ g2
  - Direct power cylinder peak firing pressure measurement
  - Enables auto-balancing of engine in combination with electronically controlled fuel injection
- Modify Heads to receive PCC
  - PCC – pre-combustion chambers
- Installation of ePCi ™
  - Electronic pre-combustion chamber fueling injectors
  - Use instead of mechanical fuel check valves for PCCs
- Upgraded Turbocharger
  - Necessary to meet necessary air specification for lean operation to reduce NOx

The solution for a medium reduction in emissions (6g) (traditional "lean burn conversion") is intended to include the following items:

- Modify Heads to receive PCC
- Installation of ePCi ™
- Upgraded Turbocharger

The KVS engines, as 4-stroke design, have a second fuel injection modification option for a 2 gm-NOx emissions levels: Port4™ – Mid-Pressure Injection into air intake port system.

Assumptions

We have made the following assumptions for the price & scope indication outlined above:

- Power cylinder heads do not have PCCs; but they can be machined to accept PCCs.
- Engines do not have turbochargers, or require replacement turbochargers to meet necessary air spec for NOx reduction
- Existing turbo pads are adequate for supporting the new turbocharger, its mounting structure and modification to piping.
- Assume engines have PLC based Unit Control Panels
- Our controls will be placed in their own subpanel with HMI and set adjacent to existing unit control panels.
- Altitude of all engines is ~ 1170 feet ASL
- The major components have been designed based on standard pipeline quality gas. Should gas quality change significantly, there may be additional costs associated with modifications to components to accommodate that change.
- CO-carbon monoxide – is not under regulatory permit restricted level and may increase to drive NOx down
- Modified cylinder heads for pre-chambers and the turbo charger will be the long lead items
- Estimated total project duration is 42 weeks ARO.

- 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.
- No underground piping, civil, or excavation work will be required for the project.
- Safety, inspectors, and fire watch personnel have not been included in this estimate.
- No pricing escalation is factored in at this time

DCP also asked via email for some typical maintenance costs.

  - Only increase will be more frequent replacement of spark plugs ~ every 90 days.
  - Engine and turbocharger LO and coolant service, inspection and overhaul schedules remain standard.
  - HPFi hydraulic system will need to be bled for air as needed. Estimated 6,000 hours of operation.

With best regards,

Mario Polselli
Project Development Manager, Modernizations & Upgrades
SE O SV NA S M&U PAC
Mobile: (360) 961-5968
mail: mario.polselli@siemens.com

Customer: DCP
Date: 8/18/2020

Ref. Item	Description	Unit Qty	Recmn'd Svc. Interval	Svc. Freq, P/Yr	Price,	Ext'd Price P/Yr
1	Pilot fuel check valve	10	2K	4	$ 880.16	$ 35,206.40
2	Gasket	10	2K	4	$ 2.01	$ 80.40
3	Element, filter	1	4K	2	$ 307.78	$ 615.56
4	Pre-chamber assy	10	8K	1	$ 1,250.00	$ 12,500.00
5	Gasket	10	8K	1	$ 46.65	$ 466.50
6	Seal, O-ring	10	8K	1	$ 1.49	$ 14.90
7	Turbocharger	1	24K	0.33	$ 20,000.00	$ 6,600.00
8	Wastegate assy	1	24K	0.33	$ 3,000.00	$ 990.00
9	Aux. water TCV assy	0	8K	1	$ -	$ -
10	Motor-driven L/O pump	0	24K	0.33	$ -	$ -
11	Induction air I/C	0	24K	0.33	$ -	$ -
12	Aux. water heat exchanger	0	24K	0.33	$ -	$ -
						$ 56,473.76

Kyle Dunn

Subject: FW: DCP Chitwood Plant - Oxy Cat Costs

Lynn,

For budgetary purposes, $40,000 a unit is a conservative estimate.

The annual price for washes / gasket would be $800.

Replacements would be needed between 3 – 5 years at a cost of $7,000.

Please give me a call at your convenience.

Thanks,

Mike

MIRATECH

Meet with me virtually! – *Book now*

MIKE WIELAND *Regional Account Manager, Gas Compression*

M: +1.918.527.1533 **O**: +1.918.442.2402 **F**: +1.918.933.6266

SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

KEVIN STITT
Governor

Mike Bednar
Grand River Dam Authority
8142 Hwy 412B
PO Box 609
Chouteau, OK 74337-0609

July 1, 2020

Subject: Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Mr. Bednar:

This letter is to inform you that the Oklahoma Department of Environmental Quality (DEQ) has identified the Grand River Energy Center located in Mayes County, Oklahoma, as subject to a four-factor reasonable progress analysis under the Regional Haze Rule. DEQ is in the development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

The states in the Central States Air Resources Agencies (CenSARA) organization, which include Oklahoma, contracted with Ramboll US Corporation (Ramboll) to produce a study examining the impact of stationary sources of NOx and SO_2 on each Class 1 area in the central region of the United States. DEQ used a method based on this study to determine which sources may have the greatest potential for contributing to visibility impairment at Oklahoma's Class 1 area: the Wichita Mountains Wilderness Area.

DEQ must develop a long-term strategy to address visibility impairment and make "reasonable" progress toward a goal of no anthropogenic visibility impairment by 2064. The Regional Haze Rule provides four factors (40 CFR §51.308(f)(2)(i)) by which a state must consider potential control measures for the long-term strategy: 1) the cost of compliance; 2) the time necessary for compliance; 3) the energy and non-air quality environmental impacts of compliance; and 4) the remaining useful life of existing sources subject to this requirement.

DEQ requests that GRDA perform a four-factor analysis of all potential control measures for SO_2 on the following emission units at the Grand River Energy Center:

1. Electric Power Generation Unit 2

For any technically feasible control measure, the following information should be provided in detail:

I. Emission reductions achievable by implementation of the measure
   a. Baseline emission rate (lb/hr, lb/MMBTU, etc)
   b. Controlled emission rate (same form as baseline rate)
   c. Control effectiveness (percent reduction expected)

d. Annual emission reductions expected (ton/year)

II. Time necessary to implement the measure

III. Remaining useful life

a. Remaining useful life of the control measure, or

b. The corresponding life of the unit may be used if an enforceable shutdown date of the emission unit is no later than 2028.

IV. Energy and non-air quality environmental impacts of the measure.

a. Detail any cost of energy, waste disposal, regulatory requirement, etc. incurred with implementation of the control measure.

V. Cost of implementing the measure

a. Capital costs

b. Annual operating and maintenance costs

c. Annualized costs

DEQ respectfully requests that your company submit a report containing the complete 4-factor analysis no later than September 1, 2020. This will allow DEQ to review and identify any cost-effective control measure to be incorporated into the Regional Haze state implementation plan prior to the submission deadline of July 31, 2021.

Please contact DEQ if you have any questions about the method for conducting a 4-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical review required under the Rule.

Thank you for your assistance with this matter. Please contact Cooper Garbe at 405-702-4169 or Melanie Foster at 405-702-4218 for your questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

TRAINING, SAFETY &
ENVIRONMENTAL
8142 Hwy 412B, PO Box 609
Chouteau, OK 74337-0609
918-256-5545

GRDA
Grand River Dam Authority

September 10, 2020

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SEP 14 2020
AIR QUALITY

Kendal Stegmann, Director
Air Quality Division
Department of Environmental Quality
707 N. Robinson
PO Box 1677
Oklahoma City, Oklahoma 73101-1677

Subject: 4-factor analysis for SO_2
Grand River Dam Authority
Grand River Energy Center
Electric Power Generation Unit 2

Dear Ms. Stegmann:

In response to the *"Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program"* letter dated July 1, 2020, the Grand River Dam Authority (GRDA) respectfully submits the following documents for your review:

1) Four Factor Analysis – Grand River Energy Center Unit 2, prepared for the GRDA by Black & Veatch Corporation, September 8, 2020, CONFIDENTIAL (unredacted), includes Attachment A and Attachment B, submitted via certified mail
2) Four Factor Analysis – Grand River Energy Center Unit 2, prepared for the GRDA by Black & Veatch Corporation, September 8, 2020, PUBLIC (redacted)

As indicated by the submitted documents, the GRDA has contracted with an experienced engineering firm, Black & Veatch Corporation (B&V), to perform the requested 4-factor analysis. In support of the analysis, commercially sensitive information, such as economic criteria, Unit capacity factor forecasts, and Unit remaining life projections were shared with B&V and included in the unredacted version of the report. As such information isn't publicly released by GRDA and is classified as confidential by 27A O.S. § 2-5-105(17), we request that the unredacted version of the report be treated as confidential.

If you have any questions, please do not hesitate to contact me.

Sincerely,

Michael L. Bednar

Michael L. Bednar
Manager of Environmental Compliance
Grand River Dam Authority

We deliver affordable, reliable ELECTRICITY, with a focus on EFFICIENCY and a commitment to ENVIRONMENTAL STEWARDSHIP.

We are dedicated to ECONOMIC DEVELOPMENT, providing resources and supporting economic growth.

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FINAL

FOUR FACTOR ANALYSIS

Grand River Energy Center Unit 2

B&V PROJECT NO. 405969
B&V FILE NO. 40.1000

PREPARED FOR

Grand River Dam Authority

8 SEPTEMBER 2020

Reviewed by:

Paul Lee Digitally signed by Paul Lee DN: C=US, E=leep@bv.com, O=Black & Veatch, OU=Power, CN=Paul Lee Reason: I am approving this document Date: 2020.09.09 08:22:32-06'00'

Signature

Sept 8, 2020

Date

Paul Lee

Printed Name

Reviewed by:

Mark R Bleckinger Digitally signed by Mark R Bleckinger DN: C=US, E=bleckingermr@bv.com, O=Black & Veatch, OU=Energy, CN=Mark R Bleckinger Date: 2020.09.08 18:52:52-05'00'

Signature

Sept 8, 2020

Date

Mark Bleckinger

Printed Name

Professional Engineer:

Signature

08Sep20

Date

LICENSED PROFESSIONAL ENGINEER
MONTY E. HINTZ
22927
STATE OF OKLAHOMA

Monty Hintz

Printed Name

22927

License No.

Approved by:

Signature

09/08/2020

Date

Kyle Lucas

Printed Name

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Acronym List

A/C	Air-to-Cloth
BART	Best Available Retrofit Technology
CaO	Calcium Oxide
CDS	Circulating Dry Scrubber
DEQ	Department of Environmental Quality
DSI	Dry Sorbent Injection
EGU	Electric Generating Unit
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
EWRT	Extinction Weighted Residence Time
FGD	Flue Gas Desulfurization
FPM	Filterable PM
GRDA	Grand River Dam Authority
GREC	Grand River Energy Center
HCl	Hydrochloric Acid
MATS	Mercury Air Toxics Standards
NO_x	Nitrogen Oxide
PAC	Powdered Activated Carbon
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
PPS	Polyphenylene Sulfide
Round 2	Second Planning Period
SBS	Sodium Bisulfate
SCAQMD	South Coast Air Quality Management District
SDA	Spray Dryer Absorber
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
WFGD	Wet Flue Gas Desulfurization

Executive Summary

The Oklahoma Department of Environmental Quality (DEQ) identified Grand River Dam Authority's (GRDA) Grand River Energy Center (GREC) Unit 2 as subject to a four-factor reasonable progress analysis under the Regional Haze Rule covering the second planning period (Round 2) of 2021 to 2028. The rule provides four-factors (40 C.F.R. § 51.308(f)(2)(i)) by which a state must consider potential control measures for the long-term strategy. These are: 1) the cost of compliance; 2) the time necessary for compliance; 3) the energy and non-air quality environmental impacts of compliance; and 4) the remaining useful life of existing sources subject to this requirement. The analysis requested is for sulfur dioxide (SO_2).

A review was required to identify the best air quality control technology for the reduction of SO_2 emissions. Prior to performing the engineering analysis, a simplified design basis was established for Unit 2. The design basis was established from supplied plant operating data, performed combustion calculations, and industry-standard engineering assumptions made for this analysis. A summary of the operational characteristics is shown in Section 3. The economic design criteria established for the engineering analysis was used to estimate the cost of control technologies. This was done for the technologies identified as being technically feasible and to perform the impact analysis to determine their cost-effectiveness. Data for the economic design criteria was developed with GRDA to best represent the actual operational costs for Unit 2.

The design basis was then used to establish the anticipated emissions reduction for each applicable technology, which is also termed as the control effectiveness. The control effectiveness for each applicable technology is shown in Table 4-2.

The four steps that need to be considered for each identified control technology are as follows: In Step 1 of the methodology, the report identifies SO_2 available retrofit emissions control technologies that may be practically implemented at Unit 2. From this list of available technologies, technically feasible control technologies were identified in Step 2. A control technology is technically feasible if it is determined to have been successfully implemented at a similar facility and/or is available commercially. The technologies that were considered technically feasible in accordance with Step 2 include the following:

- Coal washing.
- Circulating dry scrubber (CDS).
- Dry sorbent injection (DSI).
- New spray dryer absorber (SDA).
- Wet flue gas desulfurization (WFGD).

In Step 3, characteristics and features of the technically feasible control technologies were evaluated, and the estimated control effectiveness of the technology as applied to Unit 2 was determined. Also evaluated in this step were the retrofit requirements for the control technology at the existing plant site; these were determined by considering the current configuration of the equipment and the operational requirements at the plant site. Control effectiveness is a measure of the emissions reduction expected after the implementation of the control technology.

For Step 4 of the review process, cost-effectiveness was evaluated. Impact analysis for each technically feasible control technology was performed for this purpose. The impact analysis considered such issues as the cost of compliance, energy impacts, non-air quality impacts, and the remaining useful life of the source. After the impact analysis of each control technology was completed, the cost-effectiveness was calculated. The incremental cost-effectiveness range for the evaluated technologies was approximately \$21,000 to \$177,000 per ton removed, with the total amount of SO_2 removed ranging from 37 to 294 tons per year.

While the threshold for cost effectiveness may vary between states and EPA regions, these values are well above what has typically been considered cost effective. Although GREC Unit 2 is not an affected BART unit, in 2010 DEQ had determined cost effectiveness on a per ton of SO_2 removed basis for similar coal fired generating units in Oklahoma.[1] The results of this analysis showed that similar technology was not cost effective even escalated to 2020 cost which are below the costs stated above. Considering GREC Unit 2 is already equipped with an SDA, the high costs associated with the potential incremental SO_2 reductions are cost prohibitive. This is compounded by the fact that this analysis was done on a [redacted]-year period. By the time the DEQ's SIP is reviewed, accepted, and a control technology agreed upon and installed, the remaining life of the Unit 2 will be much less than [redacted] years, potentially as short as [redacted] years. This would only further increase the costs associated with additional controls and increase the cost effectiveness values.

[1] Oklahoma Department of Environmental Quality, Air Quality Division. Regional Haze Agreement. February 17, 2020.

1.0 Introduction

The United States Environmental Protection Agency (EPA) introduced the Regional Haze Rule in 1999 to protect the visibility in national parks and wilderness areas, or Class I Areas. To do so, the EPA called for each state to develop a State Implementation Plan (SIP) to address emissions that are reasonably anticipated to cause or contribute to visibility impairment. The second round of SIPs are due to the EPA by July 31, 2021.

In a July 2020 letter to the Grand River Dam Authority (GRDA), the Oklahoma Department of Environmental Quality (DEQ) requested that a four-factor analysis be conducted on Grand River Energy Center (GREC) Unit 2. The four-factor analysis is to be done on all potential sulfur dioxide (SO_2) control measures. GREC Unit 2 is a 520 MW unit that burns subbituminous coal from the Powder River Basin (PRB). Unit 2 was constructed and placed in operation in 1985.

This report provides the four-factor analysis pursuant to the DEQ's request and is consistent with the requirements of the Regional Haze Rule, 40 C.F.R. § 51.308(f). The report identifies available SO_2 emissions control technologies, eliminates technically infeasible control technology options, and evaluates the control effectiveness of the remaining control technologies. A four-factor analysis is then conducted on each of the remaining control technologies.

1.1 DEFINITION OF "FOUR-FACTOR ANALYSIS"

The phrase "four-factor analysis" is shorthand for the analysis of the many different possible retrofit emissions control technologies that exist in the marketplace and that may be applied to an emissions unit to help meet reasonable progress goals that may be established in a SIP and adopted to implement the requirements of the Regional Haze Rule. The four factors are as follows:

- Factor 1 – Costs of compliance
- Factor 2 – Time necessary for compliance
- Factor 3 – Energy and non-air quality environmental impacts of compliance
- Factor 4 – Remaining useful life of any potentially affected anthropogenic source of visibility impairment

The four factors are listed in the federal Clean Air Act, Section 169A(g)(1), which states that:

> In determining reasonable progress there shall be taken into consideration **the costs of compliance, the time necessary for compliance, and the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements.**

Also, the Regional Haze Rule at 40 C.F.R. § 51.308(d)(1)(i)(A) lists the four factors, stating that:

> In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must . . . Consider **the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources**, and include a demonstration showing how these factors were taken into consideration in selecting the goal.

The Regional Haze Rule at 40 C.F.R. § 51.308(f) specifically discusses a state's requirements in the subsequent Regional Haze planning periods (including in the second planning period), which include, among other requirements, in (f)(2)(i):

> 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.

1.2 UNIT 2 FOUR FACTOR APPLICABILITY

States have discretion regarding the sources to be considered for controls in the second planning period. The following briefly summarizes several key aspects of Unit 2 that should be considered by DEQ when determining whether Unit 2 should be included in DEQ's implementation plan for the second planning period.

Construction of Unit 2 began after 1977 and the unit itself went operational in 1985 as an electric generating unit (EGU). Thus, Unit 2 was permitted under the Prevention of Significant Deterioration's New Source Review program along with any applicable modifications the unit has undergone since, including those for applicable air quality programs. Because of other air quality regulations, Unit 2 is in compliance and, therefore, already a well-controlled unit for criteria pollutants (including SO_2) and should not be subject to further analysis.

1.2.1 SO_2 Emissions

On June 17, 2020, DEQ provided a presentation addressing updates to the Regional Haze SIP, round two. DEQ must develop a long-term strategy for meeting a "reasonable" progress goal for this second period that considers emission controls through a four-factor analysis. DEQ indicated that the Central States Air Resources Agencies (CenSARA) organization, which includes

Oklahoma, contracted with Ramboll US Corporation (Ramboll) to produce a study examining the impact of stationary sources of NO_X and SO_2 on each Class 1 area in the central region of the United States. DEQ used a method based on this study to determine which sources may have the greatest potential for contributing to visibility impairment at Oklahoma's Class 1 area: the Wichita Mountains Wilderness Area. The emission data used for the study was from 2016. It should be noted that the SO_2 emissions for GREC were 8,987 tons emitted during this year. However, only 629 tons of SO_2 (at a [redacted]% capacity factor) or approximately [redacted] percent of the total plant emissions, were generated by Unit 2 in 2016. Given this fact, it is not appropriate for GREC's total emissions to be used to determine Unit 2's eligibility for the four-factor analysis. Furthermore, Unit 1 ceased to operate on coal on April 16, 2017 pursuant to an Administrative Order with the U.S. Environmental Protection Agency.

1.2.2 Significant Emissions Impacts on Class I Areas

The Federal Land Manager's *Air Quality Related Values Work Group*; Phase 1 Report – Revised (2010) adopted criteria from EPA's 2005 BART guidelines to screen out projects from air quality related value review from conducting visibility analyses for Federal Class I areas by determining the significance of visibility impairing pollutants on Class I areas. In simple terms, this method provides the ability to screen out sources with relatively small amounts of emissions located a large distance from a Class I area. This methodology is commonly referred to as "$Q/D \leq 10$". Thus, for Unit 2 the result is 1.9 with the following assumptions:

Q = 630 tons SO_2 emitted in 2016

D=~335 km from Wichita Mountains Wilderness Area

Therefore, Unit 2's relatively small amount of SO_2 emissions would screen out from further analysis for visibility impairment using the guidance from Phase 1. Additionally, for the case of the four-factor applicability, DEQ indicated that a trigger of (EWRT)*(Q/D)>0.5[2] was applied, with EWRT being the extinction weighted residence time.

1.2.3 MATS Compliance

Additionally, the EPA's recent *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*[3] provides direction on how to address sources that already have state-of-the-art emission controls installed. The EPA guidance in Section II. Regional Haze SIP development steps, Step 3: Selection of sources for analysis, f) Sources that already have effective emission control technology in place, states:

> For the purpose of SO_2 control measures, an EGU that has add-on flue gas desulfurization (FGD) and that meets the applicable alternative SO_2 emission limit of the 2012 Mercury Air Toxics Standards (MATS) rule for power plants. The two limits in the rule (0.2 lb/MMBtu

[2] The criteria was provided to GRDA by DEQ.

[3] *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (Issued August 20, 2019 – EPA-457/B-19-003)

for coal-fired EGUs or 0.3 lb/MMBtu for EGUs fired with oil-derived solid fuel) are low enough that it is unlikely that an analysis of control measures for a source already equipped with a scrubber and meeting one of these limits would conclude that even more stringent control of SO_2 is necessary to make reasonable progress.[4]

MATS provides emission limits for coal fired EGUs pursuant to Section 112(d) of the Clean Air Act, and the rule requirements are codified at 40 C.F.R. Part 63, Subpart UUUUU. In the MATS rule, EPA established an emissions limit for SO_2 emissions from existing coal-fired EGUs at 0.20 lb/MMBtu (30-day rolling average). This emission limit reflects maximum achievable control technology for existing units. GREC Unit 2 continuously complies with this limit. Since Unit 2 continuously meets and is consistently below the emissions limits required by MATS, the control technologies can be considered maximum achievable control technology for SO_2 control.

1.2.4 Summary

The aforementioned discussion has provided a summary of why GREC's Unit 2 should not be considered a stationary source impacting a Class I area and should be excluded from the second planning period. However, to be responsive to the DEQ request, a four-factor analysis has been developed and is discussed in the following sections.

[4] US Environmental Protection Agency, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, (Research Triangle Park, 2019), page 23.

2.0 Plant Descriptions

A basic description of GREC is provided in the following sections. A summary of the unit configuration and operational characteristics used in the analysis is provided in Section 3.0.

2.1 GRAND RIVER ENERGY CENTER OVERVIEW

The GREC is located in Mayes County in northeastern Oklahoma, approximately 3 miles east of Chouteau, Oklahoma. The facility is situated approximately 0.5 mile north of Highway 412 near the Grand River. Currently GREC is comprised of one coal fired EGU, Unit 2, and one combined cycle EGU, Unit 3. GREC was originally built in 1978 with one coal-fired EGU (Unit 1), and this was later joined by Unit 2 in 1985. The two coal-fired units were similar with wall-fired boilers made by Foster Wheeler. As noted earlier, Unit 1 ceased to operate on coal on April 16, 2017 pursuant to an Administrative Order with the U.S. Environmental Protection Agency.

Existing air quality control equipment on Unit 2 consists of low nitrogen oxide (NO_X) burner/overfire air combustion control systems for NO_X emissions controls and a spray dryer absorber (SDA) followed by a pulse jet fabric filter (PJFF) for SO_2 and particulate matter (PM) emissions control. Unit 2 also injects powdered activated carbon (PAC) into the flue gas for mercury removal.

2.2 EMISSIONS DATA

Table 2-1 summarizes the Title V (Permit No. 2014-1728-TVR3 (M-3)) permitted emissions limits for GREC Unit 2. Data provided from GRDA shows the SO_2 emissions from Unit 2 have been in compliance with all of its permitted emission limits over the last 5 years.

Table 2-1 Unit 2 Emissions Limits

	EMISSIONS LIMITS	EMISSIONS 2019
SO_2	• 0.6 lb/MMBtu (permit condition) • 3,177 lb/h (permit condition) • 0.20 lb/MMBtu (Part 63, UUUUU)	[redacted] lb/MMBtu [redacted] tons/yr)[1]
Notes: 1) The capacity factor for 2019 was % due to a force outage that lasted months.		

3.0 Design Basis

3.1 FUEL

GREC has historically used PRB coal from Wyoming, and the facility has occasionally mixed the PRB coal with up to 10 percent of Oklahoma coal. GRDA plans on using exclusively Wyoming coal in the future, so this study used the coal characteristics in Table 3-1.

Table 3-1 Wyoming Design Coal

FUEL PROPERTY (WET BASIS)	WYOMING PRB
Carbon, %	46.81
Hydrogen, %	3.25
Sulfur, %	0.40
Nitrogen, %	0.66
Oxygen, %	11.86
Ash, %	6.01
Moisture, %	31.00
Total, %	100
Higher Heating Value, Btu/lb	8,400

3.2 OPERATING PARAMETERS

Tables 3-2 and 3-3 show the critical operating parameters for GREC Unit 2 that were used in developing this study.

Table 3-2 Operating Parameters for Unit 2 Boiler

UNIT PARAMETER	VALUE AT MAXIMUM CONTINUOUS RATING
Unit Rating, gross MW	575
Capacity Factor, % (forecast)	[redacted][1]
Boiler Manufacturer	Foster Wheeler
Boiler Type	Wall Fired
Boiler Heat Input, MMBtu/h	5,296
ECONOMIZER OUTLET CONDITIONS	
Flue Gas Temperature, °F	718
Flue Gas Mass Flow Rate, lb/h	5,266,000
Volumetric Flue Gas Flow Rate, acfm	2,652,000
AIR HEATER OUTLET CONDITIONS	
Flue Gas Temperature, °F	330

UNIT PARAMETER	VALUE AT MAXIMUM CONTINUOUS RATING
Flue Gas Pressure, in. wg	-22.0

Notes:

1) The 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.

Table 3-3 Operating Parameters for Unit 2 Emissions Control Systems

UNIT PARAMETER	VALUE AT FULL LOAD
Lime Slurry Preparation System	
Lime Slurry Mill	Ball Mill (2 x 100% trains)
Design Slurry Solids % after Ball Mill	18
Design Slurry Solids % to Feed Tank	33
Lime, specified CaO %	90
Ball Mill Capacity, lb/h (per train)	17,800
Spray Dryer Absorber	
Number of Atomizers/ Vessel	3
Number of Absorber Vessels	4
Design Approach Temperature	~20° F
SO_2 Removal Guarantee, %	85 (all four modules operating)
SO_2 Removal Guarantee, lb/MMBtu	0.6
Max Sulfur Loading in Coal, %	[redacted] (as originally designed); GREC is no longer mixing PRB with Oklahoma coal, so the max sulfur loading today and going forward is [redacted]%.
Pulse Jet Fabric Filter	
Number of Casings	2
Bag Material	16 oz. PPS felt
Air-to-Cloth Ratio, gross / net	2.44 / 3.26

4.0 Four-Factor Analysis – SO_2

This section identifies the control technologies for SO_2 emissions, followed by an evaluation of those technologies in a step-by-step approach. Step 1 of the evaluation process identifies all available SO_2 emissions control technologies. A high-level description of each emissions control technology is provided. Technically infeasible options are eliminated in Step 2. In Step 3, the control effectiveness of the remaining control technologies is presented. Finally, Step 4 evaluates each of the remaining SO_2 control technologies against the following four factors.

- Factor 1 – Costs of compliance.
- Factor 2 – Time necessary for compliance.
- Factor 3 – Energy and non-air quality environmental impacts of compliance.
- Factor 4 – Remaining useful life of any potentially affected anthropogenic source of visibility impairment

4.1 STEP 1: IDENTIFY ALL AVAILABLE TECHNOLOGIES

There are several different ways that SO_2 emissions from an EGU can be reduced. Some reduction methods reduce the amount of sulfur in the fuel, either by fuel switching or cleaning (e.g. coal washing). Others involve using a reagent to chemically react with SO_2 in the flue gas, post-combustion.

There are other technologies that have been developed for reducing SO_2 emissions, but many have not moved past laboratory-scale demonstrations. Because of their lack of commercial demonstrations, these technologies are not reviewed in the following summaries, because they do not meet the definition of technically feasible. A summary of all identified SO_2 control technologies that meet a minimum amount of proven capabilities is provided in the subsequent subsections.

4.1.1 Coal Washing

Coal washing or coal cleaning is a process in which coal is passed through a solvent (typically water) to remove various compounds such as sulfur. Prior to washing the coal, the coal is often crushed to separate coal pieces that have differing amounts of mineral content. The overall process of crushing and cleaning the coal has been demonstrated to improve the heat content, lower the ash content, and remove impurities such as sulfur and mercury.

While not widely implemented, coal washing has been successfully demonstrated at multiple facilities. The process seems most beneficial for reclaiming coal in the coal yard, but the process does have the capability of providing a continuous amount of coal. One vendor estimated that coal washing can remove anywhere from 5 to 25 percent of sulfur in the coal, and since GREC Unit 2 burns PRB, the amount of sulfur reduction is expected to be on the lower end of that range.

4.1.2 Circulating Dry Scrubber

The circulating dry scrubber (CDS) process is a semi-dry, lime-based FGD process that uses a circulating fluid bed. The CDS absorber module is a vertical solid/gas reactor between the air heater and particulate control device. Water is sprayed into the reactor to reduce the flue gas temperature to the optimum temperature for reaction of SO_2 with the reagent. Hydrated lime ($Ca(OH)_2$) and recirculated dry solids from the particulate control device are injected into the flue gas by the base of the reactor just above the water sprays. The gas velocity in the reactor is reduced, and a suspended bed of reagent and fly ash is developed. The SO_2 in the flue gas reacts with the reagent to form predominately calcium sulfite. Fine particles of byproduct solids, excess reagent, and fly ash are carried out of the reactor and removed by the particulate control device. Over 90 percent of these solids are returned to the reactor to improve reagent utilization and increase the surface area for SO_2/reagent contact.

The CDS is an acceptable FGD removal technology in some applications because of its ability to remove significant amounts of SO_2, the commercial status of the technology, and the use of conventional reagents. It has disadvantages relating to the downstream particulate load imposed on collectors, and at GREC Unit 2, the recently installed PJFF would need to be modified to install air slides below the hoppers for recycling solids back to the CDS absorber. This would require raising the PJFF structure from its current elevation to accommodate this orientation.

4.1.3 Dry Sorbent Injection

Dry sorbent injection (DSI) has been used to remove a variety of acids from flue gas, including hydrochloric acid (HCl), SO_2, and sulfur trioxide (SO_3). DSI systems are most effective when targeting SO_3 or HCl emissions, and while there are some installations intended for SO_2 removal, most are used to lower SO_3 or HCl emissions. DSI systems inject a reagent directly into flue gas ductwork to absorb its targeted pollutant. Multiple reagents can be used, such as sodium bisulfate (SBS), Trona, hydrated lime, and magnesium-based compounds.

The reagent is typically trucked onto the site, where it is unloaded and held in a storage silo. From the silo, it is pneumatically conveyed to the injection points, where the reagent flows through lances into the flue gas stream. The lances are typically a carbon steel pipe with a proprietary design, depending on the system provider. The lances can be located in a variety of places along the flue gas process, but careful design considerations must be given to where the reagent is injected. For example, if a system is using PAC for mercury control, then a DSI's injection points should occur upstream of a PAC's injection points, because SO_3 is an inhibitor of PAC adsorbing mercury. Additionally, since DSI may contribute a significant addition to the dust loading, DSI should always be upstream of adequate particulate removal devices.

When used for SO_2 removal, sodium-based sorbents such as SBS or Trona are typically used, because excessive amounts of hydrated lime are required to obtain the necessary levels of SO_2 removal. While cheaper than sodium-based sorbents, the elevated consumption rates of hydrated lime leads to larger storages silos, rotary feeders, etc. This results in a more expensive system in terms of up-front capital and annual operating costs.

For sodium-based sorbents, DSI systems come with the option to mill the reagent. Milling reduces the reagent's particle size, which effectively increases the surface area for reactions to occur. Milling can occur in-line or prior to conveying, but rat-holing and other problems can occur if milled reagent is stored. Depending on the sorbent used, vendors stated that up to 50 percent less sorbent is used to achieve similar removal rates when milling is used.

4.1.4 Pulse Jet Fabric Filter Upgrades

Although primarily a particulate control device, PJFF upgrades are considered for SO_2 emissions, because not all of the lime slurry reacts with acid gases inside the absorber vessel. Therefore, a significant level of SO_2 removal occurs in the particulate control device downstream of an SDA. The chemical reactions are dependent on acid gases interacting with lime particles in the gas. A PJFF is able to better promote the chemical reactions compared to an electrostatic precipitator (ESP) by providing a physical barrier (the PJFF bags with a cake of fly ash, SDA byproducts, and unreacted lime particles) that SO_2 entrained in the flue gas must pass through.

The PJFF on Unit 2 was installed in 2016 as a conversion of the original ESP. Southern Environmental/FLSmidth provided the PJFF with a performance guarantee of 0.010 lb/MMBtu of filterable PM (FPM), using an air-to-cloth (A/C) ratio of 3.26 ft/min net (one compartment out of service) and 2.44 ft/min gross. The A/C ratios are within industry experience, if not slightly on the lower end. Lower A/C ratios mean that there is more bag surface area for the flue gas to pass through, which helps increase the bag life because of less pressure drop across the bags. The PJFF's performance is also better at lower A/C ratios, because particulates are more likely to pass through the bags at higher pressure drops. While the low A/C ratio on Unit 2's PJFF is good for bag life and performance, it could potentially hurt the residual SO_2 removal in the baghouse, because the flue gas has more surface area to pass through, as opposed to being forced through more limited areas containing unreacted lime particles. However, bags are thoroughly coated with a filter cake that generally has a consistent makeup of fly ash and SDA byproducts, including unreacted lime, so it is uncertain whether or not increasing the A/C ratio would have a beneficial effect on an SDA's removal efficiency. A literature search on the effects of A/C ratio on SO_2 removal could not find any concrete data or case studies.

Another PJFF modification that could potentially increase SO_2 removal is changing the material of the bags. Currently, Unit 2's PJFF uses 16-ounce polyphenylene sulfide (PPS) felt bags, which are widely used for coal fired applications. A common method to improving the PJFF performance is changing the bag material, especially if there are any concerns with sticky particulates or temperature excursions. Unit 2 does not have these concerns, so changing out the bags would solely be driven by increasing the SO_2 removal efficiency. Case studies could not be found that demonstrated a particular bag material improving SO_2 removal in a PJFF after an SDA. Vendors were contacted (Menardi and BHA), and their representatives also did not know of any data or studies that proved one particular bag type was more effective than others. PPS is an effective bag material and there is no guarantee on the effects of changing the bags to another material.

4.1.5 Spray Dryer Absorber Upgrades

Along with additional controls that can be installed at GREC Unit 2, modifications to the existing SDA system were evaluated in this study. 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. Still, as part of the top-down approach, upgrades to the existing system were considered.

Lime slurry is the reagent used in the SDA, and depending on the lime slurry quality, upgrades are possible with the lime slurry preparation system. First, the lime received by the facility must meet specifications. The system's original design data sheets call for 90 percent available calcium oxide (CaO) in the pebble lime. Based on information from the plant, 90 percent CaO is consistently met by the delivered lime. Once the lime is received on-site, it is stored and eventually slaked into a slurry. There are two types of slakers that dominate lime slurry preparation system: paste and ball mill. While both types have been shown to be effective, if a facility experiences problems with excessive grit or inconsistent slurry quality, ball mill slakers have been shown to be more effective than paste mill slakers in producing a reliable slurry over a range of lime qualities. However, an upgrade to a ball mill slaker is not available for Unit 2, because it already uses the most robust slaker type. There are also no significant issues with the lime slurry quality, indicating that the equipment is working as designed. The system's original mass balances call for 30 percent solids in the lime slurry that are injected through the atomizers, and Unit 2's data shows solids percentages slightly above 30 percent.

Another potential upgrade to the existing SDA is changing out the atomizer. However, there is no evidence that the existing atomizers are underperforming, because the system is achieving the SO_2 removal efficiency it was designed to achieve. Furthermore, replacing the atomizers with a more modern version is not a simple change that can be seamlessly implemented. The SDA absorber vessel was designed for the current atomizers, with flow modeling being one of the many engineering steps done to ensure that the sprayed slurry droplets to not impinge against the absorber's walls. A new atomizer must be evaluated through the same engineering process, and it is not known if there is any tangible benefit to changing atomizers at this time.

One deviation from the original design is that Unit 2 currently operates around a 30° F approach temperature, which is the difference between the SDA outlet temperature and the flue gas dew point temperature. The original design calls for a 20° F approach temperature. Generally, higher removal efficiencies are achieved when operating at lower approach temperatures; however, if the system operates at too low of an approach temperature, localized cold spots downstream of the SDA will condense acid gases in the flue gas and corrode equipment. Black & Veatch has observed approach temperatures to be typically 30° F and above. While operating according to the original design's 20° F approach temperature could enhance SO_2 removal, this will come at the expense of corroding downstream equipment and is not recommended.

SDAs are a well proven technology, and many installations have been able to achieve SO_2 removal efficiencies of over 90 percent. GREC Unit 2 was designed for a removal efficiency of 85 percent, and it currently operates in this range. Therefore, upgrades to the existing system to increase SO_2 removal are limited, but a new SDA system (absorber vessel, atomizers, and lime preparation system) that is designed for higher SO_2 removal is a viable option.

4.1.6 New Spray Dryer Absorber

The semi-dry SDA FGD process has been one of the most widely applied FGD technologies for low-sulfur coal. Generally, these installations are applied when the maximum fuel sulfur content is less than 2 percent, which is typically the case when either lignite or subbituminous coal (such as PRB) is the primary fuel.

There are several variations of this process, but the most prevalent is the installation of one or more SDA vessels downstream of the air heater and upstream of a unit's particulate control device. Multiple absorber modules are used to accommodate the higher flue gas flows.

Lime slurry is sprayed into the SDA vessel as an atomized mist using either rotary atomizers or dual-fluid nozzles, depending on the equipment supplier. All current SDA designs use a vertical gas flow absorber. In all cases, atomizers are located in the roof of the absorber to create an umbrella of atomized reagent slurry through which the flue gas passes. The SO_2 in the flue gas is absorbed reacts with calcium in the lime slurry to form calcium sulfite and calcium sulfate. Before the slurry droplets can reach the absorber wall, the water in the droplet evaporates, and a dry particulate is formed.

The flue gas, containing fly ash and FGD byproduct solids, leaves the absorber and is directed to the particulate control device. On some SDA systems, such as GREC Unit 2's, a recycle slurry system is used to improve reagent utilization. The recycle system slurries a portion of the solids from the particulate control device, which will contain some unused calcium particles. The recycle slurry and fresh lime slurry are combined to make a final feed slurry that is sprayed into the SDA vessel. The rest of the fly ash and byproduct solids collected in the particulate control device are pneumatically transferred to a silo for disposal.

SDA's have been successfully installed and demonstrated at many coal-fired facilities, and it is a viable option for improving the SO_2 removal at GREC Unit 2.

4.1.7 Wet Flue Gas Desulfurization

Wet flue gas desulfurization (WFGD) removes sulfur by passing flue gas through multiple levels of slurry spray in a vertical absorber tower. The slurry commonly is created from limestone, although other minerals such as magnesium oxide have been infrequently used. The WFGD tower is downstream of a particulate control device, such as a PJFF or ESP, because of the complications that fly ash can create in the absorber tower, such as erosion, clogging, and darkening the solution that is ultimately dewatered into saleable gypsum.

Limestone is delivered to site by rail or truck and ground into a lime slurry by a horizontal ball mill slaker. The resulting lime slurry is passed through a series of hydrocyclones to obtain the desired slurry consistency before it is sent to the absorber tower. At the absorber, the solution lies at the bottom where recycle pumps continually send the slurry to various levels of spray headers. The spray headers atomize the slurry into fine droplets that react with the acid gases in the flue gas, and the liquid falls back to the bottom of the absorber vessel. Oxidation air is provided to the slurry solution to completely oxidize the reaction products to form gypsum, which is recovered through from a bleed stream off the absorber.

WFGDs have been successfully installed and demonstrated at many coal-fired facilities, and it is a viable option for improving the SO_2 removal at GREC Unit 2.

4.2 STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

After technologies have been identified, the technically infeasible options must be eliminated from further evaluation, as briefly discussed in the previous sections for each technology. Drawing from the BART Guidelines (40 C.F.R. Part 51, Appendix Y, Section IV.D.2.) as general guidance, this entails determining whether technical difficulties would preclude the successful use of the control option on the emissions unit under review based on physical, chemical, or engineering principles. As described in 40 C.F.R. Part 51, Appendix Y, Section IV.D.2:

> "Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: 'availability' and 'applicability.'... a technology is considered 'available' if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is 'applicable' if it can reasonably be installed and operated on the source type under consideration." The EPA does "not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as 'available' for purposes of BART review." (40 C.F.R. Part 51, Appendix Y, Section IV.D.2.2.)

With this understanding, Table 4-1 shows an evaluation of the technologies considered above.

Table 4-1 Evaluation to Eliminate Control Options

TECHNOLOGY	DESCRIPTION/APPLICABILITY TO GREC UNIT 2	CONSIDERED FURTHER
Coal Washing	Crush and wash coal in coal yard to remove sulfur and other impurities	Yes
CDS	Circulating fluidized bed of solids with hydrated lime to remove acid gases	Yes
DSI	Injection of dry sorbent into flue gas to react with acid gases	Yes
PJFF Upgrades	A/C ratio and bag material alterations	No – lack of firm data on beneficial effects of changing design parameters

TECHNOLOGY	DESCRIPTION/APPLICABILITY TO GREC UNIT 2	CONSIDERED FURTHER
SDA Upgrades	Change system components to increase removal efficiency	No, current system achieves designed removal efficiency; evaluate new SDA instead
SDA, New	Lime slurry is sprayed into absorber vessel as an atomized mist using either rotary or two-fluid atomizers to remove acid gases.	Yes
WFGD	Limestone slurry sprayed inside absorber tower to react with acid gases	Yes

4.3 STEP 3: EVALUATE CONTROL EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

The remaining control technologies after Step 2 were evaluated further based on their effectiveness in removing SO_2. The metric used to determine control effectiveness was lb/MMBtu and lb/h. These metrics are eventually converted to a ton/year estimate based upon a projected annual capacity factor.

The control effectiveness values were based on expected performance values for the control technologies at Unit 2 as it currently is. Coal washing and DSI are able to remove additional SO_2 with the current SDA online, so the lb/MMBtu emissions were based with the SDA still removing 85 percent of its inlet SO_2 loading. This is a best-case scenario, as the SDA may not be able to maintain its current removal efficiency (85 percent) due to the lower inlet concentrations of SO_2. The removal efficiencies of the coal washing and DSI systems were based on discussions with vendors and past Black & Veatch experiences, but a contractual, vendor guarantee may ultimately be different than what was assumed in this analysis. Due to differences in flue gas composition and characteristics, as well as the facility's ductwork layouts, the performance by one DSI system is not completely applicable to another.

The CDS, new SDA, and the WFGD were evaluated with the existing SDA decommissioned, because it would be prohibitively expensive to install and operate any of these control systems with the SDA still online. In each instance, the removal efficiency was determined according to what other facilities have been able to demonstrate. It is important to note a system's maximum percentage removal and lowest emissions in lb/MMBtu do not always coincide. For example, a WFGD has been shown to remove approximately 98 percent of the inlet SO_2 and down to 0.04 to 0.06 lb/MMBtu. Because of the low level of sulfur in Unit 2's coal, 0.04 lb/MMBtu is used as the limit, resulting in 96 percent removal efficiency. Reductions below 0.04 lb/MMBtu are difficult to consistently achieve because eventually the concentration of SO_2 gets too low for additional reactions with the reagent to occur.

Table 4-2 Control Effectiveness for SO_2 Control Technologies

TECHNOLOGY	EXPECTED CONTROL EFFICIENCY (%)	EXPECTED EMISSIONS (LB/MMBTU)
Coal Washing	10[1]	0.18
CDS	94	0.06
DSI	50[1]	0.07[2]
SDA (new)	94	0.06
WFGD	96	0.04

Notes:

1) Unknown if vendor guarantees can be provided on a 30-day rolling average.
2) The value can only be demonstrated by site specific evaluations.

4.4 STEP 4: EVALUATE FACTORS

With the technologies identified and vetted for further analysis, the four-factor analysis can be applied. As discussed in Section 1.0, the four factors are cost of compliance, time necessary for compliance, energy impacts and non-air quality environmental impacts, and the remaining useful life of the potentially affected source. This section applies the four-factors to the appropriate technologies from the previous sections.

4.4.1 Factor 1: Costs of Compliance

Cost estimates for the technologies were developed using the EPA Cost Manual's updated Section 5: SO_2 and Acid Gas Controls (posted August 5, 2020). Budgetary costs and information were gathered based on previous project estimates for coal washing, as the Control Manual does not cover coal washing. For DSI, Black & Veatch used in-house databases from past projects to develop costs, because the Cost Manual does not cover DSI other than a system description. Economic factors, such as reagent costs, worker salaries, etc., were obtained through a combination of GRDA and vendor quotes. Refer to Appendix A for a list of all economic factors used in this analysis and Appendix B for details of the cost analyses.

The following notes apply to the derivation of the cost estimates:

- The Cost Manual does not provide separate cost derivations for a CDS, but instead groups the CDS with the SDA. While the technologies are similar, A CDS generally will cost more, so a ratio of the values between a CDS and SDA in Table 1.4 of Section 5 of the Cost Manual was applied.
- The updated Section 5 of the Cost Manual does not state whether or not the BOP equations for semi-dry FGDs account for a particulate control device, which is integral to both a CDS and SDA. This analysis does not try to subtract costs for a PJFF but acknowledges that Unit 2's PJFF can be reused for a new SDA. A new CDS

will require significant modifications to the existing PJFF, as air slides will be needed below the PJFF to reintroduce solids from the PJFF into the absorber.

- A wet limestone scrubber was selected for this analysis instead of a packed bed WFGD.
- Gypsum sales were not included as part of this analysis, because there is no guarantee a regionally available off-take facility is available if a WFGD is installed.
- The WFGD is planned to be located across GREC's South Road. The access to build ductwork from the PJFF to the WFGD, and from the WFGD to a new wet chimney (located south of the decommissioned Unit 1) is relatively clear. Factors for difficult retrofits were not applied.
- The DSI system was estimated with Trona as a reagent. Hydrated lime, while cheaper, is not as effective as sodium sorbents when targeting SO_2, Black & Veatch has observed that the silo sizes and consumption rates are excessively large for implementation. Because Trona is used, the DSI system's cost was estimated with mills to reduce sorbent consumption rates.
- Coal washing is capable of removing around 10 percent of the sulfur in low-sulfur coal, depending on the facility and conditions of service. For the purpose of this study, 10 percent of the overall SO_2 at the stack was assumed to be removed due to the benefits of coal washing.
- The cost of compliance is based on a [redacted]-year period, given that GREC Unit 2's operating projections (subject to change based on multiple factors) is scheduled to run through [redacted]
- The cost of compliance is based on the amount of SO_2 additionally removed from current operations, or 0.198 lb/MMBtu (368 tpy at [redacted]% capacity factor), to the predicted SO_2 removal value for each feasible control technology. The baseline emissions of uncontrolled SO_2 of 0.95 lb/MMBtu is not used, because each control technology would be reducing SO_2 emissions from the current emission rate of 0.198 lb/MMBtu.

Table 4-3 SO_2 Control Technologies Costs and Effectiveness

CONTROL TECHNOLOGY	TOTAL ANNUALIZED COST ($1K/YR)	EMISSIONS REDUCTIONS FROM BASE (TPY)	CONTROL COST EFFECTIVENESS ($/TON)
Coal Washing	$4,671	37	$126,796
DSI	$5,076	236	$21,187
SDA	$39,755	257	$143,321
CDS	$48,363	257	$176,851
WFGD	$44,113	294	$140,109

4.4.2 Factor 2: Time Necessary for Compliance

Based on Black & Veatch's experience, the high-level time durations shown in Table 4-4 can be expected for each of the control technologies. Twelve months was applied as a standard duration for the permitting process, but Black & Veatch's clients have experienced longer times to fully execute the permitting process. There are also concerns how the current pandemic could impact the process, which were not accounted for in this analysis. Additionally, an analysis would need to be conducted to determine how the use of water to support these technologies, and the disposal of the used water, will keep the GREC in compliance with its current permits. Additional permits may be required, and this must also be thoroughly evaluated. The time durations also do not show how activities will occur concurrently, such as certain construction activities that can start while engineering and procurement activities have yet to be completed. Three months of outage-time was also assumed for the CDS and SDA, compared to two for the WFGD, due to demolition of the current SDA system.

Table 4-4 Time Necessary for Compliance in Months

	CW	CDS	DSI	SDA	WFGD
Conceptual Engineering	1	3	2	3	3
Permitting	12	12	12	12	12
Detailed Engineering/Procurement	1	22	8	22	22
Construction	0.5	24	6	21	24
Outage Tie-In	0	3	0	3	2
Startup and Testing	0	3	2	3	3
Total Time	14.5	67	30	64	66

4.4.3 Factor 3: Energy Impacts and Non-Air Quality Environmental Impacts of Compliance

4.4.3.1 Coal Cleaning

Energy Impacts of Compliance

Coal cleaning will consume power provided by diesel generator sets. While this alleviates any demand on the plant's power, this still consumes diesel fuel and generates air emissions.

Non-Air Quality Environmental Impacts of Compliance

Coal cleaning will consume water, but in the past, vendors have used on-site ponds for cleaning the coal, returning the water to the pond. Precise consumption and discharge rates would need to be determined through a detailed analysis of the fuel by a supplier. The facility already operates under an OPDES permit, which requires multiple internal monitoring points. This technology would likely cause increases in some of the monitored parameters such as copper, suspended solids, phosphorous, dissolved solids, and iron.

4.4.3.2 Dry Sorbent Injection

Energy Impacts of Compliance

A DSI system will consume about 214 kW of energy during normal operations at full load. These energy demands are primarily associated with the conveying blowers and mills.

Non-Air Quality Environmental Impacts of Compliance

Other impacts to installing a DSI system include environmental impacts from mining the reagent (Trona) and transporting the reagent to GREC. These activities will require fuel to be burned, dust to be generated, and also consume utilities such as water. The mills in the DSI system will also intermittently consume water for cleaning, on the order of about 800 gallons/day.

Trona is a sodium-based reagent, and it will alter the chemistry of the fly ash that is ultimately collected and landfilled. While sodium is not considered toxic, this study will assume all the future fly ash will have to go to an outside landfill due to the change to the solids' chemistry, particularly due to the water solubility of sodium compounds. The current offtake agreements for beneficial reuse will not be available due to the change in chemistry, and the current landfill facility is not designed to accommodate this additional sodium loading. Any leachate from the solids containing Trona will have to be properly accounted for.

4.4.3.3 Circulating Dry Scrubber

Energy Impacts of Compliance

The CDS will consume about 7.3 MW of energy based on the Control Manual's equations for the similar SDA. However, power consumptions is expected in actuality to be higher due to a higher pressure drop across the absorbers in a CDS versus an SDA. A CDS fluidized bed can be expected to cause about 2 inches of water pressure drop more than an SDA, which would require about 790 kW of additional fan power. Since the pressure drop associated with the Cost Manual's equations are not known, this was not incorporated into the cost estimates.

Non-Air Quality Environmental Impacts of Compliance

A CDS will consume water on the order of 338,000 gal/h, based on the Cost Manual's equations for water consumption by an SDA. While the two technologies are different, the water consumption should be in the same range due to the water sprayed to lower the flue gas temperature and create the reagent from raw pebble lime to hydrated lime.

The generated byproduct of the CDS will be similar to the SDA, so changes to the chemistry of the waste solids should not be a concern.

4.4.3.4 Spray Dryer Absorber

Energy Impacts of Compliance

The SDA will have similar energy impacts to what is already installed at the facility, although the energy usage should be slightly higher due to being designed for more SO_2 removal.

Non-Air Quality Environmental Impacts of Compliance

The SDA will have similar non-air quality impacts to what is already installed at the facility.

4.4.3.5 Wet Flue Gas Desulfurization

Energy Impacts of Compliance

A WFGD will consume on the order of 7.2 MW based on the Cost Manual's equations. This energy demand consists of the additional pressure drop through the vessel, recycle pumps, ball mill slakers, limestone slurry transfer pumps, and other ancillary equipment.

Non-Air Quality Environmental Impacts of Compliance

Two main non-air quality environmental impacts associated with a WFGD are the water consumption and waste generation. The WFGD is expected to consume about 42,000 gallons of water an hour and generate about 8 tons an hour of byproduct. The byproduct can be dewatered and sold as gypsum, or in the absence of a contract, landfilled. In addition to the byproduct, wastewater from the WFGD must be treated before it is released into environment, and the cost of a wastewater treatment center is included in this analysis for this purpose. The wastewater will contain a concentrated level of chlorides and heavy metals that will require remediation.

4.4.4 Factor 4: Remaining Useful Life of the Potentially Affected Source

The prescribed equipment life from the EPA's Cost Manual was not used for the evaluated control systems because GRDA anticipates Unit 2 operating through 2029 (subject to change). While any new system may be able to operate for 30 years, its life will be limited by the facility's operations.

4.5 SUMMARY

Based on the top-down analysis method, the control technologies that are technically feasible for reducing SO_2 emissions will cost anywhere from \$21,000 to \$177,000 per ton SO_2 removed according to Unit 2's current emissions, with the total amount of SO_2 removed ranging from 37 to 294 tons per year. While the threshold for cost effectiveness may vary between states and EPA regions, these values are well above what has typically been considered cost effective by DEQ and would be classified as cost prohibitive. This is compounded by the fact that this analysis was based on Unit 2 having a remaining life of [redacted]-years. By the time the DEQ's SIP is reviewed, accepted, and a control technology agreed upon and installed, the remaining life of the source will be much less than [redacted] years, potentially as short as [redacted] years. This would only further increase the cost per ton values.

Appendix A. Economic Criteria

CRITERIA	VALUE	SOURCE
Capacity Factor Forecast	[redacted]% (next [redacted] years)	GRDA
Makeup Water Cost	$0.85/1000 gallons	GRDA
Electricity	$0.076/kWh	GRDA
Pebble Lime Price	$182.7/ton	GRDA
Economic Life	[redacted] years[1]	GRDA
Landfill Cost (onsite)	$15/ton	GRDA
Limestone Cost	$55/ton	Vendor Quote
Trona Cost	$120/ton	Vendor Quote

Notes:

1) The forecasted economic life is not definitive; present circumstances and expectations suggest the potential value indicated. The increasing levels of renewable generation in the Southwest Power Pool mean that the current conditions for economic dispatch of coal-fired generation are not likely to change.

SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

KEVIN STITT
Governor

January 31, 2022

Mike Bednar
Grand River Dam Authority
PO Box 609
Chouteau, OK 74337-0609

Subject: Additional clarifications on Grand River Dam Authority 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Mr. Bednar:

In a letter dated July 1, 2020, the Oklahoma Department of Environmental Quality (DEQ) identified the Grand River Energy Center located in Mayes County, Oklahoma, as subject to a four-factor reasonable progress analysis under the Regional Haze Rule as part of DEQ's development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

On September 8, 2020, the Grand River Dam Authority (GRDA) submitted its four-factor analysis to DEQ. GRDA included in its response that there were no cost-effective sulfur dioxide (SO_2) control measures available for Unit 2 in addition to considering its remaining useful life. DEQ included these conclusions in its draft Regional Haze SIP for Planning Period 2 that was shared with the Federal Land Managers (FLM) and the U.S. Environmental Protection Agency (EPA). Based on EPA and FLM review of Oklahoma's draft SIP, DEQ requests that GRDA review its four-factor analysis for potential SO_2 control measures and respond to the following questions, which are based on EPA's review of Oklahoma's draft SIP. We understand that much of the requested data/analysis may be gleaned or explained from DEQ's permitting and compliance files, and/or GRDA's full unredacted submittal. However, your response will allow GRDA to document the information that best explains and supports the conclusions of GRDA's four-factor analysis. DEQ intends to continue its analysis in parallel.

1. 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.

2. The four-factor analysis is based on a maximum sulfur loading percentage that is based on the exclusive use of Powder River Basin (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 maximum sulfur loading percentage changed in light of this switch.

3. 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[1], 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.)

4. Some of the control scenarios evaluated in the four-factor analysis include replacing the existing spray dryer absorber (SDA) with a new SDA with higher SO_2 removal efficiency, a circulating dry scrubber (CDS), or wet flue gas desulfurization (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.)

5. Please provide line-item 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).

DEQ respectfully requests that GRDA respond to EPA's questions no later than February 28, 2022. Thank you for your assistance with this matter. Please contact Melanie Foster at 405-702-4218 for any questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

[1] https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

GRAND RIVER ENERGY CENTER
8142 Hwy 412B, PO Box 609
Chouteau OK 74337
918-256-5545, 918-825-7791 Fax

GRDA
Grand River Dam Authority

February 28, 2022

Kendal Stegmann
Air Quality Division
Oklahoma Department of Environmental Quality (DEQ)
707 N. Robinson
Oklahoma City, OK, 73101-1677

Subject: Additional Clarifications on
GRDA Four-Factor Analysis Addendum Response

Dear Ms. Stegmann,

I'm writing in response to the Oklahoma Department of Environmental Quality (DEQ) letter dated January 31, 2022, requesting additional clarifications on the Grand River Dam Authority (GRDA) four-factor analysis on control scenarios under the Clean Air Act Regional Haze Program for the Grand River Energy Center (GREC) in Mayes County. GRDA's original Four-factor analysis was submitted to DEQ on September 10, 2020. Please find below written responses to each of the items identified:

1. **DEQ's Comment:**

   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.

   GRDA's Reply:

   The forecasted capacity factor was based on recent historical operations of GREC from 2016-2020.

2. **DEQ's Comment:**

   The four-factor analysis is based on a maximum sulfur loading percentage that is based on the exclusive use of Powder River Basin (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 maximum sulfur loading percentage changed in light of this switch.

GRAND RIVER ENERGY CENTER
8142 Hwy 412B, PO Box 609
Chouteau OK 74337
918-256-5545, 918-825-7791 Fax

GRDA
Grand River Dam Authority

GRDA's Reply:

The GREC facility is permitted to burn PRB coal, and up to 10% Oklahoma coal. However, for various reasons the facility practice since early 2001 has been to burn 100% PRB coal. The primary drivers in electing to not use Oklahoma coal were that PRB coal has a lower sulfur content, and the Oklahoma coal introduced unnecessary equipment reliability issues. More recently, the closure of Oklahoma coal mines for commercial purposes has entirely removed that option as a consideration for fuel.

3. **DEQ's Comment:**

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.)

GRDA's Reply:

The life of control equipment in the EPA Control Cost Manual, for example, provides a range, e.g., 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 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.

4. **DEQ's Comment:**

Some of the control scenarios evaluated in the four-factor analysis include replacing the existing spray dryer absorber (SDA) with a new SDA with higher SO2 removal efficiency, a circulating dry scrubber (CDS), or wet flue gas desulfurization (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

GRAND RIVER ENERGY CENTER
8142 Hwy 412B, PO Box 609
Chouteau OK 74337
918-256-5545, 918-825-7791 Fax

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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.)

GRDA's Reply:

The scrubber and baghouse casing were commissioned in 1986. GRDA has determined that this equipment has been depreciated and has limited salvage value. As indicated by the submitted documents, the GRDA has contracted with an experienced engineering firm, Black & Veatch Corporation (B&V), to perform the requested four-factor analysis for the GREC facility. B&V has also estimated the GRDA cost to surgically remove the SDA as to not impact the unit's future operation, including the salvage (or recycled) value of materials, at approximately $1,920,000. B&V further suggested that leaving the SDA in place until the unit is retired and could be demolished with the remainder of the unit would be more economical. Further, it was noted that the SDA itself, if it could be removed in its current condition for reuse, does not have a market in the US and would cost GRDA significantly more than the aforementioned surgical demolition option.

5. **DEQ's Comment:**

Please provide line-item 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).

GRDA's Reply:

As previously noted, B&V performed the requested four-factor analysis for the GREC facility. In support of the analysis, commercially sensitive information, such as economic criteria and cost calculations are included in the unredacted version of the report. As such information isn't publicly released by GRDA and is classified as confidential by 27A O.S. § 2-5-105(17), we request that the unredacted version of the report be considered as confidential when and if shared with EPA.

GRAND RIVER ENERGY CENTER
8142 Hwy 412B, PO Box 609
Chouteau OK 74337
918-256-5545, 918-825-7791 Fax

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The line-item cost calculations are shown in the appendices of the unredacted version. We consider the values for variables used in the analysis to be valid.

If you have any questions or require additional information, please don't hesitate to contact me at 918-824-7565 or mike.bednar@grda.com

Best regards,

Michael L Bednar

Michael L. Bednar
Manager of Environmental Compliance

Electronic and mail.

We deliver affordable, reliable ELECTRICITY, with a focus on EFFICIENCY and a commitment to ENVIRONMENTAL STEWARDSHIP.

We are dedicated to ECONOMIC DEVELOPMENT, providing resources and supporting economic growth.

Our EMPLOYEES are our greatest asset in meeting our mission to be an Oklahoma Agency of Excellence.

SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

KEVIN STITT
Governor

Nancy Caperton
Holcim US Inc
14500 CR 1550
Ada, OK 74820

July 1, 2020

Subject: Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Ms. Caperton:

This letter is to inform you that the Oklahoma Department of Environmental Quality (DEQ) has identified the Ada Plant located in Pontotoc County, Oklahoma, as subject to a four-factor reasonable progress analysis under the Regional Haze Rule. DEQ is in the development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

The states in the Central States Air Resources Agencies (CenSARA) organization, which include Oklahoma, contracted with Ramboll US Corporation (Ramboll) to produce a study examining the impact of stationary sources of NOx and SO_2 on each Class 1 area in the central region of the United States. DEQ used a method based on this study to determine which sources may have the greatest potential for contributing to visibility impairment at Oklahoma's Class 1 area: the Wichita Mountains Wilderness Area.

DEQ must develop a long-term strategy to address visibility impairment and make "reasonable" progress toward a goal of no anthropogenic visibility impairment by 2064. The Regional Haze Rule provides four factors (40 CFR §51.308(f)(2)(i)) by which a state must consider potential control measures for the long-term strategy: 1) the cost of compliance; 2) the time necessary for compliance; 3) the energy and non-air quality environmental impacts of compliance; and 4) the remaining useful life of existing sources subject to this requirement.

DEQ requests that Holcim perform a four-factor analysis of all potential control measures for SO_2 on the following emission units at the Ada Plant:

1. Kiln

For any technically feasible control measure, the following information should be provided in detail:

I. Emission reductions achievable by implementation of the measure
    a. Baseline emission rate (lb/hr, lb/MMBTU, etc)
    b. Controlled emission rate (same form as baseline rate)
    c. Control effectiveness (percent reduction expected)
    d. Annual emission reductions expected (ton/year)

SCOTT A. THOMPSON
Executive Director

KEVIN STITT
Governor

II. Time necessary to implement the measure
III. Remaining useful life
    a. Remaining useful life of the control measure, or
    b. The corresponding life of the unit may be used if an enforceable shutdown date of the emission unit is no later than 2028.
IV. Energy and non-air quality environmental impacts of the measure.
    a. Detail any cost of energy, waste disposal, regulatory requirement, etc. incurred with implementation of the control measure.
V. Cost of implementing the measure
    a. Capital costs
    b. Annual operating and maintenance costs
    c. Annualized costs

DEQ respectfully requests that your company submit a report containing the complete 4-factor analysis no later than September 1, 2020. This will allow DEQ to review and identify any cost-effective control measure to be incorporated into the Regional Haze state implementation plan prior to the submission deadline of July 31, 2021.

Please contact DEQ if you have any questions about the method for conducting a 4-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical review required under the Rule.

Thank you for your assistance with this matter. Please contact Cooper Garbe at 405-702-4169 or Melanie Foster at 405-702-4218 for your questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

Holcim
Holcim (US) Inc.
14500 CR 1550
Ada, Oklahoma 74820
Phone 580 421-8900
Fax 580 436-3273
www.lafargeholcim.us

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VIA E-MAIL AND CERTIFIED MAIL

July 27, 2020

Cooper Garbe
707 North Robinson
P.O. Box 1677
Oklahoma City, OK 73101-1677
cooper.garbe@deq.ok.gov

RE: DEQ's request for regional haze four-factor analysis
Holcim US Inc. – Ada Plant

Dear Mr. Garbe,

In accordance with Ms. Kendal Stegmann's July 1, 2020 letter ("the DEQ letter"), this response is provided to you with a copy to Ms. Melanie Foster.

The DEQ letter requests that Holcim perform a four-factor analysis of all potential control measures for SO_2 emissions from the Kiln at its Ada Plant. It goes into detail regarding what technical, operational, and economic information Holcim should provide. Holcim understands that the Ada Plant Kiln was selected by the DEQ based on a source-screening analysis that used a metric known as *% EWRT*Q/d*, and that the full results of that analysis are summarized in a June 17, 2020 presentation.[1]

Based on the DEQ's presentation (slide 60), its analysis of the Ada Plant's SO_2 emissions resulted in a *% EWRT*Q/d* of 1.43 %, which is greater than the DEQ's threshold of 0.5 %.[2] The presentation also shows a *Q/d* value of 12.00789. As confirmed during your July 16, 2020 conversation and subsequent e-mail with Mr. Jeremy Jewell of Trinity Consultants, *Q/d* is the emission rate of SO_2 in tons per year (tpy), *Q*, divided by the distance from the Ada Plant to the Wichita Mountains Class I area in kilometers (km), *d*. Per your July 16, 2020 e-mail to Mr. Jewell, the DEQ used calendar year 2016 emissions, 2,203 tpy, as the basis for *Q*, and a *d* value of 183 km.

The use of 2016 emissions as the basis of the DEQ's analysis renders the results invalid because the Ada Plant no longer operates the kilns that were in operation in 2016. The old kilns were dismantled in 2016/17, and a new kiln began operating on February 14, 2017. In other words, the request is for an analysis on emission units that no longer exist.

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[1]https://www.deq.ok.gov/wp-content/uploads/air-division/AQAC_2020_JUN_Presentations_revised.pdf (slides 55 – 67).

[2] The Ada Plant's NO_x emissions were also evaluated. The result, as presented, was a % EWRT*Q/d of 0.38 %, which is below the DEQ threshold.

Moreover, the SO_2 emissions from the new kiln are substantially less than the emissions from the old kilns: 45 tpy in 2017, 68 tpy in 2018, and 84 tpy in 2019. If the DEQ has selected or reviewed any of these more recent and representative operating year Ada would have fallen well below screening criteria. Using the maximum of the annual emission rates for the new kiln, the *Q/d* value for the Ada Plant becomes 0.46, or 26 times less than the DEQ's presented *Q/d* value. According to Mr. Jewell, the *% EWRT*Q/d* value would not necessarily decrease by the same amount, but it is reasonable to conclude that it would decrease to less than the 0.5 % threshold set by the DEQ. As such, the DEQ's source-screening method excludes the Ada Plant, in its current configuration, from the four-factor analysis requirement.

For these reasons – that the DEQ's request pertains to non-existent emission units and that the Ada Plant screens out of the requirement based on its current emissions – Holcim requests that the DEQ formally rescind its July 1, 2020 request for a four-factor analysis for the Ada Plant.

Thank you for your consideration of this request. Please contact Mr. Mark Miller at (972) 221-4646 or Mr. Jeremy Jewell at (918) 622-7111 ext. 1 if you have any questions regarding this request.

Sincerely,

Nancy Caperton

Nancy Caperton
Ada Plant Manager

ec: Melanie Foster (melanie.foster@deq.ok.gov)
Mark Miller (mark.miller@aggregate-us.com)
Jeremy Jewell (jjewell@trinityconsultants.com)

Sunni Stephenson
Mustang Gas Products
9800 N. Oklahoma Ave.
Oklahoma City, OK 73114

July 1, 2020

Subject: Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Ms. Stephenson:

This letter is to inform you that the Oklahoma Department of Environmental Quality (DEQ) has identified the Binger Gas Plant located in Caddo County, Oklahoma, as subject to a four-factor reasonable progress analysis under the Regional Haze Rule. DEQ is in the development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

The states in the Central States Air Resources Agencies (CenSARA) organization, which include Oklahoma, contracted with Ramboll US Corporation (Ramboll) to produce a study examining the impact of stationary sources of NOx and SO_2 on each Class 1 area in the central region of the United States. DEQ used a method based on this study to determine which sources may have the greatest potential for contributing to visibility impairment at Oklahoma's Class 1 area: the Wichita Mountains Wilderness Area.

DEQ must develop a long-term strategy to address visibility impairment and make "reasonable" progress toward a goal of no anthropogenic visibility impairment by 2064. The Regional Haze Rule provides four factors (40 CFR §51.308(f)(2)(i)) by which a state must consider potential control measures for the long-term strategy: 1) the cost of compliance; 2) the time necessary for compliance; 3) the energy and non-air quality environmental impacts of compliance; and 4) the remaining useful life of existing sources subject to this requirement.

DEQ requests that Mustang Gas Products perform a four-factor analysis of all potential control measures for NOx on all fuel-burning equipment with a heat input of 50 MMBTU/hr or more including but not limited to the following emission units at the Binger Gas Plant:

1. CM-2322; White-Superior 12G825
2. CM-2323; Waukesha L7042GSI
3. CM-2325; Waukesha L7042GSI

For any technically feasible control measure, the following information should be provided in detail:

I. Emission reductions achievable by implementation of the measure
    a. Baseline emission rate (lb/hr, lb/MMBTU, etc)

b. Controlled emission rate (same form as baseline rate)
c. Control effectiveness (percent reduction expected)
d. Annual emission reductions expected (ton/year)

II. Time necessary to implement the measure

III. Remaining useful life
a. Remaining useful life of the control measure, or
b. The corresponding life of the unit may be used if an enforceable shutdown date of the emission unit is no later than 2028.

IV. Energy and non-air quality environmental impacts of the measure.
a. Detail any cost of energy, waste disposal, regulatory requirement, etc. incurred with implementation of the control measure.

V. Cost of implementing the measure
a. Capital costs
b. Annual operating and maintenance costs
c. Annualized costs

DEQ respectfully requests that your company submit a report containing the complete 4-factor analysis no later than September 1, 2020. This will allow DEQ to review and identify any cost-effective control measure to be incorporated into the Regional Haze state implementation plan prior to the submission deadline of July 31, 2021.

Please contact DEQ if you have any questions about the method for conducting a 4-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical review required under the Rule.

Thank you for your assistance with this matter. Please contact Cooper Garbe at 405-702-4169 or Melanie Foster at 405-702-4218 for your questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

September 1, 2020

Ms. Kendal Stegmann
Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

SUBJECT: Response to 4-Factor Analysis on Control Scenarios Request
Clean Air Act Regional Haze Program
Binger Gas Plant
Permit No. 2015-1174-TVR3 (M-1)
Mustang Gas Products, LLC

Dear Ms. Stegmann:

Altamira-US, LLC (Altamira) on behalf of Mustang Gas Products, LLC (Mustang) in response to the request from the Oklahoma Department of Environmental Quality (ODEQ) received on July 1, 2020 is submitting a four-factor analysis of all potential control measures for nitrogen oxide (NOx) on all fuel-burning equipment with a heat input of 50 Million British Thermal Units Per Hour (MMBTU/hr) or more located at the Binger Gas Plant (Facility). This response is being provided prior to the deadline of September 1, 2020 as specified in the request.

Regulatory Requirement

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by remedying existing, anthropogenic visibility impairment and preventing future impairments. On July 1, 1999, the U.S. Environmental Protection Agency (EPA) published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across the United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977. In accordance with the RHR the ODEQ has set goals which provide for reasonable progress towards achieving natural visibility conditions at Oklahoma's Class 1 area, the Wichita Mountains Wilderness Area.

Introduction

The Facility consists of four (4) natural gas-fired four-stroke rich-burn (4SRB) engines with a heat input of 50 MMBTU/hr or more. Therefore, the engines are the only sources at the Facility which meet the applicable criteria of the four-factor analysis. As requested, this analysis provides achievable emission reductions, a timeframe for implementation, the remaining useful life of the equipment, all non-air-quality environmental impacts, and the cost of implementation for the reduction of NOx at the Facility.

Table 1. Equipment Summary

Emission Unit ID	Emission Unit	Manufacture Date	Horsepower
CM-2322	White Superior 12G825	1976	1,200
CM-2323	Waukesha L7042 GSI	1975	1,232
CM-2324	Waukesha L7042 GSI	2019	1,232
CM-2325	Waukesha L7042 GSI	1975	1,232

Potential NOx Controls for 4SRB Engines

A review of the RACT/BACT/LAER clearinghouse (RBLC) shows NOx reduction in 4SRB natural gas-fired engines can be accomplished by three general methods.

1. Operational control methods and good combustion practices.
2. Combustion control techniques such as reducing combustion temperatures and introducing catalysts to limit the formation of NOx.
3. The construction and operation of post combustion control technologies.

The following NOx controls for 4SRB engines were identified based on principles of control technologies and engineering experience for combustion units. The technical feasibility and anticipated performance of each control is provided below.

Good Combustion Practices

NOx emissions are caused by the oxidation of nitrogen during fuel combustion as a result of high temperatures and an insufficient air to fuel mixture within the cylinders. By following the Environmental Protection Agency's (EPA) "Good Working Practices" guidance document, good combustion practices can be achieved and maintained. Through means of experience, engineering controls, best management practices, and by operating the engines in accordance with manufacturer specifications, Mustang ensures the engines operate as intended with the lowest potential NOx emissions. Further, by means of routine inspections, regular maintenance, and conducting overhauls as needed the engines employ good combustion practices. As some of these conditions are required by specific conditions within the permit as well as federal regulations, no further assessment of these control practices are included in this report.

Clean Burn Technology

Clean burn technology (CBT) is a process of adjusting the fuel to air ratio mixture during combustion to obtain a desired effect. This is often done through the installation of an air fuel ratio controller (AFRC) which allows the operator to adjust the combustion mixture to a more desirable ratio. Engines with a higher air to fuel ratio operate with lower combustion temperatures and therefore lower NOx emissions. However, because rich burn engines are designed to operate close to a stoichiometric air to fuel ratio of 16:1, adding an AFRC can be problematic. Manufacturer performance curves have shown when air to fuel ratios exceed 18:1 the combustion temperature, horsepower, and NOx emissions of the engine begin to decrease. As the air ratio continues to increase in relation to the fuel, modifications such as turbochargers and pre-combustion chambers are required to promote stable combustion within the cylinders to aid in the ignition of the lean fuel mixture. The installations of such devices on the units CM-2322 and CM-2323 would be considered a modification under 40 CFR Part 60 for New Source Performance Standards (NSPS) opening the Facility up to additional testing requirements and further accrued cost. The most restricting issue with this type of control method for 4SRB engines is they cannot operate for extended periods of time with an air to fuel ratio higher than 20:1 without experiencing a loss of power. As these engines are permitted to operate 24/7 this presents a very large operational drawback. Due to the cost associated with retrofitting the engines, limited operational flexibility, and an increase in regulatory requirements, Mustang does not believe it is feasible to control the engines using an AFRC.

Selective Catalytic Reduction

A Selective Catalytic Reduction (SCR) is the process of injecting a nitrogen-based reagent, such as ammonia or urea, into the exhaust stream of an engine to control the emission of NOx. The injected reagent reacts selectively with the NOx to produce molecular nitrogen (N2) and water (H2O). An SCR system includes the catalyst, catalyst housing, reagent storage tank, reagent injector, reagent pump, pressure regulator, and an electronic control system. The electronic controls regulate the amount of reagent injected based on the engine load, speed, and temperature. However, when controlling a 4SRB engine with an SCR the effectiveness of the catalyst can decrease over time and potentially become ineffective. Often a portion of the ammonia is not completely consumed during the reaction and is expelled via the exhaust stream which is referred to as an ammonia slip. Unreacted ammonia in the exhaust will often form ammonium sulfates which can plug or corrode downstream equipment. If the resulting particulates become over abundant the catalyst can become encumbered and may require the application of a soot blower. Additionally, for an SCR system to function properly, the exhaust gas must be within an optimal temperature range of 450 and 850 °F. The temperature however can be altered by the type of catalyst used which if allowed to increase beyond the standard, NOx and ammonia will pass through the catalyst unreacted. As previously mentioned 4SRB engines are built to operate close to a stochiometric air-fuel ratio which causes the exhaust oxygen levels for rich-burn engines to be relatively low. For this reason, 4SRB engines are not typically controlled using an SCR as demonstrated in the attached RBLC table. In addition, AP-42 Section 3.2 does not list an SCR as an available control technology. Due to the number of issues with controlling a 4SRB engine with an SCR, Mustang does not believe this type of control is feasible.

Non-Selective Catalytic Reduction

A Non-Selective Catalytic Reduction (NSCR) is a control technique that uses residual hydrocarbons and carbon monoxide (CO) in engine exhaust as a reducing agent for NOx. In an NSCR system, hydrocarbons and CO are oxidized by oxygen and NOx. The excess hydrocarbons, CO and NOx pass over a catalyst typically made of platinum, rhodium, or palladium, that oxidizes the excess hydrocarbons and converts NOx to nitrogen (N2). This technique does not require additional reagents to be injected because the unburned hydrocarbons in the engine exhaust are used as the reductant. The applications of an NSCR is limited to engines with normal exhaust oxygen levels of 4% or less. This includes naturally aspirated 4SRB engines and some turbocharged 4SRB engines. In order to achieve effective NOx reduction, the engine may need to be run with a richer fuel adjustment than normal, resulting in an exhaust excess oxygen level closer to 1%. The exhaust oxygen levels for 4SRB engines are sufficiently low to support the reactions and therefore, this technology is routinely used to control NOx emissions from rich burn engines. Furthermore, AP-42 Section 3.2 does list a NSCR as a potential control of NOx emissions from 4SRB engines. For these reasons, it has been determined that this method of NOx control is feasible for the 4SRB engines at the Facility.

Time necessary to implement the measure

As the engines are located at a Title V Major Source the implementation of controls will establish additional regulatory requirements, particularly compliance assurance monitoring (CAM). Due to operational and permitting time restraints, Mustang estimates it will take approximately 2 years to budget, design, procure, authorize, and install the NSCR control equipment at the Facility.

Remaining Useful Life

The estimated useful life of the NSCR equipment is 20 years, based on default values from the EPA Air Pollution Control Cost Manual. However, the catalyst beds are estimated to require changing every 2 years based on operational hours and best engineering practices.

Energy and non-air quality environmental impacts of the measure

There are no anticipated unique or site-specific energy or non-air impacts imposed by continuing to use good combustion practices and fuel selection. The implementation of an NSCR on the 4SRB engine would result in requiring to periodically replace the catalyst, dispose of the catalyst, and will also require additional energy consumption.

Cost of implementing the measure

Based on prior knowledge of the equipment, Mustang has estimated the initial capital costs associated with purchasing the controls, installation, downtime, and compliance requirements. In addition, annual costs associated with incurred maintenance and operating requirements for the project have been incorporated. This cost estimate assumes that the NSCR will reduce NOx emissions to an outlet concentration of 3.00 g/hp-hr based on an engine test of a similar engine which is controlled by a NSCR. Cost effectiveness for each engine's control option is summarized in Table 2. To calculate the emission reductions, Mustang compared the 2019 Emission Inventory (EI) data to the maximum PTE emission rate of the equipment post-control. The Total Annual Cost was then divided by the Emission Reduction to come up with a Cost Effectiveness ($/ton) amount.

Table 2. Cost Analysis Summary

Control Equipment	Unit	Capital Cost ($)	Total Annual Cost ($)	Emission Reduction (TPY)	Cost Effectiveness ($/ton)
Non-Selective Catalytic Reduction	CM-2322	40,250	4,250	172.24	24.67
	CM-2323	16,250	4,250	177.10	24.00

Analysis Summary

Based on a comprehensive evaluation of available control technologies for 4SRB engines, Mustang has determined that an NSCR in conjunction with good combustion practices will be best suited to control engines CM-2322 and CM-2323 at the Facility. As these engines are currently already retrofitted with a single catalyst housing, the capital cost for these engines will be accrued through the purchase and installation of the elements along with the associated cost of maintaining compliance. However, due to the unforeseen nature of controlling these historically uncontrolled engines, a second catalyst and housing has been accounted for in the capitol cost for CM-2322. As required by permit No. 2015-1174-TVR3 (M-1), engines CM-2324 and CM-2325 are already operated with properly functioning NSCRs as well as with good combustion practices. A 90% control efficiency has already been demonstrated based on recent Portable Emissions Analyzer (PEA) testing in comparison to the uncontrolled manufactured specifications for these engines. Based on these findings, Mustang believes adding further controls to these engines would be uneconomical and unnecessary.

If you have any questions or need additional information, please contact me at (405) 748-9488.

Sincerely,
Mustang Gas Products, LLC

Sunni Stephenson
EHS Environmental Coordinator

cc: Mr. Steve Hoppe, Mustang Gas Products, LLC
Mr. Camren McMillan, Altamira-US, LLC

Enclosures:
Appendix 1. Cost Analysis Breakdown
Appendix 2. RBLC Tables

Cost Analysis Breakdown

NOX REDUCTION EMISSIONS SUMMARY
BINGER GAS PLANT
MUSTANG GAS PRODUCTS, LLC

Emissions Source	Emission Point Identification	2019 Emission Inventory NO_x (lb/hr)	2019 Emission Inventory NO_x (T/yr)	Controlled Emissions NO_x (lb/hr)	Controlled Emissions NO_x (T/yr)	Emission Reduction NOx (lb/hr)	Emission Reduction NOx (T/yr)
White Superior 12G825 Compressor Engine (1,200 Hp)	CM-2322	47.26	207.00	7.94	34.76	39.32	172.24
Waukesha L7042GSI Compressor Engine (1,232 Hp)	CM-2323	48.58	212.79	8.15	35.69	40.43	177.10
	Totals	**109.74**	**480.58**	**17.89**	**78.36**	**79.76**	**349.35**

COST ANALYSIS BREAKDOWN
BINGER GAS PLANT
MUSTANG GAS PRODUCTS, LLC

Emissions Source	Emission Point Identification	Cost per Catalyst [1]	Cost per Housing	Installation Cost	Cost due to downtime	Cost due to CAM	Total Cost
White Superior 12G825 Compressor Engine (1,200 Hp)	CM-2322	$6,000	$18,000	$3,000	$1,500	$5,750	$40,250
Waukesha L7042GSI Compressor Engine (1,232 Hp)	CM-2323	$6,000	--	$3,000	$1,500	$5,750	$16,250

Emission Source	Emission Point Identification	Annual Cost to PEA Test	Annual Cost due to CAM	Total Annual Cost	Cost Effectiveness
White Superior 12G825 Compressor Engine (1,200 Hp)	CM-2322	$1,500	$2,750	$4,250	$24.67
Waukesha L7042GSI Compressor Engine (1,232 Hp)	CM-2323	$1,500	$2,750	$4,250	$24.00

1. It is conservatively assumed engine CM-2322 will require two catalysts to meet the proposed NOx reduction.

RBLC Tables

4SRB ENGINES					
RBLC ID	**Facility Name**	**Process Name**	**Throughput**	**Pollutant**	**Control Method**
KY-0110	Nucor Steel Branding	Tempering Furnace Rolls Emergency Generator	636 HP	NOx	Good Combustion and Operating Practices
MI-0440	Michigan State University	FGENGINES	16500 HP	NOx	Selective catalytic reduction
MI-0441	LBWL-Erickson Station	EUEMGNG1 -- A 1500 HP natural gas fueled emergency engine	1500 HP	NOx	Burn natural gas and be NSPS compliant
MI-0420	DTE Gas Company -- Milford Compressor Station	EUN_EM_GEN	225 H/YR	NOx	Low Nox design and goo combustion practices.
CA-1240	Gold Coast Packing	Internal Combustion Engine	881 bhp	NOx	SCR catalyst-Urea injection
LA-0292	Holbrook Compressor Station	Waukesha 16V-275GL Compressor Engine Nos. 1-12	5000 HP	NOx	Lean-burn combustion, burn natural gas, proper combustion techniques
TX-0755	Ramsey Gas Plant	Internal combustion Engines	2016149 MMBtu/yr	NOx	Ultra-Lean burn engines firing natural gas
LA-0287	Alexandria Compressor Station	Emergency Generator Reciprocating Engine	1175 HP	NOx	Good combustion practices, burn natural gas fuel
PA-0302	Clermont Compressor Station	Spark Ignited 4 Stroke Rich Burn Engine (7 units)	0	NOx	NSCR
KS-0035	Lacey Randal Generation Facility	Spark ignition four stroke lean burn reciprocating internal combustion engine (RICE) electric generating units	12526 BHP	NOx	Selective catalytic reduction (SCR) system and oxidation catalyst
TX-0692	Red Gate Power Plant	(12) reciprocating internal combustion engines	18 MW	NOx	Selective Catalytic Reduction (SCR)
MI-0412	Holland Board of Public Works - East 5th Street	Emergency Engine -- natural gas (EUNGENGINE)	1000 kW	NOx	Good combustion practices
TX-0680	Sonora Gas Plant	Recompression compressor engine	1380 HP	NOx	ultra-lean burn technology
IN-0167	Magnetation LLC	Emergency Generator	620 HP	NOx	Natural gas and good combustion practices
OK-0153	Rose Valley Plant	Emergency Generators 2,889-HP CAT G3520C IM	2,889 HP	NOx	Lean-burn combustion
OK-0148	Buffalo Creek Processing Plant	Large Internal combustion Engines	2370 HP	NOx	Ultra lean burn
OK-0148	Buffalo Creek Processing Plant	Large Internal combustion Engines	1775 HP	NOx	Ultra lean burn
PA-0303	NATL Fuel Gas Supply/Ellisburg Station	Emergency Generator Set, Rich Burn, 850 BHP	850 BHP	NOx	Miratech model IQ-24-10-ECI NSCR system
LA-0257	Sabine Pass LNG Terminal	Generator Engines (2)	2012 HP	NOx	Comply with 40 CFR 60 Subpart JJJJ
CA-1222	Kyocera America Inc.	ICE: Spark Ignition	2889 BHP	NOx	SCR with process control Nox monitor
CA-1192	Avenal Energy Project	Emergency IC Engine	550 KW	NOx	SCR, operation limit of 50 Hrs/yr
MI-0393	Ray Compressor Station	Five spark ignition internal combustion engines	32 MMBTU/H	NOx	low emission design and good combustion practices

SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

KEVIN STITT
Governor

January 31, 2022

Sunni Stephenson
Mustang Gas Products
9800 N. Oklahoma Ave.
Oklahoma City, OK 73114

Subject: Additional clarifications on Mustang's Binger Gas Plant 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Ms. Stephenson:

In a letter dated July 1, 2020, the Oklahoma Department of Environmental Quality (DEQ) identified the Binger Gas Plant located in Caddo County, Oklahoma, as subject to a four-factor reasonable progress analysis under the Regional Haze Rule as part of DEQ's development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

On September 1, 2020, Mustang submitted its four-factor analysis to DEQ. Mustang included in its response that non-selective catalytic reduction (NSCR) is the most cost-effective nitrogen oxides (NO_x) control measure available for the engines. Three engines already have NSCR installed, and Mustang committed to applying for installation of NSCR on engine CM-2322 as well. DEQ included these conclusions in its draft Regional Haze SIP for Planning Period 2 that was shared with the Federal Land Managers (FLM) and the U.S. Environmental Protection Agency (EPA) for their review and comment. DEQ requests that Mustang review its four-factor analysis for potential NO_x control measures and respond to the following questions, which are based on EPA's review of Oklahoma's draft SIP. We understand that some of the requested data/analysis may be gleaned or explained from DEQ's permitting and compliance files, and/or Mustang's submittal. However, your response will allow Mustang to document the information that best explains and supports the conclusions of Mustang’s four-factor analysis. DEQ intends to continue its analysis in parallel.

1. 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.

2. Additional discussion is needed for the elimination of selective catalytic reduction (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?

3. The company compared actual 2019 emissions inventory data to the maximum potential to emit (PTE) rate to calculate the emission reductions for the NSCR control scenario. Please explain how the maximum PTE rate of the units was estimated/calculated for the NSCR control scenario.

4. 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.

DEQ respectfully requests that Mustang respond to EPA's questions no later than February 28, 2022. Thank you for your assistance with this matter. Please contact Melanie Foster at 405-702-4218 for any questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

Mustang Gas Products, LLC
A Subsidiary of Mustang Fuel Corporation

9800 North Oklahoma Avenue
Oklahoma City, OK 73114-7406

O: 405-748-9400
F: 405-748-9200

1-800-332-9400
(out of state)

February 24, 2022

Ms. Kendal Stegmann
Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

SUBJECT: Response to 4-Factor Analysis on Control Scenarios Request
Clean Air Act Regional Haze Program
Binger Gas Plant
Permit No. 2015-1174-TVR3 (M-1)
Mustang Gas Products, LLC

Dear Ms. Stegmann:

Mustang Gas Products, LLC ("Mustang") in response to the four-factor analysis additional clarification request from the Oklahoma Department of Environmental Quality ("ODEQ") received on January 31, 2022 is submitting the enclosed information for the Binger Gas Plant ("Facility"). This response is being provided prior to the deadline of February 28, 2022 as specified in the request.

1. *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.*

Mustang retracts the original statement included in the initial submittal. After further discussion with field operations and engineering it was determined Mustang has historically installed AFRCs on Mustang's controlled engines and will continue to do so going forward. In addition, Mustang has confirmed engines CM-2323, CM-2324, and CM-2325 are equipped with an AFRC as represented in Permit No. 2020-0500-TVR4, which is currently in review with the DEQ. Mustang agrees the installation of an AFRC is a viable option for controlling these engines.

2. *Additional discussion is needed for the elimination of selective catalytic reduction ("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 NOX 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?*

As covered in the previous submittal and discussed in AP-42 Section 3.2 Natural Gas-fired Engines, an SCR is a type of precombustion technology typically used to control a lean burn engine. As the engines located at Binger are naturally aspirated rich burn engines, these controls are not compatible. For an SCR to work properly the exhaust temperature of the controlled engine must be maintained in the range of 450 to 850 degrees Fahrenheit (F). Per the manufacturer specifications for these engines, the exhaust temperatures are rated above the recommended threshold for an SCR. Mustang notes the engines listed in the RACT/BACT/LAER clearinghouse all appear to be lean burn engines and therefore are not similar engines. Accordingly, the control method is not a viable option for these engines.

3. *The company compared actual 2019 emissions inventory data to the maximum potential to emit ("PTE") rate to calculate the emission reductions for the NSCR control scenario. Please explain how the maximum PTE rate of the units was estimated/calculated for the NSCR control scenario.*

The maximum PTE controlled rates were calculated using the following conditions. Please note while Mustang agrees the installation of a AFRC and NSCR will result in a 90% control of emissions, Mustang would like to maintain more conservative emission factors in the permit to prevent any future compliance issues. Mustang notes there have been changes made at the facility since the submittal of the original analysis. An AFRC and NSCR were installed on engine CM-2323, as demonstrated in the pending Title V Permit Renewal No. 2020-0500-TVR4.

Unit	Permitted Emission Factor (g/hp-hr)	Percent Reduction (%)	Proposed Permit Emission Limit (g/hp-hr)	Proposed Potential Emission Limit (TPY)
CM-2322	18.00	56	9.00	104.29
CM-2323	18.00	83	3.00	35.69

4. *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.*

Please see the below table for a comparison of the engine uncontrolled emissions and the quarterly Portable Emissions Analyzer test results for engines CM-2324 and CM-2325 which demonstrate an emission reduction of 90% or greater.

Unit	Uncontrolled Emission Factor (g/hp-hr)	Uncontrolled Emissions (lb/hr)	2021 Q2 (NOx lb/hr)	2021 Q3 (NOx lb/hr)	2021 Q4 (NOx lb/hr)	2022 Q1 (NOx lb/hr)
CM-2324	18.00	48.89	4.403	2.756	0.498	2.284
CM-2325	18.00	48.89	2.416	4.798	4.090	3.784

According to the most recent modeled predictions based on observation data in the Wichita Mountains, Oklahoma is ahead of schedule for the reduction of regional haze. Please see the respective chart included in Appendix A.

If you have any questions or need additional information, please contact me at (405) 748-9488.

Sincerely,
Mustang Gas Products, LLC

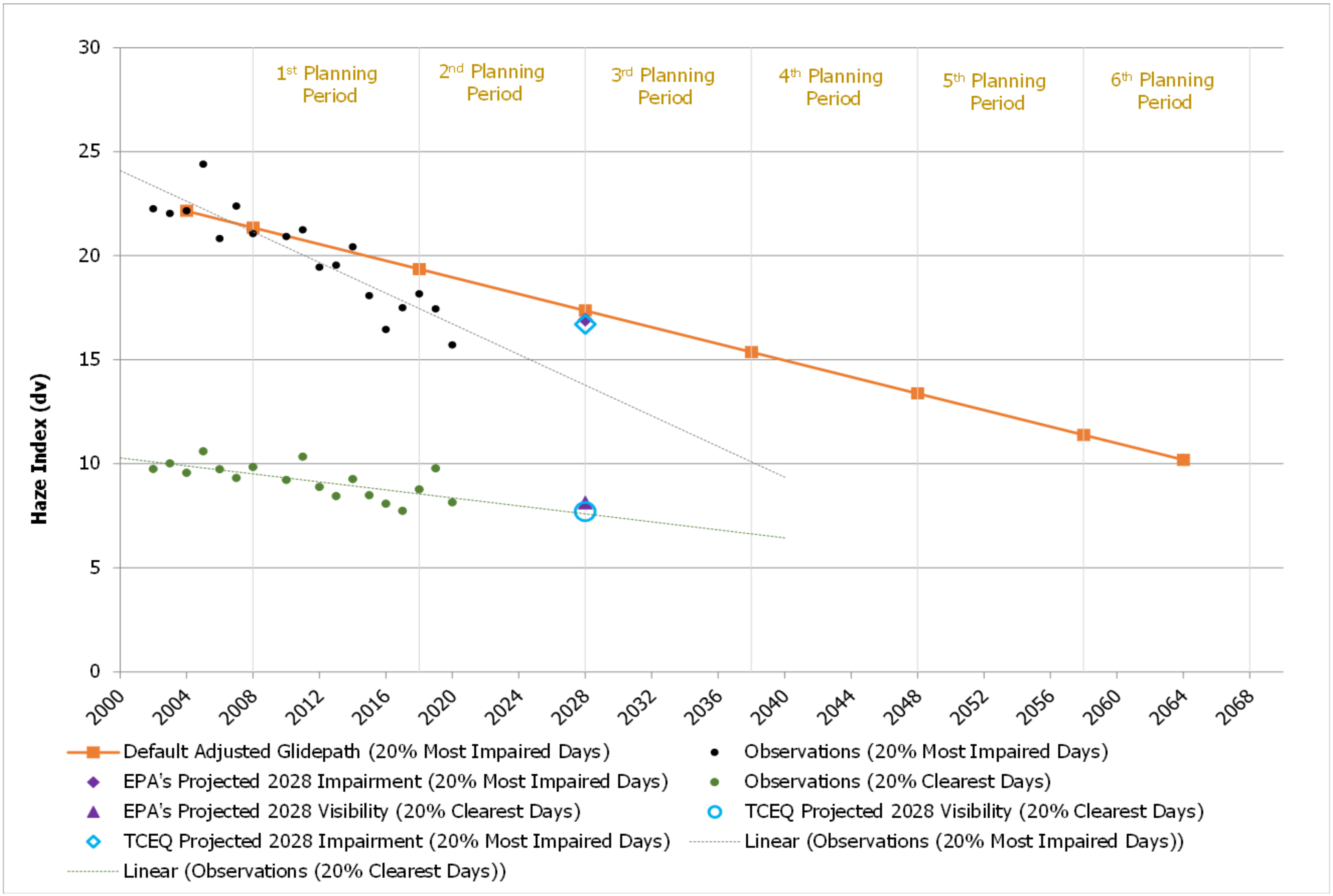
Sunni Stephenson
EHS Environmental Coordinator

cc: Mr. Steve Hoppe, Mustang Gas Products, LLC
Mr. Camren McMillan, Altamira-US, LLC

Enclosures:
Appendix 1. Area Visibility Observation Data Comparison

Area Visibility Observation Data Comparison

Wichita Mountain Class Area Visibility Observation Data for 2002 – 2020 and Modeled Predictions for 2028 Compared to the EPA Glidepath



SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

KEVIN STITT
Governor

Robert Benham
Oklahoma Gas & Electric
PO Box 321 MC610
Oklahoma City, OK 73102-0321

July 1, 2020

Subject: Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Mr. Benham:

This letter is to inform you that the Oklahoma Department of Environmental Quality (DEQ) has identified Oklahoma Gas & Electric's (OGE's) Horseshoe Lake Generating Station and Mustang Generating Station as facilities subject to a four-factor reasonable progress analysis under the Regional Haze Rule. DEQ is in the development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

The members of the Central States Air Resources Agencies (CenSARA) organization, which include Oklahoma, contracted with Ramboll US Corporation (Ramboll) to produce a study examining the impact of stationary sources of NOx and SO_2 on each Class 1 area in the central region of the United States. DEQ used a method based on this study to determine which sources may have the greatest potential for contributing to visibility impairment at Oklahoma's Class 1 area: the Wichita Mountains Wilderness Area.

DEQ must develop a long-term strategy to address visibility impairment and make "reasonable" progress toward a goal of no anthropogenic visibility impairment by 2064. The Regional Haze Rule provides four factors (40 CFR §51.308(f)(2)(i)) by which a state must consider potential control measures for the long-term strategy: 1) the cost of compliance; 2) the time necessary for compliance; 3) the energy and non-air quality environmental impacts of compliance; and 4) the remaining useful life of existing sources subject to this requirement.

DEQ requests that OGE perform a four-factor analysis of all potential control measures for NOx on all fuel-burning equipment with a heat input of 50 MMBTU/hr or more including but not limited to the following emission units:

<u>Horseshoe Lake Generating Station</u>

1. Electric Generation Unit 6
2. Electric Generation Unit 7
3. Electric Generation Unit 8
4. Unit 9 Turbine
5. Unit 10 Turbine

Mustang Generating Station

1. Electric Generating Unit 3
2. Electric Generating Unit 4

For any technically feasible control measure, the following information should be provided in detail:

I. Emission reductions achievable by implementation of the measure
   a. Baseline emission rate (lb/hr, lb/MMBTU, etc)
   b. Controlled emission rate (same form as baseline rate)
   c. Control effectiveness (percent reduction expected)
   d. Annual emission reductions expected (ton/year)
II. Time necessary to implement the measure
III. Remaining useful life
   a. Remaining useful life of the control measure, or
   b. The corresponding life of the unit may be used if an enforceable shutdown date of the emission unit is no later than 2028.
IV. Energy and non-air quality environmental impacts of the measure.
   a. Detail any cost of energy, waste disposal, regulatory requirement, etc. incurred with implementation of the control measure.
V. Cost of implementing the measure
   a. Capital costs
   b. Annual operating and maintenance costs
   c. Annualized costs

DEQ respectfully requests that your company submit a report containing the complete 4-factor analysis no later than September 1, 2020. This will allow DEQ to review and identify any cost-effective control measure to be incorporated into the Regional Haze state implementation plan prior to the submission deadline of July 31, 2021.

Please contact DEQ if you have any questions about the method for conducting a 4-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical review required under the Rule.

Thank you for your assistance with this matter. Please contact Cooper Garbe at 405-702-4169 or Melanie Foster at 405-702-4218 for your questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

REGIONAL HAZE FOUR-FACTOR REASONABLE PROGRESS ANALYSIS

Oklahoma Gas and Electric - OGE Energy Corp.
Horseshoe Lake Generating Station

Prepared By:

Jeremy Jewell – Principal Consultant
Jeremy Townley – Managing Consultant
Robin Hamman – Consultant

TRINITY CONSULTANTS
5801 E. 41st St.
Suite 450
Tulsa, OK 74135
(918) 622-7111

September 14, 2020
Updated September 29, 2020

Project 203701.0015

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1. INTRODUCTION

Trinity Consultants (Trinity) prepared this report on behalf of Oklahoma Gas and Electric Company - OGE Energy Corp. (OG&E) in response to the July 1, 2020 "Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program" (the July 1, 2020 request) from the Oklahoma Department of Environmental Quality (the ODEQ) to OG&E's Horseshoe Lake Generating Station (Horseshoe Lake) located in Harrah, Oklahoma (OK).

OG&E operates five (5) electric generating units (EGUs) at Horseshoe Lake under the authority of ODEQ Part 70 Operating Permit No. 2018-1482-TVR3 ("the permit"): Unit 6, Unit 7, Unit 8, Unit 9, and Unit 10.

Unit 6 is a Babcock & Wilcox dry-bottom wall-firing boiler that was installed in 1958. It has a heat input capacity of 1,740 million British thermal units per hour (MMBtu/hr). It burns primarily natural gas and secondarily (but with no restrictions in the permit) #2 and #6 fuel oils and company-generated non-hazardous materials including, but not limited to, used oil, used solvents, corrosion inhibitors, on-line cleaning solution, and antifreeze.

Unit 7 is a Babcock & Wilcox boiler that was installed in 1963. It has a heat input capacity of 2,379 MMBtu/hr. It burns primarily natural gas and secondarily (but with no restrictions in the permit) #2 and #6 fuel oils and company-generated non-hazardous materials including, but not limited to, used oil, used solvents, corrosion inhibitors, on-line cleaning solution, and antifreeze. Unit 7 was previously a combined-cycle unit with a gas-fired turbine. The gas turbine was retired in 2015 (it stopped operating in January 2015), and it was removed from the permit in March 2017.

Unit 8 is a Combustion Engineering tangential firing boiler that was installed in 1968. It has a heat input capacity of 4,150 MMBtu/hr. It burns natural gas only.

Units 7 and 8 were BART-eligible units during the development of the initial state implementation plan (SIP) for the Regional Haze Program. Both the state and EPA approved a determination that these units did not cause or contribute to visibility impairment in any Class I area. At a minimum, that determination should still apply to these two units. That determination also suggests that emission reductions from the other units at Horseshoe Lake may not reasonably be anticipated to have any effect on visibility conditions in Class I areas. The visibility data for the Wichita Mountains Class I area further suggests that the steps taken by OG&E at other units pursuant to the Regional Haze Program have resulted in visibility improvements beyond what the state is required to achieve in the upcoming SIP.

Unit 9 and Unit 10 are GE/LM6000 PC Sprint natural-gas fired turbines. Both were installed in 2000, and each has a heat input capacity of 550 MMBtu/hr. They are limited by the permit to 4,000 hours of operation per year. Water injection is used for the control of nitrogen oxide (NO_X) emissions for both units.

The following specific technical and economic information, where applicable, is provided in this report for each emissions reduction option considered for Horseshoe Lake Units 6, 7, 8, 9, and 10 in accordance with instructions in the July 1, 2020 request:

- Technical feasibility
- Control effectiveness
- Emissions reductions

- Time necessary for implementation[1]
- Remaining useful life[1]
- Energy and non-air quality environmental impacts[1]
- Costs of implementation[1]

The information was developed in consultation with Sargent & Lundy (S&L), which completed a thorough site-specific control cost evaluation. S&L's report is included in Appendix A.

Additionally, Appendices B and C include reports related to additional factors that should be considered by the ODEQ in its development of a long-term strategy (LTS) and SIP for the regional haze second planning period (2PP). Those reports suggest that reasonable progress toward natural visibility conditions in the relevant Class I areas will be made without any emission reductions at Horseshoe Lake. Specifically, Appendix B demonstrates that the current projected emissions reductions by sources in Oklahoma (including several sources owned and operated by OG&E) are sufficient to show reasonable progress without the installation of any additional controls during this planning period. In addition, even if additional emission reductions were necessary or desirable for the 2PP SIP, the Appendix C report shows that Horseshoe Lake is not a good candidate source for those reductions because it is upwind from Wichita Mountains only 0.02 % of the time on the 20 % most impaired days.

[1] These are the four factors that must be included in evaluating emission reduction measures necessary to make reasonable progress determinations. *See* 40 CFR § 51.308(f)(2)(i).

2. NO_X EMISSIONS REDUCTION OPTIONS

This report addresses the following potentially applicable NO_X emissions reduction options for the two types of EGUs at Horseshoe Lake based on knowledge of the power generation industry and in consultation with S&L:

- Boilers (Units 6, 7, and 8)
  - Selective Catalytic Reduction (SCR),
  - Selective Non-Catalytic Reduction (SNCR), and
  - Combustion Technologies, i.e., Low-NO_X Burners (LNB), Overfire Air (OFA), and Flue Gas Recirculation (FGR).
- Turbines (Units 9 and 10)
  - SCR

2.1 Technical Feasibility

SCR is technically feasible for the Unit 6 and Unit 8 boilers. It is not technically feasible for Unit 7 due to the low flue gas temperatures of Unit 7. As described in S&L's report, this issue could be potentially remedied via additional combustion, but that would create more combustion emissions and it would clearly be economically infeasible based on the cost estimates for Units 6 and 8 (Unit 7 costs would be even greater). SCR is also technically feasible for the Unit 9 and Unit 10 turbines.

SNCR is technically feasible for the Unit 6, Unit 7, and Unit 8 boilers. As described in S&L's report, SNCR is not technically feasible for the Units 9 and 10 combustion turbines. LNB+OFA+FGR is technically feasible for the Unit 6, Unit 7, and Unit 8 boilers. These technologies are not options for combustion turbines. Note again that water injection is already employed at Units 9 and 10.

2.2 Control Effectiveness

Table 2-1 lists the expected emission rates for the technically feasible NO_X emissions reduction options.

Table 2-1. Emission Rates of NO_X Emissions Reduction Options

NO_X Reduction Option	Unit(s)	Controlled Emission Rate (lb/MMBtu)
SCR	6 and 8	0.02 [2]
	9 and 10	0.01 [2]
SNCR	6	0.15
	7 and 8	0.12
LNB+OFA+FGR	6, 7, and 8	0.15

[2] It should be noted that these values are significantly less than (and thus more conservative) than what is presented by EPA in the Air Pollution Control Cost Manual spreadsheet for SCR, which specifies 0.05 lb/MMBtu. The values used here reflect engineering experience with contemporary SCR installation.

Compared to actual "baseline" emission rates based on Air Markets Program Data (AMPD)[3] for 2016,[4] the control efficiencies for SCR are 90 % for Units 8, 9, and 10, and 92 % for Unit 6; the control efficiencies for SNCR are 30 % for Unit 7, 40 % for Unit 8, and 41 % for Unit 6; and the control efficiencies for LNB+OFA+FGR are 12 % for Unit 7, 27 % for Unit 8, and 41 % for Unit 6.

2.3 Emissions Reductions

Table 2-2 presents the baseline emission rates (from 2016), controlled emission rates, and emission reduction potentials for the technically feasible NO_X emissions reduction options.

Table 2-2. Baseline and Controlled Emission Rates and Emissions Reduction Potentials of NO_X Emissions Reduction Options

Unit	NO_X Reduction Option	Baseline Emission Rate (tpy)	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
Unit 6	SCR	257	20	237
	SNCR		151	106
	LNB+OFA+FGR		151	106
Unit 7	SNCR	188	132	56
	LNB+OFA+FGR		165	23
Unit 8	SCR	332	32	300
	SNCR		200	133
	LNB+OFA+FGR		242	91
Unit 9	SCR	28	3	25
Unit 10	SCR	28	3	25

2.4 Time Necessary for Implementation

Counting from the effective date of an approved determination, a minimum of four years would be needed for implementing SCR on one unit, and a minimum of two years would be needed for implementing either SNCR or LNB+OFA+FGR on one unit. If controls were to be required for multiple units then additional time would be needed for planning staggered outages.

2.5 Remaining Useful Life

There are no enforceable limitations on the remaining useful life (RUL) of any of the Horseshoe Lake units. However, Unit 8 is 52 years old, Unit 7 is 57 years old, and Unit 6 is 62 years old, and it is not realistic to expect these units to operate for more than another 20 years at most. Therefore, for the purposes of the control cost assessment, a 20-year RUL is used for Units 6, 7, and 8. A 30-year RUL is used for Units 9 and 10.

---

[3] https://ampd.epa.gov/ampd/.

[4] 2016 was selected as the base case year because it is the year used by the ODEQ for screening sources for four-factor analyses and because it is a reasonable representation of expected 2028 operations and emissions. Emission rates for 2016, calculated as total annual emissions divided by total annual heat input, were 0.26 lb/MMBtu, 0.17 lb/MMBtu, 0.21 lb/MMBtu, 0.10 lb/MMBtu, and 0.10 lb/MMBtu for Units 6, 7, 8, 9, and 10, respectively.

2.6 Energy and Non-air Quality Environmental Impacts

SCR and SNCR systems create a demand for electricity that currently does not exist. SCR also creates a new solid waste stream (spent catalyst) that must be managed. Both options also pose as threats for potentially significant non-air quality environmental impacts because both require the storage of large amounts of ammonia or urea. The storage of aqueous ammonia in quantities greater than 10,000 pounds (lbs) is regulated by EPA's risk management program (RMP) because the accidental release of ammonia has the potential to cause serious injury and death.

Additionally, SCR and SNCR will result in emissions of unreacted ammonia to the atmosphere (i.e., ammonia slip) during any periods of time when temperatures are too low for effective operation or if too much ammonia is injected (possibly in an attempt to reduce NO_X further). Ammonia emissions will react to directly form ammonium sulfate and ammonium nitrate – the anthropogenically emitted compounds most responsible for regional haze in the Wichita Mountains Class I area. The amount of the potential visibility impact attributable to the use of ammonia in a SCR has not been quantified, but it would presumably negate some of the calculated visibility improvement that would otherwise be associated with the NO_X emission reductions.

2.7 Costs

The following tables summarize the total and annualized capital costs and annual operations and maintenance (O&M) costs for each technically feasible NO_X reduction option based on the site-specific evaluation completed by S&L. The cost effectiveness based on the emission reduction values from Table 2-2 are also presented. All costs are based on current-year (2020) pricing.

Table 2-3. Estimated Costs of NO_X Emissions Reduction Options for Unit 6

NO_X Reduction Option	Capital Costs ($M)	Annualized Capital Costs ($M/year)	Annual O&M Costs ($M/year)	Total Annual Costs ($M/year)	Average Cost Effectiveness ($/ton)
LNB+OFA+FGR	11,221	1,059	444	1,503	14,179
SNCR	13,308	1,256	1,344	2,600	24,528
SCR	40,651	3,837	2,532	6,369	26,873

Table 2-4. Estimated Costs of NO_X Emissions Reduction Options for Unit 7

NO_X Reduction Option	Capital Costs ($M)	Annualized Capital Costs ($M/year)	Annual O&M Costs ($M/year)	Total Annual Costs ($M/year)	Average Cost Effectiveness ($/ton)
LNB+OFA+FGR	22,235	2,099	877	2,976	129,391
SNCR	9,842	929	1,093	2,022	36,107

Table 2-5. Estimated Costs of NO_X Emissions Reduction Options for Unit 8

NO_X Reduction Option	Capital Costs ($M)	Annualized Capital Costs ($M/year)	Annual O&M Costs ($M/year)	Total Annual Costs ($M/year)	Average Cost Effectiveness ($/ton)
LNB+OFA+FGR	27,904	2,634	1,105	3,739	41,088
SNCR	18,103	1,709	1,573	3,282	36,066
SCR	40,110	3,786	2,675	6,461	21,537

Table 2-6. Estimated Costs of NO_X Emissions Reduction Options for Unit 9

NO_X Reduction Option	Capital Costs ($M)	Annualized Capital Costs ($M/year)	Annual O&M Costs ($M/year)	Total Annual Costs ($M/year)	Average Cost Effectiveness ($/ton)
SCR	17,160	1,383	1,390	2,773	110,920

Table 2-7. Estimated Costs of NO_X Emissions Reduction Options for Unit 10

NO_X Reduction Option	Capital Costs ($M)	Annualized Capital Costs ($M/year)	Annual O&M Costs ($M/year)	Total Annual Costs ($M/year)	Average Cost Effectiveness ($/ton)
SCR	17,160	1,383	1,390	2,773	110,920

2.8 Conclusions

All technically feasible NO_X emissions reduction options are economically infeasible based on a thorough site-specific evaluation. Therefore, no additional controls should be required for Horseshoe Lake for the regional haze second planning period.

APPENDIX A. SITE-SPECIFIC CONTROL COST EVALUATION

HORSESHOE LAKE STATION UNIT 6-10

OKLAHOMA REGIONAL HAZE SECOND PLANNING PERIOD COST EVALUATION TO SUPPORT FOUR-FACTOR ANALYSIS

SL-015897
Final

September 28, 2020
Project No. 11418-053

Sargent & Lundy

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000
www.sargentlundy.com

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A. NOx Control Summary
B. NO_X Control Cost Estimates

ABBREVIATIONS/ACRONYMS

Abbreviation/Acronym	Explanation
AMPD	US EPA Air Markets Program Data
BART	Best Available Retrofit Technology
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2	carbon dioxide
EPA	Environmental Protection Agency
FGR	flue gas recirculation
G&A	general and administration
HSL	Horseshoe Lake Station
LNB	Low-NO_X burner
MMBtu	million British thermal units
MW	megawatt
MWg	megawatt gross
NH_3	ammonia
NO_X	nitrogen oxides
ODEQ	Oklahoma Department of Environmental Quality
OFA	overfire air
O&M	operations and maintenance
PI	process information data
RRI	rich reagent injection
S	sulfur
S&L	Sargent & Lundy, L.L.C.
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SOFA	separated overfire air

1. INTRODUCTION

The Oklahoma Department of Environmental Quality (ODEQ) requested that Oklahoma Gas & Electric (OG&E) prepare a Reasonable Progress four-factor analysis for the control of nitrogen oxide (NO_X) emissions from Horseshoe Lake Station Unit 6-10. As a result, OG&E engaged Sargent & Lundy (S&L) to prepare a technical and economic evaluation of potential NOx control technologies. Trinity Consultants ("Trinity") will be preparing the overall four-factor analysis (FFA).

Horseshoe Lake Station is located in Oklahoma County, approximately 20 miles east of Oklahoma City, OK. Horseshoe Lake Station consists of five units located in two main areas. Units 6, 7 and 8 are located close to the center of Horseshoe Lake and went into operation in 1958, 1963 and 1969 respectively. Units 9 and 10 are located approximately 2000 feet to the northwest and went into operation in 2001. All five units burn natural gas supplied by pipeline.

Unit 6 is a wall-fired natural gas boiler with flue gas recirculation, initially installed for temperature controls. Unit 7 is a wall-fired natural gas boiler that originally had a gas turbine discharging into a combustion duct, combined with forced draft fan discharge. Therefore, Unit 7 does not have an air heater, similar to traditional wall fired boilers. The gas turbine was taken out of service in 2015. In addition, Unit 7 has a gas recirculation duct installed for gas tempering. Unit 8 is a tangential-fired natural gas boiler. Units 9 and 10 are both simple cycle combustion turbines, LM6000 machines, made by General Electric.

The evaluation includes an assessment of potentially available emission reduction measures for two of the four statutory factors listed in 40 CFR 51.308(f)(2), and takes into consideration U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period* (the "Draft EPA Guidance"). Technically feasible NO_X emission reduction measures are evaluated for the following four statutory factors:

- Factor 1: The cost of compliance
- Factor 2: The time necessary to achieve compliances
- Factor 3: The energy and non-air quality environmental impact of compliance
- Factor 4: The remaining useful life of any existing source subject to such requirements

Factors 3 and 4 are not discussed in this report.

1.1 UNIT OVERVIEW

Unit 6 is a 167 MW gross, Babcock and Wilcox (B&W) natural gas wall-fired boiler which went into commercial operation 1958. It is original equipped with a flue gas recirculation (FGR) system primarily used for load/steam temperature control and not used for NOx control. Based on the B&W Contract Data Sheet, Unit 6 has an original MCR rating of 1,200,000 lb/hr main steam flow at 1935 psig and 1005°F. The original reheat steam flow rate is 1,015,000 lb/hr at 470 psig and 1005°F (with all feedwater heaters in service).

Unit 7 is a 210 MW gross, Babcock and Wilcox (B&W) natural gas wall-fired boiler which went into commercial operation 1963. It was original equipped with a combustion gas turbine which exhausted in the secondary windbox but was decommissioned and no longer operated since 2015. Based on the B&W Contract Data Sheet, Unit 7 was designed for natural gas, coal and fuel oil as standby and has an original MCR rating of 1,339,404 lb/hr main steam flow at 1930 psig and 1005°F. The original reheat steam flow rate is 1,307,000 lb/hr at 422 psig and 1005°F.

Unit 8 is a 404 MW gross, Combustion Engineering (now GE Power) natural gas tangentially-fired boiler which went into commercial operation 1969. Based on the Combustion Engineering Contract Data Sheet, Unit 8 has an original MCR rating of 2,781,000 lb/hr main steam flow at 2460 psig and 1005°F (peak output of 3,075,000 lb/hr at 2,610 psig and 1005°F). The original reheat steam flow rate is 2,411,000 lb/hr at 519 psig and 1005°F.

Units 9 and 10 are both 45.5 MW gross, General Electric LM6000 PC simple cycle machines. Both units have existing water spray systems, installed for NOx control when the units went online in 2001.

1.2 BASELINE NO_X EMISSIONS

The first step in developing the Four Factor Analysis is to establish Horseshoe Lake Unit 6-10 baseline NO_X emissions. To establish representative baseline emissions to be used for determining annual emissions reductions for each control option, S&L evaluated data obtained from the Horseshoe Lake Unit 6-10 continuous emissions monitoring system (CEMS) that was reported to EPA's Clean Air Markets in 2016. The year 2016 was used for this evaluation as it has been deemed most representative of 2028 operation. The annual average emission rate during the representative time period was used to establish baseline annual emissions (in terms of tons per year). Representative baseline emission factors (in terms of pounds per million British Thermal Units (lb/MMBtu)) were developed using baseline annual average emissions and the respective baseline annual heat inputs.

Table 1-1 provides a summary of the Horseshoe Lake Unit 6-10 NO_X representative baseline emissions.

Table 1-1. Horseshoe Lake Unit 6-10 Baseline Emissions

Unit No.	Baseline Controls	Baseline Emissions		Heat Input	Capacity Factor
		lb/MMBtu	tons/yr	MMBtu/yr	
U6	None	0.26	256.8	2,010,462.0	10%
U7	None	0.17	188.4	2,203,618.8	7%
U8	None	0.21	332.4	3,220,554.0	7%
U9	Water Injection	0.10	27.6	577,177.2	12%
U10	Water Injection	0.10	27.6	573,142.8	12%

1.3 TECHNOLOGIES EVALUATED

S&L used a top-down approach to identify and evaluate the technical feasibility and effectiveness of potentially available NOx control measures. S&L followed Steps 1 through 3 of the top-down approach described in the Best Available Retrofit Technologies (BART) Guidelines to identify all available retrofit emission control measures, eliminate technically infeasible options, and evaluate the effectiveness of the technically feasible options.

1.3.1 NOX Control Technologies Evaluated

Based on a review of available NOx control technologies, as well as equipment optimization of existing control systems, potentially available options to control NOx emissions from Units 6-10 are listed below.

- Selective Catalytic Reduction (SCR) (Unit 6, 8, 9, 10)
- Selective Non-Catalytic Reduction (SNCR) (Unit 6, 7, 8)
- Low-NO_X burner (LNB)/overfire air (OFA) and Flue Gas Recirculation (FGR) (Units 6, 7, 8)
- Rich Reagent Injection (RRI) (N/A on all units)
- Gas Reburn (N/A on all units)

1.4 APPROACH

S&L evaluated each control technology's reduction capability on an individual unit basis, as compared to the current emissions using vendor information and similarly sized projects to determine if meaningful improvements could be achieved. In order to determine the additional emission reduction potential, S&L conducted a desktop review of the existing systems: including review of Process Information (PI) Data, the U.S. Environmental Protection Agency's (EPA) Air Markets Program Data (AMPD), existing equipment and component data pages, and process flow diagrams (PFD). Based on this review, current operations were evaluated, limitations of the systems were determined, and the list of potential control technologies were finalized.

2. NO_X EMISSIONS TECHNOLOGY EVALUATIONS

Horseshoe Lake Units 6, 7 & 8 do not currently have any NOx emissions controls systems. Horseshoe Lake Units 9 & 10 have water injection spray systems installed for NOx emissions controls. It has been assumed that the water injection on Units 9 and 10 continue to operate for all of the technologies discussed below.

2.1 SCR

SCR is a process by which ammonia reacts with nitric oxide (NO) and nitrogen dioxide (NO_2), collectively NOx, in the presence of a catalyst to reduce the NO_X to nitrogen (N_2) and water. SCR technology has been applied to NO_X-bearing flue gases generated from power generating facilities burning various types of coal and natural gas. The principal reactions resulting in NO_X reduction are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NO_2 + 8NH_3 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

Because these reactions proceed slowly at typical boiler exit gas temperatures, a catalyst is used to increase the reaction rate between NO_X and ammonia. Depending on the specific constituents in the flue gas, a typical temperature window of 550°F to 780°F is necessary to achieve normal performance of the catalyst. Horseshoe Lake Unit 7 does not have an air heater, meaning the inlet air to the boiler is ambient prior to combustion. The economizer outlet flue gas temperature is approximately 500-525°F. Therefore, SCR technology was not evaluated further for Unit 7.

The temperature window for this process, in a typical boiler, is downstream of the economizer and upstream of the air preheater (APH). SCR technology can be applied as a "full-scale" SCR, which consists of an independent reactor vessel including inlet and outlet ducting and multiple catalyst layers, or an "in-line" SCR, which utilizes the current ductwork (modified as required to expand the dimensions) to hold a single catalyst layer. The "full-scale" SCR is a more common approach for coal-fired applications. The "In-line" SCR is typically more applicable to gas-fired units. Installation of an "in-line" SCR requires expanding the ductwork to reduce the normal 60 feet per second (fps) flue gas velocities to the required 20 to 25 fps range. Thus, physical space must be available around the existing ductwork to accommodate the larger duct dimensions.

In the case of Horseshoe Lake Units 6 & 8, the space between the economizer outlet and the air heater inlet is limited for ductwork modifications. The area around the existing ductwork is limited as well; therefore, separate reactor structures were assumed as the basis. For Units 6 and 8, the estimated emission with SCR is 0.02 lb/MMBtu on an annual average. In the case of Horseshoe Lake Units 9 & 10, an "in-line" SCR was the basis for the estimate where the top of the stack would be removed to facilitate addition of the SCR. The SCR structure was assumed to be supported separately from the stack, with the top of the stack being replaced on top of the SCR structure. For Units 9 and 10, the estimated emission with SCR is 0.01 lb/MMBtu on an annual average.

The emission rates stated above should not be construed to represent proposed permit limits. Corresponding permit limits must be evaluated on a control system-specific basis taking into consideration the corresponding averaging time; however, additional margin would likely be needed to account for off-design operating conditions.

2.2 SNCR

SNCR involves the direct injection of ammonia (NH_3) or urea ($CO(NH_2)_2$) at high flue gas temperatures (approximately 1,600ºF – 2,100ºF) in an oxidizing environment. The ammonia or urea reacts with NOx in the flue gas to produce nitrogen gas (N_2) and water as shown below.

$$(NH_2)\,2CO + 2NO + \tfrac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$

$$2NH_3 + 2NO + \tfrac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reagent injection can greatly affect NOx removal efficiencies and the quantity of NH_3 or urea that will pass through the SNCR unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective in the range of 1,600ºF – 2,100ºF. At temperatures below the desired operating range, the NOx reduction reactions diminish and unreacted NH3 emissions increase. Above the desired temperature range, NH3 is oxidized to NOx resulting in low NOx reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Furnace geometry, urea spray coverage, and droplet size must be considered when developing good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reagent and flue gas in that temperature window. As the boiler cycles in load, the optimum injection region may change; thus, most facilities require multiple injection zones which are placed in and out of service as the unit ramps in load. This can include modifying the zones of injectors that are operating at different loads and temperatures.

In addition to temperature and mixing, several other factors influence the performance of an SNCR system, including residence time, reagent-to-NOx ratio, and fuel sulfur content. Increasing urea solution flow through the injectors or changing the concentration of urea in the solution can improve NOx removal. However, too high of reagent injection rates will increase the ammonia slip beyond the recommended 10 ppmvd limit. Above this concentration, there are expected to be major impacts to the formation of ammonia salts on the boiler tube banks, reducing heat transfer efficiency, and air heater baskets, causing corrosion.

Based on the boiler residence time, temperature profile, and stoichiometry, it is estimated that an SNCR system could achieve an average controlled NO_X emission rate of approximately 0.15 lb/MMBtu for Unit 6 and 0.12 lb/MMBtu for Units 7 and 8 while limiting ammonia slip to 10 ppmvd. It should be noted that computational fluid dynamic modeling and temperature mapping of the boiler would be needed to confirm that the reduction in NO_X emission is achievable without creating unacceptable operational issues.

2.3 LNB/OFA/FGR

LNB and OFA optimize combustion to reduce NOx emissions. LNBs are designed to control fuel and air mixing at each burner in order to create larger and more branched flames. Peak flame temperature is thereby reduced, and results in less NOx formation. The improved flame structure also reduces the amount of oxygen available in the hottest part of the flame thus limiting oxygen availability for NOx formation. OFA diverts combustion air from the primary combustion zone to allow for staged combustion that limits the required combustion temperature and in turn the reduces the formation of thermal NOx.

FGR controls NOx by recycling a portion of the flue gas from the economizer outlet and back into the primary combustion zone in the windbox. The recycled air lowers NOx emissions by two mechanisms: (1) the recycled gas, consisting of products which are inert during combustion, lowers the combustion temperatures; and (2) the recycled gas reduces the oxygen content in the primary flame zone. The amount of recirculation is based on flame stability requirements. The mixed flue gas/combustion air flow supplied to the windbox should be controlled such that the windbox oxygen content is not lower than approximately 17%. Lower oxygen content impacts flame stability and could promote the formation of excess CO and VOC emissions. It is estimated that low NOx burners, OFA ports and FGR could achieve an average controlled NO_X emission rate of 0.15 lb/MMBtu for Units 6, 7 and 8. Units 9 & 10 are simple cycle LM6000 machines, therefore this technology does not apply to Units 9 & 10.

2.4 RRI

Similar to SNCR, the concept of rich reagent injection (RRI) is to use a nitrogen-containing additive (e.g., urea) injected into a reducing environment to promote NO_X removal. RRI is a commercial technology for cyclone boilers only. Therefore, this technology is not applicable to the units at Horseshoe Lake Station and was not considered further.

2.5 GAS REBURN

Gas reburn is a retrofit technique that has been used to control NO_X emissions from coal- and oil-fired boilers. Gas reburn involves combustion in three distinct zones within the boiler: (1) a primary combustion zone, where the primary fuel is fired using conventional burners; (2) a reburn zone, where secondary fuel, typically natural gas, is introduced into the boiler; and (3) an OFA burnout zone. The units at Horseshoe Lake do not burn coal or oil as the primary fuel. Therefore, this technology is not applicable to any of the evaluated units.

3. SUMMARY OF EMISSIONS TECHNOLOGY EVALUATION

Table 3-1 below provides a summary of the average achievable emission rates for the feasible NOx options evaluated.

Table 3-1. Feasible Control Technologies

Control Option	Design Emission Rate (lb/MMBtu)[1]				
	Unit 6	Unit 7	Unit 8	Unit 9	Unit 10
NO_X					
SCR	0.02	N/A	0.02	0.01	0.01
SNCR	0.15	0.12	0.12	N/A	N/A
LNB/OFA/FGR	0.15	0.15	0.15	N/A	N/A

1. Emission rates shown represent average emission rates that the control options would be expected to achieve on an on-going long-term basis under normal operating conditions. Emission rates are provided for comparative purposes and should not be construed to represent proposed permit emission limits. Corresponding permit limits must be evaluated on a control system-specific basis.

Appendix A provides a summary of the control technologies per unit, including control efficiency, emission rates and total reduction in emissions per year.

4. CAPITAL AND OPERATIONS AND MAINTENANCE COSTS

Capital and operations and maintenance (O&M) cost estimates were developed for each of the feasible NO_X control options in accordance with EPA Control Cost Manual. The Horseshoe Lake Units 6-10 cost estimates are conceptual in nature. Equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on Horseshoe Lake unit-specific design parameters, including typical fuel characteristics, full load heat input, and flue gas temperatures and flow rates), and recent pricing for similar equipment.

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimate (e.g., mobilization and demobilization, consumables, Contractor General and Administrative (G&A) expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes. Capital costs were annualized using a capital recovery factor based on an annual interest rate of 7%[1]. The equipment life assumed for each of the control technologies was based on the number of years the equipment would be in service. Units 6, 7 and 8 have been in operation for approximately 60 years. Due to the advanced age of those units, an equipment life of 20 years was used for Units 6, 7 and 8. An equipment life of 30 years was used for Units 9 and 10, given their relatively recent installation. Per the EPA control cost manual, costs have been represented as overnight costs in $2020. Escalation to a construction start date after State Implementation Plan approval has not been included in the cost estimates.

The capital cost estimates generally include the following major components:

- Purchased Equipment Costs
- Equipment and material
- Instrumentation
- Sales Tax
- Freight on Materials
- Direct Installation Costs
- Labor
- Scaffolding
- Mobilization / Demobilization
- Cost due to Overtime

[1] Based on EPA Cost Manual Section 1, Chapter 2, page 16.

- Indirect Costs
- Contractor's General and Administration
- Contractor's Profit
- Engineering, Procurement and Project Services, including Owner's Cost for permitting, engineering, procurement and project services
- Construction Management/Field Engineering
- Startup and Commissioning
- Spare Parts
- Project Contingency

Direct Installation Costs include costs for equipment and balance of plant equipment and commodities. This includes piping, insulation, pipe supports, steel structures, foundations, cables, erection and others. Indirect Costs include contractors General and Administration Expense, Contractors Profit, Engineering, Procurement and Projects services, Owner's Cost, Construction Management and Field Engineering, Start up, Commissioning, and Spare Parts. Project contingency costs are included to cover unforeseen costs that may arise, such as escalation, design changes or modification of equipment. The contents of the S&L estimates are consistent with the definitions in EPA Control Cost Manual.

To confirm that the equipment was not undersized for all potential operating conditions, S&L created an equipment design basis inlet NOx value per unit. The design basis inlet NOx was determined by evaluating three years of hourly data from AMPD, starting January 1, 2017 and ending on December 31, 2019. The NOx values for the top 10% of unit output were extracted and averaged. The equipment design basis inlet NOx values are stated below in Table 4-1.

Table 4-1. Design Basis Inlet NOx for Equipment Sizing

	Inlet NOx (lb/MMBtu)				
	Unit 6	**Unit 7**	**Unit 8**	**Unit 9**	**Unit 10**
Equipment Design Basis	0.30	0.20	0.44	0.10	0.10

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements. The cost of auxiliary power requirements reflects the additional power requirements associated with the operation of the new control technology (compared to the existing technology). All O&M costs reflect the incremental increase in O&M costs compared to the costs incurred to operate the existing NOx controls.

Appendix B provides a summary of costs to control NOx emissions per technology discussed below.

4.1 SCR COST ESTIMATE BASIS

The following summarizes the design inputs used as the basis for the Horseshoe Lake Units 6-10 SCR System cost estimates:

Table 4-2. Design Inputs for SCR Cost Estimates

	NOx Emission Rate (lb/MMBtu)			
	Unit 6	**Unit 8**	**Unit 9**	**Unit 10**
NO_X Inlet – Equipment Design	0.30	0.44	0.09	0.09
Design NO_X Outlet	0.02	0.02	0.01	0.01

The scope of work for the SCR cost estimate includes the following major items:

- SCR equipment per unit:
  - SCR reactor boxes
  - Catalyst
  - Ammonia injection grid and mixers
  - SCR cleaning devices
- Aqueous Ammonia Unloading, Storage and Forwarding
- New Forced Draft (FD) fans, sized for the pressure drop of the new SCR system
- Civil and structural BOP including support steel, foundations, ductwork, insulation and expansion joints
- Mechanical BOP including compressed air system, eyewash/safety showers, pumps, tanks, interconnecting piping, pipe supports, valves, and insulation
- Electrical and instrumentation/controls BOP

4.1.1 Capital Cost Estimate

Table 4-3 summarizes the SCR capital cost estimate.

Table 4-3. SCR Capital Cost Estimate ($2020)

Capital Cost	Unit 6	Unit 8	Unit 9	Unit 10
Purchased Equipment	13,165,000	13,394,000	5,378,000	5,378,000
Direct Installation	11,205,000	10,653,000	4,910,000	4,910,000
Indirects	9,506,000	9,379,000	4,012,000	4,012,000
Contingency	6,775,000	6,685,000	2,860,000	2,860,000
Total Capital Investment	**40,651,000**	**40,111,000**	**17,160,000**	**17,160,000**

4.1.2 Variable O&M Costs

The following unit costs in Table 4-4 were used to develop the variable O&M costs. Values were developed based on OG&E input when unit pricing was available or assumed based on S&L's conceptual cost estimating system.

Table 4-4. SCR Variable O&M Unit Costs

Unit Cost	Units	Unit 6	Unit 8	Unit 9	Unit 10
Aqueous Ammonia	$/gal	1.50	1.50	1.50	1.50
Catalyst Replacement and Disposal	$/m^3$	255.00	255.00	255.00	255.00
Auxiliary Power	$/MWh	36.10	36.10	36.10	36.10

Table 4-5 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the SCR system.

Table 4-5. SCR Variable O&M Consumption Rates and First-Year Costs

Parameter	Units	Unit 6	Unit 8	Unit 9	Unit 10
SCR System					
Aqueous Ammonia Consumption	gpm	2.0	3.5	0.3	0.3
Catalyst Replacement and Disposal	ft^3	2,472	4,379	1,200	1,200
Auxiliary Power Consumption	kW	1,177	2,946	59	59

Parameter	Units	Unit 6	Unit 8	Unit 9	Unit 10
First-Year Variable O&M Costs[1] (@CF)					
Aqueous Ammonia Cost	$/year	164,000	196,000	25,000	25,000
Catalyst Replacement and Disposal Cost[2]	$/year	138,000	244,000	62,000	62,000
Auxiliary Power Cost	$/year	39,000	66,000	3,000	3,000
Lost Generation Cost[3]	$/year	0	0	5,000	5,000
Total First Year Variable O&M Cost	**$/year**	**341,000**	**506,000**	**95,000**	**95,000**

Notes:
1. First-year costs are provided in $2020.
2. Catalyst replacement schedule for gas-fired units is based on 5 years.
3. Lost generation is due to the increase back pressure on the combustion turbines.

4.1.3 Fixed O&M Costs

The fixed O&M costs for the systems consist of maintenance costs (including material and labor). Based on typical design for the SCR system, the estimated staffing addition is 1 person per unit.

Operating Labor costs are estimated based on 2 shifts/day, 365 days per year at an operator charge rate of $60/hour. Supervisor labor is estimated to be 15% of the total operating labor costs.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (materials and labor) were estimated to be approximately 1.5% of the total purchased equipment cost and direct installation costs.

Table 4-6 below summarizes the first year fixed O&M costs.

Table 4-6. SCR First Year Fixed O&M Costs

First Year Fixed O&M Costs[1]	Units	Unit 6	Unit 8	Unit 9	Unit 10
Operating Labor[2]	$/year	526,000	526,000	526,000	526,000
Supervisor Labor	$/year	79,000	79,000	79,000	79,000
Maintenance Material and Labor[3]	$/year	366,000	361,000	154,000	154,000
Total First Year Fixed O&M	**$/year**	**971,000**	**966,000**	**759,000**	**759,000**

Notes:
1. First-year costs are provided in $2020.
2. Operating labor costs are based on a labor rate of $60/hr, which is based on OG&E's input.
3. Maintenance labor cost included in maintenance materials.

Table 4-7. SCR Indirect Operating Costs

Indirect Operating Costs[1]	Units	Unit 6	Unit 8	Unit 9	Unit 10
Property Taxes	$/year	0	0	0	0
Insurance	$/year	407,000	401,000	172,000	172,000
Administration	$/year	813,000	802,000	343,000	343,000
Total Indirect Operating Cost	**$/year**	**1,220,000**	**1,203,000**	**515,000**	**515,000**

Note:
1. Indirect operating costs are provided in $2020.

4.2 SNCR COST ESTIMATE BASIS

The following summarizes the design inputs used as the basis for the Horseshoe Lake Units 6-10 SNCR System cost estimates:

Table 4-8. Design Inputs for SNCR Cost Estimates

	NOx Concentrations (lb/MBtu)		
	Unit 6	**Unit 7**	**Unit 8**
NO_X Inlet – Equipment Design	0.30	0.19	0.44
Design NO_X Outlet	0.15	0.12	0.12

The scope of work for the SNCR cost estimate includes the following major items:

- SNCR equipment per unit:
    - Solutionizing tank
    - Urea storage tanks, circulating module and dilution water module
    - Metering & distribution modules
    - Injection lances
- Structural BOP including support steel, foundations, ductwork, insulation and expansion joints
- Mechanical BOP including compressed air system, eyewash/safety showers, pumps, tanks, interconnecting piping, pipe supports, valves, and insulation
- Electrical and instrumentation/controls BOP

4.2.1 Capital Cost Estimate

Table 4-9 summarizes the SNCR capital cost estimate.

Table 4-9. SNCR Capital Cost Estimate ($2020)

Capital Cost	Unit 6	Unit 7	Unit 8
Purchased Equipment	5,275,000	3,910,000	7,162,000
Direct Installation	2,703,000	1,990,000	3,691,000
Indirects	3,112,000	2,302,000	4,232,000
Contingency	2,218,000	1,640,000	3,017,000
Total Capital Investment	**13,308,000**	**9,842,000**	**18,102,000**

4.2.2 Variable O&M Costs

The following unit costs in Table 4-10 were used to develop the variable O&M costs. Values were developed based on OG&E input when unit pricing was available or assumed based on S&L's conceptual cost estimating system.

Table 4-10. SNCR Variable O&M Unit Costs

Unit Cost	Units	Unit 6	Unit 7	Unit 8
50% Urea Solution	$/gal	1.66	1.66	1.66
Demineralized Water	$/1000 gal	5.00	5.00	5.00
Auxiliary Power	$/MWh	36.10	36.10	36.10

Table 4-11 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the SNCR system.

Table 4-11. SNCR Variable O&M Consumption Rates and First-Year Costs

Parameter	Units	Unit 6	Unit 7	Unit 8
SNCR System				
50% Urea Consumption	gpm	2.4	1.5	4.2
Demineralized Water Consumption	gpm	29	18	51
Auxiliary Power Consumption	kW	364	280	513
First-Year Variable O&M Costs[1] (@CF)				
Urea Cost	$/year	200,000	93,000	241,000
Demineralized Water Cost[2]	$/year	8,000	4,000	9,000
Auxiliary Power Cost	$/year	12,000	7,000	12,000
Total First Year Variable O&M Cost	**$/year**	**220,000**	**104,000**	**262,000**

Notes:
1. First-year costs are provided in $2020.

4.2.3 Fixed O&M Costs

The fixed O&M costs for the systems consist of maintenance costs (including material and labor). Based on typical design for the SNCR system, the estimated staffing addition is 1 person per unit.

Operating Labor costs are estimated based on 2 shifts/day, 365 days per year at an operator charge rate of $60/hour. Supervisor labor is estimated to be 15% of the total operating labor costs.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (materials and labor) were estimated to be approximately 1.5% of the total purchased equipment cost and direct installation costs.

Table 4-12 below summarizes the first year fixed O&M costs.

Table 4-12. SNCR First Year Fixed O&M Costs

First Year Fixed O&M Costs[1]	Units	Unit 6	Unit 7	Unit 8
Operating Labor[2]	$/year	526,000	526,000	526,000
Supervisor Labor	$/year	79,000	79,000	79,000
Maintenance Material and Labor[3]	$/year	120,000	89,000	163,000
Total First Year Fixed O&M	**$/year**	**725,000**	**694,000**	**768,000**

Notes:
1. First-year costs are provided in $2020.
2. Operating labor costs are based on a labor rate of $60/hr, which is based on OG&E's input.
3. Maintenance labor cost included in maintenance materials.

Table 4-13. SNCR Indirect Operating Costs

Indirect Operating Costs[1]	Units	Unit 6	Unit 7	Unit 8
Property Taxes	$/year	0	0	0
Insurance	$/year	133,000	98,000	181,000
Administration	$/year	266,000	197,000	362,000
Total Indirect Operating Cost	**$/year**	**399,000**	**295,000**	**543,000**

Note:
1. Indirect operating costs are provided in $2020.

4.3 LNB/OFA/FGR COST ESTIMATE BASIS

The following summarizes the design inputs used as the basis for the Horseshoe Lake Units 6-10 LNB/OFA/FGR System cost estimates:

Table 4-14. Design Inputs for LNB/OFA/FGR Cost Estimates

	NOx Concentrations (lb/MBtu)		
	Unit 6	**Unit 7**	**Unit 8**
NO_X Inlet – Equipment Design	0.30	0.19	0.44
Design NO_X Outlet	0.15	0.15	0.15

The scope of work for the LNB/OFA/FGR cost estimate includes the following major items:

- New Low NOx Burners, including modifications to natural gas supply piping and vents
- New Overfire Air Ports, including modifications to boiler and tubing

- New Flue Gas Recirculation Fans, lubricating oil skids, fan controls and associated instrumentation
- Ductwork modifications
- Civil and structural BOP including support steel, foundations, ductwork, insulation and expansion joints
- Mechanical BOP including compressed air system, eyewash/safety showers, pumps, tanks, interconnecting piping, pipe supports, valves, and insulation
- Electrical and instrumentation/controls BOP

The above list applies to all units, with exception to Unit 6. Unit 6 has existing gas recirculation fans which may be for NOx controls with modification to the ductwork. For the purposes of the cost evaluation, it has been assumed that the gas recirculation fans will be reused for NOx control, however, the fans should be assessed in further detail to confirm this assumption.

4.3.1 Capital Cost Estimate

Table 4-15 summarizes the LNB/OFA/FGR capital cost estimate.

Table 4-15. LNB/OFA/FGR Capital Cost Estimate ($2020)

Capital Cost	Unit 6	Unit 7	Unit 8
Purchased Equipment	3,340,000	9,725,000	7,730,000
Direct Installation	3,387,000	3,605,000	8,999,000
Indirects	2,624,000	5,199,000	6,524,000
Contingency	1,870,000	3,706,000	4,651,000
Total Capital Investment	**11,221,000**	**22,235,000**	**27,904,000**

4.3.2 Variable O&M Costs

The following unit costs in Table 4-16 were used to develop the variable O&M costs. Values were developed based on OG&E input when unit pricing was available or assumed based on S&L's conceptual cost estimating system.

Table 4-16. LNB/OFA/FGR Variable O&M Unit Costs

Unit Cost	Units	Unit 6	Unit 7	Unit 8
Auxiliary Power	$/MWh	36.10	36.10	36.10

Table 4-17 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the LNB/OFA/FGR system.

Table 4-17. LNB/OFA/FGR Variable O&M Consumption Rates and First-Year Costs

Parameter	Units	Unit 6	Unit 7	Unit 8
Auxiliary Power Consumption	kW	224	403	775
First-Year Variable O&M Costs[1] (@CF)				
Auxiliary Power Cost	$/year	7,000	11,000	18,000
Total First Year Variable O&M Cost	**$/year**	**7,000**	**11,000**	**18,000**

Notes:
1. First-year costs are provided in $2020.

4.3.3 Fixed O&M Costs

The fixed O&M costs for the systems consist of maintenance costs (including material and labor). For LNB/OFA/FGR systems, there is no expected increase in staffing.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (materials and labor) were estimated to be approximately 1.5% of the total purchased equipment cost and direct installation costs.

Table 4-18 below summarizes the first year fixed O&M costs.

Table 4-18. LNB/OFA/FGR First Year Fixed O&M Costs

First Year Fixed O&M Costs[1]	Units	Unit 6	Unit 7	Unit 8
Operating Labor	$/year	0	0	0
Supervisor Labor	$/year	0	0	0
Maintenance Material and Labor[2]	$/year	101,000	200,000	251,000
Total First Year Fixed O&M	**$/year**	**101,000**	**200,000**	**251,000**

Notes:
1. First-year costs are provided in $2020.
2. Maintenance labor cost included in maintenance materials.

Table 4-19. LNB/OFA/FGR Indirect Operating Costs

Indirect Operating Costs[1]	Units	Unit 6	Unit 7	Unit 8
Property Taxes	$/year	0	0	0

Indirect Operating Costs[1]	Units	Unit 6	Unit 7	Unit 8
Insurance	$/year	112,000	222,000	279,000
Administration	$/year	224,000	445,000	558,000
Total Indirect Operating Cost	**$/year**	**336,000**	**667,000**	**837,000**

Note:
1. Indirect operating costs are provided in $2020.

5. SUMMARY OF COST EVALUATION

Table 5-1 through Table 5-5 summarize the annualized capital cost, annual operating cost and total annualized cost for each alternative NOx control technology per unit.

Table 5-1. Unit 6 Annualized NOx Control Costs Summary ($2020)

	Unit 6		
	SCR	SNCR	LNB/OFA/FGR
Annualized Capital Cost[1], $	3,837,000	1,256,000	1,059,000
Total Annual Operating Costs, $/yr	2,532,000	1,344,000	444,000
Total Annualized Cost, $/yr	**6,369,000**	**2,600,000**	**1,503,000**

Note:
1. Capital costs annualized using an interest rate of 7% with an evaulation period of 20 years for Unit 6.

Table 5-2. Unit 7 Annualized NOx Control Costs Summary ($2020)

	Unit 7		
	SCR	SNCR	LNB/OFA/FGR
Annualized Capital Cost[1], $/yr	N/A	929,000	2,099,000
Total Annual Operating Costs, $/yr	N/A	1,093,000	877,000
Total Annualized Cost, $/yr	N/A	**2,022,000**	**2,976,000**

Note:
1. Capital costs annualized using an interest rate of 7% with an evaulation period of 20 years for Unit 7.

Table 5-3. Unit 8 Annualized NOx Control Costs Summary ($2020)

	Unit 8		
	SCR	SNCR	LNB/OFA/FGR
Annualized Capital Cost[1], $/yr	3,786,000	1,709,000	2,634,000
Total Annual Operating Costs, $/yr	2,675,000	1,573,000	1,105,000
Total Annualized Cost, $/yr	**6,461,000**	**3,282,000**	**3,739,000**

Note:

1. Capital costs annualized using an interest rate of 7% with an evaulation period of 20 years for Unit 8.

Table 5-4. Unit 9 Annualized NOx Control Costs Summary ($2020)

	Unit 9		
	SCR	SNCR	LNB/OFA/FGR
Annualized Capital Cost[1], $/yr	1,383,000	N/A	N/A
Annualized Outage Cost, $/yr	21,000	N/A	N/A
Total Annual Operating Costs, $/yr	1,369,000	N/A	N/A
Total Annualized Cost, $/yr	**2,773,000**	N/A	N/A

Note:

1. Capital costs annualized using an interest rate of 7% with an evaulation period of 30 years for Unit 9.

Table 5-5. Unit 10 Annualized NOx Control Costs Summary ($2020)

	Unit 10		
	SCR	SNCR	LNB/OFA/FGR
Annualized Capital Cost[1], $/yr	1,383,000	N/A	N/A
Annualized Outage Cost, $/yr	21,000	N/A	N/A
Total Annual Operating Costs, $/yr	1,369,000	N/A	N/A
Total Annualized Cost, $/yr	**2,773,000**	N/A	N/A

Note:

1. Capital costs annualized using an interest rate of 7% with an evaulation period of 30 years for Unit 10.

6. TIME NECESSARY FOR COMPLIANCE (STATUTORY FACTOR TWO)

The time necessary for compliance is generally defined as the time needed for full implementation of the technically feasible control options. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. If reasonable progress measures are required at Horseshoe Lake Station for the Regional Haze second planning period, the anticipated compliance deadline would be in 2028. However, this compliance deadline must provide a reasonable amount of time for the source to implement the control measure.

Table 6-1 includes estimated timeframes needed to implement each of the technically feasible control options. Notably, the estimated timeframes do not account for time needed for Oklahoma to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve Oklahoma's SIP.

Table 6-1. NO_X Emissions Control System Implementation Schedule (months after SIP approval)

NO_X Control Option	Unit 6	Unit 7	Unit 8	Unit 9	Unit 10
SCR	48	N/A	48	48	48
SNCR	22	22	22	N/A	N/A
LNB/OFA/FGR	18	18	18	N/A	N/A

Table 6-2. NO_X Emissions Control System Outage Duration (weeks)

NO_X Control Option	Unit 6	Unit 7	Unit 8	Unit 9	Unit 10
SCR	6 to 8	N/A	6 to 8	12 to 14	12 to 14
SNCR	6 to 8	6 to 8	6 to 8	N/A	N/A
LNB/OFA/FGR	6 to 8	6 to 8	6 to 8	N/A	N/A

APPENDIX A

NO_X CONTROL SUMMARY

Horseshoe Lake Station Units 6-10
NO_X Control Summary

Table 1. HSL Station Units 6-10 Operating Parameters

Parameter	Units	Unit 6	Unit 7	Unit 8	Unit 9	Unit 10	Notes
Nominal Power Output	MW	167	214	404	46	46	Source: NEEDS database
Annual Heat Input	MMBtu/yr	2,010,462	2,203,619	3,220,554	577,177	573,143	Source: Trinity Consultants
Annual Capacity Factor	%	10%	7%	7%	12%	12%	Based on Heat Input

Table 2. NO_X Control Effectiveness

	Unit 6				Unit 7				Unit 8				Unit 9				Unit 10			
Control Technology	Control Efficiency	Expected Emissions	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/MMBtu)	(ton/year)	(%)	(ton/year)	(lb/MMBtu)	(ton/year)
SCR	92%	20	0.02	237					90%	32	0.02	300	90%	3	0.01	25	90%	3	0.01	25
SNCR	41%	151	0.15	106	30%	132	0.12	56	40%	200	0.12	133								
Low NOx Burner/OFA/FGR	41%	151	0.15	106	12%	165	0.15	23	27%	242	0.15	91								
Baseline (Unit 6-8 no controls, Unit 9-10 water sprays)		257	0.26			188	0.17			332	0.21			28	0.10			28	0.10	

APPENDIX B

NO_X CONTROL COST ESTIMATES

Horseshoe Lake Units 6, 8
NO_X Control Cost Evaluation
SCR

NO_X Control Option Description	SCR	
	Unit 6	Unit 8
Post Upgrade NO_X Emissions, lb/MMBtu	0.02	0.02
Capacity Factor used of Cost Estimates (%)	10.4%	7.1%

CAPITAL COSTS	Cost (2020$) Unit 6	Unit 8	Basis
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$12,538,000	$12,756,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$0	$0	0% of Equipment/Material Cost; Exempt per OG&E
Freight	$627,000	$638,000	5% of Equipment/Material Cost
Total PEC	$13,165,000	$13,394,000	
Direct Installation Costs			
Labor	$10,280,000	$9,773,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$257,000	$244,000	2.5% of Labor
Mobilization / Demobilization	$154,000	$147,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency	$514,000	$489,000	5% of Labor
Total Direct Installation Costs	$11,205,000	$10,653,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$24,370,000**	**$24,047,000**	
Indirect Costs			
Contractor's General and Administration Expense	$2,437,000	$2,405,000	10% of Total Direct Costs
Contractor's Profit	$1,219,000	$1,202,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$4,387,000	$4,328,000	18% of Total Direct Costs; includes Owner's Cost (10% of Total Direct Costs) for Owner's engineering, procurement and project services
Construction Management/Field Engineering	$975,000	$962,000	4% of Total Direct Costs
S-U / Commissioning	$366,000	$361,000	1.5% of Total Direct Costs
Spare Parts	$122,000	$120,000	0.5% of Total Direct Costs
Total Indirect Costs	**$9,506,000**	**$9,378,000**	
Contingency	**$6,775,000**	**$6,685,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$40,651,000**	**$40,110,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0944	0.0944	20 year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)	**$3,837,000**	**$3,786,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Ammonia Reagent Cost	$164,000	$196,000	Based on 19% aqueous ammonia reagent cost of $1.50/gallon.
Catalyst Replacement and Disposal Cost	$138,000	$244,000	Based on catalyst cost of $227/ft^3 and catalyst replacement cost of $28 per m^3.
Auxiliary Power Cost	$39,000	$66,000	Based on auxiliary power cost of $36.10 per MWh.
Total Variable O&M Costs	$341,000	$506,000	
Fixed O&M Costs			
Additional Operators per Shift	1	1	
Operating Labor	$526,000	$526,000	Per OG&E $60/hr for each additional operator
Supervisor Labor	$79,000	$79,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$366,000	$361,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$971,000	$966,000	
Indirect Operating Cost			
Property Taxes	$0	$0	Excluded per OG&E
Insurance	$407,000	$401,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$813,000	$802,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$1,220,000	$1,203,000	
Total Annual Operating Cost	**$2,532,000**	**$2,675,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$3,837,000	$3,786,000	
Annual Operating Cost	$2,532,000	$2,675,000	
Total Annual Cost	**$6,369,000**	**$6,461,000**	

Horseshoe Lake Units 9, 10
NO_X Control Cost Evaluation
SCR

NO_X Control Option Description	SCR	
	Unit 9	Unit 10
Post Upgrade NO_X Emissions, lb/MMBtu	0.01	0.01
Capacity Factor used of Cost Estimates (%)	12%	12%

CAPITAL COSTS	Cost (2020$) Unit 9	Unit 10	Basis
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment and Materials	$5,122,000	$5,122,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	Included in equipment and materials cost
Sales Tax	$0	$0	0% of Equipment/Material Cost; Exempt per OG&E
Freight	$256,000	$256,000	5% of Equipment/Material Cost
Total PEC	$5,378,000	$5,378,000	
Direct Installation Costs			
Labor	$4,504,000	$4,504,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$113,000	$113,000	2.5% of Labor
Mobilization / Demobilization	$68,000	$68,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency	$225,000	$225,000	5% of Labor
Total Direct Installation Costs	$4,910,000	$4,910,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$10,288,000**	**$10,288,000**	
Indirect Costs			
Contractor's General and Administration Expense	$1,029,000	$1,029,000	10% of Total Direct Costs
Contractor's Profit	$514,000	$514,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$1,852,000	$1,852,000	18% of Total Direct Costs; includes Owner's Cost (10% of Total Direct Costs) for Owner's engineering, procurement and project services
Construction Management/Field Engineering	$412,000	$412,000	4% of Total Direct Costs
S-U / Commissioning	$154,000	$154,000	1.5% of Total Direct Costs
Spare Parts	$51,000	$51,000	0.5% of Total Direct Costs
Total Indirect Costs	**$4,012,000**	**$4,012,000**	
Contingency	**$2,860,000**	**$2,860,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$17,160,000**	**$17,160,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0806	0.0806	30 year life of equipment (years) @7% interest.
Annualized Capital Costs (CRF x TCI)	**$1,383,000**	**$1,383,000**	
OUTAGE COSTS			
Outage Costs			
Standard Outage Duration (weeks/yr)	6	6	
Outage Duration due to Retrofit (weeks/yr)	14	14	Estimate
Lost Revenue due to Retrofit	**$264,000**	**$263,000**	Based on 12 Mwg power output, '12% capacity factor, $36.01/MWh
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0806	0.0806	30 year life of equipment (years) @ 7% interest.
Annualized Outage Costs (CRF x TCI)	**$21,000**	**$21,000**	
OPERATING COSTS			
Operating & Maintenance Costs			
Variable O&M Costs			
Dry Urea Reagent Cost	$0	$0	
Ammonia Reagent Cost	$25,000	$25,000	Based on 19% aqueous ammonia reagent cost of $1.50/gallon.
Catalyst Replacement and Disposal Cost	$62,000	$62,000	Based on catalyst cost of $227/ft^3 and catalyst replacement cost of $28 per m^3.
Lost Generation Cost	$5,000	$5,000	Based on auxiliary power cost of $36.10 per MWh.
Auxiliary Power Cost	$3,000	$3,000	Based on auxiliary power cost of $36.10 per MWh.
Total Variable O&M Costs	$95,000	$95,000	
Fixed O&M Costs			
Additional Operators per Shift	1	1	
Operating Labor	$526,000	$526,000	Per OG&E $60/hr for each additional operator
Supervisor Labor	$79,000	$79,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$154,000	$154,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$759,000	$759,000	
Indirect Operating Cost			
Property Taxes	$0	$0	Excluded per OG&E
Insurance	$172,000	$172,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$343,000	$343,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$515,000	$515,000	
Total Annual Operating Cost	**$1,369,000**	**$1,369,000**	
TOTAL ANNUAL COST			
Annualized Capital Cost	$1,383,000	$1,383,000	
Annualized Outage Cost	$21,000	$21,000	
Annual Operating Cost	$1,369,000	$1,369,000	
Total Annual Cost	**$2,773,000**	**$2,773,000**	

Horseshoe Lake Units 6, 7, 8
NO_X Control Cost Evaluation
SNCR

NO_X Control Option Description	SNCR		
	Unit 6	Unit 7	Unit 8
Post Upgrade NO_X Emissions, lb/MMBtu	0.15	0.12	0.12
Capacity Factor used of Cost Estimates (%)	10.4%	7.5%	7.1%

CAPITAL COSTS	Cost (2020$) Unit 6	Unit 7	Unit 8	Basis
Direct Costs				
Purchased Equipment Costs (PEC)				
Equipment and Materials	$5,024,000	$3,724,000	$6,821,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	$0	Included in equipment and materials cost
Sales Tax	$0	$0	$0	0% of Equipment/Material Cost; Exempt per OG&E
Freight	$251,000	$186,000	$341,000	5% of Equipment/Material Cost
Total PEC	$5,275,000	$3,910,000	$7,162,000	
Direct Installation Costs				
Labor	$2,480,000	$1,826,000	$3,386,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$62,000	$46,000	$85,000	2.5% of Labor
Mobilization / Demobilization	$37,000	$27,000	$51,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency	$124,000	$91,000	$169,000	5% of Labor
Total Direct Installation Costs	$2,703,000	$1,990,000	$3,691,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$7,978,000**	**$5,900,000**	**$10,853,000**	
Indirect Costs				
Contractor's General and Administration Expense	$798,000	$590,000	$1,085,000	10% of Total Direct Costs
Contractor's Profit	$399,000	$295,000	$543,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$1,436,000	$1,062,000	$1,954,000	18% of Total Direct Costs; includes Owner's Cost (10% of Total Direct Costs) for Owner's engineering, procurement and project services
Construction Management/Field Engineering	$319,000	$236,000	$434,000	4% of Total Direct Costs
S-U / Commissioning	$120,000	$89,000	$163,000	1.5% of Total Direct Costs
Spare Parts	$40,000	$30,000	$54,000	0.5% of Total Direct Costs
Total Indirect Costs	**$3,112,000**	**$2,302,000**	**$4,233,000**	
Contingency	**$2,218,000**	**$1,640,000**	**$3,017,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$13,308,000**	**$9,842,000**	**$18,103,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0944	0.0944	0.0944	20 year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)	**$1,256,000**	**$929,000**	**$1,709,000**	
OPERATING COSTS				
Operating & Maintenance Costs				
Variable O&M Costs				
Urea Reagent Cost	$200,000	$93,000	$241,000	Based on 50% Urea cost of $1.66/gallon.
Demin Water Cost	$8,000	$4,000	$9,000	Based on a water cost of $5.00/1,000gal.
Auxiliary Power Cost	$12,000	$7,000	$12,000	Based on auxiliary power cost of $36.10 per MWh.
Total Variable O&M Costs	$220,000	$104,000	$262,000	
Fixed O&M Costs				
Additional Operators per Shift	1	1	1	
Operating Labor	$526,000	$526,000	$526,000	Per OG&E $60/hr for each additional operator
Supervisor Labor	$79,000	$79,000	$79,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$120,000	$89,000	$163,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$725,000	$694,000	$768,000	
Indirect Operating Cost				
Property Taxes	$0	$0	$0	Excluded per OG&E
Insurance	$133,000	$98,000	$181,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$266,000	$197,000	$362,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$399,000	$295,000	$543,000	
Total Annual Operating Cost	**$1,344,000**	**$1,093,000**	**$1,573,000**	
TOTAL ANNUAL COST				
Annualized Capital Cost	$1,256,000	$929,000	$1,709,000	
Annual Operating Cost	$1,344,000	$1,093,000	$1,573,000	
Total Annual Cost	**$2,600,000**	**$2,022,000**	**$3,282,000**	

Horseshoe Lake Units 6, 7, 8
NO_X Control Cost Evaluation
Low Nox Burner (LNB), Over-fired Air (OFA) and Flue Gas Recirculation (FGR)

NO_X Control Option Description	LNB, OFA & FGR		
	Unit 6	Unit 7	Unit 8
Post Upgrade NO_X Emissions, lb/MMBtu	0.15	0.15	0.15
Capacity Factor used of Cost Estimates (%)	10.4%	7.5%	7.1%

CAPITAL COSTS	Cost (2020$) Unit 6	Unit 7	Unit 8	Basis
Direct Costs				
Purchased Equipment Costs (PEC)				
Equipment and Materials	$3,181,000	$9,262,000	$7,362,000	Based on Sargent & Lundy's conceptual cost estimating system.
Instrumentation	$0	$0	$0	Included in equipment and materials cost
Sales Tax	$0	$0	$0	0% of Equipment/Material Cost; Exempt per OG&E
Freight	$159,000	$463,000	$368,000	5% of Equipment/Material Cost
Total PEC	$3,340,000	$9,725,000	$7,730,000	
Direct Installation Costs				
Labor	$3,107,000	$3,307,000	$8,256,000	Based on Sargent & Lundy's conceptual cost estimating system.
Scaffolding	$78,000	$83,000	$206,000	2.5% of Labor
Mobilization / Demobilization	$47,000	$50,000	$124,000	1.5% of Labor
Labor Cost Due To Overtime Inefficiency	$155,000	$165,000	$413,000	5% of Labor
Total Direct Installation Costs	$3,387,000	$3,605,000	$8,999,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$6,727,000**	**$13,330,000**	**$16,729,000**	
Indirect Costs				
Contractor's General and Administration Expense	$673,000	$1,333,000	$1,673,000	10% of Total Direct Costs
Contractor's Profit	$336,000	$667,000	$836,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$1,211,000	$2,399,000	$3,011,000	18% of Total Direct Costs; includes Owner's Cost (10% of Total Direct Costs) for Owner's engineering, procurement and project services
Construction Management/Field Engineering	$269,000	$533,000	$669,000	4% of Total Direct Costs
S-U / Commissioning	$101,000	$200,000	$251,000	1.5% of Total Direct Costs
Spare Parts	$34,000	$67,000	$84,000	0.5% of Total Direct Costs
Total Indirect Costs	**$2,624,000**	**$5,199,000**	**$6,524,000**	
Contingency	**$1,870,000**	**$3,706,000**	**$4,651,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI)	**$11,221,000**	**$22,235,000**	**$27,904,000**	sum of direct capital costs, indirect capital costs, and contingency
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.0944	0.0944	0.0944	20 year life of equipment (years) @ 7% interest.
Annualized Capital Costs (CRF x TCI)	**$1,059,000**	**$2,099,000**	**$2,634,000**	
OPERATING COSTS				
Operating & Maintenance Costs				
Variable O&M Costs				
Auxiliary Power Cost	$7,000	$10,000	$17,000	Based on auxiliary power cost of $36.10 per MWh.
Total Variable O&M Costs	$7,000	$10,000	$17,000	
Fixed O&M Costs				
Additional Operators per Shift	0	0	0	No additional operators expected.
Operating Labor	$0	$0	$0	Per OG&E $60/hr for each additional operator
Supervisor Labor	$0	$0	$0	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$101,000	$200,000	$251,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	$0	Included in cost for maintenance materials.
Total Fixed O&M Cost	$101,000	$200,000	$251,000	
Indirect Operating Cost				
Property Taxes	$0	$0	$0	Excluded per OG&E
Insurance	$112,000	$222,000	$279,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$224,000	$445,000	$558,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$336,000	$667,000	$837,000	
Total Annual Operating Cost	**$444,000**	**$877,000**	**$1,105,000**	
TOTAL ANNUAL COST				
Annualized Capital Cost	$1,059,000	$2,099,000	$2,634,000	
Annual Operating Cost	$444,000	$877,000	$1,105,000	
Total Annual Cost	**$1,503,000**	**$2,976,000**	**$3,739,000**	

APPENDIX B. ADDITIONAL FACTOR - VISIBILITY CONDITIONS AT WICHITA MOUNTAINS CLASS I AREA

WICHITA MOUNTAINS CLASS I AREA IMPROVE MONITORING DATA SUMMARY

Prepared By:

Jeremy Jewell – Principal Consultant
Stephen Beene – Senior Consultant

TRINITY CONSULTANTS
5801 E. 41st St.
Suite 450
Tulsa, OK 74135
(918) 622-7111

September 3, 2020

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1. INTRODUCTION

This report summarizes the observed visibility impairment conditions for the Wichita Mountains Wildlife Refuge Class I area ("WIMO" or "WIMO1") from the Interagency Monitoring of Protected Visual Environments (IMPROVE) network monitoring data,[1] and compares these conditions to the Uniform Rate of Progress (URP) glidepath ("adjusted default" option) for the area from EPA's September 19, 2019 memorandum *Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling*.[2] In addition, the current visibility conditions for the clearest days are compared to projected (modeled) 2028 visibility for the clearest days.

[1] As of the drafting of this report, summarized annual IMPROVE monitoring data is available through the year 2018.

[2] https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf

2. BACKGROUND

Visibility impairment or "haze" is described by the light extinction visibility metric in units of inverse megameters (Mm^{-1}). Because the inverse-distance units are difficult to conceptualize, the deciview haze index (dv) was developed. Extinction values are converted to deciviews using a logarithmic equation[3] such that the deciview scale is nearly zero for a pristine atmosphere, and, like the decibel scale for sound, equivalent changes in deciviews are perceived similarly across a wide range of background conditions.[4] Light extinction in the Class I areas is observed via the IMPROVE network of Class I area air monitors. IMPROVE visibility data are available on the IMPROVE website.[5]

EPA has selected the deciview scale as the most appropriate visibility metric for regulatory purposes because it is more conducive to describing and comparing humanly perceptible visibility changes at different Class I areas and for a wide range of visibility conditions. According to EPA, a one-deciview change represents a "small but noticeable change in haziness" and, depending on conditions, a change of greater than one deciview may be necessary to be perceived by the human eye.[6] Other studies, however, have suggested that a "1-deciview change never produces a perceptible change in haze."[7]

Section 169A of the Clean Air Act (CAA) sets forth a national goal for the "prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution." In 1999, the Regional Haze Program was promulgated to require states to include provisions to address impairment of visibility in Class I areas in their *State Implementation Plans*.[8] The Regional Haze Program requires setting reasonable progress goals towards achieving natural visibility conditions at each Class I area. The reasonable progress goals must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period.[9] Reasonable progress goals are compared to the Uniform Rate of Progress ("URP") or "glidepath" needed to achieve natural conditions in 2064.[10] The URP is a straight line from baseline visibility conditions (average of the 20 percent most impaired days as of 2004) to natural visibility conditions (to be achieved in 2064 for the 20 percent most impaired days).

The EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (SIP Guidance)[11] provides guidance to states for the development of the implementation plans. There are a few key distinctions from the processes that took place during the first planning period (2004-2018). Most notably, the second planning period analysis distinguishes between natural (or "biogenic") and manmade

[3] Deciview = 10 × ln (Extinction ÷ 10)

[4] U.S. EPA, Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress at 1-5 - 1-7 (November 2001).

[5] http://vista.cira.colostate.edu/Improve/

[6] Regional Haze Regulations, 64 Fed. Reg. 35,725-27 (July 1999).

[7] Ronald C. Henry, "Just-Noticeable Differences in Atmospheric Haze," Journal of the Air & Waste Management Association, Vol. 52 at 1,238 (October 2002).

[8] 64 FR 35714

[9] 40 CFR 51.308(d)(1)

[10] 40 CFR 51.308(f)(1)(iv)(A)

[11] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 2019, EPA-457/B-19-003.

(or "anthropogenic") sources of emissions. The EPA's *Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program* (Visibility Guidance)[12] provides guidance to states on methods for selecting the twenty (20) percent most impaired days to track visibility and determining natural visibility conditions. This method has been applied by the IMPROVE group to the data collected at WIMO1.

For the second planning period, the tracking of the 20 percent clearest days remains unchanged. The selection of the 20 percent clearest days does not include any processing to factor out natural sources of impairment. The tracking of the 20 percent clearest days is to ensure that the visibility on the clearest days is not being degraded.

[12] Technical Guidance on Tracking Visibility Progress for the Second Implementation Period of the Regional Haze Program, December 2018, EPA-454/R-18-010.

3. SUMMARY AND COMPARISON FOR WICHITA MOUNTAINS

Table 3-1 presents a summary of the annual-average haze index values for each year from 2002 to 2018 for the WIMO1 monitor.

Table 3-1. Summary of Annual-Average Haze Index Values for WIMO1

Year	Average of 20 Percent Most Impaired Days (dv)	Average of 20 Percent Clearest Days (dv)
2002	9.75	22.26
2003	10.02	22.02
2004	9.56	22.16
2005	10.59	24.39
2006	9.74	20.83
2007	9.32	22.38
2008	9.85	21.06
2009	-- [A]	-- [A]
2010	9.22	20.92
2011	10.34	21.24
2012	8.88	19.44
2013	8.44	19.54
2014	9.26	20.42
2015	8.49	18.08
2016	8.08	16.45
2017	7.74	17.50
2018	8.77	18.16

[A] Summarized data are not available for WIMO1 for 2009.

Figure 3-1 presents a comparison of the annual-average haze index values for the most impaired days from Table 3-1 to the URP glidepath proposed by EPA for WIMO.[13] As seen in Figure 3-1, the actual observed visibility impairment at WIMO has declined overall and has remained below the glidepath since 2015. Thus, the current Class I area visibility conditions are better than necessary (or ahead of schedule) to achieve the goal of the regional haze program.

In addition, the projected (modeled) 2028 haze index values from EPA's September 19, 2019 memorandum *Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling* are shown in the figure. EPA's modeling shows the projected 2028 haze index values are satisfying the objective of the Regional Haze Program to improve the most impaired days and not cause additional degradation to the clearest days.

Lastly, the projected 2028 most-impaired days value from modeling completed by the Texas Commission on Environmental Quality (TCEQ) is also shown in the figure.[14] TCEQ conducted CAMx visibility modeling to

[13] Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling, September 19, 2019 (https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf)

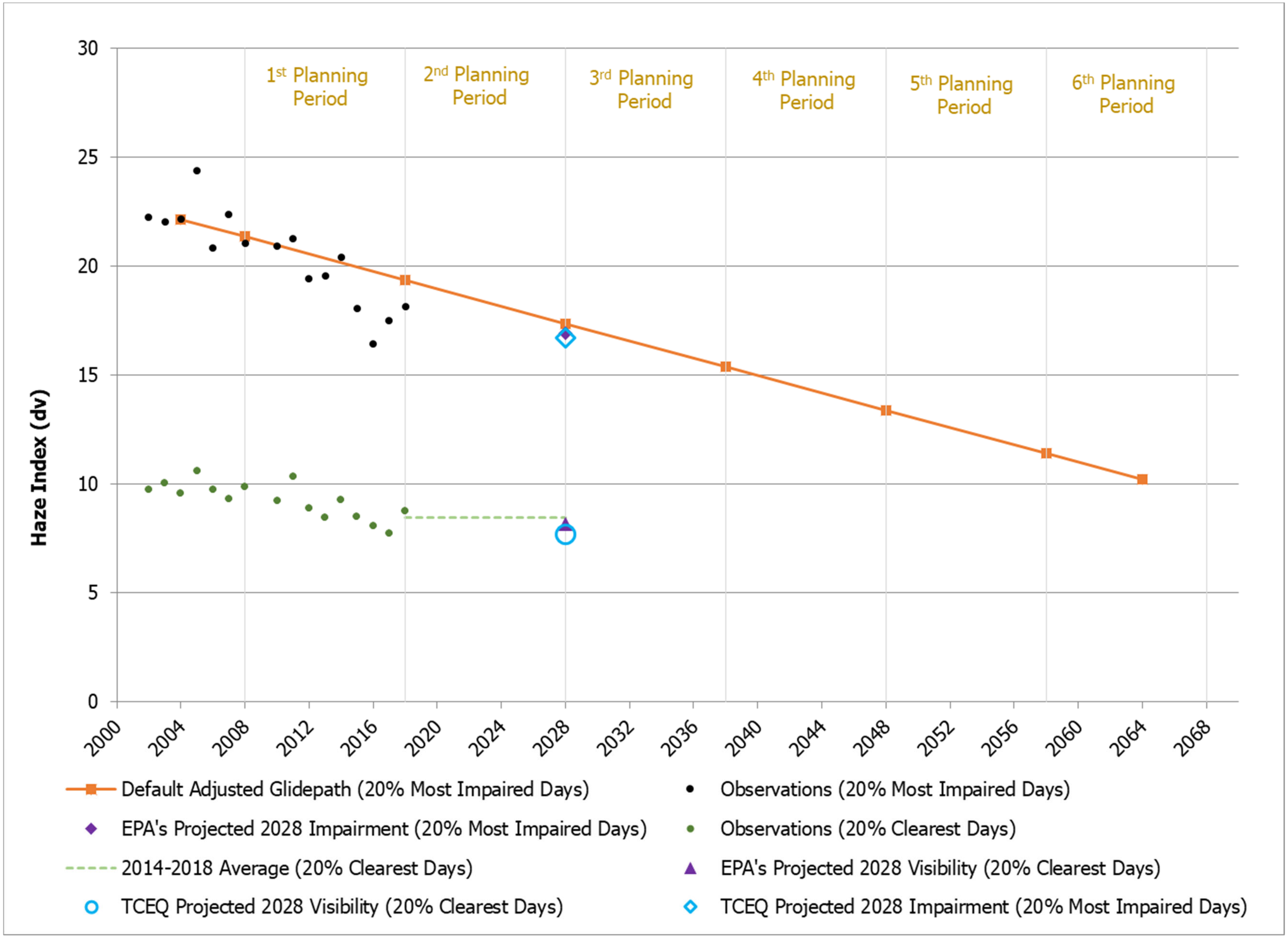
[14] Regional Haze Modeling to Evaluating Progress in Improving Visibility in and near Texas, dated January 21, 2020 (https://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/pm/5822010567009-20200121-ramboll-RegionalHazeModelingEvaluateProgressVisibility.pdf)

assist with Step 6 of the SIP Guidance.[15] It also indicates that the 2028 projected visibility impairment at WIMO is below the glidepath.

Because the EPA and TCEQ CAMx modeling for WIMO shows the projected 2028 haze index below the URP glide path, the current projected emissions reductions are sufficient to show reasonable progress and no additional controls are needed for this planning period.

[15] Step 6 of the SIP Guidance is regional scale modeling of the long-term strategy (LTS) to set the reasonable progress goals (RPGs) for 2028.

Figure 3-1. Observations Compared to Glidepaths for WIMO



APPENDIX C. ADDITIONAL FACTOR – REFINED HYSPLIT MODELING

WICHITA MOUNTAINS CLASS I AREA HYSPLIT MODELING SUMMARY

Prepared By:

Jeremy Jewell – Principal Consultant
Jeremy Townley – Managing Consultant

TRINITY CONSULTANTS
5801 E. 41st St.
Suite 450
Tulsa, OK 74135
(918) 622-7111

September 3, 2020

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1. INTRODUCTION

The Central States Air Resource Agencies (CenSARA) regional planning organization (RPO) completed Area of Influence (AOI) analyses for several Class I areas, including the Wichita Mountains Wildlife Refuge Class I area ("WIMO" or "WIMO1"), using the National Oceanic and Atmospheric Administration's (NOAA)'s Hybrid-Single Particle Lagrangian Integrated Trajectory Model (HYSPLIT) to assist its states, including Oklahoma, with source screening. The Oklahoma Department of Environmental Quality (ODEQ) relied on CenSARA's analysis as the basis for determining which sources would be required to complete a regional haze reasonable progress four-factor analysis.

Oklahoma Gas & Electric (OG&E) contracted with Trinity to evaluate the CenSARA modeling and complete a refined analysis for WIMO. This report summarizes the analysis completed by Trinity.

2. HYSPLIT METHODOLOGY

HYSPLIT is a hybrid model using both the Lagrangian approach, which uses a moving frame of reference for the advection and diffusion calculations as the trajectories or air parcels move from their initial location and the Eulerian methodology, which uses a fixed three-dimensional grid as a frame of reference to compute pollutant air concentrations. The dispersion of a hypothetical pollutant is calculated by assuming either puff or particle dispersion. The back-trajectory analysis utilized applies a particle model, where a fixed number of particles are advected about the model domain by the mean wind field and spread by a turbulent component. The model's default configuration assumes a 3-dimensional particle distribution (horizontal and vertical).

There are two HYSPLIT modeling techniques available: dispersion modeling, which models the concentration of dispersed pollutants in a plume, or trajectory modeling, which calculates the transport of pollution along a finite path. In its analysis, Trinity employed the trajectory modeling tool to calculate the back-trajectories for every hour of the 20 percent most impaired days from calendar years 2013 through 2016.

There are several options available for meteorological datasets. To resolve topographic features and mesoscale meteorological phenomena, the 12-km North American Model sigma-pressure hybrid dataset (NAMS) meteorological dataset was used. The following protocol was implemented:

- The HYSPLIT model was run for each hour of each visibility impaired day (i.e., 24 runs per day);
- A 72-hour back-trajectory was calculated for each of the 24 runs to capture the transport of pollutants from all nearby sources to a selected endpoint. The model calculated the back-trajectories in 1-hour time steps; and
- The sigma height option was used, with an initial target height of 0.5 sigma, which represents half the height of the boundary layer. This height is considered representative of the mean ground level of ambient air since the boundary layer is well-mixed/homogenous.

The back-trajectories were then aggregated into a residence time frequency matrix where the columns are longitude bins and rows are latitude bins. For each grid cell (i,j), the frequency, F, is calculated using the following equation:

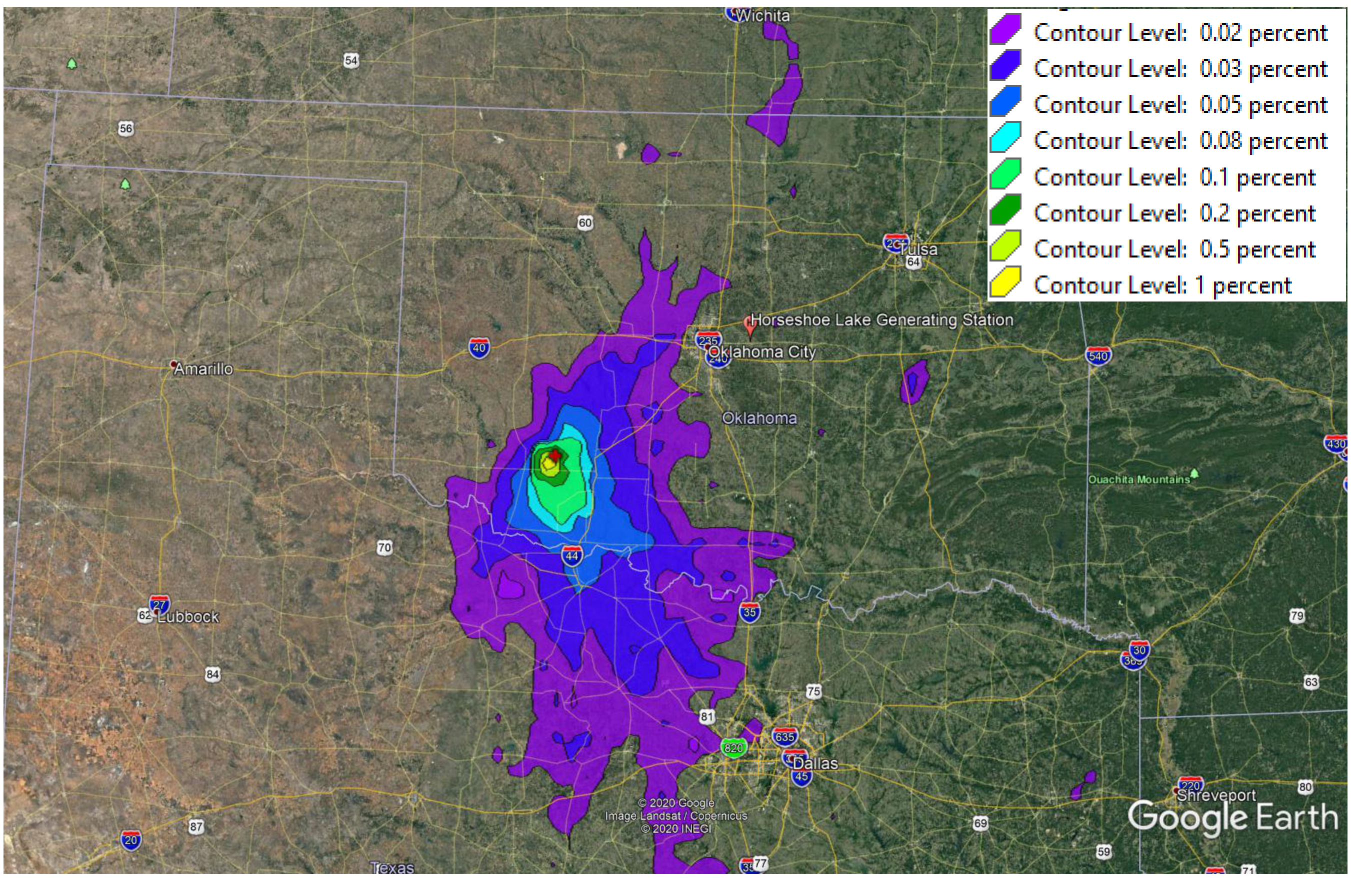
$$F_{i,j} = \frac{1}{N} \sum T_{i,j} \qquad \text{(equation 1)}$$

where T is the number of trajectory points that are located in a grid cell (i,j), and N is the total number of trajectory points analyzed.

3. FREQUENCY COMPARISION FOR WICHITA MOUNTAINS

The residence time frequency analysis described was conducted for the WIMO monitor location. The results of this analysis reveal that the cumulative residence times of air parcels contributing to the 20 percent most impaired days in the grid cell containing the OG&E Horseshoe Lake Generating Station (Horseshoe Lake) located in Harrah, Oklahoma (OK) are less than 0.02 %. In other words, according to this analysis, Horseshoe Lake is upwind of WIMO for less than 1.5 hours of the total time represented by the 20 % most impaired days of the four modeled years. The residence time frequency analysis results for the entire region are depicted in Figure 3-1. The map was generated using the HYSPLIT "trajfreq" and "concplot" executables, which output interpolated contours based on the discrete grid cell frequency values.

Figure 3-1. HYSPLIT Residence Time Percent Frequency for WIMO



OGE Energy Corp. PO Box 321
Oklahoma City, Oklahoma 73101-0321
405-553-3000
www.oge.com

OG&E

July 15, 2020

E-MAILED

Ms. Kendal Stegmann, Director, Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

Re: Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program
Facility: Mustang Generating Station

Dear Ms. Stegmann:

On July 1, 2020, OG&E received a request from the Oklahoma Department of Environmental Quality (ODEQ) requesting that Oklahoma Gas and Electric (OG&E) perform a 4-factor analysis of all potential control measures for nitrogen oxides (NO_x) on Electric Generating Units (EGUs) 3 and 4 at our Mustang Generating Station (Mustang).

Units 3 and 4 at Mustang were permanently retired on December 31, 2017 and have not operated since as required by Permit No. 2011-1008-C (M-1) issued December 11, 2015. In addition to the retirement being required by the Permit, Units 3 and 4 have been permanently disconnected from their fuel source and are no longer physically operable. OG&E submitted a Retired Unit Exemption on January 18, 2018 regarding the cessation of operation for Units 3 and 4 (see attachment).

No additional reduction of NOx emissions is possible from Units 3 and 4 at Mustang because they have been permanently retired. OG&E believes that this information satisfies ODEQ's request of July 1, 2020 for information on cost effective NOx reductions at Mustang Units 3 and 4.

In fact, OG&E believes that the retirement of Units 3 and 4 is well beyond what would have been deemed cost effective if the units continued to operate. Their retirement is contributing to the observed visibility conditions in Wichita Mountains being well below the Uniform Rate of Progress. OG&E hopes that this contribution to visibility improvement will be credited by DEQ in determining what, if any, additional contribution is reasonable from OG&E in connection with the 2021 regional haze SIP. If you need additional information or have questions, please contact me at (405)553-3221.

Sincerely,

Ford Benham
Director Environmental Operations

OGE Energy Corp. PO Box 321
Oklahoma City, Oklahoma 73101-0321
405-553-3000
www.oge.com

OG&E

January 18, 2018

CERTIFIED MAIL: 7015 3010 0000 9575 2302

Mr. Raymond Magyar (6EN-AA)
Air Enforcement Section
EPA Region 6
1445 Ross Avenue
Dallas, Texas 75202-2733

**Re: Oklahoma Gas & Electric Co. (OG&E)
Mustang Generating Station, Unit 3 & 4
Retired Unit Exemption**

Dear Mr. Magyar:

In accordance with 40 CFR 72.8(b)(2) OG&E is submitting the attached Retired Unit Exemption forms, for Mustang Generating Station's Units 3 & 4 (ORIS 2953). The units have ceased operation and were permanently retired December 31, 2017.

Both Units 3 & 4 have been isolated and will be left in place until it becomes necessary to remove them from their current location. The units have been permanently disconnected from their fuel source and are no longer physically operable. OG&E will make appropriate changes to the facility permits during the next renewal cycle. OG&E will also continue to comply with the requirements of §72.8(d) for this unit.

If you have any questions, please contact me at (405)553-3031.

Sincerely,

Michael Hixon
Alternate Designated Representative

Cc: U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Mail Code 6204M
Attn: Retired Unit Exemption
Washington, DC 20460

IXOS: T. Shook
R. Butler

SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

KEVIN STITT
Governor

January 31, 2022

Ford Benham
Oklahoma Gas & Electric
PO Box 321 MC601
Oklahoma City, OK 73102-0321

Subject: Additional clarifications on OG&E's 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Mr. Benham:

In a letter dated July 1, 2020, the Oklahoma Department of Environmental Quality (DEQ) identified the Horseshoe Lake Generating Station as subject to a four-factor reasonable progress analysis under the Regional Haze Rule as part of DEQ's development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

On September 29, 2020, OG&E submitted its four-factor analysis to DEQ for the Horseshoe Lake Generating Station. OG&E included in its response that there were no cost-effective nitrogen oxides (NO_x) control measures available for units 6 through 10. DEQ included these conclusions in its draft Regional Haze SIP for Planning Period 2 that was shared with the Federal Land Managers and the U.S. Environmental Protection Agency (EPA) for their review and comment. DEQ requests that OG&E review its four-factor analysis for potential NO_x control measures for Horseshoe Lake and respond to the following questions, which are based on EPA's review of Oklahoma's draft SIP. We understand that some of the requested data/analysis may be gleaned or explained from DEQ's permitting and compliance files, and/or OG&E's submittal. However, your response will allow OG&E to document the information that best explains and supports the conclusions of your four-factor analysis. DEQ intends to continue its analysis in parallel.

1. 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.

2. For the time necessary for implementation, please explain why it is anticipated that it would take a minimum of four years to install selective catalytic reduction (SCR) on one unit. Based

on historical data, the installation of SCR at similar units can be typically completed in three years.

3. The federal reviewers stated that 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.[1]" (See August 2019 Guidance at 34.)

4. The federal reviewers stated that the use of a 7% interest rate in the cost analysis is not appropriate. 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[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.

DEQ respectfully requests that OG&E respond to EPA's questions no later than February 28, 2022. Thank you for your assistance with this matter. Please contact Melanie Foster at 405-702-4218 for any questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

[1] https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf
[2] https://www.epa.gov/sites/default/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

OGE Energy Corp. PO Box 321
Oklahoma City, Oklahoma 73101-0321
405-553-3000
www.oge.com

OG&E

February 25, 2022

DELIVERED VIA E-MAIL

Kendal Stegmann
Director, Air Quality Division
Oklahoma Department of Environmental Quality
707 N. Robinson
P.O. Box 1677
Oklahoma City, OK 73101-1677

RE: Reply to ODEQ's January 31, 2022 request for additional clarifications on OG&E's September 29, 2020 Regional Haze 4-Factor Analysis for Horseshoe Lake Generating Station

Dear Ms. Stegmann:

This letter provides Oklahoma Gas & Electric Company's (OG&E's) replies to the four items requested in the Oklahoma Department of Environmental Quality's (ODEQ's) above-referenced letter.

DEQ Request #1. *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.*

Reply #1. Actual 2016 emissions were used to represent 2028 emissions for several reasons. First, 2016 is what the Central States Air Resource Agencies (CenSARA) used in its Area of Impact (AOI) analysis that ODEQ relied upon to select sources for evaluation. Therefore, OG&E's use of 2016 emissions maintains consistency with previous agency decisions and analyses that underlie emission control choices for the Department. Second, OG&E's resource group advised that 2016 was the best prediction of future emissions in 2028 based on their analysis of projected demand, scheduled outages, generation portfolio, projected fuel prices, and other factors. The historically low natural gas prices in 2018 and 2019 are not expected to remain in effect in 2028 and make those years not appropriate for use in projections. Also note that 2020 emissions data was not available when the four-factor analysis was submitted in September 2020.

DEQ Request #2. *For the time necessary for implementation, please explain why it is anticipated that it would take a minimum of four years to install selective catalytic reduction (SCR) on one unit. Based on historical data, the installation of SCR at similar units can be typically completed in three years.*

Reply #2. The request's statement about "historical data [on] the installation of SCR at similar units" does not identify any specific units that are considered similar and that have SCR. 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 which has a unique physical configuration that limits the available space for SCR installation. Based on the best information available to OG&E,[1] an implementation schedule for SCR installation at Horseshoe Lake consists of three phases totaling four years:

1. Design, specification, and procurement, which is expected to take a total of 10 months due to the need for significant architect/engineer work on physical arrangement of systems in light of current plant layout;
2. Off-site fabrication and delivery, which is expected to take an additional 18 months, and expediting the time frame is likely to be impossible with supply chain and pandemic disruptions; and
3. Installation, commissioning, startup, and balance of plant constructions, which is expected to take another 20 months.

DEQ Request #3. *The federal reviewers stated that 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."*

Reply #3. Each of the above-mentioned units is more than 50 years old. As stated in various public reports, including the Integrated Resource Plan, OG&E does not expect that the Horseshoe Lake units will operate for even 20 more years. Nevertheless, 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.

DEQ Request #4. *The federal reviewers stated that the use of a 7% interest rate in the cost analysis is not appropriate. 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.*

Reply #4. The first part of the request, which suggests that 7 percent is not appropriate, represents a fundamental shift in policy. The Office of Management and Budget (OMB)-recommended 7 percent interest rate has been relied upon commonly for control technology analyses for many years, even decades, including during the regional haze first planning period when the bank prime rate was exactly the same as it is now (3.25%), i.e., from December 2008 to December 2015.

The second part of the request suggests that EPA's Control Cost Manual presents the bank prime rate as a default absent a company-specific interest rate. This is incorrect. The bank prime rate is mentioned as one of several indicators of the cost of borrowing. Moreover, the purpose of the bank prime rate is not

[1] See Appendix B of OG&E's September 29, 2020 *Regional Haze Four-Factor Reasonable Progress Analysis* submittal.

at all related to the cost of capital for an individual company. It certainly does not represent OG&E's cost of borrowing. As of May 24, 2019, OG&E's cost of borrowing was documented to be 7.31 percent.[2]

In addition to these replies, OG&E is providing one update to its September 29, 2020 *Regional Haze Four-Factor Reasonable Progress Analysis* submittal. Figure 3-1 in Appendix B of that submittal has been updated to include the most recent Class I area observation data (for years 2019 and 2020). The updated version is enclosed. It demonstrates that actual visibility conditions in the Wichita Mountains have continued to improve, and this substantiates the conclusions drawn in OG&E's submittal – primarily that no additional controls are needed for this planning period.

Thank you for the opportunity to provide this information. OG&E looks forward to working with the ODEQ in its revisions to the regional haze SIP. Please contact me at 405-553-3221 or benhamf@oge.com if you have any questions or need any additional information.

Sincerely

OG&E

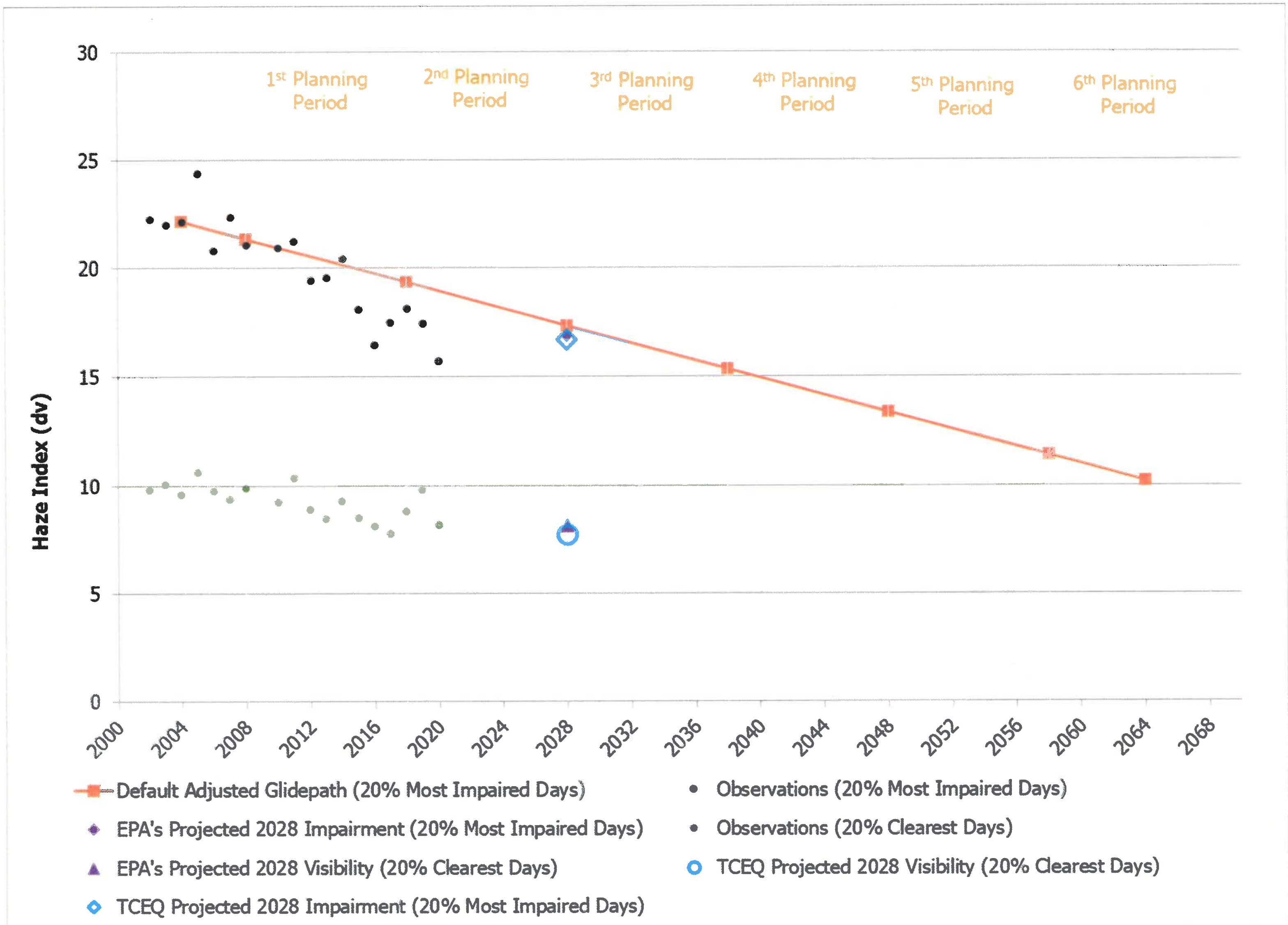
Ford Benham
Director of Environmental Operations

Enclosure Updated Figure 3-1 from Appendix B of OG&E's September 29, 2020 *Regional Haze Four-Factor Reasonable Progress Analysis* submittal

cc: Charles Wehland, Jones Day
Jeremy Jewell, Trinity Consultants
Ruseal Brewer, OGE Legal

[2] Donald R. Rowlett's *Testimony in Support of the Non-unanimous Joint Stipulation and Settlement Agreement* before the Corporation Commission of Oklahoma (May 24, 2019), page 3. (https://ogeenergy.gcs-web.com/static-files/b8aae59a-2677-45d3-ad90-c2a9283da3a9)

Updated Figure 3-1. Observations and Model Predictions Compared to Glidepath for WIMO



SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

KEVIN STITT
Governor

Jenny Ellette
ONEOK Field Services
PO Box 871
Tulsa, OK 74102-0871

July 1, 2020

Subject: Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Ms. Ellette:

This letter is to inform you that the Oklahoma Department of Environmental Quality (DEQ) has identified ONEOK's Maysville Gas Plant and Lindsay Booster Station as facilities subject to a four-factor reasonable progress analysis under the Regional Haze Rule. DEQ is in the development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

The members of the Central States Air Resources Agencies (CenSARA) organization, which include Oklahoma, contracted with Ramboll US Corporation (Ramboll) to produce a study examining the impact of stationary sources of NOx and SO_2 on each Class 1 area in the central region of the United States. DEQ used a method based on this study to determine which sources may have the greatest potential for contributing to visibility impairment at Oklahoma's Class 1 area: the Wichita Mountains Wilderness Area.

DEQ must develop a long-term strategy to address visibility impairment and make "reasonable" progress toward a goal of no anthropogenic visibility impairment by 2064. The Regional Haze Rule provides four factors (40 CFR §51.308(f)(2)(i)) by which a state must consider potential control measures for the long-term strategy: 1) the cost of compliance; 2) the time necessary for compliance; 3) the energy and non-air quality environmental impacts of compliance; and 4) the remaining useful life of existing sources subject to this requirement.

DEQ requests that ONEOK perform a four-factor analysis of all potential control measures for NOx on all fuel-burning equipment with a heat input of 50 MMBTU/hr or more including but not limited to the following emission units:

Maysville Gas Plant

1. C-1 through C-7; Clark RA-8 and RA-6
2. C-8 through C-14; Clark HRA-8, HBA-8, and HBA-5

Lindsay Booster Station

1. C-13 and C-14; 800 hp Clark RA-8
2. C-15 and C-16; 880 hp Clark HRA-8
3. C-19 and C-20; 1,760 hp Clark HRA-8

4. C-21; 1,350 Cooper-Bessemer GMVA-10
5. C-22; 1,100 Cooper-Bessemer GMV-10

For any technically feasible control measure, the following information should be provided in detail:

I. Emission reductions achievable by implementation of the measure
   a. Baseline emission rate (lb/hr, lb/MMBTU, etc)
   b. Controlled emission rate (same form as baseline rate)
   c. Control effectiveness (percent reduction expected)
   d. Annual emission reductions expected (ton/year)
II. Time necessary to implement the measure
III. Remaining useful life
   a. Remaining useful life of the control measure, or
   b. The corresponding life of the unit may be used if an enforceable shutdown date of the emission unit is no later than 2028.
IV. Energy and non-air quality environmental impacts of the measure.
   a. Detail any cost of energy, waste disposal, regulatory requirement, etc. incurred with implementation of the control measure.
V. Cost of implementing the measure
   a. Capital costs
   b. Annual operating and maintenance costs
   c. Annualized costs

DEQ respectfully requests that your company submit a report containing the complete 4-factor analysis no later than September 1, 2020. This will allow DEQ to review and identify any cost-effective control measure to be incorporated into the Regional Haze state implementation plan prior to the submission deadline of July 31, 2021.

Please contact DEQ if you have any questions about the method for conducting a 4-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical review required under the Rule.

Thank you for your assistance with this matter. Please contact Cooper Garbe at 405-702-4169 or Melanie Foster at 405-702-4218 for your questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

KEVIN STITT
Governor

Whitney Hall
Oxbow Calcining
11826 N 30th St
Kremlin, OK 73753

July 1, 2020

Subject: Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Ms. Hall:

This letter is to inform you that the Oklahoma Department of Environmental Quality (DEQ) has identified the Kremlin Calcining Plant located in Garfield County, Oklahoma, as subject to a four-factor reasonable progress analysis under the Regional Haze Rule. DEQ is in the development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

The states in the Central States Air Resources Agencies (CenSARA) organization, which include Oklahoma, contracted with Ramboll US Corporation (Ramboll) to produce a study examining the impact of stationary sources of NOx and SO_2 on each Class 1 area in the central region of the United States. DEQ used a method based on this study to determine which sources may have the greatest potential for contributing to visibility impairment at Oklahoma's Class 1 area: the Wichita Mountains Wilderness Area.

DEQ must develop a long-term strategy to address visibility impairment and make "reasonable" progress toward a goal of no anthropogenic visibility impairment by 2064. The Regional Haze Rule provides four factors (40 CFR §51.308(f)(2)(i)) by which a state must consider potential control measures for the long-term strategy: 1) the cost of compliance; 2) the time necessary for compliance; 3) the energy and non-air quality environmental impacts of compliance; and 4) the remaining useful life of existing sources subject to this requirement.

DEQ requests that Oxbow perform a four-factor analysis of all potential control measures for SO_2 on the following emission units at the Kremlin Calcining Plant:

1. Kiln 1
2. Kiln 2
3. Kiln 3

For any technically feasible control measure, the following information should be provided in detail:

I. Emission reductions achievable by implementation of the measure
    a. Baseline emission rate (lb/hr, lb/MMBTU, etc)
    b. Controlled emission rate (same form as baseline rate)

c. Control effectiveness (percent reduction expected)
d. Annual emission reductions expected (ton/year)

II. Time necessary to implement the measure

III. Remaining useful life
a. Remaining useful life of the control measure, or
b. The corresponding life of the unit may be used if an enforceable shutdown date of the emission unit is no later than 2028.

IV. Energy and non-air quality environmental impacts of the measure.
a. Detail any cost of energy, waste disposal, regulatory requirement, etc. incurred with implementation of the control measure.

V. Cost of implementing the measure
a. Capital costs
b. Annual operating and maintenance costs
c. Annualized costs

DEQ respectfully requests that your company submit a report containing the complete 4-factor analysis no later than September 1, 2020. This will allow DEQ to review and identify any cost-effective control measure to be incorporated into the Regional Haze state implementation plan prior to the submission deadline of July 31, 2021.

Please contact DEQ if you have any questions about the method for conducting a 4-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical review required under the Rule.

Thank you for your assistance with this matter. Please contact Cooper Garbe at 405-702-4169 or Melanie Foster at 405-702-4218 for your questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

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REGIONAL HAZE REASONABLE PROGRESS ANALYSIS

Oxbow Calcining LLC
Kremlin Calcined Coke Plant

Presented To:

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

Prepared By:

Jeremy Jewell – Principal Consultant
Stephen Beene – Senior Consultant

TRINITY CONSULTANTS
5801 E. 41st St.
Suite 450
Tulsa, OK 74135
(918) 622-7111

September 29, 2020

Project 203702.0092

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1. INTRODUCTION

Trinity Consultants (Trinity) prepared this report on behalf of Oxbow Calcining LLC (Oxbow) for its Calcined Coke Plant located between Enid and Kremlin, Oklahoma (the Plant)[1] in response to the July 1, 2020 letter *Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program* (the request letter) from the Oklahoma Department of Environmental Quality (ODEQ). Per the request letter and ODEQ's June 17, 2020 presentation *Regional Haze SIP Development Update*, the request is based on an Area of Influence (AOI) study completed by the Central States Air Resources Agencies (CenSARA) for the Wichita Mountains Class I area. In correspondence dated August 21, 2020, ODEQ granted an extension until September 30, 2020 to respond to the request.[2]

Per the request, this report provides information related to sulfur dioxide (SO_2) emissions reduction options for the Plant's three coke calcining kilns: Kiln 1, Kiln 2, and Kiln 3. The following specific technical and economic information, where applicable, is provided in this report for each emissions reduction option considered for the kilns, in accordance with instructions in the request letter:

- Technical feasibility
- Control effectiveness and emissions reductions
- Time necessary for implementation[3]
- Remaining useful life[3]
- Energy and non-air quality environmental impacts[3]
- Costs of implementation[3]

Appendix A of this report includes a redacted version of a site-specific controls studies prepared by Sargent & Lundy (S&L). A confidential version of this report with non-redacted pages in Appendix A is submitted via hand delivery as recommended by ODEQ.

In addition to the information requested by the request letter, Appendices B and C include reports related to additional factors that Oxbow believes ODEQ should consider in the development of Oklahoma's state implementation plan (SIP) for the regional haze second planning period (2PP). Based on information presented in these reports, Oxbow also believes that ODEQ should adopt the adjusted default URP glidepath presented by EPA for the Wichita Mountains,[4] take notice of the fact that current and projected visibility conditions in the Wichita Mountains are better than the URP glidepath and consider visibility benefits, if any, in conducting analyses of emission reduction measures for the 2PP.

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[1] The Plant is referred to as the "Kremlin Calcining Plant" in ODEQ's July 1, 2020 letter and simply as "Kremlin" in various documents generated by ODEQ and CenSARA related to the AOI study.

[2] ODEQ asked Oxbow to provide a status update no later than September 15, 2020. This was provided via conference call on September 14, 2020.

[3] These are the four factors that must be included in evaluating emission reduction measures necessary to make reasonable progress determinations. See, 40 CFR § 51.308(f)(2)(i). As noted above, Oxbow also recommends that ODEQ consider visibility benefits, if any, in conducting analyses of emission reduction measures for the 2PP. See, 40 CFR § 51.308(f)(2)(iv)(B).

[4] *Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling*, September 19, 2019, (https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf)

2. SO_2 EMISSIONS REDUCTIONS OPTIONS

Add-on SO_2 emissions controls are not common in the petroleum coke calcining industry. The U.S. Environmental Protection Agency's (EPA's) Reasonably Available Control Technology (RACT), Best Available Control Technology (BACT), and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) includes no SO_2 emissions control options for petroleum coke calcining kilns. Nevertheless, based on consultation with the premier engineering and project management firm, S&L, the following SO_2 emissions reduction options are evaluated as potentially applicable to the Plant's petroleum coke calcining kilns.

- Pre-Combustion SO_2 Control Strategies
- Combustion SO_2 Control Strategies
- Post-Combustion ("Add-on") Control Strategies
  - Wet Flue Gas Desulfurization (WFGD)
  - Dry Flue Gas Desulfurization (DFGD)
  - Dry Sorbent Injection (DSI)

Each of these options, including potential differences in design and operation of each option, are described in the site-specific evaluation report completed by S&L: *SO_2 Control Technologies Evaluation to Support Regional Haze Rule Analysis* (the S&L Report), provided in Appendix A to this report.

2.1 Technical Feasibility

In accordance with EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, [5] (the EPA SIP Guidance) at p. 22, "The first step in characterizing control measures for a source is the identification of technically feasible control measures for those pollutants that contribute to visibility impairment." The EPA SIP Guidance does not define the term technically feasible. The only known definition of that term within the regional haze context is found in EPA's *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations* (the BART Guidelines), which states:[6]

> *Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: "availability" and "applicability." …a technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.*

The BART Guidelines also discuss the criteria for demonstrating that a control option is not technically feasible for a particular emissions unit:[7]

---

[5] *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 2019, EPA-457/B-19-003.

[6] See, 70 Fed. Reg. 39,165 (July 6, 2005).

[7] Ibid.

> *…a demonstration of technical infeasibility…should explain, based on physical, chemical, or engineering principles, why technical difficulties would preclude the successful use of the control option on the emissions unit under review.*
>
> *…a control option…is technically infeasible… [if] specific circumstances preclude its application to a particular emission unit.*

2.1.1 Pre-Combustion and Combustion SO_2 Control Strategies

As documented in the S&L Report (Sections 4.1 and 4.2), both pre-combustion and combustion SO_2 control strategies are technically infeasible for the Plant's kilns due to both physical (e.g., sizing) and chemical (e.g., ingredients) issues.

2.1.2 Post-Combustion SO_2 Control Strategies

Oxbow understands that there are a few commercially operating post-combustion SO_2 control systems installed on petroleum coke kilns in the U.S. Unfortunately, there is limited information publicly available on the design and operation of the existing systems to determine the types of systems installed and the SO_2 removal efficiencies demonstrated in practice. Oxbow is unable to verify which particular systems – WFGD, DFGD, or DSI – are being used on petroleum coke calcining kilns. Despite a lack of demonstration, for the purposes of this report, these technologies are evaluated as first-of-its-kind applications for this industry sector.

With regards to the site-specific application of WFGD, DFGD, or DSI at the Kremlin Plant, as detailed in the S&L Report (Section 2), there is a high-level of uncertainty about the availability of water that would be required to operate any of the controls. Oxbow is aware that the City of Enid is planning to develop a new water pipeline from Kaw Lake (the "Enid-Kaw Lake Pipeline"), which is approximately 70 miles from Enid and 65 miles from the Kremlin Plant, and a new municipal water treatment plant. To utilize this source of water, if it is developed and has capacity, would require the construction of a separate pipeline to the Kremlin Plant. Another theoretically possible but equally uncertain option for obtaining water would be to bring it to the Plant via trucks.

ODEQ may conclude that the WFGD, DFGD, and DSI options are technically infeasible because of the plant-specific water supply uncertainty. However, for the purposes of this report, Oxbow, S&L, and Trinity have prepared evaluations of the control strategies assuming the water supply scenarios are viable and based on best engineering judgment at this time.

2.2 Control Effectiveness

S&L estimated the control effectiveness of each SO_2 emissions reduction option based on a source specific engineering evaluation of the Oxbow kilns considering the lack of published information on application of controls to petroleum coke calcining kilns. S&L's evaluation established uncontrolled emission rates for each kiln based on the hourly average emissions rates from 2015 – 2019. This five-year period was selected to ensure a robust evaluation of control efficiency and controlled emission rates. The estimation of control efficiency and controlled emission rates was based on engineering principles, discussions with control vendors, and prior experience with each of the technologies on other types of emission units, particularly utility boilers. Table 2-1 summarizes the approximate control efficiencies theoretically possible for each option and the resulting emission rates provided in the S&L Report on a long term average basis (Table 2-2 *Current Stack Emissions* and Appendix A *SO_2 Control Summary*, Table 2 *SO_2 Control Effectiveness*).

Table 2-1. Control Effectiveness of SO_2 Emissions Reduction Options

SO_2 Emissions Reduction Option	Control Efficiency (%)	Uncontrolled SO_2 Emission Rate (lb/hr)			Controlled SO_2 Emission Rate (lb/hr)		
		Kiln 1	Kiln 2	Kiln 3	Kiln 1	Kiln 2	Kiln 3
WFGD	94	1,626	1,447	925	92	82	52
DFGD	92				138	122	78
DSI	40				976	868	555

Considering the operational differences between industrial sources such as the Plant's kilns and utility-sized boilers, the control efficiency values summarized above are consistent with evaluations of these control options completed by ODEQ and EPA for utility boilers.[8]

2.3 Emissions Reductions

The request letter does not specify a baseline period. Oxbow, S&L, and Trinity have evaluated several years of historic operations and emissions information, and January 1, 2018 to December 31, 2019 is proposed as an appropriate baseline period. This is consistent with 4-factor analyses in other states, e.g., Louisiana. Baseline emission rates are set equal to the annual-average value from the baseline period in accordance with EPA's Air Pollution Control Cost Manual (CCM)[9] and general practice for control cost assessments that has been applied to hundreds of prior regional haze analyses. Table 2-2 presents these baseline emission rates and the controlled emission rates and emission reduction potentials, as detailed in the S&L Report (Table 2-2 *Current Stack Emissions* and Appendix A *SO_2 Control Summary*, Table 2 *SO_2 Control Effectiveness*), for each of the SO_2 emissions reduction options.

[8] For example, for BART in Oklahoma EPA evaluated WFGD and DFGD for six coal-fired utility boilers (two boilers at each of the Oklahoma Gas & Electric's Muskogee Power Plant and Sooner Power Plant and two boilers at the American Electric Power / Public Service of Oklahoma (AEP/PSO) Northeastern Power Plant) based on control efficiency values of 98% for WFGD and 90% to 95% (depending on boiler specifics and coal sulfur content) for DFGD. See, 76 Fed. Reg. 16,187, 16,188 (March 22, 2011). EPA completed additional evalulations for DFGD and DSI for the AEP/PSO Northeastern Power Plant based on control efficiency values of 90-91% and 56%, respectively. See, See, 79 Fed. Reg. 12,954-12,957 and *Technical Support Document for the AEP/PSO BART Revision to the Oklahoma Regional Haze State Implementation Plan and Federal Implementation Plan* (July 2013), p. 8.

In a more recent determination, EPA evaluated WFGD, DFGD (SDA), and DSI for Entergy's Nelson Unit 6 in Louisiana based on control efficiency values of 94.74%, 92.11%, and 50 %, respectively. See, 82 Fed. Reg. 32,298, 32,299 (July 13, 2017).

[9] *EPA Air Pollution Control Cost Manual*, Sixth Edition (https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual), Section 5, Chapter 1 *SO_2 and Acid Gas Controls*.

Table 2-2. Baseline and Controlled Emission Rates and Emissions Reductions of SO_2 Emissions Reduction Options

Emissions Unit	Baseline SO_2 Emission Rate (tpy)	SO_2 Emissions Reduction Option	Controlled SO_2 Emission Rate (tpy)	SO_2 Emissions Reduction (tpy)
Kiln 1	6,556	WFGD	371	6,185
		DFGD	556	6,000
		DSI	3,934	2,622
Kiln 2	5,674	WFGD	322	5,352
		DFGD	478	5,196
		DSI	3,404	2,270
Kiln 3	2,950	WFGD	166	2,784
		DFGD	249	2,701
		DSI	1,770	1,180

2.4 Time Necessary for Implementation

The S&L Report (Section 7) provides a high-level implementation schedule, including key elements such as equipment design, procurement, fabrication, construction, and commissioning, for each of the SO_2 emissions reduction options. Allowing for some contingency, Oxbow proposes a minimum of five years for implementing either the WFGD option or the DFGD option and two years for the DSI option.

The implementation would begin on the effective date of an approved determination (e.g., approved SIP). Consistent with other states' (e.g., Louisiana's) 4-factor analyses, it is assumed that EPA will approve ODEQ's regional haze 2PP SIP on or around January 31, 2023. Adding the times necessary for implementation to this projected date results in assumed implementation dates of February 1, 2025 for DSI and February 1, 2028 for WFGD and DFGD.

2.5 Remaining Useful Life

Oxbow has no plans to shut down any of the kilns, and there are no enforceable limitations on the remaining useful life (RUL) of the kilns. For the purposes of the control cost assessment, an industry standard 20-year RUL is used. This is consistent with the CCM. As discussed in the S&L Report (Section 8), a longer RUL is theoretically possible, but planning for a longer RUL is not prudent considering the novelty of these control options for petroleum coke calcining kilns. Additionally, planning for a longer RUL would necessitate substantial increases in both capital and operating costs. According to the S&L Report, the 20-year equipment life is representative of the most economical equipment design.

2.6 Energy and Non-air Quality Environmental Impacts

All of the SO_2 emissions reduction options require additional energy for operation and would result in various non-air quality environmental impacts primarily related to additional water usage, wastewater management, and solid waste management. To the extent possible, these impacts have been quantified in the cost analysis prepared by S&L and summarized below.

2.7 Costs

Table 2-3 and Table 2-4 summarize, for the two water supply scenarios, the estimated costs, including total and annualized capital costs,[10] annual operations and maintenance (O&M) costs, and cost effectiveness based on the emission reduction values from Table 2-2 for each of the SO_2 emissions reduction options. Based on the anticipated determination dates and implementation schedules discussed in Section 2.4, and in accordance with the CCM, 2024 is used as the zero-year cost basis. Details of the cost estimates are presented in the S&L Report.

Table 2-3. Estimated Costs of SO_2 Emissions Reduction Options – City of Enid Water Supply Scenario

Emissions Unit	SO_2 Emissions Reduction Option	Capital Costs ($)	Annualized Capital Costs ($/year)	Annual O&M Costs ($/year)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Kiln 1	WFGD	144,865,000	17,016,000	23,644,000	40,660,000	6,574
	DFGD	139,944,000	16,438,000	23,704,000	40,142,000	6,691
	DSI	113,618,000	13,346,000	21,995,000	35,341,000	13,477
Kiln 2	WFGD	140,639,000	16,519,000	23,038,000	39,557,000	7,390
	DFGD	135,748,000	15,945,000	22,812,000	38,757,000	7,460
	DSI	109,618,000	12,876,000	21,041,000	33,917,000	14,944
Kiln 3	WFGD	127,395,000	14,964,000	20,613,000	35,577,000	12,778
	DFGD	123,005,000	14,448,000	19,825,000	34,273,000	12,688
	DSI	100,116,000	11,760,000	17,798,000	29,558,000	25,049

Table 2-4. Estimated Costs of SO_2 Emissions Reduction Options – Trucked-In Water Supply Scenario

Emissions Unit	SO_2 Emissions Reduction Option	Capital Costs ($)	Annualized Capital Costs ($/year)	Annual O&M Costs ($/year)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
Kiln 1	WFGD	146,205,000	17,173,000	61,419,000	78,592,000	12,707
	DFGD	141,857,000	16,662,000	59,918,000	76,580,000	12,764
	DSI	113,687,000	13,354,000	51,914,000	65,268,000	24,889
Kiln 2	WFGD	141,958,000	16,674,000	59,924,000	76,598,000	14,311
	DFGD	136,887,000	16,079,000	55,642,000	71,721,000	13,804
	DSI	109,691,000	12,884,000	50,317,000	63,201,000	27,847
Kiln 3	WFGD	127,283,000	14,951,000	46,529,000	61,480,000	22,082
	DFGD	122,569,000	14,397,000	42,128,000	56,525,000	20,926
	DSI	98,988,000	11,627,000	38,237,000	49,864,000	42,258

[10] The capital costs are annualized using capital recovery factors (CRFs) based on the RUL presented in Section 2.5 and an interest rate of ten (10) percent based confidential company-specific capital market information, as presented in the S&L Report.

2.8 Conclusions

As suspected based on the quantity of water involved, the City of Enid water supply scenario results in lower overall annual costs (and cost effectiveness values) than the trucked-in water supply scenario, which would require estimated annual expenditure for trucking in water of approximately $94 million for WFGD, $85 million for DFGD, and $75 million for DSI in addition to the normal annual O&M costs (totals for all three kilns).

The cost effectiveness values for all three control options are economically infeasible even based on the less expensive water supply scenario. Based on the detailed, site-specific evaluation completed by S&L, the cost effectiveness for DFGD ranges from approximately $6,500/ton to approximately $12,500/ton. This cost range is economically infeasible based on precedents from (a) Oklahoma-specific determinations related to regional haze Best Available Retrofit Technology (BART) five-factor analyses[11] and BACT analyses, and (b) regional haze reasonable progress four-factor analysis determinations in other states in EPA Region VI.[12]

The same range of cost effectiveness applies to the WFGD option, and it is similarly economically infeasible. The cost effectiveness for DSI, ranging from approximately $13,200/ton to approximately $24,500/ton, is even more unreasonable.

Based on this evaluation of the regional haze reasonable progress four statutory factors (specifically the lack of demonstration of these control options for petroleum coke calcining kilns and the economic infeasibility of the options for the Plant's kilns) and the additional factors presented in Appendices B and C that should be considered (specifically the fact that current and projected conditions for the Wichita Mountains are better than the URP glidepath and the likely inability of any control options to result in appreciable visibility impacts), no SO_2 emissions reductions options are reasonable for the Plant's kilns.

[11] For example, EPA approved Oklahoma's BART determination for DSI at $1,758/ton, rejecting DFGD at $3,211/ton, for the AEP/PSO Northeastern power plant. See, See, 79 Fed. Reg. 12,954-12,957 and *Technical Support Document for the AEP/PSO BART Revision to the Oklahoma Regional Haze State Implementation Plan and Federal Implementation Plan* (July 2013), p. 16 – 17.

[12] For example, EPA used a cost threshold of $3,332/ton for first planning period reasonable progress four-factor analyses in Texas. See, 81 Fed. Reg. 296, 304, Fnt. 42 (Jan. 5, 2016).

Additionally, EPA's approval of Arkansas' first planning period SIP revisions included a reasonable progress analysis cost effectiveness value of $2,742/ton for DFGD for Entergy's Independence Plant (See, 83 Fed. Reg. 62,230 (Nov. 30, 2018)), and EPA approved Arkansas' determination that the control would not be required when weighing of the costs of compliance along with the other reasonable progress factors (specifically visibility modeling). See, 84 Fed. Reg. 51,033, 51,040 (Sep. 27, 2019).

APPENDIX A. SITE-SPECIFIC CONTROLS STUDY

Sargent & Lundy, *SO_2 Control Technologies Evaluation to Support Regional Haze Rule Analysis*, Report SL-015705

Oxbow

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Oxbow Calcining L.L.C.
Kremlin, OK Units 1, 2 and 3

SO_2 Control Technologies Evaluation to Support Regional Haze Rule Analysis

Report SL-015705

Revision 0

September 29, 2020

Project No.: 14083-001

55 East Monroe Street
Chicago, IL 60603-5780 USA
312-269-2000
www.sargentlundy.com

Sargent & Lundy

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ISSUE SUMMARY AND APPROVAL PAGE

This is to certify that this document has been prepared, reviewed and approved in accordance with Sargent & Lundy's Standard Operating Procedure SOP-0405, which is based on ANSI/ISO/ASQC Q9001 Quality Management Systems.

Contributors

Prepared by:

Name	Title	Signature	Date
[redacted]	Associate	[redacted]	9/29/2020
[redacted]	Senior Associate II	[redacted]	9/29/2020

Reviewed by:

Name	Title	Signature	Date
[redacted]	Senior Consultant	[redacted]	9/29/2020
[redacted]	Senior Project Manager	[redacted]	9/29/2020
[redacted]	Senior Environmental Manager	[redacted]	9/29/2020

Approved by:

[redacted]

9/29/2020

Date

[redacted]
Senior Environmental Manager

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CERTIFICATION PAGE

Sargent & Lundy, L.L.C. is registered in the State of Oklahoma to practice engineering.
The registration number is CA 2149 PE (expiration date: 06-30-2021).

I certify that this deliverable was prepared by me or under my supervision and that I am a registered professional engineer under the laws of the State of Oklahoma.

Certified By: [redacted] Date: 9/29/2020

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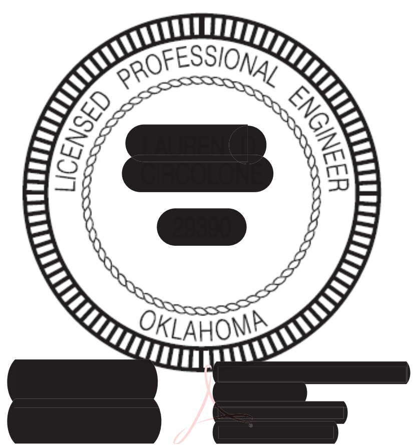

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1. INTRODUCTION

1.1. PURPOSE

Sargent & Lundy, L.L.C. (S&L) was retained to support the development of a Regional Haze Rule reasonable progress four-factor analysis for the control of sulfur dioxide (SO_2) from the Oxbow Calcining L.L.C. (Oxbow) Kremlin calcined coke facility. Emission units at the Oxbow Kremlin facility include three (3) rotary kilns that produce both anode and non-anode grade calcined petroleum coke. This report includes an evaluation of air pollution control (APC) technologies that may be available to reduce SO_2 emissions from the kilns, including an evaluation of technical feasibility, effectiveness, and costs.

As part of the Regional Haze second planning period State Implementation Plan, the Oklahoma Department of Environmental Quality (ODEQ) requested that Oxbow prepare a reasonable progress four-factor analysis of control measures for SO_2 on Kilns 1, 2 and 3 at the Kremlin calcined coke facility. S&L was engaged to prepare an evaluation of available control technologies including feasibility and effectiveness, and to develop capital costs and operating and maintenance (O&M) cost estimates for the technically feasible options.

1.2. TECHNOLOGIES EVALUATED

With respect to the control of SO_2 emissions, S&L was contracted to identify available emissions control technologies that are deemed to have a practical potential for application to the existing kilns. Potentially feasible SO_2 options include:

- Wet Flue Gas Desulfurization (WFGD)
- Dry Flue Gas Desulfurization (DFGD)
- Dry Sorbent Injection (DSI)

S&L evaluated each control technology for technical feasibility and effectiveness on an individual unit basis. Capital and O&M costs were prepared for each technically feasible control technology option. Cost estimates were prepared in accordance with U.S. Environmental Protection Agency (EPA) guidelines. Technical feasibility, effectiveness, and costs were evaluated based on current emissions from each unit using recent site-specific information provided by Oxbow.

1.3. APPROACH

As an initial step in our evaluation of technical feasibility, and to determine potential emission reductions, S&L conducted a desktop engineering review of the existing Oxbow systems, including a review of process information, existing equipment and component drawings, and process flow diagrams (PFD). Based on this review, current baseline operating parameters were established; limitations of the APC systems were determined; and potential water availability and flue gas temperature reduction technologies, as required for the APC systems, were identified and evaluated.

2. FACILITY DESCRIPTION

The Oxbow Kremlin facility located near the cities of Kremlin and Enid, Garfield County, OK, commenced operation in the 1963-1970 time frame. The facility has three (3) rotary kilns that produce both anode and non-anode grade Calcined Petroleum Coke (CPC). CPC is a high purity carbon and is manufactured by calcining raw or Green Petroleum Coke (GPC) at temperatures of 2,000°F to 2,500°F. Calcining at these high temperatures removes moisture (%) and volatile matter (%) (or hydrocarbons) from the GPC, decreases the electrical resistivity (ohm inches) (improving the electrical conducting properties), increases the density (grams/cm^3), and improves the coke structure by increasing the mean crystallite thickness (Å) (size of the carbon crystals). The calcining process creates a very pure form of carbon by increasing the carbon content from approximately 89 % for GPC to 99 % in the CPC. CPC is primarily sold globally to aluminum smelters, and to titanium dioxide (TiO_2), recarburizer, and specialty industries. CPC quality requirements vary among each of the industries.

CPC quality is dependent on the chemical and physical characteristics of the GPC used in the calcining process. Raw material GPC used at the Kremlin facility is primarily sourced from the various refineries in the mid-continental U.S., but it also receives some GPC from other refineries in the U.S. and internationally. The Kremlin facility receives GPC by railcar and/or truck deliveries. GPC is one of two solid substances that is produced in a refinery. Distilled liquid streams at the refinery are subjected to high temperatures and pressures in a coker vessel to produce the solid GPC. The quality of GPC is dependent upon which crude(s) are processed in the refinery. Some of the sulfur and metals in the crude end up in the GPC, thereby impacting quality. Refineries typically produce anode quality or non-anode quality GPC. Anode quality GPC is used to produce CPC for the aluminum industries while non-anode GPC is used to produce CPC for the TiO_2, recarburizer and other specialty sectors.

Because no single source can supply GPC to meet all CPC customer specifications and quantities, GPC is purchased from various suppliers and blended together at appropriate percentages to meet individual customer specifications. Therefore, sourcing the correct raw material GPC is a critical aspect of Oxbow's business and selection parameters are closely monitored. The appropriate blend of different GPCs is metered at the appropriate feed rates into each rotary kiln. As a result, the GPC blends fed to the kilns at any given time can have a wide range of properties (e.g., volatile matter, moisture, sulfur, metals, etc.).

Rotary kilns are large tubular shells with lined refractory where the GPC is converted to CPC using natural gas as the heating medium. Calcining involves burning the volatile content of the process material in a reducing atmosphere in the kiln to heat the carbon and remove moisture to achieve the required physical properties. Customer specification for the CPC determines the calcining temperatures of the kiln where the calcined petroleum coke is densified, typically 2,000°F to 2,500°F. The calcined carbon product is then cooled to approximately 350°F in rotary coolers using quench water sprays before storing the material prior to shipment. The product is primarily sold to U.S. customers via truck or rail, but may ship to international customers via rail cars, trucks or loaded in Oklahoma and then transferred to ships in the Gulf Coast.

The temperature and combustion of the natural gas and carbon affects the percent yield of the CPC from GPC, and thereby affects flue gas flow from the kilns (actual cubic feet per minute, acfm), as well as flue gas temperature, gas constituents, and other factors. The resulting flue gas from the calcining process is sent to a settling chamber to capture any large unburned carbon particles. The settling chamber is followed by a combustion chamber that combines the flue gas with excess air to combust the remnant fine carbon particles in the flue gas. The combustion chamber is connected to a stack that regulates the kiln draft via a control damper.

The Kremlin facility has open space available on-site, north of the existing kilns, which can be used for any additional equipment. The three (3) kilns are located on the northern half of the property. Units 1 and 2 are arranged in parallel with the process running west to east, with the combustion chambers and stacks located on the east side of the property. Unit 3 is located directly west of the other units and runs east to west, with the combustion chamber and stack located on the west side of the property. The units are bordered on the west by the facility's rail tracks, on the south by several facility buildings and the GPC yard. The relatively large amount of open space directly north of the kilns is currently used for facility water runoff, as part of the facility water management (all water, including storm water, is contained, no discharge). Kilns 1 and 2 are located in close proximity to each other, which precludes any new equipment being built in-between those kilns. Kiln 3 is isolated by two branches of the facility's rail tracks. These physical restrictions require any new equipment to be built to the east of Kilns 1 and 2 and to the west of Kiln 3, which in turn will require the demolition and relocation of some of the existing buildings.

Any new APC system would be tied into each existing kiln's flue gas path at the outlet of the combustion chamber. The kilns run continuously 24 hours a day, 7 days a week at processing rates that range from a minimum of approximately [redacted]% of typical rates depending on customer specifications and GPC quality. Annual maintenance outages for each kiln and its supporting systems are scheduled to only have one kiln offline at a time in order to maintain maximum CPC production flexibility in the remaining operating kilns. The design and layout of an APC system would need to maintain the same level of operational flexibility. Process parameters listed in Table 2-1 were developed from information provided by Oxbow.

Table 2-1 — Process Parameters

Parameter	Kiln 1	Kiln 2	Kiln 3
Kiln Design Parameters			
Design Petroleum Coke Processing Rates (tph)	40	40	35
Diameter (ft-in)	[redacted]	[redacted]	[redacted]
Length (ft-in)	[redacted]	[redacted]	[redacted]
Kiln Operating Rates[1]			
Typical Petroleum Coke Processing Rates (tph)	[redacted]	[redacted]	[redacted]
Minimum Petroleum Coke Processing Rates (tph)	[redacted]	[redacted]	[redacted]
Flue Gas Conditions at Combustion Chamber Outlet[1]			
Temperature (°F)	1,850	1,850	1,700
Pressure (in. w.c.)	Combustion Chamber = -0.2 to -0.4 Stack = -1.0 to -1.2	Combustion Chamber = -0.2 to -0.4 Stack = -1.0 to -1.2	Combustion Chamber = -0.2 to -0.4 Stack = -1.0 to -1.2

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Parameter	Kiln 1	Kiln 2	Kiln 3
Mass Flow Rate (lb/hr)	625,000	625,000	583,000
Volumetric Flow Rate (acfm)	646,000	646,000	564,000

Note:

1. These process parameters are representative of typical average conditions. They should not be construed as maximum values or unit design values.

The cooling process for the CPC product requires approximately 45-62 gallons per minute (gpm) of water for Kiln 1, 43-60 gpm for Kiln 2 and 35-48 gpm for Unit 3 when operating. In addition, approximately 500 gpm is used for dust mitigation, for a total instantaneous water consumption of approximately 670 gpm for the site. The Kremlin facility currently obtains water from the City of Enid municipal supply via a ten (10) inch treated water line, owned by the City of Enid, which also services the municipality of Kremlin, Oklahoma. Residential water use is prioritized (by the City of Enid) during periods of water shortages and frequently results in rationing due to seasonal drought and other infrastructure-related supply limitations. The aquifers that supply the majority of the City of Enid's municipal water have seen a historical decline in water levels; therefore, in periods of drought and reduced water supply, the municipal water available to the Kremlin facility may be further restricted to the point of reducing plant operation. The City of Enid has indicated that the existing water line is currently operating at its maximum flow capacity and, due to the inability to obtain a required easement across private property, the cost of replacing this line is prohibitive, and that alternate routes and a new underground water supply line must be utilized should the Kremlin facility require any additional water consumption requirements. Reduced available water supply at the site combined with the expected increase in cost of water has forced the plant to consider water optimization, water usage reduction or alternative water sources at the site. Three (3) water wells have been investigated but were found to only yield approximately 5-15 gpm each. The well water was also found to have a high sodium and calcium content, which is not compatible with the manufacture of Oxbow's CPC products without additional water treatment. Therefore, the supply of any additional water to meet consumption requirements for the facility would be subject to significant risks.

The City of Enid is currently in Phase 3 (final design, land acquisition, environmental permitting, bid documents) for the installation of a new water supply pipeline from Kaw Lake (referred to as the "Enid Kaw Lake Pipeline"), approximately 70 miles to the northeast of the city, that will supply a new City of Enid water treatment facility. If constructed, the Enid Kaw Lake Pipeline is not scheduled to be operational until 2023-24 and will not achieve full flowrate until after that date as additional pump-stations are placed online. Recent discussions with local representatives have confirmed that the Enid Kaw Lake Pipeline project is likely to complete its final phases and be constructed, but completion is not guaranteed. Raw water may be available from the proposed Enid Kaw Lake Pipeline, which runs approximately six (6) miles directly south from the facility at its nearest point. One potential option to supply additional water to the facility would be to tap into the Enid Kaw Lake Pipeline to feed untreated lake water directly to the Kremlin facility. This option assumes that excess water would be available for Oxbow use and is contingent upon the express approval from the City of Enid. Oxbow would be responsible for the installation and maintenance of the connection line(s) and necessary pumping station and would incur additional costs for obtaining permits, easements, and rights-of-way for a new underground supply pipeline as the City is not required to make the connection to the Kremlin facility. Obtaining the water supply pipeline rights-of-way will increase the pipeline length between approximately eight (8) and twelve (12) miles, depending on the routing. In addition to being responsible for the facility supply pipeline costs, the cost of water may still be subject to change based on the City of Enid.

The City of Enid may also decide that if excess water is available for Oxbow use, in lieu of allowing the Kremlin

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facility to tap directly into the Enid Kaw Lake Pipeline, a new supply line would be routed to the facility with treated water from the new water treatment plant. As indicated by the City of Enid engineering department, the nearest connection point to a treated water line capable of providing the necessary flow rate if easements could be obtained, is nine and a half (9.5) miles away (the treated water line is located seven and a half (7.5) miles south of the Kremlin facility, with a connection point an additional two (2) miles east). If use of this line is allowed, it would require additional right-of-way procurement by the plant across private property, as well as the potential installation of one or more pump-stations. This option also makes the future water costs subject to change.

In the event that a direct supply line from the Enid Kaw Lake Pipeline and increased water consumption from the City of Enid are not feasible options, any additional water consumption requirements for the facility could potentially be supplied by trucking in water, but would come at a significant annual cost. Approximately 75,000 to 94,000 trucks would be required annually to supply the additional water consumption needs, depending on the APC technology and size of the delivery vehicles. This would create a burden on the limited roadway infrastructure, increase traffic safety risk, and may be viewed as a nuisance by neighbors. Due to the large number of trucks required, it is expected that a larger water storage volume will be needed to ensure no interruptions to the operation of the APC system.

For the purpose of this evaluation, the best case scenario assumes that additional water required could be obtained and that a connection to a new underground water supply line that ties into the new Enid Kaw Lake Pipeline would be available to feed untreated lake water directly to the Kremlin facility at Oxbow's expense. For this case, estimated costs for new water infrastructure to supply and treat the additional water required for the APC system and any other necessary supporting systems are included as well as assumed costs of additional easement rights for the new supply line, which assumption adds significant cost uncertainty. The costs of the new water supply pipeline are based on using the average distance of ten (10) miles to account for the easement right-of-way routing. The worst-case scenario, which would require trucking additional water to the facility, was also considered as part of this evaluation. Costs for both options are included as part of this evaluation and are reflected in the cost tables in Appendix A.

2.1. CURRENT EMISSIONS

As mentioned previously, GPC is a co-product produced by a refinery's petroleum coking process and is produced with varying sulfur and metal contents that require calcining to meet the required specifications for use in other industries. Refineries that operate petroleum coker units may supply GPC to the Kremlin facility. Not all refineries produce GPC. The quality of the crude oil that the refinery is processing affects the quality of GPC. Low sulfur GPC is in short supply due to the shutdown of refineries that produce low sulfur GPC or refineries transitioning to higher sulfur GPC. There is no flexibility in sourcing low sulfur GPC. Logistics affect the availability and cost of supplying GPC to the Kremlin facility. International GPC has high logistics costs to deliver the GPC to the Kremlin facility. The higher logistic cost limits the usage of GPC from international refineries.

Sulfur oxides (SOx) emissions from the GPC calcining process consists primarily of SO_2 emissions, and negligible quantities of sulfur trioxide (SO_3) and gaseous sulfates due to the elevated temperatures leaving the process. These compounds form in the waste flue gas stream as a portion of the bound sulfur in the GPC is evolved during the calcining process, thereby, achieving desulfurization of the CPC product.

The generation of SO_2 is directly related to the sulfur content in the GPC. The Kremlin facility has historically received GPC with a sulfur content ranging from [redacted] wt% to [redacted] wt%, with an average of [redacted] wt%. However,

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the sulfur content of the GPC has increased over time and is likely to continue to increase in the future as refineries meet specifications for lower-sulfur refined products.

The SO_2 emissions were provided by Oxbow based on a review of historical operating data from January 2015 to December 2019. Hourly emission rates (lb/hr) specified in Table 2-2 represent the average hourly SO_2 emission rate measured at each kiln during the January 2015 to December 2019 period. Hourly emission rates are representative of a wide range of operating conditions and fluctuations and are used as the basis for the technical feasibility evaluation and O&M cost estimates provided herein. Annual average SO_2 emission rates (tpy) provided in Table 2-2 represent annual average emissions from January 2018 to December 2019, which is the baseline period proposed by Oxbow and is used as the basis for the cost effectiveness of each technology in terms of tons of SO_2 emissions removed. Maximum monthly SO_2 emission rates (tons/month) provided in Table 2-2 represent the month in which the kiln measured the maximum total SO_2 monthly emissions from January 2018 to December 2019. As the maximum monthly emissions represent actual extremes the units have experienced in the past, the maximum monthly emission over the baseline period was used for sizing the control technology systems and was the basis for the capital cost evaluations provided herein. The hourly and annual average SO_2 emissions were used to determine annual capacity factors for the kilns for 2018 and 2019. These annual capacity factors in turn were used to determine O&M costs for 2020 and subsequent years as provided herein. Capacity factors are based on historical operation and may not represent future operation.

Table 2-2 — Current Stack Emissions

Emission	Kiln 1	Kiln 2	Kiln 3
Hourly SO_2 [1]	1,626 lb/hr	1,447 lb/hr	924 lb/hr
Annual Average SO_2 [2]	6,556 tons/yr	5,674 tons/yr	2,950 tons/yr
Maximum Monthly SO_2[3]	761 tons/month	755 tons/month	381 tons/month
Capacity Factor[4]	[redacted]	[redacted]	[redacted]

Note:

1. Hourly emission rates shown represent the average lb/hr rates for the period of January 2015 to December 2019.
2. Annual emission rates shown represent the 12-month annual average tons/yr for the period of January 2018 to December 2019.
3. Maximum monthly emissions rates shown represent the monthly total tons/month for the baseline period of January 2018 to December 2019. It should be noted that the facility's existing Operating Permit Air Permit No. 2014-1698-TVR2 (M-2), dated August 9, 2017, includes a combined maximum SO_2 emission limit of 4,790.90 lb/hr for the facility, as such, the maximum monthly emission rates reflect the maximum that each unit has reached separately, not operating at once.
4. Based on the direct correlation between kiln operation and corresponding SO_2 emissions, capacity factors were determined for each kiln using the difference between actual annual average SO_2 emissions and hypothetical annual SO_2 emissions that would be generated based on the average hourly SO_2 emission rate on a continuous operating basis (i.e., 8,760 hours/year). Because of the correlation between SO_2 emissions and kiln operations, this approach is expected to provide a relatively accurate estimate of the individual kiln capacity factors for 2020 and subsequent years. Capacity factors provided herein are based on historical operation and may not represent future operation.

3. APC FLUE GAS TEMPERATURE REQUIREMENTS

Flue gas from each of the three kilns is currently exhausted to atmosphere at temperatures of approximately 1,700-1,850°F. To install additional APC system(s) to reduce SO_2 emissions, flue gas temperatures would need to be lowered to an acceptable temperature range required for each control APC technology. For this evaluation, an inlet temperature of 400°F was used as the required design inlet temperature, applicable to all of the emission control technologies.[1] Thus, as an initial step in the control technology feasibility evaluation, flue gas cooling technologies capable of reducing flue gas temperatures from 1,700-1,850°F to 400°F were evaluated. The flue gas cooling system would be located downstream of the kiln exhaust stack and upstream of the SO_2 control system and would need to be implemented with each of the APC systems evaluated.

Options to reduce the flue gas temperatures could include:

- Water-based quenching
- Air-based quenching
- Waste heat recovery with steam production
- Waste heat recovery with steam/electricity production

Each of the available flue gas cooling technologies are evaluated for technical feasibility and practical application at the Kremlin facility.

3.1. QUENCHING

3.1.1. Water-Based Quenching

Water-based quenching of the flue gas involves injecting water into the flue gas stream downstream of the combustion settling chamber. 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. For example, based on flue gas flow rates and temperatures, and assuming a temperature of 400°F at the inlet to the SO_2 control system, 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.

As noted in Section 2, the facility will require a new water supply to meet any additional water requirements; thus, the large quantity of water required to reduce flue gas temperatures to 400°F, in addition to the water requirements of the SO_2 control system, would require a new pipeline and supply pumps in the best case scenario or would need to be delivered by truck in the worst case scenario. In either case, untreated lake water will require pretreatment and demineralization prior to injection to the flue gas to mitigate potential ductwork corrosion concerns. Therefore, water-based quenching is considered a technically feasible flue gas

[1] Refer to Section 4 for additional justifications for inlet temperature limitations for each individual technology.

temperature control option for the Oxbow kilns. However, 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, water-based quenching is not considered to be a reliable or practical flue gas temperature control option for the Kremlin facility and was not evaluated further.

3.1.2. Air-Based Quenching

In an air-based quenching system, a tubular heat exchanger (gas/air), also known as a gas-to-air recuperator, would be installed downstream of the combustion chamber to utilize ambient air to cool the flue gas. Heat energy from the flue gas would be transferred to ambient air and exhausted, or wasted, to the environment. Modular-type recuperators are commercially available and expected to be able to achieve an outlet temperature of 400°F with the right materials of construction and arrangement. However, heat transfer from the flue gas to air is not an efficient process when compared to flue gas to water heat transfer which has better latent heat absorption and surface wetting capabilities. Because of the less efficient heat transfer, recuperators are generally much larger than water-based quenching to provide the increased heat transfer area required to achieve the same temperature differential. Since air-based quenching uses ambient air, there is also risk for dew-point corrosion in the heat exchanger which will require higher maintenance costs. Dew-point corrosion could also require more frequent outages to address corrosion of heat transfer surfaces and therefore will impact the kilns overall availability and the facility CPC production rates. Due to the relatively larger footprint in an already severely space constrained location as compared to water-based quenching, corrosion risks and potentially 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.

3.2. WASTE HEAT RECOVERY FLUE GAS COOLER (FGC)

A third option to reduce flue gas temperatures upstream of an SO_2 control system would be to install a waste heat recovery system to take advantage of excess heat from the calcination kilns, which would otherwise be wasted. A waste heat recovery boiler (WHRB) or a heat recovery steam generator (HRSG) could be used to reduce flue gas temperatures down to the target value of 400°F at the inlet to the SO_2 control system; these designs are generically referred in industry as “Flue Gas Coolers” (FGC). WHRBs and HRSGs serve the same purpose, that is to capture excess or waste heat from a process; however, their designs and industry applications are different, as described in more detail below:

- HRSGs were developed specifically for the utility industry to convert simple-cycle gas turbine combustion (typically from clean natural gas firing) to a combined-cycle in order to capture and utilize the waste heat to produce steam. HRSGs typically consist of an expanding obtuse angle inlet duct (evase section) followed by vertical evaporator, superheater (SH), reheater (RH) and economizer to generate steam at multiple pressures. Typical HRSG materials of construction can handle Inlet temperatures at or below 1,200°F (similar to combustion turbine exit temperatures). However, higher inlet temperatures, as experienced on the Oxbow kilns, may require one (or a combination) of the following design modifications to protect the HRSG materials of construction:
    - Refractory lined inlet ductwork along with an evaporative section of water-cooled surfaces upstream of the heat transfer surface for additional cooling. To avoid shutdown of operations during extreme flue gas temperature excursions, an emergency damper bypass system utilizing the existing kiln hot stacks may also need to be considered, however, this bypass condition would need to be allowed within the rules of the air permit.

  - A water spray quenching system can be installed upstream to operate on an as needed basis.

- WHRBs are typically used for industrial applications and usually consist of a shop or field assembled single pressure water tube steam package or field erected boiler containing an entrance furnace box prior to the heat transfer surface. The water-cooled furnace box allows the WHRB materials of construction to handle very high inlet flue gas temperatures up to 2,300°F without any prior cooling. Heat transfer surfaces are more conservatively spaced without extended/finned tubing which minimizes fouling.

- Both designs also feature the following:

  - Design flexibility for any steam pressure and temperature process cycle needs and typically employ a single or multiple set of steam drums to produce power in a steam turbine generator (STG) and/or supply any other steam process needs.

  - The heat surfaces can be arranged either horizontally or vertically, and feature fully drainable surfaces to facilitate maintenance needs.

  - Typically arranged for natural, positive circulation, but forced circulation designs are also available.

  - Design can be either fully or partially shop modularized for faster field erection.

Thus, a WHRB and HRSG each have advantages and disadvantages, while also sharing some similarities. A more detailed engineering evaluation will be required to determine the optimized design that would be selected for the process conditions and project design goals. However, the overall capital and operating costs of these systems would be similar since the same amount of heat transfer surface would ultimately be required for each design to achieve an outlet temperature of 400°F. Implementing a natural circulation single pressure WHRB or HRSG would meet the waste heat recovery design requirements and both technologies are assumed to achieve the acceptable temperature range required for each emission control technology. The WHRB and HRSG will be referred to commonly as an FGC in this report.

The waste heat recovery system could be used to produce steam and/or generate electricity; these options are discussed below.

3.2.1. Steam Production

FGCs can be designed for steam production, typically for use in industrial application. However, the existing Kremlin facility does not have a need for on-site steam production, and potential end-users (i.e., other industrial facilities with steam requirements) are located many miles from the Kremlin facility. Transporting steam over long distances would result in variations in steam quality that would likely make it unusable. For these reasons, designing the FGC for steam production is not considered a technically feasible option with a practical application at the Kremlin facility.

3.2.2. Electricity Production

With this arrangement, the FGCs would be designed to utilize waste heat from flue gas at the exit of the combustion chamber to generate steam at a single pressure and the steam produced would be sent to a steam turbine generator (STG) to generate electricity. Flue gas would be redirected from the existing hot stack inlet in a single duct and passed through the FGCs prior to the APC control system inlet. Note that the flue gas path configuration will vary slightly depending on the control technology implemented. To meet operational requirements, an individual FGC would be installed for each kiln (vs. installing a single, larger FGC to serve two kilns) so as not to limit kiln production if the FGC had to be shut down for maintenance, and that two (2) STGs would be installed for the facility; thus, 2 FGCs would serve 1 STG on Unit 1 and 2 and 1 FGC would serve 1 STG on Unit 3, helping to reduce the amount of new equipment on site. Each STG would have a dedicated cooling tower to maintain the separation of the cooling loads. In the event an FGC had to come offline, the kiln would also be taken offline in order to protect the downstream SO_2 control system from elevated flue gas temperatures, or, if allowed, control system bypass to prevent damage. Nevertheless, an allowance for these instances should be considered as part of the development of the emission calculations and control system cost-effectiveness calculations.

The FGCs, STGs and supporting equipment would form a new energy center (EC) at the facility. Since the Kremlin facility has lower power demands relative to the electricity that could be produced by the STGs, the EC would be sized to produce electricity with distribution to an external power grid. It would be imprudent and unreasonable to specify smaller STGs that would only produce enough electricity to meet the facility's low power demands because additional equipment such as condensers would then be required to manage more than 90% of the steam generated by the FGCs. The limited space, added process complexity, and additional equipment costs render any option that would not distribute excess electricity to the grid impractical and cost ineffective for the Kremlin facility. The second option to size the EC to only produce the required amount of power was evaluated but was determined to not be an economical option as there would not be an appreciable amount of cost savings to justify the reduced size. Therefore, for this evaluation, it is assumed that the FGC, STGs and supporting equipment would be sized to produce excess electricity that could potentially be sold to an external power grid.

Steam from the FGCs would be directed to the new STGs to generate electricity for sale to the electrical grid. Given the amount of heat potentially recovered in the FGCs, and the corresponding steam production, more electricity could be generated from the waste heat than required for the APC equipment loads and existing facility needs (refer to Section 6 for the expected auxiliary power consumption of the new equipment for the SO_2 control options).

Oklahoma has a regulated electricity market. In general, electric power generation and distribution in a regulated state is comprised of vertically integrated utilities that are involved with the entire power generation and distribution chain with oversight from a public regulatory commission. Oklahoma's investor owned and publicly owned utilities both generate and distribute electric power to the consumer. Oversight of the electric power generation/distribution system in Oklahoma is vested in the Oklahoma Corporation Commission (OCC). The OCC is an independent regulatory agency with the responsibility to assure safe, reliable, and reasonably priced services are provided by public utilities. State statute exempts most cooperatives and all municipally owned utilities from rate regulation by the OCC.

Electric power can be generated by independent power producers (IPP) in Oklahoma. An IPP owns one or more power plants but does not provide retail service. IPPs may sell power to utilities, to marketers, or to direct-access consumers. Sometimes an IPP will use a portion of the power it produces to operate its own facility, such as an oil refinery, and sell the surplus power. IPPs may enter into long-term contracts or operate as merchant generators, selling power on a short-term basis into the wholesale market. Oklahoma regulations allow for a class of independent power producers called exempt wholesale generators (EWGs) that are generally exempt from OCC oversight and organizational restrictions. An EWG may generate electricity and sell power wholesale to utilities and other wholesale bulk power purchasers, such as rural electric cooperatives. The power plant's location, size, type of customer the power plant sells energy to, and whether the power plant sells energy in "interstate commerce" will determine what permits/approvals will be required.

In addition to the capital costs associated with the construction of a power generating facility, any IPP or EWG proposing to distribute power to the grid would be required to conduct an interconnection study and obtain approval from the utility receiving the power for distribution. Each utility has comprehensive interconnect procedures that must be followed prior to obtaining approval to generate power. Review and approval procedures typically include three general steps: (1) the power generating facility submits an interconnection application; (2) the utility assigns a queue position and executes the technical review; and (3) the parties enter into a joint interconnection agreement.[2] The interconnection agreement is a legal contract between the electric utility and generator establishing all terms and conditions associated with operating generating facility in parallel with the utility's electric power system.

Interconnection studies typically result in transmission/distribution system upgrades that require significant capital investment. Transmission/distribution system upgrades required for a new generation project can generally be divided into three parts: spur transmission, POI (Point of Interconnection), and bulk transmission.[3] Spur transmission is the relatively short length of line connecting the generator to the bulk transmission grid. Based on publicly available data from the Department of Homeland Security, the spur transmission line could be either directly adjacent to the property or up to approximately 5.4 miles away from the Kremlin facility, depending on the required transmission line voltage requirement. POI is the set of facilities that allow the connection between the spur line and the bulk grid. The bulk transmission grid is the shared infrastructure that allows transfer of electricity from multiple generation plants to the demands. The introduction of a new generation project could result in modifications of existing substations and overloads to the existing transmission system under different conditions which could require that the existing lines be reinforced or that new lines be incorporated into the system to provide for the new generator. All of these additional costs will be borne by the new generator.

Interconnection studies conducted for a proposed new power generating facility model the existing transmission system and evaluate various points of interconnection. Power from the facility is typically injected to the grid at defined interconnection points to evaluate impacts to the transmission system and identify what system upgrades may be required at a given interconnection location and expected generation output.

Transmission system upgrades and interconnection costs can add significantly to a power generation project. For example, in the case of a new generating station, it is very likely that upgrades would be required in all three parts of the transmission system.[4] Because interconnection costs cannot be defined without an interconnection assessment, for this evaluation costs were only developed for the energy center (e.g., FGC/STG) and transmission infrastructure to the substation. No costs were included for upgrades to the existing transmission/distribution system that may be required. As such, electric power generating costs provided herein represent the minimum cost Oxbow would incur to construct the EC.

[2] Excluding any delays caused by utility's queue position, interconnection studies typically take four (4) to eight (8) weeks depending on project complexity and can range from $10k-$50k in order to complete.
[3] See, e.g., The University of Texas at Austin, Executive Summary: The Full Cost of Electricity (FCe-), April 1, 2018, available at: http://energy.utexas.edu/the-full-cost-of-electricity-fce/ .
[4] *Id.*

3.3. APC TEMPERATURE REQUIREMENTS CONCLUSIONS

Considering the limited water availability, site footprint constraints and absence of steam users near the Kremlin facility, this analysis includes costs for waste heat recovery FGC systems with electric generation. The large amount of waste heat removed from the system will generate power that will supply the auxiliary power for the base plant and APC systems. Since the primary purpose of the heat 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.

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4. SO_2 EMISSIONS TECHNOLOGY EVALUATIONS

The first step in characterizing control measures for a source is the identification of technically feasible control measures.[5] A state must reasonably pick and justify the measures that it will consider, recognizing that there are no statutory or regulatory requirements to consider all technically feasible measures or any specific measures.[6]

Control technologies are considered technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: "availability" and "applicability." A technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.[7]

Once a set of potential control measures have been identified for a selected source, the state must collect data on and apply the four statutory factors that will be considered in selecting the measure(s) for that source that are necessary to make reasonable progress.[8]

Several techniques can potentially be used to reduce SO_2 emissions from a calcined petroleum coke kiln. SO_2 control techniques can be divided into pre-combustion strategies, combustion techniques and post-combustion controls. The technical feasibility of each potential control option is discussed below.

4.1. PRE-COMBUSTION SO_2 CONTROL

The generation of SO_2 is related to the sulfur content of the GPC, which can vary dramatically depending on the refinery. Pre-combustion SO_2 control strategies designed to reduce overall SO_2 emissions could theoretically include restrictions on sourcing GPC from refineries with lower sulfur contents; GPC water washing; and/or other processing prior to the calcining process. However, sourcing lower sulfur content GPC from refineries is not feasible due to the extremely limited quantity of very low sulfur GPC available. In addition, the very low sulfur GPC that is available is very expensive and would result in an unacceptably priced CPC product for Oxbow customers. In the hypothetical event that the required quantity of low sulfur GPC could be sourced without impacting CPC product pricing, it would only offer a marginal reduction in SO_2 emissions and would not lower SO_2 appreciably compared to other options. As a result, reduced sulfur GPC is not a technically feasible way to proceed.

As the sulfur content of the GPC is part of the GPC carbon matrix, water washing will be ineffective at removing the sulfur content of the GPC and, thereby, not achieve any reduction in SO_2 emissions. Furthermore, even if water washing was a feasible SO_2 control strategy, this process would be detrimental to the kiln operations as the additional moisture content would impact the GPC sizing distribution, which leads to lower yields of

[5] U.S. EPA, *Guidance on Regional Haze State Implementation Plans for the Second Planning Period* at 29, (August 20, 2019).
[6] *Id*. at 28.
[7] 40 CFR Appendix Y to Part 51.
[8] U.S. EPA, *Guidance on Regional Haze State Implementation Plans for the Second Planning Period* at 29, (August 20, 2019).

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CPC and would create additional waste streams that would be prohibitively expensive to manage. Other GPC processing, such as potentially removing the sulfur content with solvents or acids, is not a viable option due to the GPC sizing. Use of solvents or acids would require crushing the GPC to a very small size (0.1 mm) and the resultant material is too fine to calcine or be saleable to Oxbow customers. Even if this type of processing could yield a commercially viable GPC, the process would create additional waste streams that would be prohibitively expensive to manage. For these reasons, both of these processes, GPC water washing and treatment with solvents or acids, are not technically feasible and cannot be done in commercial scale operations. Therefore, pre-combustion SO_2 controls are not technically feasible and are not considered further.

4.2. COMBUSTION SO_2 CONTROL

The generation of SO_2 is an inherent part of the CPC production process. A combustion SO_2 control method, occurring inside the kiln, while theoretically available, involves adding calcium oxide (CaO) to the GPC prior to the calcining process. The presence of CaO inside the kiln would react with the sulfur released from the GPC and form calcium sulfite ($CaSO_3$). The CaO addition will likely increase the ash carryover to the settling and combustion chambers which may require modifications to the existing settling chambers and/or additional particulate collection systems downstream of the combustion chambers to prevent any increase in kiln outlet particulate emissions. Furthermore, the addition of CaO to the calcining process would cause detrimental impacts to the CPC quality, increasing the calcium and ash content, which are considered to be contaminants to Oxbow CPC customers. All Oxbow CPC customers have maximum specifications for allowable calcium and/or ash contents. CPC produced in this manner would be unsaleable to Oxbow customers. Therefore, combustion SO_2 control is not considered a technically feasible SO_2 control option and was not considered further.

4.3. POST-COMBUSTION SO_2 CONTROL

Post-combustion flue gas desulfurization (FGD) has been the most frequently used SO_2 control technology for large pulverized coal-fired utility boilers and has also been used for SO_2 control on other industrial stationary emission sources. FGD systems, including wet scrubbers, dry scrubbers and dry sorbent injection (DSI), have been designed to effectively remove SO_2 from boiler, incinerator and other various industrial source flue gas.

Compared to large utility-sized coal-fired boilers, there is limited information publicly available for post-combustion SO_2 controls installed on calcining kilns. The U.S. EPA's Reasonably Available Control Technology (RACT)- Best Available Control Technology (BACT)- Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database for post-combustion SO_2 controls required on petroleum coke-fired industrial boilers and calcining kilns does not specifically identify post-combustion SO_2 controls as BACT for this category of stationary sources. However, S&L is aware of a few commercially operating SO_2 control systems installed on petroleum coke kilns in the U.S. Unfortunately, there is limited information publicly available on the design and operation of the existing systems to determine the types of systems installed and the SO_2 removal efficiencies demonstrated in practice.

Therefore, the following technology evaluation is primarily based on transferring experience on pulverized coal-fired units to process conditions and flue gas characteristics at Oxbow, information available in technical literature, technology suppliers' input, and engineering judgment.

4.3.1. WFGD

WFGD technology is an established SO_2 control technology for various industries. Wet scrubbing systems have been designed to utilize various alkaline scrubbing solutions including calcium-based reagents (i.e. lime, limestone, and magnesium-enhanced lime), sodium-based reagents and ammonia-based reagents. Wet scrubbing systems have also been designed with packed bed reactors, spray tower reactors and reaction vessels (e.g., jet bubbling reactor). Although the flue gas/reactant contact systems may vary, the chemistry involved in all wet scrubbing systems is essentially identical. All wet scrubbing systems use an alkaline slurry that reacts with SO_2 in the flue gas to form insoluble sulfite and sulfate solid compounds that are typically dewatered and properly disposed of in landfills.[9]

A large majority of the WFGD systems designed to remove SO_2 from existing high-sulfur utility boilers have been designed as wet limestone scrubbers with spray towers and forced oxidation systems. Therefore, for this evaluation, it was assumed that the WFGD control system for the Oxbow kilns would be designed as a limestone spray tower scrubber with forced oxidation given the higher sulfur properties of GPC. Other potentially available wet scrubber designs are not specifically included in this evaluation because the chemistry involved in all wet scrubbing systems are essentially identical, alternative designs would not provide any additional SO_2 control, and control system costs would be similar.

Wet Limestone Scrubbing

In a wet limestone scrubbing system, limestone ($CaCO_3$) is mixed with water to formulate the alkali scrubber slurry. Flue gas enters the absorber vessel and contacts the absorbent slurry in a countercurrent spray tower, with the flue gas passing upward through the absorber tower, while the slurry is sprayed downward through a series of spray nozzles. As the flue gas and slurry come into contact, SO_2 reacts with the limestone slurry to form insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) and the flue gas becomes saturated with the water. After passing through a series of mist eliminators, the saturated flue gas will exit the top of the absorber and out a wet stack. As the slurry falls through the flue gas, it eventually falls into the reaction tank where dissolved sulfur compounds are precipitated as calcium salts. Fresh limestone slurry is added to recirculated slurry as needed to maintain an excess of calcium in the reaction tank to ensure all sulfur is reacted.

The reaction tank is sized to provide sufficient time for precipitation of the sulfur compounds to occur before being recirculated back to the absorber spray headers. The slurry typically contains from 5 to 15% suspended solids consisting of fresh additive, absorption reaction products, and lesser amounts of other inert particulate matter. To regulate the accumulation of solids, a bleed stream from the reaction tank is routed to the solid/liquid separation equipment. Due to the solids content of the recirculated slurry and corrosive environment inside the vessels, all absorber vessel internals (supports, recycle grids, nozzles, tanks, etc.) and, in most cases, recycle piping is made of corrosion resistant fiber-reinforced plastic (FRP) with a wear-resistant coating. The FRP internals can be designed to handle normal operating temperatures of 180-220°F on a continuous basis and can withstand short excursions up to 350°F without serious structural damage. During

[9] Disposal costs for the landfilled gypsum could increase significantly if the material has a pH >12 or exhibits any other hazardous waste characteristics which would require management and disposal of the material as a hazardous waste. Gypsum produced from WFGDs installed on coal-fired units is considered to be a nonhazardous waste. Although WFGD has not been demonstrated on a petroleum coke calcining kiln, it is assumed that the produced gypsum will also be classified as a nonhazardous waste and, therefore, O&M costs are based on traditional, nonhazardous landfilling.

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normal operation, the recycle slurry sprayed into the vessel adiabatically cools the flue gas down to saturation temperatures (approximately 130°F). An emergency quench system is designed to reduce the flue gas temperatures below the maximum continuous allowable temperature for the FRP internals if there is a loss of quenching water from the recycled slurry spray. 400°F is typically used as the sizing basis for the emergency quench system design. Therefore, it is assumed that a waste heat recovery system would be required on the Oxbow kilns to achieve an inlet temperature of 400°F.

Forced oxidation of the scrubber slurry may be used with limestone WFGD systems to force oxidize $CaSO_3$ to $CaSO_4$ to produce calcium sulfate dihydrate solids ($CaSO_4 \cdot H_2O$), commonly known as gypsum, as the final product. Air blown into the reaction tank provides oxygen typically to achieve greater than 99% oxidation of the $CaSO_3$ to $CaSO_4$. Forced oxidation of the scrubber slurry provides a more stable by-product and reduces the potential for scaling in the spray tower. The gypsum by-product from this process must be dewatered and may be salable if a local market for gypsum is available, reducing the quantity of solid waste that needs to be landfilled. However, because a market for salable gypsum is not likely available, for the purpose of this evaluation, it was assumed that produced gypsum would be disposed of as a nonhazardous solid waste in a landfill.[10]

The chemistry of wet scrubbing consists of a complex series of kinetic and equilibrium-controlled reactions occurring in the gas, liquid and solid phases within the absorber tower. In general, the amount of SO_2 absorbed from the flue gas is governed by the vapor-liquid equilibrium between SO_2 in the flue gas and the absorbent or slurry liquid. If no soluble alkaline species are present in the slurry, the liquid quickly becomes saturated with SO_2 and absorption is limited.[11] Likewise, as the flue gas SO_2 concentration goes down, absorption will be limited by the SO_2 equilibrium vapor pressure; thus, higher removal efficiencies are generally achieved on units with higher inlet SO_2 concentrations in the flue gas.

Control efficiencies achieved with wet limestone, forced oxidation WFGD systems depend upon a number of design and operating parameters including, but not limited to, inlet SO_2 concentrations, flue gas temperatures, trace constituents in the flue gas, tower design, limestone quality, flue gas/slurry contact, residence time, operating load and load changes. WFGD technology has primarily been applied on large coal-fired boilers firing medium- to high-sulfur coals, with uncontrolled SO_2 emission rates of approximately 2.0 lb/MMBtu or greater and SO_2 concentrations in the flue gas greater than 1,000 ppmvd.[12] WFGD has demonstrated the ability to achieve removal efficiencies of 96% or more on medium/high sulfur coal-fired boilers at full-load steady-state operating conditions. The control technology has also been demonstrated on boilers firing lower-sulfur coals, but at reduced control efficiencies.[13]

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[10] Id.

[11] Combustion Fossil Power – A Reference Book on Fuel Burning and Steam Generation, edited by Joseph P. Singer, Combustion Engineering, Inc., 4th ed., 1991 (pp. 15-41).

[12] Medium-sulfur coals are generally defined as coals with sulfur contents greater than 1%, but less than 2%, which, depending on the heating value of the coal, equates to an uncontrolled SO_2 emissions in the range of 2.0 to approximately 3.8 lb/MMBtu SO_2 (or approximately 1,000 to 2,000 ppmvd). High-sulfur coals are generally defined as coals with sulfur contents greater than 2%, which equates to uncontrolled SO_2 emissions of 3.8 lb/MMBtu or more (or >2,000 ppmvd). See, U.S. Dept. of Energy. National Energy Technology Laboratory, Detailed Coal Specifications, DOE/NETL-401/012111, 2012 for additional details.

[13] Low-sulfur coals are generally defined as coals with sulfur contents less than 1%, which equates to uncontrolled SO_2 emission of approximately 1.0 lb/MMBtu SO_2 or less (or approximately 525 ppmvd).

As described in Section 2, the potential range of inlet SO_2 concentrations in the flue gas leaving the Oxbow combustion chambers varies significantly. Assuming GPC heating values between 13,400 Btu/lb and 15,800 Btu/lb and sulfur concentrations between [redacted] wt% to [redacted] wt%, and approximately [redacted]% conversion rate of GPC to CPC, resulting in [redacted]% of the GPC sulfur being exhausted as SO_2,[14] uncontrolled SO_2 emissions in the flue gas varies between 1.04 lb/MMBtu (approximately 180-270 ppmvd) and 6.96 lb/MMBtu (approximately 2,000 ppmvd). In addition to the significant variability in inlet SO_2 loading to the WFGD, kiln operating loads, fluctuations in inlet temperatures and flue gas flow rates, variations in trace constituents in GPC and the flue gas, and variability in the limestone quality will affect SO_2 removal efficiency. Higher removal efficiencies would be expected when the kilns are processing higher sulfur GPC and operating at full load steady-state conditions, while lower removal efficiencies would be achieved when processing lower sulfur GPC and changing operating conditions. While removal efficiencies and controlled emission rates have not been demonstrated or achieved in practice on somewhat similar processes, removal efficiencies considered to be achievable at Oxbow on a short term basis may range from approximately 90% when firing low sulfur GPC to as high as 96% or more when firing high-sulfur GPC at full load steady-state conditions. It should be noted, however, that there is very limited commercial experience or operating history upon which to verify WFGD performance on a calcined petroleum coke kiln.

Based on engineering judgment and information from control system vendors, it is concluded that WFGD is a technically feasible and commercially available SO_2 control option for the kilns. Taking into consideration the wide range of GPC sulfur concentrations and variable kiln operating conditions, it is concluded that the WFGD control system could be designed to achieve an SO_2 removal efficiency of approximately 96% when processing high-sulfur GPC and operating at full load steady state conditions. Based on the historical hourly SO_2 emissions from the kiln summarized in Table 2-2, 96% removal from a theoretical uncontrolled rate of 2,000 lb/hr to 2,300 lb/hr for Units 1 and 2 and 1,300 lb/hr for Unit 3 (i.e., [redacted]% GPC)[15] results in a controlled SO_2 emission rate of 92 lb/hr for Unit 1, 82 lb/hr for Unit 2 and 52 lb/hr for Unit 3. Somewhat lower removal efficiencies would be expected when processing lower sulfur GPC, as GPC sulfur concentrations fluctuate based on the available supply. For example, a removal efficiency of approximately 94% would be needed to achieve a controlled rate of 92 lb/hr when processing GPC with an average uncontrolled SO_2 emission rate of 1,160 lb/hr for Unit 1. An emission rate of 92 lb/hr for Unit 1, 82 lb/hr for Unit 2 and 52 lb/hr for Unit 3 represents a long-term average emission rate that the kilns would be expected to typically achieve under normal operating conditions with varied GPC sulfur concentrations and should not be construed to represent an enforceable regulatory limit. Control to this rate would result in an emissions reduction of approximately 2,780 tons per year to 6,190 tons per year from the annual average emissions during the baseline period. Corresponding regulatory limits must be evaluated on a control system-specific basis taking into consideration normal operating variability.

4.3.2. DFGD

DFGD systems have been used in various industries for SO_2 removal. The most common types of DFGD systems include the spray dryer absorber (SDA) and circulating dry scrubber (CDS). Both dry scrubbing systems are designed with a baghouse (fabric filter) for particulate control. Both dry scrubbing systems utilize similar chemical reaction kinetics for the SO_2 removal process.

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[14] [redacted]% yield is based on a review of historical operating data from January 2015 to December 2019.
[15] It should be noted that the facility's existing Operating Permit Air Permit No. 2014-1698-TVR2 (M-2), dated August 9, 2017, includes a combined maximum SO_2 emission limit of 4,790.90 lb/hr for the facility. Therefore, when firing high-sulfur GPC, kiln operation is limited such that the hourly maximum SO_2 emission limit is not exceeded.

Dry scrubbing involves the introduction of hydrated lime (CaO) as a solid or as a hydrated lime slurry (depending on the type of DFGD implemented) into a reaction vessel (also referred to as absorber vessel, absorber module, reaction tower, etc.) where it reacts with SO_2 in the flue gas to form calcium sulfite and sulfate solids. Unlike WFGD systems that produce a slurry by-product, DFGD systems are designed to produce a dry by-product that is removed downstream of the absorber vessel in the particulate control equipment. Inlet flue gas temperature to the absorber vessel is an important DFGD design parameter. Temperatures above 300°F allow for more water and hydrated lime to be injected into the flue gas, thereby increasing SO_2 removal and the utilization of the hydrated lime. If the inlet temperature is below approximately 300°F, the efficiency of the dry scrubber will be reduced. In addition, baghouses with woven fiberglass polytetrafluoroethylene (PTFE) membrane bags capable of handling temperatures of 400-450°F are typically specified. Therefore, to provide sufficient margin to ensure optimal SO_2 removal performance and protection of the membrane bags are achieved, it is assumed that a waste heat recovery system would be installed on the Oxbow kilns to achieve an inlet temperature of 400°F.

There are benefits and limitations of each type of DFGD technology. Both SDA and CDS systems are evaluated in more detail below.

<u>Spray Dryer Absorber (SDA) / Fabric Filter (FF)</u>

SDA control systems are designed to use a lime slurry and water injected into the reaction modules to remove SO_2 from the combustion gases. The reaction modules are designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a dry by-product. Process equipment associated with an SDA control system includes an alkaline storage tank, mixing and feed tanks, atomizer assembly, spray chamber module, integrated fabric filter, and solids recycle system. The recycle system collects solid reaction by-products and recycles them back to the spray dryer feed system to maximize reactant utilization.

Various process parameters affect the efficiency of the SDA process including: the type and quality of the reactant, reactant-to-sulfur stoichiometric ratio, how close the SDA is operated to saturation conditions, and content of the by-product solids recycled to the atomizer. SDA systems are typically designed to operate within approximately 30°F adiabatic approach to saturation temperature at the SDA outlet. Operating closer to the adiabatic saturation temperature would theoretically allow for higher SO_2 control efficiencies; however, outlet temperatures too close to the saturation temperature will result in severe operating problems including reactant build-up in the absorber modules, blinding of the fabric filter bags, and corrosion in the fabric filter and ductwork.

SO_2 removal efficiencies in an SDA are also dependent upon good gas-to-liquid contact, which is generally a function of spray nozzle design. Reactant spray nozzle designs are vendor-specific and include both dual-fluid nozzles and rotary atomizers. The atomizing nozzle assembly is typically located in the SDA penthouse and flange mounted to the roof of the absorber vessel. To maximize utilization of the lime reactant (which is expensive compared to limestone), the system must be designed with a solids recycling system to mix some of the controlled particulate solids product with fresh lime slurry and re-inject the mixture into the SDA.

An SDA/FF control system is a technically feasible and commercially available SO_2 control option for the Oxbow kilns. Due to inherent design limitations, including limited Ca:S stoichiometry, limited residence time within the reaction vessel due to temperature limitations, and approach-to-saturation constraints, SDA/FF control systems are generally installed on emission units with lower uncontrolled SO_2 concentrations, such as coal-fired boilers that burn lower sulfur fuels. SO_2 removal efficiencies achievable with SDA are a function of

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several design and operating parameters and are generally limited to approximately 80-95% depending on the inlet SO_2 concentration and flue gas temperatures. However, as discussed below, although an SDA/FF and CDS/FF system would have similar costs, in the event a DFGD system was to be implemented, the CDS/FF system would likely be selected due to its improved performance over a range of inlet SO_2 loadings and its application on other petroleum coke kilns.

Circulating Dry Scrubber (CDS) / Fabric Filter (FF)

CDS systems use a circulating fluidized bed of hydrated lime reagent within the reaction tower to remove SO_2 rather than an atomized lime slurry injection. In a CDS, flue gas is treated in an absorber vessel where the flue gas stream flows through a fluidized bed of hydrated lime and recycled byproduct. Water is injected into the absorber through a venturi located at the base of the absorber for temperature control, similar to SDA systems, CDS systems are designed to operate within approximately 30°F adiabatic approach-to-saturation temperature. Flue gas velocity through the vessel is maintained to keep the fluidized bed of particles suspended in the absorber. The hydrated lime absorbs SO_2 from the gas and forms calcium sulfite and calcium sulfate solids. Desulfurized flue gas passes out of the absorber, along with entrained particulate matter (i.e., reaction products, unreacted hydrated lime, calcium carbonate, and fly ash) to the fabric filter. Because the addition of hydrated lime, recycle solids, and water are decoupled in a CDS system, the technology is able to more effectively respond to changes in flue gas flow, temperature, and inlet sulfur loading. This allows CDS technology to treat higher sulfur inlet loadings and provides more consistent control throughout a wide range of operating conditions.

A CDS/FF control system is a technically feasible and commercially available SO_2 control option for the Oxbow kilns. Based on removal efficiencies achieved in practice on coal-fired boilers, it is anticipated that a CDS/FF system could be designed to achieve SO_2 removal efficiencies in the range of 93 to 95% when processing higher sulfur GPC (i.e., [redacted]% GCP and inlet SO_2 concentrations of approximately 2,000 ppmvd).

DFGD Conclusions

Based on engineering judgement and information from control system vendors, DFGD, designed as either SDA or CDS, is considered to be a technically feasible and commercially available SO_2 control option for the Oxbow kilns. Comparing the two options, CDS technology is considered to be simpler than SDA technology as it does not require lime slaking or recycle slurry subsystems, which results in less equipment overall and no slurry handling. However, the CDS system requires slightly more lime consumption compared to an SDA system, and the increased amount of solids recirculation requires a larger baghouse and ID fan to handle the higher pressure drop. Nevertheless, because the CDS system provides the most flexibility in terms of variations in inlet sulfur loadings and operation and will provide increased margin on the outlet SO_2 emissions, it was assumed for this evaluation that the DFGD control system would be designed as a CDS system.

In theory, CDS technology could be designed to treat any inlet sulfur loading; however, design constraints, including inlet SO_2 loading, flue gas flow rates, flue gas temperatures, and approach to saturation limit removal efficiency. Lower removal efficiencies would be expected with changing operating conditions. In addition, at higher removal efficiencies (i.e., greater than approximately 93%), the amount of sorbent required for SO_2 removal from the flue gas increases substantially, which may result in economics favoring wet scrubbing due to high reagent consumption. Taking into consideration the wide range of GPC sulfur concentrations and variable kiln operating conditions, including flue gas flows and temperatures, it is expected that a CDS/FF system could be designed to achieve an SO_2 removal efficiency of approximately 94% when processing high-sulfur GPC and operating at full load steady state conditions. Based on the historical hourly SO_2 emissions from the kilns summarized in Table 2-2, 94% removal from an uncontrolled rate of 2,000 lb/hr to 2,300 lb/hr for Units 1 and 2 and 1,300 lb/hr for Unit 3 (i.e. [redacted]% GPC) results in a controlled SO_2 emission rate of 138 lb/hr for Unit 1, 122 lb/hr for Unit 2 and 78 lb/hr for Unit 3.

Somewhat lower removal efficiencies would be expected during periods of time when kiln operation is variable; however, a higher level of SO_2 removal could theoretically be achieved by over-injecting reagent to handle fluctuations in operation but would result in a much higher operating cost. Higher injection rates result in diminishing returns in overall cost effectiveness of the control technology; therefore, it is assumed that operating costs would be maintained for these fluctuations. For example, a removal efficiency of approximately 92% would be needed to achieve a controlled rate of 138 lb/hr when processing GPC with an average uncontrolled SO_2 emission rate of 1,160 lb/hr for Unit 1. An emission rate of 138 lb/hr for Unit 1, 122 lb/hr for Unit 2 and 78 lb/hr for Unit 3 represents a long-term average emission rate that the kilns would be expected to achieve under normal operating conditions with varied GPC sulfur concentrations (including the high sulfur case) and varied operating conditions, and should not be construed to represent an enforceable regulatory limit. Control to these rates would result in an emissions reduction of approximately 2,700 tons per year to 6,000 tons per year from the annual average emissions during the baseline period. Corresponding regulatory limits must be evaluated on a control system-specific basis taking into consideration normal operating variability.

4.3.3. DSI

Alkali based Dry Sorbent Injection (DSI) is a proven technology for the removal of SO_3 and other acid gases (e.g., hydrochloric acid (HCl) and hydrofluoric acid (HF)) from flue gas and can also be used to provide moderate SO_2 control. In a DSI control system, powdered, dry sorbent is injected directly into the ductwork prior to a particulate collection device. DSI systems are relatively simple systems consisting of material storage, reactant feeding mechanisms, blowers, transfer lines, and an injection device.

Sorbent injected into the flue gas reacts with SO_2, SO_3, condensed sulfuric acid (H_2SO_4) and other acid gases, in the flue gas when injected at an appropriate rate and within the proper temperature range for that sorbent. The process works through neutralization of the gases with the alkaline sorbent. The neutralization reaction occurs as long as the sorbent remains in contact with the flue gas within the required temperature range.

Dry sorbents that have been used for SO_2 control on coal-fired boilers and other industries include:

- Hydrated Lime ($Ca(OH)_2$)
- Trona (sodium sesquicarbonate) or Sodium Bicarbonate (SBC)

Trona and SBC are both sodium-based sorbents, which react with SO_2 to form sodium sulfate salts that are water soluble. Hydrated lime reacts with SO_2 to form calcium sulfate salts. The effectiveness of the sorbent is dependent upon many factors, including surface area of the reactant particle, injection location temperature, and sorbent particle/flue gas contact time. Of those factors, particle surface area is particularly significant. One way to increase surface area is to mechanically reduce the particle size by grinding the sorbent. Effectiveness of the sodium sorbents can be increased by injecting the sorbent into flue gas within a temperature range of 275°F to 800°F. At these temperatures, the sodium sorbent will rapidly decompose to sodium carbonate (Na_2CO_3) which results in micropores on the sorbent surface and expands the sorbent particles, increasing the particle surface area. Maximizing the contact time between the flue gas and sorbent will also improve performance but will depend on the injection location. During the preliminary design phase

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of a DSI system, these factors must be evaluated to determine which sorbents, temperatures and particulate control system are best for the unit.

The resulting particulate matter (PM) is removed from the flue gas by the particulate control system. An electrostatic precipitator (ESP) or baghouse fabric filter (FF) could be used as the particulate control device. An ESP could be operated with higher flue gas inlet temperatures (i.e. less heat recovery), but at the risk of increasing resistivity of the particulate matter making it more difficult to collect and thereby reducing the ESP particulate control performance. Although sodium-based sorbents can lower (improve) fly ash resistivity, the estimated injection rates required at the Oxbow kilns for SO_2 control are high enough that the beneficial effects of a resistivity-lowering sorbent would be outweighed by the significant increase in solids loading. Although fabric filters have a higher pressure drop compared to ESPs, the increased residence and reaction that takes place in the filter cake that forms on the fabric filter bags can improve the overall performance of the DSI system. Fabric filters with woven fiberglass polytetrafluoroethylene (PTFE) membrane bags are capable of handling temperatures of 400-450°F. Considering these variables, a large ESP would be required to achieve the same performance as an FF, rendering an ESP as the higher capital cost option. Therefore, for the purpose of this evaluation, a DSI/FF system is assumed, in conjunction with a waste heat recovery system to achieve an inlet temperature of 400°F.

For either Trona or SBC, the sorbent should be injected into flue gas above 275°F, and kept above this temperature for at least 1 second, to maximize the micropore structure. However, if the flue gas is too hot, the solids will sinter and surface area will be reduced. Sintering occurs at a lower temperature for SBC than for Trona or hydrated lime. Based on industry experience with DSI, SBC injection should be limited to gas streams below 800°F and more preferably below 650°F.

It was previously thought that hydrated lime effectiveness was not as influenced as much by temperature as sodium-based sorbents. Currently, there is no evidence that high flue gas temperatures physically impact hydrated lime effectiveness. In some pulverized coal plants, hydrated lime has been injected directly into the upper furnace for SO_2 control where temperatures range from 1,800 to 2,200°F. Based on the allowable temperature windows of the sorbents, sorbent injection could be located at places in the flue gas path upstream of the baghouse with higher temperatures (i.e. either non-cooled or substantially less cooled flue gas than the required FF inlet temperature of 400°F). However, to reduce the complexity of the flue gas cooler (FGC) system, it is assumed that the DSI injection point will be located downstream of the FGC and upstream of the FF, in an area with flue gas temperatures of approximately 400°F.

Based on engineering judgment and information from control system vendors, it is concluded that a DSI/FF system is a technically feasible and commercially available SO_2 control option for the Oxbow kilns. Design considerations for the DSI/FF control system include the type of sorbent, flue gas temperatures, residence time, and sorbent/flue gas mixing. Hydrated lime is somewhat less reactive towards SO_2 compared to the sodium based dry sorbents; thus, higher injection rates and longer residence times would be required to achieve the same removal efficiency. However, hydrated lime has a lower unit cost compared to other dry sorbent options, generally offsetting the higher injection rates required when considering the operating costs over the life of a project. Hydrated lime is less sensitive to flue gas temperatures and does not result in a water-soluble solid waste that can present significant waste management/disposal challenges. Because it is less expensive overall and more operationally flexible, a hydrated lime DSI/FF system was assumed for the basis of this evaluation.

Taking into consideration the wide range of GPC sulfur concentrations, variable kiln operating conditions, and information available from control system vendors, it is concluded that a hydrated lime DSI/FF control system could be designed to achieve an SO_2 removal efficiency of approximately 50% when processing high-sulfur GPC and operating at full load steady state conditions. Based on the historical hourly SO_2 emissions from the kilns summarized in Table 2-2, 50% removal from a theoretical uncontrolled rate of 2,000 lb/hr to 2,300 lb/hr for Units 1 and 2 and 1,300 lb/hr for Unit 3 (i.e., [redacted]% GPC) results in a controlled SO_2 emission rate of 1,000 lb/hr for Unit 1, 1,150 lb/hr for Unit 2 and 650 lb/hr for Unit 3. Somewhat lower removal efficiencies would be expected during periods of time when kiln operation is variable and when processing lower sulfur GPC, as GPC sulfur concentrations fluctuate based on the available supply. However, a higher level of SO_2 removal could theoretically be achieved by over-injecting reagent to handle fluctuations in operation (e.g., increasing the stoichiometric ratio of moles of SO_2 to moles of reagent) but would result in a higher operating cost. Higher injection rates result in diminishing returns in overall cost effectiveness of the control technology; therefore, it is assumed that operating costs would be maintained for these fluctuations. Therefore, when processing GPC with an average uncontrolled SO_2 emission rate of 1,447 lb/hr to 1,626 lb/hr for Units 1 and 2 and 924 for Unit 3, a hydrated lime DSI system is expected to be capable of achieving approximately 40% removal, resulting in a controlled SO_2 emission rate of approximately 976 lb/hr for Unit 1, 868 lb/hr for Unit 2 and 555 lb/hr for Unit 3. These emission rates represent a long-term average emission rate that the kilns would be expected to achieve under normal operating conditions with varied GPC sulfur concentrations (including the high sulfur case) and varied operating conditions and should not be construed to represent an enforceable regulatory limit. Control to these rates would result in an emissions reduction of approximately 1,180 tons per year to 2,622 tons per year from the annual average emissions during the baseline period. Corresponding regulatory limits must be evaluated on a control system-specific basis taking into consideration normal operating variability.

5. SUMMARY OF EMISSIONS TECHNOLGY EVAUATION

Table 5-1 below provides a summary of the average achievable emission rate for the feasible SO_2 control options evaluated.

Table 5-1 — Feasible Control Technologies to be Included in Cost Estimate

Control Option	Emission Rate (lb/hr)[1]		
	Kiln 1	Kiln 2	Kiln 3
SO_2 - Baseline	1,626	1,467	925
WFGD	92	82	52
DFGD	138	122	78
DSI	976	868	555

Note:

1. Emission rates shown represent long-term average emission rates that the control options would be expected to achieve under historical operating conditions with varied GPC characteristics (including the high sulfur case) and varied operating conditions. Emission rates are provided for comparative purposes and should not be construed to represent enforceable regulatory limits. Corresponding regulatory limits must be evaluated on a control system-specific basis taking into consideration normal operating variability parameters such as the raw material sulfur content, inlet SO_2 loading to the control system, operating loads, fluctuations in inlet temperatures and flow rates, and varying reagent quality; all of which can result in short-term increases in the controlled SO_2 emission rate. Because control systems do not operate continuously at steady state conditions, compliance margin is needed between the expected actual emission rate and an enforceable regulatory limit. Compliance margin must be evaluated on a system-specific basis taking into consideration changes to normal operational parameters and the corresponding emission rate averaging time; however, an additional 10-15% margin would likely be needed to account for operating margin for each control system included in this evaluation.

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6. CAPITAL AND OPERATIONS AND MAINTENANCE COST ESTIMATES

Capital and operating and maintenance (O&M) cost estimates were developed for each of the feasible SO_2 control options. The kiln cost estimates are conceptual in nature, supplemented with budgetary quotes where applicable. Equipment costs are based on conceptual designs developed for the retrofit control systems, preliminary equipment sizing developed for the major pieces of equipment (based on kiln-specific design parameters, including typical flue gas characteristics, full load production rates, and flue gas temperatures and flow rates), and recent pricing for similar equipment. S&L would characterize the cost estimates for the kiln retrofit technologies as study-level cost estimates generally based on parametric models, judgment, or analogy, resulting in an estimate accuracy consistent with a Class 4 cost estimate as defined by the Association for Advancement of Cost Engineering International (AACEI), which AACEI defines as a "study or feasibility"-level cost estimate.

For purposes of the second planning period, EPA recommends that states follow the source type-relevant recommendations in the EPA Air Pollution Control Cost Manual[16] that are stated in the manual as applying to cost estimates in a permitting context when characterizing the cost of compliance factor.[17] EPA recommends using source-specific estimates if those estimates are adequately documented and available or can be prepared.[18]

Control technology equipment costs for the retrofit options were developed by scaling cost estimates prepared by S&L for other similar projects. Major equipment costs were developed based on equipment costs recently developed for similar projects, and include the equipment, material, labor, and all other direct costs needed to retrofit the units with the control technology. Sub-accounts for the capital cost estimate (e.g., mobilization and demobilization, consumables, Contractor General and Administrative (G&A) expense, freight on materials, etc.) were developed by applying ratios from detailed cost estimates that were prepared for projects with similar scopes. To help reduce overall capital costs and minimize the required footprint, common SO_2 control equipment that serves more than one (1) kiln were implemented where possible in lieu of having individual SO_2 control systems per kiln.

Fixed O&M costs include operating labor, maintenance labor, maintenance material, and administrative labor. Variable O&M costs include the cost of consumables, including reagent, water consumption, and auxiliary power requirements. The cost of auxiliary power requirements reflects the additional power requirements associated with the operation of the new control technology (compared to the existing technology).

The capital cost estimates generally include the following major components:

- Purchased Equipment Costs
- Equipment and material

[16] U.S. EPA Air Pollution Control Cost Manual, https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.
[17] U.S. EPA, *Guidance on Regional Haze State Implementation Plans for the Second Planning Period* at 31, (August 20, 2019).
[18] *Id*.

- Instrumentation
- Sales Tax
- Freight on Materials
- Direct Installation Costs
- Labor
- Scaffolding
- Mobilization / Demobilization
- Cost due to Overtime
- Indirect Field Costs
- Contractor's General and Administration
- Contractor's Profit
- Engineering, Procurement and Project Services
- Construction Management/Field Engineering
- Startup and Commissioning
- Spare Parts
- Owners Cost
- Project Contingency

6.1. WFGD COST ESTIMATE BASIS

All costs associated with installing and operating new WFGD and heat recovery systems have been included in this estimate. The WFGD retrofit estimate is based on S&L prior experience with the system and vendor quotes. The balance of plant (BOP) costs were estimated from S&L's conceptual cost estimating system from installation of similar projects. The scope of work in the WFGD SO_2 control technology cost estimate includes the following major items:

- Hot ductwork & dampers for continued existing hot stack operation, as needed
- Heat recovery system[19] to reduce flue gas temperatures:
  - 1 FGC per kiln
  - 2 STGs – 1 per Kiln 1 & 2 and 1 for Kiln 3

[19] Refer to Section 3.2.2 for reasoning for heat recovery system configuration.

  - 2 cooling towers (CT) – 1 per STG
- Induced Draft (ID) fans, sized for the pressure drop of the new FGC, interconnecting ductwork, WFGD system and new stack. ID fans will be downstream of FGC, upstream of WFGD.
- 2 WFGD systems – 1 per Kiln 1 & 2 and 1 for Kiln 3, each system including all necessary pumps and other appurtenances. WFGD systems will be designed to accommodate individual kiln operations. Note that a common system for Kilns 1 & 2 was selected to alleviate some site space constraints.
- Cold stack downstream of each WFGD system with a liner capable of wet flue gas operation, continuous emission monitoring system (CEMS) and foundation
- Common limestone handling, storage and preparation system
- Common by-product dewatering, storage and handling system
- Common 10 mile, underground 14" HPDE water supply pipeline, including trenching, matting (access), road crossings, tie-in and valves, and a pumping station
- Common water supply and storage system (facility)
- Common wastewater management & treatment system
- Civil and structural BOP
- Interconnecting piping, valves, and insulation
- Pipe supports and pipe rack
- Compressed air system and receivers
- Electrical and instrumentation/controls
- Electrical aux power systems and switchyard
- Demolition and replacement of existing buildings or structures, including:
  - Demolition and replacement of the Metal Building– Kiln 3
  - Demolition and replacement of the Main Facility Building (Office, lab and employee locker room) – Kilns 1 & 2
  - Relocation of covered parking lot structure – Kilns 1 & 2

6.1.1. WFGD Capital Cost Estimate

Table 6-1 summarizes the WFGD capital cost estimate and is provided in 2020 dollars.

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Table 6-1 — WFGD Capital Cost Estimate

Capital Cost	Kiln 1	Kiln 2	Kiln 3
Purchased Equipment[1]	$54,096,000	$53,280,000	$48,039,000
Direct Installation	$27,781,000	$26,209,000	$23,965,000
Indirect	$25,382,000	$24,641,000	$22,320,000
Contingency	$21,452,000	$20,826,000	$18,865,000
Total Capital Investment	**$128,711,000**	**$124,956,000**	**$113,189,000**

Note:

1. In the event water must be trucked onto site, it is expected that the water storage volume will need to be increased to allow for seven (7) days of storage to ensure no interruptions to the operation of the APC system. Increasing the water storage capacity at the site would result in a purchased equipment cost increase of $3,319,000 for Unit 1, $3,312,000 for Unit 2, and $2,870,000 for Unit 3.

6.1.2. WFGD Variable O&M Costs

The following unit costs in Table 6-2 were used to develop the variable O&M costs. All values, except for the limestone and water costs, were provided by Oxbow and are consistent with typical industry values. The limestone and water costs are based on S&L's conceptual cost estimating system and are provided in 2020 dollars.

Table 6-2 — WFGD Variable O&M Costs

Unit Cost	Units	Kilns 1-3
Limestone	$/ton	57
Makeup Water[1]	$/1,000 gal	7.70
Demineralized Water[2]	$/gal	0.07
Byproduct Disposal	$/ton	35
Disposal Truck[3]	$/truck	150
Auxiliary Power	$/kWh	0.0442

Note:

1. As noted previously in Section 2, the cost of makeup water may be subject to change based on the uncertainty surrounding the source of the water supply. This figure represents the reasonable best case and the cost shown assumes there will be no change to the current City of Enid water pricing.
2. The demineralized water cost is based on an assumed raw water total dissolved solids (TDS) of 500 ppm and demineralized in rental ion-exchange trailers.
3. Waste disposal truck capacity assumed to be 25 tons.

Table 6-3 summarizes the estimated consumption rates as well as the first year variable O&M costs for the

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WFGD system provided in 2020 dollars.

Table 6-3 — WFGD Variable O&M Rates and First Year Costs

Parameter	Units	Kiln 1	Kiln 2	Kiln 3
Variable O&M Rates				
Limestone Consumption	lb/hr	3,480	3,111	2,001
Increased Byproduct Waste Production	lb/hr	5,195	4,629	2,965
Increased Auxiliary Power Consumption	kW	1,457	1,399	1,163
Increased Makeup Water Consumption	gpm	474	473	411
Demin. Water Consumption	gpm	21	21	18
Variable O&M Costs (CF[1])				
Limestone Cost	$/year	800,000	695,000	364,000
Increased Byproduct Waste Disposal Cost	$/year	991,000	848,000	441,000
Increased Auxiliary Power Cost	$/year	519,000	485,000	328,000
Increased Makeup Water Cost[2]	$/year	1,690,000	1,638,000	1,160,000
Demin. Water Cost	$/year	678,000	659,000	460,000
Total First Year Variable O&M Cost	**$/year**	**4,678,000**	**4,325,000**	**2,753,000**

Note:

1. First-year costs are calculated using annual capacity factors of [redacted]%, [redacted]% and [redacted]%, for kilns 1-3, respectively. Based on the direct correlation between kiln operation and corresponding SO_2 emissions, capacity factors were determined for each kiln using the difference between actual 12-month annual average SO_2 emissions from January 2018 to December 2019 (see, Table 2-2) and hypothetical annual SO_2 emissions that would be generated based on the average hourly SO_2 emission rate from January 2015 to December 2019 (see, Table 2-2) on a continuous operating basis (i.e., 8,760 hours/year). Because of the correlation between SO_2 emissions and kiln operations, this approach is expected to provide a relatively accurate estimate of the individual kiln capacity factors for 2020 and subsequent years. Capacity factors provided herein are based on historical operation and may not represent future operation.
2. In the event water must be trucked onto site, makeup water costs are expected to be $35,263,000 for Unit 1, $34,423,000 for Unit 2, and $24,261,000 for Unit 3, which would significantly increase variable operating O&M costs.

6.1.3. WFGD Fixed O&M Costs

The fixed O&M costs for the systems consist of operating personnel, maintenance costs (including material and labor), and rental water treatment system costs. It should be noted that current kiln operators are specialized and dedicated to maintaining the CPC product quality and, therefore, will not be considered available for any work related to the new systems, which will require all new staff. Based on typical design for the WFGD and heat recovery systems, the estimated staffing additions are as follows:

- 2 people for reagent unloading activities – Common

- 8 people for monitoring of FGD & FGC process operations – Per FGD system (16 total)
- 2 Laboratory Technician – Common
- 1 SO_2 Control System Engineer – Common
- 5 people for EC operation – Per STG/CT system (10 total)
- 3 people for monitoring of EC system – Per STG/CT system (6 total)
- 5 people for dewatering/reagent preparation – Common
- 2 people for gypsum handling activities – Common
- 2 people for Wastewater Treatment – Common

This results in an estimated 46 additional full-time operators and maintenance personnel that the WFGD and other systems will require for each shift for all kilns. The total additional personnel were divided equally among the 3 kilns. Operating Labor costs are estimated based on three (3) shifts/day, 365 days per year at an operator charge rate of $50/hour. Supervisor labor is estimated to be 15% of the total operating labor costs.[20]

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (materials and labor) were estimated to be approximately 1.5% of the total purchased equipment cost and direct installation costs.[21]

The annual water treatment system costs are based on S&L's conceptual cost estimating system which assumes that three (3) x 50% rental water treatment trains will be utilized to reduce the impact on Oxbow operations labor. The operations and maintenance costs include experienced water treatment operators as part of the rental fee. Rental water treatment is also a low capital cost option as the system requires only an operating pad, water connections, and electricity.

Table 6-4 summarizes the first year fixed O&M costs and are provided in 2020 dollars.

[20] Sorrels, John, et. al, U.S. EPA, *Cost Estimation: Concepts and Methodology* (Nov. 2017), 2-31, 2-32, https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf ("Cost Control Manual").
[21] *Id.* at 2-32.

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Table 6-4 — WFGD First Year Fixed O&M Costs

Parameter	Units	Kiln 1	Kiln 2	Kiln 3
Operating Labor[1]	$/year	6,716,000	6,716,000	6,716,000
Supervisor Labor	$/year	1,007,000	1,007,000	1,007,000
Maintenance Material	$/year	1,228,000	1,192,000	1,080,000
Maintenance Labor[2]	$/year	0	0	0
Water Supply Pipeline Right-of-Way[3]	$/year	70,000	70,000	70,000
Water Treatment System Rental[4]	$/yr	2,160,000	2,160,000	2,160,000
Total First Year Fixed O&M Cost	**$/year**	**11,181,000**	**11,145,000**	**11,033,000**

Notes:
1. Operating labor costs are based on a labor rate of $50/hr, provided by Oxbow.
2. Maintenance labor cost included in maintenance materials.
3. Based upon consultation with local owners and legal counsel, the land rental cost for a private entity to acquire the additional rights-of-way necessary from the private landowners adjacent to the facility in order to connect to the Enid Kaw Lake Pipeline is expected to be $4.00 per foot annually. Water supply pipeline right-of-way costs are based on a 10-mile pipeline.
4. Cost developed based on 3 process trains (n+1) of rental water treatment equipment.

6.1.4. WFGD Indirect Operating Costs

Indirect operating costs necessary to own and operate a facility with WFGD and heat recovery systems include property taxes, insurance, and administrative services. Property taxes and insurance charges are estimated to be 1% of the total capital investment.[22] Administration is estimated to be 2% of the total capital investment.[23]

Table 6-5 summarizes the indirect operating costs and are provided in 2020 dollars.

Table 6-5 — WFGD First Year Indirect Operating Costs

Parameter	Units	Kiln 1	Kiln 2	Kiln 3
Property Taxes	$/year	1,287,000	1,250,000	1,132,000
Insurance	$/year	1,287,000	1,250,000	1,132,000
Administration	$/year	2,574,000	2,499,000	2,264,000
Total Indirect Operating Cost	**$/year**	**5,148,000**	**4,999,000**	**4,528,000**

A summary cost table associated with the WFGD option is summarized in **Appendix A**.

[22] *Id.* at 2-31 2-32.
[23] *Id.*

6.2. DFGD COST ESTIMATE BASIS

All costs associated with installing and operating new DFGD and heat recovery systems have been included in this estimate. The DFGD retrofit estimate is based on S&L prior experience with the system and vendor quotes. The BOP costs were estimated from S&L's conceptual cost estimating system from similar projects. The scope of work in the DFGD SO_2 control technology cost estimate includes the following major items:

- Hot ductwork & dampers for continued existing hot stack operation, as needed
- Heat recovery system[24] to reduce flue gas temperatures:
  - 1 FGC per kiln
  - 2 STGs – 1 per Kiln 1 & 2 and 1 for Kiln 3
  - 2 cooling towers (CT) – 1 per STG
- 2 DFGD systems – 1 per Kiln 1 & 2 and 1 for Kiln 3, including all necessary appurtenances. DFGD systems will be designed to accommodate individual kiln operations. Note that a common system for Kilns 1 & 2 was selected to alleviate some site space constraints.
- Induced Draft (ID) fans, sized for the pressure drop of the new FGCs, interconnecting ductwork, DFGD system and new stack. ID fans will be downstream of the DFGD.
- Cold stack downstream of each DFGD system, including CEMS and foundation
- Common pebble lime handling, storage and preparation system
- Common by-product storage and handling system.
- Common 10 mile, underground 12" HPDE water supply pipeline, including trenching, matting (access), road crossings, tie-in and valves, and a pumping station
- Common water supply and storage system (facility)
- Wastewater management
- Civil and structural BOP
- Interconnecting piping, valves, and insulation
- Pipe supports and pipe rack
- Compressed air system and receivers
- Electrical and instrumentation/controls
- Electrical aux power systems and switchyard

[24] Refer to Section 3.2.2 for reasoning for heat recovery system configuration.

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- Demolition and replacement of existing buildings or structures, including:
    - Demolition and replacement of the Metal Building– Kiln 3
    - Demolition and replacement of the Main Facility Building (Office, lab and employee locker room) – Kilns 1 & 2
    - Relocation of covered parking lot structure – Kilns 1 & 2

6.2.1.DFGD Capital Cost Estimate

Table 6-6 summarizes the DFGD capital cost estimate and is provided in 2020 dollars.

Table 6-6 — DFGD Capital Cost Estimate

Capital Cost	Kiln 1	Kiln 2	Kiln 3
Purchased Equipment[1]	$52,340,000	$51,533,000	$46,463,000
Direct Installation	$26,755,000	$25,191,000	$23,058,000
Indirect	$24,520,000	$23,784,000	$21,552,000
Contingency	$20,723,000	$20,102,000	$18,215,000
Total Capital Investment	**$124,338,000**	**$120,610,000**	**$109,288,000**

Note:

1. In the event water must be trucked onto site, it is expected that the water storage volume will need to be increased to allow for seven (7) days of storage to ensure no interruptions to the operation of the APC system. Increasing the water storage capacity at the site would result in a purchased equipment cost increase of $3,236,000 for Unit 1, $2,997,000 for Unit 2, and $2,510,000 for Unit 3.

6.2.2.DFGD Variable O&M Costs

The following unit costs in Table 6-7 were used to develop the variable O&M costs. All values, except for the water and bag and cage replacement costs were provided by Oxbow and are consistent with typical industry values. The water and bag and cage replacement costs are based on S&L's conceptual cost estimating system from installation of similar systems. Costs are provided in 2020 dollars.

Table 6-7 — DFGD Variable O&M Costs

Unit Cost	Units	Kilns 1-3
Lime	$/ton	160
Makeup Water[1]	$/1,000 gal	7.70
Demineralized Water[2]	$/gal	0.07

Unit Cost	Units	Kilns 1-3
Byproduct Disposal	$/ton	35
Disposal Truck[3]	$/truck	150
Auxiliary Power	$/kWh	0.0442
Bag and Cage Replacement	$/bag	156

Note:

1. As noted previously in Section 2, the cost of makeup water may be subject to change based on the uncertainty surrounding the source of the water supply. This figure represents the reasonable best case and the cost shown assumes there will be no change to the current City of Enid water pricing.
2. The demineralized water cost is based on an assumed raw water TDS of 500 ppm and demineralized in rental ion-exchange trailers.
3. Waste disposal truck capacity assumed to be 25 tons.

Table 6-8 summarizes the estimated consumption rates as well as the first year variable O&M costs for the DFGD system and are provided in 2020 dollars.

Table 6-8 — DFGD Variable O&M Rates and First Year Costs

Parameter	Units	Kiln 1	Kiln 2	Kiln 3
Variable O&M Rates				
Lime Consumption	lb/hr	3,278	2,942	1,899
Increased Byproduct Waste Production	lb/hr	6,612	5,930	3,824
Increased Auxiliary Power Consumption	kW	1,033	1,028	946
Increased Makeup Water Consumption	gpm	454	421	354
Demin. Water Consumption	gpm	21	21	18
Bag Replacement	bags	1,024	1,024	955
Variable O&M Costs (CF[1])				
Lime Cost	$/year	2,115,000	1,846,000	969,000
Increased Byproduct Waste Disposal Cost	$/year	1,127,000	983,000	516,000
Increased Auxiliary Power Cost	$/year	368,000	356,000	267,000
Increased Makeup Water Cost[2]	$/year	1,615,000	1,450,000	991,000
Demin. Water Cost	$/year	678,000	659,000	460,000
Bag Replacement Cost	$/year	53,000	53,000	50,000

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Parameter	Units	Kiln 1	Kiln 2	Kiln 3
Total First Year Variable O&M Cost	**$/year**	**5,956,000**	**5,347,000**	**3,253,000**

Notes:

1. First-year costs are calculated using annual capacity factors of [redacted]%, [redacted]% and [redacted]%, for kilns 1-3, respectively. Based on the direct correlation between kiln operation and corresponding SO_2 emissions, capacity factors were determined for each kiln using the difference between actual 12-month annual average SO_2 emissions from January 2018 to December 2019 (see, Table 2-2) and hypothetical annual SO_2 emissions that would be generated based on the average hourly SO_2 emission rate from January 2015 to December 2019 (see, Table 2-2) on a continuous operating basis (i.e., 8,760 hours/year). Because of the correlation between SO_2 emissions and kiln operations, this approach is expected to provide a relatively accurate estimate of the individual kiln capacity factors for 2020 and subsequent years. Capacity factors provided herein are based on historical operation and may not represent future operation.
2. In the event water must be trucked onto site, makeup water costs are expected to be $33,775,000 for Unit 1, $30,639,000 for Unit 2, and $20,897,000 for Unit 3, which would significantly increase variable operating O&M costs.

6.2.3. DFGD Fixed O&M Costs

The fixed O&M costs for the systems consist of operating personnel, maintenance costs (including material and labor), and rental water treatment system costs. It should be noted that current kiln operators are specialized and dedicated to maintaining the CPC product quality and, therefore, will not be considered available for any work related to the new systems, which will require all new staff. Based on typical design for the DFGD and heat recovery systems, the estimated staffing additions are as follows:

- 2 people for reagent unloading activities – Common
- 8 people for monitoring of FGD & FGC process operations – Per FGD System (16 total)
- 1 Laboratory Technician – Common
- 1 SO_2 Control System Engineer – Common
- 5 people for EC operation – Per STG/CT system (10 total)
- 3 people for monitoring of EC system – Per STG/CT system (6 total)
- 3 people for recycle and by-product handling activities – Common
- 1 person for Wastewater Treatment – Common

This results in an estimated 40 additional full-time operators and maintenance personnel that the DFGD and other systems will require for each shift for all kilns. The total additional personnel were divided equally among the 3 kilns. Operating Labor costs are estimated based on three (3) shifts/day, 365 days per year at an operator charge rate of $50/hour. Supervisor labor is estimated to be 15% of the total operating labor costs.[25]

[25] Sorrels, John, et. al, U.S. EPA, *Cost Estimation: Concepts and Methodology* (Nov. 2017), 2-31, 2-32, https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf ("Cost Control Manual").

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The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (materials and labor) were estimated to be approximately 1.5% of the total purchased equipment cost and direct installation costs.[26]

The annual water treatment system costs are based on S&L's conceptual cost estimating system which assumes that two (2) x 50% rental water treatment trains will be utilized to reduce the impact on Oxbow operations labor. The operations and maintenance costs include experienced water treatment operators as part of the rental fee. Rental water treatment is also a low capital cost option as the system requires only an operating pad, water connections, and electricity.

Table 6-9 summarizes the first year fixed O&M costs and are provided in 2020 dollars.

Table 6-9 — DFGD First Year Fixed O&M Costs

Parameter	Units	Kiln 1	Kiln 2	Kiln 3
Operating Labor[1]	$/year	5,840,000	5,840,000	5,840,000
Supervisor Labor	$/year	876,000	876,000	876,000
Maintenance Material	$/year	1,186,000	1,151,000	1,043,000
Maintenance Labor[2]	$/year	0	0	0
Water Supply Pipeline Right-of-Way[3]	$/year	70,000	70,000	70,000
Water Treatment System Rental[4]	$/year	2,160,000	2,160,000	2,160,000
Total First Year Fixed O&M Cost	**$/year**	**10,132,000**	**10,097,000**	**9,989,000**

Notes:
1. Operating labor costs are based on a labor rate of $50/hr, provided by Oxbow.
2. Maintenance labor cost included in maintenance materials.
3. Based upon consultation with local owners and legal counsel, the land rental cost for a private entity to acquire the additional rights-of-way necessary from the private landowners adjacent to the facility in order to connect to the Enid Kaw Lake Pipeline is expected to be $4.00 per foot annually. Water supply pipeline right-of-way costs are based on a 10-mile pipeline.
4. Cost developed based on 2 process trains (n+1) of rental water treatment equipment.

6.2.4. DFGD Indirect Operating Costs

Indirect operating costs necessary to own and operate a facility with DFGD and heat recovery systems include property taxes, insurance, and administrative services. Property taxes and insurance charges are estimated to be 1% of the total capital investment.[27] Administration is estimated to be 2% of the total capital investment.[28]

[26] *Id.* at 2-32.
[27] *Id.* at 2-31 2-32.
[28] *Id.*

Table 6-10 summarizes the indirect operating costs and are provided in 2020 dollars.

Table 6-10 — DFGD First Year Indirect Operating Costs

Parameter	Units	Kiln 1	Kiln 2	Kiln 3
Property Taxes	$/year	1,243,000	1,206,000	1,093,000
Insurance	$/year	1,243,000	1,206,000	1,093,000
Administration	$/year	2,487,000	2,412,000	2,186,000
Total Indirect Operating Cost	**$/year**	**4,973,000**	**4,824,000**	**4,372,000**

A summary cost table associated with the DFGD option is summarized in **Appendix A**.

6.3. DSI COST ESTIMATE BASIS

All costs associated with installing and operating new DSI and heat recovery systems have been included in this estimate. The DSI retrofit estimate is based on S&L prior experience with the system and vendor quotes. The BOP costs were estimated from S&L's conceptual cost estimating system from similar projects. The scope of work in the DSI SO_2 control technology cost estimate includes the following major items:

- Hot ductwork & dampers for continued existing hot stack operation, as needed
- Heat recovery system[29] to reduce flue gas temperatures:
    - 1 FGC per kiln
    - 2 STGs – 1 per Kiln 1 & 2 and 1 for Kiln 3
    - 2 cooling towers (CT) – 1 per STG
- Single DSI system per kiln including all injection splitters and lances and other appurtenances
- 2 FF systems – 1 per Kiln 1 & 2 and 1 for Kiln 3 including all necessary appurtenances. FF systems will be designed to accommodate individual kiln operations. Note that a common system for Kilns 1 & 2 was selected to alleviate some site space constraints.
- Induced Draft (ID) fans, sized for the pressure drop of the new FGCs, interconnecting ductwork, DSI/FF systems and new stack. ID fans will be downstream of the FF.
- Cold stack downstream of each FF system, including CEMS and foundation
- Common hydrated lime handling and storage system, including dehumidifiers, heat exchangers and conveying blowers.

[29] Refer to Section 3.2.2 for reasoning for heat recovery system configuration.

- Common by-product storage and handling system
- Common 10 mile, underground 12” HPDE water supply pipeline, including trenching, matting (access), road crossings, tie-in and valves, and a pumping station
- Common water supply and storage system (facility)
- Wastewater management
- Civil and structural BOP
- Interconnecting piping, valves, and insulation
- Pipe supports and pipe rack
- Compressed air system and receivers
- Electrical and instrumentation/controls
- Electrical aux power systems and switchyard
- Demolition and replacement of existing buildings or structures, including:
  - Demolition and replacement of the Metal Building– Kiln 3
  - Demolition and replacement of the Main Facility Building (Office, lab and employee locker room) – Kilns 1 & 2
  - Relocation of covered parking lot structure – Kilns 1 & 2

6.3.1. DSI Capital Cost Estimate

Table 6-11 summarizes the DSI capital cost estimate and is provided in 2020 dollars.

Table 6-11 — DSI Capital Cost Estimate

Capital Cost	Kiln 1	Kiln 2	Kiln 3
Purchased Equipment[1]	$43,380,000	$42,641,000	$38,674,000
Direct Installation	$20,836,000	$19,315,000	$17,911,000
Indirect	$19,907,000	$19,206,000	$17,542,000
Contingency	$16,825,000	$16,232,000	$14,825,000
Total Capital Investment	**$100,948,000**	**$97,394,000**	**$88,952,000**

Note:

1. In the event water must be trucked onto site, it is expected that the water storage volume will need to be increased to allow for seven (7) days of storage to ensure no interruptions to the operation of the APC system. Increasing the water storage capacity at the site would result in a purchased equipment cost increase of $2,666,000 for Unit 1, $2,666,000 for Unit 2, and $2,296,000 for Unit 3.

6.3.2.DSI Variable O&M Costs

The following unit costs in Table 6-12 were used to develop the variable O&M costs. All values, except for the hydrated lime, water and bag and cage replacement costs were provided by Oxbow and are consistent with typical industry values. The hydrated lime, water and bag and cage replacement costs are based on S&L's conceptual cost estimating system from installation of similar systems. Costs are provided in 2020 dollars.

Table 6-12 — DSI Variable O&M Costs

Unit Cost	Units	Kilns 1-3
Hydrated Lime	$/ton	189
Makeup Water[1]	$/1,000 gal	7.70
Demineralized Water[2]	$/gal	0.07
Byproduct Disposal	$/ton	35
Disposal Truck[3]	$/truck	150
Auxiliary Power	$/kWh	0.0442
Bag and Cage Replacement	$/bag	156

Note:
1. As noted previously in Section 2, the cost of makeup water may be subject to change based on the uncertainty surrounding the source of the water supply. This figure represents the reasonable best case and the cost shown assumes there will be no change to the current City of Enid water pricing.
2. The demineralized water cost is based on an assumed raw water TDS of 500 ppm and demineralized in rental ion-exchange trailers.
3. Waste disposal truck capacity assumed to be 25 tons.

Table 6-13 summarizes the estimated consumption rates as well as the first year variable O&M costs for the DSI system and are provided in 2020 dollars.

Table 6-13 — DSI Variable O&M Rates and First Year Costs

Parameter	Units	Kiln 1	Kiln 2	Kiln 3
Variable O&M Rates				
Hydrated Lime Consumption	lb/hr	4,500	4,000	2,600
Increased Byproduct Waste Production	lb/hr	5,100	4,500	2,900
Increased Auxiliary Power Consumption	kW	1,224	1,172	976

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Parameter	Units	Kiln 1	Kiln 2	Kiln 3
Increased Makeup Water Consumption	gpm	376	376	325
Demin. Water Consumption	gpm	21	21	18
Bag Replacement	bags	1,024	1,024	955
Variable O&M Costs (CF[1])				
Hydrated Lime Cost	$/year	3,424,000	2,960,000	1,565,000
Increased Byproduct Waste Disposal Cost	$/year	870,000	747,000	392,000
Increased Auxiliary Power Cost	$/year	436,000	406,000	275,000
Increased Makeup Water Cost	$/year	1,323,000	1,287,000	905,000
Demin. Water Cost	$/year	678,000	659,000	460,000
Bag Replacement Cost	$/year	40,000	40,000	37,000
Total First Year Variable O&M Cost	**$/year**	**6,771,000**	**6,099,000**	**3,634,000**

Notes:

1. First-year costs are calculated using annual capacity factors of [redacted]%, [redacted]% and [redacted]%, for kilns 1-3, respectively. Based on the direct correlation between kiln operation and corresponding SO_2 emissions, capacity factors were determined for each kiln using the difference between actual 12-month annual average SO_2 emissions from January 2018 to December 2019 (see, Table 2-2) and hypothetical annual SO_2 emissions that would be generated based on the average hourly SO_2 emission rate from January 2015 to December 2019 (see, Table 2-2) on a continuous operating basis (i.e., 8,760 hours/year). Because of the correlation between SO_2 emissions and kiln operations, this approach is expected to provide a relatively accurate estimate of the individual kiln capacity factors for 2020 and subsequent years. Capacity factors provided herein are based on historical operation and may not represent future operation.
2. In the event water must be trucked onto site, makeup water costs are expected to be $27,972,000 for Unit 1, $27,364,000 for Unit 2, and $19,185,000 for Unit 3, which would significantly increase variable operating O&M costs.

6.3.3. DSI Fixed O&M Costs

The fixed O&M costs for the systems consist of operating personnel, maintenance costs (including material and labor), and rental water treatment system costs. It should be noted that current kiln operators are specialized and dedicated to maintaining the CPC product quality and, therefore, will not be considered available for any work related to the new systems, which will require all new staff. Based on typical design for the DSI and heat recovery systems, the estimated staffing additions are as follows:

- 3 people for reagent unloading activities – Common
- 3 people for monitoring of DSI/FF & FGC process operations – Per Kiln (9 total)
- 1 Laboratory Technician – Common
- 1 SO_2 Control System Engineer – Common

- 5 people for EC operation – Per STG/CT system (10 total)
- 3 people for monitoring of EC system – Per STG/CT system (6 total)
- 2 people for by-product handling activities – Common
- 1 person for Wastewater Treatment – Common

This results in an estimated 33 additional full-time operators and maintenance personnel that the DSI and other systems will require for each shift for all kilns. The total additional personnel were divided equally among the 3 kilns. Operating Labor costs are estimated based on three (3) shifts/day, 365 days per year at an operator charge rate of $50/hour. Supervisor labor is estimated to be 15% of the total operating labor costs.[30]

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (materials and labor) were estimated to be approximately 1.5% of the total purchased equipment cost and direct installation costs.[31]

The annual water treatment system costs are based on S&L's conceptual cost estimating system which assumes that two (2) x 50% rental water treatment trains will be utilized to reduce the impact on Oxbow operations labor. The operations and maintenance costs include experienced water treatment operators as part of the rental fee. Rental water treatment is also a low capital cost option as the system requires only an operating pad, water connections, and electricity.

Table 6-14 summarizes the first year fixed O&M costs and are provided in 2020 dollars.

Table 6-14 — DSI First Year Fixed O&M Costs

Parameter	Units	Kiln 1	Kiln 2	Kiln 3
Operating Labor[1]	$/year	4,818,000	4,818,000	4,818,000
Supervisor Labor	$/year	723,000	723,000	723,000
Maintenance Material	$/year	963,000	929,000	849,000
Maintenance Labor[2]	$/year	0	0	0
Water Supply Pipeline Right-of-Way[3]	$/year	70,000	70,000	70,000
Water Treatment System Rental[4]	$/year	2,160,000	2,160,000	2,160,000
Total First Year Fixed O&M Cost	**$/year**	**8,734,000**	**8,700,000**	**8,620,000**

[30] Sorrels, John, et. al, U.S. EPA, *Cost Estimation: Concepts and Methodology* (Nov. 2017), 2-31, 2-32, https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf ("Cost Control Manual").
[31] *Id.* at 2-32.

Notes:

1. Operating labor costs are based on a labor rate of $50/hr, provided by Oxbow.
2. Maintenance labor cost included in maintenance materials.
3. Based upon consultation with local owners and legal counsel, the land rental cost for a private entity to acquire the additional rights-of-way necessary from the private landowners adjacent to the facility in order to connect to the Enid Kaw Lake Pipeline is expected to be $4.00 per foot annually. Water supply pipeline right-of-way costs are based on a 10-mile pipeline.
4. Cost developed based on 2 process trains (n+1) of rental water treatment equipment.

6.3.4. DSI Indirect Operating Costs

Indirect operating costs necessary to own and operate a facility with a DSI and heat recovery systems include property taxes, insurance, and administrative services. Property taxes and insurance charges are estimated to be 1% of the total capital investment.[32] Administration is estimated to be 2% of the total capital investment.[33]

Table 6-15 summarizes the indirect operating costs and are provided in 2020 dollars.

Table 6-15 — DSI First Year Indirect Operating Costs

Parameter	Units	Kiln 1	Kiln 2	Kiln 3
Property Taxes	$/year	1,009,000	974,000	890,000
Insurance	$/year	1,009,000	974,000	890,000
Administration	$/year	2,019,000	1,948,000	1,779,000
Total Indirect Operating Cost	**$/year**	**4,037,000**	**3,896,000**	**3,559,000**

A summary cost table associated with the DSI option is summarized in **Appendix A**.

[32] *Id.* at 2-31 2-32.
[33] *Id.*

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7. TIME NECESSARY FOR COMPLIANCE

The time necessary for compliance is generally defined as the time needed for full implementation of the technically feasible control options. This includes the time needed to develop and implement the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. Therefore, compliance deadlines must consider the time necessary for compliance by setting a compliance deadline that provides a reasonable amount of time for the source to implement the control measure.

Table 7-1 includes estimated timeframes needed to implement each of the technically feasible controls. Notably, the estimated timeframes do not account for time needed for Oklahoma to develop and implement the regulations; nor the amount of time needed for EPA to take proposed and final action to approve Oklahoma's State Implementation Plan (SIP). Therefore, the scheduled activities identified below commence immediately after SIP approval and are subject to the maintenance outage schedules of the individual kiln.

Table 7-1 — SO_2 Emissions Control System Implementation Schedule

SO2 Control Option	Design/ Specification/ Procurement (months)	Detail Design/ Fabrication (months)	Construction/ Commissioning / Startup / Training (months)	Total (months after SIP approval)
WFGD	12	22	22	56
DFGD	12	20	20	52
DSI/FF	6	6	6	18

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8. EQUIPMENT LIFE

The evaluation of technically feasible SO_2 controls options considers the useful life of the control equipment in determining the costs of compliance. In general, the remaining useful life of the source itself will be longer than the useful life of the emission control measure under consideration unless there is an enforceable requirement for the source to cease operation sooner. Thus, the useful life of the control measure will normally be used in the four-factor analysis to calculate emission reductions, amortized costs, and cost-effectiveness. However, if there is an enforceable requirement for the source to cease operation by a date before the end of what would otherwise be the useful life of the control measure under consideration, then the enforceable shutdown date should be used to calculate remaining useful life and evaluate control technology cost-effectiveness. If the remaining useful life exceeds the useful life of the control options, the remaining use life has no effect on the cost evaluation.

The cost of compliance for each control option (see Section 9) currently calculates the annual capital recovery cost by multiplying the total capital investment by a capital recovery factor (CRF) from a formula based on a 20-year equipment lifetime. No dates have been identified for the remaining useful life of the Oxbow kilns before the end of what would otherwise be the useful life of the control measures that were evaluated for Oxbow kilns. Emission control equipment life can vary depending on the process conditions, original design specifications, equipment operation and maintenance practices and site location. 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.

9. SUMMARY OF COST EVALUATION

The economic analysis performed as part of this evaluation examines the cost-effectiveness of each technically feasible control technology on a dollar per ton of pollutant removed basis. Annual emissions, calculated for a particular control device, are subtracted from baseline annual emissions to calculate tons of pollutant controlled per year. Annual costs for each control option are calculated relative to the base case by adding annual operation and maintenance (O&M) costs to the annualized cost of capital. Capital costs were annualized using a capital recovery factor based on an annual interest rate of 10.0%[34] and equipment life of 20 years in accordance with the capital recovery approach described in the U.S. EPA Cost Control Manual.

Implementation of the APC project would begin after the effective date of an approved SIP because this determination would create the obligation to allocate funding to the APC project. As a result, although this report was written in 2020, it would be arbitrary and unreasonable to use 2020 as the year funds are expended. In the event SO_2 controls are required at the Kremlin facility, it is assumed that notification of the required SO_2 reduction would be provided in 2023 to allow time for Oklahoma to develop and implement the regulations and for EPA to take proposed and final action to approve Oklahoma's SIP. As such, the annualized capital cost and O&M costs were escalated to 2024 using a 3% annual average escalation rate. This approach is consistent with the approach described in the Cost Control Manual which requires costs to be presented in constant dollars based on the year funds are first expended (i.e., the zero year).

Table 9-1 through Table 9-3 summarize the annualized capital cost, annual operating cost and total annualized cost for each SO_2 control technology. These costs are representative of the reasonable best-case assumption that water connection to the Enid Kaw Lake Pipeline is both feasible and acceptable to the City of Enid. Costs are provided in escalated 2024 dollars.

Table 9-1 — WFGD Annualized Costs Summary

Parameter	Kiln 1	Kiln 2	Kiln 3
Annualized Capital Cost, $ (per unit)	17,016,000	16,519,000	14,964,000
Total Annual Operating Costs, $/yr (per unit)	23,644,000	23,038,000	20,613,000
Total Annualized Cost, $/yr (per unit)	**40,660,000**	**39,557,000**	**35,577,000**

Table 9-2 — DFGD Annualized Costs Summary

Parameter	Kiln 1	Kiln 2	Kiln 3
Annualized Capital Cost, $ (per unit)	16,438,000	15,945,000	14,448,000
Total Annual Operating Costs, $/yr (per unit)	23,704,000	22,812,000	19,825,000

[34] Interest rate is based on Oxbow's actual ability to borrow money for this project as evidenced by the confidential lender proposal specifically provided to Oxbow and included herein as Appendix B. Oxbow claims Appendix B and the associated interest rate as confidential business information pursuant to 27A O.S. § 2-5-105 (17) and OAC 252:4-1-5(d), and requests that it be treated as confidential and not be subject to public disclosure.

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Parameter	Kiln 1	Kiln 2	Kiln 3
Total Annualized Cost, $/yr (per unit)	**40,142,000**	**38,757,000**	**34,273,000**

Table 9-3 — DSI Annualized Costs Summary

Parameter	Kiln 1	Kiln 2	Kiln 3
Annualized Capital Cost, $ (per unit)	13,346,000	12,876,000	11,760,000
Total Annual Operating Costs, $/yr (per unit)	21,995,000	21,041,000	17,798,000
Total Annualized Cost, $/yr (per unit)	**35,341,000**	**33,917,000**	**29,558,000**

Summary tables indicating the average annual cost effectiveness of the technically feasible SO_2 control options for the Oxbow kilns are included in **Appendix A**. Cost effectiveness ($/ton) of a particular control option is simply the annual cost ($/yr) divided by the annual reduction in annual emissions (ton/yr).

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APPENDIX A. SUMMARY CONTROL COST EVALUATION TABLES

Oxbow - Kremlin Units 1, 2 and 3
Reasonable Progress Four Factor Analysis
Baseline Emissions Estimates

Table 1. Kremlin Units 1, 2 and 3 - Baseline Emissions

Unit No.	Pollutant	Baseline Controls	Baseline Emissions		Maximum Monthly Emissions	Petcoke Processing Rate (typical)	Capacity Factor	Notes
			lb/hr	tons/yr	tons/month	TPH	%	
Kremlin Unit 1	SO_2	None	1,626	6,556	761	[redacted]	[redacted]	Hourly SO_2 emissions based on average lb/hr for period 2015-2019. Annual SO_2 emissions based on 12-month annual average tpy for period 2018-2019. Maximum Monthly emissions are based on the month with the highest SO_2 emissions from January 2018 to December 2019. Capacity factor calculated using the difference between actual 12-month annual average SO_2 emissions from January 2018 to December 2019 and hypothetical annual SO_2 emissions that would be generated based on the average hourly SO_2 emission rate from January 2015 to December 2019 on a continuous operating basis (i.e., 8,760 hours/year).
Kremlin Unit 2	SO_2	None	1,447	5,674	755	[redacted]	[redacted]	Hourly SO_2 emissions based on average lb/hr for period 2015-2019. Annual SO_2 emissions based on 12-month annual average tpy for period 2018-2019. Maximum Monthly emissions are based on the month with the highest SO_2 emissions from January 2018 to December 2019. Capacity factor calculated using the difference between actual 12-month annual average SO_2 emissions from January 2018 to December 2019 and hypothetical annual SO_2 emissions that would be generated based on the average hourly SO_2 emission rate from January 2015 to December 2019 on a continuous operating basis (i.e., 8,760 hours/year).
Kremlin Unit 3	SO_2	None	925	2,950	381	[redacted]	[redacted]	Hourly SO_2 emissions based on average lb/hr for period 2015-2019. Annual SO_2 emissions based on 12-month annual average tpy for period 2018-2019. Maximum Monthly emissions are based on the month with the highest SO_2 emissions from January 2018 to December 2019. Capacity factor calculated using the difference between actual 12-month annual average SO_2 emissions from January 2018 to December 2019 and hypothetical annual SO_2 emissions that would be generated based on the average hourly SO_2 emission rate from January 2015 to December 2019 on a continuous operating basis (i.e., 8,760 hours/year).

Kremlin Units 1, 2 and 3
SO_2 Control Summary
Baseline Emissions Estimates

Table 1. Kremlin Units 1, 2 and 3 Operating Parameters

Table 1. - Baseline Emissions	Units	Unit 1	Unit 2	Unit 3	Notes
Nameplate Petcoke Processing	TPH	40	40	35	
Typical Petcoke Processing	TPH	[redacted]	[redacted]	[redacted]	
Annual SO_2 Emission	TPY	6,556	5,674	2,950	SO_2 emissions based on 12-month annual average tpy for period 2018-2019
Annual Capacity Factor	%	[redacted]	[redacted]	[redacted]	Capacity factor calculated using difference between 12-month annual and hypothetical annualized emissions generated from the hourly data
Baseline Hourly Emission	lb/hr	1,626	1,447	925	Hourly SO_2 emissions based on average lb/hr for period 2015-2019

Table 2. SO_2 Control Effectiveness

	Unit 1				Unit 2				Unit 3			
Control Technology	Control Efficiency	Expected Emissions	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Expected Emissions Reduction	Control Efficiency	Expected Emissions	Emission Rate	Expected Emissions Reduction
	(%)	(ton/year)	(lb/hr)	(ton/year)	(%)	(ton/year)	(lb/hr)	(ton/year)	(%)	(ton/year)	(lb/hr)	(ton/year)
Wet FGD	94%	371	92	6,185	94%	322	82	5,352	94%	166	52	2,784
Dry FGD (CDS + FF)	92%	556	138	6,000	92%	478	122	5,196	92%	249	78	2,701
DSI	40%	3,934	976	2,622	40%	3,404	868	2,270	40%	1,770	555	1,180
Baseline	0%	6,556	1,626		0%	5,674	1,447		0%	2,950	925	
Uncontrolled SO_2		6,556	1,626			5,674	1,447			2,950	925	

Table 3a. SO2 Control Cost Effectiveness - Unit 1 ($2024)

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)
Wet FGD	371	6,185	$144,865,000	$17,016,000		$23,644,000	$40,660,000	**$6,574**
Dry FGD (CDS + FF)	556	6,000	$139,944,000	$16,438,000		$23,704,000	$40,142,000	**$6,691**
DSI	3,934	2,622	$113,618,000	$13,346,000		$21,995,000	$35,341,000	**$13,477**
Baseline	6,556							

Table 3b. SO2 Control Cost Effectiveness - Unit 1 ($2024) - Trucked Water

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)
Wet FGD	371	6,185	$146,205,000	$17,173,000		$61,419,000	$78,592,000	**$12,707**
Dry FGD (CDS + FF)	556	6,000	$141,857,000	$16,662,000		$59,918,000	$76,580,000	**$12,764**
DSI	3,934	2,622	$113,687,000	$13,354,000		$51,914,000	$65,268,000	**$24,889**
Baseline	6,556							

Table 4a. SO2 Control Cost Effectiveness - Unit 2 ($2024)

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)
Wet FGD	322	5,352	$140,639,000	$16,519,000		$23,038,000	$39,557,000	**$7,390**
Dry FGD (CDS + FF)	478	5,196	$135,748,000	$15,945,000		$22,812,000	$38,757,000	**$7,460**
DSI	3,404	2,270	$109,618,000	$12,876,000		$21,041,000	$33,917,000	**$14,944**
Baseline	5,674							

Table 4b. SO2 Control Cost Effectiveness - Unit 2 ($2024) - Trucked Water

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)
Wet FGD	322	5,352	$141,958,000	$16,674,000		$59,924,000	$76,598,000	**$14,311**
Dry FGD (CDS + FF)	478	5,196	$136,887,000	$16,079,000		$55,642,000	$71,721,000	**$13,804**
DSI	3,404	2,270	$109,691,000	$12,884,000		$50,317,000	$63,201,000	**$27,847**
Baseline	5,674							

Table 5a. SO2 Control Cost Effectiveness - Unit 3 ($2024)

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)
Wet FGD	166	2,784	$127,395,000	$14,964,000		$20,613,000	$35,577,000	**$12,778**
Dry FGD (CDS + FF)	249	2,701	$123,005,000	$14,448,000		$19,825,000	$34,273,000	**$12,688**
DSI	1,770	1,180	$100,116,000	$11,760,000		$17,798,000	$29,558,000	**$25,049**
Baseline	2,950							

Table 5b. SO2 Control Cost Effectiveness - Unit 3 ($2024) - Trucked Water

Control Technology	Emissions	Tons of SO_2 Removed	Total Capital Requirement	Annualized Capital Cost	Annualized Outage Cost	Total Annual Operating Costs	Total Annual Costs	Average Cost Effectiveness
	(tpy)	(tpy)	($)	($/year)	($/year)	($/year)	($)	($/ton)
Wet FGD	166	2,784	$127,283,000	$14,951,000		$46,529,000	$61,480,000	**$22,082**
Dry FGD (CDS + FF)	249	2,701	$122,569,000	$14,397,000		$42,128,000	$56,525,000	**$20,926**
DSI	1,770	1,180	$98,988,000	$11,627,000		$38,237,000	$49,864,000	**$42,258**
Baseline	2,950							

Kremlin Units 1, 2 and 3
SO_2 Control Cost Evaluation
Wet FGD

Table 1. - Baseline Emissions	Wet FGD		
	Unit 1	Unit 2	Unit 3
Baseline SO_2 Emissions, ton/yr	6,556	5,674	2,950
Baseline SO_2 Emissions, lb/hr	1,626	1,447	925
Post Upgrade SO_2 Emissions, lb/hr	92	82	52
Capacity Factor used of Cost Estimates (%)	[redacted]	[redacted]	[redacted]
Current Year for Escalation	2020		
Construction Start Year for Escalation	2024		

CAPITAL COSTS	Costs Unit 1	Costs Unit 2	Costs Unit 3	Basis
Direct Costs ($2020)				
Purchased Equipment Costs (PEC)				
Equipment and Materials	$49,178,000	$48,436,000	$43,671,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation. Costs include Heat Recovery and AQCS system. AQCS system is based on common SO2 systems for Units 1&2 and a single system for Unit 3.
Instrumentation	$0	$0	$0	Included in equipment and materials cost
Sales Tax	$2,459,000	$2,422,000	$2,184,000	5% of Equipment/Material Cost
Freight	$2,459,000	$2,422,000	$2,184,000	5% of Equipment/Material Cost
Total PEC	$54,096,000	$53,280,000	$48,039,000	
Direct Installation Costs				
Labor	$25,488,000	$24,045,000	$21,986,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include Heat Recovery and AQCS system.
Scaffolding	$637,000	$601,000	$550,000	2.5% of Labor
Mobilization / Demobilization	$382,000	$361,000	$330,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$1,274,000	$1,202,000	$1,099,000	5% of Labor
Total Direct Installation Costs	$27,781,000	$26,209,000	$23,965,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$81,877,000**	**$79,489,000**	**$72,004,000**	
Indirect Costs ($2020)				
Contractor's General and Administration Expense	$8,188,000	$7,949,000	$7,200,000	10% of Total Direct Costs
Contractor's Profit	$4,094,000	$3,974,000	$3,600,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$6,550,000	$6,359,000	$5,760,000	8% of Total Direct Costs
Construction Management/Field Engineering	$3,275,000	$3,180,000	$2,880,000	4% of Total Direct Costs
S-U / Commissioning	$1,228,000	$1,192,000	$1,080,000	1.5% of Total Direct Costs
Spare Parts	$409,000	$397,000	$360,000	0.5% of Total Direct Costs
Owner's Cost	$1,638,000	$1,590,000	$1,440,000	2% of Total Direct Costs
Total Indirect Costs	**$25,382,000**	**$24,641,000**	**$22,320,000**	
Contingency ($2020)	**$21,452,000**	**$20,826,000**	**$18,865,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI) ($2020)	**$128,711,000**	**$124,956,000**	**$113,189,000**	sum of direct capital costs, indirect capital costs, and contingency
Escalated Total Capital Investment ($2024)	**$144,865,000**	**$140,639,000**	**$127,395,000**	Based on construction start of 2024 and a 3% escalation rate.
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.1175	0.1175	0.1175	20 year life of equipment (years) @ 10.0% interest.
Annualized Capital Costs (CRF x TCI) ($2020)	**$15,118,000**	**$14,677,000**	**$13,295,000**	
Escalated Annualized Capital Costs (CRFxTCI) ($2024)	**$17,016,000**	**$16,519,000**	**$14,964,000**	
OPERATING COSTS				
Operating & Maintenance Costs ($2020)				
Variable O&M Costs				
Increased Waste Disposal Cost	$991,000	$848,000	$441,000	Based on disposal rate of $35 per ton + $150 per truck, assuming 25 ton trucks utilized.
Lime Reagent Cost	$0	$0	$0	Based on lime reagent cost of $160 per ton.
Hydrated Lime Reagent Cost	$0	$0	$0	Based on hydrated lime cost of $189 per ton.
Limestone Reagent Cost	$800,000	$695,000	$364,000	Based on limestone reagent cost of $57 per ton.
Increased Auxiliary Power Cost	$519,000	$485,000	$328,000	Based on auxiliary power cost of $0.0442 per kWh.
Increased Water Cost	$1,690,000	$1,638,000	$1,160,000	Based on water cost of $7.70 per 1,000 gallons.
Demineralized Water Cost	$678,000	$659,000	$460,000	Based on demineralizer cost of $0.07 per gallon.
Bag and Cage Replacement	$0	$0	$0	Based on bag and cage cost of $156 per bag.
Total Variable O&M Costs	$4,678,000	$4,325,000	$2,753,000	
Fixed O&M Costs				
Additional Operators per Shift	15.3	15.3	15.3	Includes personnel for AQCS and Heat Recovery
Operating Labor	$6,716,000	$6,716,000	$6,716,000	Assume $50/hr for each additional operator
Supervisor Labor	$1,007,000	$1,007,000	$1,007,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$1,228,000	$1,192,000	$1,080,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	$0	Included in cost for maintenance materials.
Water Supply Pipeline Right-of-Way Cost	$70,000	$70,000	$70,000	Based on land rental cost of $4.00 per foot. 10 mile pipeline shared between all 3 kilns.
Water Treatment System Rental	$2,160,000	$2,160,000	$2,160,000	Based on 3 trains (N+1) of rental water treatment equipment
Total Fixed O&M Cost	$11,181,000	$11,145,000	$11,033,000	
Indirect Operating Cost ($2020)				
Property Taxes	$1,287,000	$1,250,000	$1,132,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$1,287,000	$1,250,000	$1,132,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$2,574,000	$2,499,000	$2,264,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$5,148,000	$4,999,000	$4,528,000	
Total Annual Operating Cost ($2020)	**$21,007,000**	**$20,469,000**	**$18,314,000**	
Escalated Total Annual Operating Cost ($2024)	**$23,644,000**	**$23,038,000**	**$20,613,000**	Based on construction start of 2024 and a 3% escalation rate.
TOTAL ANNUAL COST				
Annualized Capital Cost ($2020)	$15,118,000	$14,677,000	$13,295,000	
Annual Operating Cost ($2020)	$21,007,000	$20,469,000	$18,314,000	
Total Annual Cost ($2020)	**$36,125,000**	**$35,146,000**	**$31,609,000**	
Escalated Annualized Capital Cost ($2024)	$17,016,000	$16,519,000	$14,964,000	
Escalated Annualized Operating Cost ($2024)	$23,644,000	$23,038,000	$20,613,000	
Total Annual Cost ($2024)	**$40,660,000**	**$39,557,000**	**$35,577,000**	

Kremlin Units 1, 2 and 3
SO_2 Control Cost Evaluation
Dry FGD (CDS + FF)

Table 1. - Baseline Emissions	Dry FGD (CDS + FF)		
	Unit 1	Unit 2	Unit 3
Baseline SO_2 Emissions, ton/yr	6,556	5,674	2,950
Baseline SO_2 Emissions, lb/hr	1,626	1,447	925
Post Upgrade SO_2 Emissions, lb/hr	138	122	78
Capacity Factor used of Cost Estimates (%)	[redacted]	[redacted]	[redacted]
Current Year for Escalation	2020		
Construction Start Year for Escalation	2024		

CAPITAL COSTS	Costs Unit 1	Unit 2	Unit 3	Basis
Direct Costs ($2020)				
Purchased Equipment Costs (PEC)				
Equipment and Materials	$47,582,000	$46,849,000	$42,239,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation. Costs include Heat Recovery and AQCS system. AQCS system is based on common SO2 systems for Units 1&2 and a single system for Unit 3.
Instrumentation	$0	$0	$0	Included in equipment and materials cost
Sales Tax	$2,379,000	$2,342,000	$2,112,000	5% of Equipment/Material Cost
Freight	$2,379,000	$2,342,000	$2,112,000	5% of Equipment/Material Cost
Total PEC	$52,340,000	$51,533,000	$46,463,000	
Direct Installation Costs				
Labor	$24,546,000	$23,110,000	$21,154,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include Heat Recovery and AQCS system.
Scaffolding	$614,000	$578,000	$529,000	2.5% of Labor
Mobilization / Demobilization	$368,000	$347,000	$317,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$1,227,000	$1,156,000	$1,058,000	5% of Labor
Total Direct Installation Costs	$26,755,000	$25,191,000	$23,058,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$79,095,000**	**$76,724,000**	**$69,521,000**	
Indirect Costs ($2020)				
Contractor's General and Administration Expense	$7,910,000	$7,672,000	$6,952,000	10% of Total Direct Costs
Contractor's Profit	$3,955,000	$3,836,000	$3,476,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$6,328,000	$6,138,000	$5,562,000	8% of Total Direct Costs
Construction Management/Field Engineering	$3,164,000	$3,069,000	$2,781,000	4% of Total Direct Costs
S-U / Commissioning	$1,186,000	$1,151,000	$1,043,000	1.5% of Total Direct Costs
Spare Parts	$395,000	$384,000	$348,000	0.5% of Total Direct Costs
Owner's Cost	$1,582,000	$1,534,000	$1,390,000	2% of Total Direct Costs
Total Indirect Costs	**$24,520,000**	**$23,784,000**	**$21,552,000**	
Contingency ($2020)	**$20,723,000**	**$20,102,000**	**$18,215,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI) ($2020)	**$124,338,000**	**$120,610,000**	**$109,288,000**	sum of direct capital costs, indirect capital costs, and contingency
Escalated Total Capital Investment ($2024)	**$139,944,000**	**$135,748,000**	**$123,005,000**	Based on construction start of 2024 and a 3% escalation rate.
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.1175	0.1175	0.1175	20 year life of equipment (years) @ 10.0% interest.
Annualized Capital Costs (CRF x TCI) ($2020)	**$14,605,000**	**$14,167,000**	**$12,837,000**	
Escalated Annualized Capital Costs (CRFxTCI) ($2024)	**$16,438,000**	**$15,945,000**	**$14,448,000**	
OPERATING COSTS				
Operating & Maintenance Costs ($2020)				
Variable O&M Costs				
Increased Waste Disposal Cost	$1,127,000	$983,000	$516,000	Based on disposal rate of $35 per ton + $150 per truck, assuming 25 ton trucks utilized.
Lime Reagent Cost	$2,115,000	$1,846,000	$969,000	Based on lime reagent cost of $160 per ton.
Hydrated Lime Reagent Cost	$0	$0	$0	Based on hydrated lime cost of $189 per ton.
Limestone Reagent Cost	$0	$0	$0	Based on limestone reagent cost of $57 per ton.
Increased Auxiliary Power Cost	$368,000	$356,000	$267,000	Based on auxiliary power cost of $0.0442 per kWh.
Increased Water Cost	$1,615,000	$1,450,000	$991,000	Based on water cost of $7.70 per 1,000 gallons.
Demineralized Water Cost	$678,000	$659,000	$460,000	Based on demineralizer cost of $0.07 per gallon.
Bag and Cage Replacement	$53,000	$53,000	$50,000	Based on bag and cage cost of $156 per bag.
Total Variable O&M Costs	$5,956,000	$5,347,000	$3,253,000	
Fixed O&M Costs				
Additional Operators per Shift	13.3	13.3	13.3	Includes personnel for AQCS and Heat Recovery
Operating Labor	$5,840,000	$5,840,000	$5,840,000	Assume $50/hr for each additional operator
Supervisor Labor	$876,000	$876,000	$876,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$1,186,000	$1,151,000	$1,043,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	$0	Included in cost for maintenance materials.
Water Supply Pipeline Right-of-Way Cost	$70,000	$70,000	$70,000	Based on land rental cost of $4.00 per foot. 10 mile pipeline shared between all 3 kilns.
Water Treatment System Rental	$2,160,000	$2,160,000	$2,160,000	Based on 3 trains (N+1) of rental water treatment equipment
Total Fixed O&M Cost	$10,132,000	$10,097,000	$9,989,000	
Indirect Operating Cost ($2020)				
Property Taxes	$1,243,000	$1,206,000	$1,093,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$1,243,000	$1,206,000	$1,093,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$2,487,000	$2,412,000	$2,186,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$4,973,000	$4,824,000	$4,372,000	
Total Annual Operating Cost ($2020)	**$21,061,000**	**$20,268,000**	**$17,614,000**	
Escalated Total Annual Operating Cost ($2024)	**$23,704,000**	**$22,812,000**	**$19,825,000**	Based on construction start of 2024 and a 3% escalation rate.
TOTAL ANNUAL COST				
Annualized Capital Cost ($2020)	$14,605,000	$14,167,000	$12,837,000	
Annual Operating Cost ($2020)	$21,061,000	$20,268,000	$17,614,000	
Total Annual Cost ($2020)	**$35,666,000**	**$34,435,000**	**$30,451,000**	
Escalated Annualized Capital Cost ($2024)	$16,438,000	$15,945,000	$14,448,000	
Escalated Annualized Operating Cost ($2024)	$23,704,000	$22,812,000	$19,825,000	
Total Annual Cost ($2024)	**$40,142,000**	**$38,757,000**	**$34,273,000**	

Kremlin Units 1, 2 and 3
SO_2 Control Cost Evaluation
DSI

Table 1. - Baseline Emissions	DSI		
	Unit 1	Unit 2	Unit 3
Baseline SO_2 Emissions, ton/yr	6,556	5,674	2,950
Baseline SO_2 Emissions, lb/hr	1,626	1,447	925
Post Upgrade SO_2 Emissions, lb/hr	976	868	555
Capacity Factor used of Cost Estimates (%)	[redacted]	[redacted]	[redacted]
Current Year for Escalation	2020		
Construction Start Year for Escalation	2024		

CAPITAL COSTS	Costs Unit 1	Unit 2	Unit 3	Basis
Direct Costs ($2020)				
Purchased Equipment Costs (PEC)				
Equipment and Materials	$39,436,000	$38,765,000	$35,158,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation. Costs include Heat Recovery and AQCS system. AQCS system is based individual DSI systems for each kiln, and a common baghouse for Units 1&2 and a single baghouse for Unit 3.
Instrumentation	$0	$0	$0	Included in equipment and materials cost
Sales Tax	$1,972,000	$1,938,000	$1,758,000	5% of Equipment/Material Cost
Freight	$1,972,000	$1,938,000	$1,758,000	5% of Equipment/Material Cost
Total PEC	$43,380,000	$42,641,000	$38,674,000	
Direct Installation Costs				
Labor	$19,115,000	$17,720,000	$16,432,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include Heat Recovery and AQCS system.
Scaffolding	$478,000	$443,000	$411,000	2.5% of Labor
Mobilization / Demobilization	$287,000	$266,000	$246,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$956,000	$886,000	$822,000	5% of Labor
Total Direct Installation Costs	$20,836,000	$19,315,000	$17,911,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$64,216,000**	**$61,956,000**	**$56,585,000**	
Indirect Costs ($2020)				
Contractor's General and Administration Expense	$6,422,000	$6,196,000	$5,659,000	10% of Total Direct Costs
Contractor's Profit	$3,211,000	$3,098,000	$2,829,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$5,137,000	$4,956,000	$4,527,000	8% of Total Direct Costs
Construction Management/Field Engineering	$2,569,000	$2,478,000	$2,263,000	4% of Total Direct Costs
S-U / Commissioning	$963,000	$929,000	$849,000	1.5% of Total Direct Costs
Spare Parts	$321,000	$310,000	$283,000	0.5% of Total Direct Costs
Owner's Cost	$1,284,000	$1,239,000	$1,132,000	2% of Total Direct Costs
Total Indirect Costs	**$19,907,000**	**$19,206,000**	**$17,542,000**	
Contingency ($2020)	**$16,825,000**	**$16,232,000**	**$14,825,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI) ($2020)	**$100,948,000**	**$97,394,000**	**$88,952,000**	sum of direct capital costs, indirect capital costs, and contingency
Escalated Total Capital Investment ($2024)	**$113,618,000**	**$109,618,000**	**$100,116,000**	Based on construction start of 2024 and a 3% escalation rate.
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.1175	0.1175	0.1175	20 year life of equipment (years) @ 10.0% interest.
Annualized Capital Costs (CRF x TCI) ($2020)	**$11,857,000**	**$11,440,000**	**$10,448,000**	
Escalated Annualized Capital Costs (CRFxTCI) ($2024)	**$13,346,000**	**$12,876,000**	**$11,760,000**	
OPERATING COSTS				
Operating & Maintenance Costs ($2020)				
Variable O&M Costs				
Increased Waste Disposal Cost	$870,000	$747,000	$392,000	Based on disposal rate of $35 per ton + $150 per truck, assuming 25 ton trucks utilized.
Lime Reagent Cost	$0	$0	$0	Based on lime reagent cost of $160 per ton.
Hydrated Lime Reagent Cost	$3,424,000	$2,960,000	$1,565,000	Based on hydrated lime cost of $189 per ton.
Limestone Reagent Cost	$0	$0	$0	Based on limestone reagent cost of $57 per ton.
Increased Auxiliary Power Cost	$436,000	$406,000	$275,000	Based on auxiliary power cost of $0.0442 per kWh.
Increased Water Cost	$1,323,000	$1,287,000	$905,000	Based on water cost of $7.70 per 1,000 gallons.
Demineralized Water Cost	$678,000	$659,000	$460,000	Based on demineralizer cost of $0.07 per gallon.
Bag and Cage Replacement	$40,000	$40,000	$37,000	Based on bag and cage cost of $156 per bag.
Total Variable O&M Costs	$6,771,000	$6,099,000	$3,634,000	
Fixed O&M Costs				
Additional Operators per Shift	11.0	11.0	11.0	Includes personnel for AQCS and Heat Recovery
Operating Labor	$4,818,000	$4,818,000	$4,818,000	Assume $50/hr for each additional operator
Supervisor Labor	$723,000	$723,000	$723,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$963,000	$929,000	$849,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	$0	Included in cost for maintenance materials.
Water Supply Pipeline Right-of-Way Cost	$70,000	$70,000	$70,000	Based on land rental cost of $4.00 per foot. 10 mile pipeline shared between all 3 kilns.
Water Treatment System Rental	$2,160,000	$2,160,000	$2,160,000	Based on 3 trains (N+1) of rental water treatment equipment
Total Fixed O&M Cost	$8,734,000	$8,700,000	$8,620,000	
Indirect Operating Cost ($2020)				
Property Taxes	$1,009,000	$974,000	$890,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$1,009,000	$974,000	$890,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$2,019,000	$1,948,000	$1,779,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$4,037,000	$3,896,000	$3,559,000	
Total Annual Operating Cost ($2020)	**$19,542,000**	**$18,695,000**	**$15,813,000**	
Escalated Total Annual Operating Cost ($2024)	**$21,995,000**	**$21,041,000**	**$17,798,000**	Based on construction start of 2024 and a 3% escalation rate.
TOTAL ANNUAL COST				
Annualized Capital Cost ($2020)	$11,857,000	$11,440,000	$10,448,000	
Annual Operating Cost ($2020)	$19,542,000	$18,695,000	$15,813,000	
Total Annual Cost ($2020)	**$31,399,000**	**$30,135,000**	**$26,261,000**	
Escalated Annualized Capital Cost ($2024)	$13,346,000	$12,876,000	$11,760,000	
Escalated Annualized Operating Cost ($2024)	$21,995,000	$21,041,000	$17,798,000	
Total Annual Cost ($2024)	**$35,341,000**	**$33,917,000**	**$29,558,000**	

Kremlin Units 1, 2 and 3
SO_2 Control Cost Evaluation
Wet FGD with Water Truck Deliveries

Table 1. - Baseline Emissions	Wet FGD		
	Unit 1	Unit 2	Unit 3
Baseline SO_2 Emissions, ton/yr	6,556	5,674	2,950
Baseline SO_2 Emissions, lb/hr	1,626	1,447	925
Post Upgrade SO_2 Emissions, lb/hr	92	82	52
Capacity Factor used of Cost Estimates (%)	[redacted]	[redacted]	[redacted]
Current Year for Escalation	2020		
Construction Start Year for Escalation	2024		

CAPITAL COSTS	Costs Unit 1	Unit 2	Unit 3	Basis
Direct Costs ($2020)				
Purchased Equipment Costs (PEC)				
Equipment and Materials	$45,460,000	$44,718,000	$39,953,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation. Costs include Heat Recovery and AQCS system. AQCS system is based on common SO2 systems for Units 1&2 and a single system for Unit 3. Costs for water supply pipeline removed.
Water Storage Cost Adjustment	$3,319,000	$3,312,000	$2,870,000	Additional cost for increased water storage capacity to provide 7 days of storage.
Instrumentation	$0	$0	$0	Included in equipment and materials cost
Sales Tax	$2,439,000	$2,402,000	$2,141,000	5% of Equipment/Material Cost
Freight	$2,439,000	$2,402,000	$2,141,000	5% of Equipment/Material Cost
Total PEC	$53,657,000	$52,834,000	$47,105,000	
Direct Installation Costs				
Labor	$24,372,000	$22,930,000	$20,870,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include Heat Recovery and AQCS system. Costs for water supply pipeline removed.
Additional Labor for Increased Water Storage	$2,212,000	$2,208,000	$1,913,000	
Scaffolding	$665,000	$628,000	$570,000	2.5% of Labor
Mobilization / Demobilization	$399,000	$377,000	$342,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$1,329,000	$1,257,000	$1,139,000	5% of Labor
Total Direct Installation Costs	$28,977,000	$27,400,000	$24,834,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$82,634,000**	**$80,234,000**	**$71,939,000**	
Indirect Costs ($2020)				
Contractor's General and Administration Expense	$8,263,000	$8,023,000	$7,194,000	10% of Total Direct Costs
Contractor's Profit	$4,132,000	$4,012,000	$3,597,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$6,611,000	$6,419,000	$5,755,000	8% of Total Direct Costs
Construction Management/Field Engineering	$3,305,000	$3,209,000	$2,878,000	4% of Total Direct Costs
S-U / Commissioning	$1,240,000	$1,204,000	$1,079,000	1.5% of Total Direct Costs
Spare Parts	$413,000	$401,000	$360,000	0.5% of Total Direct Costs
Owner's Cost	$1,653,000	$1,605,000	$1,439,000	2% of Total Direct Costs
Total Indirect Costs	**$25,617,000**	**$24,873,000**	**$22,302,000**	
Contingency ($2020)	**$21,650,000**	**$21,021,000**	**$18,848,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI) ($2020)	**$129,901,000**	**$126,128,000**	**$113,089,000**	sum of direct capital costs, indirect capital costs, and contingency
Escalated Total Capital Investment ($2024)	**$146,205,000**	**$141,958,000**	**$127,283,000**	Based on construction start of 2024 and a 3% escalation rate.
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.1175	0.1175	0.1175	20 year life of equipment (years) @ 10.0% interest.
Annualized Capital Costs (CRF x TCI) ($2020)	**$15,258,000**	**$14,815,000**	**$13,283,000**	
Escalated Annualized Capital Costs (CRFxTCI) ($2024)	**$17,173,000**	**$16,674,000**	**$14,951,000**	
OPERATING COSTS				
Operating & Maintenance Costs ($2020)				
Variable O&M Costs				
Increased Waste Disposal Cost	$991,000	$848,000	$441,000	Based on disposal rate of $35 per ton + $150 per truck, assuming 25 ton trucks utilized.
Lime Reagent Cost	$0	$0	$0	Based on lime reagent cost of $160 per ton.
Hydrated Lime Reagent Cost	$0	$0	$0	Based on hydrated lime cost of $189 per ton.
Limestone Reagent Cost	$800,000	$695,000	$364,000	Based on limestone reagent cost of $57 per ton.
Increased Auxiliary Power Cost	$519,000	$485,000	$328,000	Based on auxiliary power cost of $0.0442 per kWh.
Trucked Water Cost	$35,263,000	$34,423,000	$24,261,000	Based on water cost of $153.85 per 1,000 gallons.
Demineralized Water Cost	$678,000	$659,000	$460,000	Based on demineralizer cost of $0.07 per gallon.
Bag and Cage Replacement	$0	$0	$0	Based on bag and cage cost of $156 per bag.
Total Variable O&M Costs	$38,251,000	$37,110,000	$25,854,000	
Fixed O&M Costs				
Additional Operators per Shift	15.3	15.3	15.3	Includes personnel for AQCS and Heat Recovery
Operating Labor	$6,716,000	$6,716,000	$6,716,000	Assume $50/hr for each additional operator
Supervisor Labor	$1,007,000	$1,007,000	$1,007,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$1,240,000	$1,204,000	$1,079,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	$0	Included in cost for maintenance materials.
Water Treatment System Rental	$2,160,000	$2,160,000	$2,160,000	Based on 3 trains (N+1) of rental water treatment equipment
Total Fixed O&M Cost	$11,123,000	$11,087,000	$10,962,000	
Indirect Operating Cost ($2020)				
Property Taxes	$1,299,000	$1,261,000	$1,131,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$1,299,000	$1,261,000	$1,131,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$2,598,000	$2,523,000	$2,262,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$5,196,000	$5,045,000	$4,524,000	
Total Annual Operating Cost ($2020)	**$54,570,000**	**$53,242,000**	**$41,340,000**	
Escalated Total Annual Operating Cost ($2024)	**$61,419,000**	**$59,924,000**	**$46,529,000**	Based on construction start of 2024 and a 3% escalation rate.
TOTAL ANNUAL COST				
Annualized Capital Cost ($2020)	$15,258,000	$14,815,000	$13,283,000	
Annual Operating Cost ($2020)	$54,570,000	$53,242,000	$41,340,000	
Total Annual Cost ($2020)	**$69,828,000**	**$68,057,000**	**$54,623,000**	
Escalated Annualized Capital Cost ($2024)	$17,173,000	$16,674,000	$14,951,000	
Escalated Annualized Operating Cost ($2024)	$61,419,000	$59,924,000	$46,529,000	
Total Annual Cost ($2024)	**$78,592,000**	**$76,598,000**	**$61,480,000**	

Kremlin Units 1, 2 and 3
SO_2 Control Cost Evaluation
Dry FGD (CDS + FF) with Water Truck Deliveries

Table 1. - Baseline Emissions	Dry FGD (CDS + FF)		
	Unit 1	Unit 2	Unit 3
Baseline SO_2 Emissions, ton/yr	6,556	5,674	2,950
Baseline SO_2 Emissions, lb/hr	1,626	1,447	925
Post Upgrade SO_2 Emissions, lb/hr	138	122	78
Capacity Factor used of Cost Estimates (%)	[redacted]	[redacted]	[redacted]
Current Year for Escalation	2020		
Construction Start Year for Escalation	2024		

CAPITAL COSTS	Costs Unit 1	Unit 2	Unit 3	Basis
Direct Costs ($2020)				
Purchased Equipment Costs (PEC)				
Equipment and Materials	$44,197,000	$43,465,000	$38,855,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation. Costs include Heat Recovery and AQCS system. AQCS system is based on common SO2 systems for Units 1&2 and a single system for Unit 3. Costs for water supply pipeline removed.
Water Storage Cost Adjustment	$3,236,000	$2,997,000	$2,510,000	Additional cost for increased water storage capacity to provide 7 days of storage.
Instrumentation	$0	$0	$0	Included in equipment and materials cost
Sales Tax	$2,372,000	$2,323,000	$2,068,000	5% of Equipment/Material Cost
Freight	$2,372,000	$2,323,000	$2,068,000	5% of Equipment/Material Cost
Total PEC	$52,177,000	$51,108,000	$45,501,000	
Direct Installation Costs				
Labor	$23,530,000	$22,094,000	$20,138,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include Heat Recovery and AQCS system. Costs for water supply pipeline removed.
Additional Labor for Increased Water Storage	$2,158,000	$1,998,000	$1,673,000	
Scaffolding	$642,000	$602,000	$545,000	2.5% of Labor
Mobilization / Demobilization	$385,000	$361,000	$327,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$1,284,000	$1,205,000	$1,091,000	5% of Labor
Total Direct Installation Costs	$27,999,000	$26,260,000	$23,774,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$80,176,000**	**$77,368,000**	**$69,275,000**	
Indirect Costs ($2020)				
Contractor's General and Administration Expense	$8,018,000	$7,737,000	$6,928,000	10% of Total Direct Costs
Contractor's Profit	$4,009,000	$3,868,000	$3,464,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$6,414,000	$6,189,000	$5,542,000	8% of Total Direct Costs
Construction Management/Field Engineering	$3,207,000	$3,095,000	$2,771,000	4% of Total Direct Costs
S-U / Commissioning	$1,203,000	$1,161,000	$1,039,000	1.5% of Total Direct Costs
Spare Parts	$401,000	$387,000	$346,000	0.5% of Total Direct Costs
Owner's Cost	$1,604,000	$1,547,000	$1,386,000	2% of Total Direct Costs
Total Indirect Costs	**$24,856,000**	**$23,984,000**	**$21,476,000**	
Contingency ($2020)	**$21,006,000**	**$20,270,000**	**$18,150,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI) ($2020)	**$126,038,000**	**$121,622,000**	**$108,901,000**	sum of direct capital costs, indirect capital costs, and contingency
Escalated Total Capital Investment ($2024)	**$141,857,000**	**$136,887,000**	**$122,569,000**	Based on construction start of 2024 and a 3% escalation rate.
Capital Recovery Factor (CRF) = $i(1+i)^n / (1+i)^n - 1$	0.1175	0.1175	0.1175	20 year life of equipment (years) @ 10.0% interest.
Annualized Capital Costs (CRF x TCI) ($2020)	**$14,804,000**	**$14,286,000**	**$12,791,000**	
Escalated Annualized Capital Costs (CRFxTCI) ($2024)	**$16,662,000**	**$16,079,000**	**$14,397,000**	
OPERATING COSTS				
Operating & Maintenance Costs ($2020)				
Variable O&M Costs				
Increased Waste Disposal Cost	$1,127,000	$983,000	$516,000	Based on disposal rate of $35 per ton + $150 per truck, assuming 25 ton trucks utilized.
Lime Reagent Cost	$2,115,000	$1,846,000	$969,000	Based on lime reagent cost of $160 per ton.
Hydrated Lime Reagent Cost	$0	$0	$0	Based on hydrated lime cost of $189 per ton.
Limestone Reagent Cost	$0	$0	$0	Based on limestone reagent cost of $57 per ton.
Increased Auxiliary Power Cost	$368,000	$356,000	$267,000	Based on auxiliary power cost of $0.0442 per kWh.
Trucked Water Cost	$33,775,000	$30,639,000	$20,897,000	Based on water cost of $153.85 per 1,000 gallons.
Demineralized Water Cost	$678,000	$659,000	$460,000	Based on demineralizer cost of $0.07 per gallon.
Bag and Cage Replacement	$53,000	$53,000	$50,000	Based on bag and cage cost of $156 per bag.
Total Variable O&M Costs	$38,116,000	$34,536,000	$23,159,000	
Fixed O&M Costs				
Additional Operators per Shift	13.3	13.3	13.3	Includes personnel for AQCS and Heat Recovery
Operating Labor	$5,840,000	$5,840,000	$5,840,000	Assume $50/hr for each additional operator
Supervisor Labor	$876,000	$876,000	$876,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$1,203,000	$1,161,000	$1,039,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	$0	Included in cost for maintenance materials.
Water Treatment System Rental	$2,160,000	$2,160,000	$2,160,000	Based on 3 trains (N+1) of rental water treatment equipment
Total Fixed O&M Cost	$10,079,000	$10,037,000	$9,915,000	
Indirect Operating Cost ($2020)				
Property Taxes	$1,260,000	$1,216,000	$1,089,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$1,260,000	$1,216,000	$1,089,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$2,521,000	$2,432,000	$2,178,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$5,041,000	$4,864,000	$4,356,000	
Total Annual Operating Cost ($2020)	**$53,236,000**	**$49,437,000**	**$37,430,000**	
Escalated Total Annual Operating Cost ($2024)	**$59,918,000**	**$55,642,000**	**$42,128,000**	Based on construction start of 2024 and a 3% escalation rate.
TOTAL ANNUAL COST				
Annualized Capital Cost ($2020)	$14,804,000	$14,286,000	$12,791,000	
Annual Operating Cost ($2020)	$53,236,000	$49,437,000	$37,430,000	
Total Annual Cost ($2020)	**$68,040,000**	**$63,723,000**	**$50,221,000**	
Escalated Annualized Capital Cost ($2024)	$16,662,000	$16,079,000	$14,397,000	
Escalated Annualized Operating Cost ($2024)	$59,918,000	$55,642,000	$42,128,000	
Total Annual Cost ($2024)	**$76,580,000**	**$71,721,000**	**$56,525,000**	

Kremlin Units 1, 2 and 3
SO_2 Control Cost Evaluation
DSI with Water Truck Deliveries

Table 1. - Baseline Emissions	**DSI**		
	Unit 1	**Unit 2**	**Unit 3**
Baseline SO_2 Emissions, ton/yr	6,556	5,674	2,950
Baseline SO_2 Emissions, lb/hr	1,626	1,447	925
Post Upgrade SO_2 Emissions, lb/hr	976	868	555
Capacity Factor used of Cost Estimates (%)	[redacted]	[redacted]	[redacted]
Current Year for Escalation	2020		
Construction Start Year for Escalation	2024		

CAPITAL COSTS	**Costs Unit 1**	**Unit 2**	**Unit 3**	**Basis**
Direct Costs ($2020)				
Purchased Equipment Costs (PEC)				
Equipment and Materials	$36,051,000	$35,381,000	$31,773,000	Based on Sargent & Lundy's conceptual cost estimating system. Includes costs for equipment, material and installation. Costs include Heat Recovery and AQCS system. AQCS system is based individual DSI systems for each kiln, and a common baghouse for Units 1&2 and a single baghouse for Unit 3. Costs for water supply pipeline removed.
Water Storage Cost Adjustment	$2,666,000	$2,666,000	$2,296,000	Additional cost for increased water storage capacity to provide 7 days of storage.
Instrumentation	$0	$0	$0	Included in equipment and materials cost
Sales Tax	$1,936,000	$1,902,000	$1,703,000	5% of Equipment/Material Cost
Freight	$1,936,000	$1,902,000	$1,703,000	5% of Equipment/Material Cost
Total PEC	$42,589,000	$41,851,000	$37,475,000	
Direct Installation Costs				
Labor	$18,100,000	$16,705,000	$15,417,000	Based on Sargent & Lundy's conceptual cost estimating system. Costs include Heat Recovery and AQCS system. Costs for water supply pipeline removed.
Additional Labor for Increased Water Storage	$1,777,000	$1,777,000	$1,531,000	
Scaffolding	$497,000	$462,000	$424,000	2.5% of Labor
Mobilization / Demobilization	$298,000	$277,000	$254,000	1.5% of Labor
Labor Cost Due To Overtime Ineffiency	$994,000	$924,000	$847,000	5% of Labor
Total Direct Installation Costs	$21,666,000	$20,145,000	$18,473,000	
Total Direct Costs (PEC + Direct Installation Costs)	**$64,255,000**	**$61,996,000**	**$55,948,000**	
Indirect Costs ($2020)				
Contractor's General and Administration Expense	$6,426,000	$6,200,000	$5,595,000	10% of Total Direct Costs
Contractor's Profit	$3,213,000	$3,100,000	$2,797,000	5% of Total Direct Costs
Engineering, Procurement, & Project Services	$5,140,000	$4,960,000	$4,476,000	8% of Total Direct Costs
Construction Management/Field Engineering	$2,570,000	$2,480,000	$2,238,000	4% of Total Direct Costs
S-U / Commissioning	$964,000	$930,000	$839,000	1.5% of Total Direct Costs
Spare Parts	$321,000	$310,000	$280,000	0.5% of Total Direct Costs
Owner's Cost	$1,285,000	$1,240,000	$1,119,000	2% of Total Direct Costs
Total Indirect Costs	**$19,919,000**	**$19,220,000**	**$17,344,000**	
Contingency ($2020)	**$16,835,000**	**$16,243,000**	**$14,658,000**	20% of Direct and Indirect Costs
Total Capital Investment (TCI) ($2020)	**$101,009,000**	**$97,459,000**	**$87,950,000**	sum of direct capital costs, indirect capital costs, and contingency
Escalated Total Capital Investment ($2024)	**$113,687,000**	**$109,691,000**	**$98,988,000**	Based on construction start of 2024 and a 3% escalation rate.
Capital Recovery Factor (CRF) = $i(1+ i)^n / (1 + i)^n - 1$	0.1175	0.1175	0.1175	20 year life of equipment (years) @ 10.0% interest.
Annualized Capital Costs (CRF x TCI) ($2020)	**$11,864,000**	**$11,447,000**	**$10,331,000**	
Escalated Annualized Capital Costs (CRFxTCI) ($2024)	**$13,354,000**	**$12,884,000**	**$11,627,000**	
OPERATING COSTS				
Operating & Maintenance Costs ($2020)				
Variable O&M Costs				
Increased Waste Disposal Cost	$870,000	$747,000	$392,000	Based on disposal rate of $35 per ton + $150 per truck, assuming 25 ton trucks utilized.
Lime Reagent Cost	$0	$0	$0	Based on lime reagent cost of $160 per ton.
Hydrated Lime Reagent Cost	$3,424,000	$2,960,000	$1,565,000	Based on hydrated lime cost of $189 per ton.
Limestone Reagent Cost	$0	$0	$0	Based on limestone reagent cost of $57 per ton.
Increased Auxiliary Power Cost	$436,000	$406,000	$275,000	Based on auxiliary power cost of $0.0442 per kWh.
Trucked Water Cost	$27,972,000	$27,364,000	$19,185,000	Based on water cost of $153.85 per 1,000 gallons.
Demineralized Water Cost	$678,000	$659,000	$460,000	Based on demineralizer cost of $0.07 per gallon.
Bag and Cage Replacement	$40,000	$40,000	$37,000	Based on bag and cage cost of $156 per bag.
Total Variable O&M Costs	$33,420,000	$32,176,000	$21,914,000	
Fixed O&M Costs				
Additional Operators per Shift	11.0	11.0	11.0	Includes personnel for AQCS and Heat Recovery
Operating Labor	$4,818,000	$4,818,000	$4,818,000	Assume $50/hr for each additional operator
Supervisor Labor	$723,000	$723,000	$723,000	15% of Operating Labor. EPA Cost Manual Section 1, Chapter 2, page 2-31.
Maintenance Materials	$964,000	$930,000	$839,000	Includes costs for maintenance materials and maintenance labor. Based on 1.5% of Total Direct Costs
Maintenance Labor	$0	$0	$0	Included in cost for maintenance materials.
Water Treatment System Rental	$2,160,000	$2,160,000	$2,160,000	Based on 3 trains (N+1) of rental water treatment equipment
Total Fixed O&M Cost	$8,665,000	$8,631,000	$8,540,000	
Indirect Operating Cost ($2020)				
Property Taxes	$1,010,000	$975,000	$880,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Insurance	$1,010,000	$975,000	$880,000	1% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Administration	$2,020,000	$1,949,000	$1,759,000	2% of TCI. EPA Cost Manual Section 1, Chapter 2, page 2-34.
Total Indirect Operating Cost	$4,040,000	$3,899,000	$3,519,000	
Total Annual Operating Cost ($2020)	**$46,125,000**	**$44,706,000**	**$33,973,000**	
Escalated Total Annual Operating Cost ($2024)	**$51,914,000**	**$50,317,000**	**$38,237,000**	Based on construction start of 2024 and a 3% escalation rate.
TOTAL ANNUAL COST				
Annualized Capital Cost ($2020)	$11,864,000	$11,447,000	$10,331,000	
Annual Operating Cost ($2020)	$46,125,000	$44,706,000	$33,973,000	
Total Annual Cost ($2020)	**$57,989,000**	**$56,153,000**	**$44,304,000**	
Escalated Annualized Capital Cost ($2024)	$13,354,000	$12,884,000	$11,627,000	
Escalated Annualized Operating Cost ($2024)	$51,914,000	$50,317,000	$38,237,000	
Total Annual Cost ($2024)	**$65,268,000**	**$63,201,000**	**$49,864,000**	

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APPENDIX B. OXBOW CONFIDENTIAL LENDER PROPOSAL

The entirety of this Appendix is confidential and is withheld in accordance with 27A O.S. § 2-5-105(17) and OAC 252:4-1-5(d).

APPENDIX B. ADDITIONAL FACTOR REPORT ON REFINED HYSPLIT MODELING

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WICHITA MOUNTAINS CLASS I AREA REFINED HYSPLIT MODELING SUMMARY

Prepared For:

Oxbow Calcining LLC
Kermlin Calcined Coke Plant

Prepared By:

Jeremy Jewell – Principal Consultant
Jeremy Townley – Managing Consultant

TRINITY CONSULTANTS
5801 E. 41st St.
Suite 450
Tulsa, OK 74135
(918) 622-7111

September 25, 2020

Project 203702.0092

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1. INTRODUCTION

The Central States Air Resource Agencies (CenSARA) regional planning organization (RPO) completed Area of Influence (AOI) analyses using the National Oceanic and Atmospheric Administration's (NOAA)'s Hybrid-Single Particle Lagrangian Integrated Trajectory Model (HYSPLIT) for each of its Class I areas to assist its states with source screening. The Oklahoma Department of Environmental Quality (ODEQ) relied on CenSARA's analysis results for the Wichita Mountains Wildlife Refuge Class I area ("WIMO" or "WIMO1") as the basis for determining which sources would be required to complete a regional haze reasonable progress four-factor analysis – ultimately selecting Oxbow Calcining LLC (Oxbow) in Kremlin, Oklahoma as one of the sources.

Oxbow contracted with Trinity to evaluate the CenSARA modeling and complete a refined analysis for WIMO. This report summarizes the analysis completed by Trinity.

2. HYSPLIT METHODOLOGY

HYSPLIT is a hybrid model using both the Lagrangian approach, which uses a moving frame of reference for the advection and diffusion calculations as the trajectories or air parcels move from their initial location and the Eulerian methodology, which uses a fixed three-dimensional grid as a frame of reference to compute pollutant air concentrations. The dispersion of a hypothetical pollutant is calculated by assuming either puff or particle dispersion. The back-trajectory analysis utilized applies a particle model, where a fixed number of particles are advected about the model domain by the mean wind field and spread by a turbulent component. The model's default configuration assumes a 3-dimensional particle distribution (horizontal and vertical).

There are two HYSPLIT modeling techniques available: (1) dispersion modeling, which models the concentration of dispersed pollutants in a plume, and (2) trajectory modeling, which calculates the transport of pollution along a finite path. In its refined analyses, Trinity employed the trajectory modeling tool to calculate the back-trajectories for every hour of the 20 percent most impaired days from calendar years 2013 through 2016.

There are several options available for meteorological datasets. To resolve topographic features and mesoscale meteorological phenomena, Trinity used the 12-km North American Model sigma-pressure hybrid dataset (NAMS) meteorological dataset. The following protocol was implemented:

- The HYSPLIT model was run for each hour of each visibility impaired day (i.e., 24 runs per day)[1]
- A 72-hour back-trajectory was calculated for each of the 24 runs per day to capture the transport of pollutants from all nearby sources to a selected endpoint
- The sigma height option was used, with an initial target height of 0.5 sigma, which represents half the height of the boundary layer. This height is considered to be representative of the mean ground level of ambient air since the boundary layer is well-mixed/homogenous.

The back-trajectories were then aggregated into a residence time frequency matrix in which the columns are longitude bins and rows are latitude bins. For each grid cell (i,j), the frequency, F, is calculated using the following equation:

$$F_{i,j} = \frac{1}{N} \sum T_{i,j} \qquad \text{(equation 1)}$$

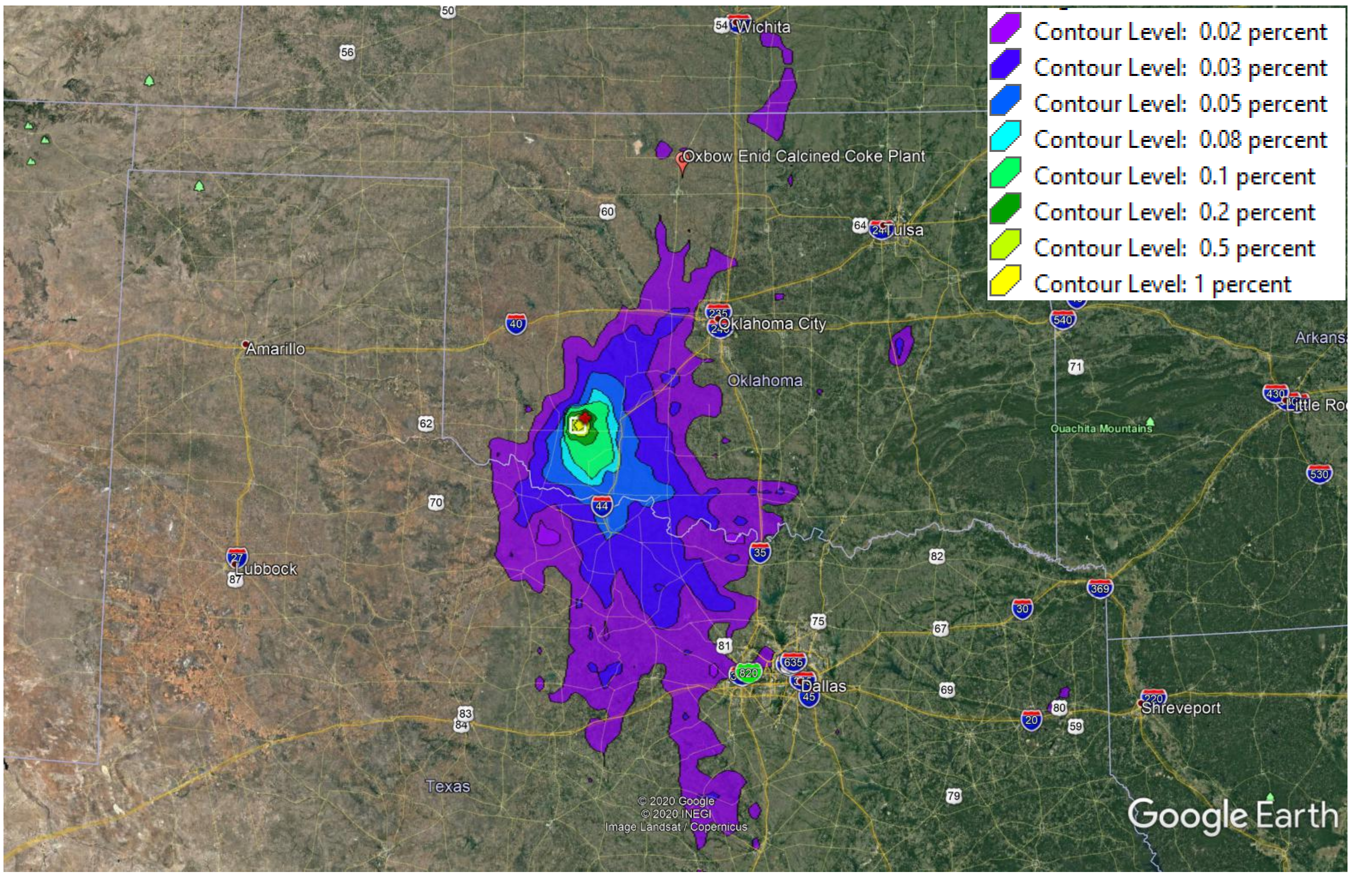
where T is the number of trajectory points that are located in a grid cell (i,j), and N is the total number of trajectory points analyzed.

[1] CenSARA's analysis calculated back-trajectories every six hours, or one-sixth of the total number of time-steps for the back-trajectories used in the Trinity analysis.

3. FREQUENCY COMPARISION FOR WICHITA MOUNTAINS

The residence time frequency analysis was conducted for the WIMO monitor location. The results of this analysis reveal that the cumulative residence times of air parcels contributing to the 20 percent most impaired days in the grid cell containing the Plant are less than 0.02 %. In other words, according to this analysis, the Plant is upwind of WIMO for less than 1.5 hours of the total time represented by the 20 % most impaired days of the four modeled years. The residence time frequency analysis results for the entire region are depicted in Figure 3-1. The map was generated using the HYSPLIT "trajfreq" and "concplot" executables, which output interpolated contours based on the discrete grid cell frequency values.

Figure 3-1. HYSPLIT Residence Time Percent Frequency for WIMO



APPENDIX C. ADDITIONAL FACTOR REPORT ON EXISTING VISIBILITY CONDITIONS FOR THE WICHITA MOUNTAINS

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EXISTING VISIBILITY CONDITIONS FOR THE WICHITA MOUNTAINS

Prepared For:

Oxbow Calcining LLC
Kermlin Calcined Coke Plant

Prepared By:

Jeremy Jewell – Principal Consultant
Stephen Beene – Senior Consultant

TRINITY CONSULTANTS
5801 E. 41st St.
Suite 450
Tulsa, OK 74135
(918) 622-7111

September 24, 2020

Project 203702.0092

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1. INTRODUCTION

Section 51.308(f) of EPA's Regional Haze Regulations requires Oklahoma to revise and submit a revision to its regional haze state implementation plan (SIP) by July 2021, for the second implementation period ending in 2028. This report is focused on the requirement for the SIP to account for regional haze in each mandatory Class I area in Oklahoma. The only Class I area in Oklahoma is the Wichita Mountains Wildlife Refuge (Wichita Mountains).

The EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*,[1] (the EPA SIP Guidance) at p. 5-6, presents eight "key steps in developing a regional haze SIP for the second implementation period." Step 7, entitled *Progress, degradation, and* [uniform rate of progress] *glidepath checks,* requires states to complete the following demonstrations for each in-state Class I area:

- "Demonstrate that there will be an improvement on the 20 percent most anthropogenically impaired days in 2028 at the in-state Class I area, compared to 2000-2004 conditions.
- Demonstrate that there will be no degradation on the 20 percent clearest days in 2028 at the in-state Class I area, compared to 2000-2004 conditions.
- Determine the [uniform rate of progress (URP) glidepath] that would achieve natural conditions at the in-state Class I area in 2064. The [URP glidepath] may be adjusted for international anthropogenic impacts and certain wildland prescribed fires subject to EPA approval as part of EPA's action on the SIP submission.
- Compare the 2028 [reasonable progress goal (RPG)] for the 20 percent most anthropogenically impaired days to the 2028 point on the [URP] glidepath for the in-state Class I area. If the [RPG] is above the [URP] glidepath demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the state that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the [long term strategy]. If the [reasonable progress goal] is above the [URP] glidepath, also provide the number of years needed to reach natural conditions."

Each of these requirements may be demonstrated for each in-state Class I area through a review of historical and current visibility conditions/observations and model-predicted 2028 conditions and a comparison of these conditions to the URP glidepath provided by the EPA in its September 19, 2019 memorandum *Availability of Modeling Data and Associated Technical Support Document for the EPA's Updated 2028 Visibility Air Quality Modeling*[2] (the EPA 2028 Modeling TSD).

This report provides Trinity's review for the Wichita Mountains Class I area Interagency Monitoring of Protected Visual Environments (IMPROVE) network monitor (WIMO1).

[1] *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, August 2019, EPA-457/B-19-003

[2] https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf

2. ANALYSIS OF VISIBILITY CONDITIONS AT WICHITA MOUNTAINS

2.1 Background

Visibility impairment or "haze" is described by the light extinction visibility metric in units of inverse megameters (Mm^{-1}). Because the inverse-distance units are difficult to conceptualize, the deciview haze index (dv) was developed. Extinction values are converted to deciviews using a logarithmic equation[3] such that the deciview scale is nearly zero for a pristine atmosphere, and, like the decibel scale for sound, equivalent changes in deciviews are perceived similarly across a wide range of background conditions.[4] Light extinction in the Class I areas is observed via the IMPROVE network of Class I area air monitors. IMPROVE visibility data are available on the IMPROVE website.[5]

EPA has selected the deciview scale as the most appropriate visibility metric for regulatory purposes because it is more conducive to describing and comparing humanly perceptible visibility changes at different Class I areas and for a wide range of visibility conditions. According to EPA, a "one-deciview change in haziness is a small but noticeable change in haziness under most circumstances".[6] However, other studies disagree and have suggested that a "1-deciview change never produces a perceptible change in haze."[7]

Section 169A of the Clean Air Act (CAA) sets forth a national goal for the "prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution." In 1999, the Regional Haze Program was promulgated to require states to include provisions to address impairment of visibility in Class I areas in their SIPs.[8] The Regional Haze Program requires setting reasonable progress goals towards achieving natural visibility conditions at each Class I area. The reasonable progress goals must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period.[9] Reasonable progress goals are compared to the Uniform Rate of Progress (URP) or "glidepath" needed to achieve natural conditions in 2064.[10] The URP is a straight line from baseline visibility conditions (average of the 20 percent most impaired days as of 2004) to natural visibility conditions (to be achieved in 2064 for the 20 percent most impaired days).

The EPA SIP Guidance contains a few key differences from the processes that took place during the first planning period. Most notably, the second planning period analysis distinguishes between natural (or biogenic) and manmade (or anthropogenic) sources of emissions, and allows for the adjustment of the URP glidepath to account for the impact of international sources on the Class I areas. The methods described in the EPA Visibility Tracking Guidance for selecting the twenty (20) percent most impaired days to track

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[3] Deciview = 10 × ln (Extinction ÷ 10).

[4] U.S. EPA, Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress at 1-5 - 1-7 (November 2001).

[5] http://vista.cira.colostate.edu/Improve/.

[6] Regional Haze Regulations, 64 Fed. Reg. 35,725-27 (July 1999).

[7] Ronald C. Henry, "Just-Noticeable Differences in Atmospheric Haze," Journal of the Air & Waste Management Association, Vol. 52 at 1,238 (October 2002).

[8] 64 FR 35714.

[9] 40 CFR 51.308(d)(1)

[10] 40 CFR 51.308(f)(1)(iv)(A)

visibility have been applied by the IMPROVE group to the data collected for each Class I area, including the WIMO1 monitor.

The differences also result in changes to the URP glidepath established during the first planning period. The EPA 2028 Modeling TSD presents four glidepath options for each Class I area: unadjusted, adjusted default, adjusted minimum, and adjusted maximum. Trinity understands that ODEQ plans to adopt the adjusted default URP glidepath presented by EPA.

The EPA also requires the tracking of the 20 percent clearest days at each Class I area to ensure that the visibility on the clearest days is not being degraded. For the second planning period, the tracking of the 20 percent clearest days remains unchanged. The selection of the 20 percent clearest days does not include any processing to factor out natural sources of impairment.

2.2 Visibility Conditions at Wichita Mountains

Table 2-1 presents a summary of the annual-average haze index values (dv) based on observations for the 20 percent most impaired days and the 20 percent clearest days for each year from 2002 to 2018[11] for WIMO1.

Table 2-1. Summary of Haze Index Values for WIMO1 (2002-2018)

Year	Average of 20 Percent Most Impaired Days (dv)	Average of 20 Percent Clearest Days (dv)
2002	22.26	9.75
2003	22.02	10.02
2004	22.16	9.56
2005	24.39	10.59
2006	20.83	9.74
2007	22.38	9.32
2008	21.06	9.85
2009	-- [A]	-- [A]
2010	20.92	9.22
2011	21.24	10.34
2012	19.44	8.88
2013	19.54	8.44
2014	20.42	9.26
2015	18.08	8.49
2016	16.45	8.08
2017	17.50	7.74
2018	18.16	8.77

[A] Summarized data are not available.

Figure 2-1 at the end of this section plots the observation data in Table 2-1 and the URP glidepath to show how the observed visibility impairment at WIMO1 has decreased (i.e., improved) overall and has remained below the URP glidepath for the last several years. As shown in Figure 2-1, the current Class I area visibility conditions are better than necessary (or ahead of schedule) to return Wichita Mountains to natural visibility conditions in 2064.

[11] As of the drafting of this report, summarized annual IMPROVE monitoring data is available through the year 2018.

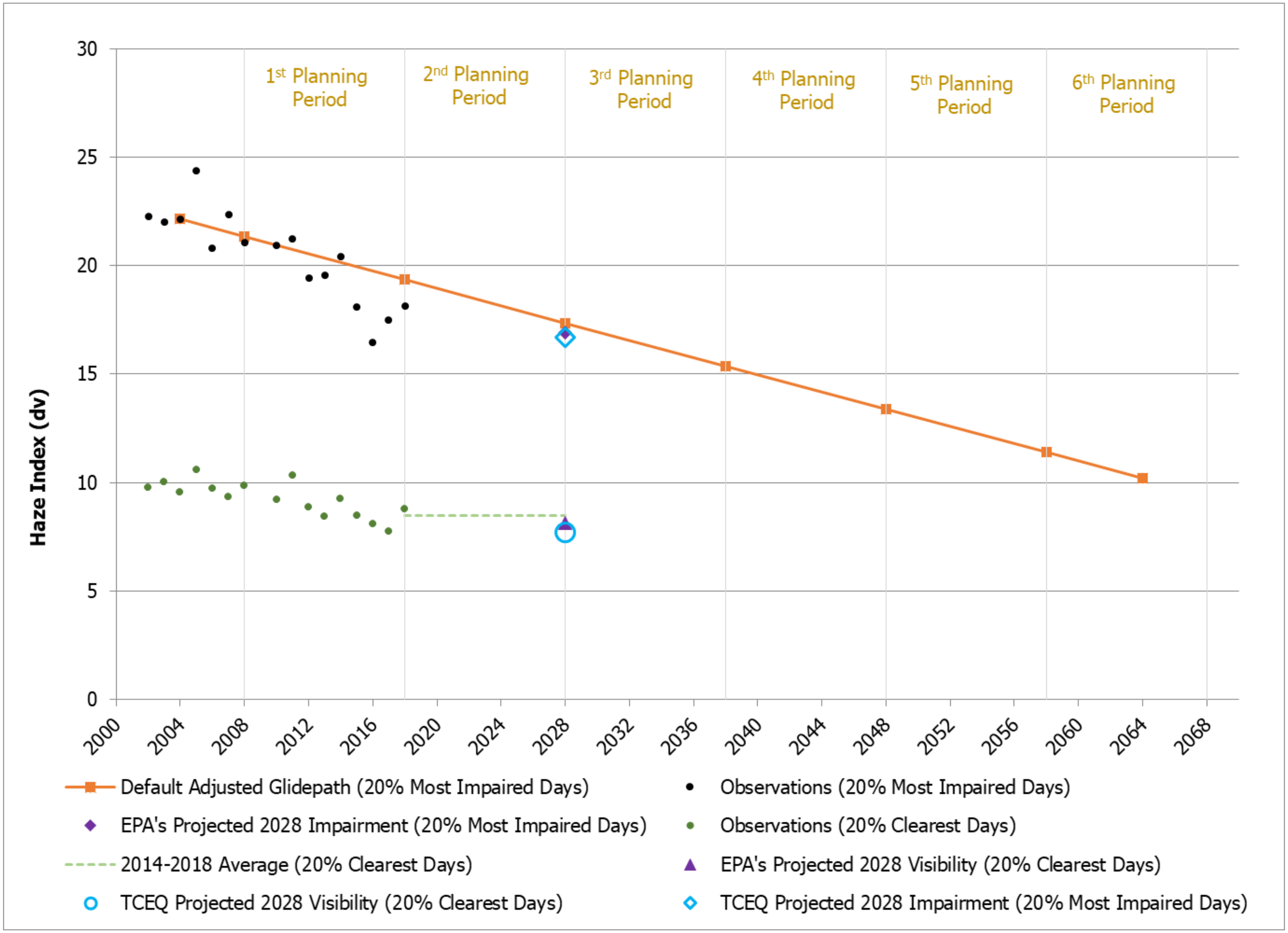
Figure 2-1 also shows the projected 2028 haze index values from the EPA 2028 Modeling TSD. EPA's modeling shows the projected 2028 haze index is three percent (3%) below the URP Glidepath. Therefore, if the EPA projected 2028 haze index values were adopted by ODEQ as the RPG in 2028 the objective of the Regional Haze Program to improve the most impaired days and not cause additional degradation to the clearest days would be satisfied. Additionally, the projected 2028 haze index values show that projected Class I area visibility conditions at the end the second planning period are better than necessary (or ahead of schedule) to return Wichita Mountains to natural visibility conditions in 2064.

Lastly, the projected 2028 most-impaired days result from recent CAMx modeling completed by the Texas Commission on Environmental Quality (TCEQ) is also shown in Figure 2-1.[12] It also indicates that the 2028 projected visibility impairment at WIMO1 is below the URP glidepath.

Taken together, all monitoring evidence and modeled predictions indicate that current projected emissions are sufficient to show reasonable progress at Wichita Mountains without the operation of additional emission controls for sources under the ODEQ's reasonable progress analyses.

[12] *Regional Haze Modeling to Evaluating Progress in Improving Visibility in and near Texas*, dated January 21, 2020 (https://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/pm/5822010567009-20200121-ramboll-RegionalHazeModelingEvaluateProgressVisibility.pdf)

Figure 2-1. Observations and Modeled Predictions Compared to URP Glidepath for WIMO1



3. CONCLUSIONS

The observed visibility impairment at the WIMO1 has decreased (i.e., improved) overall and is below the URP glidepath required by the regional haze program. In addition, EPA's and TCEQ's modeling indicates that the 2028 projected visibility impairment is below the URP glidepath. Therefore, emissions reductions currently contained in the modeling are sufficient to show reasonable progress for this round of the Regional Haze planning. In addition to emissions reductions currently contained in the modeling, additional emissions decreases have occurred or are soon to occur at two other sources that allegedly contribute to visibility impairment at WIMO1: LafargeHolcim's cement plant in Ada, OK[13] (183.49 km from the Wichita Mountains) and American Electric Power's Oklaunion power plant in Vernon, TX (just south of the Oklahoma-Texas border and approximately 83.67 km from the Wichita Mountains).[14] These reductions should provide additional progress for the second planning period.

In summary, based on the current visibility data and known emission reductions, additional emission reductions from Oklahoma industrial facilities are not necessary to show reasonable progress for this round of Regional Haze planning.

[13] The reported and modeled 2016 emission rate and modeled 2028 emission rate was 2,203 tpy, but reported 2018 emissions (following a plant rebuild in 2017) were 68 tpy.

[14] Distances are from the Area of Influence analysis spreadsheet (facilityemis.ewrt.qd2028.alltraj.xlsx) generated by Ramboll for the Central States Air Resources Agencies (CenSARA) and utilized by ODEQ for source screening.

APPENDIX D. PROJECTED EMISSION RATE ERROR IN CENSARA'S AREA OF INFLUENCE ANALYSIS

CenSARA, ODEQ, and EPA used various sources of historical and projected 2028 emissions in support of the Regional Haze SIP development process. For example, CenSARA conducted an Area of Influence (AOI) analysis to assist states, including Oklahoma, in selecting sources for four-factor analyses. The CenSARA AOI analysis evaluated 2016 actual emissions and 2028 projected emissions from the following EPA emissions inventories:

- Historical actual 2016 emissions are from the 2016NEI version alpha, and
- Projected 2028 emissions are from the 2011v6.3 Modeling Platform, which based projected 2028 emissions on 2011 actual emissions with adjustments for non-electrical generating units with regards to known closures and expected emissions reductions from other programs (none of these adjustments were applied to the Plant).

CenSARA's projected 2028 SO_2 emission rate for the Plant was 10,070 tpy. This value is less than the projected 2028 SO_2 emission rate in EPA's latest modeling platform (2016v7.2 beta and Regional Haze): 12,663 tpy. This level of SO_2 emissions is representative of the anticipated 2028 SO_2 emissions from the Plant. For any additional analyses based on 2028 projected emissions, EPA's 2016v7.2 (beta and Regional Haze) or EPA's 2016v1 (final version of the 2016 modeling platform) should be used.

Oxbow and Trinity understand that ODEQ used the correct, historical actual 2016 emissions (12,663 tpy) for its source selection decisions.

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

SCOTT A. THOMPSON
Executive Director

KEVIN STITT
Governor

January 31, 2022

Scott E. Stewart
Oxbow Calcining LLC
11826 N 30th St.
Kremlin, OK 73753

Subject: Additional clarifications on Oxbow's 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Mr. Stewart:

In a letter dated July 1, 2020, the Oklahoma Department of Environmental Quality (DEQ) identified the Kremlin Calcining Plant located in Garfield County, Oklahoma, as subject to a four-factor reasonable progress analysis under the Regional Haze Rule as part of DEQ's development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

On October 1, 2020, Oxbow submitted its four-factor analysis to DEQ. Oxbow included in its response that there were no cost-effective sulfur dioxide (SO_2) control measures available for Kilns 1, 2, or 3. DEQ included these conclusions in its draft Regional Haze SIP for Planning Period 2 that was shared with the Federal Land Managers and the U.S. Environmental Protection Agency (EPA) for their review and comment. DEQ requests that Oxbow review its four-factor analysis for potential SO_2 control measures and respond to the following questions, which are based on EPA's review of Oklahoma's draft SIP. We understand that some of the requested data/analysis may be gleaned or explained from DEQ's permitting and compliance files, and/or Oxbow's full unredacted submittal. However, your response will allow Oxbow to document the information that best explains and supports the conclusions of your four-factor analysis. DEQ intends to continue its analysis in parallel.

1. 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[1], "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 EPA has historically observed and available literature, an assumption of 30 years for the equipment life of scrubbers and dry sorbent injection (DSI) is reasonable and consistent with EPA's Control Cost Manual[2].

[1] https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf
[2] https://www.epa.gov/sites/default/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

2. 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. 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.[3] 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.

3. The four-factor analysis explains that average hourly SO_2 emission rates (measured at each kiln during the January 2015 to December 2019 period) and annual average SO_2 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 SO_2 emission rates and annual average SO_2 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.

DEQ respectfully requests that Oxbow respond to EPA's questions no later than February 28, 2022. Thank you for your assistance with this matter. Please contact Melanie Foster at 405-702-4218 for any questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

[3] 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.

OXBOW CALCINING LLC

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VIA ELECTRONIC MAIL

March 7, 2022

Kendal Stegmann, Director
Air Quality Division
Oklahoma Dept. of Environmental Quality
707 N. Robinson
Oklahoma City, OK 73101

RE: Response to request for additional clarifications on Oxbow's 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program
Oxbow Calcining L.L.C. – Kremlin Calcined Coke Facility

Dear Ms. Stegmann:

In response to your January 31, 2022, letter requesting additional clarifications to our Regional Haze Reasonable Progress Analysis (FFA) submittal, Oxbow Calcining L.L.C. (Oxbow) is submitting this letter that we trust will address the questions that the Oklahoma Department of Environmental Quality (DEQ) received from the U.S. Environmental Protection Agency (EPA).

As certain information in this Response is confidential, trade secret business information pursuant to 27A O.S. 2-5-105(17) (*i.e.,* information that derives independent economic value from not being generally known or readily ascertainable by proper means by other persons or entities who could obtain economic value from its disclosure or use and for which Oxbow has exercised reasonable efforts to maintain the secrecy of such information), Oxbow is asserting a claim of confidentiality regarding such information. Accordingly, two versions of this Response are being provided: a Confidential Version which contains the confidential, trade secret business information, and a Nonconfidential Version from which the confidential, trade secret business information has been redacted. This is the Nonconfidential Version of the Response. The Confidential Version was submitted on March 7, 2022, under separate cover via hand delivery.

Pursuant to Oklahoma Administrative Code 252:4-1-5(d), Oxbow requests the DEQ determine the confidentiality of the confidential, trade secret business information identified in this Confidential Version of the Response and advise Oxbow of its determination via an affirmative statement in writing.

In order facilitate a clear and final response, we copied each comment and provided a response below it. Where the comment covers multiple subtopics, we broke the comment down and provided a response to each subsection.

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COMMENT 1

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,[1] *"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 EPA has historically observed and available literature, an assumption of 30 years for the equipment life of scrubbers and dry sorbent injection (DSI) is reasonable and consistent with EPA's Control Cost Manual.*

RESPONSE:

Oxbow assumes that the EPA's historical observation and literature reference of a 30-year equipment life for the scrubbers and DSI is taken from the wet FGD example cost estimate provided in Section 5, Chapter 1 of the Control Cost Manual (updated April 2021). In that example, EPA noted that although remaining life of the controlled unit may be a determining factor when deciding on the correct equipment life for calculating total annual costs, "we [EPA] expect an equipment life of 20 to 30 years for wet FGD systems." It is important to emphasize that EPA's own document specifies a range and the manual does not mandate using a 30-year equipment for all SO_2 and acid gas control technologies. (Control Cost Manual, Section 5, Chapter 1, April 2021).

Typically, in an economic evaluation, the design or economic life of a control system is considered to end when the capital cost of the equipment has fully depreciated and O&M costs become more representative of annual system costs. Section 1, Chapter 2 of the Control Cost Manual (updated in November 2017) notes that the equipment life used to annualize capital costs is the expected design or operational life of the control equipment, and that it 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." However, just as there are many parameters and plant-specific considerations that can yield widely differing estimates of the economic life of a control technology, these same parameters and plant-specific considerations will affect the operational life of the control equipment. The operational life of emission control equipment will vary depending on process conditions, original design specifications, equipment operation and maintenance practices, site location, and other site-specific design and operating conditions. When comparing competing technologies and evaluating the cost-effectiveness of competing control technologies, the economic analysis should be based on an expected operational life of the equipment taking into consideration plant-specific design and operating conditions.

When process conditions are well established, an industry standard equipment operational life of 20 years is assumed to be representative of an economical equipment design. In other words,

1 USEPA, Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, USEPA Office of Air Quality Planning and Standards, EPA-457/B-19-003, August 2019, available at: https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

materials of construction, equipment components and other design aspects are engineered and 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 operational life; while, on the other hand, materials of construction, equipment components, and other design aspects of the system are not overdesigned. Equipment could be designed to achieve a longer operational life, one greater than industry standard, but would result in increased capital costs and skew the results of the control technology comparison.

Furthermore, due to the novel application of this equipment on the calcining process, the effects that the process flue gas characteristics will have on the operational life of the control equipment and how increased capital costs could be applied to achieve longer equipment lifespans is not well established. For these reasons, the 20-year operational life of the control technologies evaluated in the Oxbow FFA represents a reasonable estimate of equipment life taking into consideration site-specific process design and operating conditions, and should be used in the analysis to calculate emission reductions, amortized costs, and cost-effectiveness.

COMMENT 2

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. 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.[2] 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.

RESPONSE:

It appears from EPA's comment that the commenter is equating bank prime rate and company-specific interest rate as equal choices. This is an incorrect reading of EPA's Control Cost Manual. As a result, before responding to the substance of the comment, it is important to note that EPA's Control Cost Manual expresses a clear preference for company-specific interest rates – ". . . assessments of private cost **should be prepared using firm-specific interest rates if possible**, or the bank prime rate if firm-specific interest rates cannot be estimated or verified."[3] Further, EPA's Control Cost Manual cautions that "[a]nalysts **should use the bank prime rate with caution** as these base rates used by banks do not reflect entity and project specific characteristics and risks including the length of the project, and credit risks of the borrowers."[4] EPA's Control Cost Manual

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.
3 Id. at 16 (emphasis added).
4 Id. (emphasis added).

clearly favors using company-specific interest rates when available and Oxbow justified the use of the company-specific interest rates in its FFA submittal.

In its original FFA submittal, Oxbow provided a detailed evaluation prepared by its lead banker, Bank of America, that fully justified Oxbow's ability to qualify for financing the addition of a potential pollution control system. In your request, you ask for "[a] letter from a chief financial officer for [Bank of America], or another official with [Bank of America] that is in a position to know the company's debt and equity, that documents [Bank of America's] commitment to lend at the specified interest rate . . . " This is wholly unreasonable and suggests that EPA does not understand how the financial markets work for individual companies. Oxbow has no connection to the CFO of Bank of America and in Oxbow's original submittal it provided a detailed document prepared by "another official" of Bank of America documenting the interest rate which Oxbow qualified for if it were to undertake the potential pollution control project. It is not clear what EPA means by a "commitment to lend," but to the extent EPA is requesting a confirmation from Bank of America, that is not possible because the project has not been fully developed to the point where anyone would commit financing to it.

Further, it is our understanding that no other company presented the level of detail to justify its company-specific interest rate that Oxbow provided in its FFA submittal and we do not believe further justification is warranted. However, in order to address EPA's confusion, Oxbow attaches an Affidavit from its Treasurer providing additional proprietary confidential business information related to the request for financing done in 2020 in support of the FFA. In short, as Oxbow's Treasurer explains, Oxbow's financial position and the nature of the potential project dictated the parameters of the financing available and supported the company-specific interest rate of 10% used in the evaluations.

COMMENT 3

The four-factor analysis explains that average hourly SO_2 emission rates (measured at each kiln during the January 2015 to December 2019 period) and annual average SO_2 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 SO_2 emission rates and annual average SO_2 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.

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SUBCOMMENT

"Please explain why the range of years used for the average hourly SO_2 emission rates and annual average SO_2 emission rates are not the same."

RESPONSE:

Average hourly SO_2 emission rates used in the FFA are based on an evaluation of historical operating data from January 2015 to December 2019 and are representative of the wide range of operating conditions and fluctuations experienced at each kiln. Because it is difficult to predict fluctuations in the composition of green petroleum coke (GPC), the average hourly emission rates are used as the basis for the technical feasibility evaluation and O&M cost estimates, as they were determined to be representative of typical operating conditions and fluctuations experienced at each kiln.

Annual average SO_2 emission rates used in the FFA are based on historical operating data from January 2018 to December 2019, a period of time during which the kilns experienced somewhat higher sulfur GPC. During the extended baseline period of January 2015 to December 2019, the Kremlin facility's kilns processed GPC with a sulfur content ranging from [redacted] wt% to 6.0 wt% with an average of [redacted] wt%. Between January 2018 and December 2019, the average sulfur content of GPC processed increased to [redacted] wt%. Operating data from the facility demonstrates that the sulfur content of the GPC has increased over time and is likely to continue to increase in the future as refineries are required to meet specifications for lower-sulfur refined products. Because the generation of SO_2 is directly related to the sulfur content in the GPC, the more recent emissions data are expected to be more representative of future emissions, and were therefore used as the basis for the calculations of tons of SO_2 emissions removed and control technology cost effectiveness.

SUBCOMMENT

"the four-factor analysis should also provide the calculations for the capacity factors, with redactions in the publicly available version if necessary."

RESPONSE:

Because of the indirect correlation between kiln operation and corresponding SO_2 emissions, capacity factors were determined for each kiln by dividing the actual 12-month annual average SO_2 emissions from January 2018 to December 2019 (tpy) by the annual SO_2 emissions that would be generated based on the average hourly SO_2 emission rate from January 2015 to December 2019 (lb/hr) on a continuous operating basis (i.e., 8,760 hours/year). Capacity factors were calculated using following equation:

$$\text{Capacity Factor} = \frac{\textit{Annual Average Emission}, \frac{ton}{year}}{\frac{\textit{Annual Average Hourly Emission lb}}{hour} \times \frac{1\ ton}{2000\ lb} \times \frac{8760\ hours}{year}} \times 100$$

Capacity factors were calculated in this manner because the use of recent annual average emissions is meant to reflect potential SO_2 emissions from the units in the future. Emissions need to be estimated separately from a direct reference to kiln production rates because SO_2 emissions don't specifically correlate to kiln operation (such as a coal fired power plant).

SUBCOMMENT

"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."

RESPONSE

The kilns at the Kremlin facility operate continuously 24 hours a day, 7 days a week at processing rates that range from a minimum of approximately [redacted]% of typical rates depending on customer specifications and GPC quality (i.e., the kilns are not typically operated at their design nameplate rating). Annual maintenance outages for each kiln and its supporting systems are scheduled to only have one kiln offline at a time in order to maintain maximum calcined petroleum coke (CPC) production flexibility in the remaining operating kilns. Given the range of factors impacting operation and, more importantly, the fluctuation in raw feed sulfur content, establishing a capacity factor based on kiln production rates does not accurately correlate to SO_2 emissions.

As mentioned previously, it is difficult to predict fluctuations in the GPC composition. Because no single source can supply GPC to meet all CPC customer specifications and quantities, GPC is purchased from various suppliers and blended together at appropriate percentages to meet individual customer specifications. Therefore, sourcing the correct raw material GPC is a critical aspect of Oxbow's business and selection parameters are closely monitored. The appropriate blend of different GPCs is metered at the appropriate feed rates into each rotary kiln. As a result, the GPC blends fed to the kilns at any given time can have a wide range of properties (e.g., volatile matter, moisture, sulfur, metals, etc.).

Products produced at the facility will change based on customers and their sulfur specifications. Customers are increasing their sulfur specification on the CPC they purchase to try to save money because the lower sulfur GPC raw material that yields a lower sulfur CPC is in short supply and is more expensive. In addition, the customers the facility has from year-to-year change based on competition from other calciners, availability of GPC and the GPC sulfur level, and economic conditions. Customers' requirements for CPC specifications will fluctuate based on the customers' production requirements at the time of the order. Although the capacity factors used are the best available, for all of the reasons provided in the original FFA and this additional explanation, they may not represent actual future operation. There are no recent enforceable requirements that may cause capacity factors to change in the future.

If you have any questions regarding the submittal, please contact me at (561) 907-5576 or at scott.stewart@oxbow.com.

Sincerely,

Scott E. Stewart
VP, Environmental, Health & Safety

Attachment: Affidavit of Benjamin Klein, Treasurer
Oxbow Carbon LLC & Oxbow Calcining LLC

AFFIDAVIT OF BENJAMIN KLEIN

STATE OF FLORIDA §

COUNTY OF PALM BEACH §

Before me, the undersigned Notary Public in and for the State of Florida, personally appeared Benjamin Klein, the affiant, whose identity is known to me. After I administered an oath, affiant testified as follows:

1. My name is Benjamin Klein. I am over 18 years of age, of sound mind, and capable of making this affidavit. The facts in this affidavit are within my personal knowledge and are true and correct.

2. I am the duly appointed Treasurer of Oxbow Carbon LLC and its subsidiaries including Oxbow Calcining LLC (collectively referred to as "Oxbow"). In this capacity I am knowledgeable about the financial affairs of Oxbow including its liquidity and its ability to obtain debt financing.

3. During the summer of 2020 I was asked to provide guidance on how Oxbow could finance the construction of new pollution control equipment at our calciners (the "Project").

4. Oxbow's capital structure had following characteristics:

   a) Oxbow is considered a non-investment grade company based on ratings issued by both Moody's and Standard & Poor's (the "Rating Agencies").

   b) [redacted]

   c) [redacted]

   d) [redacted]

5. Given the l[redacted]mitation of Oxbow's capital structure, [redacted] all—in-yield (borrowing cost) of approximately 10%.

6. [redacted] Illustrative Financing Discussion, dated July 17, 2020, that reflects the financing options available to Oxbow for the Project and the yield (borrowing cost) of approximately 10% that would be required for Oxbow to finance the Project.

BENJAMIN KLEIN

Sworn and subscribed before me by Benjamin Klein on this 7 day of March, 2022, 2022.

Notary Public in and for the State of Florida

My commission expires: NICOLINA SOLIMENE Commission # HH 121108 Expires August 23, 2025 Bonded Thru Troy Fain Insurance 800-385-7019

David Hennessy
Panhandle Eastern Pipeline Co.
8111 Westchester Dr, Ste. 600
Dallas, TX 75225

July 1, 2020

Subject: Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Mr. Hennessy:

This letter is to inform you that the Oklahoma Department of Environmental Quality (DEQ) has identified the Cashion Compressor Station located in Kingfisher County, Oklahoma, as subject to a four-factor reasonable progress analysis under the Regional Haze Rule. DEQ is in the development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

The states in the Central States Air Resources Agencies (CenSARA) organization, which include Oklahoma, contracted with Ramboll US Corporation (Ramboll) to produce a study examining the impact of stationary sources of NOx and SO_2 on each Class 1 area in the central region of the United States. DEQ used a method based on this study to determine which sources may have the greatest potential for contributing to visibility impairment at Oklahoma's Class 1 area: the Wichita Mountains Wilderness Area.

DEQ must develop a long-term strategy to address visibility impairment and make "reasonable" progress toward a goal of no anthropogenic visibility impairment by 2064. The Regional Haze Rule provides four factors (40 CFR §51.308(f)(2)(i)) by which a state must consider potential control measures for the long-term strategy: 1) the cost of compliance; 2) the time necessary for compliance; 3) the energy and non-air quality environmental impacts of compliance; and 4) the remaining useful life of existing sources subject to this requirement.

DEQ requests that Panhandle Eastern Pipeline perform a four-factor analysis of all potential control measures for NOx on all fuel-burning equipment with a heat input of 50 MMBTU/hr or more including but not limited to the following emission units at the Cashion Compressor Station:

1. U-338 and U-339; Fairbanks Morse 38DS8 MEP-8
2. U-2301 and U-2302; Cooper Quad 12Q155HC

For any technically feasible control measure, the following information should be provided in detail:

I. Emission reductions achievable by implementation of the measure
    a. Baseline emission rate (lb/hr, lb/MMBTU, etc)
    b. Controlled emission rate (same form as baseline rate)

c. Control effectiveness (percent reduction expected)
d. Annual emission reductions expected (ton/year)

II. Time necessary to implement the measure

III. Remaining useful life
a. Remaining useful life of the control measure, or
b. The corresponding life of the unit may be used if an enforceable shutdown date of the emission unit is no later than 2028.

IV. Energy and non-air quality environmental impacts of the measure.
a. Detail any cost of energy, waste disposal, regulatory requirement, etc. incurred with implementation of the control measure.

V. Cost of implementing the measure
a. Capital costs
b. Annual operating and maintenance costs
c. Annualized costs

DEQ respectfully requests that your company submit a report containing the complete 4-factor analysis no later than September 1, 2020. This will allow DEQ to review and identify any cost-effective control measure to be incorporated into the Regional Haze state implementation plan prior to the submission deadline of July 31, 2021.

Please contact DEQ if you have any questions about the method for conducting a 4-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical review required under the Rule.

Thank you for your assistance with this matter. Please contact Cooper Garbe at 405-702-4169 or Melanie Foster at 405-702-4218 for your questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

Four-Factor Analysis for Regional Haze Planning in Oklahoma

Cashion Compressor Station
Kingfisher County, Oklahoma
FAC ID 1373

Panhandle Eastern Pipeline Company

14998 West 6th Avenue Suite 800 80401 Golden Colorado USA | 11216304 | September 2020

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Appendix A Table 1 - NOx Engine Test Data, Reported Emissions, and Q/d Analysis

1. Executive Summary

In response to the Oklahoma Department of Environmental Quality (DEQ) letter dated July 1, 2020, GHD Services Inc. (GHD) was retained by Panhandle Eastern Pipeline Co. to prepare a four-factor analysis for the DEQ Regional Haze Second Planning Period Progress Analysis under the Clean Air Act (CAA) and Regional Haze Rule (40 CFR §51.300 to 51.309). As a part of this Progress Analysis, nitrogen oxides (NO_x) emissions were evaluated at the Cashion Compressor Station (Cashion CS) (Site/Facility).

The four-factor analysis is codified in 40 CFR §51.308(d)(1)(i)(A) and is designated as a means for establishing reasonable progress goals towards achieving natural visibility conditions by the year 2064. The four factors to consider are:

1. The costs of compliance
2. The time necessary for compliance
3. The energy and non-air quality environmental impacts of compliance
4. The remaining useful life of any potentially affected sources

The purpose of the four-factor analysis is to identify control measures for reducing emissions that could be used to establish the long-term strategy for attaining state visibility goals. Ramboll US Corporation (Ramboll) produced a study examining the impact of stationary sources of NO_x and SO_2 on each Class I Area in the central region of the United States. DEQ used a method based on this study to determine which sources may have the greatest potential for contributing to visibility impairment at Oklahoma's Class I Area: the Wichita Mountains Wilderness Area. Based on the Ramboll study and DEQ follow-up determinations, DEQ has requested evaluations of potential control measures for NO_x on the following emission units at Cashion CS:

1. U-338 and U-339; Fairbanks Morse 38DS8 MEP-8
2. U-2301 and U-2302; Cooper Quad 12Q155H

The analysis used by DEQ was based on the NOx emissions reported for 2016. As allowed by DEQ, the reported emissions for the Cashion CS were equal to the potential to emit for the Site. Based on the actual emissions from the last 5 years, it appears that this Site does not meet the Four Factor Analysis applicability since the Q/d value is below 5.0. Additionally, by analyzing the wind patterns in the area, the prevailing winds in the area are northerly and southerly. Therefore, emissions from the Cashion CS have a negligible effect on visibility at the Wichita Mountains Wilderness Area since the winds from that direction are very infrequent. Based on these reasons, we believe that any emission reductions made at the Cashion CS would not have a substantive effect in meeting the visibility goals at this Class I Area. Thus, this analysis does not include an economic evaluation of the viable emission controls.

2. Class I Area Impact Analysis

2.1 PSD and TV Permit Evaluations

The nearest Class I area is the Wichita Mountains Wilderness Area, located about 129 km from the Facility. Visibility impacts at this Class I area were evaluated in previous Prevention of Significant Deterioration (PSD) and Title V (TV) permit applications for the Cashion CS. A DEQ memo, dated February 16, 1999, summarizes the visibility evaluation findings:

"The nearest Class I area is the Wichita Mountains Wilderness Area, about 129 km from the facility. The two important tests for impaction on a Class I area are visibility impairment and ambient air quality effect. A significant air quality impact is defined as an ambient concentration increase of 1 $\mu g/m^3$ (24 hour average). No impacts which exceeded this level were modeled beyond 25 km from the source. The protracted transport distance to the nearest Class I area precludes any significant air quality impact from the facility."

In addition, a DEQ memo, dated April 1, 2019, approving the 2018 DEQ Title V renewal permit for the Cashion CS states on page 14: "Ambient air quality standards are not threatened at this site."

2.2 Q/d Analysis

To determine which facilities are subject to the Regional Haze four factor analysis, a Q/d value is calculated using site-wide emissions as tons per year (Q) divided by the distance to the nearest Class I Area in kilometers (d). For the Cashion CS, DEQ used the 2016 Emission Inventory as the baseline NOx emissions, which were reported based on permitted emission factors and hours of operation instead of actual NOx emissions based on the most recent engine test data. Using actual 2016 NOx emissions based on the 2016 engine test results yields a Q/d of 3.6, which is below the Regional Haze selection criteria of 5. By using actual 2016 NOx emissions in the selection evaluation, Cashion CS should have screened out of the four factor analysis requirement.

Additionally, it is projected that a more representative year for future operations at the Cashion CS is 2019. Using 2019 instead of 2016 yields a Q/d of 2.1, which is far below the selection criteria of 5. Based on this information, the Cashion CS should be considered for removal from the four factor analysis requirement. A comparison of annual Q/d values is in Table 2.1 below:

Table 2.1 Annual Q/d Values Comparison

Reporting Year	**Actual** Site-wide Q/d based on recent engine test data	**Reported** Site-wide Q/d based on permitted emission factors
2016	3.6	5.5
2017	4.3	6.0
2018	2.3	4.0
2019	2.1	4.8

NOx engine test data, reported NOx emissions, and a Q/d analysis are presented in Appendix A.

2.3 Air Dispersion Modeling Analysis

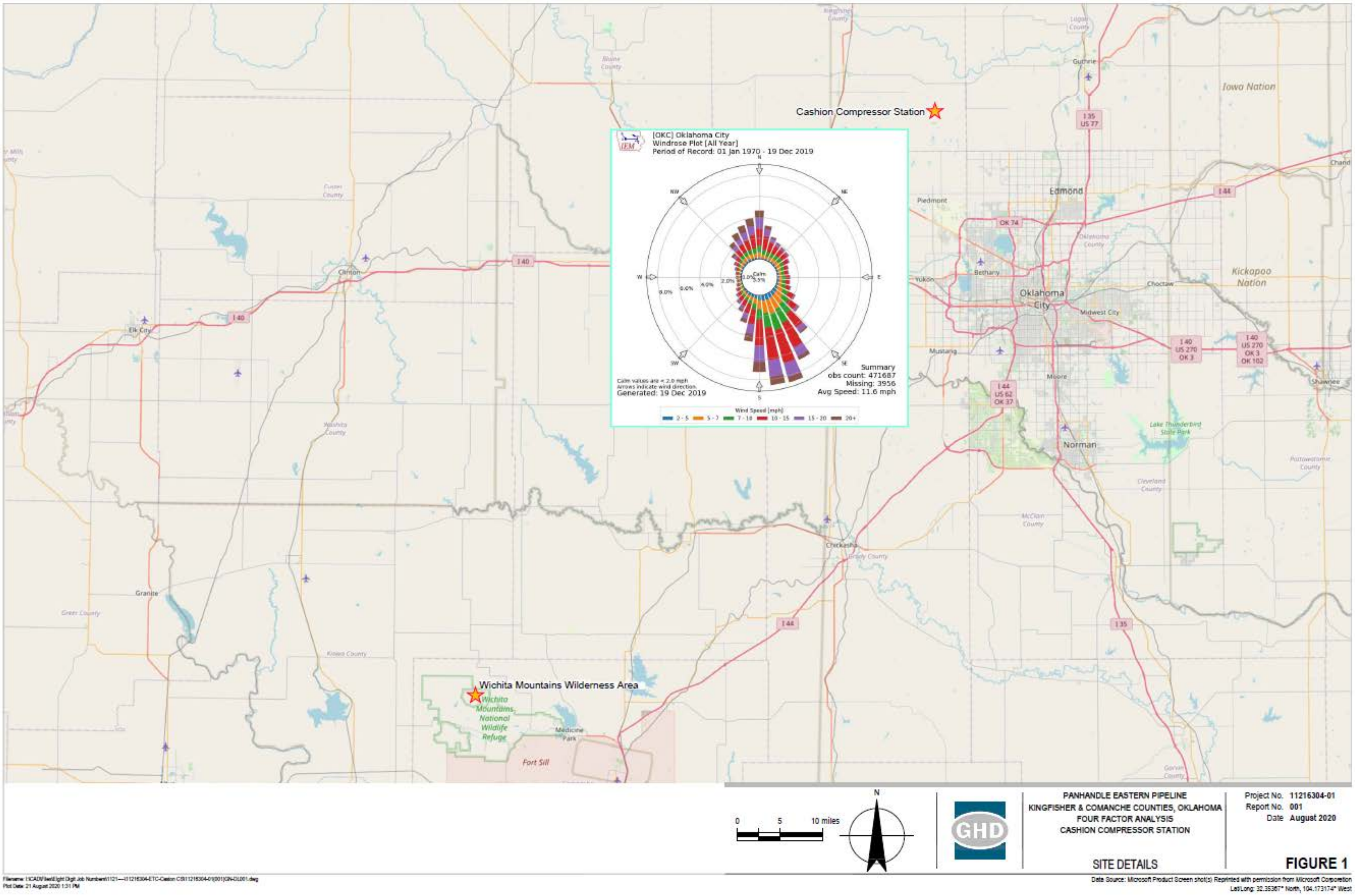
2.3.1 Distance

Previous PSD and TV permit applications (submitted 4/29/1980 and 2/17/1997, respectively) for the Cashion CS included air dispersion modeling to evaluate National Ambient Air Quality Standards (NAAQS) and potential impacts to nearby Class I Areas. The results of this air modeling showed no impacts beyond 25 km from the Facility. The nearest Class I Area, the Wichita Mountains Wilderness Area, is 129 km from the Facility.

2.3.2 Direction

The results from the air modeling also showed the extent of impacts from Facility emission sources were predominantly to the north and south. The nearest Class I Area, the Wichita Mountains Wilderness Area, is approximately 129 km southwest of the Facility. Figure 2.1 depicts the Site and the closest Class I Area with an overlay of the Oklahoma City wind rose from 1970-2019. This wind rose shows that the predominant wind direction in this area is from the north and south. However the Cashion CS Site is located northeast of the Class I Area. Winds blowing from that wind direction happen about 2% of the time. Thus, the emissions from the engines at the Cashion CS are not likely to affect visibility at the Class I Area since the engines would have to be emitting and the wind would have to be blowing from the northeast direction. The probability of both of those events happening at the same time is very low.

Figure 2.1 Wind Rose for the Oklahoma City Airport



3. Four Factor Analysis

3.1 RICE Engine Source Category Description

Cashion CS operates four Reciprocating Internal Combustion Engines (RICE) that are subject to the four-factor analysis. Two engines are 1800 hp Fairbanks Morse 38DS8 MEP-8 compressor engines (Units U-338 and U-339) and the other two engines are 4,500 hp Cooper Quad 12Q155HC compressor engines (Units U-2301 and U-2302). All four RICE engines are natural gas fired, 2-cycle lean burn, and used for transportation of natural gas.

3.2 NOx Emissions and Control Options

3.2.1 NOx Emissions

NO_x is generated from the combustion of natural gas used to power the applicable compressor engines. The exhaust gases are released to the atmosphere through stacks associated with each engine. There are several categories of NO_x formation in combustion processes. The combustion process taking place in RICE predominantly produces thermal NO_x[1], which is formed when nitrogen and oxygen unite during high temperature and high pressure combustion.[2]

3.2.2 Infeasible Control Options Evaluated

A Best Available Control Technology (BACT) evaluation was performed for previous permit applications for the engines at the Cashion CS. The options evaluated are the same that are currently available. These options are deemed infeasible for implementation as described below.

3.2.2.1 Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is a post-combustion control technology that could be considered a potential control technology for lean burn engines. SCR systems have not been demonstrated to provide proven NO_X reductions over varying load conditions; present significant problems with ammonia slip under varying load conditions; and do not have a proven track record of reliability or durability under typical pipeline operating conditions. For the foregoing reasons, SCR is not a technically practical alternative for engines in natural gas pipeline service.

While SCR has been applied to large boilers and turbines in the power generation industry, its application on new RICE in the gas transmission industry has been rare, and retrofitted applications for existing lean burn RICE had not occurred as of 2014.[4] Additionally, Chapter 2 of the EPA cost manual (updated June 2019) supports the 2014 reference document. According to the EPA cost manual, the only example provided for SCR technology used on a RICE engine occurred in 1994 on a new 1,800 hp diesel-fired engine but not for a natural gas engine. All other examples of SCR applications were for other types of combustion equipment often in industries other than oil & gas.

3.2.2.2 Electric Replacement Engine

Electrical motors require a reliable and substantial supply of electrical power. The Cashion CS is in a remote location where the electrical supply is limited and unreliable. For this reason, the use of electrical motors as an alternate compressor drive unit is considered technically infeasible and impractical.

3.2.3 Feasible Control Option Evaluated

3.2.3.1 LEC Control Option

LEC is a combination of combustion controls in which various engine modifications, upgrades, and tuning methods provide lower emission combustion.

One common upgrade includes increasing the air-to-fuel ratio (AFR) to reduce thermal NO_x formation by diluting combustion gases and lowering peak flame temperature. Upgrades to the AFR controller and turbocharger would be required. Adjusting ignition timing is another modification associated with LEC. This control delays ignition in the power stroke when the chamber is below its maximum pressure. This causes ignition at a lower temperature, thus lowering thermal NO_x formation during combustion. Other LEC options include installing cylinder heads fitted with pre-combustion chambers, larger intercooling applications, enhanced mixing, bypass valves, and increased ignition energy.[3]

These LEC options would have to be evaluated for operational feasibility since they may affect the reliability of the engines.

3.3 Fairbanks Morse Engines (Units U-338 and U-339)

Fairbanks Morse vendors were contacted about quotes for potential LEC upgrades, but none have responded with a willingness or an ability to install LEC upgrades on this model engine at the time of the writing of this report. Previous PSD and TV permit applications (submitted 4/29/1980 and 2/17/1997, respectively) state that "it is not possible to run these engines leaner than their current setting and they are being operated at their minimum emissions point."

Additionally, the current TV operating permit requires both engines to run no more than approximately 50% of the time, and from 2016 to 2019 both Fairbanks Morse engines only contributed between 7 and 20 % of the total Facility NOx emissions combined.

Since there has not been a vendor identified who is willing and able to perform LEC upgrades, documentation that operation of these engines is already limited to about 50% by the current Facility permit, the relatively small contribution they have to Facility NOx emissions (<20% combined), and documentation that the engines are running at their minimum emissions point, the Fairbanks Morse engines (Units U-338 and U-339) were not evaluated in this four factor analysis.

3.4 Cooper Quad Engines (Units U-2301 and U-2302)

3.4.1 Potential NOx Control Options

Table 3.1 below summarizes potential control technology options:

Table 3.1 Summary of Potential NOx Options

Technology	Description	Feasibility	Performance (% reduction)
Low Emission Combustion (LEC)	Engine tuning improvements to increase combustion efficiency.	Potentially feasible reduction of NOx emission factor for Units 2301 and 2302	70-80%
Selective Catalytic Reduction (SCR)	Exhaust control that converts NO_x to nitrogen and water using ammonia or urea.	**Not technically feasible** based on documented difficulty implementing technology on RICE engines	70-90%[5]
Electric Replacement Engines	Replace natural gas fired engine with electric motor	**Not technically feasible** based on unreliable electricity source at remote site location	100%

3.4.2 Additional Considerations

A four factor analysis is not included in this report since there are complex technical and practical considerations that would need to be evaluated. For example, new LEC upgrades have the potential to limit the range of engine variability under different operating scenarios. In particular, hyper controls have presented issues on the Cooper Quad engines in the past. A detailed evaluation of engine technicalities would be required including a site visit from the LEC vendor to identify what is technically feasible and would not interfere with operations. The field staff at the Cashion CS perform ongoing maintenance on the engines to maximize efficiency and increase reliability. These activities tend to result in lower emissions.

Additionally, we believe that this analysis should not be required since it would have a negligible visibility improvement at the Class I Area. We seek concurrence from DEQ on this assessment.

4. References

1. U.S Environmental Protection Agency (USEPA). *Technical Support Document for Controlling NOx Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines*. March 2007.

2. U.S Environmental Protection Agency (USEPA). *Nitrogen Oxides (NOx), Why and How They Are Controlled.* November 1999.

3. INGAA Foundation, Inc. *Potential Impacts of the Ozone and Particulate Matter NAAQS on Retrofit NOx Control for Natural Gas Transmission and Storage Compressor Drivers*. December 2017.

4. INGAA Foundation, Inc. *Availability and Limitations of NOx Emission Control Resources for Natural Gas-Fired Reciprocating Engine Prime Movers Used in the Interstate Natural Gas Transmission Industry.* July 2014.

5. U.S Environmental Protection Agency (USEPA). *EPA Air Pollution Control Technology Fact Sheet for SCR.*

6. U.S Environmental Protection Agency (USEPA). *EPA Air Pollution Control Cost Manual, 6th Edition*, USEPA Research Triangle Park, NC. January 2002.

7. Northeast States for Coordinated Air Use Management (NESCAUM). *Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines*. December 2000.

8. U.S Environmental Protection Agency (USEPA). *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*. August 20, 2019.

9. Western Regional Air Partnership (WRAP). *Reasonable Progress Source Identification and Analysis Protocol, WRAP Regional Haze Planning Work Group – Control Measures Subcommittee*.

Appendix A

Table 1 – NOx Engine Test Data, Reported Emissions, and Q/d Analysis

Table 1 - NOx Engine Test Data, Reported Emissions, and Q/d Analysis

Cashion Compressor Station - Kingfisher County, Oklahoma

Panhandle Eastern Pipeline Co.

Company ID: 346, Facility ID: 1373

Unit ID	Test Date	Engine Test NOx Emissions (lb/hr)	Permitted NOx Emissions (lb/hr)	Annual Runtime (hrs)	Engine Test NOx Emission Factor (g/hp-hr)	Permitted NOx Emission Factor (g/hp-hr)	Engine Test Annual NOx Emissions (tpy)	Reported Annual NOx Emissions (tpy)
U-2301	5/3/2016	51.745	89.3	6399	5.2	9.0	165.55	286.00
U-2301	3/15/2017	66.858		7979	6.7		266.73	356.00
U-2301	2/16/2018	54.312		5485	5.5		148.95	244.85
U-2301	1/22/2019	48.445		6257	4.9		151.57	279.72
U-2302	5/3/2016	67.462	89.3	7875	6.8	9.0	265.63	351.60
U-2302	3/15/2017	68.631		7188	6.9		246.65	321.00
U-2302	2/16/2018	54.833		4810	5.5		131.88	214.74
U-2302	1/23/2019	50.851		2486	5.1		63.20	110.95
U-338	6/30/2016	15.690	54.77	2283	4.0	13.8	17.91	6.26
U-338	5/24/2017	26.150		1627	6.6		21.27	44.50
U-338	5/16/2018	17.610		1212	4.4		10.67	33.18
U-338	1/23/2019	11.504		4696	2.9		27.01	128.59
U-339	6/30/2016	15.040	54.77	2169	3.8	13.8	16.31	59.40
U-339	5/24/2017	25.040		1941	6.3		24.30	53.10
U-339	5/16/2018	16.810		681	4.2		5.72	18.63
U-339	1/22/2019	13.511		3811	3.4		25.75	104.35

Annual Q/d Comparison		
Year	**Actual Sitewide Q/d from engine test data**	**Reported Sitewide Q/d based on permit data**
2016	3.6	5.5
2017	4.3	6.0
2018	2.3	4.0
2019	2.1	4.8

Notes:

1. Q = facility sitewide NOx emissions in tons per year (tpy)
2. d = distance from facility to Wichita Mountains Wilderness Area in kilometers (approximately 129 km)
3. Q/d value of 5 was used by Ramboll and DEQ as the threshold for determining facilities subject to the Regional Haze Rule 4 Factor Analysis.

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SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

KEVIN STITT
Governor

January 31, 2022

David Hennessy
Panhandle Eastern Pipeline Co.
8111 Westchester Dr., Ste. 600
Dallas, TX 75225

Subject: Additional clarifications on Panhandle Eastern's Cashion Compressor Station 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Mr. Hennessy:

In a letter dated July 1, 2020, the Oklahoma Department of Environmental Quality (DEQ) identified the Cashion Compressor Station located in Kingfisher County, Oklahoma, as subject to a four-factor reasonable progress analysis under the Regional Haze Rule as part of DEQ's development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

On September 2, 2020, Panhandle Eastern submitted its report to DEQ. Panhandle Eastern included in its response that there were no cost-effective nitrogen oxides (NO_x) control measures available for U-338, U-339, U-2301, or U-2302. DEQ included these conclusions in its draft Regional Haze SIP for Planning Period 2 that was shared with the Federal Land Managers and the U.S. Environmental Protection Agency (EPA) for their review and comment. DEQ requests that Panhandle Eastern review its four-factor analysis for potential NO_x control measures and respond to the following information request, which is based on EPA's review of Oklahoma's draft SIP. We understand that some of the requested data/analysis may be gleaned or explained from DEQ's permitting and compliance files. However, your response will allow Panhandle Eastern to document the information that best explains and supports the conclusions of your four-factor analysis. DEQ intends to continue its analysis in parallel.

> 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.

DEQ respectfully requests that Panhandle Eastern respond to this information request no later than February 28, 2022. Thank you for your assistance with this matter. Please contact Melanie Foster at 405-702-4218 for any questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

PANHANDLE EASTERN PIPE LINE
An ENERGY TRANSFER Company

February 28, 2022

Submitted by E-mail

Ms. Kendal Stegmann
Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

SUBJECT: Response tó 4-Factor Analysis on Control Scenarios Request
Clean Air Act Regional Haze Program
Cashion Compressor Station
Permit No. 2013-1330-TVR3 (M-1)
Panhandle Eastern Pipeline Company

Dear Ms. Stegmann:

Panhandle Eastern Pipeline Co. (PEPL) is submitting this response to the four-factor analysis additional clarification request from the Oklahoma Department of Environmental Quality (ODEQ) received on January 31, 2022 for the Cashion Compressor Station (Facility). This response is being provided per the deadline of February 28, 2022 as specified in the request.

ODEQ Information Request

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.

The Cooper engines U-2301 and U-2302 at Cashion Compressor Station are currently authorized in the ODEQ issued Permit No. 2013-1330-TVR3 (M-3) at 4,500 Hp; however, these engines are limited to 3,940 Hp by FERC certificate. The historical emission inventories utilized the permitted horsepower rating and permit factors rather than the FERC limited horsepower and engine test data. The FERC horsepower limitation was not identified in our previously submitted 4-factor analysis. The Fairbanks Morse engines are limited in the permit to 9,100 hours combined annually.

The historical emissions inventories utilized a permitted NOx emission factor for the Coopers of 9.0 g/hp-hr. In the initial response PEPL provided a summary of portable engine analyzer (PEA) tests performed on May 3, 2016, March 15, 2017, February 16, 2018, January 22 and 23, as required by the ODEQ issued permit compliance demonstration, to determine emissions from the engines. The PEA test results for the 2016, 2017, 2018 and 2019 were summarized and included in the initial submittal. Since that time PEPL has conducted additional inhouse PEA tests and on February 10, 2022 PEPL had a third-party vendor conduct a PEA test on the units to confirm and verify the lower emissions using the FERC limited horsepower rating. Table 1 shows a comparison of the most recent test results.

Table 1 – Comparison of PEA Tests

Unit	1/10,15/2020 in-house Test Result (lb/hr)	1/10,15/2020 in-house Test Result (g/hp-hr)	2/10/2022 Test 3rd party Result (lb/hr)	2/10/2022 Test 3rd party Result (g/hp-hr)
U-2301	37.423	4.31	31.55	3.95
U-2302	44.125	5.08	33.392	4.03

These results substantiate our analysis that Cashion CS has negligible contribution to visibility impairment at the Wichita Mountains Wilderness Area and that by utilizing our actual emission results, the site did not and does not trigger the Four Factor Analysis applicability criteria for this area. PEPL believes that had the FERC limited horsepower and the emission factor from the PEA test been utilized in the annual emissions inventory calculations, the Cashion Compressor Station would not have been selected for this Four-Factor Analysis based on the Q/d applicability criteria. Attached hereto are the referenced emission test reports.

If you have any questions or comments please do not hesitate to contact me at (214) 840-5693 or by email at David.Hennessy@energytransfer.com .

Sincerely,

David Hennessy
Director – Environmental
Energy Transfer Partners

Attachments

Engine Emissions Test Report

SCAQMD 1110.2

Emissions Test Date: 01/15/2020 Q1

Cashion Station
Panhandle Eastern Pipeline
Jason Hembree
Phone: 580-327-2029
26441 N. 2950 Rd.
Cashion, OK 73016
Mobile: 580-747-2413
Email: jason.hembree@energytransfer.com

CO: lb/hr	NOx: lb/hr
10.665	37.423
Pass	Pass
(22.82 lb/hr)	(89.3 lb/hr)

PHYSICAL LOCATION

Operational Area: Liberal

Facility Name: Cashion Station

EQUIPMENT INFORMATION

Equipment:	2301		Unit #:	2301		AF Controller Make:			
Model:	Cooper Quad 12Q155HC		Serial #:	48764		AF Controller Model:			
Service :	Natural Gas Compression		Ignition Timing:			Catalytic Converter Make:			
Stack Flow:			Fuel Type:	Gas: Natural		Catalytic Converter Model:			
Intake MP:	Left:		Intake MT:	Left:		Fuel Consumption:	26300		
	Right:			Right:		Horsepower:	3520		
Stack Height:	'		FuelSG:			RPM:			
Equipment Hours:			Fuel Pressure:			MV Target Set Point:			
Stepper Position:	Left:		Exhaust Temp:	Left:		MV Actual:	Left:		
	Right:			Right:			Right:		
Catalyst dp:			Pre-Catalyst Temp:			Post-Catalyst Temp:			

PERMIT INFORMATION

Permit #: 2013-1330-TVR3

Permit Equipment #: U2301

Permit Date: 08/06/2015

Permit Units: lb/hr @ 0 % O2

Permit CO Limit: 22.82

Permit NOx Limit: 89.3

ANALYZER INFORMATION

Model:

Last Linearity Test : 00/00/00

Serial #: 7364

Last Stability Test : 00/00/00

EMISSIONS TEST RESULTS

	Test 1			
Parameter	Average Measured	Cal Adjusted	Cal Adjusted @ 0% O2	Permit Limit @ 0% O2
O2%	13.55	13.49		
CO ppm	217.82	216.36	610.24	22.82
NO ppm	420.55	416.78		
NO2 ppm	51.82	50.79		
NOx ppm		467.57	1318.79	89.30

Drift correction applied: 78.144

	Test 2			
Parameter	Average Measured	Cal Adjusted	Cal Adjusted @ 0% O2	Permit Limit @ 0% O2
O2%	13.73	13.66		
CO ppm	224.64	223.13	644.28	22.82
NO ppm	405.00	401.30		
NO2 ppm	48.73	47.76		
NOx ppm		449.06	1296.67	89.30

	Test 3			
Parameter	Average Measured	Cal Adjusted	Cal Adjusted @ 0% O2	Permit Limit @ 0% O2
O2%	13.58	13.52		
CO ppm	220.82	219.34	620.91	22.82
NO ppm	445.09	441.22		
NO2 ppm	49.82	48.83		
NOx ppm		490.05	1387.28	89.30

	Combined Tests
Parameter	Overall Average
O2%	13.62
CO ppm	221.09
NO ppm	423.55
NO2 ppm	50.12
NOx ppm	473.67

Cell Temperature		
Start	End	Ambient Temp
76.5F	79.0F	81.5F

RampUp 1 - 01/15/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
11:06:46	14.30	202.00	3.70	465.00	54.00	519.00	0.00	0.00	69.30	71.60
11:07:46	14.20	207.00	3.80	456.00	54.00	510.00	0.00	0.00	70.20	73.00
11:08:46	14.10	208.00	3.80	451.00	54.00	505.00	0.00	0.00	71.10	73.90

Test 1 - 01/15/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
11:08:48	14.10	208.00	3.80	451.00	54.00	505.00	0.00	0.00	71.10	73.90
11:09:48	14.00	208.00	3.90	454.00	54.00	508.00	0.00	0.00	72.00	74.50
11:10:48	14.00	211.00	3.90	444.00	53.00	497.00	0.00	0.00	72.70	75.00
11:11:48	13.80	214.00	4.00	430.00	52.00	482.00	0.00	0.00	73.40	75.90
11:12:48	13.60	218.00	4.10	428.00	52.00	480.00	0.00	0.00	74.10	76.30
11:13:48	13.50	219.00	4.20	418.00	52.00	470.00	0.00	0.00	74.80	77.00
11:14:48	13.40	220.00	4.20	404.00	51.00	455.00	0.00	0.00	75.60	77.40
11:15:48	13.30	223.00	4.30	404.00	51.00	455.00	0.00	0.00	76.10	78.10
11:16:48	13.20	224.00	4.30	392.00	50.00	442.00	0.00	0.00	76.80	78.80
11:17:48	13.10	225.00	4.40	401.00	51.00	452.00	0.00	0.00	77.40	79.30
11:18:48	13.10	226.00	4.40	400.00	50.00	450.00	0.00	0.00	77.90	79.30

Average O2 =	13.55 %	Average NOx =	472.36 ppm	Average CO =	217.82 ppm

Average NO =	420.55 ppm	Average NO2 =	51.82 ppm

Purge 1 - 01/15/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
11:18:56	13.10	226.00	4.40	393.00	50.00	443.00	0.00	0.00	78.10	79.30
11:19:56	19.60	10.00	0.80	15.00	0.00	15.00	0.00	0.00	78.60	79.90
11:20:56	19.70	6.00	0.70	10.00	0.00	10.00	0.00	0.00	79.00	79.70
11:21:56	20.00	4.00	0.60	8.00	0.00	8.00	0.00	0.00	79.30	79.50

RampUp 2 - 01/15/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
11:21:59	20.00	4.00	0.60	8.00	0.00	8.00	0.00	0.00	79.30	79.50
11:22:59	13.40	219.00	4.20	415.00	50.00	465.00	0.00	0.00	79.50	79.90
11:23:59	13.40	223.00	4.20	404.00	51.00	455.00	0.00	0.00	79.70	79.90

Test 2 - 01/15/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
11:24:00	13.40	223.00	4.20	404.00	51.00	455.00	0.00	0.00	79.70	79.90
11:25:00	13.40	221.00	4.20	411.00	50.00	461.00	0.00	0.00	79.90	80.10
11:26:00	13.50	221.00	4.20	406.00	50.00	456.00	0.00	0.00	80.20	80.10
11:27:00	13.50	224.00	4.20	391.00	49.00	440.00	0.00	0.00	80.40	79.90
11:28:00	13.70	226.00	4.10	389.00	48.00	437.00	0.00	0.00	80.40	79.20
11:29:00	13.80	230.00	4.00	387.00	48.00	435.00	0.00	0.00	80.40	79.00
11:30:00	13.90	228.00	4.00	391.00	48.00	439.00	0.00	0.00	80.20	79.20
11:31:00	13.90	223.00	4.00	426.00	48.00	474.00	0.00	0.00	80.20	78.80
11:32:00	14.10	223.00	3.80	421.00	48.00	469.00	0.00	0.00	80.20	78.40
11:33:00	13.90	223.00	4.00	430.00	49.00	479.00	0.00	0.00	80.10	78.80
11:34:00	13.90	229.00	4.00	399.00	47.00	446.00	0.00	0.00	80.10	79.20

Average O2 =	13.73 %	Average NOx =	453.73 ppm	Average CO =	224.64 ppm
Average NO =	405.00 ppm	Average NO2 =	48.73 ppm		

Purge 2 - 01/15/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
11:34:09	13.90	230.00	4.00	409.00	47.00	456.00	0.00	0.00	80.10	79.20
11:35:09	20.90	10.00	0.00	15.00	0.00	15.00	0.00	0.00	80.10	79.00
11:36:09	21.00	5.00	0.00	11.00	0.00	11.00	0.00	0.00	80.10	78.80
11:37:09	20.80	4.00	0.00	9.00	0.00	9.00	0.00	0.00	80.10	79.00

RampUp 3 - 01/15/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
11:37:12	20.80	4.00	0.00	9.00	0.00	9.00	0.00	0.00	80.10	79.00
11:38:12	13.70	219.00	4.10	415.00	48.00	463.00	0.00	0.00	80.10	79.30
11:39:12	13.60	223.00	4.10	417.00	49.00	466.00	0.00	0.00	80.20	79.70

Test 3 - 01/15/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
11:39:14	13.60	223.00	4.10	417.00	49.00	466.00	0.00	0.00	80.20	79.70
11:40:14	13.60	223.00	4.10	429.00	49.00	478.00	0.00	0.00	80.40	79.50
11:41:14	13.70	224.00	4.10	440.00	49.00	489.00	0.00	0.00	80.40	79.70
11:42:14	13.70	224.00	4.10	427.00	49.00	476.00	0.00	0.00	80.40	79.90
11:43:14	13.60	226.00	4.10	424.00	49.00	473.00	0.00	0.00	80.60	80.40
11:44:14	13.60	221.00	4.10	430.00	49.00	479.00	0.00	0.00	80.80	80.40
11:45:14	13.60	221.00	4.10	435.00	50.00	485.00	0.00	0.00	81.00	80.40
11:46:14	13.60	222.00	4.10	466.00	51.00	517.00	0.00	0.00	81.10	80.20
11:47:14	13.50	216.00	4.20	473.00	51.00	524.00	0.00	0.00	81.10	80.60
11:48:14	13.50	215.00	4.20	476.00	51.00	527.00	0.00	0.00	81.30	80.80
11:49:14	13.40	214.00	4.20	479.00	51.00	530.00	0.00	0.00	81.50	81.50

Average O2 =	13.58 %	Average NOx =	494.91 ppm	Average CO =	220.82 ppm
Average NO =	445.09 ppm	Average NO2 =	49.82 ppm		

Purge 3 - 01/15/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
11:49:22	13.40	214.00	4.20	480.00	51.00	531.00	0.00	0.00	81.50	81.50
11:50:22	20.10	10.00	0.50	19.00	0.00	19.00	0.00	0.00	81.70	81.10
11:51:22	20.10	6.00	0.50	14.00	0.00	14.00	0.00	0.00	81.90	81.10
11:52:22	20.00	4.00	0.60	12.00	0.00	12.00	0.00	0.00	82.00	81.30

ANALYZER AVERAGE INFORMATION

Total Average O2 =	13.62 %	Total Average NOx =	473.67 ppm	Total Average CO =	221.09 ppm
Total Average NO =	423.55 ppm	Total Average NO2 =	50.12 ppm		

NOTES:

TEST COMPLETED BY:

Jeff Simon
Panhandle Eastern Pipeline
42589 Grady Rd.
Alva, OK 73717
Phone: 580-327-2029
Mobile:
Email: jeff.simon@energytransfer.com
Home Page:

Technician ____________ Date 1-15-2020

Pre & Post Calibration Test Report

Calibration Test Date: 01/15/2020

Cashion Station
Panhandle Eastern Pipeline
Jason Hembree
Phone: 580-327-2029
26441 N. 2950 Rd.
Cashion, OK 73016
Mobile: 580-747-2413
Email: jason.hembree@energytransfer.com

Sensor	Span Gas Value	Expiration date	Zero Error % Limit	Cal Error % Limit	Zero Drift % Limit	Span Drift % Limit
O2 %	20.9	4/8/2014	0.5	0.5	0.5	0.5
CO ppm	296	12/5/2024	5	5	5	5
NO ppm	708	7/27/2026	5	5	5	5
NO2 ppm	396	2/2/2021	25	5	5	50

PHYSICAL LOCATION

Operational Area: Liberal

Facility Name: Cashion Station

EQUIPMENT INFORMATION

Equipment:	338	Unit #:	338	AF Controller Make:	
Model:	Fairbanks Morse 38DS8	Serial #:	38D879004S18RM	AF Controller Model:	
Service :	Natural Gas Compression	Ignition Timing:		Catalytic Converter Make:	
Stack Flow:		Fuel Type:	Gas: Natural	Catalytic Converter Model:	
Intake MP:	Left:	Intake MT:	Left:	Fuel Consumption:	9950
	Right:		Right:	Horsepower:	1414
Stack Height:	'	FuelSG:		RPM:	
Equipment Hours:		Fuel Pressure:		MV Target Set Point:	
Stepper Position:	Left:	Exhaust Temp:	Left:	MV Actual:	Left:
	Right:		Right:		Right:
Catalyst dp:		Pre-Catalyst Temp:		Post-Catalyst Temp:	

PERMIT INFORMATION

Permit #: 2013-1330-TVR3
Permit Equipment #: U338

Permit Date: 08/06/2015
Permit Units: lb/hr @ 0 % O2

Permit CO Limit: 6.87
Permit NOx Limit: 54.77

ANALYZER INFORMATION

Model:
Last Linearity Test : 00/00/00

Serial #: 7364

Last Stability Test : 00/00/00

Calibration Specs

	O2 %	CO ppm	NO ppm	NO2 ppm
Pre-Test Zero %	0.0	0.0	0.0	0.0
Post-Test Zero %	0.0	0.0	4	0.0
Mean Zero, Ccz	0.0	0.0	2.0	0.0
Zero Result	Pass	Pass	Pass	Pass
Pre-Test Span	21.0	297	714	406
Pre-Test Result	Pass	Pass	Pass	Pass
Post Test Span	21.0	299	712	402
Post Test Drift %	0.5	1.0	0.6	1.5
Post Test Results	Pass	Pass	Pass	Pass
Span Drift (%)	0.0	0.7	0.3	1.0
Mean Span, Ccm	21.0	298.0	713.0	404.0

Pre Test Calibration

Time	O2	CO	NO	NO2	IFlow
10:19:16	0.0	0.0	0.0	0.0	0.00
10:20:15	0.0 ★[1]	0.0	0.0	0.0	2.60
10:20:16	0.0	0.0	0.0	0.0	2.60
10:20:21	0.0	0.0 ★[1]	0.0	0.0	2.60
10:20:26	0.0	0.0	0.0 ★[1]	0.0	2.60
10:20:27	0.0	0.0	0.0	0.0 ★[1]	2.60
10:20:48	21.0 ★[2]	0.0	0.0	0.0	2.46
10:21:16	21.0	0.0	0.0	0.0	2.45
10:22:16	0.2	197	0.0	0.0	2.33
10:23:16	0.0	289	0.0	0.0	2.34
10:24:16	0.0	292	0.0	0.0	2.34
10:25:16	0.0	293	0.0	0.0	2.33
10:26:16	0.0	293	0.0	0.0	2.34
10:27:16	0.0	293	0.0	0.0	2.34
10:28:16	0.0	296	0.0	0.0	2.35
10:29:16	0.0	296	0.0	0.0	2.36
10:30:16	0.0	296	0.0	0.0	2.37
10:31:16	0.0	296	0.0	0.0	2.37
10:32:16	0.0	296	0.0	0.0	2.37
10:33:16	0.0	297	0.0	0.0	2.37
10:34:16	0.0	297	0.0	0.0	2.38
10:34:21	0.0	297 ★[2]	0.0	0.0	2.39
10:35:16	20.8	25	0.0	0.0	2.49
10:36:16	8.2	6	205	111	2.35
10:37:16	0.0	5	692	34	2.36
10:38:16	0.0	3	705	21	2.35
10:39:16	0.0	3	711	17	2.37
10:40:16	0.0	3	710	15	2.37
10:41:16	0.0	2	713	14	2.37
10:41:58	0.0	2	714 ★[2]	14	2.35
10:42:16	14.5	1	123	13	2.48
10:43:16	20.9	0.0	13	4	2.48
10:44:16	20.9	1	8	2	2.48

Pre Test Calibration

10:45:16	20.9	1	5	1	2.50
10:46:16	0.0	2	76	125	2.37
10:47:16	0.0	2	74	176	2.38
10:48:16	0.0	1	67	220	2.35
10:49:16	0.0	2	61	258	2.35
10:50:16	0.0	1	56	289	2.31
10:51:16	0.0	1	52	315	2.33
10:52:16	0.0	1	49	339	2.35
10:53:16	0.0	1	46	358	2.36
10:54:16	0.0	1	43	374	2.31
10:55:16	0.0	1	42	387	2.29
10:56:21	0.0	1	40	400	2.31
10:56:49	0.0	1	39	406 ★2	2.35

Post Test Drift Check

Time	O2	CO	NO	NO2	IFlow
13:13:13	21.0	0.0	7	0.0	2.48
13:13:18	21.0	0.0 ★1	6	0.0	2.48
13:13:21	21.0	0.0	6	0.0 ★1	2.49
13:14:13	21.0	0.0	6	0.0	2.49
13:15:03	0.0 ★1	248	7	0.0	2.42
13:15:13	0.0	278	7	0.0	2.43
13:16:13	0.0	296	6	0.0	2.42
13:17:13	0.0	298	5	0.0	2.43
13:17:27	0.0	299 ★2	5	0.0	2.42
13:18:13	2.9	300	5	0.0	2.50
13:18:46	21.0 ★2	22	5	0.0	2.50
13:19:13	21.0	8	5	0.0	2.49
13:20:13	21.0	1	4	1	2.47
13:21:13	0.0	1	65	220	2.42
13:22:13	0.0	0.0	59	281	2.43
13:23:13	0.0	0.0	53	322	2.41
13:24:13	0.0	0.0	49	352	2.39
13:25:13	0.0	0.0	46	375	2.38
13:26:13	0.0	0.0	44	393	2.38
13:26:44	0.0	0.0	43	402 ★2	2.40
13:27:14	16.7	0.0	17	180	2.46
13:28:13	21.0	0.0	7	11	2.47
13:29:13	21.0	0.0	6	5	2.46
13:30:13	21.0	0.0	5	3	2.46
13:31:13	21.0	0.0	5	2	2.46
13:32:00	21.0	0.0	4 ★1	1	2.45
13:32:13	21.0	0.0	4	1	2.45
13:33:13	0.0	0.0	667	100	2.40
13:34:13	0.0	0.0	699	49	2.40
13:35:13	0.0	0.0	708	38	2.41

Post Test Drift Check					
13:35:50	0.0	0.0	712 ★[2]	34	2.43

★[1] : Captured Zero
★[2] : Captured Cal Response

NOTES:

TEST COMPLETED BY:

Jeff Simon
Panhandle Eastern Pipeline
42589 Grady Rd.
Alva, OK 73717
Phone: 580-327-2029
Mobile:
Email: jeff.simon@energytransfer.com
Home Page:

Technician ____________________ Date 1-15-2020 ecom®

Engine Emissions Test Report

SCAQMD 1110.2

Emissions Test Date: 01/10/2020 Q1

Cashion Station
Panhandle Eastern Pipeline
Jason Hembree
Phone: 580-327-2029
26441 N. 2950 Rd.
Cashion, OK 73016
Mobile: 580-747-2413
Email: jason.hembree@energytransfer.com

CO: lb/hr	NOx: lb/hr
6.278	44.125
Pass	Pass
(22.82 lb/hr)	(89.3 lb/hr)

PHYSICAL LOCATION

Operational Area: Liberal

Facility Name: Cashion Station

EQUIPMENT INFORMATION

Equipment:	2302		Unit #:	2302		AF Controller Make:			
Model:	Cooper Quad 12Q155HC		Serial #:	48765		AF Controller Model:			
Service :	Natural Gas Compression		Ignition Timing:			Catalytic Converter Make:			
Stack Flow:			Fuel Type:	Gas: Natural		Catalytic Converter Model:			
Intake MP:	Left:		Intake MT:	Left:		Fuel Consumption:	23961		
	Right:			Right:		Horsepower:	3292		
Stack Height:	'		FuelSG:			RPM:			
Equipment Hours:			Fuel Pressure:			MV Target Set Point:			
Stepper Position:	Left:		Exhaust Temp:	Left:		MV Actual:		Left:	
	Right:			Right:				Right:	
Catalyst dp:			Pre-Catalyst Temp:			Post-Catalyst Temp:			

PERMIT INFORMATION

Permit #: 2013-1330-TVR3
Permit Equipment #: U2302

Permit Date: 08/06/2015
Permit Units: lb/hr @ 0 % O2

Permit CO Limit: 22.82
Permit NOx Limit: 89.3

ANALYZER INFORMATION

Model:
Last Linearity Test : 00/00/00

Serial #: 7364

Last Stability Test : 00/00/00

EMISSIONS TEST RESULTS

	Test 1			
Parameter	Average Measured	Cal Adjusted	Cal Adjusted @ 0% O2	Permit Limit @ 0% O2
O2%	14.00	13.93		
CO ppm	129.09	129.09	387.27	22.82
NO ppm	571.82	568.41		
NO2 ppm	50.64	48.09		
NOx ppm		616.50	1849.49	89.30

Drift correction applied: 166.944

	Test 2			
Parameter	Average Measured	Cal Adjusted	Cal Adjusted @ 0% O2	Permit Limit @ 0% O2
O2%	14.15	14.08		
CO ppm	128.45	128.45	393.54	22.82
NO ppm	545.36	542.07		
NO2 ppm	47.91	45.50		
NOx ppm		587.56	1800.09	89.30

	Test 3			
Parameter	Average Measured	Cal Adjusted	Cal Adjusted @ 0% O2	Permit Limit @ 0% O2
O2%	14.35	14.28		
CO ppm	140.64	140.64	443.81	22.82
NO ppm	456.55	453.62		
NO2 ppm	43.18	41.01		
NOx ppm		494.63	1560.92	89.30

	Combined Tests
Parameter	Overall Average
O2%	14.16
CO ppm	132.73
NO ppm	524.58
NO2 ppm	47.24
NOx ppm	571.82

Cell Temperature		
Start	End	Ambient Temp
78.8F	81.1F	78.3F

RampUp 1 - 01/10/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
10:30:07	18.10	0.00	1.60	158.00	18.00	176.00	0.00	0.00	76.60	75.90
10:31:07	14.00	124.00	3.90	594.00	54.00	648.00	0.00	0.00	76.80	75.90
10:32:07	14.00	127.00	3.90	592.00	53.00	645.00	0.00	0.00	77.00	75.90

Test 1 - 01/10/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
10:32:08	14.00	127.00	3.90	592.00	53.00	645.00	0.00	0.00	77.00	75.90
10:33:08	14.00	128.00	3.90	568.00	51.00	619.00	0.00	0.00	77.20	75.90
10:34:08	14.00	129.00	3.90	576.00	51.00	627.00	0.00	0.00	77.20	76.10
10:35:08	14.00	129.00	3.90	581.00	51.00	632.00	0.00	0.00	77.40	76.10
10:36:08	14.00	129.00	3.90	577.00	51.00	628.00	0.00	0.00	77.40	76.30
10:37:08	14.00	128.00	3.90	556.00	50.00	606.00	0.00	0.00	77.50	76.30
10:38:08	14.00	129.00	3.90	568.00	51.00	619.00	0.00	0.00	77.50	76.50
10:39:08	14.00	131.00	3.90	556.00	50.00	606.00	0.00	0.00	77.70	76.60
10:40:08	14.00	129.00	3.90	574.00	49.00	623.00	0.00	0.00	77.70	76.60
10:41:08	14.00	129.00	3.90	555.00	49.00	604.00	0.00	0.00	77.90	76.60
10:42:08	14.00	132.00	3.90	587.00	51.00	638.00	0.00	0.00	77.90	76.60

Average O2 =	14.00 %	Average NOx =	622.45 ppm	Average CO =	129.09 ppm

Average NO =	571.82 ppm	Average NO2 =	50.64 ppm

Purge 1 - 01/10/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
10:42:18	14.00	131.00	3.90	578.00	50.00	628.00	0.00	0.00	77.90	76.60
10:43:19	20.50	6.00	0.30	14.00	0.00	14.00	0.00	0.00	78.10	76.60
10:44:19	20.50	3.00	0.30	9.00	0.00	9.00	0.00	0.00	78.10	76.80
10:45:19	20.60	2.00	0.20	7.00	0.00	7.00	0.00	0.00	78.30	77.00

RampUp 2 - 01/10/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
10:45:21	20.60	2.00	0.20	7.00	0.00	7.00	0.00	0.00	78.30	77.00
10:46:21	14.10	125.00	3.80	531.00	49.00	580.00	0.00	0.00	78.30	76.80
10:47:21	14.10	124.00	3.80	555.00	50.00	605.00	0.00	0.00	78.40	77.00

Test 2 - 01/10/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
10:47:23	14.10	124.00	3.80	555.00	50.00	605.00	0.00	0.00	78.40	77.00
10:48:23	14.10	124.00	3.80	557.00	49.00	606.00	0.00	0.00	78.40	77.20
10:49:23	14.10	126.00	3.80	573.00	49.00	622.00	0.00	0.00	78.40	77.20
10:50:23	14.10	125.00	3.80	572.00	49.00	621.00	0.00	0.00	78.40	77.20
10:51:23	14.10	128.00	3.80	566.00	49.00	615.00	0.00	0.00	78.60	77.20
10:52:23	14.10	127.00	3.80	557.00	49.00	606.00	0.00	0.00	78.60	77.40
10:53:23	14.20	128.00	3.80	556.00	48.00	604.00	0.00	0.00	78.60	77.20
10:54:23	14.20	130.00	3.80	537.00	47.00	584.00	0.00	0.00	78.60	77.20
10:55:23	14.20	132.00	3.80	513.00	46.00	559.00	0.00	0.00	78.60	77.40
10:56:23	14.20	133.00	3.80	518.00	46.00	564.00	0.00	0.00	78.80	77.40
10:57:23	14.20	136.00	3.80	495.00	45.00	540.00	0.00	0.00	78.80	77.40

Average O2 =	14.15 %	Average NOx =	593.27 ppm	Average CO =	128.45 ppm
Average NO =	545.36 ppm	Average NO2 =	47.91 ppm		

Purge 2 - 01/10/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
10:57:33	14.20	136.00	3.80	490.00	45.00	535.00	0.00	0.00	78.80	77.40
10:58:33	20.60	7.00	0.20	15.00	0.00	15.00	0.00	0.00	78.80	77.50
10:59:33	20.60	3.00	0.20	10.00	0.00	10.00	0.00	0.00	79.00	77.50
11:00:33	20.70	2.00	0.00	8.00	0.00	8.00	0.00	0.00	79.00	77.50

RampUp 3 - 01/10/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
11:00:37	20.70	2.00	0.00	8.00	0.00	8.00	0.00	0.00	79.00	77.50
11:01:37	14.40	143.00	3.70	404.00	41.00	445.00	0.00	0.00	79.00	77.50
11:02:37	14.40	145.00	3.70	406.00	42.00	448.00	0.00	0.00	79.20	77.50

Test 3 - 01/10/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
11:02:39	14.40	145.00	3.70	409.00	42.00	451.00	0.00	0.00	79.20	77.50
11:03:39	14.40	147.00	3.70	398.00	42.00	440.00	0.00	0.00	79.20	77.70
11:04:39	14.40	149.00	3.70	393.00	42.00	435.00	0.00	0.00	79.20	77.90
11:05:39	14.40	147.00	3.70	412.00	42.00	454.00	0.00	0.00	79.30	77.90
11:06:39	14.40	145.00	3.70	429.00	42.00	471.00	0.00	0.00	79.30	78.10
11:07:39	14.30	142.00	3.70	450.00	42.00	492.00	0.00	0.00	79.30	78.10
11:08:39	14.30	141.00	3.70	471.00	44.00	515.00	0.00	0.00	79.70	78.30
11:09:39	14.30	139.00	3.70	512.00	44.00	556.00	0.00	0.00	79.50	78.30
11:10:39	14.30	133.00	3.70	482.00	44.00	526.00	0.00	0.00	79.50	78.40
11:11:39	14.30	130.00	3.70	523.00	45.00	568.00	0.00	0.00	79.70	78.40
11:12:39	14.30	129.00	3.70	543.00	46.00	589.00	0.00	0.00	79.70	78.30

Average O2 =	14.35 %	Average NOx =	499.73 ppm	Average CO =	140.64 ppm
Average NO =	456.55 ppm	Average NO2 =	43.18 ppm		

Purge 3 - 01/10/20

Time	O2	CO	CO2	NO	NO2	NOx	SO2	CxHy	Tgas	Tamb
11:12:51	14.30	129.00	3.70	542.00	46.00	588.00	0.00	0.00	79.70	78.30
11:13:51	20.60	6.00	0.20	16.00	0.00	16.00	0.00	0.00	79.70	77.90
11:14:51	20.60	3.00	0.20	11.00	0.00	11.00	0.00	0.00	79.70	77.90
11:15:51	20.60	2.00	0.20	9.00	0.00	9.00	0.00	0.00	79.70	78.10

ANALYZER AVERAGE INFORMATION

Total Average O2 =	14.16 %	Total Average NOx =	571.82 ppm	Total Average CO =	132.73 ppm
Total Average NO =	524.58 ppm	Total Average NO2 =	47.24 ppm		

NOTES:

TEST COMPLETED BY:

Jeff Simon
Panhandle Eastern Pipeline
42589 Grady Rd.
Alva, OK 73717
Phone: 580-327-2029
Mobile:
Email: jeff.simon@energytransfer.com
Home Page:

Technician ______ Date 1-10-2020

Pre & Post Calibration Test Report

Calibration Test Date: 01/10/2020

Cashion Station
Panhandle Eastern Pipeline
Jason Hembree
Phone: 580-327-2029
26441 N. 2950 Rd.
Cashion, OK 73016
Mobile: 580-747-2413
Email: jason.hembree@energytransfer.com

Sensor	Span Gas Value	Expiration date	Zero Error % Limit	Cal Error % Limit	Zero Drift % Limit	Span Drift % Limit
O2 %	20.9	4/8/2014	0.5	0.5	0.5	0.5
CO ppm	296	12/5/2024	5	5	5	5
NO ppm	708	7/27/2026	5	5	5	5
NO2 ppm	396	2/2/2021	25	5	5	50

PHYSICAL LOCATION

Operational Area: Liberal

Facility Name: Cashion Station

EQUIPMENT INFORMATION

Equipment:	2302	Unit #:	2302	AF Controller Make:	
Model:	Cooper Quad 12Q155HC	Serial #:	48765	AF Controller Model:	
Service :	Natural Gas Compression	Ignition Timing:		Catalytic Converter Make:	
Stack Flow:		Fuel Type:	Gas: Natural	Catalytic Converter Model:	
Intake MP:	Left:	Intake MT:	Left:	Fuel Consumption:	23961
	Right:		Right:	Horsepower:	3292
Stack Height:	'	FuelSG:		RPM:	
Equipment Hours:		Fuel Pressure:		MV Target Set Point:	
Stepper Position:	Left:	Exhaust Temp:	Left:	MV Actual:	Left:
	Right:		Right:		Right:
Catalyst dp:		Pre-Catalyst Temp:		Post-Catalyst Temp:	

PERMIT INFORMATION

Permit #: 2013-1330-TVR3
Permit Equipment #: U2302

Permit Date: 08/06/2015
Permit Units: lb/hr @ 0 % O2

Permit CO Limit: 22.82
Permit NOx Limit: 89.3

ANALYZER INFORMATION

Model:
Last Linearity Test : 00/00/00

Serial #: 7364

Last Stability Test : 00/00/00

Calibration Specs

	O2 %	CO ppm	NO ppm	NO2 ppm
Pre-Test Zero %	0.0	0.0	0.0	0.0
Post-Test Zero %	0.0	0.0	2	0.0
Mean Zero, Ccz	0.0	0.0	1.0	0.0
Zero Result	Pass	Pass	Pass	Pass
Pre-Test Span	21.0	296	716	437
Pre-Test Result	Pass	Pass	Pass	Fail
Post Test Span	21.0	296	708	397
Post Test Drift %	0.5	0.0	0.0	0.3
Post Test Results	Pass	Pass	Pass	Pass
Span Drift (%)	0.0	0.0	1.1	9.2
Mean Span, Ccm	21.0	296.0	712.0	417.0

Pre Test Calibration

Time	O2	CO	NO	NO2	IFlow
09:11:58	21.0	0.0	0.0	0.0	2.46
09:12:02	21.0	0.0 ★[1]	0.0	0.0	2.46
09:12:04	21.0	0.0	0.0 ★[1]	0.0	2.46
09:12:05	21.0	0.0	0.0	0.0 ★[1]	2.46
09:12:39	21.0 ★[2]	0.0	0.0	0.0	2.46
09:12:43	21.0 ★[2]	0.0	0.0	0.0	2.46
09:12:44	21.0 ★[2]	0.0	0.0	0.0	2.46
09:12:44	21.0 ★[2]	0.0	0.0	0.0	2.46
09:12:45	21.0 ★[2]	0.0	0.0	0.0	2.46
09:12:45	21.0 ★[2]	0.0	0.0	0.0	2.46
09:12:45	21.0 ★[2]	0.0	0.0	0.0	2.46
09:12:46	21.0 ★[2]	0.0	0.0	0.0	2.46
09:12:58	21.0	0.0	0.0	0.0	2.45
09:13:58	21.0	0.0	0.0	0.0	2.46
09:14:58	21.0	0.0	0.0	0.0	2.45
09:15:58	5.8	11	2	0.0	2.34
09:16:49	0.0 ★[1]	275	0.0	0.0	2.34
09:16:58	0.0	276	0.0	0.0	2.35
09:17:58	0.0	279	0.0	0.0	2.36
09:18:58	0.0	281	0.0	0.0	2.36
09:19:58	0.0	281	0.0	0.0	2.36
09:20:58	0.0	281	0.0	0.0	2.37
09:21:58	0.0	282	0.0	0.0	2.37
09:22:58	0.0	282	0.0	0.0	2.37
09:23:58	0.0	282	0.0	0.0	2.37
09:24:58	0.0	282	0.0	0.0	2.37
09:25:58	0.0	282	0.0	0.0	2.36
09:26:58	0.0	296	0.0	0.0	2.37
09:27:58	0.0	296	0.0	0.0	2.37
09:28:58	0.0	296	0.0	0.0	2.37
09:29:58	0.0	296	0.0	0.0	2.37
09:30:58	0.0	296	0.0	0.0	2.36
09:31:58	0.0	296	0.0	0.0	2.37

Pre Test Calibration

09:32:58	0.0	296	0.0	0.0	2.37
09:33:25	0.0	296 ★[2]	0.0	0.0	2.37
09:33:58	19.4	206	0.0	0.0	2.47
09:34:58	21.0	7	0.0	0.0	2.47
09:35:58	21.0	4	0.0	0.0	2.47
09:36:58	0.0	5	662	52	2.38
09:37:58	0.0	3	681	25	2.38
09:38:58	0.0	4	686	19	2.37
09:39:58	0.0	4	691	16	2.38
09:40:58	0.0	3	694	15	2.38
09:41:58	0.0	3	696	14	2.38
09:42:58	0.0	2	709	13	2.37
09:43:58	0.0	2	711	12	2.37
09:44:58	0.0	1	713	12	2.37
09:45:58	0.0	1	714	11	2.38
09:46:58	0.0	1	715	10	2.38
09:47:58	0.0	0.0	716	10	2.38
09:48:16	0.0	0.0	716 ★[2]	10	2.39
09:48:58	21.0	0.0	26	10	2.47
09:49:58	21.0	0.0	11	3	2.46
09:50:58	21.0	0.0	7	1	2.46
09:51:58	0.0	1	70	142	2.37
09:52:58	0.0	1	69	212	2.35
09:53:58	0.0	1	63	248	2.37
09:54:58	0.0	1	57	279	2.37
09:55:58	0.0	1	53	307	2.37
09:56:58	0.0	1	49	331	2.35
09:57:58	0.0	1	46	352	2.36
09:58:58	0.0	1	44	371	2.35
09:59:58	0.0	0.0	41	387	2.35
10:00:58	0.0	0.0	39	401	2.35
10:01:58	0.0	0.0	37	412	2.32
10:02:58	0.0	0.0	36	422	2.33
10:03:58	0.0	0.0	34	431	2.33
10:04:43	0.0	0.0	33	437 ★[2]	2.32

Post Test Drift Check

Time	O2	CO	NO	NO2	IFlow
14:00:20	21.0	0.0	5	0.0	2.47
14:00:23	21.0	0.0 ★[1]	5	0.0	2.47
14:00:25	21.0	0.0	5	0.0 ★[1]	2.46
14:01:20	21.0	0.0	5	0.0	2.46
14:02:20	21.0	0.0	4	0.0	2.46
14:03:20	21.0	0.0	4	0.0	2.47
14:04:20	21.0	0.0	4	0.0	2.47
14:05:20	21.0	0.0	4	0.0	2.47

Post Test Drift Check

14:06:20	21.0	0.0	4	0.0	2.47
14:07:20	21.0	0.0	3	0.0	2.46
14:08:20	21.0	0.0	3	0.0	2.45
14:09:20	21.0	0.0	3	0.0	2.46
14:10:20	21.0	0.0	3	0.0	2.45
14:11:20	0.5	124	7	2	2.36
14:11:28	0.0 ★[1]	220	5	1	2.36
14:12:20	0.0	291	3	0.0	2.36
14:13:20	0.0	295	3	0.0	2.39
14:14:06	0.0	296 ★[2]	3	0.0	2.39
14:14:20	0.0	296 ★[2]	3	0.0	2.39
14:14:20	0.0	296	3	0.0	2.39
14:15:20	21.0	15	2	0.0	2.46
14:15:24	21.0 ★[2]	11	3	0.0	2.46
14:16:20	4.3	7	46	97	2.37
14:17:20	0.0	0.0	60	241	2.36
14:18:20	0.0	0.0	51	294	2.37
14:19:20	0.0	0.0	45	330	2.37
14:20:20	0.0	0.0	41	357	2.40
14:21:20	0.0	0.0	38	376	2.34
14:22:20	0.0	0.0	36	391	2.32
14:22:45	0.0	0.0	35	397 ★[2]	2.32
14:23:20	20.9	0.0	8	87	2.42
14:24:20	21.0	0.0	4	9	2.44
14:25:20	21.0	0.0	3	4	2.44
14:26:20	21.0	0.0	3	2	2.43
14:27:20	21.0	0.0	3	1	2.43
14:28:20	21.0	0.0	3	1	2.42
14:29:20	21.0	0.0	2	1	2.42
14:30:21	21.0	0.0	2	0.0	2.44
14:31:20	21.0	0.0	2	0.0	2.44
14:32:20	21.0	0.0	2	0.0	2.43
14:33:20	21.0	0.0	2	0.0	2.43
14:34:20	21.0	0.0	2	0.0	2.43
14:35:20	21.0	0.0	2	0.0	2.43
14:36:20	21.0	0.0	2	0.0	2.44
14:37:20	21.0	0.0	2	0.0	2.43
14:37:55	21.0	0.0	2 ★[1]	0.0	2.43
14:38:20	6.0	0.0	450	81	2.30
14:39:20	0.0	0.0	688	39	2.34
14:40:20	0.0	0.0	703	23	2.34
14:41:13	0.0	0.0	708 ★[2]	18	2.35

★[1] : Captured Zero

★[2] : Captured Cal Response

NOTES:

TEST COMPLETED BY:

Jeff Simon
Panhandle Eastern Pipeline
42589 Grady Rd.
Alva, OK 73717
Phone: 580-327-2029
Mobile:
Email: jeff.simon@energytransfer.com
Home Page:

Technician ____________ Date 1-10-2020

ODEQ Quarterly Compliance
Performance Test Report

Test Type: Quarterly
Test Date: 02-10-2022

Source:
Cooper Quad 12Q155HC
Lean Burn 4 Cycle Engine

Unit Number: U-2301
Serial Number: 48764
Engine Hours: 234682

Permit: #2018-0674-TVR4

Location:
Cashion Compressor Station
Kingfisher County, Oklahoma

Prepared on Behalf of:
Panhandle Eastern Pipeline

	CO	NOx
	State	State
Results ppmvd	189.190	309.282
Results lb/hr	11.750	31.552
Permit lb/hr	22.820	89.300
Results g/hp-hr	1.471	3.949
Results TPY	51.465	138.199
Permit TPY	99.960	391.150
PASS ALL	**Pass**	**Pass**

Test Started: 11:29 Test Completed: 12:35

GAS

303 W. 3rd St (580) 225-0403 Elk City, OK 73644

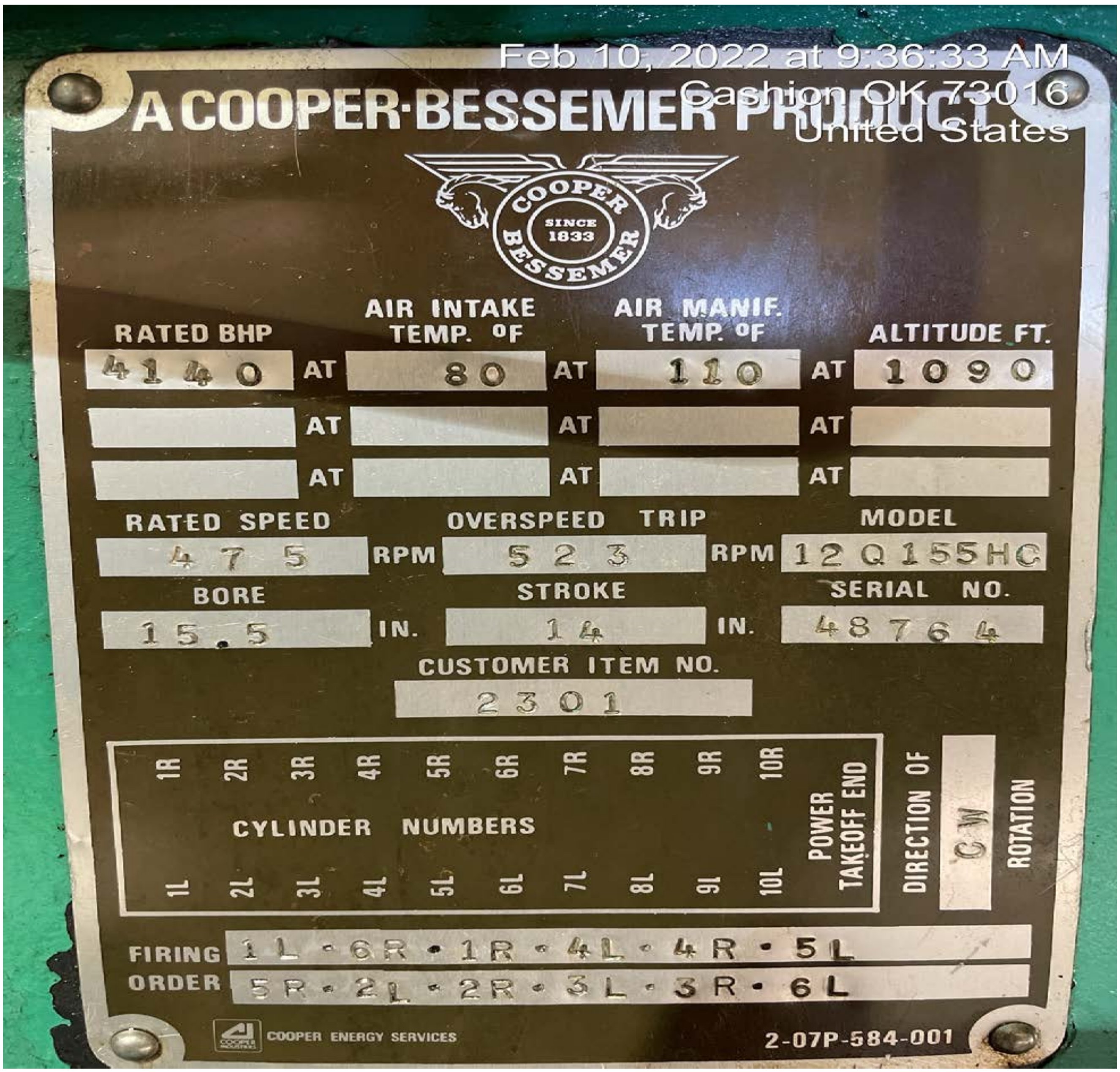
4.0 Test Summary

Unit U-2301 with a serial number of 48764 which is a Cooper Quad 12Q155HC engine located at Cashion Compressor Station and operated by Panhandle Eastern Pipeline was tested for emissions of: (Oxides of Nitrogen) (Carbon Monoxide) . The test was conducted on 02-10-2022 by Jeremiah Giles with Great Plains Analytical Services, Inc. All quality assurance and quality control tests were within acceptable tolerances.

The engine is a natural gas fired Lean Burn (4 Cycle) engine rated at 3940 brake horse power (BHP) at 450 RPM. The engine was operating at 3624.00 BHP and 450 RPM which is 91.98% of maximum engine load during the test.

This test will satisfy the testing requirements for ODEQ Quarterly Compliance. Unit U-2301 is authorized to operate under permit #2018-0674-TVR4.

Site Verification Photos



4.0 Test Summary

Engine/Compressor Specs					
Location	Cashion Compressor Station		*Unit ID*	U-2301	
Make	Cooper Quad		*Site Elevation ft.*	1220	
Model	12Q155HC		*Atmospheric Pressure psi.*	14.05	
Serial number	48764				
mfg. rated hp	3940		*Catalyst*	No	
mfg. rated rpm	450		*Date of Manufacture*		

Test Summary

Engine/Compressor Operation	**Run 1**	**Run 2**	**Run 3**	**3 Run Average**
Test Horsepower	3624	3624	3624	3624
Test RPM	450	450	450	450
Percent Load %	91.98%	91.98%	91.98%	91.98%
Intake Manifold Pressure (hg)	17.00	17.00	17.00	17.00
Intake Manifold Temperature (F)	90.10	90.10	90.10	90.10
Ambient Conditions				
Ambient Temperature Dry (F)	55.00	55.00	55.00	55.00
Exhaust Flow Data				
Q Stack (dscfh)	854712.62	854712.62	854712.62	854712.62
Q Stack (dscm/hr)	24202.54	24202.54	24202.54	24202.54
Fuel Consumption (Btu/hp-hr)	7470.00	7470.00	7470.00	7470.00
Fuel Flow (dscfh)	108876.32	109044.67	109061.32	108994.10
Fuel (Btu/scf)	1022.00	1022.00	1022.00	1022.00
O2 F factor	8710.00	8710.00	8710.00	8710.00
		Results		
Oxygen %	15.13%	15.14%	15.14%	15.14%

Permitted Standards				***Results***				
Test Start/Completed Times:				***11:29***	***11:51***	***12:13***	***12:35***	***2/10/22***
		State		**Run 1**	**Run 2**	**Run 3**	**3 Run Average**	**Pass Permits**
CO (g/hp-hr)				1.466	1.472	1.475	1.471	
CO (lbs/hr)		22.820		11.710	11.757	11.783	11.750	Pass
CO (TPY)		99.960		51.291	51.497	51.608	51.465	Pass
CO (ppmvd) @15% O2				192.941	194.016	194.463	193.807	
CO (ppbvd) @15% O2				192940.840	194016.264	194462.666	193806.590	
CO (ppmvd)				188.549	189.308	189.714	189.190	
			CO (mol wt)	28.01				
NOx (g/hp-hr)				3.951	3.976	3.921	3.949	
NOx (lbs/hr)		89.300		31.569	31.763	31.324	31.552	Pass
NOx (TPY)		391.150		138.274	139.122	137.201	138.199	Pass
NOx (ppmvd) @15% O2				316.657	319.092	314.734	316.828	
NOx (ppbvd) @15% O2				316656.648	319092.389	314733.500	316827.512	
NOx (ppmvd)				309.449	311.348	307.048	309.282	
			NOx (mol wt)	46.01				

5.0 Calibrations/System Bias & Drift Check

Span Gas

CO	1302.00
NO	790.10
NO2	100.50
O2	20.90%

Analyzer

Make:	Testo
Model:	350
Serial Number:	7855

Longest Response Time
0:01:40

Direct Calibrations

Start Time:	6:37				
Bottle Concentration			Calibration Response	Absolute Difference	<5% of Span
Zero	CO	0.00	0.00	0.00	0.00%
	NO	0.00	0.00	0.00	0.00%
	NO2	0.00	1.37	1.37	1.36%
	O2	0.00%	0.00%	0.00	0.00%
CO	Mid Level	1302.00	1295.13	6.88	0.53%
NO	Mid Level	790.10	785.13	4.98	0.63%
NO2					
	High Level	100.50	101.30	0.80	0.80%
O2					
	High Level	20.90%	20.90%	0.00%	0.00%

Post

Start Time:	12:40						
Bottle Concentration			System Response	Absolute Difference	<5% of Span	<5% Drift	
Zero	CO	0.00	0.00	0.00	0.00%		
	NO	0.00	0.00	0.00	0.00%		
	NO2	0.00	2.07	2.07	2.06%		
	O2	0.00%	0.03%	0.00	0.14%		
CO	Upscale	1302.00	1289.38	12.63	0.97%	0.45%	
NO	Upscale	790.10	782.63	7.48	0.95%	0.32%	
NO2	Upscale	100.50	100.73	0.22	0.22%	0.57%	
O2	Upscale	20.90%	20.90%	0.00	0.00%	0.00%	

6.0 Engine Parameter Data Sheet

Great Plains Analytical Services, Inc

Company	Panhandle Eastern Pipeline
Facility	Cashion Compressor Station
Date	2/10/2022
Site Elevation (ft)	1,220
Unit ID	U-2301
Make	Cooper Quad
Model	12Q155HC
Serial Number	48764
Technician	Jeremiah Giles

	Run 1	**Run 2**	**Run 3**	**Completed**
Run Start Times	11:29	11:51	12:13	12:35
Engine Hours	234682	234682	234682	234682

	Engine Parameter Data			
	Run 1	Run 2	Run 3	Average
Engine Speed (RPM)	450	450	450	450
Intake Manifold Pressure (psi)	17.0	17.0	17.0	17.0
Intake Manifold Temp °F	90.1	90.1	90.1	90.1
Engine Load (BHP)	3624.00	3624.00	3624.00	3624.00
Ambient Temp °F	55	55	55	55
Humidity %	35	35	35	35
Dew Point °F	27	27	27	27
AFR Manufacturer/Type	Altronics	Altronics	Altronics	Altronics
AFR Setting (Target Left Bank)	3.0	3.0	3.0	3.0
Suction Pressure (psi)	245.0	245.0	245.0	245.0
Discharge Pressure (psi)	848.0	848.0	848.0	848.0
Catalyst (Yes or No)	No	No	No	No

<--- Not available on this unit

11.0 Signature Page

R0

Job/File Name: Panhandle Eastern Pipeline; Cashion Compressor Station; U-2301; ODEQ Quarterly Compliance;

We certify that based on review of test data, knowledge of those individuals directly responsible for conducting this test, we believe the submitted information to be accurate and complete.

Company:	G.A.S. Inc.	Date:	2/16/22
Print Name:	Jeremiah Giles		
Title:	Director of PEA Testing		
Signature:	Jeremiah Giles		
Phone Number:	580-515-2920		

Company:	G.A.S. Inc.	Date:	2/16/22
Print Name:	Jeremiah Giles		
Title:	Emissions Specialist		

Company:			
Print Name:		Date:	
Signature:			
Title:			
Phone Number:			

Appendices

(PEA) Special CO/NO High

Airgas

CERTIFICATE OF ANALYSIS

Grade of Product: EPA Protocol

Part Number:	E03NI99E15A7XK1	Reference Number:	54-401126470-1
Cylinder Number:	CC1007	Cylinder Volume:	144.4 Cubic Feet
Laboratory:	124 - Chicago (SAP) - IL	Cylinder Pressure:	2015 PSIG
PGVP Number:	B12018	Valve Outlet:	660
Gas Code:	CO,NO,NOX,BALN	Certification Date:	Mar 01, 2018

Expiration Date: Mar 01, 2026

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a mole/mole basis unless otherwise noted.
Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
NOX	3500 PPM	3533 PPM	G1	+/- 1% NIST Traceable	02/19/2018, 03/01/2018
NITRIC OXIDE	3500 PPM	3526 PPM	G1	+/- 1% NIST Traceable	02/19/2018, 03/01/2018
CARBON MONOXIDE	4500 PPM	4517 PPM	G1	+/- 1.0% NIST Traceable	02/22/2018
NITROGEN	Balance			-	

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
GMIS	124264848107	SG9148003BAL	5454 PPM NITRIC OXIDE/NITROGEN	+/- 0.7%	Aug 14, 2023
NTRM	14060160	CC437085	990.9 PPM CARBON MONOXIDE/NITROGEN	+/- 0.6%	Nov 18, 2019
GMIS	1114201605	CC506716	4.995 PPM NITROGEN DIOXIDE/NITROGEN	+/- 2.0%	Nov 14, 2019
PRM	12367	APEX1099237	10.0 PPM NITROGEN DIOXIDE/AIR	+/- 1.5%	Jun 02, 2017
NTRM	13060213	CC401957	4950 PPM CARBON MONOXIDE/NITROGEN	+/- 0.4%	Feb 15, 2019

The SRM, PRM or RGM noted above is only in reference to the GMIS used in the assay and not part of the analysis.

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
CO-2 SIEMENS ULTRAMAT 6E N1J5700	NDIR	Jan 21, 2018
Nicolet 6700 AHR0801332	FTIR	Feb 21, 2018
Nicolet 6700 AHR0801332	FTIR	Feb 21, 2018

Triad Data Available Upon Request

Signature on file

Approved for Release

Page 1 of 54-401126470-1

(PEA) Mid CO/NO

Airgas

CERTIFICATE OF ANALYSIS

Grade of Product: EPA Protocol

Part Number:	E03NI99E15AC2T0	Reference Number:	54-401845408-1
Cylinder Number:	CC285225	Cylinder Volume:	144.4 CF
Laboratory:	124 - Chicago (SAP) - IL	Cylinder Pressure:	2015 PSIG
PGVP Number:	B12020	Valve Outlet:	660
Gas Code:	CO,NO,NOX,BALN	Certification Date:	Jul 14, 2020

Expiration Date: Jul 14, 2028

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a mole/mole basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
NOX	800.0 PPM	790.1 PPM	G1	+/- 0.6% NIST Traceable	07/07/2020, 07/14/2020
NITRIC OXIDE	800.0 PPM	790.1 PPM	G1	+/- 0.6% NIST Traceable	07/07/2020, 07/14/2020
CARBON MONOXIDE	1300 PPM	1302 PPM	G1	+/- 0.6% NIST Traceable	07/07/2020
NITROGEN	Balance			-	

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	15060242	CC449815	997.2 PPM NITRIC OXIDE/NITROGEN	+/- 0.5%	Nov 07, 2020
PRM	12386	D685025	9.91 PPM NITROGEN DIOXIDE/AIR	+/- 2.0%	Feb 20, 2020
GMIS	7302017104	CC506604	4.426 PPM NITROGEN DIOXIDE/NITROGEN	+/- 2.1%	Jul 03, 2022
NTRM	08012238	KAL004643	2466 PPM CARBON MONOXIDE/NITROGEN	+/- 0.5%	May 24, 2024

The SRM, PRM or RGM noted above is only in reference to the GMIS used in the assay and not part of the analysis.

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
CO-2 SIEMENS ULTRAMAT 6E N1J5700	NDIR	Jun 10, 2020
Nicolet 6700 AMP0900100	FTIR	Jun 15, 2020
Nicolet 6700 AMP0900100	FTIR	Jun 15, 2020

Triad Data Available Upon Request

PERMANENT NOTES:GREAT PLAINS ANALYTICAL

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(PEA) CO/NO Low

Airgas

CERTIFICATE OF ANALYSIS

Grade of Product: EPA Protocol

Part Number:	E03NI99E15AC2S8	Reference Number:	54-401721512-1
Cylinder Number:	CC472329	Cylinder Volume:	144.4 CF
Laboratory:	124 - Chicago (SAP) - IL	Cylinder Pressure:	2015 PSIG
PGVP Number:	B12020	Valve Outlet:	660
Gas Code:	CO,NO,NOX,BALN	Certification Date:	Feb 17, 2020

Expiration Date: Feb 17, 2028

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a mole/mole basis unless otherwise noted.
Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
NOX	150.0 PPM	148.9 PPM	G1	+/- 1.4% NIST Traceable	02/10/2020, 02/17/2020
NITRIC OXIDE	150.0 PPM	148.8 PPM	G1	+/- 1.4% NIST Traceable	02/10/2020, 02/17/2020
CARBON MONOXIDE	220.0 PPM	222.9 PPM	G1	+/- 1% NIST Traceable	02/10/2020
NITROGEN	Balance			-	

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	15060350	CC448769	241.0 PPM NITRIC OXIDE/NITROGEN	+/- 0.5%	Mar 30, 2021
PRM	12386	D685025	9.91 PPM NITROGEN DIOXIDE/AIR	+/- 2.0%	Feb 20, 2020
NTRM	18060128	KAL004272	249.9 PPM NITRIC OXIDE/NITROGEN	+/- 0.4	Nov 08, 2023
GMIS	7302017104	CC506604	4.426 PPM NITROGEN DIOXIDE/NITROGEN	+/- 2.1%	Jul 03, 2022
NTRM	13010131	ND48544	495.4 PPM CARBON MONOXIDE/NITROGEN	+/- 0.6%	Jul 03, 2024

The SRM, PRM or RGM noted above is only in reference to the GMIS used in the assay and not part of the analysis.

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Nicolet 6700 AMP0900100	FTIR	Feb 03, 2020
Nicolet 6700 AMP0900100	FTIR	Feb 03, 2020
Nicolet 6700 AMP0900100	FTIR	Feb 03, 2020

Triad Data Available Upon Request

PERMANENT NOTES: GREAT PLAINS ANALYTICAL

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(PEA) NO2 High

Airgas Specialty Gases
Airgas USA, LLC
12722 S. Wentworth Ave.
Chicago, IL 60628
Airgas.com

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

Part Number:	E02NI99E15W51V7	Reference Number:	54-402246614-1
Cylinder Number:	CC503115	Cylinder Volume:	144.0 CF
Laboratory:	124 - Chicago (SAP) - IL	Cylinder Pressure:	2016 PSIG
PGVP Number:	B12021	Valve Outlet:	660
Gas Code:	NO2,BALN	Certification Date:	Oct 20, 2021

Expiration Date: Oct 20, 2024

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a mole/mole basis unless otherwise noted.
Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
NITROGEN DIOXIDE	100.0 PPM	100.5 PPM	G1	+/- 2% NIST Traceable	10/12/2021, 10/20/2021
NITROGEN	Balance				

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
GMIS	1534002020601	EB0130023	101 PPM NITROGEN DIOXIDE/NITROGEN	+/- 1.4%	Apr 30, 2024
PRM	12397	D887665	74.2 PPM NITROGEN DIOXIDE/AIR	+/- 1.3%	Feb 02, 2022

The SRM, PRM or RGM noted above is only in reference to the GMIS used in the assay and not part of the analysis.

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
MKS FTIR NO2 017707558	FTIR	Oct 14, 2021

Triad Data Available Upon Request

PERMANENT NOTES: OXYGEN ADDED TO MAINTAIN STABILITY

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7.0 Raw Data

CO/NO Pre

Date / time	% O_2	ppm CO	ppm NO	ppm NO_2	ppm NOx	l/min Pump
6:37:46	20.9	0.0	0.0	1.7	1.7	0.82
6:37:56	20.9	0.0	0.0	1.5	1.5	0.98
6:38:06	20.9	0.0	0.0	0.9	0.9	0.98
6:38:16	15.8	333.0	451.0	0.5	451.5	0.98
6:38:26	4.4	1104.0	577.0	0.2	577.2	0.98
6:38:36	2.7	1188.0	687.0	0.0	687.0	0.98
6:38:46	1.5	1243.0	699.0	0.0	699.0	0.98
6:38:56	0.9	1267.0	723.0	0.0	723.0	0.98
6:39:06	0.2	1278.0	745.0	0.0	745.0	0.98
6:39:16	0.1	1282.0	772.0	0.0	772.0	0.98
6:39:26	0.0	1288.0	778.0	0.0	778.0	0.99
6:39:36	0.0	1290.0	780.0	0.0	780.0	0.98
6:39:46	0.0	1292.0	781.0	0.0	781.0	0.98
6:39:56	0.0	1293.0	782.0	0.0	782.0	0.98
6:40:06	0.0	1293.0	783.0	0.0	783.0	0.98
6:40:16	0.0	1293.0	783.0	0.0	783.0	0.98
6:40:26	0.0	1293.0	783.0	0.0	783.0	0.98
6:40:36	0.0	1294.0	784.0	0.0	784.0	0.98
6:40:46	0.0	1294.0	784.0	0.0	784.0	0.98
6:40:56	0.0	1294.0	784.0	0.0	784.0	0.98
6:41:06	0.0	1294.0	784.0	0.0	784.0	0.98
6:41:16	0.0	1295.0	785.0	0.0	785.0	0.98
6:41:26	0.0	1295.0	785.0	0.0	785.0	0.98
6:41:36	0.0	1295.0	785.0	0.0	785.0	0.98
6:41:46	0.0	1295.0	785.0	0.0	785.0	0.99
6:41:56	0.0	1295.0	785.0	0.0	785.0	0.98
6:42:06	0.0	1296.0	786.0	0.0	786.0	0.98
6:42:16	0.0	1296.0	786.0	0.0	786.0	0.98
6:42:26	0.0	1296.0	786.0	0.0	786.0	0.98
6:42:36	0.0	1296.0	786.0	0.0	786.0	0.98
6:42:46	0.0	1297.0	786.0	0.0	786.0	0.98
6:42:56	12.9	1119.0	787.0	0.0	787.0	0.99
6:43:06	18.9	667.0	443.0	0.0	443.0	0.99
6:43:16	20.2	421.0	211.0	0.0	211.0	0.98
6:43:26	20.9	213.0	96.0	0.0	96.0	0.98
6:43:36	21.0	67.0	53.0	0.0	53.0	0.98
6:43:46	21.1	15.0	21.0	0.0	21.0	0.98

NO2 Pre

Date / time	% O_2	ppm CO	ppm NO	ppm NO_2	ppm NOx	l/min Pump
7:00:51	20.9	0.0	0.0	1.6	1.6	1.43
7:01:01	20.9	0.0	0.0	1.2	1.2	0.98
7:01:11	20.9	0.0	0.0	1.0	1.0	0.98
7:01:21	10.9	0.0	0.0	66.7	66.7	0.98
7:01:31	3.4	0.0	0.0	93.2	93.2	0.98
7:01:41	2.8	0.0	0.0	98.6	98.6	0.98
7:01:51	1.0	0.0	0.0	100.2	100.2	0.98
7:02:01	0.7	0.0	0.0	100.9	100.9	0.98
7:02:11	0.1	0.0	0.0	101.0	101.0	0.98
7:02:21	0.1	0.0	0.0	101.1	101.1	0.98
7:02:31	0.1	0.0	0.0	101.3	101.3	0.98
7:02:41	0.1	0.0	0.0	101.7	101.7	0.98
7:02:51	0.1	0.0	0.0	101.2	101.2	0.98
7:03:01	0.1	0.0	0.0	101.2	101.2	0.98
7:03:11	0.1	0.0	0.0	101.2	101.2	0.98
7:03:21	0.1	0.0	0.0	101.2	101.2	0.98
7:03:31	0.1	0.0	0.0	101.2	101.2	0.99
7:03:41	0.1	0.0	0.0	101.2	101.2	0.98
7:03:51	0.1	0.0	0.0	101.3	101.3	0.98
7:04:01	0.1	0.0	0.0	101.3	101.3	0.98
7:04:11	0.1	0.0	0.0	101.3	101.3	0.98
7:04:21	0.1	0.0	0.0	101.3	101.3	0.98
7:04:31	0.1	0.0	0.0	101.3	101.3	0.98
7:04:41	0.1	0.0	0.0	101.3	101.3	0.98
7:04:51	0.1	0.0	0.0	101.3	101.3	0.98
7:05:01	0.1	0.0	0.0	101.3	101.3	0.98
7:05:11	0.1	0.0	0.0	101.3	101.3	0.98
7:05:21	0.1	0.0	0.0	101.3	101.3	0.98
7:05:31	0.1	0.0	0.0	101.4	101.4	0.98
7:05:41	0.1	0.0	0.0	101.4	101.4	0.98
7:05:51	0.1	0.0	0.0	101.4	101.4	0.98
7:06:01	19.9	0.0	0.0	28.8	28.8	0.98
7:06:11	20.5	0.0	0.0	6.7	6.7	0.98
7:06:21	20.7	0.0	0.0	1.9	1.9	0.98
7:06:31	20.7	0.0	0.0	0.6	0.6	0.98
7:06:41	20.8	0.0	0.0	0.2	0.2	0.98
7:06:51	20.9	0.0	0.0	0.0	0.0	0.98

Source Test

Date / time	% O_2	ppm CO	ppm NO	ppm NO_2	ppm NOx	l/min Pump
11:28:55	20.9	0.0	0.0	1.1	1.1	1.36
11:29:05	20.9	2.0	0.0	3.7	3.7	0.98
11:29:15	20.9	2.0	2.0	3.0	5.0	0.98
11:29:25	19.1	2.0	22.0	6.1	28.1	0.98
11:29:35	16.0	49.0	73.0	11.7	84.7	0.98
11:29:45	15.4	146.0	177.0	21.7	198.7	0.98
11:29:55	15.3	178.0	213.0	25.7	238.7	0.98
11:30:05	15.2	183.0	236.0	27.7	263.7	0.98
11:30:15	15.2	183.0	248.0	29.0	277.0	0.98
11:30:25	15.2	184.0	255.0	29.7	284.7	0.98
11:30:35	15.2	185.0	256.0	30.2	286.2	0.98
11:30:45	15.2	185.0	256.0	30.7	286.7	0.98
11:30:55	15.1	186.0	258.0	31.3	289.3	0.98
11:31:05	15.1	187.0	258.0	31.8	289.8	0.98
11:31:15	15.1	186.0	263.0	32.9	295.9	0.98
11:31:25	15.1	186.0	272.0	34.0	306.0	0.98
11:31:35	15.1	185.0	268.0	34.0	302.0	0.98
11:31:45	15.1	184.0	267.0	34.5	301.5	0.99
11:31:55	15.1	186.0	273.0	35.2	308.2	0.98
11:32:05	15.2	186.0	264.0	34.8	298.8	0.98
11:32:15	15.1	188.0	264.0	35.3	299.3	0.98
11:32:25	15.1	190.0	266.0	35.6	301.6	0.98
11:32:35	15.1	189.0	268.0	36.0	304.0	0.98
11:32:45	15.2	189.0	265.0	36.0	301.0	0.98
11:32:55	15.2	189.0	262.0	36.0	298.0	0.98
11:33:05	15.1	188.0	261.0	36.3	297.3	0.98
11:33:15	15.1	189.0	265.0	36.6	301.6	0.98
11:33:25	15.1	189.0	265.0	36.7	301.7	0.98
11:33:35	15.4	190.0	264.0	36.7	300.7	0.98
11:33:45	15.1	189.0	264.0	36.7	300.7	0.98
11:33:55	15.2	189.0	265.0	37.0	302.0	0.98
11:34:05	15.1	189.0	266.0	37.1	303.1	0.98
11:34:15	15.1	191.0	265.0	37.2	302.2	0.98
11:34:25	15.1	191.0	263.0	37.1	300.1	0.98
11:34:35	15.1	190.0	264.0	37.4	301.4	0.98
11:34:45	15.1	189.0	265.0	37.5	302.5	0.98
11:34:55	15.1	188.0	270.0	37.8	307.8	0.98
11:35:05	15.1	187.0	272.0	38.0	310.0	0.98
11:35:15	15.1	187.0	267.0	37.7	304.7	0.98
11:35:25	15.1	188.0	268.0	37.8	305.8	0.98
11:35:35	15.1	189.0	270.0	38.0	308.0	0.98
11:35:45	15.1	189.0	262.0	37.5	299.5	0.98
11:35:55	15.2	189.0	263.0	37.5	300.5	0.98
11:36:05	15.1	191.0	263.0	37.8	300.8	0.98
11:36:15	15.2	191.0	265.0	38.0	303.0	0.98
11:36:25	15.1	191.0	264.0	38.2	302.2	0.98

11:36:35	15.1	189.0	269.0	38.5	307.5	0.98
11:36:45	15.1	190.0	271.0	38.5	309.5	0.98
11:36:55	15.1	188.0	270.0	38.5	308.5	0.98
11:37:05	15.1	188.0	269.0	38.3	307.3	0.98
11:37:15	15.1	189.0	271.0	38.6	309.6	0.98
11:37:25	15.1	188.0	272.0	38.6	310.6	0.98
11:37:35	15.1	188.0	277.0	39.1	316.1	0.98
11:37:45	15.1	189.0	277.0	39.0	316.0	0.98
11:37:55	15.2	189.0	272.0	38.6	310.6	0.98
11:38:05	15.1	189.0	269.0	38.4	307.4	0.98
11:38:15	15.2	189.0	270.0	38.4	308.4	0.98
11:38:25	15.1	190.0	269.0	38.2	307.2	0.99
11:38:35	15.1	189.0	268.0	38.3	306.3	0.98
11:38:45	15.1	188.0	269.0	38.4	307.4	0.98
11:38:55	15.1	189.0	273.0	38.7	311.7	0.98
11:39:05	15.1	191.0	271.0	38.4	309.4	0.98
11:39:15	15.1	189.0	270.0	38.3	308.3	0.98
11:39:25	15.1	189.0	272.0	38.4	310.4	0.98
11:39:35	15.1	188.0	274.0	38.7	312.7	0.98
11:39:45	15.1	189.0	278.0	39.1	317.1	0.98
11:39:55	15.1	188.0	277.0	38.8	315.8	0.98
11:40:05	15.1	187.0	273.0	38.4	311.4	0.98
11:40:15	15.1	189.0	272.0	38.4	310.4	0.98
11:40:25	15.2	188.0	273.0	38.4	311.4	0.98
11:40:35	15.2	188.0	272.0	38.3	310.3	0.98
11:40:45	15.1	188.0	269.0	38.1	307.1	0.98
11:40:55	15.2	188.0	267.0	38.0	305.0	0.98
11:41:05	15.1	188.0	267.0	37.9	304.9	0.98
11:41:15	15.1	187.0	269.0	38.3	307.3	0.98
11:41:25	15.2	188.0	273.0	38.4	311.4	0.98
11:41:35	15.1	187.0	274.0	38.7	312.7	0.98
11:41:45	15.1	188.0	277.0	38.7	315.7	0.98
11:41:55	15.1	187.0	276.0	38.5	314.5	0.98
11:42:05	15.1	187.0	273.0	38.5	311.5	0.98
11:42:15	15.1	189.0	272.0	38.3	310.3	0.98
11:42:25	15.1	187.0	270.0	38.2	308.2	0.98
11:42:35	15.1	190.0	268.0	37.9	305.9	0.98
11:42:45	15.2	189.0	267.0	38.0	305.0	0.98
11:42:55	15.1	188.0	271.0	38.2	309.2	0.98
11:43:05	15.1	187.0	269.0	38.2	307.2	0.98
11:43:15	15.1	186.0	269.0	38.3	307.3	0.98
11:43:25	15.1	188.0	273.0	38.5	311.5	0.98
11:43:35	15.1	189.0	276.0	38.8	314.8	0.98
11:43:45	15.2	189.0	274.0	38.3	312.3	0.98
11:43:55	15.2	188.0	270.0	38.2	308.2	0.98
11:44:05	15.2	188.0	273.0	38.5	311.5	0.98
11:44:15	15.1	188.0	273.0	38.4	311.4	0.98
11:44:25	15.2	188.0	278.0	38.8	316.8	0.98

11:44:35	15.1	187.0	280.0	38.9	318.9	0.98
11:44:45	15.1	185.0	280.0	39.0	319.0	0.98
11:44:55	15.1	188.0	278.0	38.9	316.9	0.98
11:45:05	15.1	189.0	280.0	39.0	319.0	0.98
11:45:15	15.1	188.0	278.0	38.9	316.9	0.98
11:45:25	15.1	188.0	275.0	38.8	313.8	0.98
11:45:35	15.2	189.0	274.0	38.6	312.6	0.98
11:45:45	15.1	190.0	272.0	38.6	310.6	0.98
11:45:55	15.1	189.0	277.0	38.7	315.7	0.98
11:46:05	15.2	190.0	276.0	38.8	314.8	0.98
11:46:15	15.1	190.0	279.0	39.2	318.2	0.98
11:46:25	15.1	189.0	279.0	39.2	318.2	0.98
11:46:35	15.1	187.0	279.0	39.3	318.3	0.98
11:46:45	15.1	187.0	275.0	38.8	313.8	0.98
11:46:55	15.2	187.0	270.0	38.8	308.8	0.98
11:47:05	15.2	189.0	271.0	38.8	309.8	0.98
11:47:15	15.2	191.0	273.0	38.8	311.8	0.98
11:47:25	15.2	189.0	274.0	39.0	313.0	0.98
11:47:35	15.1	188.0	277.0	39.2	316.2	0.98
11:47:45	15.1	187.0	277.0	39.1	316.1	0.98
11:47:55	15.2	188.0	274.0	38.9	312.9	0.98
11:48:05	19.1	189.0	158.0	12.9	170.9	0.98
11:48:15	20.4	101.0	61.0	4.3	65.3	0.98
11:48:25	20.7	32.0	29.0	1.9	30.9	0.98
11:48:35	20.9	10.0	17.0	1.0	18.0	0.98
11:48:45	20.9	4.0	12.0	0.7	12.7	0.98
11:48:55	20.9	2.0	8.0	0.5	8.5	0.98
11:49:05	20.9	1.0	6.0	0.5	6.5	0.98
11:49:15	20.9	1.0	5.0	0.4	5.4	0.98
11:49:25	20.9	0.0	4.0	0.3	4.3	0.98
11:49:35	20.9	1.0	3.0	0.3	3.3	0.98
11:49:45	21.0	0.0	3.0	0.2	3.2	0.98
11:49:55	21.0	0.0	2.0	0.2	2.2	0.98
11:50:05	21.0	0.0	2.0	0.2	2.2	0.98
11:50:15	20.8	0.0	1.0	0.2	1.2	0.98
11:50:25	20.9	0.0	1.0	0.2	1.2	0.98
11:50:35	20.9	0.0	1.0	0.1	1.1	0.98
11:50:45	21.0	0.0	1.0	0.2	1.2	0.98
11:50:55	21.1	0.0	1.0	0.1	1.1	0.99
11:51:05	16.6	0.0	100.0	43.1	143.1	0.98
11:51:15	15.4	95.0	174.0	55.5	229.5	0.98
11:51:25	15.2	164.0	200.0	48.2	248.2	0.98
11:51:35	15.2	180.0	220.0	40.5	260.5	0.98
11:51:45	15.2	186.0	244.0	37.6	281.6	0.98
11:51:55	15.2	191.0	260.0	38.3	298.3	0.98
11:52:05	15.1	190.0	264.0	38.2	302.2	0.98
11:52:15	15.5	189.0	272.0	38.8	310.8	0.98
11:52:25	15.2	189.0	272.0	38.7	310.7	0.98

11:52:35	15.2	190.0	272.0	38.7	310.7	0.98
11:52:45	15.2	191.0	269.0	38.4	307.4	0.98
11:52:55	15.2	190.0	267.0	38.2	305.2	0.98
11:53:05	15.2	190.0	264.0	38.2	302.2	0.98
11:53:15	15.2	191.0	267.0	38.3	305.3	0.98
11:53:25	15.2	192.0	270.0	38.6	308.6	0.98
11:53:35	15.2	190.0	273.0	38.6	311.6	0.98
11:53:45	15.4	188.0	276.0	38.8	314.8	0.98
11:53:55	15.1	188.0	272.0	38.5	310.5	0.98
11:54:05	15.1	188.0	268.0	38.3	306.3	0.98
11:54:15	15.2	188.0	270.0	38.5	308.5	0.98
11:54:25	15.1	189.0	270.0	38.4	308.4	0.98
11:54:35	15.1	187.0	274.0	38.7	312.7	0.98
11:54:45	15.1	188.0	275.0	38.8	313.8	0.98
11:54:55	15.1	187.0	275.0	38.8	313.8	0.98
11:55:05	15.1	187.0	275.0	39.0	314.0	0.98
11:55:15	15.1	189.0	275.0	39.1	314.1	0.98
11:55:25	15.1	189.0	277.0	39.2	316.2	0.98
11:55:35	15.3	187.0	278.0	39.2	317.2	0.98
11:55:45	15.1	186.0	275.0	38.9	313.9	0.98
11:55:55	15.1	187.0	273.0	38.9	311.9	0.98
11:56:05	15.2	188.0	271.0	38.7	309.7	0.98
11:56:15	15.2	188.0	269.0	38.7	307.7	0.98
11:56:25	15.2	188.0	271.0	39.1	310.1	0.98
11:56:35	15.1	188.0	275.0	39.3	314.3	0.98
11:56:45	15.1	188.0	272.0	39.0	311.0	0.99
11:56:55	15.2	187.0	277.0	39.5	316.5	0.98
11:57:05	15.1	188.0	279.0	39.5	318.5	0.98
11:57:15	15.1	188.0	279.0	39.5	318.5	0.98
11:57:25	15.1	189.0	280.0	39.6	319.6	0.98
11:57:35	15.1	189.0	276.0	39.3	315.3	0.98
11:57:45	15.1	189.0	277.0	39.3	316.3	0.98
11:57:55	15.1	190.0	273.0	38.9	311.9	0.98
11:58:05	15.1	189.0	272.0	38.9	310.9	0.98
11:58:15	15.1	189.0	270.0	38.7	308.7	0.98
11:58:25	15.1	186.0	273.0	39.2	312.2	0.98
11:58:35	15.1	186.0	276.0	39.3	315.3	0.98
11:58:45	15.1	187.0	273.0	39.0	312.0	0.98
11:58:55	15.1	187.0	277.0	39.3	316.3	0.98
11:59:05	15.3	189.0	276.0	39.1	315.1	0.98
11:59:15	15.2	189.0	272.0	38.8	310.8	0.98
11:59:25	15.2	189.0	273.0	38.8	311.8	0.98
11:59:35	15.1	189.0	270.0	38.7	308.7	0.98
11:59:45	14.9	190.0	268.0	38.5	306.5	0.98
11:59:55	15.1	191.0	268.0	38.6	306.6	0.98
12:00:05	15.1	189.0	271.0	38.8	309.8	0.98
12:00:15	15.3	190.0	274.0	38.8	312.8	0.98
12:00:25	15.1	190.0	275.0	38.9	313.9	0.98

12:00:35	15.3	188.0	279.0	39.3	318.3	0.98
12:00:45	15.1	189.0	278.0	39.2	317.2	0.98
12:00:55	15.1	189.0	274.0	38.9	312.9	0.98
12:01:05	15.2	190.0	269.0	38.7	307.7	0.98
12:01:15	15.2	191.0	266.0	38.2	304.2	0.98
12:01:25	15.2	191.0	262.0	38.0	300.0	0.98
12:01:35	15.2	190.0	262.0	38.1	300.1	0.98
12:01:45	15.1	189.0	263.0	38.4	301.4	0.98
12:01:55	15.2	193.0	264.0	38.2	302.2	0.98
12:02:05	15.2	193.0	264.0	38.3	302.3	0.98
12:02:15	15.1	191.0	265.0	38.3	303.3	0.98
12:02:25	15.1	191.0	269.0	38.6	307.6	0.98
12:02:35	15.2	191.0	272.0	38.7	310.7	0.98
12:02:45	15.1	190.0	274.0	38.9	312.9	0.98
12:02:55	15.1	188.0	275.0	38.9	313.9	0.98
12:03:05	15.1	188.0	273.0	38.8	311.8	0.98
12:03:15	15.1	189.0	279.0	39.3	318.3	0.98
12:03:25	15.2	188.0	281.0	39.4	320.4	0.98
12:03:35	15.1	189.0	276.0	39.1	315.1	0.98
12:03:45	15.1	188.0	277.0	38.9	315.9	0.98
12:03:55	15.1	189.0	275.0	38.9	313.9	0.98
12:04:05	15.1	189.0	276.0	39.0	315.0	0.98
12:04:15	15.2	190.0	274.0	38.9	312.9	0.98
12:04:25	15.2	189.0	271.0	38.8	309.8	0.98
12:04:35	15.2	188.0	274.0	38.9	312.9	0.98
12:04:45	15.0	190.0	274.0	38.8	312.8	0.98
12:04:55	15.2	190.0	275.0	39.0	314.0	0.98
12:05:05	15.2	191.0	275.0	39.1	314.1	0.98
12:05:15	15.1	192.0	274.0	38.9	312.9	0.98
12:05:25	15.2	191.0	276.0	39.1	315.1	0.98
12:05:35	15.1	191.0	275.0	39.0	314.0	0.98
12:05:45	15.1	192.0	272.0	38.8	310.8	0.98
12:05:55	15.2	191.0	270.0	38.6	308.6	0.98
12:06:05	15.2	189.0	268.0	38.5	306.5	0.98
12:06:15	15.2	191.0	269.0	38.6	307.6	0.98
12:06:25	15.2	191.0	266.0	38.3	304.3	0.98
12:06:35	15.2	190.0	266.0	38.2	304.2	0.98
12:06:45	15.1	189.0	269.0	38.6	307.6	0.98
12:06:55	15.1	190.0	270.0	38.7	308.7	0.98
12:07:05	15.2	192.0	269.0	38.6	307.6	0.98
12:07:15	15.1	190.0	268.0	38.5	306.5	0.98
12:07:25	15.2	190.0	275.0	39.0	314.0	0.98
12:07:35	15.1	190.0	275.0	38.8	313.8	0.98
12:07:45	15.1	188.0	272.0	38.8	310.8	0.98
12:07:55	15.1	188.0	273.0	38.6	311.6	0.98
12:08:05	15.2	189.0	272.0	38.6	310.6	0.98
12:08:15	15.2	190.0	270.0	38.5	308.5	0.98
12:08:25	15.2	192.0	270.0	38.7	308.7	0.98

12:08:35	15.2	192.0	267.0	38.4	305.4	0.98
12:08:45	15.2	189.0	265.0	38.1	303.1	0.98
12:08:55	15.2	188.0	267.0	38.3	305.3	0.98
12:09:05	15.2	188.0	276.0	38.9	314.9	0.98
12:09:15	15.1	190.0	278.0	39.1	317.1	0.98
12:09:25	15.2	190.0	274.0	38.6	312.6	0.98
12:09:35	15.1	189.0	272.0	38.7	310.7	0.98
12:09:45	15.1	191.0	274.0	38.8	312.8	0.98
12:09:55	15.2	190.0	276.0	38.9	314.9	0.98
12:10:05	19.5	188.0	143.0	11.5	154.5	0.98
12:10:15	20.7	90.0	50.0	3.1	53.1	0.98
12:10:25	20.8	24.0	25.0	1.2	26.2	0.98
12:10:35	20.9	7.0	16.0	0.6	16.6	0.98
12:10:45	20.9	3.0	11.0	0.4	11.4	0.98
12:10:55	21.0	2.0	9.0	0.3	9.3	0.98
12:11:05	20.9	1.0	7.0	0.2	7.2	0.98
12:11:15	20.9	1.0	5.0	0.1	5.1	0.98
12:11:25	21.0	1.0	4.0	0.1	4.1	0.98
12:11:35	20.9	1.0	4.0	0.1	4.1	0.98
12:11:45	21.0	0.0	3.0	0.1	3.1	0.98
12:11:55	21.0	0.0	3.0	0.1	3.1	0.98
12:12:05	20.9	0.0	2.0	0.0	2.0	0.98
12:12:15	21.0	0.0	2.0	0.1	2.1	0.98
12:12:25	20.9	0.0	2.0	0.0	2.0	0.98
12:12:35	21.0	0.0	1.0	0.0	1.0	0.98
12:12:45	21.0	0.0	1.0	0.0	1.0	0.98
12:12:55	21.0	0.0	1.0	0.0	1.0	0.98
12:13:05	16.3	3.0	109.0	42.2	151.2	0.98
12:13:15	15.4	98.0	177.0	53.1	230.1	0.98
12:13:25	15.3	166.0	204.0	47.6	251.6	0.98
12:13:35	15.2	181.0	221.0	38.6	259.6	0.98
12:13:45	15.2	186.0	242.0	37.2	279.2	0.98
12:13:55	15.2	188.0	255.0	37.6	292.6	0.98
12:14:05	15.2	188.0	254.0	37.5	291.5	0.98
12:14:15	15.2	189.0	259.0	37.8	296.8	0.98
12:14:25	15.2	190.0	260.0	37.8	297.8	0.98
12:14:35	15.2	189.0	265.0	38.2	303.2	0.98
12:14:45	16.2	188.0	266.0	38.3	304.3	0.98
12:14:55	15.2	189.0	267.0	38.4	305.4	0.98
12:15:05	15.2	191.0	266.0	38.2	304.2	0.98
12:15:15	15.2	191.0	264.0	38.2	302.2	0.98
12:15:25	15.2	190.0	265.0	38.2	303.2	0.98
12:15:35	15.2	188.0	271.0	38.7	309.7	0.98
12:15:45	15.1	188.0	277.0	38.9	315.9	0.98
12:15:55	15.3	187.0	271.0	38.5	309.5	0.98
12:16:05	15.1	188.0	271.0	38.4	309.4	0.98
12:16:15	15.2	188.0	270.0	38.5	308.5	0.98
12:16:25	15.1	189.0	272.0	38.4	310.4	0.98

12:16:35	15.2	190.0	271.0	38.3	309.3	0.98
12:16:45	15.2	190.0	270.0	38.3	308.3	0.98
12:16:55	15.2	190.0	272.0	38.5	310.5	0.98
12:17:05	15.1	189.0	274.0	38.8	312.8	0.98
12:17:15	15.1	187.0	278.0	39.0	317.0	0.98
12:17:25	15.1	186.0	276.0	38.8	314.8	0.98
12:17:35	15.2	186.0	272.0	38.7	310.7	0.98
12:17:45	15.2	188.0	270.0	38.5	308.5	0.98
12:17:55	15.2	189.0	270.0	38.4	308.4	0.98
12:18:05	15.2	188.0	269.0	38.3	307.3	0.98
12:18:15	15.2	190.0	268.0	38.4	306.4	0.98
12:18:25	15.2	191.0	267.0	38.3	305.3	0.98
12:18:35	15.2	190.0	266.0	38.2	304.2	0.98
12:18:45	15.2	189.0	264.0	38.2	302.2	0.98
12:18:55	15.1	189.0	269.0	38.4	307.4	0.98
12:19:05	15.2	191.0	271.0	38.7	309.7	0.98
12:19:15	15.1	192.0	271.0	38.5	309.5	0.98
12:19:25	15.2	192.0	268.0	38.4	306.4	0.98
12:19:35	15.2	190.0	267.0	38.3	305.3	0.98
12:19:45	15.2	190.0	267.0	38.2	305.2	0.98
12:19:55	15.2	190.0	265.0	38.0	303.0	0.98

CO/NO Post

Date / time	% O_2	ppm CO	ppm NO	ppm NO_2	ppm NOx	l/min Pump
12:40:30	20.9	0.0	0.0	2.1	2.1	0.00
12:40:40	20.9	0.0	0.0	2.1	2.1	0.98
12:40:50	20.9	0.0	0.0	2.0	2.0	0.98
12:41:00	7.2	11.0	0.0	517.6	517.6	0.97
12:41:10	0.8	661.0	428.0	167.3	595.3	0.98
12:41:20	0.3	1123.0	651.0	47.7	698.7	0.98
12:41:30	0.2	1236.0	715.0	21.6	736.6	0.98
12:41:40	0.2	1264.0	746.0	14.4	760.4	0.98
12:41:50	0.1	1273.0	758.0	11.6	769.6	0.98
12:42:00	0.1	1278.0	765.0	10.2	775.2	0.98
12:42:10	0.1	1280.0	769.0	9.2	778.2	0.98
12:42:20	0.1	1282.0	772.0	8.6	780.6	0.98
12:42:30	0.1	1283.0	773.0	8.1	781.1	0.98
12:42:40	0.1	1284.0	775.0	7.6	782.6	0.98
12:42:50	0.0	1285.0	776.0	7.2	783.2	0.98
12:43:00	0.1	1286.0	777.0	7.0	784.0	0.98
12:43:10	0.0	1286.0	778.0	6.7	784.7	0.98
12:43:20	0.0	1287.0	779.0	6.5	785.5	0.98
12:43:30	0.0	1287.0	780.0	6.2	786.2	0.98
12:43:40	0.0	1288.0	780.0	6.1	786.1	0.98
12:43:50	0.0	1288.0	781.0	6.0	787.0	0.98
12:44:00	0.0	1288.0	781.0	5.8	786.8	0.98
12:44:10	0.0	1289.0	782.0	5.7	787.7	0.98
12:44:20	0.0	1289.0	782.0	5.5	787.5	0.98
12:44:30	0.0	1289.0	783.0	5.5	788.5	0.98
12:44:40	0.0	1290.0	783.0	5.3	788.3	0.98
12:44:50	0.0	1290.0	784.0	5.3	789.3	0.98
12:45:00	0.0	1292.0	785.0	5.2	790.2	0.98
12:45:10	0.0	1291.0	784.0	5.2	789.2	0.98
12:45:20	0.0	1290.0	784.0	5.1	789.1	0.98
12:45:30	0.0	1290.0	784.0	5.0	789.0	0.98
12:45:40	15.3	1276.0	384.0	3.0	387.0	0.98
12:45:50	19.2	673.0	133.0	2.0	135.0	0.98
12:46:00	20.3	165.0	60.0	1.3	61.3	0.98
12:46:10	20.6	55.0	34.0	0.8	34.8	0.98
12:46:20	20.8	28.0	23.0	0.6	23.6	0.98
12:46:30	20.8	18.0	16.0	0.4	16.4	0.98

NO2 Post

Date / time	% O_2	ppm CO	ppm NO	ppm NO_2	ppm NOx	l/min Pump
12:58:07	20.9	0.0	0.0	0.6	0.6	0.00
12:58:17	20.9	0.0	0.0	1.3	1.3	0.98
12:58:27	20.9	0.0	0.0	1.1	1.1	0.98
12:58:37	6.8	4.0	22.0	79.2	101.2	0.98
12:58:47	0.8	62.0	0.0	93.1	93.1	0.99
12:58:57	0.4	21.0	0.0	97.8	97.8	0.98
12:59:07	0.1	3.0	0.0	99.3	99.3	0.98
12:59:17	0.1	0.0	0.0	99.8	99.8	0.98
12:59:27	0.1	0.0	0.0	100.0	100.0	0.98
12:59:37	0.1	0.0	0.0	100.1	100.1	0.98
12:59:47	0.1	0.0	0.0	100.3	100.3	0.98
12:59:57	0.1	0.0	0.0	100.3	100.3	0.98
13:00:07	0.1	0.0	0.0	100.4	100.4	0.98
13:00:17	0.1	0.0	0.0	100.5	100.5	0.98
13:00:27	0.1	0.0	0.0	100.4	100.4	0.98
13:00:37	0.1	0.0	0.0	100.5	100.5	0.98
13:00:47	0.1	0.0	0.0	100.5	100.5	0.98
13:00:57	0.1	0.0	0.0	100.6	100.6	0.98
13:01:07	0.1	0.0	0.0	100.6	100.6	0.98
13:01:17	0.1	0.0	0.0	100.6	100.6	0.98
13:01:27	0.1	0.0	0.0	100.6	100.6	0.98
13:01:37	0.1	0.0	0.0	100.7	100.7	0.98
13:01:47	0.1	0.0	0.0	100.7	100.7	0.99
13:01:57	0.1	0.0	0.0	100.7	100.7	0.98
13:02:07	0.1	0.0	0.0	100.8	100.8	0.98
13:02:17	0.1	0.0	0.0	100.7	100.7	0.98
13:02:27	0.1	0.0	0.0	100.8	100.8	0.98
13:02:37	0.1	0.0	0.0	100.8	100.8	0.98
13:02:47	0.1	0.0	0.0	100.8	100.8	0.98
13:02:57	0.1	0.0	0.0	100.8	100.8	0.98
13:03:07	0.1	0.0	0.0	100.8	100.8	0.98
13:03:17	15.1	0.0	2.0	27.9	29.9	0.98
13:03:27	19.1	0.0	2.0	9.6	11.6	0.98
13:03:37	20.3	0.0	1.0	3.2	4.2	0.98
13:03:47	20.7	0.0	0.0	1.7	1.7	0.98
13:03:57	20.8	0.0	0.0	1.1	1.1	0.98
13:04:07	20.8	0.0	0.0	0.8	0.8	0.98

ODEQ Quarterly Compliance
Performance Test Report

Test Type: Quarterly
Test Date: 02-10-2022

Source:
Cooper Quad 12Q155HC
Lean Burn 4 Cycle Engine

Unit Number: U-2302
Serial Number: 48765
Engine Hours: 231969

Permit: #2018-0674-TVR4

Location:
Cashion Compressor Station
Kingfisher County, Oklahoma

Prepared on Behalf of:
Panhandle Eastern Pipeline

	CO	NOx
	State	State
Results ppmvd	216.110	311.849
Results lb/hr	14.088	33.392
Permit lb/hr	22.820	89.300
Results g/hp-hr	1.701	4.032
Results TPY	61.703	146.256
Permit TPY	99.960	391.150
PASS ALL	**Pass**	**Pass**

Test Started: 7:55 Test Completed: 9:01

303 W. 3rd St (580) 225-0403 Elk City, OK 73644

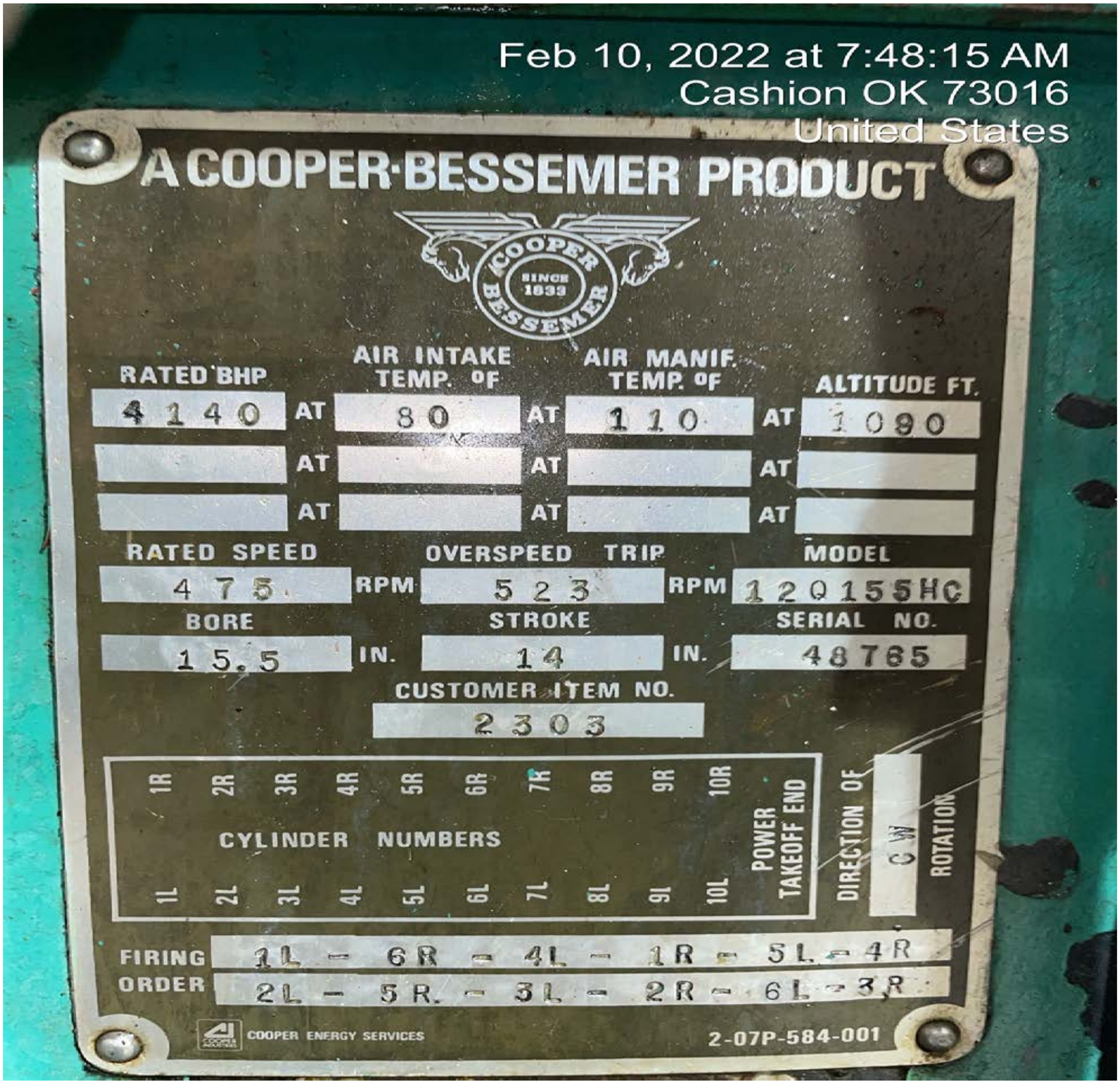
4.0 Test Summary

Unit U-2302 with a serial number of 48765 which is a Cooper Quad 12Q155HC engine located at Cashion Compressor Station and operated by Panhandle Eastern Pipeline was tested for emissions of: (Oxides of Nitrogen) (Carbon Monoxide) . The test was conducted on 02-10-2022 by Jeremiah Giles with Great Plains Analytical Services, Inc. All quality assurance and quality control tests were within acceptable tolerances.

The engine is a natural gas fired Lean Burn (4 Cycle) engine rated at 3940 brake horse power (BHP) at 450 RPM. The engine was operating at 3757.00 BHP and 450 RPM which is 95.36% of maximum engine load during the test.

This test will satisfy the testing requirements for ODEQ Quarterly Compliance. Unit U-2302 is authorized to operate under permit #2018-0674-TVR4.

Site Verification Photos



4.0 Test Summary

Test Summary

Engine/Compressor Specs					
Location	Cashion Compressor Station		*Unit ID*	U-2302	
Make	Cooper Quad		*Site Elevation ft.*	1220	
Model	12Q155HC		*Atmospheric Pressure psi.*	14.04	
Serial number	48765				
mfg. rated hp	3940		*Catalyst*	No	
mfg. rated rpm	450		*Date of Manufacture*		

Engine/Compressor Operation	Run 1	Run 2	Run 3	3 Run Average
Test Horsepower	3757	3757	3757	3757
Test RPM	450	450	450	450
Percent Load %	95.36%	95.36%	95.36%	95.36%
Intake Manifold Pressure (hg)	16.20	16.20	16.20	16.20
Intake Manifold Temperature (F)	90.00	90.00	90.00	90.00
Ambient Conditions				
Ambient Temperature Dry (F)	44.00	44.00	44.00	44.00
Exhaust Flow Data				
Q Stack (dscfh)	897097.19	897097.19	897097.19	897097.19
Q Stack (dscm/hr)	25402.72	25402.72	25402.72	25402.72
Fuel Consumption (Btu/hp-hr)	6904.00	6904.00	6904.00	6904.00
Fuel Flow (dscfh)	119266.82	114188.80	114143.16	115866.26
Fuel (Btu/scf)	1022.00	1022.00	1022.00	1022.00
O2 F factor	8710.00	8710.00	8710.00	8710.00
Results				
Oxygen %	15.64%	15.40%	15.40%	15.48%

Permitted Standards				***Results***				
		Test Start/Completed Times:		***7:55***	***8:17***	***8:39***	***9:01***	***2/10/22***
		State		**Run 1**	**Run 2**	**Run 3**	**3 Run Average**	**Pass Permits**
CO (g/hp-hr)				1.663	1.719	1.721	1.701	
CO (lbs/hr)		22.820		13.774	14.237	14.252	14.088	Pass
CO (TPY)		99.960		60.329	62.359	62.422	61.703	Pass
CO (ppmvd) @15% O2				236.852	234.398	234.541	235.264	
CO (ppbvd) @15% O2				236852.412	234398.425	234540.532	235263.790	
CO (ppmvd)				211.297	218.407	218.626	216.110	
			CO (mol wt)	28.01				
NOx (g/hp-hr)				3.807	4.131	4.157	4.032	
NOx (lbs/hr)		89.300		31.530	34.219	34.427	33.392	Pass
NOx (TPY)		391.150		138.100	149.877	150.791	146.256	Pass
NOx (ppmvd) @15% O2				330.072	342.969	344.923	339.321	
NOx (ppbvd) @15% O2				330072.092	342969.417	344922.533	339321.347	
NOx (ppmvd)				294.458	319.570	321.519	311.849	
			NOx (mol wt)	46.01				

5.0 Calibrations/System Bias & Drift Check

Span Gas

CO	1302.00
NO	790.10
NO2	100.50
O2	20.90%

Analyzer

Make:	Testo
Model:	350
Serial Number:	7855

Longest Response Time
0:01:40

Direct Calibrations

Start Time:	6:37				
Bottle Concentration			Calibration Response	Absolute Difference	<5% of Span
Zero	CO	0.00	0.00	0.00	0.00%
	NO	0.00	0.00	0.00	0.00%
	NO2	0.00	1.37	1.37	1.36%
	O2	0.00%	0.00%	0.00	0.00%
CO	Mid Level	1302.00	1295.13	6.88	0.53%
NO	Mid Level	790.10	785.13	4.98	0.63%
NO2					
	High Level	100.50	101.30	0.80	0.80%
O2					
	High Level	20.90%	20.90%	0.00%	0.00%

Post

Start Time:	12:40						
Bottle Concentration			System Response	Absolute Difference	<5% of Span	<5% Drift	
Zero	CO	0.00	0.00	0.00	0.00%		
	NO	0.00	0.00	0.00	0.00%		
	NO2	0.00	2.07	2.07	2.06%		
	O2	0.00%	0.03%	0.00	0.14%		
CO	Upscale	1302.00	1289.38	12.63	0.97%	0.45%	
NO	Upscale	790.10	782.63	7.48	0.95%	0.32%	
NO2	Upscale	100.50	100.73	0.22	0.22%	0.57%	
O2	Upscale	20.90%	20.90%	0.00	0.00%	0.00%	

6.0 Engine Parameter Data Sheet

Company	Panhandle Eastern Pipeline
Facility	Cashion Compressor Station
Date	2/10/2022
Site Elevation (ft)	1,220
Unit ID	U-2302
Make	Cooper Quad
Model	12Q155HC
Serial Number	48765
Technician	Jeremiah Giles

	Run 1	**Run 2**	**Run 3**	**Completed**
Run Start Times	7:55	8:17	8:39	9:01
Engine Hours	231969	231969	231969	231969

	Engine Parameter Data			
	Run 1	Run 2	Run 3	Average
Engine Speed (RPM)	450	450	450	450
Intake Manifold Pressure (psi)	16.2	16.2	16.2	16.2
Intake Manifold Temp °F	90.0	90.0	90.0	90.0
Engine Load (BHP)	3757.00	3757.00	3757.00	3757.00
Ambient Temp °F	44	44	44	44
Humidity %	58	58	58	58
Dew Point °F	30	30	30	30
AFR Manufacturer/Type	Altronic	Altronic	Altronic	Altronic
AFR Setting (Target Left Bank)	3.0	3.0	3.0	3.0
Suction Pressure (psi)	245.0	245.0	245.0	245.0
Discharge Pressure (psi)	841.0	841.0	841.0	841.0
Catalyst (Yes or No)	No	No	No	No

<--- Not available on this unit

11.0 Signature Page

R0

Job/File Name: Panhandle Eastern Pipeline; Cashion Compressor Station; U-2302; ODEQ Quarterly Compliance;

We certify that based on review of test data, knowledge of those individuals directly responsible for conducting this test, we believe the submitted information to be accurate and complete.

Company:	G.A.S. Inc.	Date:	2/16/22
Print Name:	Jeremiah Giles		
Title:	Director of PEA Testing		
Signature:	Jeremiah Giles		
Phone Number:	580-515-2920		

Company:	G.A.S. Inc.	Date:	2/16/22
Print Name:	Jeremiah Giles		
Title:	Emissions Specialist		

Company:			
Print Name:		Date:	
Signature:			
Title:			
Phone Number:			

Appendices

(PEA) Special CO/NO High

Airgas

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

Part Number:	E03NI99E15A7XK1	Reference Number:	54-401126470-1
Cylinder Number:	CC1007	Cylinder Volume:	144.4 Cubic Feet
Laboratory:	124 - Chicago (SAP) - IL	Cylinder Pressure:	2015 PSIG
PGVP Number:	B12018	Valve Outlet:	660
Gas Code:	CO,NO,NOX,BALN	Certification Date:	Mar 01, 2018

Expiration Date: Mar 01, 2026

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a mole/mole basis unless otherwise noted.
Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
NOX	3500 PPM	3533 PPM	G1	+/- 1% NIST Traceable	02/19/2018, 03/01/2018
NITRIC OXIDE	3500 PPM	3526 PPM	G1	+/- 1% NIST Traceable	02/19/2018, 03/01/2018
CARBON MONOXIDE	4500 PPM	4517 PPM	G1	+/- 1.0% NIST Traceable	02/22/2018
NITROGEN	Balance			-	

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
GMIS	124264848107	SG9148003BAL	5454 PPM NITRIC OXIDE/NITROGEN	+/- 0.7%	Aug 14, 2023
NTRM	14060160	CC437085	990.9 PPM CARBON MONOXIDE/NITROGEN	+/- 0.6%	Nov 18, 2019
GMIS	1114201605	CC506716	4.995 PPM NITROGEN DIOXIDE/NITROGEN	+/- 2.0%	Nov 14, 2019
PRM	12367	APEX1099237	10.0 PPM NITROGEN DIOXIDE/AIR	+/- 1.5%	Jun 02, 2017
NTRM	13060213	CC401957	4950 PPM CARBON MONOXIDE/NITROGEN	+/- 0.4%	Feb 15, 2019

The SRM, PRM or RGM noted above is only in reference to the GMIS used in the assay and not part of the analysis.

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
CO-2 SIEMENS ULTRAMAT 6E N1J5700	NDIR	Jan 21, 2018
Nicolet 6700 AHR0801332	FTIR	Feb 21, 2018
Nicolet 6700 AHR0801332	FTIR	Feb 21, 2018

Triad Data Available Upon Request

Signature on file
Approved for Release

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(PEA) Mid CO/NO

Airgas

CERTIFICATE OF ANALYSIS

Grade of Product: EPA Protocol

Part Number:	E03NI99E15AC2T0	Reference Number:	54-401845408-1
Cylinder Number:	CC285225	Cylinder Volume:	144.4 CF
Laboratory:	124 - Chicago (SAP) - IL	Cylinder Pressure:	2015 PSIG
PGVP Number:	B12020	Valve Outlet:	660
Gas Code:	CO,NO,NOX,BALN	Certification Date:	Jul 14, 2020

Expiration Date: Jul 14, 2028

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a mole/mole basis unless otherwise noted.

Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
NOX	800.0 PPM	790.1 PPM	G1	+/- 0.6% NIST Traceable	07/07/2020, 07/14/2020
NITRIC OXIDE	800.0 PPM	790.1 PPM	G1	+/- 0.6% NIST Traceable	07/07/2020, 07/14/2020
CARBON MONOXIDE	1300 PPM	1302 PPM	G1	+/- 0.6% NIST Traceable	07/07/2020
NITROGEN	Balance			-	

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	15060242	CC449815	997.2 PPM NITRIC OXIDE/NITROGEN	+/- 0.5%	Nov 07, 2020
PRM	12386	D685025	9.91 PPM NITROGEN DIOXIDE/AIR	+/- 2.0%	Feb 20, 2020
GMIS	7302017104	CC506604	4.426 PPM NITROGEN DIOXIDE/NITROGEN	+/- 2.1%	Jul 03, 2022
NTRM	08012238	KAL004643	2466 PPM CARBON MONOXIDE/NITROGEN	+/- 0.5%	May 24, 2024

The SRM, PRM or RGM noted above is only in reference to the GMIS used in the assay and not part of the analysis.

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
CO-2 SIEMENS ULTRAMAT 6E N1J5700	NDIR	Jun 10, 2020
Nicolet 6700 AMP0900100	FTIR	Jun 15, 2020
Nicolet 6700 AMP0900100	FTIR	Jun 15, 2020

Triad Data Available Upon Request

PERMANENT NOTES:GREAT PLAINS ANALYTICAL

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(PEA) CO/NO Low

Airgas

CERTIFICATE OF ANALYSIS

Grade of Product: EPA Protocol

Part Number:	E03NI99E15AC2S8	Reference Number:	54-401721512-1
Cylinder Number:	CC472329	Cylinder Volume:	144.4 CF
Laboratory:	124 - Chicago (SAP) - IL	Cylinder Pressure:	2015 PSIG
PGVP Number:	B12020	Valve Outlet:	660
Gas Code:	CO,NO,NOX,BALN	Certification Date:	Feb 17, 2020

Expiration Date: Feb 17, 2028

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a mole/mole basis unless otherwise noted.
Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
NOX	150.0 PPM	148.9 PPM	G1	+/- 1.4% NIST Traceable	02/10/2020, 02/17/2020
NITRIC OXIDE	150.0 PPM	148.8 PPM	G1	+/- 1.4% NIST Traceable	02/10/2020, 02/17/2020
CARBON MONOXIDE	220.0 PPM	222.9 PPM	G1	+/- 1% NIST Traceable	02/10/2020
NITROGEN	Balance			-	

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
NTRM	15060350	CC448769	241.0 PPM NITRIC OXIDE/NITROGEN	+/- 0.5%	Mar 30, 2021
PRM	12386	D685025	9.91 PPM NITROGEN DIOXIDE/AIR	+/- 2.0%	Feb 20, 2020
NTRM	18060128	KAL004272	249.9 PPM NITRIC OXIDE/NITROGEN	+/- 0.4	Nov 08, 2023
GMIS	7302017104	CC506604	4.426 PPM NITROGEN DIOXIDE/NITROGEN	+/- 2.1%	Jul 03, 2022
NTRM	13010131	ND48544	495.4 PPM CARBON MONOXIDE/NITROGEN	+/- 0.6%	Jul 03, 2024

The SRM, PRM or RGM noted above is only in reference to the GMIS used in the assay and not part of the analysis.

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
Nicolet 6700 AMP0900100	FTIR	Feb 03, 2020
Nicolet 6700 AMP0900100	FTIR	Feb 03, 2020
Nicolet 6700 AMP0900100	FTIR	Feb 03, 2020

Triad Data Available Upon Request

PERMANENT NOTES: GREAT PLAINS ANALYTICAL

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(PEA) NO2 High

Airgas
an Air Liquide company

Airgas Specialty Gases
Airgas USA, LLC
12722 S. Wentworth Ave.
Chicago, IL 60628
Airgas.com

CERTIFICATE OF ANALYSIS
Grade of Product: EPA Protocol

Part Number:	E02NI99E15W51V7	Reference Number:	54-402246614-1
Cylinder Number:	CC503115	Cylinder Volume:	144.0 CF
Laboratory:	124 - Chicago (SAP) - IL	Cylinder Pressure:	2016 PSIG
PGVP Number:	B12021	Valve Outlet:	660
Gas Code:	NO2,BALN	Certification Date:	Oct 20, 2021

Expiration Date: Oct 20, 2024

Certification performed in accordance with "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards (May 2012)" document EPA 600/R-12/531, using the assay procedures listed. Analytical Methodology does not require correction for analytical interference. This cylinder has a total analytical uncertainty as stated below with a confidence level of 95%. There are no significant impurities which affect the use of this calibration mixture. All concentrations are on a mole/mole basis unless otherwise noted.
Do Not Use This Cylinder below 100 psig, i.e. 0.7 megapascals.

ANALYTICAL RESULTS

Component	Requested Concentration	Actual Concentration	Protocol Method	Total Relative Uncertainty	Assay Dates
NITROGEN DIOXIDE	100.0 PPM	100.5 PPM	G1	+/- 2% NIST Traceable	10/12/2021, 10/20/2021
NITROGEN	Balance				

CALIBRATION STANDARDS

Type	Lot ID	Cylinder No	Concentration	Uncertainty	Expiration Date
GMIS	1534002020601	EB0130023	101 PPM NITROGEN DIOXIDE/NITROGEN	+/- 1.4%	Apr 30, 2024
PRM	12397	D887665	74.2 PPM NITROGEN DIOXIDE/AIR	+/- 1.3%	Feb 02, 2022

The SRM, PRM or RGM noted above is only in reference to the GMIS used in the assay and not part of the analysis.

ANALYTICAL EQUIPMENT

Instrument/Make/Model	Analytical Principle	Last Multipoint Calibration
MKS FTIR NO2 017707558	FTIR	Oct 14, 2021

Triad Data Available Upon Request

PERMANENT NOTES: OXYGEN ADDED TO MAINTAIN STABILITY

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7.0 Raw Data

CO/NO Pre

Date / time	% O_2	ppm CO	ppm NO	ppm NO_2	ppm NOx	l/min Pump
6:37:46	20.9	0.0	0.0	1.7	1.7	0.82
6:37:56	20.9	0.0	0.0	1.5	1.5	0.98
6:38:06	20.9	0.0	0.0	0.9	0.9	0.98
6:38:16	15.8	333.0	451.0	0.5	451.5	0.98
6:38:26	4.4	1104.0	577.0	0.2	577.2	0.98
6:38:36	2.7	1188.0	687.0	0.0	687.0	0.98
6:38:46	1.5	1243.0	699.0	0.0	699.0	0.98
6:38:56	0.9	1267.0	723.0	0.0	723.0	0.98
6:39:06	0.2	1278.0	745.0	0.0	745.0	0.98
6:39:16	0.1	1282.0	772.0	0.0	772.0	0.98
6:39:26	0.0	1288.0	778.0	0.0	778.0	0.99
6:39:36	0.0	1290.0	780.0	0.0	780.0	0.98
6:39:46	0.0	1292.0	781.0	0.0	781.0	0.98
6:39:56	0.0	1293.0	782.0	0.0	782.0	0.98
6:40:06	0.0	1293.0	783.0	0.0	783.0	0.98
6:40:16	0.0	1293.0	783.0	0.0	783.0	0.98
6:40:26	0.0	1293.0	783.0	0.0	783.0	0.98
6:40:36	0.0	1294.0	784.0	0.0	784.0	0.98
6:40:46	0.0	1294.0	784.0	0.0	784.0	0.98
6:40:56	0.0	1294.0	784.0	0.0	784.0	0.98
6:41:06	0.0	1294.0	784.0	0.0	784.0	0.98
6:41:16	0.0	1295.0	785.0	0.0	785.0	0.98
6:41:26	0.0	1295.0	785.0	0.0	785.0	0.98
6:41:36	0.0	1295.0	785.0	0.0	785.0	0.98
6:41:46	0.0	1295.0	785.0	0.0	785.0	0.99
6:41:56	0.0	1295.0	785.0	0.0	785.0	0.98
6:42:06	0.0	1296.0	786.0	0.0	786.0	0.98
6:42:16	0.0	1296.0	786.0	0.0	786.0	0.98
6:42:26	0.0	1296.0	786.0	0.0	786.0	0.98
6:42:36	0.0	1296.0	786.0	0.0	786.0	0.98
6:42:46	0.0	1297.0	786.0	0.0	786.0	0.98
6:42:56	12.9	1119.0	787.0	0.0	787.0	0.99
6:43:06	18.9	667.0	443.0	0.0	443.0	0.99
6:43:16	20.2	421.0	211.0	0.0	211.0	0.98
6:43:26	20.9	213.0	96.0	0.0	96.0	0.98
6:43:36	21.0	67.0	53.0	0.0	53.0	0.98
6:43:46	21.1	15.0	21.0	0.0	21.0	0.98

NO2 Pre

Date / time	% O_2	ppm CO	ppm NO	ppm NO_2	ppm NOx	l/min Pump
7:00:51	20.9	0.0	0.0	1.6	1.6	1.43
7:01:01	20.9	0.0	0.0	1.2	1.2	0.98
7:01:11	20.9	0.0	0.0	1.0	1.0	0.98
7:01:21	10.9	0.0	0.0	66.7	66.7	0.98
7:01:31	3.4	0.0	0.0	93.2	93.2	0.98
7:01:41	2.8	0.0	0.0	98.6	98.6	0.98
7:01:51	1.0	0.0	0.0	100.2	100.2	0.98
7:02:01	0.7	0.0	0.0	100.9	100.9	0.98
7:02:11	0.1	0.0	0.0	101.0	101.0	0.98
7:02:21	0.1	0.0	0.0	101.1	101.1	0.98
7:02:31	0.1	0.0	0.0	101.3	101.3	0.98
7:02:41	0.1	0.0	0.0	101.7	101.7	0.98
7:02:51	0.1	0.0	0.0	101.2	101.2	0.98
7:03:01	0.1	0.0	0.0	101.2	101.2	0.98
7:03:11	0.1	0.0	0.0	101.2	101.2	0.98
7:03:21	0.1	0.0	0.0	101.2	101.2	0.98
7:03:31	0.1	0.0	0.0	101.2	101.2	0.99
7:03:41	0.1	0.0	0.0	101.2	101.2	0.98
7:03:51	0.1	0.0	0.0	101.3	101.3	0.98
7:04:01	0.1	0.0	0.0	101.3	101.3	0.98
7:04:11	0.1	0.0	0.0	101.3	101.3	0.98
7:04:21	0.1	0.0	0.0	101.3	101.3	0.98
7:04:31	0.1	0.0	0.0	101.3	101.3	0.98
7:04:41	0.1	0.0	0.0	101.3	101.3	0.98
7:04:51	0.1	0.0	0.0	101.3	101.3	0.98
7:05:01	0.1	0.0	0.0	101.3	101.3	0.98
7:05:11	0.1	0.0	0.0	101.3	101.3	0.98
7:05:21	0.1	0.0	0.0	101.3	101.3	0.98
7:05:31	0.1	0.0	0.0	101.4	101.4	0.98
7:05:41	0.1	0.0	0.0	101.4	101.4	0.98
7:05:51	0.1	0.0	0.0	101.4	101.4	0.98
7:06:01	19.9	0.0	0.0	28.8	28.8	0.98
7:06:11	20.5	0.0	0.0	6.7	6.7	0.98
7:06:21	20.7	0.0	0.0	1.9	1.9	0.98
7:06:31	20.7	0.0	0.0	0.6	0.6	0.98
7:06:41	20.8	0.0	0.0	0.2	0.2	0.98
7:06:51	20.9	0.0	0.0	0.0	0.0	0.98

Source Test

Date / time	% O_2	ppm CO	ppm NO	ppm NO_2	ppm NOx	l/min Pump
7:55:19	20.9	0.0	2.0	0.1	2.1	0.06
7:55:29	20.9	0.0	2.0	0.0	2.0	0.98
7:55:39	20.9	0.0	1.0	0.0	1.0	0.97
7:55:49	16.7	44.0	168.0	50.2	218.2	0.96
7:55:59	16.3	143.0	205.0	48.8	253.8	0.97
7:56:09	16.1	167.0	226.0	42.2	268.2	0.97
7:56:19	16.0	182.0	236.0	30.2	266.2	0.97
7:56:29	16.0	189.0	261.0	19.8	280.8	0.97
7:56:39	16.0	186.0	276.0	17.5	293.5	0.97
7:56:49	16.1	184.0	274.0	16.9	290.9	0.97
7:56:59	16.1	183.0	279.0	17.3	296.3	0.97
7:57:09	16.1	184.0	285.0	17.5	302.5	0.97
7:57:19	16.0	184.0	287.0	17.6	304.6	0.97
7:57:29	16.0	184.0	287.0	17.8	304.8	0.97
7:57:39	16.0	185.0	290.0	18.1	308.1	0.97
7:57:49	16.0	184.0	290.0	18.2	308.2	0.97
7:57:59	16.0	185.0	286.0	18.0	304.0	0.97
7:58:09	16.0	186.0	282.0	17.9	299.9	0.97
7:58:19	16.0	185.0	287.0	18.6	305.6	0.97
7:58:29	16.0	185.0	287.0	18.8	305.8	0.97
7:58:39	16.0	186.0	292.0	19.5	311.5	0.97
7:58:49	15.9	188.0	290.0	19.4	309.4	0.97
7:58:59	16.0	189.0	283.0	19.1	302.1	0.97
7:59:09	15.9	188.0	284.0	19.6	303.6	0.97
7:59:19	15.9	189.0	289.0	20.2	309.2	0.97
7:59:29	15.9	191.0	292.0	20.7	312.7	0.97
7:59:39	15.9	190.0	291.0	21.1	312.1	0.96
7:59:49	15.9	192.0	293.0	21.2	314.2	0.97
7:59:59	15.8	193.0	287.0	21.1	308.1	0.97
8:00:09	15.9	194.0	279.0	20.7	299.7	0.97
8:00:19	15.8	195.0	276.0	20.8	296.8	0.98
8:00:29	15.9	196.0	274.0	21.1	295.1	0.98
8:00:39	15.9	197.0	270.0	21.0	291.0	0.98
8:00:49	15.8	197.0	263.0	21.1	284.1	0.98
8:00:59	15.8	198.0	263.0	21.1	284.1	0.98
8:01:09	15.9	200.0	255.0	20.9	275.9	0.98
8:01:19	15.9	203.0	252.0	21.3	273.3	0.98
8:01:29	15.8	206.0	251.0	21.3	272.3	0.98
8:01:39	15.9	206.0	251.0	22.0	273.0	0.98
8:01:49	15.8	210.0	253.0	22.1	275.1	0.98
8:01:59	15.8	209.0	253.0	22.1	275.1	0.98
8:02:09	15.8	206.0	250.0	22.1	272.1	0.98
8:02:19	15.8	205.0	252.0	22.2	274.2	0.98
8:02:29	15.8	209.0	245.0	22.2	267.2	0.98
8:02:39	15.8	211.0	244.0	22.4	266.4	0.98
8:02:49	15.8	211.0	247.0	22.8	269.8	0.98

8:02:59	15.7	210.0	248.0	22.9	270.9	0.98
8:03:09	15.8	208.0	244.0	22.7	266.7	0.98
8:03:19	15.8	210.0	243.0	22.9	265.9	0.98
8:03:29	15.7	212.0	245.0	23.1	268.1	0.98
8:03:39	15.7	213.0	239.0	22.9	261.9	0.98
8:03:49	15.7	215.0	236.0	22.7	258.7	0.98
8:03:59	15.7	214.0	241.0	23.2	264.2	0.98
8:04:09	15.7	214.0	241.0	23.6	264.6	0.98
8:04:19	15.7	213.0	252.0	24.3	276.3	0.98
8:04:29	15.7	209.0	252.0	24.3	276.3	0.98
8:04:39	15.7	212.0	251.0	24.2	275.2	0.98
8:04:49	15.7	213.0	247.0	24.3	271.3	0.98
8:04:59	15.7	213.0	253.0	24.8	277.8	0.98
8:05:09	15.7	213.0	253.0	24.8	277.8	0.98
8:05:19	15.7	215.0	250.0	24.7	274.7	0.98
8:05:29	15.6	219.0	245.0	24.5	269.5	0.98
8:05:39	15.8	218.0	242.0	24.4	266.4	0.98
8:05:49	15.7	217.0	242.0	24.4	266.4	0.98
8:05:59	15.7	214.0	252.0	25.2	277.2	0.98
8:06:09	15.6	211.0	262.0	26.2	288.2	0.98
8:06:19	15.6	213.0	260.0	25.8	285.8	0.98
8:06:29	15.6	214.0	260.0	26.1	286.1	0.98
8:06:39	15.6	214.0	265.0	26.2	291.2	0.98
8:06:49	15.6	214.0	259.0	26.0	285.0	0.98
8:06:59	15.6	217.0	266.0	26.7	292.7	0.98
8:07:09	15.6	218.0	262.0	26.4	288.4	0.98
8:07:19	15.6	217.0	257.0	26.2	283.2	0.98
8:07:29	15.5	219.0	259.0	26.3	285.3	0.98
8:07:39	15.6	219.0	255.0	26.0	281.0	0.98
8:07:49	15.5	215.0	250.0	25.8	275.8	0.98
8:07:59	15.6	218.0	252.0	26.2	278.2	0.98
8:08:09	15.6	222.0	256.0	26.7	282.7	0.98
8:08:19	15.6	223.0	265.0	27.4	292.4	0.98
8:08:29	15.5	220.0	267.0	27.4	294.4	0.98
8:08:39	15.6	218.0	268.0	27.4	295.4	0.98
8:08:49	15.5	216.0	275.0	28.0	303.0	0.98
8:08:59	15.5	216.0	280.0	28.3	308.3	0.98
8:09:09	15.5	216.0	280.0	28.2	308.2	0.98
8:09:19	15.5	216.0	278.0	28.4	306.4	0.98
8:09:29	15.5	214.0	277.0	28.1	305.1	0.98
8:09:39	15.5	215.0	270.0	27.8	297.8	0.98
8:09:49	15.6	217.0	269.0	27.8	296.8	0.98
8:09:59	15.5	214.0	271.0	27.9	298.9	0.98
8:10:09	15.5	213.0	273.0	28.2	301.2	0.98
8:10:19	15.5	216.0	279.0	28.9	307.9	0.98
8:10:29	15.5	217.0	286.0	29.4	315.4	0.98
8:10:39	15.5	215.0	292.0	30.1	322.1	0.98
8:10:49	15.5	213.0	292.0	29.5	321.5	0.98

8:10:59	15.5	214.0	285.0	29.1	314.1	0.98
8:11:09	15.5	213.0	283.0	29.3	312.3	0.98
8:11:19	15.5	216.0	282.0	29.2	311.2	0.98
8:11:29	15.5	219.0	290.0	30.0	320.0	0.98
8:11:39	15.5	217.0	291.0	29.9	320.9	0.98
8:11:49	15.5	214.0	292.0	30.5	322.5	0.98
8:11:59	15.5	214.0	300.0	31.0	331.0	0.98
8:12:09	15.4	213.0	303.0	31.2	334.2	0.98
8:12:19	15.5	213.0	298.0	30.6	328.6	0.98
8:12:29	15.5	213.0	293.0	30.3	323.3	0.98
8:12:39	15.5	213.0	288.0	29.8	317.8	0.98
8:12:49	15.5	212.0	281.0	29.7	310.7	0.98
8:12:59	15.5	214.0	288.0	30.8	318.8	0.98
8:13:09	15.5	216.0	297.0	31.1	328.1	0.98
8:13:19	15.4	212.0	300.0	31.5	331.5	0.98
8:13:29	15.4	213.0	302.0	31.6	333.6	0.98
8:13:39	15.4	213.0	303.0	31.4	334.4	0.98
8:13:49	15.4	212.0	294.0	30.8	324.8	0.98
8:13:59	15.4	214.0	290.0	30.7	320.7	0.98
8:14:09	15.5	216.0	291.0	31.0	322.0	0.98
8:14:19	15.5	217.0	294.0	31.4	325.4	0.98
8:14:29	19.6	212.0	157.0	8.7	165.7	0.98
8:14:39	20.8	100.0	57.0	2.2	59.2	0.98
8:14:49	21.0	27.0	31.0	0.7	31.7	0.98
8:14:59	21.0	10.0	21.0	0.2	21.2	0.98
8:15:09	21.0	5.0	16.0	0.1	16.1	0.98
8:15:19	20.9	3.0	13.0	0.0	13.0	0.98
8:15:29	21.0	3.0	11.0	0.0	11.0	0.98
8:15:39	21.0	2.0	10.0	0.0	10.0	0.98
8:15:49	21.0	2.0	9.0	0.0	9.0	0.98
8:15:59	21.0	1.0	8.0	0.0	8.0	0.98
8:16:09	21.0	1.0	8.0	0.0	8.0	0.98
8:16:19	21.0	1.0	7.0	0.0	7.0	0.98
8:16:29	21.0	1.0	7.0	0.0	7.0	0.98
8:16:39	21.0	1.0	6.0	0.0	6.0	0.99
8:16:49	21.0	1.0	6.0	0.0	6.0	0.98
8:16:59	21.0	1.0	6.0	0.0	6.0	0.98
8:17:09	21.0	1.0	6.0	0.0	6.0	0.98
8:17:19	21.0	1.0	5.0	0.0	5.0	0.98
8:17:29	16.8	3.0	114.0	59.4	173.4	0.97
8:17:39	15.7	112.0	185.0	78.4	263.4	0.98
8:17:49	15.6	183.0	211.0	60.3	271.3	0.98
8:17:59	15.5	201.0	230.0	48.9	278.9	0.98
8:18:09	15.4	210.0	274.0	37.0	311.0	0.98
8:18:19	15.5	214.0	295.0	35.5	330.5	0.98
8:18:29	15.5	209.0	300.0	35.2	335.2	0.98
8:18:39	15.5	208.0	300.0	35.1	335.1	0.98
8:18:49	15.5	207.0	309.0	36.1	345.1	0.98

8:18:59	15.5	206.0	318.0	36.9	354.9	0.98
8:19:09	15.5	206.0	316.0	36.5	352.5	0.98
8:19:19	15.5	205.0	318.0	36.5	354.5	0.98
8:19:29	15.4	205.0	321.0	36.4	357.4	0.98
8:19:39	15.5	204.0	318.0	36.0	354.0	0.98
8:19:49	15.4	204.0	312.0	35.1	347.1	0.98
8:19:59	15.6	204.0	310.0	35.2	345.2	0.98
8:20:09	15.5	205.0	306.0	34.7	340.7	0.98
8:20:19	15.5	207.0	311.0	35.0	346.0	0.98
8:20:29	15.5	205.0	315.0	35.6	350.6	0.98
8:20:39	15.5	206.0	316.0	35.3	351.3	0.98
8:20:49	15.5	208.0	305.0	34.4	339.4	0.98
8:20:59	15.5	209.0	298.0	33.5	331.5	0.98
8:21:09	15.5	210.0	295.0	33.4	328.4	0.98
8:21:19	15.5	208.0	298.0	33.7	331.7	0.98
8:21:29	15.4	207.0	311.0	35.1	346.1	0.98
8:21:39	15.4	207.0	309.0	34.5	343.5	0.98
8:21:49	15.5	206.0	296.0	33.0	329.0	0.98
8:21:59	15.6	209.0	286.0	32.6	318.6	0.98
8:22:09	15.5	209.0	287.0	32.8	319.8	0.98
8:22:19	15.5	211.0	288.0	32.9	320.9	0.98
8:22:29	15.5	214.0	290.0	33.1	323.1	0.98
8:22:39	15.6	214.0	284.0	32.4	316.4	0.98
8:22:49	15.6	216.0	276.0	31.8	307.8	0.98
8:22:59	15.5	215.0	279.0	32.1	311.1	0.98
8:23:09	15.5	213.0	279.0	32.1	311.1	0.98
8:23:19	15.5	213.0	279.0	32.1	311.1	0.98
8:23:29	15.5	213.0	280.0	32.1	312.1	0.98
8:23:39	15.5	214.0	279.0	32.2	311.2	0.98
8:23:49	15.5	215.0	281.0	32.3	313.3	0.98
8:23:59	15.4	218.0	278.0	32.0	310.0	0.98
8:24:09	15.5	218.0	275.0	31.7	306.7	0.98
8:24:19	15.5	220.0	263.0	30.7	293.7	0.98
8:24:29	15.5	223.0	260.0	30.6	290.6	0.98
8:24:39	15.5	223.0	262.0	31.0	293.0	0.98
8:24:49	15.5	221.0	268.0	31.6	299.6	0.98
8:24:59	15.4	219.0	265.0	31.2	296.2	0.98
8:25:09	15.5	218.0	272.0	31.6	303.6	0.98
8:25:19	15.4	218.0	267.0	31.2	298.2	0.98
8:25:29	15.5	219.0	265.0	30.9	295.9	0.98
8:25:39	15.4	222.0	263.0	30.8	293.8	0.98
8:25:49	15.4	224.0	267.0	31.2	298.2	0.98
8:25:59	15.4	224.0	275.0	31.6	306.6	0.98
8:26:09	15.4	222.0	278.0	31.7	309.7	0.98
8:26:19	15.4	218.0	282.0	32.1	314.1	0.98
8:26:29	15.5	218.0	281.0	32.2	313.2	0.98
8:26:39	15.4	220.0	282.0	32.2	314.2	0.98
8:26:49	15.4	223.0	275.0	31.6	306.6	0.98

8:26:59	15.5	223.0	269.0	31.2	300.2	0.98
8:27:09	15.4	223.0	278.0	32.2	310.2	0.98
8:27:19	15.4	222.0	281.0	32.3	313.3	0.98
8:27:29	15.4	221.0	288.0	32.7	320.7	0.98
8:27:39	15.4	220.0	287.0	32.7	319.7	0.98
8:27:49	15.4	221.0	284.0	32.3	316.3	0.98
8:27:59	15.4	221.0	282.0	32.5	314.5	0.98
8:28:09	15.3	224.0	281.0	32.6	313.6	0.98
8:28:19	15.4	223.0	276.0	32.1	308.1	0.98
8:28:29	15.4	222.0	274.0	32.0	306.0	0.98
8:28:39	15.4	222.0	269.0	31.8	300.8	0.98
8:28:49	15.4	223.0	274.0	32.2	306.2	0.98
8:28:59	15.4	227.0	270.0	31.7	301.7	0.98
8:29:09	15.4	226.0	267.0	31.4	298.4	0.98
8:29:19	15.4	224.0	270.0	31.9	301.9	0.98
8:29:29	15.4	224.0	275.0	32.1	307.1	0.98
8:29:39	15.4	225.0	278.0	32.2	310.2	0.98
8:29:49	15.4	224.0	284.0	32.9	316.9	0.98
8:29:59	15.3	221.0	294.0	33.6	327.6	0.98
8:30:09	15.3	218.0	287.0	32.7	319.7	0.98
8:30:19	15.3	222.0	278.0	32.3	310.3	0.98
8:30:29	15.4	222.0	276.0	32.1	308.1	0.98
8:30:39	15.4	222.0	279.0	32.3	311.3	0.98
8:30:49	15.3	222.0	287.0	33.0	320.0	0.98
8:30:59	15.3	222.0	288.0	32.6	320.6	0.98
8:31:09	15.3	219.0	288.0	32.9	320.9	0.98
8:31:19	15.4	221.0	288.0	32.7	320.7	0.98
8:31:29	15.4	223.0	280.0	32.5	312.5	0.98
8:31:39	15.4	224.0	279.0	32.2	311.2	0.98
8:31:49	15.4	223.0	284.0	32.7	316.7	0.98
8:31:59	15.4	222.0	292.0	33.4	325.4	0.98
8:32:09	15.4	222.0	295.0	33.8	328.8	0.98
8:32:19	15.3	220.0	305.0	34.5	339.5	0.98
8:32:29	15.3	219.0	311.0	34.7	345.7	0.98
8:32:39	15.3	215.0	303.0	34.0	337.0	0.98
8:32:49	15.3	215.0	301.0	34.1	335.1	0.98
8:32:59	15.3	218.0	310.0	34.8	344.8	0.98
8:33:09	15.3	218.0	308.0	34.4	342.4	0.98
8:33:19	15.3	216.0	313.0	35.0	348.0	0.98
8:33:29	15.4	214.0	311.0	34.5	345.5	0.98
8:33:39	15.4	218.0	304.0	34.1	338.1	0.98
8:33:49	15.4	217.0	304.0	34.0	338.0	0.98
8:33:59	15.3	214.0	302.0	33.9	335.9	0.98
8:34:09	15.4	213.0	307.0	34.4	341.4	0.98
8:34:19	15.3	215.0	307.0	34.2	341.2	0.98
8:34:29	15.4	215.0	307.0	34.5	341.5	0.98
8:34:39	15.4	215.0	307.0	34.3	341.3	0.98
8:34:49	15.4	213.0	313.0	35.3	348.3	0.98

8:34:59	15.4	214.0	307.0	34.5	341.5	0.98
8:35:09	15.4	217.0	298.0	33.7	331.7	0.98
8:35:19	15.4	218.0	289.0	33.1	322.1	0.98
8:35:29	15.4	218.0	295.0	33.6	328.6	0.98
8:35:39	15.4	218.0	297.0	33.9	330.9	0.98
8:35:49	15.4	217.0	302.0	34.0	336.0	0.98
8:35:59	15.4	216.0	305.0	34.3	339.3	0.98
8:36:09	15.3	216.0	314.0	35.0	349.0	0.98
8:36:19	15.3	216.0	313.0	34.8	347.8	0.98
8:36:29	19.4	212.0	161.0	11.2	172.2	0.98
8:36:39	20.8	107.0	68.0	3.1	71.1	0.98
8:36:49	20.9	32.0	38.0	1.2	39.2	0.98
8:36:59	21.0	12.0	25.0	0.6	25.6	0.98
8:37:09	21.0	6.0	19.0	0.1	19.1	0.98
8:37:19	21.0	4.0	15.0	0.0	15.0	0.98
8:37:29	21.0	3.0	13.0	0.0	13.0	0.98
8:37:39	21.0	2.0	11.0	0.0	11.0	0.98
8:37:49	21.0	2.0	10.0	0.0	10.0	0.98
8:37:59	21.0	1.0	9.0	0.0	9.0	0.98
8:38:09	21.0	1.0	9.0	0.0	9.0	0.98
8:38:19	21.0	1.0	8.0	0.0	8.0	0.98
8:38:29	21.0	1.0	7.0	0.0	7.0	0.98
8:38:39	21.0	1.0	7.0	0.0	7.0	0.98
8:38:49	21.0	1.0	7.0	0.0	7.0	0.98
8:38:59	21.0	1.0	6.0	0.0	6.0	0.98
8:39:09	21.0	0.0	6.0	0.0	6.0	0.98
8:39:19	21.0	0.0	6.0	0.0	6.0	0.98
8:39:29	17.0	3.0	110.0	61.0	171.0	0.97
8:39:39	15.6	113.0	189.0	75.0	264.0	0.98
8:39:49	15.5	186.0	216.0	56.8	272.8	0.98
8:39:59	15.4	202.0	234.0	47.5	281.5	0.98
8:40:09	15.5	209.0	265.0	36.8	301.8	0.98
8:40:19	15.5	216.0	299.0	37.9	336.9	0.98
8:40:29	15.5	212.0	306.0	38.1	344.1	0.98
8:40:39	15.4	210.0	312.0	38.7	350.7	0.98
8:40:49	15.4	208.0	315.0	39.0	354.0	0.98
8:40:59	15.5	209.0	319.0	39.1	358.1	0.98
8:41:09	15.5	206.0	322.0	39.4	361.4	0.98
8:41:19	15.5	207.0	310.0	37.6	347.6	0.98
8:41:29	15.5	212.0	288.0	35.9	323.9	0.98
8:41:39	15.5	215.0	289.0	36.2	325.2	0.98
8:41:49	15.5	214.0	300.0	37.0	337.0	0.98
8:41:59	15.5	212.0	305.0	37.3	342.3	0.98
8:42:09	15.5	213.0	306.0	37.0	343.0	0.98
8:42:19	15.5	214.0	298.0	35.8	333.8	0.98
8:42:29	15.5	215.0	288.0	35.0	323.0	0.98
8:42:39	15.4	213.0	293.0	35.2	328.2	0.98
8:42:49	15.5	214.0	296.0	35.3	331.3	0.98

8:42:59	15.5	215.0	290.0	34.7	324.7	0.98
8:43:09	15.5	215.0	286.0	34.2	320.2	0.98
8:43:19	15.5	216.0	291.0	34.6	325.6	0.98
8:43:29	15.5	217.0	296.0	35.0	331.0	0.98
8:43:39	15.5	216.0	289.0	34.2	323.2	0.98
8:43:49	15.5	214.0	284.0	33.8	317.8	0.98
8:43:59	15.5	216.0	280.0	33.3	313.3	0.98
8:44:09	15.5	218.0	281.0	33.6	314.6	0.98
8:44:19	15.4	218.0	289.0	34.1	323.1	0.98
8:44:29	15.5	215.0	298.0	34.7	332.7	0.98
8:44:39	15.5	211.0	289.0	33.7	322.7	0.98
8:44:49	15.5	212.0	277.0	32.9	309.9	0.98
8:44:59	15.5	214.0	269.0	32.2	301.2	0.98
8:45:09	15.5	216.0	272.0	32.6	304.6	0.98
8:45:19	15.4	217.0	282.0	33.8	315.8	0.98
8:45:29	15.4	216.0	287.0	33.6	320.6	0.98
8:45:39	15.5	217.0	282.0	33.0	315.0	0.98
8:45:49	15.5	216.0	264.0	31.8	295.8	0.98
8:45:59	15.5	221.0	254.0	31.3	285.3	0.98
8:46:09	15.6	222.0	256.0	31.3	287.3	0.98
8:46:19	15.5	224.0	261.0	32.1	293.1	0.98

CO/NO Post

Date / time	% O_2	ppm CO	ppm NO	ppm NO_2	ppm NOx	l/min Pump
12:40:30	20.9	0.0	0.0	2.1	2.1	0.00
12:40:40	20.9	0.0	0.0	2.1	2.1	0.98
12:40:50	20.9	0.0	0.0	2.0	2.0	0.98
12:41:00	7.2	11.0	0.0	517.6	517.6	0.97
12:41:10	0.8	661.0	428.0	167.3	595.3	0.98
12:41:20	0.3	1123.0	651.0	47.7	698.7	0.98
12:41:30	0.2	1236.0	715.0	21.6	736.6	0.98
12:41:40	0.2	1264.0	746.0	14.4	760.4	0.98
12:41:50	0.1	1273.0	758.0	11.6	769.6	0.98
12:42:00	0.1	1278.0	765.0	10.2	775.2	0.98
12:42:10	0.1	1280.0	769.0	9.2	778.2	0.98
12:42:20	0.1	1282.0	772.0	8.6	780.6	0.98
12:42:30	0.1	1283.0	773.0	8.1	781.1	0.98
12:42:40	0.1	1284.0	775.0	7.6	782.6	0.98
12:42:50	0.0	1285.0	776.0	7.2	783.2	0.98
12:43:00	0.1	1286.0	777.0	7.0	784.0	0.98
12:43:10	0.0	1286.0	778.0	6.7	784.7	0.98
12:43:20	0.0	1287.0	779.0	6.5	785.5	0.98
12:43:30	0.0	1287.0	780.0	6.2	786.2	0.98
12:43:40	0.0	1288.0	780.0	6.1	786.1	0.98
12:43:50	0.0	1288.0	781.0	6.0	787.0	0.98
12:44:00	0.0	1288.0	781.0	5.8	786.8	0.98
12:44:10	0.0	1289.0	782.0	5.7	787.7	0.98
12:44:20	0.0	1289.0	782.0	5.5	787.5	0.98
12:44:30	0.0	1289.0	783.0	5.5	788.5	0.98
12:44:40	0.0	1290.0	783.0	5.3	788.3	0.98
12:44:50	0.0	1290.0	784.0	5.3	789.3	0.98
12:45:00	0.0	1292.0	785.0	5.2	790.2	0.98
12:45:10	0.0	1291.0	784.0	5.2	789.2	0.98
12:45:20	0.0	1290.0	784.0	5.1	789.1	0.98
12:45:30	0.0	1290.0	784.0	5.0	789.0	0.98
12:45:40	15.3	1276.0	384.0	3.0	387.0	0.98
12:45:50	19.2	673.0	133.0	2.0	135.0	0.98
12:46:00	20.3	165.0	60.0	1.3	61.3	0.98
12:46:10	20.6	55.0	34.0	0.8	34.8	0.98
12:46:20	20.8	28.0	23.0	0.6	23.6	0.98
12:46:30	20.8	18.0	16.0	0.4	16.4	0.98

NO2 Post

Date / time	% O_2	ppm CO	ppm NO	ppm NO_2	ppm NOx	l/min Pump
12:58:07	20.9	0.0	0.0	0.6	0.6	0.00
12:58:17	20.9	0.0	0.0	1.3	1.3	0.98
12:58:27	20.9	0.0	0.0	1.1	1.1	0.98
12:58:37	6.8	4.0	22.0	79.2	101.2	0.98
12:58:47	0.8	62.0	0.0	93.1	93.1	0.99
12:58:57	0.4	21.0	0.0	97.8	97.8	0.98
12:59:07	0.1	3.0	0.0	99.3	99.3	0.98
12:59:17	0.1	0.0	0.0	99.8	99.8	0.98
12:59:27	0.1	0.0	0.0	100.0	100.0	0.98
12:59:37	0.1	0.0	0.0	100.1	100.1	0.98
12:59:47	0.1	0.0	0.0	100.3	100.3	0.98
12:59:57	0.1	0.0	0.0	100.3	100.3	0.98
13:00:07	0.1	0.0	0.0	100.4	100.4	0.98
13:00:17	0.1	0.0	0.0	100.5	100.5	0.98
13:00:27	0.1	0.0	0.0	100.4	100.4	0.98
13:00:37	0.1	0.0	0.0	100.5	100.5	0.98
13:00:47	0.1	0.0	0.0	100.5	100.5	0.98
13:00:57	0.1	0.0	0.0	100.6	100.6	0.98
13:01:07	0.1	0.0	0.0	100.6	100.6	0.98
13:01:17	0.1	0.0	0.0	100.6	100.6	0.98
13:01:27	0.1	0.0	0.0	100.6	100.6	0.98
13:01:37	0.1	0.0	0.0	100.7	100.7	0.98
13:01:47	0.1	0.0	0.0	100.7	100.7	0.99
13:01:57	0.1	0.0	0.0	100.7	100.7	0.98
13:02:07	0.1	0.0	0.0	100.8	100.8	0.98
13:02:17	0.1	0.0	0.0	100.7	100.7	0.98
13:02:27	0.1	0.0	0.0	100.8	100.8	0.98
13:02:37	0.1	0.0	0.0	100.8	100.8	0.98
13:02:47	0.1	0.0	0.0	100.8	100.8	0.98
13:02:57	0.1	0.0	0.0	100.8	100.8	0.98
13:03:07	0.1	0.0	0.0	100.8	100.8	0.98
13:03:17	15.1	0.0	2.0	27.9	29.9	0.98
13:03:27	19.1	0.0	2.0	9.6	11.6	0.98
13:03:37	20.3	0.0	1.0	3.2	4.2	0.98
13:03:47	20.7	0.0	0.0	1.7	1.7	0.98
13:03:57	20.8	0.0	0.0	1.1	1.1	0.98
13:04:07	20.8	0.0	0.0	0.8	0.8	0.98

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

SCOTT A. THOMPSON
Executive Director

KEVIN STITT
Governor

Gerald Butcher
Western Farmers Electric Cooperative
3000 S. Telephone Rd.
Moore, OK 73160

July 1, 2020

Subject: Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Mr. Butcher:

This letter is to inform you that the Oklahoma Department of Environmental Quality (DEQ) has identified the Western Farmers Hugo Power Plant as a facility subject to a four-factor reasonable progress analysis under the Regional Haze Rule. DEQ is in the development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

The states in the Central States Air Resources Agencies (CenSARA) organization, which include Oklahoma, contracted with Ramboll US Corporation (Ramboll) to produce a study examining the impact of stationary sources of NOx and SO_2 on each Class 1 area in the central region of the United States. DEQ used a method based on this study to determine which sources may have the greatest potential for contributing to visibility impairment at Oklahoma's Class 1 area: the Wichita Mountains Wilderness Area.

DEQ must develop a long-term strategy to address visibility impairment and make "reasonable" progress toward a goal of no anthropogenic visibility impairment by 2064. The Regional Haze Rule provides four factors (40 CFR §51.308(f)(2)(i)) by which a state must consider potential control measures for the long-term strategy: 1) the cost of compliance; 2) the time necessary for compliance; 3) the energy and non-air quality environmental impacts of compliance; and 4) the remaining useful life of existing sources subject to this requirement.

DEQ requests that Western Farmers perform a four-factor analysis of all potential control measures for SO_2 on the following emission units:

1. HU-Unit 1

For any technically feasible control measure, the following information should be provided in detail:

I. Emission reductions achievable by implementation of the measure
    a. Baseline emission rate (lb/hr, lb/MMBTU, etc)
    b. Controlled emission rate (same form as baseline rate)
    c. Control effectiveness (percent reduction expected)
    d. Annual emission reductions expected (ton/year)

II. Time necessary to implement the measure
III. Remaining useful life
    a. Remaining useful life of the control measure, or
    b. The corresponding life of the unit may be used if an enforceable shutdown date of the emission unit is no later than 2028.
IV. Energy and non-air quality environmental impacts of the measure.
    a. Detail any cost of energy, waste disposal, regulatory requirement, etc. incurred with implementation of the control measure.
V. Cost of implementing the measure
    a. Capital costs
    b. Annual operating and maintenance costs
    c. Annualized costs

DEQ respectfully requests that your company submit a report containing the complete 4-factor analysis no later than September 1, 2020. This will allow DEQ to review and identify any potential cost-effective control measure to be incorporated into the Regional Haze state implementation plan prior to the submission deadline of July 31, 2021.

Please contact DEQ if you have any questions about the method for conducting a 4-factor analysis under the Regional Haze Rule. We encourage your questions in order to help expedite the technical review required under the Rule.

Thank you for your assistance with this matter. Please contact Cooper Garbe at 405-702-4169 or Melanie Foster at 405-702-4218 for your questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

wfec
western farmers
electric cooperative

PO Box 429 Anadarko, OK 73005 (405) 247-3351 www.wfec.com

VIA E-mail (kendal.stegmann@deq.ok.gov)

August 20, 2020

Ms. Kendal Stegmann
Director, Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

Re: Regional Haze Four-Factor Analysis; Western Farmers Electric Cooperative; Hugo Power Plant Unit 1

Dear Ms. Stegmann:

The enclosed report is provided in response to your July 1, 2020 request for a regional haze four-factor analysis for Western Farmers Electric Cooperative's Hugo Power Plant Unit 1.

If you have any questions regarding this submittal, please contact me by phone at (405) 249-5440 or by e-mail at g_butcher@wfec.com.

WESTERN FARMERS ELECTRIC COOPERATIVE

Gerald Butcher

Gerald Butcher
Environmental Health & Safety Supervisor

cc: Cooper Garbe (cooper.garbe@deq.ok.gov)
Melanie Foster (melanie.foster@deq.ok.gov)
Jeremy Jewell (jjewell@trinityconsultants.com)

REGIONAL HAZE RULE FOUR-FACTOR REASONABLE PROGRESS ANALYSIS

wfec western farmers electric cooperative

Western Farmers Electric Cooperative
Hugo Electric Generating Plant

Prepared By:

Jeremy Jewell – Principal Consultant
Jeremy Townley – Managing Consultant
Robin Hamman – Consultant

TRINITY CONSULTANTS
5801 E. 41st St.
Suite 450
Tulsa, OK 74135
(918) 622-7111

August 20, 2020

Project 203701.0016

Trinity Consultants

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1. INTRODUCTION

Trinity Consultants (Trinity) prepared this report on behalf of Western Farmers Electric Cooperative (WFEC) in response to the July 1, 2020 "Notification of request for 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program" (the July 1, 2020 request) from the Oklahoma Department of Environmental Quality (the ODEQ). Per the request, this report provides a four-factor analysis of potential control measures for sulfur dioxide (SO_2) emissions from WFEC's Hugo Electric Generating Plant (Hugo) Unit 1.

The Hugo Unit 1 electric generating unit (EGU) is a wall-fired dry-bottom boiler that burns sub-bituminous coal. It has a nominal power output rating of 446 megawatts (MW) and a heat input capacity of 4,600 million British thermal units per hour (MMBtu/hr). It is equipped with an electrostatic precipitator (ESP) for particulate matter (PM) emission control.

In this report, the following specific technical and economic information is provided for each emissions reduction option considered for Hugo Unit 1, in accordance with instructions in the request:

- Technical feasibility
- Achievable emissions reductions
- Time necessary for implementation[1]
- Remaining useful life[1]
- Energy and non-air quality environmental impacts[1]
- Costs of implementation[1]

---

[1] These are the four factors that must be included in evaluating emission reduction measures necessary to make reasonable progress determinations. *See* 40 CFR § 51.308(f)(2)(i).

2. SO_2 EMISSION REDUCTION OPTIONS

This report addresses the following three (3) SO_2 emission reduction options as potentially feasible add-on controls based on a review of the numerous regional haze analyses (both for Best Available Retrofit Technology [BART] assessments and first and second planning period reasonable progress analyses) that have been conducted throughout the U.S. and especially in EPA Region 6 and Oklahoma:

- Wet Flue Gas Desulfurization (WFGD),
- Dry Flue Gas Desulfurization (DFGD), and
- Dry Sorbent Injection (DSI).

2.1 Technical Feasibility

WFGD, DFGD, and DSI are technically feasible control options for Hugo Unit 1.

2.2 Control Effectiveness

Table 2-1 summarizes the controlled emission rates for the technically feasible SO_2 emissions reduction options. The controlled emission rates for WFGD and DFGD were taken from the EPA's March 2011 Technical Support Document for the Oklahoma Regional Haze SIP and FIP[2] (herein referred to as "the 2011 TSD"), which states at B-14: "EPA concluded that installation of DFGD could achieve a 0.06 lb/mmBtu SO2 emission limit or the installation of WFGD could achieve a 0.04 lb/mmBtu SO2 emission limit at all six BART units."[3] The controlled emission rate for DSI was taken from the October 2012 Settlement Agreement for the Public Service Company of Oklahoma (PSO) Northeastern Plant[4] (herein referred to as "the Northeastern Settlement Agreement"), which states at 10: "...install and operate a dry-sorbent injection system...PSO will achieve...a 0.40 lb/MMBtu emission rate for SO_2 on a 30-day rolling average basis."

The Northeastern Units 3 and 4 (as they existed prior to the Northeastern Settlement Agreement), at 470 MW each, are assumed for the purposes of this report to be representative of Hugo Unit 1.

Table 2-1. Control Effectiveness of SO_2 Emissions Reduction Options

SO_2 Emissions Reduction Option	Controlled Emission Rate (lb/MMBtu)
WFGD	0.04
DFGD	0.06
DSI	0.4

[2] Kordzi, Joe; Snyder, Erik; Feldman, Michael; Belk, Ellen; and Carbo-Lugo, Agustin, *Technical Support Document for the Oklahoma Regional Haze State Implementation Plan and Federal Implementation Plan*, March 2011.

[3] The "six BART units" referred to by EPA were Oklahoma Gas & Electric's (OG&E's) Muskogee Generating Station units 4 and 5, OG&E's Sooner Generating Station units 1 and 2, and Public Service of Oklahoma's (PSO's) Northeastern Generating Station units 3 and 4.

[4] Parties to the Settlement Agreement included PSO, the Oklahoma Secretary of Environment, the ODEQ, the EPA, and the Sierra Club, and it was executed on or about October 17, 2012.

2.3 Emission Reductions

A baseline period of January 1, 2018 through December 31, 2019 is proposed as reasonable representation of 2028 operations and emissions. Monthly operations and emissions for this baseline period are presented in Table 2-2.[5]

Table 2-2. Baseline Operations and SO_2 Emissions

Year-Month	Operating Time (Hours)	Heat Input (MMBtu/month)	SO_2 Emissions (ton/month)	Average of Hourly SO_2 Emission Rates (lb/MMBtu)
2018-1	677.75	2,698,420.4	795.0	0.583
2018-2	650.30	2,312,446.8	645.6	0.556
2018-3	210.60	713,646.1	183.6	0.513
2018-4	276.42	882,253.7	226.4	0.518
2018-5	535.63	1,913,496.0	448.4	0.458
2018-6	720.00	2,851,567.6	656.0	0.459
2018-7	643.41	2,512,090.6	569.0	0.444
2018-8	744.00	2,823,401.9	666.2	0.471
2018-9	268.81	898,078.4	223.1	0.478
2018-10	0	0	0	0
2018-11	107.26	255,912.1	57.2	0.451
2018-12	744.00	2,865,207.7	647.2	0.452
2019-1	193.64	627,753.3	140.8	0.396
2019-2	108.88	269,552.5	60.9	0.385
2019-3	312.57	1,099,963.4	257.7	0.458
2019-4	0	0	0	0
2019-5	138.49	406,460.8	85.0	0.375
2019-6	409.67	1,386,407.2	315.0	0.435
2019-7	133.46	319,152.0	72.7	0.407
2019-8	385.06	1,115,265.3	259.4	0.445
2019-9	446.58	1,330,211.6	320.0	0.479
2019-10	78.70	276,196.2	72.1	0.524
2019-11	95.05	245,004.7	56.5	0.412
2019-12	0	0	0	0

The average of monthly operating time during the baseline is 328.35 hours/month. This monthly value is annualized (i.e., multiplied by 12) to 3,940 hours/year, which is equivalent to a 0.45 capacity factor[6] (or capacity utilization). Correspondingly, the annualized averages of monthly heat input values and SO_2 emissions are 13,901,244 MMBtu/yr and 3,379 tons per year (tpy), respectively.

The average of month-by-month – for months during which the unit operated – average hourly SO_2 emission rates is 0.462 lb/MMBtu. Applying this emission rate to the baseline heat input gives a baseline emission rate of 3,211 tpy. This value, which is slightly (approximately five percent) less than the actual

[5] Based on EPA's Air Markets Program Data, https://ampd.epa.gov/ampd, queried on July 9, 2020.

[6] This method of calculating capacity factor, based on hours of operation only, is used for consistency with the 2011 TSD, Appendix C *Revised BART Cost-Effectiveness Analysis for Flue Gas Desulfurization at Coal-Fired Electric Generating Units in Oklahoma: Sooner Units 1 & 2 Muskogee Units 4 & 5 Northeastern Units 3 & 4* by Dr. Phyllis Fox, Ph.D., P.E.

average of total mass emissions for 2018 and 2019, is taken to be representative of 2028 emissions assuming operation during each month of the year at the 0.45 capacity factor. Moreover, this is the method with which controlled emission rates based on lb/MMBtu limits must be calculated, and it is the method used by EPA in the 2011 TSD to calculate baseline emissions.

Table 2-3 presents the baseline emission rate and the controlled emission rates and emission reduction potentials for each of the technically feasible SO_2 emissions reduction options.

Table 2-3. Baseline Emission Rates and Controlled Emission Rates for SO_2 Emissions Reduction Options

SO_2 Emissions Reduction Option	Baseline SO_2 Emission Rate (tpy)	Controlled SO_2 Emission Rate (tpy)	SO_2 Emissions Reduction (tpy)
WFGD	3,211	278	2,933
DFGD		417	2,794
DSI		2,780	431

2.4 Time Necessary for Implementation

Five (5) years, counting from the effective date of an approved determination, would be needed for implementing either the WFGD or DFGD options. This is consistent with the compliance timeframes allowed for in the 2011 TSD (at 51 - 52). 3.5 years would be needed for implementing DSI. This is consistent with the compliance timeframes in the Northeastern Settlement Agreement. Assuming an EPA approval date for the ODEQ's regional haze second planning period (2PP) SIP of December 31, 2022, anticipated implementation dates would be January 1, 2028 for WFGD or DFGD and July 1, 2026 for DSI.

2.5 Remaining Useful Life

WFEC has no plans to shut down or cease burning coal at Hugo Unit 1. Therefore, a remaining useful life (RUL) value of 30 years is assumed based on information presented for DFGD and WFGD the 2011 TSD (at Appendix C).

2.6 Energy and Non-air Quality Environmental Impacts

All the SO_2 emissions reduction options under consideration demand increased power usage, and they generate solid waste that must be managed. The FGD options also require increased freshwater usage, and the WFGD option generates large volumes of wastewater that must be managed/treated.

2.7 Costs

Table 2-4 summarizes the total annual costs (capital recovery plus annual operations and maintenance (O&M) costs) for each SO_2 emission reduction option as estimated in the subsections below and presents the associated cost effectiveness based on the emission reduction values from Table 2-3.

Table 2-4. Cost Effectiveness of SO_2 Emissions Reduction Options at Hugo

SO_2 Emissions Reduction Option	Total Annual Cost ($/year)	Cost Effectiveness ($/ton)
WFGD	24,819,997	8,462
DFGD	22,919,263	8,203
DSI	17,670,253	41,003

2.7.1 DFGD

For the purposes of this report, costs estimates for DFGD are taken from the 2011 TSD, Appendix C *Revised BART Cost-Effectiveness Analysis for Flue Gas Desulfurization at Coal-Fired Electric Generating Units in Oklahoma: Sooner Units 1 & 2 Muskogee Units 4 & 5 Northeastern Units 3 & 4* by Dr. Phyllis Fox, Ph.D., P.E. (herein referred to as the "EPA/Fox Calculations") at 34 - 38 and 57 - 58. Figure 2-1 presents images of the CAPITAL COST SUMMARY and INPUTS portions of EPA/Fox Calculations.

Figure 2-1. EPA/Fox Calculations – DFGD ("Fox" Column) (1 of 2)

APPENDIX 2
Revised Cost Effectiveness Analysis for
Flue Gas Desulfurization at
Northeastern Units 3 & 4[204]

Row		Trinity[a]	Fox	Section
10	**CAPITAL COST SUMMARY**			
11				
12	Purchased Equipment Cost (PEC)	547,080,000	249,100,000	
13	Landfill Construction	25,000,000	25,000,000	
14				
15	TOTAL CAPITAL INVESTMENT (TCI)	**572,080,000**	**274,100,000**	
16				
51	**INPUTS**			
52	DFGD Capital Cost ($/kW)	582	265	
53	Net Rating (MW)	940	940	
54	Landfill costs estimated by AEP ($)	25,000,000	25,000,000	
55	Estimated Lime Usage (ton/yr)	30,893	30,893	
56	Lime Cost ($/ton)	200	200	
57	Estimated Electricity Usage (kW/hr)	6,900	6,900	
58	Cost of Electricity ($/kW)	0.05	0.05	
59	SO2 Removal Rate	0.83	0.91	
60	Water (gal/MMBtu)		4.25	
61	Water Cost ($1.40/1000 gal)		1.40	
62	Solids Generated (lb solids/lb SO2)		5	
63	Solids Disposal Cost ($/ton)		5	
64	Baseline emissions (lb SO2/MMBtu)	0.90	0.90	
65	Annual Average Firing Rate (MMBtu/hr)	4,775	4,775	
66	Capacity Factor	0.85	0.85	
67	Capital Recovery Factor	0.1019	0.0806	
68	Interest Rate	0.08	0.07	
69	Scrubber Lifetime (yr)	20	30	
70				

(a) 5/30/08 Trinity Report, Appx. F, BART Economic Analysis for DFGD (SO2).
Modified to replace $555/kW with $582/kW, based on 1/19/10 ODEQ BART Report, Table 11.

The total capital cost (TCI) in the EPA/Fox Calculations was based on a cost ratio of $265/kilowatt (kW). This cost ratio is approximately half of the actual expected cost for a DFGD based on data compiled by the

Energy Information Administration (EIA) and based on WFEC's and Trinity's knowledge of other DFGD projects. Nevertheless, because the resulting cost effectiveness values are already clearly infeasible, additional refinement to this estimate is not pursued at this time.[7]

Using the $265/kW ratio, the TCI for Hugo Unit 1, at 446 MW, is $118,190,000. The EPA/Fox Calculations used a 2009 basis. Scaling to a 2019 basis using Chemical Engineering Plant Cost Index (CEPCI) values[8] results in a TCI for Hugo Unit 1 of $137,575,062. Again, this value severely undervalues the actual expected costs for a DFGD installation at Hugo Unit 1.

Using the EPA/Fox Calculations' capital recovery factor (CRF) of 0.0806 – based on 30 years at 7 % interest and which has been used dozens if not hundreds of times by EPA in previous determinations – the estimated annualized capital cost is $11,086,679 (2019 basis). Table 2-5 summarizes the annual capital cost estimation.

Table 2-5. Estimation of Annual Capital Cost at Hugo

Variable	Value	Notes
Cost Ratio from EPA/Fox Calculations	$265/kW	2009 basis
Hugo Unit 1 Capacity	446 MW or 446,000 kW	None
Estimated TCI for Hugo Unit 1	$118,190,000	2009 basis
	$137,575,062	2019 basis
CRF	0.0806	30 years, 7 %
Annual Capital Cost at Hugo Unit 1	$11,086,679	2019 basis

Annual operations and maintenance (O&M) costs for Hugo Unit 1 were also taken from the EPA/Fox Calculations. Figure 2-2 presents an image of the ANNUAL COST SUMMARY portion of EPA/Fox Calculations.

7 WFEC reserves the right and the time to complete a site-specific control cost study if it is determined that any controls are to be installed at Hugo Unit 1.

8 From https://www.chemengonline.com/pci-home (subscription required) as of July 24, 2020:

Year:	2009	2016	2019
CEPCI:	521.9	541.7	607.5

Figure 2-2. EPA/Fox Calculations – DFGD ("Fox" Column) (2 of 2)

17			
18	ANNUAL COST SUMMARY		
19			
20	DIRECT OPERATING COST		
21	Lime Injection	6,178,600	6,178,600
22	Operating Electricity	3,022,200	3,022,200
23	Water		423,100
24	FGD Waste Disposal		727,981
25	Bag & Cage Replacement		572,000
26	Fixed O&M		4,116,350
27			
28	TOTAL DIRECT COST (DC)	**9,200,800**	**15,040,232**
29			
30	INDIRECT OPERATING COSTS		
31	Administrative Charges (2% TCI)	11,441,600	5,482,000
32	Insurance (1% TCI)	5,720,800	28,781
33	Property Taxes (1% TCI)	5,720,800	2,329,850
34	Capital Recovery (CRFxTCI)	58,267,612	22,088,733
35			
36	TOTAL INDIRECT COST (IC)	**81,150,812**	**29,929,364**
37			
38	TOTAL ANNUALIZED COST (DC+IC)	90,351,612	44,969,595
39			

Table 2-6 summaries how the EPA/Fox Calculations for Northeastern were extrapolated for Hugo.

Table 2-6. Annual O&M Costs for DFGD at Hugo

O&M Cost Variable	EPA/Fox Calculations for Northeastern		Hugo Unit 1	Notes Regarding Differences
	Both Units	One Unit		
Fixed O&M	4,116,350	2,058,175	2,395,749	Escalated from 2009 to 2019
Indirect O&M	5,482,000	2,741,000	2,751,501	Escalation of TCI
Lime	6,178,600	3,089,300	3,089,300	None
Water	423,100	211,550	165,428	Hugo Unit 1 heat input (3,528 MMBtu/hr) and capacity factor (0.45)
FGD Waste Disposal	727,981	363,991	69,855	Hugo Unit 1 emission reduction from Table 2-3
Bag & Cage Replacement	572,000	286,000	665,817	Escalated from 2009 to 2019
Auxiliary Power	3,022,200	1,511,100	1,511,100	None
Property Taxes	2,329,850	1,164,925	1,169,388	Escalation of TCI
Insurance	28,781	14,390	14,445	Escalation of TCI
Total O&M Costs	22,880,862	11,440,431	11,832,584	None

Therefore, the estimated total annual costs (annualized capital + total O&M) for the DFGD option for Hugo Unit 1 is $22,919,263/yr.

2.7.2 WFGD

Based on information in the EPA/Fox Calculations, at 47 – 48, all costs for WFGD are estimated at 9 percent greater than the DFGD costs. Therefore, the estimated total annual costs for the WFGD option for Hugo Unit 1 is $24,819,997/yr.

2.7.3 DSI

The total capital cost for DSI are taken from the ODEQ's June 20, 2013 SIP revision, Appendix II, Item 03 *Supplemental BART Determination Information, American Electric Power – Northeastern Power Plant* (herein referred to as the "EPA-Approved DSI Calculations") which was approved by EPA on March 7, 2014.[9] Figure 2-3 presents an image of the CAPITAL COSTS portion of the EPA-Approved DSI Calculations.

Figure 2-3. EPA-Approved DSI Calculations ("Cost Estimate Based on EPA's..." Column) (1 of 2)

Cost Type	Default Estimate Methodology from EPA's Control Cost Manual [a]	Cost Estimate Based on EPA's Control Cost Manual (One Unit)	*FOR COMPARISON* Cost Estimate Based on Engineering Study (2016$) (One Unit)
CAPITAL COSTS			
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment Cost (EC), including instrumentation	--	$49,883,940	$49,883,940
Sales Tax	3% of EC [b]	$0 [h]	$0 [h]
Freight	5% of EC [b]	$0 [h]	$0 [h]
Purchased Equipment Costs (PEC)		*$49,883,940*	*$49,883,940*
Direct Installation Costs			
Foundations and supports	6% of PEC [b]	$2,993,036	$11,433,582
Handling and erection	40% of PEC [b]	$19,953,576	$12,705,233
Electrical	1% of PEC [b]	$498,839	$8,181,380
Piping	5% of PEC [b]	$2,494,197	$9,536,419
Insulation for ductwork	3% of PEC [b]	$1,496,518	$3,181,956
Painting	1% of PEC [b]	$498,839	$1,232,111
Direct Installation Costs (DIC)		*$27,935,006*	*$46,270,680*
Other Direct Costs			
Site Preparation Costs (SPC)	--	$10,849,305	$10,849,305
Buildings Costs (BC)	--	$5,204,446	$5,204,446
Landfill Construction	--	$0 [i]	$0 [i]
Other Direct Costs (ODC)		*$16,053,751*	*$16,053,751*
Total Direct Capital Costs (DC = PEC + DIC + ODC)		*$93,872,698*	*$112,208,371*
Indirect Capital Costs			
Engineering	10% of PEC [b]	$4,988,394	$24,202,634
Construction and field expenses	10% of PEC [b]	$4,988,394	$8,977,897
Contractor fees	10% of PEC [b]	$4,988,394	$280,800
Start-up	1% of PEC [b]	$498,839	$3,562,477
Performance test	1% of PEC [b]	$498,839	$514,443
Contingencies	3% of PEC [b]	$1,496,518	$13,676,183
Total Indirect Capital Costs (IC)		*$17,459,379*	*$51,214,433*
TOTAL CAPITAL INVESTMENT (TCI = DC + IC)		*$111,332,077*	*$163,422,804*

[9] 79 FR 12954-12957.

The TCI included a total direct capital cost value of $93,872,698 (2016 basis), which escalates to $105,275,362 (2019 basis), and an indirect capital cost value of $17,459,379 (not escalated), for an estimated TCI of $122,734,742 (2019 basis) for Hugo Unit 1.

Using the same CRF as for DFGD, 0.0806, the estimated annualized capital cost for the DSI option for Hugo Unit 1 is $9,890,751.

Annual O&M costs for Hugo Unit 1 were also taken from the EPA-Approved DSI Calculations. Figure 2-4 presents an image of the OPERATING COSTS portion of the EPA-Approved DSI Calculations.

Figure 2-4. EPA-Approved DSI Calculations ("Cost Estimate Based on EPA's..." Column) (2 of 2)

OPERATING COSTS			
Direct Operating Costs			
Fixed O&M Costs (Labor and Materials)			
Operating Labor ($14.24/hour) [d]	8 hr/shift, 3 shifts/day [c]	$124,742	$997,939
Operating Labor Supervision	15% of op. labor [c]	$18,711	$0
Maintenance Labor ($14.24/hour) [d]	2 hr/shift, 3 shifts/day [c]	$31,186	$0
Maintenance materials	100% of maint. labor [c]	$31,186	$407,800
Fixed O&M Costs		***$205,825***	***$1,405,739***
Other Direct Operating Costs (e.g., utilities)			
Sorbent (22,776 tons/yr, $230/ton, Avg. CU) [e,f]	--	$3,500,257	$3,500,257
Electricity (5,696 kW/yr, $0.05588/kW, Avg. CU) [f]	--	$1,862,726	$1,862,726
Water (zero cost)	--	$0	$0
Waste Disposal (zero cost)	--	$0	$0
Bag and Cage Replacement (9,424 bags/cages;... ...$114 & 3-yr cycle for bag; $29 & 6-yr cycle for cages)	--	$403,661	$403,661
Other Direct Operating Costs		***$5,766,644***	***$5,766,644***
Total Direct Operating Costs (DOC)		***$5,972,469***	***$7,172,383***
Indirect Operating Costs			
Overhead	60% of O&M [c]	$0 [i]	$0 [i]
Property tax	1% of TCI [c]	$946,323 [j]	$1,389,094 [j]
Insurance	1% of TCI [c]	$11,690 [j]	$17,159 [j]
Administration	2% of TCI [c]	$2,226,642	$3,268,456
Capital Recovery (10 years, 7 %) (CRF_{10})	0.1424 of TCI	$15,851,183	$23,267,731
Capital Recovery (30 years, 7 %) (CRF_{30})	0.0806 of TCI	--	--
Total Indirect Operating Costs (IOC)		***$19,035,837***	***$27,942,440***
TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)		***$25,008,306***	***$35,114,823***

Table 2-7 summaries how the EPA-Approved DSI Calculations for the Northeastern units were extrapolated for Hugo.

Table 2-7. Annual O&M Costs for DSI at Hugo

O&M Cost Variable	Northeastern (One Unit)	Hugo Unit 1	Notes Regarding Differences
Operating Labor	$124,742	$124,742	None
Op. Labor Supervision	$18,711	$18,711	None
Maintenance Labor	$31,186	$31,186	None
Maintenance Materials	$31,186	$31,186	None
Sorbent	$3,500,257	$2,356,240	Hugo Unit 1 capacity factor (0.45)
Electricity	$1,862,726	$1,253,916	Hugo Unit 1 capacity factor (0.45)
Bag & Cage Replacement	$403,661	$452,694	Escalated from 2016 to 2019
Property Tax	$946,323	$1,043,245	Escalation of TCI
Insurance	$11,690	$12,887	Escalation of TCI
Administration	$2,226,642	$2,454,695	Escalation of TCI
Total O&M Costs	9,157,124	$7,779,502	None

Therefore, the estimated total annual costs (annualized capital + total O&M) for the DFGD option for Hugo Unit 1 is $17,670,253/yr.

3. CONCLUSIONS

WFEC and Trinity have developed this four-factor analysis based on the best information available during the timeline allowed by the ODEQ's July 1, 2020 request and in accordance with ODEQ and EPA guidance and EPA-approved/used methods. The analysis results, especially for the fourth factor, which shows estimated costs of compliance of greater than $8,000/ton for all options, demonstrates that no SO_2 emissions controls are feasible for Hugo Unit 1. WFEC requests the ODEQ's concurrence with this conclusion.

SCOTT A. THOMPSON
Executive Director

OKLAHOMA DEPARTMENT OF ENVIRONMENTAL QUALITY

KEVIN STITT
Governor

January 31, 2022

John McCreight
Western Farmers Electric Cooperative
3000 S. Telephone Rd.
Moore, OK 73160

Subject: Additional clarifications on Western Farmers' 4-factor analysis on control scenarios under the Clean Air Act Regional Haze Program

Dear Mr. McCreight:

In a letter dated July 1, 2020, the Oklahoma Department of Environmental Quality (DEQ) notified Western Farmers Electric Cooperative that the Arkansas Department of Energy and Environment had requested an analysis of the Hugo Power Plant, located in Choctaw County, Oklahoma, as subject to a four-factor reasonable progress analysis under the Regional Haze Rule as part of DEQ's development process for the state implementation plan covering the second planning period (Round 2) of 2021 – 2028.

On August 20, 2020, Western Farmers submitted its four-factor analysis to DEQ. Western Farmers included in its response that there were no cost-effective sulfur dioxide (SO_2) control measures available for Unit 1. DEQ included these conclusions in its draft Regional Haze SIP for Planning Period 2 that was shared with the Federal Land Managers (FLM) and the U.S. Environmental Protection Agency (EPA) for their review and comment. DEQ requests that Western Farmers review its four-factor analysis for potential SO_2 control measures for Unit 1 and respond to the following questions, which are based on EPA and FLM review of Oklahoma's draft SIP. We understand that some of the requested data/analysis may be gleaned or explained from DEQ's permitting and compliance files, and/or Western Farmers' submittal. However, your response will allow Western Farmers to document the information that best explains and supports the conclusions of your four-factor analysis. DEQ intends to continue its analysis in parallel.

1. The federal reviewers stated that the use of a 7% interest rate in the cost analysis is not appropriate. 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.[1] 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.

2. The cost estimates for dry flue gas desulfurization (DFGD) and wet flue gas desulfurization (WFGD) were based on cost estimates from the Technical Support Document for EPA's 2011 Oklahoma SO_2 best available retrofit technology (BART) federal implementation plan (FIP).

[1] 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.

The company escalated those cost numbers, which were based on 2009 dollars, to 2019 dollars using chemical engineering plant cost index (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. EPA recommends that the cost analysis be updated accordingly.

3. Please provide a more detailed assessment of the facility to justify the removal efficiencies used in the analysis (87% for DFGD and 91% for WFGD) since higher removal efficiencies are possible.[2]

DEQ respectfully requests that Western Farmers provide responses to these questions no later than February 28, 2022. Thank you for your assistance with this matter. Please contact Melanie Foster at 405-702-4218 for any questions or clarification.

Sincerely,

Kendal Stegmann
Director, Air Quality Division

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[2] Please see "SO_2 and Acid Gas Controls"
https://www.epa.gov/sites/default/files/2021-05/documents/wet_and_dry_scrubbers_section_5_chapter_1_control_cost_manual_7th_edition.pdf

wfec western farmers electric cooperative PO Box 429 Anadarko, OK 73005 (405) 247-3351 www.wfec.com

VIA E-MAIL

February 24, 2022

Kendal Stegmann
Director, Air Quality Division
Oklahoma Department of Environmental Quality
707 N. Robinson
P.O. Box 1677
Oklahoma City, OK 73101-1677

RE: Reply to DEQ's January 31, 2022 request for additional clarifications regarding WFEC's August 24, 2020 Regional Haze 4-four analysis for Hugo Electric Generating Plant Unit 1

Dear Ms. Stegmann:

Western Farmers Electric Cooperative (WFEC) understands the DEQ's letter as requesting additional clarifications on three items, summarized as follows: (1) capital recovery interest rate used in the control cost calculations, (2) cost estimates for wet flue gas desulfurization (WFGD) and dry flue gas desulfurization (DFGD), and (3) anticipated sulfur dioxide (SO_2) removal efficiencies for WFGD and DFGD. Each of these items is addressed below.

1. DEQ's letter provides, "[t]he federal reviewers stated that use of a 7% interest rate in the cost analysis is not appropriate." WFEC understands this to be a fundamental shift in EPA policy. A typical 7% interest rate has been relied upon commonly for control technology analyses for a long time, including during the Regional Haze first planning period when the bank prime rate was the same as it is now (3.25%), i.e., from December 2008 to December 2015. WFEC understands that it is also used by the Office of Management and Budget (OMB) to estimate the cost of environmental regulations.

   DEQ's letter goes on to suggest that the bank prime rate should be used as a default, absent a company-specific interest rate. This is incongruous with EPA's Control Cost Manual (CCM), which mentions the bank prime rate as *one of several indicators* of the cost of borrowing. Nevertheless, even if the suggested 3.25% interest rate (resulting in a capital recovery factor of 0.0527) were applied to the capital costs presented by WFEC in its August 24, 2020 report, the overall conclusion – that no control options are reasonable – remains unchanged. Using the 3.25% interest rate, the total annual cost for DFGD would be $19,082,790/yr, the total annual cost for WFGD would be $20,800,241/yr, and the cost effectiveness values would be $6,830/ton and $7,091/ton, respectively.

2. DEQ's letter states, "EPA's Control Costs Manual recommends not to escalate costs over more than 5 years." This misstates EPA's CCM. The CCM includes only a single "rule-of-thumb" parenthetical statement on page 1-

26 (Section 1.3.2.2 *Hood Sizing Procedure*) following a statement about labor cost data from 1977 (25 years earlier than the CCM publication date): "(The rule-of-thumb time limit for escalating costs is five years.)." This rule-of-thumb is not substantiated anywhere else in the 752-page CCM. WFEC views this out-of-context, rule-of-thumb statement as no repudiation of its four-factor analysis escalations from 2009 to 2019. Moreover, WFEC has compared its estimated control costs to several recent control cost estimates for other coal-fired utility boilers in Louisiana and Arkansas (see table below), and it has determined that WFEC's estimates are conservatively low, even after scaling[1] the costs based on the power output ratings (in megawatts [MW]). For these reasons, no changes are proposed to WFEC's August 24, 2020 control cost estimates.

Table 1. Comparison of Four-Factor Analysis Cost Information

Coal-Fired Utility Boiler	Estimated Total Capital Cost for DFGD ($MM)	Estimated Operations & Maintenance Cost for DFGD ($MM/yr)	Estimated Total Capital Cost for WFGD ($MM)	Estimated Operations & Maintenance Cost for WFGD ($MM/yr)
WFEC - Hugo Unit 1 (446 MW)	137.6	11.8	122.7	7.8
Cleco - Big Cajun II Unit 3 (575 MW)[2]	263.7	25.3	335.5	26.2
Entergy - Roy S. Nelson Unit 6 (556 MW)[3]	430.8	17.3	473.8	14.0
Entergy - Independence Steam Electric Station Unit 1 (839 MW)[4]	377.7	9.4	401.8	36.6
Entergy - Independence Steam Electric Station Unit 2 (839 MW)[5]	377.7	9.4	401.8	36.6

3. DEQ's letter asks for a more detailed assessment of the Hugo facility to justify the removal efficiencies used for DFGD and WFGD. First, WFEC did not present removal efficiencies in the four-factor analysis. Rather, WFEC presented emission rates, in pounds per million British thermal units (lb/MMBtu) because this is the metric by which DFGD and WFGD are typically measured. Moreover, the emission rates used by WFEC, 0.06 lb/MMBtu for DFGD and 0.04 lb/MMBtu for WFGD, are equal to both the emission rates adopted by EPA in the previous Oklahoma Regional Haze SIP/FIP (as documented in WFEC's August 24, 2020 report) and the referenced CCM (see footnote 2 of DEQ's letter). Additionally, these emission rates are equal to the emission rates used in the coal-fired utility boiler control analyses listed in the table above. If additional information regarding the Hugo facility is needed, then WFEC respectfully requests a detailed list of the requested information.

[1] Example scaling using the six-tenths rule (based on the WFGD total capital cost for Roy S. Nelson Unit 6): $473.8MM * (446 MW / 556 MW) ^ 0.6 = $415.1MM, which is more than three times the cost value presented for Hugo Unit 1.

[2] Cleco Corporate Holdings LLC, Response to March 18, 2020 Information Collection Request to Louisiana Generating, LLC-Big Cajun II Power Plant Regarding Regional Haze Four-Factor Analysis (July 30, 2020) (https://edms.deq.louisiana.gov/app/doc/view?doc=12280837).

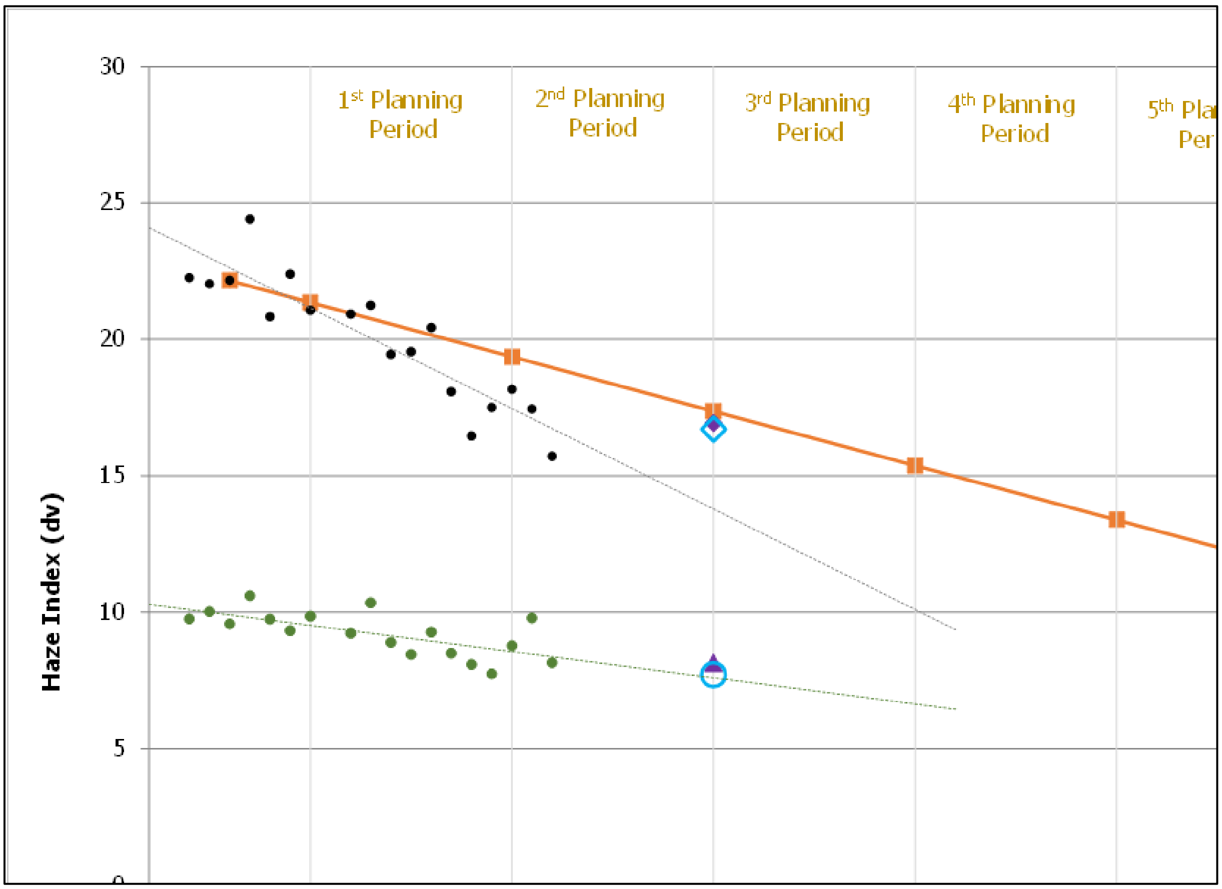
[3] Entergy Services, LLC, Entergy Louisiana, LLC. Roy S. Nelson Electric Generating Plant Regional Haze - Four-Factor Analysis Information Collection Request Response (July 30, 2020). (https://edms.deq.louisiana.gov/app/doc/view?doc=12280842)

[4] Entergy Services LLC, Response to January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request (April 7, 2020) (https://www.adeq.state.ar.us/air/planning/sip/pdfs/regional-haze/entergy_icr_response_report.pdf).

[5] Id.

In addition to the three issues addressed above, WFEC would like to note that Oklahoma's single Class I area, Wichita Mountains, has experienced significant and steady improvement in visibility conditions since the baseline period of the regional haze program. Observations of visibility conditions in the Wichita Mountains are plotted on the following figure along with linear extrapolations of the data, EPA's proposed glidepath, and the modeled predictions for 2028 (from both EPA and the Texas Commission on Environmental Quality, TCEQ), which show that visibility conditions are expected to continue to be ahead of schedule at the end of this second planning period. Based on this information, it would be unreasonable to require any emissions reductions, at any cost, during this planning period.

Figure 1. Wichita Mountains Visibility Conditions – Observation Data and Modeled Predictions – Compared to the Glidepath



Thank you for the opportunity to provide this information. WFEC looks forward to working with the DEQ in its revisions to the regional haze SIP. Please contact me at (405) 585-7250 if you have any questions or need any additional information.

Sincerely

John P. McCreight

John McCreight, EHS Supervisor
Western Farmers Electric Cooperative

cc: Jeremy Jewell, Trinity Consultants